ELECTRICITY DIVERSIFICATION, DECENTRALIZATION, AND DECARBONIZATION: THE ROLE OF U.S. STATE ENERGY POLICY

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ABSTRACT

SANYA CARLEY: Electricity diversification, decentralization, and decarbonization: The role of U.S. state energy policy
(Under the direction of Richard N. L. Andrews)

In response to mounting concerns about climate change and an over-dependence on fossil fuels, U.S. state governments have assumed leadership roles in energy policy. State leaders across the country have constructed policies that target electricity sector operations, and aim to increase the percentage of renewable electricity generation, increase the use of distributed generation, and decrease carbon footprints. The policy literature, however, lacks compelling empirical evidence that state initiatives toward these ends are effective.

This research seeks to contribute empirical insights that can help fill this void in the literature, and advance policy knowledge about the efficacy of these instruments. This three-essay dissertation focuses on the assessment of state energy policy instruments aimed at the diversification, decentralization, and decarbonization of the U.S. electricity sector.

The first essay considers the effects of state efforts to diversify electricity portfolios via increases in renewable energy. This essay asks: are state-level renewable portfolio standards (RPS) effective at increasing renewable energy deployment, as well as the share of renewable energy out of the total generation mix? Empirical results demonstrate that RPS policies so far are effectively encouraging total renewable energy deployment, but not the percentage of renewable energy generation.

The second essay considers state policy efforts to decentralize the U.S. electricity sector via instruments that remove barriers to distributed generation (DG) deployment. The primary question this essay addresses is whether the removal of legal barriers acts as a primary motivating factor for DG deployment. Empirical results reveal that net metering policies are positively associated with DG deployment; interconnection standards significantly increase the likelihood that end-users will adopt DG capacity; and utility DG adoption is related to standard market forces.

The third essay asks: what are the potential effects of state energy policy portfolios on carbon emissions within the U.S. electricity sector? The results from an electricity modeling scenario analysis reveal that state policy portfolios have modest to minimal carbon mitigation effects in the long run if surrounding states do not adopt similar portfolios as well. The effectiveness of state-level policy portfolios can increase significantly if surrounding states adopt similar portfolios, or with the introduction of a national carbon price.

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This research would not have been possible without contributions from many individuals and organizations, only a few of which I have the space to acknowledge below. Completing a dissertation is a special personal accomplishment, indeed, but it is the act of recognizing those that have inspired, financed, and encouraged me that provides me with the greatest sense of satisfaction.

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It would not have been possible to complete this dissertation without the magnanimous support of my dissertation committee. I would like to thank Gary Henry for his guidance on methods and for always looking out for me; Tim Johnson for his instruction on energy modeling and for the great attentiveness and care that he devoted to my papers; Richard Newell for his insightful feedback and generous provision of his time; and Doug Crawford-Brown for years of assistance and support, despite the distance. With a committee comprised of great physical height and that has achieved great heights of scholarship, it is apt to acknowledge that, in the spirit of Bernard of Chartres and later Isaac Newton, if I have seen anything it is by standing on the shoulders of giants. I was profoundly fortunate to be advised by such a generous and exceptional committee; I look forward to returning the many, many favors some day.

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I still remember the day in grade school when our teacher asked us to write an essay on a hero that has directly influenced our lives. I recall scoffing at the assignment and incredulously asking myself, “What makes a hero, anyway?” (in retrospect, perhaps I was destined for academia). Although I had little to draw on at the time—I, along with the majority of my class, went with the trite but true subject matter: Mom—I have had the distinct pleasure of gaining numerous “heros,” or life mentors, through the years. Each mentor has provided me with a unique perspective on life, a belief in me that was nearly palpable, and unconditional encouragement to pursue any path that I could dream up. In the order of time that our paths crossed, I would like to express my extreme appreciation to Liz Krieg, Carr Everbach, Nazmul Chaudhury, and Wendy Grapentine.

Although there are many other individuals I could name that have made this accomplishment possible, I owe my deepest gratitude to my family. From my earliest age my parents, Michal Ann Carley and Frank Lewis, encouraged me to belt out big belly laughs and to always speak my mind, even before I knew how to substantiate my claims. More than believing in myself, they taught me to foster and exhibit compassion for others, and proceed through life with awareness—awareness for the natural world, for the minutia of everyday happenings, and for the energy and emotion of others.

I am profoundly appreciative of the years of support from Claire Gargalli and David Carley. David, my Grandpa, was the one person in life that I never wanted to disappoint. Through the years, I tirelessly tried to prove to him that I could throw a baseball like a boy and argue like a lawyer. It was during the last years of his life, that I finally realized that that wry—and often devious—smile of his meant that he was proud

of me; and I did not have to prove myself to make it so. Yet I still wish that I could share this accomplishment with him now.

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LIST OF ABBREVIATIONS

ADAGE	Applied Dynamic Analysis of the Global Economy
CCS	Carbon capture and storage
CHP	Combined heat and power
DAG	Directed acyclic graph
DSM	Demand side management
DSIRE	Database for State Incentives for Renewables and Efficiency
DG	Distributed generation
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
FEVD	Fixed effect vector decomposition
GHG	Greenhouse gas
GSP	Gross state product
LCV	League of Conservation Voters
NEMS	National Energy Modeling System
NM	Net metering
NERC	North American Electric Reliability Corporation
OLS	Ordinary Least Squares
RE	Renewable energy
REC	Renewable energy credit
RPS	Renewable portfolio standard
WECC	Western Electric Coordinating Council

CHAPTER 1

INTRODUCTION

The U.S. electricity sector is a major contributor to global climate change. The sector accounts for roughly 40 percent of total U.S. carbon dioxide emissions and 30 percent of all U.S. greenhouse gas emissions. The majority of these emissions come from large, centralized fossil fuel plants, which dominate the electricity sector and generate the bulk of our electric power. Alternative sources of electricity, such as renewable energy, make up only a small fraction of the total electricity mix. As the global understanding of climate change evolves, and interacts with other significant energy concerns—including but not limited to over-dependence on foreign fossil fuels, energy security, air and water pollution, and fuel price volatility—the need for a change in electricity generation and operations grows.

In response to the proliferation of these concerns over the past decade, and a growing consensus that the combination of these issues may require public policy solutions, state governments across the country have assumed leadership roles in the energy policy arena. In the absence of a comprehensive federal congressional initiative to address climate change, states have introduced, on a piecemeal basis, a surprising number of new policy instruments in attempt to decrease their carbon footprints, increase the percentage of renewable energy in their generation portfolios, and increase the amount of generation that comes from local, dispersed energy resources. In fact, these three policy objectives—decarbonization, diversification, and decentralization—have broadly defined and guided state energy and climate policy efforts to date.

Standard policy instruments, such as a grant or tax incentive, are not well suited to deal with problems as substantial and difficult to measure as global warming or over-dependence on fossil fuels. Nor are they suited to deal with an industry in which private and public firms share a market, regulated and deregulated systems share power lines, utility service territories are not confined by state borders, utility development decisions last decades, and price signals cannot be observed when the consumer purchases electricity. In light of these challenges, state governments have exhibited immense creativity over the past decade and a half in designing new and tailoring existing instruments to meet current circumstances.

Some states have already experienced notable success with the implementation of these instruments. Texas, for instance, has increased wind energy deployment significantly as a result of its renewable portfolio standard, which requires that a certain percentage of Texas' overall electricity generation come from renewable energy sources. Aside from Texas, and a few other scattered success stories, however, the policy literature lacks compelling evidence of the effectiveness of these instruments to date on shaping electricity generation changes. Furthermore, there are few empirical studies that test whether state energy policy instruments are effectively achieving their stated objectives. The majority of literature on the subject is either qualitative in research design, or focuses exclusively on national-level policies and effects. Empirical state level electricity policy analyses are largely absent from the literature. This void in the literature is due to the difficulty of measuring state level energy policy effects, attributable to the complexity and variation of the instruments across states, the patchy nature of their state-by-state adoption, and the long time frame over which policy results become measurable. This lack of empirical evidence limits the lessons that are available to other states regarding how these instruments work, which are effective in what circumstances, and which work well together. This type of information will become increasingly important as the federal government's discussions of energy and climate policy evolve, and as steps are taken on the national level to address the policy concerns listed above.

This three-essay dissertation seeks to contribute empirical insights that can help fill this void in the literature, and concurrently advance policy knowledge about the effects of state level energy policy instruments within the electricity sector. Specifically, this dissertation focuses on policies adopted by state governments throughout what I phrase as the "era of state energy policy innovation" to try to *diversify*, *decentralize,* and *decarbonize* the U.S. electricity sector. All three essays contain empirical analyses focused on the effects and effectiveness of current U.S. policy instruments that uphold these policy objectives. The research approach of each essay is tailored to its guiding research question and the inherent limitations of the data. Particular attention is given to the selection and application of each empirical model in effort to maximize the statistical and external validity of the combined analysis.

Essay 1. Diversification: The Case of Renewable Energy and Portfolio Standards

The first essay considers recent state efforts to diversify their electricity portfolios via renewable energy development. This essay primarily focuses on the renewable portfolio standard (RPS), which, to date, is one of the most prevalent and innovative renewable state level energy policy instruments. RPS policies aim to increase the percentage of renewable energy generation in the total generation mix over time.

This essay evaluates the effectiveness of these programs with an empirical assessment of the relationship between state RPS policies and the percentage of subsequent renewable energy electricity generation. This essay addresses two guiding research questions. First, are RPS policies effective at increasing states' total renewable energy generation? Second, are RPS policies effective at increasing the percentage of renewable energy generation out of the total generation mix, as they are intended to do?

In this vein of inquiry, I compile state level data between 1998 and 2007 from a variety of sources, including the Energy Information Administration, the Database for State Incentives for Renewable Energy, and the U.S. Census Bureau, among other sources. After a thorough consideration of the causal mechanism between RPS and renewable energy deployment, and the methodological conditions that maximize one's ability to appropriately estimate this mechanism, I apply both a fixed effects model and a variant of a standard fixed effects model that is new to the empirical literature, referred to as a fixed effects vector decomposition model.

Model results demonstrate that RPS policies are, to date, effectively encouraging *total* renewable energy deployment, but not the *percentage* of renewable energy generation in states' electricity portfolios. These findings reveal a shortcoming of RPS policies, potentially attributable to weak, poorly enforced, or slowly implemented penalty mechanisms, RPS benchmarks that are too ambitious, or a lack of integration between supply-side and demand-side measures.

In response to these findings, this essay asks, should one care if states are falling short of their renewable energy percentage goals if they are still increasing total renewable energy generation? Some would argue that we ought not to care. RPS policies are effectively encouraging renewable energy investment and opening electricity markets to development, thereby making renewable technologies more competitive with traditional systems. Others would argue differently. RPS policies are one of the strongest and only mechanisms that the U.S. has yet to adopt to address climate change. Twenty-seven states have crafted regulation in promotion of renewable generation and, within the next several years, additional states and the federal government will consider adopting their own version of an RPS. Yet if the ultimate intent of renewable energy legislation is to reduce emissions associated with climate change, then increasing renewable generation without enforcing a relative decrease in the proportion of fossil fuel generation will not achieve these objectives. Increases in fossil fuel generation will continue to increase carbon emission levels in the atmosphere. One may conclude, therefore, that RPS policies may ultimately be more effective if implemented in conjunction with programs that target energy demand with efficiency and conservation measures or, alternatively, with carbon cap-and-trade mechanisms.

Essay 2. Decentralization: The Case of Distributed Generation and Metering Standards

While centralized electricity and large-scale transmission and distribution networks still dominate the U.S. electric industry, this model of electricity generation has been challenged in recent decades. Critics of large-scale electricity operations question their costs, security vulnerabilities, environmental impacts, and waste in generation and transmission, and advocate instead for a more decentralized industry composed of a greater number of smaller-scale and more localized generating facilities. In view of these concerns, some industry leaders have begun to modify the scale of their electricity operations. Federal and state policymakers have concurrently enacted legislation that specifically focuses on size and scale of power generation.

The second essay of this dissertation considers policy efforts to decentralize the U.S. electricity sector, specifically via instruments that remove the barriers to distributed generation (DG) deployment.[1] The primary research questions of this essay are, what are the motivating factors behind the trend toward a more decentralized electricity industry, and how great of a role do public policy incentives play in DG adoption and deployment?

This essay primarily focuses on two policy instruments: net metering policies and interconnection standards. Net metering policies allow end-users to "hook" their DG units to the electricity grid, and buy (or "sell") electricity from (to) the grid when the DG capacity is short (in excess) of the customers' electricity needs. Interconnection standards are state-implemented standards that explicitly outline the protocols that a utility must adhere to when hooking DG units up to the grid.

I begin this essay with a review of the associated literature, and a synthesis of the varied definitions and classifications of DG systems that populate the literature. I additionally discuss how the link between DG deployment and decentralized energy policies remains tenuous in the literature. In effort to classify this link, I compile a database from a variety of public sources and aggregate the data at the utility level. The

[1] Distributed generation is a small-scale electricity unit, generally between 1 kW and 5 MW in size, that can be isolated from the electric grid. DG units are generally located close to the end-user—"decentralized"—in order to maximize transmission and distribution efficiency. DG is generally touted as a cleaner and more efficient electricity supply option, relative to large-scale fossil fuel operations.

data are in 2005 values. In testing the relationship between DG capacity and these two policy instruments, I additionally control for confounders that affect both policy implementation and DG deployment, including utility characteristics, electricity market conditions, socio-economic factors, and supporting state legislation. I also estimate the association between RPS policies and renewable-based DG deployment.

The empirical model considers utility decisions of whether to adopt DG operations and, if so, how much capacity to deploy. According to these objectives, I estimate a two-part model and bootstrap the standard errors of the marginal effects. I additionally divide the sample into customer- and utility-owned DG, respectively, and estimate separate probit models for the likelihood of DG ownership for each sample.

The results of this analysis demonstrate that state policies that aim to reduce these barriers are effectively obtaining their policy objectives. Interconnection standards and net metering policies significantly increase the likelihood that a consumer will adopt DG capacity. It is evident that a trend toward more integrated and standard protocols for electricity interconnection reduces costs and bureaucratic hassles associated with consumer DG hook-ups. Net metering protocols, it can be further inferred, reduce the technical barriers to DG deployment and make DG adoption on the customer side of the meter more feasible. Utility DG adoption, on the other hand, is not enhanced by technical and technological standards, as are customer DG operations, but is instead strongly related to standard market forces that introduce competition and price signals into a historically heavily regulated market. Specifically, deregulation, electricity price, and household income are all positively and significantly associated with utility DG adoption.

The empirical results indicate, however, that there may be conflicts between concurrent movements or transitions within the electric industry, specifically between a move toward greater reliance on renewable energy versus on distributed generation. Utilities that are mandated to comply with an RPS policy are less inclined to deploy DG power, and appear to prioritize their investments in renewables over their investment in DG. This paper suggests avenues for further investigation of this issue.

Essay 3. Decarbonization: The Case of Carbon Mitigation and State Energy Policy Portfolios

Concurrent with diversification and decentralization efforts, state governments also seek to reduce greenhouse gas emissions, or “decarbonize” the U.S. electricity sector. To date, most state level decarbonization efforts typically include a portfolio of state-selected and -tailored energy policy instruments. The number of states that have already adopted or are currently drafting energy policy portfolios continues to rise. The empirical literature, however, has yet to conclude that state energy policy portfolios can generate results in a similar magnitude or manner to their presumed carbon mitigation potential.

The third essay considers state level policy efforts to decarbonize the U.S. electricity sector, and is guided by the following research question: what are the potential effects of the adoption of state energy policy portfolios on carbon emissions in the U.S. electricity sector? This essay seeks to address the lack of policy evidence of state level decarbonization efforts and contribute empirical insights on the carbon mitigation effects of state energy portfolios within the U.S. electricity sector. Following the precedent set by national-level energy modeling analyses, this essay analyzes the effects of portfolio scenarios in a dynamic modeling environment. Additionally, this analysis considers the carbon mitigation effects of state portfolios both with and without a national carbon price.

Using a dynamic, long-term electricity dispatch model with U.S. power plant, utility, and transmission and distribution data between 2010 and 2030, the third essay models a series of state policy portfolios in a comparative scenario analysis. The effects on greenhouse gas mitigation, electricity price, and generation resources are compared across state scenarios.

Model results reveal that state energy policy portfolios have the potential to reduce greenhouse emissions over the long run. Coordinated energy policy portfolio efforts, as facilitated across multiple states, a region, or the nation, can produce minor to significant improvements in the decarbonization potential of policy actions. The difference in decarbonization potential between isolated state policies and larger, more coordinated policy efforts is due to in large part to carbon leakage, which is the export of carbon intensive fossil fuel-based electricity across state lines. Results also confirmed that a carbon price of $50/metric ton CO_2e can generate substantial carbon savings. Although both policy options—energy policy or climate policy—are effective, neither is as effective alone as when the two strategies are combined.

The third essay concludes that, in the continued absence of national climate change legislation, the effectiveness of state decarbonization policies can be improved with efforts to coordinate energy and climate policy action across state borders, via either state partnership agreements or regional policy coordination. Assuming that the primary objective of energy policy portfolios is to reduce GHG emissions over the long run, individual states can also make concerted efforts to align the policy objectives, and therefore the policy design features, of the various policy instruments in their portfolios.

The concluding chapter combines findings from each of the three essays, compares and synthesizes them, and discusses implications as they relate to the role of public policy in altering operations within the U.S. electricity sector. Among other questions, the conclusion addresses the following. What are the effects and how effective are state level energy policy instruments at attaining their policy objectives? How compatible, or not, are policy instruments that focus on decentralization, diversification, and decarbonization? Which lessons can be extracted regarding the role and potential limitations of state policy efforts? Based on these findings, what are possible avenues for future research?

CHAPTER 2

DIVERSIFICATION: THE CASE OF RENEWABLE ENERGY AND PORTFOLIO STANDARDS

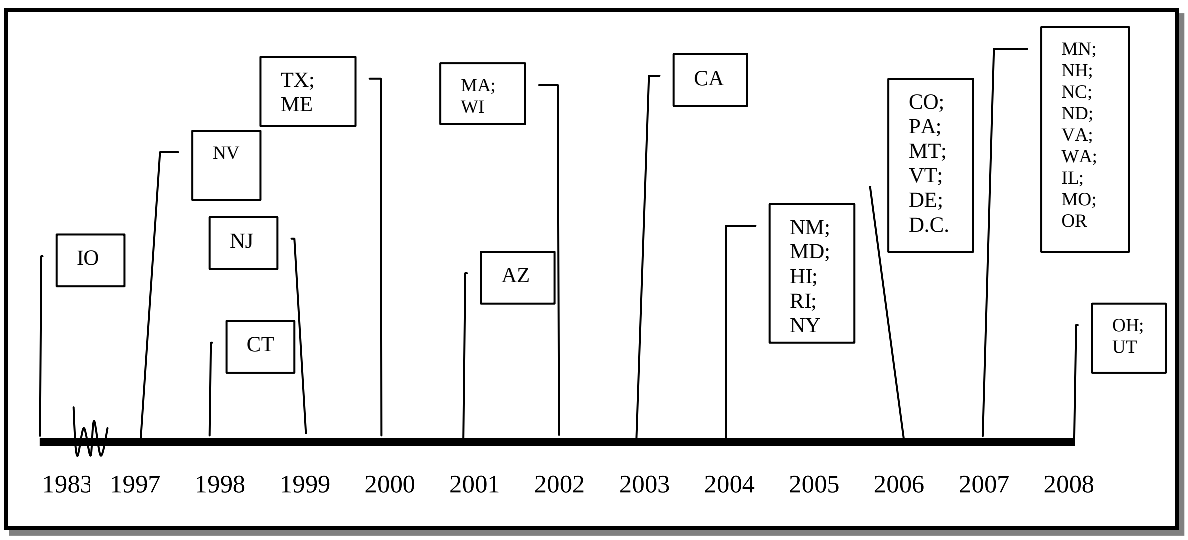
Introduction

Perhaps now, more than ever in the realm of environmental history, does Carl Van Horn's assertion that state governments are "arguably the most responsive, innovative, and effective level of government in the American federal system" (Van Horn, 1993, p. ix) ring true. Indeed, in response to global calls for a systematic solution to climate change, state governments are proving themselves as clean energy pioneers. State leaders across the country are adopting renewable energy incentives, enforcing integrated resource planning programs, and some have even set carbon abatement levels to reduce future emissions.

While states have a variety of incentives and regulations from which to choose, one of the most prevalent and innovative policy instruments is the renewable portfolio standard (RPS). An RPS is a state-mandated program in which a percentage (or share) of a state's overall electricity generation must come from renewable energy (hereafter denoted as RE). Under an RPS program, utilities are required to invest in RE systems in order to meet their percentage requirement. In 1998 only three states had adopted an RPS policy. By 2001, nine states (18%) had adopted an RPS and by early 2008, 27 states

(54%) had non-voluntary RPS programs; the adoption rate continues to rise. Figure 2.1 presents a timeline of RPS adoption across all states according to the year in which each policy became effective. Supporting incentive and regulation packages, created on a state-by-state basis, also aim to assist in the development and deployment of renewable energy.

Figure 2.1 RPS Timeline



This trend of state energy policymaking is encouraging to those who fear the ramifications of global warming and an over-reliance on foreign fossil fuels. Yet few studies verify that state initiatives toward these ends are highly effective at increasing the electricity sector's diversification of fuel sources. Despite the resurgence in research attention that is now devoted to RE policy, the causal link between state RE policies and RE development remains tenuous. This study aims to explore the relationship between state policy incentives and RE deployment and, by doing so, shed light on the current debate surrounding the effectiveness of state RE policy innovation in the wake of climate change.

Background

RPS policy design

Different renewable portfolio standards across the country have considerable variation in policy objectives and policy design. The majority of policy objectives aim to facilitate the diversification of electricity generation mixes, increase renewable energy deployment, reduce state reliance on fossil fuels, help renewable energy sources become cost-competitive with conventional energy sources, reduce carbon emissions, enhance economic development, or various combinations thereof. Policy design features tend to vary in the following attributes: structure, size, application, eligibility, and administration. For a more thorough discussion of these variations in design, refer to Wiser et al. (2007). Despite these sources of variation, all RPS policies aim to increase the percentage or the total amount of renewable energy. All non-voluntary RPS policies mandate that such a percentage or total must be attained by a given year, save Massachusetts' RPS policy. Table 2.1 presents the final percentage goal and year for all states with mandatory standards. States with a non-percentage based goal have an equivalent percentage displayed in parenthesis. Voluntary standards are not included in this table, although all statewide voluntary RPS policies are included in Figure 2.1 above.

Table 2.1. State RPS Final Targets and Years

State	Current Final Target	Current Terminal Year
Arizona	15%	2025
California	33%	2020
Colorado	20%	2020
Connecticut	27%	2020
Delaware	10%	2019
Hawaii	20%	2020
Illinois	25%	2025
Iowa	105 MW (~2%)	1999
Maine	30%[a]	2000
Maryland	22.5%	2020
Massachusetts	4%[b]	2009
Minnesota	25%[c]	2025
Montana	15%	2015
Nevada	20%	2015
New Hampshire	24%	2025
New Jersey	25%	2021
New Mexico	20%[d]	2020
New York	24%	2013
North Carolina	12.5%[e]	2021
Ohio	25%	2025
Oregon	25%[f]	2025
Pennsylvania	18%	2021
Rhode Island	16%	2020
Texas	5,880 MW (~4.4%)	2015
Utah	20%[g]	2025
Wisconsin	10%	2015
Washington	15%	2020
Washington D.C.	11%	2022

a. In 2006, Maine enacted new RPS legislation that mandates that 10% of all new generation must come from RE by 2017.
b. Massachusetts' RPS mandates 4% RE by 2009 and an additional 1% for each year thereafter with no specified terminal year.
c. Minnesota's RPS mandates that Xcel Energy deploy 30% RE by 2020 and that all other utilities deploy 25% by 2025.
d. New Mexico also mandates 10% RE by 2020 for all rural electric cooperatives.
e. North Carolina also mandates that 10% of all 2020 retail sales be RE for cooperatives and municipal utilities.
f. Oregon also mandates that small utilities deploy 10% and smallest utilities deploy 5% RE by 2025.
Utah's RPS, passed in 2008, is considered by some to be a "goal" because the mandate specifies that RE must be deployed when "it is cost-effective" to do so (DSIRE, 2008).

RPS policies require utilities to invest in RE systems in order to meet their percentage requirements. The majority of states with RPS policies allow utilities to exchange renewable energy credits (RECs), or renewable energy certificates, to help utilities comply with RE mandates. RECs are tradable wholesale electricity commodities that represent one MWh of renewable energy generation. Utilities that face RPS mandates, therefore, can purchase RECs in lieu of deploying one MWh of their own renewable energy. RECs are generally exchanged within a state or region; inter-regional or national wholesale REC markets are not yet well established (Holt and Bird, 2005).

Previous findings on renewable energy policy effects and effectiveness

The majority of literature on RE instruments relies on exploratory analyses. Some use case studies (Gan et al., 2007; Gouche et al., 2002; Langniss and Wiser, 2003) and others use additional qualitative evaluation techniques (Bird et al, 2005; Harmelink et al., 2006; Wiser et al., 2007). These analyses reveal that RPS policies have experienced a number of successes to date. In Texas, for instance, RPS legislation effectively led to the deployment of 915 MW of wind in 2001 alone, more than twice the Texas 2001 RPS benchmark (Langniss and Wiser, 2003). Some analysts, however, have noted that not all states are on a current trajectory toward meeting their RPS mandates (Wiser et al., 2007; Wiser et al., 2004). Possible reasons for these shortcomings include: inadequate policy enforcement; policy duration uncertainty; overly aggressive RPS benchmarks; too many exemptions; or too much flexibility offered to utilities (Wiser et al., 2007; Wiser et al., 2004).

Kydes (2006) and Palmer and Burtraw (2005) have modeled RPS policies using bottom-up energy models. Kydes analyzed the potential effect of a 20 percent federal non-hydroelectric-based RPS on energy markets in the U.S. using the Energy Information Administration’s (EIA) National Energy Modeling System. He concluded that RPS policies effectively increase RE adoption, reduce emissions, and increase the cost of electricity by three percent. Palmer and Burtraw modeled variations of federal RPS policy proposals and tracked policy effects on electricity prices, utility investment levels, resource deployment portfolios, and carbon emissions. They concluded that RPS costs are low for goals of 15 percent or less but rise significantly with goals of 20 percent or higher.

Despite RE policy's growing popularity in research publications, however, there are few studies that attempt to empirically estimate the effectiveness of state RE policies, nor that explore the causal inference between RE policies and RE deployment. This dearth of research is potentially attributable to the nascence of these programs, the lack of comprehensive data, the variation in RPS designs across the country that make empirical analyses difficult, or the long time frame over which energy results become apparent. Menz and Vachon (2006) present the only empirical analysis on the effects of state RE policy incentives to date. Constrained by data limitations, Menz and Vachon estimate an ordinary least squares regression model on a single-year sample of 39 states[2] to discern which state policies significantly affect the amount of wind energy capacity and the number of wind development projects, respectively. The results of this analysis, while insightful, likely suffer from statistical and external validity threats. Omitted variable bias and low sample size likely affect the authors' statistical validity and their method of sample selection affects the external generalizability of their results. Furthermore, Menz and Vachon's analysis considers the effects of RPS policies on wind energy development and deployment, not the percentage of wind energy in total generation portfolios. The

[2] The authors draw their sample as follows. They begin with all 50 states, then drop Alaska and Hawaii because they do not have data on wind potential for these states. They drop nine more states—Alabama, Florida, Georgia, Kentucky, Louisiana, Mississippi, Rhode Island, South Carolina, and Tennessee—because they have no or low wind energy potential. After running the model once, they additionally drop the two states with the highest wind potential, Texas and California. The remaining sample size is 39 states.

overwhelming majority of RPS policies, however, aim to alter the percentage of RE, not simply the total amount of RE. The collective limitations of their findings highlight the importance of critical analysis of the methods and variables related to state energy policies that are used to assert causality and verify the effects of RPS legislation.

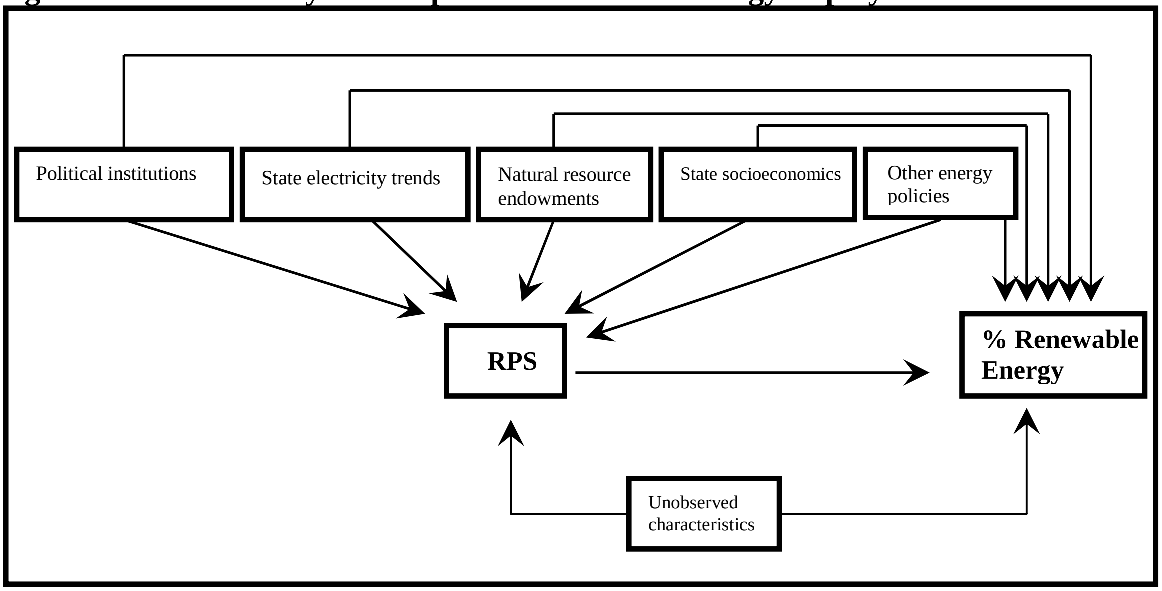
Given the lack of consensus on whether an RPS policy is an effective RE policy instrument, accompanied by a rise in new state RPS legislation and the possibility of future federal RPS legislation, there is a distinct need for further empirical exploration of the subject. The present analysis builds on previous efforts, particularly those made by Menz and Vachon, by directly testing the association between RPS policies and total RE generation. I additionally test the association between electricity-based RE policy instruments and the percentage of RE generation across states. I aim to answer the following question: do renewable portfolio standards increase a state's share of RE? This study contributes further empirical evaluation of state RE electricity policies, and also corrects for problems of low sample size, limited statistical generalizability, and omitted variable bias that have limited the applicability of previous studies.

Methodology

The primary objective of this analysis is to explore the effectiveness of RPS policies to date. I am, therefore, interested in identifying the causal effect of state RPS policies on the percentage of RE deployment. I begin this exercise by drawing a causal diagram that identifies the directional relationship between the treatment effect, an RPS policy, and the outcome of interest, the share of RE electricity. This diagram, or directed acyclic graph (DAG), is presented in Figure 2.2; it accounts for all common causes of the treatment and of the outcome, and helps identify and manage relationships between the confounders, treatment, and outcome. The selection of the DAG components is influenced by theoretical foundations of public policy and the empirical findings of the associated environmental policy literature (Bennear, 2007; Mazur and Welsh, 1999; Ringquist, 2003; Ringquist and Clark, 2002; Sapat, 2004), as well as by recent analyses that specifically focus on RPS policy choice (Huang et al., 2007; Vachon and Menz, 2006) and their outcomes (Menz and Vachon, 2006).

Assuming this DAG is an accurate representation of the relationship of interest, I can use it to first identify important elements of my methodology and then to minimize bias in the estimates of the parameters. This DAG demonstrates, for instance, that I must control for factors that confound the policy treatment variable and that, if omitted, would otherwise be captured in the error term. Omitted variable bias would cause the explanatory variable to be correlated with the error term, and thus bias the coefficient estimates. This DAG also demonstrates that it is important to control for unobservable variables that may concurrently determine the percentage of renewable energy deployed, as well as selection of policy treatment. I must use an estimation procedure, therefore, that controls for both observed and unobserved characteristics.

Figure 2.2 Directed Acyclic Graph for Renewable Energy Deployment



Beyond controlling for observed and unobserved confounders, I also proceed with one other objective—although it is not explicitly modeled in the DAG—in effort to maximize statistical validity. I aim to estimate the model on a larger sample size than those that are used in previous studies, which ought to improve the precision of estimates and generate more reliable standard errors. With only 50 states, the obvious solution is to include time series data. There are additional benefits to using state-specific panel data: it will allow me to control for unobserved characteristics that I may not otherwise be able to model explicitly; and it will allow me to track state trends over time both within and between states, which will, in turn, give me an understanding of whether the counterfactual is appropriate.

With these objectives in mind, one could choose among a variety of estimation models. One would expect a standard ordinary least squares (OLS) model to estimate biased and inconsistent parameter estimates due to this analysis' omission of time-invariant covariates. Similarly, an OLS model that does not control for state-level time-invariant characteristics will estimate biased standard errors when the errors are heteroskedastic or dependent within group. When omitted time-invariant variables are correlated with the policy instrument variables, a fixed effects model will provide a consistent and unbiased estimate of the parameters while concurrently controlling for unobserved unit heterogeneity.[3] The state fixed effects model used in this analysis is:

$$Y_{st} = \alpha_0 + \beta_1 X_{st} + \delta_1 Z_{1st} + \delta_2 Z_{2s} + \gamma_t Z_t + \varepsilon_{st}, \qquad (1)$$

where, for state '*s*' at time t, Y is the logged share of renewable energy electricity out of all sources of electricity, X represents RPS implementation, Z_1 represents all covariates that are time-variant, Z_2 represents covariates that are time-invariant[4], and Z_t represents a vector of time dummy variables. The error term, ε_{st}, can be decomposed into a time-constant state-effect and an independent and identically distributed random state-year term:

$$\varepsilon_{st} = \mu_s + \eta_{st}. \qquad (2)$$

For equation (1) to correctly identify the causal effect of an RPS policy, it must be the case that unobserved heterogeneity among states that adopt or do not adopt an RPS policy affect RE deployment but not the trends in deployment. In other words, in absence of an RPS policy, the trends in RE deployment would be parallel among states with and without RPS policies.

Plümper and Troeger (2007) present a fixed effects vector decomposition model (FEVD), which is more efficient than a standard fixed effects model when the ratio of the

[3] If, on the other hand, these omitted time-invariant variables are uncorrelated with the policy covariates, a random effects model will provide a more efficient estimate than would fixed effects. Given the nature of these state-level data, however, I expect that a fixed effects is the most appropriate. To validate this assumption, I perform a series of Bruesch-Pagan and Hausman tests. For the sake of comparison, I provide results from a random effects and a pooled OLS model in the appendix.
[4] The time-invariant variables are only included in the fixed effects vector decomposition model, which is described below.

between and within variance of the dependent variable is large, or when the correlation between the time-invariant variables and the state effects is low. Because the former is particularly true in this analysis, I estimate an FEVD model as well. This procedure additionally allows me to recover the effects of relevant time-invariant or rarely changing variables that would otherwise remain captured in the state fixed effects estimate. The FEVD technique was designed to deal with panel data variables that are rarely changing, in which the variance across units is greater than the variance over time and so the fixed effects will soak up the explanatory power of these variables. Therefore, not only does the FEVD technique provide a more efficient estimate when the percentage of RE varies only slightly in some states during the study period, but it also allows me to explicitly model time-invariant variables—such as natural resource endowment—that theory and relevant literature indicate are important. The FEVD procedure, Plümper and Troeger posit, yields correct standard errors for the invariant variables and reveals more accurate estimates of rarely changing variables' explanatory power.

Adhering to Plümper and Troeger's procedures, I take the unit effects from the first fixed effects model, and break them down into the portion that is explained by the time-invariant variables and the error term. I then re-estimate the original model with a pooled OLS, but this time include the revealed error term from the prior step and the time-invariant variables, Z_2.

Data

Public state-level energy data are rarely comprehensive. This study, therefore, compiles individual variables from a variety of public sources between 1998 and 2007 to create a state-level energy database. These years span the adoption and initial phases of RPS implementation for a number of states. With 50 states and ten years, the resulting sample size begins with 500 observations. Because the wind potential variable is missing observations for Hawaii and Alaska the final sample has 480 observations. All summary statistics are presented in Table 2.2.

Table 2.2 Variable Definitions and Summary Statistics (n=480)

Variable	Definition	Mean (or %)	Std. Dev.	Min.	Max.
RE share	Share of renewable energy electricity (in MWh) out of total generation	2.65%	0.039	0.00	0.32
RE total	Total amount of renewable energy electricity (in 1000 MWh)	180.67	343.58	0.00	2480.00
RPS	State has an operational RPS policy	23.13%	0.42	0.00	1.00
House score	LCV House of Representative pro-environment score	0.43	0.29	0.00	1.00
Per capital natural resource employees	Number of state and local natural resource employees per 1,000 capita	0.84	0.52	0.18	3.16
Petro/coal manufacturing GSP	Percent of total GSP that comes from petroleum and coal manufacturing	0.0035	0.0092	0.00	0.13
Gross state product per capita	Annual gross state product per capita	36,485.85	7,826.93	21,802.87	70,784.18
Growth rate of population	Annual change in state population	0.90%	0.02	-0.06	0.11
Electricity Price	Average annual retail electricity price (in cents/kWh)	7.34	2.27	4.00	16.45
Electricity use per capita	Average MWh electricity used per person, per state	17.50	13.81	4.58	94.46
Percent regional RPS	Percent of regional states that have an RPS policy, lagged by one year	18.38%	0.24	0.00	1.00
Wind potential	Windy land area in 10,000 km^2 as of 1991	2.17	3.60	0.00	12.37
Biomass potential	Estimated cumulative biomass quantities as of 1998 in 10,000 tons/year	1,064.28	844.73	11.55	3,335.92
Solar potential	Technical daily max in 10,000 MWh of total solar energy	7,437.54	6,013.21	156.06	3,4015.89
Tax index	Weighted index of corporate, sales, industrial, and property tax options	1.19	1.14	0.00	4.00
Subsidy index	Weighted index of grants, loans, and rebates	2.34	0.62	1.00	3.00
Deregulation	State is partially or entirely deregulated	26.4%	0.44	0.00	1.00

Outcome variables

I use two separate dependent variables. The first dependent variable is the natural log of RE percentage of electricity generation per year.[5] This variable is computed by dividing each state's annual amount of RE electricity generation, excluding hydroelectricity, measured in Megawatt-hours, by the total amount of electricity generation by all sources. I emphasize that this outcome variable is the *percentage* of RE electricity out of total state fuel blends. In the second series, the dependent variable is the *total* amount of annual RE generation, excluding hydroelectricity, measured in thousands of Megawatt-hours. This dependent variable is more consistent with the types of RE variables used in other analyses (Menz and Vachon, 2006; Bird et al., 2005; Langniss and Wiser, 2003). Data on electricity generation come from the EIA state electricity databases.

Policy Variable

The primary variable of interest is an RPS policy. I employ a dichotomous RPS variable, equal to one if a state has an RPS policy in a given year and equal to zero if the state does not have an RPS policy.[6] All policy instrument data are extracted from the Database of State Incentives for Renewables and Efficiency (DSIRE) (North Carolina Solar Center, 2009). The DSIRE outlines which policy instruments are operational across

[5] After performing a series of functional form tests—a kurtosis test for normality, a Bera McAleer test, a Box Cox test, and a Wooldridge test—I determined that the dependent variable should be logged to avoid specification error and possible biased estimates or inconsistency as a result of this error.

[6] I additionally operationalize the RPS variable in two separate ways: as a continuous variable that reflects the percentage RPS goal at the terminal year; and as an ordinal value that reflects the degree of RPS goal, where 0=no RPS, 1=voluntary RPS, 2= "weak" RPS (less than 12 percent RE by terminal year), 3= "medium" (between 12 and 24 percent RE), and 4= "strong" RPS (greater than 24 percent RE). Both variables generate model results that do not substantively differ from the main models.

the country and the date of adoption for each electricity-based policy instrument by each state.

Three assumptions are made about RPS policy program implementation. First, an RPS policy is only considered operational according to the effective date of policy implementation, not the adoption date, as listed on the DSIRE website. Second, any RPS policy that became effective in either November or December is not coded as effective until the following fiscal year. For instance, if a state effectively begins a RPS program in November 2003, the value of their RPS variable equals zero from 1998 to 2003, and one thereafter. Third, I do not code any voluntary or “goal” based RPS policies as a mandated standard.

Political and environmental institution factors

A diverse literature, embedded within the disciplines of political science and public administration, argues that institutions frame the manner in which political actors operate, and both directly and indirectly shape the structure of policy outcomes (see Shepsle, 1989; Hall and Taylor, 1996; North, 1990; Steinmo and Tolbert, 1998; Weingast, 1989). Many environmental policy theorists also hypothesize that the capacity of political organizations, the ideological underpinnings of political actors, and inter-party competition all affect the likelihood of environmental policy adoption and the degree to which outcomes conform to the policy objectives (Bennear, 2007; Mazur and Welsh, 1999; Ringquist, 2003; Ringquist and Clark, 2002; Sapat, 2004). In consideration of these theories, and countless others that may posit more intricate hypotheses of institutional dynamics and policy implementation, this study uses three political covariates to account for the institutions that help ensure, or alternatively do not ensure, the success of policy incentives or directly affect RE development and deployment.[7]

First, I include a variable that represents a state's legislative commitment toward environmental policy. State legislators are able to affect state policy through their ability to pass legislation, to continually uphold the tenets upon which a policy issue rests through support of related future legislation, and through their control of agency budgets as a possible means of control over agency capacity and ability to deal with energy issues. The League of Conservation Voters' (LCV) environmental scorecard documents the annual average pro-environmental vote for all members of the House of Representatives between 1971 and 2007. Following a conventional assumption, states with governing bodies that are oriented toward pro-environmental legislation are expected to demonstrate a greater commitment to green energy development and, consequently, have higher rates of RE deployment.[8]

Second, I include the number of per capita state and local employees in natural resource governmental positions. This variable represents the capacity that state and local bureaucracies have to respond to emerging environmental challenges. I predict that states with larger bureaucratic natural resource workforces will have a greater ability to address imminent environmental issues, tackle a variety of environmental and energy-related problems, and allocate goods and services that aim to increase RE development. This

[7] I originally included a fourth political institution variable, the number of 501(c)(3) nonprofit organizations registered with the IRS that have an environmental quality and protection purpose according to the National Taxonomy of Exempt Entities Code. After analyzing the results of our model, however, I determined that this variable is irrelevant and it would ultimately decrease the efficiency of our model if included.

[8] I intend for this variable to also reflect or at least demonstrate great overlap with public awareness of environment or energy issues. I do not include a separate public awareness variable in this model because: 1) such a variable is not available at the state level with variation in time; and 2) such a variable would be highly collinear with the LCV environmental scorecard variable.

variable is operationalized as the number of state and local natural resource employees per 1,000 people, and is extracted from U.S. Census Bureau databases.

Third, I include the percentage of total gross state product (GSP) that is attributable to petroleum and coal manufacturing. This variable is intended to represent the strength of fossil fuel-based interest groups and will likely have a negative association with RE deployment. These data are extracted from the U.S. Bureau of Economic Analysis.

State socioeconomic factors

The model includes two state socioeconomic covariates: per capita gross state product and the growth rate of the population.[9] Both variables are extracted from U.S. Census Bureau data. Consistent with other environmental policy analyses (Ringquist, 1993; Sapat 2004), I predict that states with greater wealth, other things equal, will have a higher percentage of RE because they have the ability to invest more heavily in RE deployment or other green energy opportunities. States with larger growth rates will likely build more power capacity to satisfy growing state demand for electricity; renewable energy deployment may be a viable option for satisfying rising demand. It is also possible, however, that larger population growth rates will be associated with increases in base load fossil fuel generation, such as coal-based power.

State electricity trends

[9] Originally, I also included household income and educational attainment in the model; after finding that both variables are irrelevant to the model, I removed them.

It would be inappropriate to estimate a model that considers the main drivers of renewable energy deployment without controlling for motivating trends that are specific to state electricity markets. I control for three such state electricity trends that, if omitted, would confound the policy treatment variable and bias the estimates. The first variable is the annual amount of total electricity generated per state divided by the associated state population per year. Similar to the annual population growth rate variable, it is difficult to predict a priori the effect of greater electricity use per capita on RE deployment. It is possible that greater demands for electricity could encourage RE development, yet it is also possible that greater rates of demand could promote larger investment in base load centralized power from coal or natural gas. The direction of association will likely depend on the type of electricity demand—base load, intermittent, or peak—and how this demand contributes to seasonal and daily load curves.

The second electricity market variable, deregulation, indicates whether a state has restructured its electricity market. States that have either partially or fully restructured their electricity market are coded to equal one; states that have kept their market regulated or have “destructured” their market after a period of deregulation have a regulation variable equal to zero. The deregulation variable is time-invariant and so is captured by the state fixed effects in the regular fixed effects model, but is included as an independent variable in the FEVD model. To date, there is little consensus regarding the environmental and RE development effects of electricity deregulation (Palmer, 1997). Some argue that deregulation will help ensure consumer choice, lead to greater product differentiation, and encourage increases in RE-based research and development (Delmas et al., 2007). Counter arguments contend that deregulation will merely encourage a rise in conventional, centralized fossil fuel generation due to traditional economies of scale and the cost advantage of fossil fuels over renewables.

The third electricity market variable is the average annual retail price of electricity across all end-users, measured in cents per kilowatt-hour. Electricity price data are extracted from the Energy Information Administration's Office of Coal, Nuclear, Electric, and Alternative Fuel's electricity databases. Electricity price may be negatively associated with renewable energy deployment; the higher the price of electricity, the less likely state utilities will be to invest in relatively more expensive renewable energy sources of electricity. On the other hand, electricity price may be positively associated with RE deployment: a higher price of electricity has the potential to make RE more economically feasible.

Natural resource endowment

All resource endowment variables are time-invariant and, therefore, only included in the FEVD model as separate from state fixed effects. For wind power potential, I use Elliot and his colleagues' 1991 estimates of the available land area in wind class three or higher, excluding land with zoning restrictions (Elliot et al., 1991). It is important to note that these data only include onshore land area, and do not include windy land that is located offshore but still in a state's jurisdiction. For biomass potential, I use Walsh and his colleagues' 1998 estimates of cumulative quantities of all biomass sources, recorded in tons/year (Walsh et al., 1998). Solar potential is recorded as the average monthly solar radiation over a time span of thirty years, 1961-1990, for a south-facing flat-plate collector tilted at zero degree tilt (measured in $kWh/m^2/day$), multiplied by the state area (measured in m^2). Measured in MWh per day, this variable represents the maximum electricity output that is technically possible given the solar radiation and land area of each state. Solar data are from the National Renewable Energy Laboratory's solar radiation databases (NREL, 1992).

Although these data are the most extensive of all possible sources, they do have a few drawbacks: a few of these data sources are missing information for Hawaii and Alaska; these variables rely on potentially outdated estimates; and these data do not represent actual electricity generation potential. The first issue requires that I drop Hawaii and Alaska from the sample. The second problem is not much of a concern—it is fair to assume that natural resource endowments remain relatively steady across time and pre-1998 resource endowment data is ultimately useful since these values are not contemporaneously determined with RPS implementation. The final issue requires a note of caution. The natural resource figures used in this analysis do not represent the amount or share of electricity that could come from these resource endowments; they are merely absolute figures that indicate resource potential. I do not convert from resource potential to electricity potential because this conversion would require critical assumptions about the overlap between technical, economic, and political feasibility, which is beyond the realm of this analysis.

Other state energy policies

I also control for the effects of other RE policies, including grants, loans, rebates, and tax incentives. Due to data limitations, I am not able to include sophisticated measures of annual grant or tax incentive expenditures. Working with available data from

DSIRE, I create two policy indexes: one represents the number of different types of annual operational subsidy policies and the other tax incentive policies. Grants, loans, and rebates are transformed into an equal-weighted subsidy index that ranges from zero to three. If, for instance, a state has a grant program in 2003 and both a grant and a loan program in 2004, then their subsidy index would equal one for 2003 and two for 2004. The tax incentive index is similarly constructed: all forms of tax incentives—corporate, personal, property, and sales—are made into an equal-weighted tax index that ranges from zero to four. Both variables have little variation over the study period and so I only include these variables in the FEVD model. I recognize that both variables are crude representations of supporting policy instruments, yet this method allows me to include these variables in the model without compromising degrees of freedom or unnecessarily complicating the variance-covariance matrix used for model estimation.

The choice of whether and how much RE to deploy, as well as the choice of RPS adoption, is likely influenced by regional RE markets. States within the same region may develop and deploy RE either to comply with their own RPS requirements, or to sell the resulting RECs to surrounding states. I must, therefore, control for the influence of regional REC markets on state RE deployment. I do so by including a final variable in the model: the percentage of regional states that have RPS policies, lagged by one year. I created this variable by dividing all states into their respective regions—West, Midwest, Northeast, Southwest, Southeast—and documenting all regional relationships in a social accounting matrix, and then multiplying the resulting matrix by a lagged RPS matrix. If the percentage is high, I hypothesize, states will be more likely to deploy RE and sell the credits in the regional REC market. If only a small proportion of regional states have RPS policies, a state may be less likely, if at all, to deploy RE for regional REC markets. Clearly, the way in which I operationalize this variable is less ideal than if I simply included location-specific REC prices or REC market size. Such direct variables, however, are not accessible for a large number of states or, in the event that it is accessible, consistently measured across states and time (Holt and Bird, 2005).[10]

Empirical results

Table 2.3 presents the results from the models with a dependent variable equal to the share of RE electricity. Model 1 presents the fixed effects estimates and Model 2 presents the FEVD estimates. The results of both demonstrate that RPS policies have a small, positive association with RE share of electricity. This association is not statistically significant, however, thereby suggesting that RPS policies to date have not significantly affected states' shares of RE electricity.

[10] RECs are most commonly traded in-state or within region. To date, RECs are rarely traded inter-regionally (Holt and Bird, 2005).

Table 2.3. Regression Results with Dependent Variable: Logged Share of Renewable Energy Electricity

Independent Variable	Model 1: Fixed effects	Model 2: FEVD
RPS	0.126	0.142
	(0.141)	(0.091)
House LCV voting score	2.213	2.222
	(0.424)***	(0.165)***
Natural resource employees per capita	1.540	1.498
	(0.395)***	(0.093)***
Percent petro/coal manufacturing of total GSP	-13.296	-12.837
	(6.608)**	(3.810)***
Gross state product per capita	0.0001	0.0001
	(0.00002)***	(0.0000007)***
Growth rate of population	-1.262	-1.611
	(4.509)	(3.606)
Electricity use per capita	-0.120	-0.118
	(0.030)***	(0.004)***
Average retail electricity price	-0.289	-0.281
	(0.057)***	(0.027)***
Percent regional RPS	-0.684	-0.622
	(0.267)***	(0.180)***
Tax index		-0.004
		(0.030)
Subsidy index		0.369
		(0.048)***
Deregulated		-0.753
		(0.086)***
Wind potential		-0.119
		(0.013)***
Biomass potential		-0.00008
		(0.00005)*
Solar potential		0.00006
		(0.0000007)***
Year 1999a	-0.076	-0.065
	(0.166)	(0.148)
Year 2000	-0.024	0.004
	(0.247)	(0.247)
Year 2001	0.020	0.049
	(0.177)	(0.152)
Year 2002	0.126	0.169
	(0.188)	(0.154)
Year 2003	0.302	0.340
	(0.206)	(0.156)**
Year 2004	0.222	0.267
	(0.243)	(0.161)*
Year 2005	0.213	0.251
	(0.282)	(0.167)
Year 2006	0.167	0.191
	(0.325)	(0.173)
Year 2007	0.108	0.161
	(0.366)	(0.187)
FEVD Residuals		0.987
		(0.025)***
Constant	-7.207	-7.905
	(1.095)***	(0.295)***
Observations	482	482
Number of state fixed effects	48	
R-squared	0.40	0.87

Note: standard errors in parenthesis; * p<.10, ** p<.05, ***p<.01.

a. Omitted category: 1998

The regression results indicate that the political institution covariates have highly significant associations with RE share of electricity. The LCV scorecard percentage has a positive, significant association with RE share of electricity, as does the number of natural resource state and local employees per capita. The percent of petroleum and coal manufacturing contributions to total GSP is negatively and statistically associated with RE share of electricity.

Table 2.3, with combined results from models 1 and 2, demonstrates that additional variables are significant predictors of the percentage of RE generation. Electricity market trends and state fiscal resources are also significant predictors of RE percentage growth. Both electricity price and electricity use per capita have negative, statistically significant associations with the percentage of RE, holding all else constant. Gross state product per capita is positively associated with the dependent variable. The percent of regional states with RPS variable is also statistically significant, at the one percent significance level, and negative.

The results of the FEVD regression demonstrate that additional time invariant factors are highly associated with RE share of electricity. An additional subsidy policy has a positive and significant association with RE share of electricity. All three natural resource endowment variables are significant, though the wind and biomass endowment variables are, surprisingly, negatively associated with the outcome variable. Deregulation has a negative and statistically significant association with RE share of electricity.

Table 2.4 presents a second series of fixed effects models, in which the dependent variable is each state's total RE generation. The fixed effects estimates presented in Table 2.4 are noticeably different than those in Table 2.3. The RPS variable is positive and statistically significant in both models. The political institution variables are not statistically significant at any conventional significance level, save the natural resource employee per capita variable. An increase in the amount of electricity used per person is associated with an increase in the total amount of RE, holding all else constant. Similarly to the RE share model results, the average retail price of electricity is negatively associated with total RE deployment and gross state product is positively associated. The percentage of regional states with an RPS variable is also still negative and significant. In consideration of the time invariant FEVD parameters, deregulation, biomass resources, and solar potential have positive associations with RE generation, and wind potential and tax incentives both have negative associations. All FEVD parameters are statistically significant.

Table 2.4. Regression Results with Dependent Variable: Total MWh of Renewable Energy Electricity

Independent Variable	Model 1: Fixed effects	Model 2: FEVD
RPS	349,858.906	347,794.512
	(109,869.039)***	(70,843.243)***
House LCV voting score	-135,001.074	-117,185.289
	(331,412.018)	(127,412.887)
Natural resource employees per capita	-757,086.889	-750,926.651
	(308,676.621)**	(72,912.117)***
Percent petro/coal manufacturing of total GSP	472,313.664	563,638.852
	(5,166,499.483)	(2,922,219.372)
Gross state product per capita	65.305	64.937
	(19.253)***	(4.659)***
Growth rate of population	2,295,957.491	2,520,749.922
	(3,525,241.033)	(2,852,383.485)
Electricity use per capita	12,206.701	11,962.653
	(23,287.738)	(2,348.808)***
Average retail electricity price	-14,945.502	-13,283.360
	(44,542.739)	(20,300.810)
Percent regional RPS	-757,230.118	-757,027.583
	(208,471.136)***	(140,951.934)***
Tax index		-111,710.227
		(23,680.642)***
Subsidy index		909,734.328
		(37,241.407)***
Deregulated		485,148.379
		(67,397.871)***
Wind potential		-432,039.773
		(10,225.410)***
Biomass potential		687.014
		(36.247)***
Solar potential		347.096
		(5.638)***
Year 1999	-24,599.650	-26,586.283
	(129,623.244)	(116,818.474)
Year 2000	-98,071.396	-104,577.874
	(193,425.299)	(164,405.169)
Year 2001	-112,467.797	-109,227.857
	(138,593.232)	(119,747.861)
Year 2002	-22,279.132	-16,892.397
	(147,285.887)	(121,297.935)
Year 2003	-74,748.764	-66,304.146
	(160,993.048)	(122,244.820)
Year 2004	-166,206.408	-156,852.153
	(189,766.434)	(126,215.377)
Year 2005	-194,956.479	-177,111.359
	(220,199.723)	(130,419.071)
Year 2006	-196,022.132	-168,726.629
	(254,096.668)	(134,717.005)
Year 2007	-156,664.960	-106,040.041
	(286,100.312)	(144,308.048)
FEVD Residuals		0.999
		(0.010)***
Constant	157,952.138	-4,324,110.186
	(856,118.837)	(242,842.624)***
Observations	480	480
Number of state fixed effects	48	
R-squared	0.19	0.98

Note: standard errors in parenthesis; * p<.10, ** p<.05, ***p<.01.

a. Omitted category: 1998

Discussion

The results of this analysis confirm the mixed policy effects and effectiveness evaluations that RPS policies have received to date. On the one hand, I find no strong evidence that RPS policies are, to date, obtaining their overarching objective of increasing the percentage of RE generation. An RPS policy is demonstrated to have an insignificant association with RE share of electricity; in other words, states with RPS policies do not have statistically higher rates of RE share deployment than states without RPS policies, holding all else constant. While it is documented that RPS policies have already demonstrated positive returns in selected states (Langniss and Wiser, 2003; Gouchoe et al., 2002), these results reveal that other states may struggle to invest in RE development to a degree that ensures substantial increases in the percentage of RE deployment. These results are consistent with Wiser and his colleague's (2007) findings that, despite some success stories from a handful of states, other states may not be on track to meet their RPS targets.

On the other hand, Table 2.4 reveals that states that have operational RPS policies have significantly higher rates of total renewable energy deployment than states without RPS policies, holding all else constant. These results support findings made by Menz and Vachon (2006), as discussed above, as well as other analyses (Langniss and Wiser, 2003). Based on the collective results of all sets of models, one could infer that RPS policies are to date effectively encouraging *total* RE investment and deployment but not effectively increasing the *percentage* of RE generation in states' electricity portfolios.

A lack of consistent policy successes may be attributable to poorly structured policy design features or weak enforceable penalty mechanisms, as Wiser and his colleagues suggest (2007; 2004). It is also possible, however, that the rate of RE growth may simply be overwhelmed by the rate of overall electricity demand growth, both in-state and by export sales to the national grid. From a policy evaluation standpoint, these findings reveal a potentially significant shortcoming of RPS policies. Weak or inadequately structured policy design features, a lack of enforceable penalties for noncompliance, or an inconsistency between demand growth and RPS implementation are all potentially manageable problems that could be addressed at the state level.

From any standpoint other than those held by policy analysts, however, should one care if states are falling short of their percentage RE electricity goals if they are still increasing total RE generation? Some would argue that we ought not to care. RPS policies are effectively encouraging RE investment and opening electricity markets to RE development, thereby making renewable technologies more competitive with traditional systems. Furthermore, one may predict that the growth of the RE industries will eventually become positively self-reinforcing as these businesses acquire the lobbying influence to protect themselves and further enhance their growth and profits; but the business climate simply is not there yet.

Others would argue differently. RPS policies are one of the strongest and only mechanisms that the U.S. has yet to adopt to address climate change. Twenty-seven states have crafted regulation in promotion of RE generation and, within the next several years, several more states and the federal government will consider adopting their own version of an RPS. Yet if forthcoming statistical applications reveal that RPS programs are either entirely effective or alternatively ineffective, then policymakers may respond by rushing similar legislation without addressing policy design problems or they may entirely disregard RPS policies as a viable option, respectively. Finally, if the ultimate intent of RE-based legislation is to reduce emissions associated with climate change—which is the case for some states, though not all—then increasing RE generation without enforcing a decrease in fossil fuel generation will not achieve these objectives. Increases in fossil fuel generation, as well as some alternative energy sources, will continue to increase carbon emission levels in the atmosphere. One may conclude, therefore, that RPS policies may ultimately be more effective if implemented in conjunction with programs that target energy demand with efficiency and conservation measures or, alternatively, with cap-and-trade mechanisms.

Although this range of interpretations regarding the effects of RPS policies on RE development and deployment are consistent with findings made by other researchers, it is important to acknowledge that the interpretations made in the present analysis may be too speculative; and, in actuality, RPS policies are simply too new for the majority of states to experience significant changes in RE deployment levels. Most states are still in the early stages of RPS implementation and it is plausible that implementation efforts, as well as penalty and enforcement mechanisms, are not yet at full strength. If this is the case, the present results reveal that RPS policies take a long time—several years, at least—to achieve intended levels of implementation, enforcement, and outcome success.

The model results reveal that an increase in the percentage of regional states with RPS policies is associated with a decrease in RE percentage and RE total, respectively, holding all else constant. These findings are counter to my original hypothesis, in which I predicted that a greater percentage of regional states with RPS policies would encourage a greater amount of RE development for the intent of REC sales. Given that this is the first empirical RPS analysis that attempts to include and control for REC activities, I have limited relevant literature from which to pull insights on these trends. I would, however, like to offer a couple of preliminary, yet largely speculative, explanations for these findings.

First, the results from the third essay in this dissertation, *Decarbonization: The case of carbon mitigation and state policy portfolios*, may lend some insights on the negative relationship between percentage of regional RPS states and RE deployment. This analysis finds evidence of carbon leakage across state borders as a result of inconsistent renewable energy regulations. More specifically, when one state has renewable energy-based electricity regulations and a neighboring state does not, the state with regulations is likely to export its excess fossil fuel-based generation to the state without regulations, conditional on the need for additional generation in the neighboring, non-regulated state. The state without its own renewable energy regulations, therefore, has little incentive to build its own new generation capacity, renewable-based or otherwise, when it can import its neighbor's relatively inexpensive excess power. These findings indicate that states with regional RPS partners are faced with somewhat conflicting incentives: either build new renewable energy and sell the RECs to neighboring states; or hold off on some or all new generation facilities and, instead, import neighboring states' excess generation. In the event that the latter is more cost-effective, the negative association between RE and regional RPS states, as discovered in this study, makes more sense.

The second possible explanation for these results is that REC markets are still evolving. Although the first REC market for RPS compliance was established in Texas in

1999, by 2004 only a handful of states actively traded RECs, including: Texas, Massachusetts, Connecticut, Maine, and, to some degree, New Jersey (Holt and Bird, 2004). If the creation of REC markets effectively encourages regional RE development, one should still expect a delay before that new RE is fully running and dispatching power onto the electrical grid.

The final possible explanation for these findings is that the variable of interest, percentage of regional RPS states, does not accurately represent REC markets. While it is fair to assume that a greater number of regional RPS states increases opportunities for renewable energy credit exchanges in that region, it may be a stretch to also assume that each additional regional RPS policy increases the likelihood that a state within that region will develop renewable energy for REC sales. As discussed above, a more accurate REC variable would be REC prices, by state and over time, or REC market potential, in MWh per year.

Turning to other results, state-level political and environmental institutional factors are effective determinants of a state's share of RE electricity. Specifically, the LCV estimate demonstrates that continued support for environmental legislation positively affects the share of RE electricity. Similarly, an increase in natural resource-oriented state and local government employees per capita is also positively and significantly associated with an increase in RE share, thereby suggesting that greater bureaucratic capacity can significantly influence the share of RE deployment. It is difficult to draw policy recommendations from these parameter estimates, although some may suggest that these results reflect the need to better inform state legislators about the ramifications of disregarding environmental priorities. If policymakers and state and local bureaucrats demonstrate a commitment toward environmental progress, and the capacity to address evolving energy challenges, a transition toward diversified and more sustainable state energy portfolios may be more likely.

The FEVD coefficients in both tables reveal that there are significant time-invariant fixed effects factors that are still captured in the residual term. Of the time-invariant parameters that are explicitly modeled, one can gather a couple of interesting insights. Subsidy programs are positively associated with RE share and RE total, whereas tax incentives are negatively associated with both dependent variables, although only statistically significant in the RE total model. In other words, for each additional grant, loan, or rebate program, holding all else constant, a state should expect a significant increase in RE; yet for each additional tax incentive program, states should expect a decrease in RE. The reasons behind these trends are not readily apparent. It is possible that subsidies attract larger RE system owners, while tax incentives attract homeowners and other micro-generation or distributive generation owners that make up a tiny fraction of total RE generation. Or perhaps it is the case that having a greater number of tax incentive offerings merely attenuates each respective incentive, thereby reducing the effectiveness of any given incentive offering. Supporting RE policy instrument literature offers limited insights on this issue; this limitation highlights the need for future studies that focus on the specific and direct effects of subsidy and tax incentive policy packages on electricity markets.

The results of this analysis indicate that deregulated states have lower percentages of RE generation than regulated states, yet have higher rates of total RE deployment. Competitive electricity markets, therefore, do encourage RE investment and development. Conventional fossil fuel energy sources are, however, still on average relatively less expensive and thus the majority of new generation in deregulated markets is sourced from fossil fuels instead of renewables.

The amount of windy land area in a state is negatively associated with RE share and RE total. These results are surprising in light of others' findings (Menz and Vachon, 2006; Langniss and Wiser, 2003) and conventional logic, but are supported by the underlying basic statistics used in this analysis. The bivariate correlation coefficients between windy land and the RE dependent variables are both negative, although the coefficient between windy land and RPS policy adoption is positive. A closer look at the data reveal that a number of the states with the highest windy land area—Nebraska, North Dakota, South Dakota, Kansas, Oklahoma, and Wyoming—had not adopted a mandatory RPS policy by the end of the study period, nor did they have high rates of RE deployment. Furthermore, states with the lowest 25 percent of windy land area (≤ 340 km^2) have an average RE share across the study period of 1.75 percent and states with the highest windy land (> 26,475 km^2) have an average of 1.41 percent. The states on neither extreme of the windy land distribution (> 340 km^2 and $\leq$ 26,475 km^2) have a significantly higher average RE share of 3.79 percent. The total amount of RE summarized by windy land area demonstrates similar trends. The least windy states had an average RE generation of 1.72 million MWh, the mid-level windy states had 2.29 million MWh, and the most windy states had .70 million MWh.

It is evident from these statistics that mid-level windy land area states are most aggressively pursuing RE development through RPS policies or other initiatives. States with the smallest amount of windy land are understandably lagging behind the mid-level states, but are still deploying RE at a faster rate that states with the greatest windy land. States with the greatest windy land area are evidently reluctant to adopt measures that promote RE deployment, perhaps assuming that development will occur without mandates or costly incentives. It is worth noting that these states with greater windy land area have low population growth rates and rely heavily on base-load coal as their primary source of energy. These states, therefore, have less of a need for wind development and deployment as a means for meeting relatively minor growth in demand. It is difficult, despite these cursory attempts, to accurately identify the true source of these trends. The empirical literature on this subject could benefit from future analyses that more rigorously address this issue, and include new wind data that account for offshore wind potential. For the purposes of this analysis, I can conclude that simply having decent wind energy potential across a state's boundaries is not enough to make RE deployment economically viable over conventional fossil fuel sources.

In closing, I would like to highlight the importance of a time dimension in this type of analysis. The present study takes an early look at the underlying causal associations between RE incentives and RE development. While I believe that I have appropriately captured early trends as a result RPS adoption and implementation, there is a continued need to update these and other empirical results as RPS policies mature in some states and are adopted in others. It will be particularly important to track associated effects in coming years as states' approach their individual RPS benchmarks.

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Appendix: Alternative estimation approaches

Table 2.5. Alternative Estimation Approaches with Dependent Variable: Logged Share of Renewable Energy Electricity

Independent Variable	Fixed effects	FEVD	Random effects	Pooled OLS
RPS	0.126	0.142	0.179	0.737
	(0.141)	(0.091)	(0.142)	(0.191)***
House LCV voting score	2.213	2.222	2.026	1.011
	(0.424)***	(0.165)***	(0.393)***	(0.347)***
Natural resource employees	1.540	1.498	1.555	0.470
per capita	(0.395)***	(0.093)***	(0.313)***	(0.191)**
Percent petro/coal manufacturing	-13.296	-12.837	-10.235	19.514
of total GSP	(6.608)**	(3.810)***	(6.566)	(7.957)**
Gross state product per capita	0.0001	0.0001	0.00008	-0.00005
	(0.00002)***	(0.0000007)***	(0.00002)***	(0.00001)***
Growth rate of population	-1.262	-1.611	0.451	11.910
	(4.509)	(3.606)	(4.620)	(7.670)
Electricity use per capita	-0.120	-0.118	-0.066	-0.017
	(0.030)***	(0.004)***	(0.015)***	(0.006)***
Average retail electricity price	-0.289	-0.281	-0.199	0.290
	(0.057)***	(0.027)***	(0.054)***	(0.050)***
Percent regional RPS	-0.684	-0.622	-0.732	-1.498
	(0.267)***	(0.180)***	(0.269)***	(0.381)***
Tax index		-0.004	0.062	0.002
		(0.030)	(0.050)	(0.064)
Subsidy index		0.369	0.205	0.691
		(0.048)***	(0.085)**	(0.101)***
Deregulated		-0.753	-0.332	-0.301
		(0.086)***	(0.128)***	(0.182)*
Wind potential		-0.119	-0.188	-0.137
		(0.013)***	(0.074)**	(0.028)***
Biomass potential		-0.00008	0.00006	0.0002
		(0.00005)*	(0.0003)	(0.0001)**
Solar potential		0.00006	0.000006	0.00003
		(0.0000007)***	(0.00004)	(0.00002)*
Year 1999	-0.076	-0.065	-0.050	-0.007
	(0.166)	(0.148)	(0.169)	(0.317)
Year 2000	-0.024	0.004	0.008	-0.217
	(0.247)	(0.247)	(0.252)	(0.444)
Year 2001	0.020	0.049	0.146	0.183
	(0.177)	(0.152)	(0.179)	(0.325)
Year 2002	0.126	0.169	0.309	0.466
	(0.188)	(0.154)	(0.187)*	(0.329)
Year 2003	0.302	0.340	0.523	0.787
	(0.206)	(0.156)**	(0.199)***	(0.332)**
Year 2004	0.222	0.267	0.516	0.941
	(0.243)	(0.161)*	(0.225)**	(0.342)***
Year 2005	0.213	0.251	0.538	0.991
	(0.282)	(0.167)	(0.254)**	(0.354)***
Year 2006	0.167	0.191	0.525	1.084
	(0.325)	(0.173)	(0.287)*	(0.367)***
Year 2007	0.108	0.161	0.613	1.572
	(0.366)	(0.187)	(0.326)*	(0.392)***
FEVD Residuals		0.987		
		(0.025)***		
Constant	-7.207	-7.905	-7.941	-7.581
	(1.095)***	(0.295)***	(1.000)***	(0.630)***
Observations	482	482	482	482
Number of state fixed effects	48			
R-squared	0.40	0.87		0.40

Table 2.6. Alternative Estimation Approaches with Dependent Variable: Total MWh of Renewable Energy Electricity

Independent Variable	**Fixed effects**	**FEVD**	**Random effects**	**Pooled OLS**
RPS	349,858.906	347,794.512	352,824.145	-553,442.574
	(109,869.039)***	(70,843.243)***	(110,650.963)***	(340,762.434)*
House LCV voting score	-135,001.074	-117,185.289	18,624.795	301,410.106
	(331,412.018)	(127,412.887)	(328,019.413)	(617,442.053)
Natural resource employees	-757,086.889	-750,926.651	-676,241.150	1,197,678.218
per capita	(308,676.621)**	(72,912.117)***	(293,951.872)**	(340,969.012)***
Percent petro/coal manufacturing	472,313.664	563,638.852	536,838.333	365,776.907
of total GSP	(5,166,499.483)	(2,922,219.372)	(5,178,831.823)	(14,168,521.060)
Gross state product per capita	65.305	64.937	63.027	59.576
	(19.253)***	(4.659)***	(18.452)***	(22.589)***
Growth rate of population	2,295,957.491	2,520,749.922	2,370,992.796	-42,870,000.000
	(3,525,241.033)	(2,852,383.485)	(3,556,713.028)	(13,657,917.056)***
Electricity use per capita	12,206.701	11,962.653	2,495.487	-3,844.530
	(23,287.738)	(2,348.808)***	(18,915.178)	(11,363.103)
Average retail electricity price	-14,945.502	-13,283.360	15,025.199	841,459.043
	(44,542.739)	(20,300.810)	(44,493.340)	(89,507.027)***
Percent regional RPS	-757,230.118	-757,027.583	-789,333.644	-2,329,213.271
	(208,471.136)***	(140,951.934)***	(211,210.316)***	(679,249.013)***
Tax index		-111,710.227	-102,223.649	-268,112.838
		(23,680.642)***	(38,958.121)***	(114,571.998)**
Subsidy index		909,734.328	23,515.330	681,729.517
		(37,241.407)***	(66,297.066)	(180,236.084)***
Deregulated		485,148.379	49,599.562	-380,766.990
		(67,397.871)***	(100,452.334)	(324,137.971)
Wind potential		-432,039.773	-400,904.224	-537,488.005
		(10,225.410)***	(139,021.466)***	(49,320.346)***
Biomass potential		687.014	603.707	1,128.038
		(36.247)***	(501.485)	(174.472)***
Solar potential		347.096	332.928	426.696
		(5.638)***	(76.463)***	(27.070)***
Year 1999	-24,599.650	-26,586.283	-14,045.957	932,629.376
	(129,623.244)	(116,818.474)	(130,256.376)	(564,532.783)*
Year 2000	-98,071.396	-104,577.874	-89,007.939	2,097,386.729
	(193,425.299)	(164,405.169)	(194,562.593)	(790,115.183)***
Year 2001	-112,467.797	-109,227.857	-104,735.740	727,162.415
	(138,593.232)	(119,747.861)	(139,668.968)	(579,219.023)
Year 2002	-22,279.132	-16,892.397	1,519.974	1,121,336.769
	(147,285.887)	(121,297.935)	(148,776.805)	(585,585.475)*
Year 2003	-74,748.764	-66,304.146	-42,995.759	1,040,989.576
	(160,993.048)	(122,244.820)	(161,252.548)	(590,331.257)*
Year 2004	-166,206.408	-156,852.153	-132,668.127	968,380.164
	(189,766.434)	(126,215.377)	(188,321.082)	(609,582.426)
Year 2005	-194,956.479	-177,111.359	-147,433.024	802,098.595
	(220,199.723)	(130,419.071)	(217,288.222)	(630,600.695)
Year 2006	-196,022.132	-168,726.629	-143,774.004	335,939.857
	(254,096.668)	(134,717.005)	(249,859.874)	(652,734.388)
Year 2007	-156,664.960	-106,040.041	-54,289.282	897,989.930
	(286,100.312)	(144,308.048)	(287,135.274)	(698,029.276)
FEVD Residuals		0.999		
		(0.010)***		
Constant	157,952.138	-4,324,110.186	-2,167,087.644	-11,890,000.000
	(856,118.837)	(242,842.624)***	(1,166,214.032)*	(1,121,539.846)***
Observations	480	480	480	480
Number of state fixed effects	48			
R-squared	0.19		0.98	
0.50				

CHAPTER 3

DECENTRALIZATION: THE CASE OF DISTRIBUTED GENERATION AND METERING STANDARDS

Introduction

Dating back to Edison and his close successors, the scale of electricity operations in the United States over the past century has steadily risen. Whereas the U.S. started in the late 19th century with dispersed generation units, it eventually built larger, centralized generation units in conjunction with AC generation and a more dynamic and extensive transmission and distribution infrastructure. Exploiting economies of scale, these developments enabled power producers to spread higher voltages across great distances. By the 1920s and 1930s, centralized electricity operations became the predominant scale of electricity production; electricity became the biggest industry in the U.S. economy, while federal support for the deployment of electricity operations grew at an unprecedented level.

While centralized electricity and large-scale transmission and distribution networks still dominate the industry, this model of electricity generation has been challenged in recent decades. Critics of large-scale electricity operations question their costs, security vulnerabilities, environmental impacts, and waste in generation and transmission, and advocate instead for a more decentralized industry composed of a greater number of smaller-scale and more localized generating facilities. In view of these concerns, some industry leaders have begun to modify the scale of their electricity operations. Policymakers have concurrently enacted legislation that specifically focuses on size and alternative forms of production.

The present study aims to empirically identify the motivating factors behind the trend toward a more decentralized electricity industry. Specifically, this analysis considers which factors lead an electric utility or a utility's customer to deploy distributed generation (DG) systems. Consistent with this objective, the following research questions guide this analysis: do some ownership models demonstrate a greater proclivity toward DG deployment than others and, are distributed generation policies and regulations effective at removing the barriers to distributed generation adoption and deployment?

Distributed generation: Moving beyond a definition

What is Distributed Generation?

Distributed generation is the subject of a rapidly evolving body of research. Over the past decade much attention has been devoted to the definition (Ackermann, et al., 2001; El-Khattam and Salama, 2004; King, 2006; Pepermans, 2005) and classification (Gumerman, et al., 2003; Lopes, et al., 2007; Pepermans, 2005) of DG systems. The following is the author's own working definition of distributed generation systems, classified according to defining characteristics that include size, location, and application.

Location

DG systems are frequently built close to the power load to minimize electricity losses and inefficiencies. DG units are either connected to the electricity network (hereafter referred to as the “grid”) on the customer side of the meter or at the distribution network. Traditionally, either utilities own and operate their own DG systems or their customers own the systems and “borrow” or “lend” power to the electricity grid when needed. Net metering policies and programs—the former is mandated by the state or federal government and the latter is self-initiated by specific utilities—allow commercial, industrial, and residential customers to “hook” their DG units or other micro-generation units to the grid. Under a traditional net metering framework, customers are able to buy (or “sell”) electricity from (to) the grid when the DG capacity is short (in excess) of the customers’ electricity needs.

Size

DG systems generally produce between 1 kW and 5 MW of power. Medium to large DG systems can produce over 5 MW and up to 300 MW of power, though there is some dispute over whether these larger systems can truly be classified as DG units (Ackermann et al., 2001).

The majority of studies that consider the role of DG power in the electricity, industrial, or building sectors, with the exception of those who specifically focus on the broader definition or classification of DG systems, tend to identify DG power only by location or size attributes. Some additionally classify DG power according to type of technology, as is typical of Energy Information Administration (EIA) studies and other studies that aim to model the deployment of DG power over time (see, for instance, EIA, 2005 or Boedecker et al., 2002). Yet a definition based solely on these attributes does not provide information about the application or specific use of DG systems, or about how these attributes vary according to different types of DG applications. A definition based on application, as well as size and location, therefore, can help us identify the motivating factors that lead to DG deployment in different circumstances.

Applications

There are a variety of DG system applications, all of which are designed to serve different functions and use different, yet overlapping, technology and fuel types. I conceptually divide these applications into six different classification categories: peaking plants, standby power, combined heat and power units, micro-generation systems, remote applications, and localized conventional plants.

Peak load shaving plants provide supply security during times of peak electricity usage. These plants generally deploy natural gas, diesel, petroleum, battery, solar, or flywheel power. Peaking DG plants are typically owned by either a utility or a major industrial or commercial electricity consumer. DG technologies have the ability to shave peak electricity demand and concurrently reduce grid operator costs through the provision of ancillary services and interruptible load operations (King, 2006).

Standby power systems are designed to provide power in times of outages or failures. Standby power systems are able to serve the needs of both utilities and industrial or commercial facilities. Utilities use standby systems for grid support to help meet short-term power needs during scheduled shutdowns or during power feed failures. Industrial or commercial users deploy standby systems when facility outage costs are high or when outages may potentially compromise human lives or have other severe effects. For instance, hospitals are likely to own standby DG systems when power is critical to life support. Diesel fuel is the most typical fuel source for standby power systems (EPA, 2007).

Combined heat and power (CHP) systems, also known as co-generation systems, are DG applications that generate electricity and also capture the thermal energy from the process' waste heat. The thermal energy can then be used for cooling, heating, or other power applications, and helps increase fuel efficiencies by 80 percent or more. Internal combustion engines ("reciprocating engines"), external combustion engines ("Stirling engines"), and micro-turbines are the most common CHP units. Anaerobic digesters and industrial biomass operations can also be used with CHP technologies. CHP systems are often owned and operated by commercial or institutional organizations, metal industries, paper or chemical industries, or electricity providers.

Micro-generation units are small-scale systems that are primarily powered by renewable or alternative sources, such as fuel cells, solar photovoltaic, micro-wind, or micro-hydro. These units are best catered to meet residential electricity needs and constraints. These units have positive environmental benefits but typically have high start-up and equipment costs.

The fifth type of DG technology, a remote power system, is the most general classification. Anaerobic digesters or other biomass operations, micro-hydro, wind or solar power, or a variety of natural gas systems are capable of providing power to homes, communities, or other facilities that are beyond a utility's service territory or isolated from the grid. When isolated from the grid, remote power systems are classified as dispersed power units; when connected to the grid, they are distributed generation units.

The final type of DG technology resembles a conventional power plant in purpose—it functions as a standard utility investment in generation capacity—but differs in size and location. These plants tend to be smaller and more localized than conventional, centralized power plants. Localized conventional plants tend to burn natural gas and some alternatively deploy renewable fuel sources.

Barriers to Adoption

A number of economic and institutional barriers currently prevent DG technologies from playing a more prominent role in the U.S. electricity sector (Alderfer, et al., 2000; Budhraja, et al., 1999; Dondi, et al., 2002; Johnston, et al., 2005; Johnson, 2003; King, 2006; Morgan and Zerriffi, 2002; Strachan and Dowlatabadi, 2002; Van Werven and Scheepers, 2005). The following is a list of the most frequently cited barriers that may, depending on political and economic circumstances within each state, hinder the adoption and deployment rate of all DG types.

- There are no national procedures for standard interconnection of DG systems, insurance policies, technical standards for the necessary connecting equipment, standard tariff payment schemes, and power quality characteristics;
- DG system operators must get an approval of various technical parts from either the local serving utility or their state’s regulatory commission, which requires considerable time, financial resources, and effort;
- The U.S. does not currently have greenhouse gas emissions’ regulations;

- Utilities have inexperience dealing with DG operators and thereby rarely have standard interconnection procedures of their own;
- The approval process for DG systems can be long and require significant effort;
- The associated fees for interconnection to the central grid may be very high;
- Regulatory appeals may be prohibitively expensive;
- DG systems may not recover appropriate payback due to a lack of standard tariff schemes.

Policy Instruments

In effort to address the barriers to DG, state governments across the country have introduced a variety of policies and regulations to support DG electricity market penetration. DG policies and regulations include interconnection standards, net metering programs, and renewable portfolio standards (RPS). Interconnection standards are state-implemented standards that explicitly outline the protocols—including technical, contractual and procedural—that a utility must adhere to when hooking DG units up to the grid. Net metering programs, as defined previously, mandate that utilities must allow DG owners to hook their systems up to the electrical grid, conditional on specific size and type of generation constraints. DG owners can then give or take power from the grid. Renewable portfolio standards mandate that a certain share of electricity generation comes from renewable or alternative energy sources. RPS policies vary by state in their design features, benchmark goals, and enforcement mechanisms.

Previous Findings on DG Motivators

Over the past five years, the number of quantitative analyses that focus on DG has increased significantly. The majority of these economic analyses consider the market performance of different DG systems. Some analysts review the costs associated with DG technologies (Abu-Sharkh et al., 2004) and compare them to traditional electricity operations (Ackerman, 2007). Some have devised systematic methods to track the costs and benefits of DG systems, while others have estimated a full cost-benefit analysis (Costa, 2006; Gulli, 2004; Gumerman, et al., 2003; Poullikkas, 2007). A number of analysts have used energy and building data, and occasionally DG building performance software, to model either actual or hypothetical DG systems according to optimal technology performance, location of load, and system costs (Abu-Sharkh et al., 2004; Bailey et al., 2002; Poullikkas, 2007). Finally, some analysts have estimated DG penetration rates in traditional electricity markets under different regulatory scenarios (Maribu et al., 2007; Zoka et al., 2007).

While these analyses do not necessarily share a consensus regarding which factors most effectively contribute to DG deployment, many of these analysts surmise that deployment could be accelerated with the implementation of policy incentives and regulatory measures that address the barriers listed above. Strachan and Dowlatabadi (2002) evaluated which factors have influenced the UK and the Netherlands to deploy high rates of DG capacity; they found that buy-back tariffs are effective motivators, particularly in conjunction with interconnection charges, government subsidies, and other performance-based regulation. Few studies, however, have empirically tested the association between U.S. state policy incentive adoption rates and DG deployment rates.

Dismukes and Kleit (1999) evaluated which factors lead industries to sell their DG generation to the grid or to keep their power for internal use. They found that increases in retail electricity prices and greater industrial output contribute to the likelihood of industrial DG connection to the grid.

There are no studies that consider which motivating factors lead actors to adopt DG operations. With limited insights from the supporting literature and a lack of comprehensive data on the subject, this analysis begins to approach this issue with fairly general questions and simple hypotheses regarding the motivating factors for DG deployment. The aim of this analysis, therefore, is to provide a foundation of empirical findings upon which future analyses can build. I test two main hypotheses. The first hypothesis is that state DG policies and regulations are effectively able to reduce the barriers to DG adoption and deployment. The second main hypothesis that this analysis tests is the following: private utilities are more inclined to deploy DG capacity than are various public utilities. This hypothesis is built on the assumption that private companies are more willing to make investments in relatively newer, perhaps riskier from a financial perspective, technologies and are more concerned with managing peak electricity loads.

Empirical approach

The econometric model used in this analysis considers utilities' decisions of whether to adopt DG operations and, if so, how much capacity to deploy. Roughly 94 percent of the utilities in this sample do not have active DG units hooked to the grid in their service territory. These observations, as a result, have a dependent variable—DG capacity—that is equal to zero. These zeros effectively represent the actual outcomes, i.e.

what is observed, as opposed to missing data or potential outcomes. Potential outcomes are latent, partially observed variables. An example of a potential outcome in the present context would be the amount of DG capacity that a utility would deploy *if* it had DG units hooked into their service territory, whereas the actual outcome is the *observed* amount of DG capacity among those utilities that have chosen to hook up DG units. If one is interested in potential capacity deployment, he or she would use a selection model. The present analysis, however, is interested in the actual deployment and, therefore, employs the more efficient two-part model. A two-part model is able to identify the large proportion of zeros, which are non-missing "corner solutions," and does not lose efficiency from the inclusion of the inverse Mills ratio, as a selection model would under these circumstances (Dow and Norton, 2003). The two-part model will also estimate lower mean squared errors than standard selection models.

The two-part model has two equations. The first part of the two-part model is a standard probit estimation of the probability that the dependent variable has a positive outcome:

$$\Pr[y > 0 | X] = \Phi(X\beta_1, \varepsilon_1), \tag{1}$$

where y is the dependent variable, utility has DG capacity, X is a vector of utility- and state-level parameter estimates, and ε_1 is the error term, assumed to be normally distributed. The second part model is a simple ordinary least squares estimation, conducted on the subset of the sample that has a positive dependent variable:

$$E[y \mid y > 0, X] = X\beta_2 + E[\varepsilon_2 \mid y > 0, X], \tag{2}$$

where y is the dependent variable, measured in MW of DG capacity, X is the same vector of parameters estimated in (1), and ε_2 is the error term, also assumed to be normally distributed.

The choice of the two-part model has important consequences for the interpretation and estimation of predictions and effects. When estimating marginal effects and significance of hypothesis tests it is important to similarly estimate the actual effects, and not simply the potential effects. I estimate the actual marginal effects using the equation presented by Dow and Norton (2003), and then bootstrap the standard errors:

$$\partial E[y] / \partial x_k = (\Pr[y > 0 | X] \times (\partial E[y \mid y > 0, X] / \partial x_k)) + (E[y \mid y > 0, X] \times (\partial \Pr[y > 0 | X] / \partial x_k)), \tag{3}$$

where y and x are the same as above, $\Pr[y > 0 \mid X]$ is the probability of a positive observed outcome, and $E[y \mid y > 0, X]$ is the mean outcome, conditional on that outcome being positive.

The DG units in this sample are either owned by the utility or owned by a commercial or industrial consumer within the utility's service territory and allowed access to the grid by the utility. The data used in this analysis do not explicitly distinguish between utility-owned and consumer-owned DG capacity. This distinction, however, has specific relevance to the research question and a failure to measure these differences in ownership-type could potentially result in misleading or incomplete information. In effort to capture the differences between utility-ownership and consumer-ownership of the DG units in this sample, I draw inferences from supporting data to obtain a rough estimate of the breakdown in ownership type across all units in the sample; the details of this process are outlined below. I then run separate probit models[11] on the two sample subsets; the first model tests which factors are related to consumer-owned DG adoption and the second model tests which factors are related to utility-owned DG adoption. This exercise provides a few additional insights regarding DG ownership and the relationship between utilities and their customers in the presence of DG operations.

I additionally test for heteroskedasticity with a White test (White, 1980) and multicollinearity by checking the variables' variance inflation factors and bivariate correlations. I also test the functional form of important independent variables to ensure that we operationalize these variables appropriately.[12]

Data

This analysis considers which types of utilities are more likely to adopt DG power generation and, additionally, which factors motivate these utilities to include DG in their total electricity generation mix. In this vein of inquiry, I employ a variety of data sources that include information on utility characteristics, state policies, electricity trends, and socio-economic factors. The data are primarily extracted from Energy Information Administration 2005 data. As part of EIA's "Annual Electric Power Industry Report," utility-level data are gathered via Form EIA-861. There are both advantages and disadvantages to using these data as our primary source of information. The advantage is

[11] I only run the first part of the two-part model, the probit model, because the second part, the ordinary least squares, would have incorrect standard errors from a sample size that is too small.

[12] It is not apparent, on either a theoretical basis or after looking over the data, whether utility-level variables should be combined to represent a public versus private utility construct, or left to represent entirely different utility structures. If I were to combine utility types, we would clump state, federal, municipal, political subdivision, and municipal marketing authorities (MMA) together as "public," but leave private and cooperatively owned facilities as they are. I estimate a series of specification tests—a Wald test and a Lagrange Multiplier (LM) test—to determine whether I should combine all public utility models or keep them separate; the results are presented below.

that Form 861 has a wealth of utility-specific data on firm revenues, total dispatched power, retail sales, number of customers by sector, and, crucial to this analysis, distributed generation figures. The disadvantage to using these data is that they do not contain plant-specific details. Although it would be informative to include data on plant capacities, the break down of plant types by utility, or fuel expenditures, this information is not available in Form 861. A second disadvantage is that the type of DG capacity included in the database is not clearly defined or classified. In effort to classify the DG capacity considered in this analysis according to the defining characteristics discussed above, I use supporting information in the EIA-861 database about the fuel source and technology, as discussed below.

For the purposes of the present analysis, I compile aggregate operational data from file 1, net metering data from file 5, and distributed generation data from file 6 of EIA-861. Additional variables—most of which are measured at the state level—are collected from the U.S. Census Bureau and the Database of State Incentives for Renewables and Efficiency (DSIRE). These data are limited to observations from the 48 contiguous U.S. states and exclude information on D.C., Hawaii, Alaska, American Samoa, and Puerto Rico. The resulting database is aggregated at the utility level with a sample size of 3,277 for the first-part model and 194 for the second part model. The sample size drops to 3,226 in the customer-owned DG probit model due to a few independent variables that perfectly predict the outcome variable. All data are in 2005 values, the most recent figures available at the time in which this analysis was conducted.

Dependent Variable

The dependent variable is the total amount of distributed generation capacity per utility, measured in megawatts (MW). This variable is extracted from EIA-861. As explained above, the DG units in this sample are either owned by the utility itself or owned by a commercial or industrial customer within the utility's service territory. This analysis does not include dispersed generation—grid-isolated small-scale electricity units—in the DG capacity estimates. This means that all DG systems included in this sample are connected to the grid at the customer or utility side of the meter, and are all subject to utility oversight.

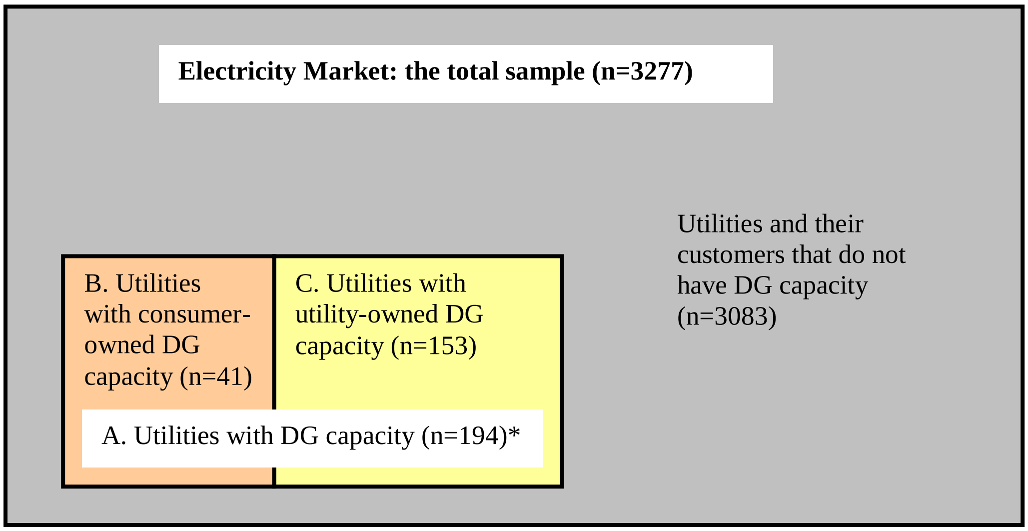
Two forms of the dependent variable are needed for a two-part model: the first part of the two-part model uses a dichotomous transformation of the variable, equal to one if the utility has DG capacity and equal to zero otherwise; the second part uses the subset of the variable that is continuous, contingent on the DG capacity being positive.

The two probit models that check the differences between customer-owned and utility-owned DG capacity use the dichotomous version of the DG variable. I distinguish between customer-owned and utility-owned DG capacity based on whether the utilities have net metering customers. If a utility reports under file 5 of Form EIA-861 that they have net metering customers and they also report under file 6 that they have DG capacity, then we assume that this capacity is consumer-owned. If, on the other hand, the utility does not participate in net metering protocols, then we assume that all the DG capacity is solely owned by the utility.

I provide a visual representation of the sample to help guide the reader through the discussion of each model's results (see Figure 3.1). The two-part model employs the dependent variable labeled "A" in the diagram, which encompasses both "B" and "C".

The consumer-owned and utility-owned probit models use “B” and “C” as the dependent variables, respectively.

Figure 3.1. Visual of Sample Distribution



* Diagram is not drawn to scale.

Independent Variables

The primary variables of interest include utility ownership types and state policies and regulations. Beginning with the former, Form EIA-861 includes seven utility ownership models: private, cooperative, municipal, Federal Power Marketing Administration, state power authority or organization, municipal marketing authority (MMA), and county-level subdivision, irrigation district, or utility district. Each of these variables is transformed into a dichotomous variable, equal to one if it appropriately represents the utility’s ownership model and equal to zero otherwise. Throughout the remainder of this study, I refer to all utilities that are independently owned as “private” and all government- or cooperative-owned utilities as “public”.

The policy instrument variables include net metering standards, RPS policies, and interconnection standards. I include a binary net metering variable in the two-part model, equal to one if the utility has net metering customers and equal to zero otherwise. This variable is not included in the consumer-owned versus utility-owned probit models. Instead, as explained above, this variable is used to help distinguish between the two ownership types. The RPS policy and interconnection standard variables are both dichotomous, coded as a one if the policy is active in 2005. Both variables are compiled from the DSIRE database. Any state that enacted a policy during or after November, 2005 is considered to have an inactive policy during the period of analysis and is coded to equal zero.

Additional utility-level characteristics are included as covariates. We control for summer peak power output, measured in megawatts. Since peak load shaving plants are one of the primary DG units included in this analysis, we assume that higher peak capacity will be associated with greater DG deployment. Peak power is the maximum amount of power that was sold in the summer of 2005 during the month and the specific day of highest electricity demand. Total sources of power, another utility-level variable, is the total megawatt-hours of power sold in retail markets over all of 2005. This variable is re-scaled by a factor of 10,000 MW. Therefore each 1 MW of total sources in the summary statistics and regression outputs represents 10,000 MW.

State-level electricity characteristics include the price of electricity and the state's status of electricity market restructuring. The price of electricity, extracted from EIA electricity data, is the average of electricity prices from all electricity sources per state in 2005. The deregulation variable indicates whether a state has restructured its electricity market. States that have either partially or fully restructured their electricity market are coded to equal one; states that have kept their market regulated or have “destructured” their market after a period of deregulation have a regulation variable equal to zero.

Finally, I control for the following state demographics: average household income, measured in $1,000 of U.S. dollars; population, measured in 100,000 citizens; and binary regional dummy variables. We include the region variables to control for location-specific dynamics that may affect DG deployment rates. Population and household income data come from U.S. Census Bureau data.

Results

Results of the collinearity diagnostics revealed that multicollinearity between variables did not exist; variance inflation factors were all small and below standard threshold levels and all bivariate correlations were well below .8. The White test did detect heteroskedasticity, however, and so we estimated robust standard errors in the final version of our two-part model to correct this problem.[13]

Before turning to the empirical results, it is informative to consider dependent variable, and note how well it conforms to the working definition of DG systems, as defined above. Beginning with a discussion of DG applications, Form EIA-861 does not

[13] Additional specification tests revealed somewhat conflicting information about the most appropriate form of the utility-type variable. I first conducted a Wald test on both parts of the two-part model to test whether the public utility parameters were equal to each other. The resulting chi-squared test statistics, with four degrees of freedom, were .77 for the first part model and 159.62 for the second part model. I therefore could not reject the null hypothesis of equality in the first part, which estimates likelihood of adoption, but could reject the null hypothesis in the second part, which estimates total capacity conditional on having any at all. A two-part model, however, should ideally include the same set of parameters in both parts of the model. I similarly conducted an LM test on both parts of the model to further explore this issue of specification. The NR^2 from the second part equation, with five degrees of freedom, was 60.16 and thereby significant at all conventional significance levels. For the LM calculation in the first part equation, I adjusted for non-linearities and heteroskedasticity as part of the NR^2 calculation. The resulting NR^2 estimate was 12.62, which was significant at the 10 percent significance level. I concluded that the utility parameters should not be clumped into one public utility variable but should remain separate variables.

explicitly distinguish between different applications of DG power—for instance, between peak load shaving and micro-generation—with one exception: CHP units are excluded from the DG classification. I can draw additional conclusions about the DG system attributes from EIA-861 supporting data. Figure 3.2 presents the percentage distribution of DG units by fuel type. Distillate fuel and natural gas are the most common types of fuel, which collectively contribute 72.6 percent of the total units. Water and other renewables provide fuel for 8.5 percent of the DG units in the sample. Figure 3.3 presents the percentage distribution by technology type. The majority of the DG units are internal combustion engines or combustion turbines. Roughly 11 percent of the DG units in the sample come from wind or hydroelectric power. Although it is not demonstrated in either graph, roughly 32 percent on average of the DG capacity is used for back-up power, the majority of which comes from internal combustion engines using distillate fuel. This information does not allow one to fully classify the technology distribution of DG units in this sample according to the above definition, although it does provide a rough picture of DG type and fuel source.[14] Based on these attributes, I conclude that the DG variable in this sample primarily represents peak load shaving and backup power, some localized conventional DG plants, as well as an occasional remote power system that is connected to the grid. CHP is not included and micro-generation is hardly included, if at all. [15]

[14] DG capacity size is discussed below in the Results section.

[15] These conclusions regarding the DG variable have been confirmed by the Department of Energy's Form EIA-861 contact in a personal phone meeting.

Figure 3.2. Percent Distributed Generation by Fuel Type

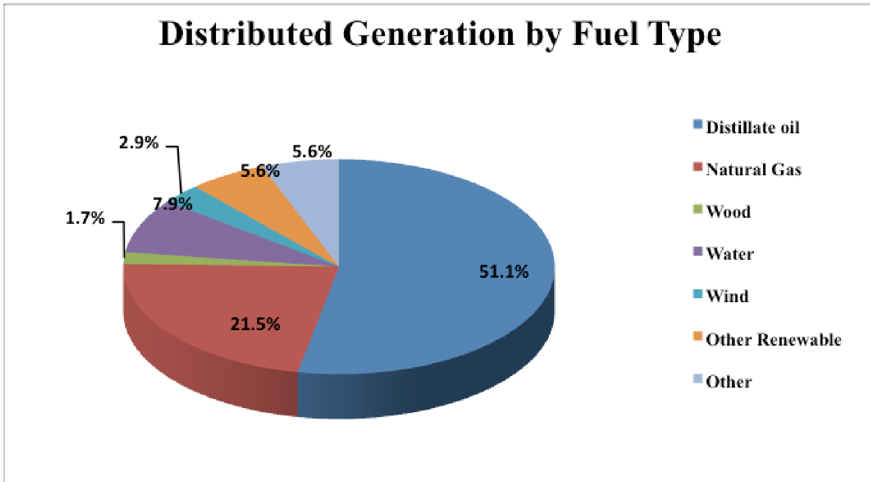
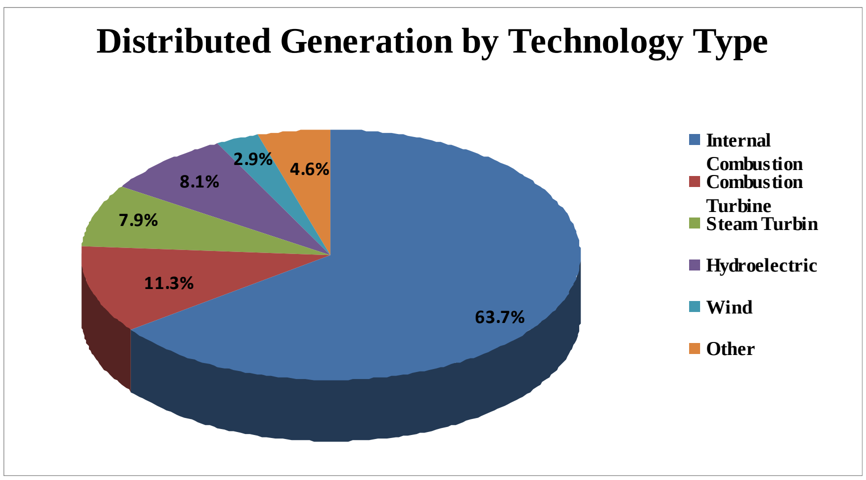


Figure 3.3. Percent Distributed Generation by Technology Type



I further divide DG fuel types according to whether the system is owned by a utility or a customer. Figures 3.4 and 3.5 reveal that utility DG systems are primarily fossil fuel-based, with roughly 78 percent of the systems powered by distillate oil or natural gas. The customer-owned DG systems, on the other hand, include a greater share of renewable fuel types. Customers appear more inclined to adopt renewable-based DG systems than utilities.

Figure 3.4. Utility-owned Distributed Generation by Fuel Type

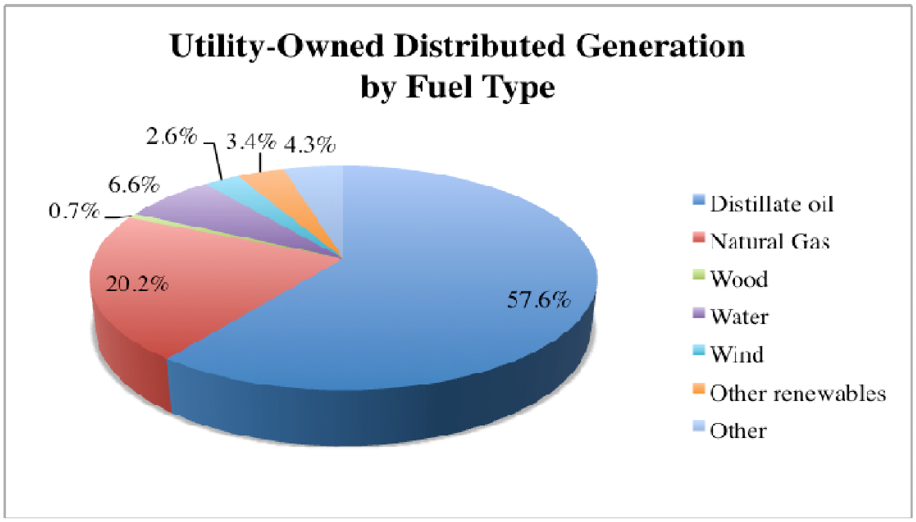
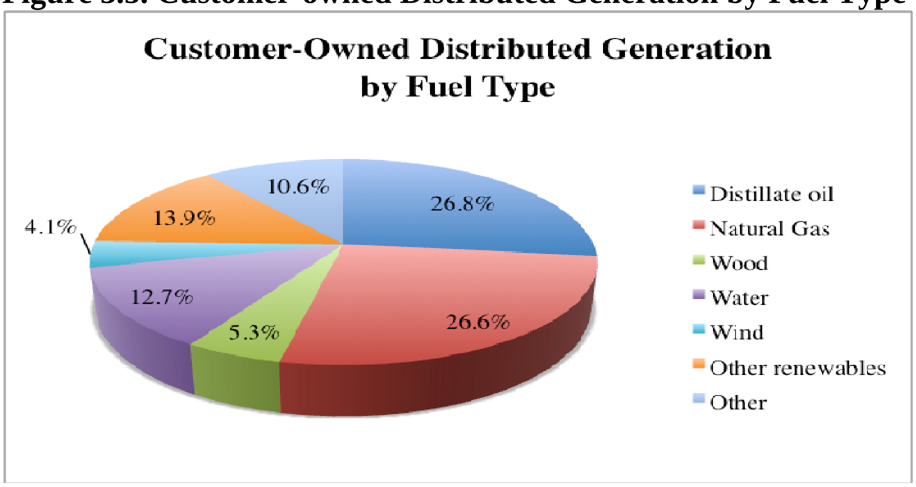


Figure 3.5. Customer-owned Distributed Generation by Fuel Type



Because I employ a two-part model, separate summary statistics are presented for the entire sample, where the dependent variable is dichotomous (see Table 3.1), and for the sub-sample of utilities that had positive DG capacity (see Table 3.2). The maximum DG capacity owned by one utility was 1,391 MW. As explained above, 3,083 utilities, or 94 percent of the sample, did not have any DG capacity. Of the remaining 194 utilities that did have DG capacity, they averaged roughly 53 MW of capacity per utility.

Table 3.1. Variable Definitions and Summary Statistics for the Entire Sample (n=3,277)

Variable	Description	Mean (or %)	Std. Dev.	Min	Max
DG capacity	Utility has distributed generation capacity	5.94%	0.236	0	1
Utility Ownership					
Private	Utility is a private company	6.67%	0.250	0	1
Co-op	Utility is a cooperative	26.91%	0.444	0	1
Muni	Utility is a municipal	56.17%	0.496	0	1
Federal	Utility is a Federal power marketing administration	0.27%	0.052	0	1
State	Utility is a state organization	0.76%	0.087	0	1
MMA	Utility is an Municipal Marketing Authority	0.61%	0.078	0	1
Pol-sub	Utility is a county-level subdivision, utility-district, or irrigation district	3.87%	0.193	0	1
Utility-level characteristics					
Summer peak	Megawatts (MW) of maximum power sold during peak summer month	290.38	1,472.11	0	31,924
Total sources	Total sources of power (MW)	265.64	1,569.38	0	42,689
Net metering	Utility has net metering customers	5.71%	0.232	0	1
State-level characteristics					
RPS policy	State has a renewable portfolio standard	32.53%	0.469	0	1
Interconnection standards	State has distributed generation interconnection standards	55.93%	0.497	0	1
Access laws	State has renewable energy access laws	71.90%	0.450	0	1
Deregulated	State is fully or partially deregulated	29.29%	0.455	0	1
Household income	Average state household income	45.21	5.56	32	63
Population	Total state population	75.19	71.37	5	361
Price of electricity	State's average price of electricity, averaged across end-use consumers	7.52	1.97	5	18
Northeast	State is in the Northeast region	9.86%	0.298	0	1
Southeast	State is in the Southeast region	21.06%	0.408	0	1
Southwest	State is in the Southwest region	11.57%	0.320	0	1
Midwest	State is in the Midwest region	43.91%	0.496	0	1
West	State is in the West region	13.61%	0.343	0	1

Table 3.2. Variable Definitions and Summary Statistics for the Subset of the Sample with Distributed Generation Capacity (n=194)

Variable	Description	Mean (or %)	Std. Dev.	Min	Max
DG capacity	Total Megawatts of distributed generation capacity	3.15	40.19	0	1391
Utility Ownership					
Private	Utility is a private company	30.26%	0.461	0	1
Co-op	Utility is a cooperative	10.26%	0.304	0	1
Muni	Utility is a municipal	52.31%	0.501	0	1
Federal	Utility is a Federal power marketing administration	0.51%	0.072	0	1
State	Utility is a state organization	1.03%	0.101	0	1
MMA	Utility is an Municipal Marketing Authority	1.03%	0.101	0	1
Pol-sub	Utility is a county-level subdivision, utility-district, or irrigation district	3.87%	0.193	0	1
Utility-level characteristics					
Summer peak	Megawatts (MW) of maximum power sold during peak summer month	1411.98	3419.06	0	22,361
Total sources	Total sources of power (MW)	911.8	2652.67	0.04	28,611
Net metering	Utility has net metering customers	21.1%	0.409	0	1
State-level characteristics					
RPS policy	State has a renewable portfolio standard	33.00%	0.471	0	1
Interconnection standards	State has distributed generation interconnection standards	62.56%	0.485	0	1
Deregulated	State is fully or partially deregulated	32.82%	0.471	0	1
Household income	Average state household income	46.84	5.41	33	61
Population	Total state population	71.15	70.74	6	362
Price of electricity	State's average price of electricity, averaged across end-use consumers	7.9	2.28	5	18
Northeast	State is in the Northeast region	9.79%	0.298	0	1
Southeast	State is in the Southeast region	7.73%	0.268	0	1
Southwest	State is in the Southwest region	7.73%	0.268	0	1
Midwest	State is in the Midwest region	46.39%	0.5	0	1
West	State is in the West region	18.56%	0.39	0	1

Of the 194 utilities that had adopted DG units by 2005 (area "A" in Figure 3.1), 59 of them were private utilities (26.9% of all private utilities in sample), 102 were municipals (5.5% of all municipals in sample), 20 were cooperatives (2.3%), nine were political subdivisions (7.1%), two were MMAs (10%), one was state (4.8%), and one was federal (11%). The distribution of DG ownership between utilities and customers is discussed below. Additionally, of the total amount of DG capacity, roughly 71 percent was present in states with RPS policies and 66 percent of the capacity was in states with interconnection standards.

Results of the two-part model are presented in Table 3.3. All ownership parameters are in reference to private utility, which was selected as the omitted category to make the interpretation of coefficient estimates—private versus various forms of public utilities—more logical. Beginning with the first part equation, which can be interpreted as a standard probit model, one should note that all utility-type coefficient estimates are negative; this implies that all utility ownership models were less likely to deploy DG units than private companies. Cooperatives and municipals are particularly less likely to deploy DG than private utilities; these estimates are statistically significant at the 1% and the 5% levels, respectively. Other utility- and state-level characteristics are also found to be statistically significant: higher summer peak levels, electricity price, and household income are found to make DG adoption more likely; utilities that operate under deregulated markets are also more likely to adopt DG capacity; and utilities that follow net metering protocols and have net metering customers are significantly more likely to deploy DG capacity. A larger population in the state in which a given utility's service territory is located, on the other hand, appears to make DG adoption less likely. Finally, relative to the Midwest, the Northeast is found to be less likely to adopt DG capacity.

Table 3.3. Two-Part Model Results with Dependent Variable: Distributed Generation Capacity in MW

Independent Variable	First Part Equation: Probit	Second Part Equation: OLS
Utility Type		
Cooperative [a]	-.807***	-22.73
	(.144)	(23.03)
Muni	-.284**	-11.65
	(.120)	(26.31)
Federal	-.439	21.11
	(.607)	(55.21)
State	-.434	1257.61***
	(.485)	(42.39)
MMA	-.030	131.58
	(.402)	(121.73)
Pol-sub	-.262	18.10
	(.206)	(50.81)
Utility-level Characteristics		
Summer Peak	.000086***	.016*
	(.000021)	(.0087)
Total Sources	-.0000054	.0031**
	(.000025)	(.0013)
Net metering	.715***	26.20
	(.130)	(33.70)
State-level Characteristics		
RPS	.012	-35.82**
	(.106)	(16.16)
Interconnection Standards	.042	-33.79
	(.101)	(25.10)
Deregulation	.216 *	-19.09
	(.116)	(15.25)
HH income	.017 *	1.61
	(.0099)	(1.38)
Population	-.0025***	.411
	(.00076)	(.258)
Price electricity	.090 ***	-2.94
	(.030)	(4.62)
Northeast region[b]	-.906***	54.36
	(.216)	(46.88)
Southwest region	-.266	43.72
	(.172)	(37.02)
Southeast region	.025	23.66
	(.122)	(21.92)
West region	-.177	2.49
	(.132)	(21.37)
Constant	-2.56 ***	-35.94
	(.446)	(78.13)
Observations	3277	194
R^2		0.6539

Note: standard errors in parenthesis; * p<.10, ** p<.05, ***p<.01.
a. Omitted category: private utility b. Omitted category: Midwest

The second stage of the two-part model can be interpreted as an ordinary least squares (OLS) regression output. Of this sub-sample of utilities that have positive DG capacity (only area "A" of Figure 3.1), state utilities are estimated to have 1,258 MW more DG capacity than private utilities. Increases in summer peak load and total sources are associated with a 16 and a 3-kilowatt increase in DG capacity, respectively, and are both statistically significant. Holding all else constant, states with active RPS policies are estimated to have significantly less DG capacity than states without RPS policies. The R-squared in this second stage equation is .65, from which one can infer that this model explains a decent degree of the variation in DG capacity. It is also possible, however, that such a high R-squared reveals a possible over-fitting of the model since we have included 19 variables for 194 observations.

Actual marginal effects from the combined model—with bootstrapped standard errors—reveal that cooperatives are estimated to have, on average, 4.4 less MW of DG capacity than private utilities, while state utilities are estimated to have 73.4 more MW than private utilities (see Table 3.4). Additionally, utilities that have active net metering programs with enrolled participants are estimated to have 4.8 more MW than utilities without net metering programs.

Table 3.4. Bootstrapped Marginal Effects from the Two-Part Model with Dependent Variable: Distributed Generation Capacity in MW

Variable	**First Part Model**		**Second Part Model**		**Combined Model**	
	Marginal Effect	Standard Error	Marginal Effect	Standard Error	Marginal Effect	Standard Error
Utility Ownership						
Co-op	-0.064***	0.011	-22.73	25.02	-4.42*	2.58
Muni	-0.031**	0.015	-11.65	27.13	-2.20	2.87
Federal	-0.033	0.081	21.11	46.06	-0.058	3.97
State	-0.033	0.024	1257.61**	623.26	73.35***	6.01
MMA	-0.003	0.036	131.58	130.55	7.63	7.85
Pol-sub	-0.023	0.016	18.10	51.07	0.234	3.24
Utility-level characteristics						
Summer peak	0.0016	0.0013	0.016	0.014	0.00094	0.00071
Total sources	0.00032	0.0018	0.0031	0.022	0.00018	0.0011
Net metering	0.115***	0.029	26.20	33.77	4.78***	1.71
State-level characteristics						
RPS policy	0.0013	0.249	-30.853**	16.05	-2.02	1.25
Interconnection standards	0.0044	0.0095	-33.79	25.56	-1.65	1.71
Deregulated	0.024*	0.014	-19.09	19.061	-0.048	0.960
Household income	0.168	0.154	1.61	1.44	0.096	0.086
Population	0.043	0.027	0.411	0.272	0.024	0.016
Price of electricity	-0.306	0.557	-2.94	5.22	-0.163	0.311
Northeast	-0.060	0.426	54.36	47.96	2.35	4.11
Southwest	-0.024	0.187	43.72	40.61	1.87	2.52
Southeast	0.0027	0.014	23.66	22.84	1.47	1.36
West	-0.017	0.065	2.49	22.08	-0.469	1.53

Note: Bootstrapped standard errors are run with 500 repetitions

When I divided the subset of the utilities that have DG capacity according to whether they have active net metering programs or not, I found that 41 of the 194 observations have net metering customers (see area "B" in Figure 3.1). I infer, therefore, that 21 percent of all utilities that report DG ownership are actually consumer-owned DG operations. The average total DG capacity reported by this sub-sample of consumer-owned operations is 91 MW; the average DG capacity reported by the remaining 153 cases (see area "C" in Figure 3.1), those that are utility-owned and operated, is 43 MW. As explained above, I ran two separate probit models on the consumer-owned and the utility-owned DG capacity, respectively. Standard probit results are presented in Table 3.5 and bootstrapped marginal effects are presented in Table 3.6.

Table 3.5. Probit Model Results with Dependent Variable: Distributed Generation Capacity in MW

Independent Variable	Model 1: Customer-Owned DG	Model 2: Utility-Owned DG
Utility Type		
Cooperative [a]	-.838***	-.711***
	(.221)	(.161)
Muni	-1.18***	-.165
	(.226)	(.129)
Federal	†	-.037
		(.587)
State	†	-.215
		(.485)
MMA	†	.128
		(.404)
Pol-sub	-.704**	-.154
	(.355)	(.222)
Utility-level Characteristics		
Summer Peak	.00011***	.000056 ***
	(.000031)	(.000022)
Total Sources	-.000025	.0000046
	(.000051)	(.000024)
State-level Characteristics		
RPS	.454**	-.079
	(.222)	(.115)
Interconnection Standards	1.03***	-.130
	(.260)	(.110)
Deregulation	-.241	.281**
	(.199)	(.128)
HH income	.027	.022**
	(.019)	(.011)
Population	-.0035***	-.0017*
	(.0011)	(.00087)
Price electricity	.003	.084***
	(.050)	(.033)
Northeast region[b]	-.419	-.873***
	(.362)	(.236)
Southwest region	.207	-.322*
	(.303)	(.189)
Southeast region	.020	.051
	(.309)	(.126)
West region	.480**	-.293
	(.214)	(.152)
Constant	-3.64***	-2.88***
	(.859)	(.494)
Observations	3226	3277

Note: standard errors in parenthesis; * p<.10, ** p<.05, ***p<.01.
a. Omitted category: private utility b. Omitted category: Midwest
† dropped due to perfect prediction

Table 3.6. Bootstrapped Marginal Effects from the Probit Models with Dependent Variable: Distributed Generation Capacity in MW

Variable	**Model 1: Customer-Owned DG**		**Model 2: Utility-Owned DG**	
	Marginal Effect	Standard Error	Marginal Effect	Standard Error
Utility Ownership				
Co-op	-.019**	0.0078	-0.048***	0.010
Muni	-.032***	0.011	-0.016	0.014
Federal	†		-0.0033	0.091
State	†		-0.017	0.029
MMA	†		0.013	0.044
Pol-sub	-.011***	0.0041	-0.013	0.019
Utility-level characteristics				
Summer peak	0.0000026***	0.00000088	0.0000051	0.0000040
Total sources	0.00000058	0.0000011	0.0000043	0.0000084
State-level characteristics				
RPS policy	0.012*	0.0071	-0.0071	0.010
Interconnection standards	0.018***	0.0044	-0.012	0.010
Deregulated	-0.0056	0.0059	0.029**	0.014
Household income	0.00063	0.00054	0.0021**	0.00093
Population	-0.000081*	0.000042	-0.00015**	0.000069
Price of electricity	0.000061	0.0015	0.0077**	0.0031
Northeast	-0.0079	0.0077	-0.051***	0.010
Southeast	0.00047	0.019	0.0048	0.012
Southwest	0.0055	0.011	-0.024**	0.012
West	0.014	0.0093	-0.023**	0.0093

Note: Bootstrapped standard errors are run with 500 repetitions
† dropped due to perfect prediction

Statistical predictors of utility-owned DG capacity resemble those that were found in the first part of the two-part model: cooperatives are less likely than private utilities to deploy DG capacity; greater peak loads, a deregulated electricity market, household income, and the price of electricity are all positively related to DG deployment; and larger populations make DG deployment less likely. In the case of the customer-owned DG capacity, I call attention to the probit estimates and marginal effects for RPS and interconnection standards. Both variables are positively and significantly associated with customer DG adoption. Additionally, cooperatives, municipals, and political subdivisions are significantly less likely to have customers that own their own DG capacity than private utilities. Summer peak levels are also positive and significant predictors of customer-owned DG deployment.

Discussion

The two-part model and the probit models collectively reveal a puzzle of overlapping and complementary results, some of which confirm my hypotheses and others suggest deeper insights into the growing trend toward a more decentralized electricity market. I focus my discussion below first on DG ownership type, then on state policies and utility programs. Whenever possible, I draw distinctions between the factors that motivate customer-owners and utility-owners.

The results from the two-part model and the utility-owned DG probit model indicate that private utilities are more likely to adopt DG capacity than other utility types, particularly cooperatives. The reasons for these findings, I believe, is directly related to the primary benefits of DG systems, as discussed in supporting literature (El-Khattam and Salama, 2004; Costa, 2006; and Pepermans et al., 2005; Zerriffi, 2004), including the following:

- DG systems offer cost savings due to large efficiency gains and reduced or no transmission and distribution costs;
- DG systems can potentially provide security, reliability, and availability improvements over conventional systems;
- DG technologies have the ability to reduce peak electricity demand and concurrently reduce grid operator costs through the provision of ancillary services and interruptible load operations;

- DG deployment could potentially defer transmission and distribution infrastructure investments and also reduce the vulnerability of an over-stressed transmission system.

Evidence suggests that private utilities are most able to take advantage of these benefits. Kwoka (2005), for instance, has demonstrated that private utilities provide on average lower power reliability than public utilities; Kwoka finds that investor owned utilities have annual service interruption values that are roughly two times greater than municipal values. In this same analysis, Kwoka also finds evidence that private utilities have higher transmission and distribution costs than public utilities but lower generation costs, and vice versa. A source of power, therefore, that is able to increase system reliability and decrease transmission and distribution costs could theoretically be more valuable to private utilities. The additional benefits associated with DG power, such as its ability to reduce or shave peak power and the opportunity it offers to delay transmission and distribution infrastructure improvements, can also work, although not exclusively, in the private utility's favor.

Results of the customer-owned DG probit model demonstrate that, relative to all other ownership types, private utilities are more likely to have customers that own DG systems. I attribute this finding to three factors. First, private utilities provide the lion's share of U.S. generating capacity. They serve a disproportionately greater number of customers and it is not surprising, therefore, that a larger total number of private utility customers own DG systems than total public utility customers. Second, as explained above, private utilities have been found to provide lower system reliability than public utilities. Private utility customers that cannot risk losing power during power outages, therefore, can purchase DG units to function as stand-by power. Third, state regulations that either directly or indirectly encourage DG adoption are not always made mandatory for public utilities, as they are for private utilities. Net metering laws, for instance, are only binding in some states for investor owned utilities. The difference between how state regulations affect customers versus utilities is further discussed below. Before proceeding to further discussion, however, I would like to take a moment to emphasize the inherent limitations that I faced in splitting the sample between customer and utility DG ownership. I address these limitations again below, in the limitations section, yet it is important to bear in mind while discussing results that we have no verifiably accurate way to split the sample and, therefore, results can only indicate potential direction and strength of relationships.

Private utilities may be more likely to adopt DG units, yet out of those utilities that have adopted DG, these model results predict that state utilities deploy a greater amount of actual DG capacity than do private utilities. There is only one state utility, the Long Island Power Authority, that deploys DG capacity in this sample; and it is the same state that deploys the greatest total DG capacity of the entire sample. The state utility coefficient estimate in the second part and combined models, therefore, comes as no surprise and does not necessarily lend itself to any deeper insights.

One of the most frequently cited barriers to DG deployment is a lack of regulatory procedures or interconnection rules that standardize DG installation and technical requirements (Alderfer, et al., 2000; Morgan and Zerriffi, 2002; Zerriffi, 2004). The results of this analysis demonstrate that state policies that aim to reduce these barriers are effectively obtaining their policy objectives. As found in Tables 3.5 and 3.6, interconnection standards and RPS policies significantly increase the likelihood that a customer will adopt DG capacity. It can be inferred that a trend toward more integrated and standard protocols for electricity interconnection—including connecting equipment, standard tariff payment schemes, and power quality characteristics—reduces costs and bureaucratic hassles associated with customer DG hook-ups. In the case of RPS policies, it appears as though utilities that face RPS mandates are more inclined to accept, or perhaps even support, their customers' adoption of alternative energy-based DG capacity so that utilities can obtain credit for these units. Utilities can support customer-owned DG by reducing administrative hurdles, decreasing connection fees or processing time, or making the hook-up process more understandable and transparent.

Utility DG adoption is not enhanced by technical and technological standards, as are customer DG operations, but is instead strongly related to standard market forces. Specifically, deregulation, electricity price, and household income are all positively and significantly associated with utility DG adoption (see Tables 3.5 and 3.6).

To date, there is little consensus regarding the effect of deregulation on the diversification of electric fuel sources. Some argue that, in the short term, deregulation will increase the amount of fossil fuel generation because large power plants are less expensive than smaller, more decentralized sources. Others argue that deregulation will lead to greater consumer choice, enhanced product differentiation, and higher levels of research and development funding (Delmas et al., 2007). These results, in part, confirm the latter. The results of the two probit models demonstrate that deregulation has a positive and significant marginal effect on utility-owned DG adoption but has no effect on customer-owned DG adoption (see Tables 3.5 and 3.6). Electricity deregulation, in other words, is more likely to motivate utilities to adopt DG power than it is to motivate customers. It may be inferred from the first part model that deregulation increases competition in the industry and allows power producers to adopt new and innovative sources of electricity, perhaps as a response to consumer demand for more diverse and alternative fuel sources (see Tables 3.3 and 3.4). However, the total marginal effect of deregulation, as obtained by combining the first and second parts of the two-part model, is not statistically significant at any conventional significance level. Further research on these dynamics could contribute insights into more urgent questions about the evolving structure of the U.S. electricity market and the potential long-term effects of deregulation on the scale and scope of electricity operations.

When the customer-ownership and utility-ownership types are combined to represent overall DG ownership, as is the case in the two-part model, most policy and utility program variables lose significance. This is because, as discussed above, these policies and programs have different effects on different owners and, when combined, these potential effects are attenuated toward zero. There are, however, two policy and program variables that are significant and noteworthy in the two-part model: net metering and RPS policies.

Table 3.4 demonstrates that net metering protocols are one of the only factors that has a positive and statistically significant marginal effect on overall DG adoption (part one of the two-part model) and actual DG deployment (combined two-part model results). Net metering protocols reduce the technical barriers to DG deployment and make DG adoption on the customer side of the meter more feasible. Not only do these estimates confirm that net metering protocols are effective, they also demonstrate that there is a significant difference between customer-owned DG and utility-owned DG, which I attempted to highlight in my discussions above.

The various effects of RPS policies are not entirely realized to date given the short duration in which most state RPS programs have been in effect. One potential effect, as discussed above, is that RPS policies encourage utilities to remove barriers to customer-owned alternatives-based DG deployment. A second effect not yet discussed is evident in the second part of the two-part model (Tables 3.3 and 3.4): out of all utilities that have DG capacity in their service territories, those who operate under RPS mandates have significantly less DG capacity than those without RPS mandates. Utilities that are mandated to comply with an RPS policy appear to have to prioritize their investments in renewables over their investment in DG. After all, it would take a large number of renewable DG units to produce an equivalent amount of power to that which a wind farm can produce. These findings suggest that utilities may invest in DG capacity but, when faced with RPS mandates, the investment will be small. In short, RPS programs may lead to direct competition between large-scale renewable energy and small-scale distributed resources.

The connection between DG systems and renewable energy could benefit from further consideration and analysis. Many tout the environmental attributes of DG systems and encourage DG adoption based on the potential for low to no emissions and high levels of efficiency. Yet the present analysis has identified several sources of information that challenge this claim, at least in part. First, when one classifies distributed generation according to application, and possibly further into technology type, it becomes evident that not all DG systems use renewable energy, nor do they all emit fewer emissions per kWh of power than some conventional sources. Second, micro-generation, combined heat and power, and renewables-based remote power or localized conventional power, can all employ renewable or relatively efficient and low-emitting energy sources; yet the actual distribution of DG sources in 2005 was heavily dominated by distillate fuel. Third, empirical results reveal that there may be conflict between large-scale renewable energy deployment and DG deployment. While the emissions' potential of various DG systems has already been the source of considerable debate, (see, for instance, Allison and Lents, 2002; Bluestein, 2000; Greene and Hammerschlag, 2000; Heath, et al., 2005; Strachan and Farrell, 2006) supporting literature has, to date, given little consideration to the connections between renewable energy and distributed generation development and deployment.

Limitations

This analysis likely suffers from a few limitations. First, if there are any omitted variables that I excluded from the probit models, even if they are not correlated with the other independent variables, then these estimates may be biased. Omitted variables that are captured in the error term of probit models increase the size of the standard error and, therefore, decrease coefficient estimates. This is because all coefficients are the beta-estimates divided by the standard error. A likely omitted variable is a utility or state buy-back rate. While other countries such as the Netherlands have standard buy-back rates, the U.S. has a patchwork of different rates that target different technologies across various states. Because there is no consistent type or regulatory body for buy-backs in the

U.S., I was not able to include this variable in the model. Future studies ought to find a way to operationalize this variable and include it in similar models.

Another potentially important omitted variable is the cost of a utility's primary sources of fuel, particularly fuel used for peaking loads. If a utility mainly supplies a particular resource during peak hours, for instance, and the price of that resource rises, the utility may be more likely to invest in DG capacity as a backstop technology. The utility could then deploy the DG before the more expensive, alternative resource when it is economically efficient to do so. I was not able to include these data, however, due to aforementioned limitations of the EIA-861 database—the data used in this analysis are utility-specific but not plant-specific. I use peak power output and electricity price variables in attempt to control for fuel prices, assuming that electricity prices generally track fuel prices, both peaking and non-peaking, within a given service territory.

Second, my estimates for customer-owned versus utility-owned DG capacity may not be perfectly accurate due to our assumption regarding the connection between net metering and customer-owned DG capacity. I acknowledge that my inference method may overestimate the number of customer-owned operations and underestimate the number of utility-owned operations. I have no verifiable method for testing this key assumption.[16] Although these estimates may not be exact, the results of these models do

[16] I do, however, run a back-of-the-envelope sensitivity analysis on these results. Since my concern is that too many DG systems are classified as customer-owned that are truly utility-owned, I randomly select customer-owned observations and reclassify them as utility-owned, re-estimate the model, return the observations to their original classification, then repeat. I estimate the sensitivity analysis model twenty times, ten times with 25 percent of the original customer-owned sample randomly reclassified as utility-owned, and ten times with 40 percent of the sample randomly reclassified. Given an original count of 41 customer-owned systems and 154 utility-owned systems, a 25 percent sensitivity analysis changes the count to 31 and 164, respectively, and a 40 percent changes it to 25 and 170. The results of the sensitivity analysis models demonstrate small changes in sign and significance for some variables, though no changes in both sign and significance simultaneously. The 25 percent models reveal only one notable source of instability: the RPS variable is no longer significant for customer ownership in three out of ten runs. The 40 percent models reveal a bit more instability. The following variables vary in significance but not sign in

not indicate potential measurement error or other error due to misspecification of the dependent variable. Nonetheless, I urge readers to consider the results of the customer-owned versus utility-owned probit models as representing a solution space of possible effects. The probit results from the two-part model, in which all DG owners are combined, represents one boundary of the solution space. The probit results from the split sample represents the opposite boundary, in which we have accounted for all potential customer-owned DG applications.

Furthermore, an alternative method of generating these data does not exist; these limitations highlight the lack of data and, consequently, the lack of empirical analyses on this subject. When DG data are available, as is the case with EIA-861, the definitional attributes of the DG capacity are often lacking or entirely missing. For instance, as discussed above, Form EIA-861 does not specify which types of power applications can be considered DG capacity and so the utilities that fill out this form must make assumptions about what classifies as distributed generation. Hence, many DG analyses continue to focus on the definition and application of DG systems with an inability to translate findings into results. Without rigorous empirical research and testable results on this subject, as well as other intricately related topics, future attempts to contribute to public policy debates or inform the general public will only perpetuate an incomplete understanding of how DG operations can be integrated into our current electricity system.

Conclusions

roughly half of the ten runs: political subdivision customer ownership; municipal utility ownership; RPS under customer-ownership; and Western utility and customer ownership.

This analysis sought to test the hypotheses that private utilities are more inclined to deploy DG capacity than are various public utilities; and DG policies and regulations are effective at removing the barriers to DG adoption and deployment. The empirical results indicated that private utilities are, in fact, more likely to adopt and deploy greater amounts of DG capacity than are public utilities, particularly cooperatives. Additionally, state policies that aim to reduce economic barriers, standardize interconnection procedures, and increase competition in the electricity sector have thus far been rather effective at obtaining their policy objectives. My estimates indicate, however, that there may be conflicts between concurrent movements or transitions within the electric industry, specifically between a move toward greater reliance on renewable energy versus distributed generation. These findings also reveal that policies and regulations affect utility and customer DG owners differently. Customer owners are more inclined to adopt DG power with the passage of technical and technological standards; utility owners are more motivated by market forces that introduce competition and price signals into a historically heavily regulated market.

The present analysis has contributed to the DG literature by helping move the focus beyond a mere classification and typology of DG operations and toward an empirical understanding of the main motivations behind DG adoption and deployment, and ultimately behind the evolving market transition toward increased reliance on decentralized power. As the electricity industry continues to evolve, the need for analyses that build on the basic premise of this study will increase. Analyses that explore the potential conflict between large-scale renewable energy development and small-scale DG development, for instance, or that consider the effects of deregulation and increased competition on customer DG ownership behavior will inevitably help inform public and private debates regarding the future of our electricity sector.

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CHAPTER 4

DECARBONIZATION: THE CASE OF CARBON MITIGATION AND ENERGY PORTFOLIOS

Introduction

Motivated by Pacala and Socolow's "stabilization wedge" concept (2004), as well as similar ideas presented by the Electric Power Research Institute—the "prism" (2007)—and others, an increasing number of states have adopted energy policy portfolios (or packages) since the early 2000s in effort to reduce carbon emissions. The rationale for portfolios, as opposed to singular policies, is appropriately captured in a common energy policy saying: "there is no silver bullet." Indeed, by the very nature of their construction, portfolio strategies allow states to assemble complimentary clusters of instruments, which may not produce significant effects individually but, when combined, have the potential to provide synergistic carbon mitigation effects (Gunningham and Gabrosky, 1998). Furthermore, state portfolios tend to include a combination of policies from a variety of sectors, including electricity supply, transportation, agriculture, forestry, land-use, and residential, commercial, and industrial. A multi-sector strategy allows states to spread the costs and responsibility of carbon mitigation among various industries. Portfolio strategies can also be more effective than singular instruments because they have the potential to target multiple externalities at once and achieve carbon reductions at a lower overall cost than a singular policy (Fisher and Newell, 2008).

There is a great need—in both the policy realm and the energy policy literature—for information on how well state portfolios perform in the electricity sector. Most immediately, empirical evidence on the carbon mitigation, or "decarbonization," effects of state level energy policy portfolios could help states draft future legislation, reevaluate and amend past legislation when appropriate, and form more complete perceptions about the actual effects of these policies on carbon mitigation and other energy sector trends. Empirical evidence could also lend insights into questions about the effects of "progressive federalism" or "collaborative federalism" (Rabe, 2008) on energy and the environment. For instance, is it effective for states to implement climate action plans on a state-by-state basis rather then pursue a regional or national level effort? Or, alternatively conceptualized, is there value in tailoring specific portfolios to specific states or would regional or national standards ultimately be more effective? Should states continue to implement energy policy portfolios even if a national level carbon tax or permit legislation is passed? This type of analysis potentially could provide broader conclusions about the overlap between energy policy and climate policy, and suggest ways in which these two policy foci can merge in future state or national legislation.

The present analysis seeks to address this need in the policy realm and contribute further empirical insights into the energy policy literature. The guiding research question is as follows: is a state energy policy portfolio an effective decarbonization strategy? This analysis is an exercise of explanation and prediction based on scenario-based electricity sector modeling. An energy modeling exercise allows one to track multiple, current trends within the electricity sector as a result of various policy scenarios, and also consider firm decision-making procedures as a result of these same scenarios. The intend of the present analysis is to compare potential policy effects in the electricity sector, primarily on carbon emissions, and secondarily on electricity price and electric generation portfolios, and to draw inferences regarding the overall effectiveness of state-level policy portfolios. In this vein of inquiry, I build a series of policy portfolio scenarios, and apply them at first to the state level and second to the regional level. Next, I run the same scenarios with the inclusion of a carbon tax, and compare results.

Background

Although the approach varies a bit from state to state, states generally assemble and prioritize different combinations of energy policies via an interactive planning process. This process is typically guided by a policymaker-appointed working group of stakeholders and members with state-specific technical knowledge (Center for Climate Strategies, 2008). Outside consultants may provide technical and analytic assistance to the working group. The working group and consultants collectively generate a climate action plan, or climate change mitigation plan, which outlines all possible multi-sector policy options, the carbon mitigation potential of each, and the cost per ton of avoided carbon. Some plans also provide suggestions for policymakers on which policies most effectively reduce the state's greenhouse gas emissions below a certain threshold. To date, twenty states have undergone this type of process, several more are currently in the middle of similar processes, and roughly ten states have established policy portfolios through different means (Center for Climate Strategies, 2008; see the Center for Climate

Strategy's website for an interactive map of different state actions). In total, 37 states have drafted some version of a climate action plan (Energy Information Administration, 2009). Often as a result of this type of taskforce, specific policies are identified as the most promising options, and further analyses are performed on the cost-effectiveness or overall costs of these policies.

The majority of climate action plans, state level carbon inventories, and specific-policy cost estimates are performed using complex spreadsheet analyses (see, for instance, New Mexico Climate Change Advisory Group, 2006; North Carolina Climate Action Plan Advisory Group, 2008; Montana Climate Change Advisory Committee, 2007). These analyses include information on historic energy data and Energy Information Administration (EIA) projected growth rates. In a review of all state-level renewable portfolio standard (RPS) cost analyses performed before March 2007, Chen and his colleagues found that 16 out of 26 studies used spreadsheet analyses (Chen et al., 2007). Spreadsheet analyses may be appropriate for estimating carbon emissions from state forestry or land-use policies, for instance, in which linear projections of policy effects may be fairly straightforward. It is immensely difficult, however, to capture the dynamics of an electricity sector in a linear spreadsheet projection. Spreadsheets cannot capture fluctuations in state exports and imports as a result of a new policy, transmission constraints, electricity system operating characteristics, wholesale power prices, or utility-level decisions that are made about which resources to develop and deploy in response to new regulatory circumstances.

The supporting peer-reviewed energy policy literature contains a number of analyses that employ dynamic models to estimate potential national electricity policy effects on carbon emissions. Kydes (2006) and Palmer and Burtraw (2005) recently modeled RPS policies using bottom-up energy models. Kydes analyzed the potential effect of a 20 percent federal non-hydro based RPS on energy markets in the U.S. using the EIA's National Energy Modeling System (NEMS). He concluded that RPS policies effectively increase renewable energy adoption, reduce emissions, and increase the cost of electricity by three percent. Palmer and Burtraw modeled variations of federal RPS policies and tracked policy effects on electricity prices, utility investment levels, resource deployment portfolios, and carbon emissions. They used Resources for the Future's Haiku model and the EIA Annual Energy Outlook 2003 data to model the RPS policies. They concluded that RPS costs are low for goals of 15 percent or less but rise significantly with goals of 20 percent or higher. Palmer and Burtraw also compared the effects of an RPS policy with those resulting from an expanded renewable energy production tax credit. They concluded that RPS policies are more cost-effective than a tax credit at decreasing total carbon emissions and increasing renewable energy deployment. They found that a cap-and-trade system, however, is more cost-effective than either an RPS or a renewable energy production tax credit.

A number of analysts modeled the clean energy technology policies (Brown et al, 2001, Gumerman et al., 2001; Hadley and Short, 2001) proposed in *Scenarios for a Clean Energy Future* (Interlaboratory Working Group, 2001), a Department of Energy document that lists and discusses the highest priority energy technologies. These analyses clustered policy instruments into a moderate policy scenario and an advanced policy scenario, respectively, and then sought to measure the economic and environmental effects of these scenarios using NEMS software. Results from these analyses indicate that national-level energy policy portfolios have the potential to significantly reduce carbon dioxide emissions by 2020.

In a recent study, Fisher and Newell (2008) built a simplified two-period electricity model, which they used to estimate the effects of various energy and climate policies on carbon mitigation and renewable energy development and deployment. Fisher and Newell's analysis has three defining characteristics that set it apart from previous studies. First, their two-period model allows for the endogeneity of technological innovation. Second, their analysis includes both energy and climate policies. They test the effects of these policies on energy and climate outcomes, i.e. renewable energy development and carbon reduction, respectively. As a result, the authors are able to draw conclusions about the relative effectiveness of energy policies for climate policy objectives and of climate policies for energy policy objectives. Third, Fisher and Newell compare the relative effectiveness of policy portfolios to singular policy outcomes. They find that an emissions price is the least costly option for emissions reductions, followed by an emissions performance standard, a fossil fuel power tax, a renewable share requirement, a renewable power subsidy, and a research and development subsidy, respectively. The authors also find that an optimal policy portfolio is associated with a significantly lower cost of emissions reduction than any single policy option.

Despite the insightful contributions that these analyses provide to the literature, not a single study models energy policy instruments or portfolios at the state level. Yet, to date, the majority of U.S. decarbonization efforts are concentrated in the states.[17] National policy modeling, as is the norm in the literature, allows for a general comparison

[17] More recently, regional level action is on the rise as well; although regional level efforts tend to use carbon policies, such as cap-and-trade initiatives, whereas state level efforts use energy policy portfolios.

of policy effects or costs, but one cannot be sure that these results translate into state-relevant lessons. National level models do not capture the interaction between neighboring states, for instance, when one state has a policy and a second state does not. National modeling exercises also do not contribute insights on energy federalism, such as the relative effects of state versus regional or national level policy efforts. Given the current trends of state level leadership in the energy-climate policy realm, and the possibility of national legislation that may alter these trends in still unforeseen ways, the need for state-specific analyses is great.

Modeling framework

Following the precedent set by these national-level energy modeling analyses, the present study tests various energy portfolio scenarios in a dynamic modeling environment. This exercise has three characteristics that distinguish it from the literature. First, this modeling analysis specifically focuses on state level portfolios, which are, as just described, currently overlooked in the supporting literature. Second, building on the efforts of Fisher and Newell (2008) and others (Brown et al, 1991, Gumerman et al., 2001; Hadley and Short, 2001), this analysis focuses on policy portfolios, not just singular policies in isolation. Finally, the present analysis models policy portfolio effects that are specific to the electricity sector.

This analysis employs an electricity dispatch optimization model, AURORAxmp, to test various policy scenarios. AURORAxmp is used, as opposed to an integrated energy model such as NEMS, because it is exceedingly difficult to isolate states, the focus of this analysis, in an integrated model. As Chen and his colleagues explain, “an integrated energy model such as NEMS is designed to analyze the national energy sector and may require substantial modification to obtain the specificity and detail that is necessary to accurately model state-level policies" (Chen et al., 2007, 37). AURORAxmp is frequently used by state utility commissions and electric utilities to simulate short-term resource dispatch based on competitive electricity market forces. AURORAxmp also has the capability to perform long-term capacity expansion modeling, which is used for the purposes of this analysis, based on hourly forecasts of fuel prices and electricity demand.

AURORAxmp's optimization model maximizes the real levelized net present value (in $/MW) of all available resources with realistic transmission capacity constraints in order to meet instantaneous electricity demand. This calculation is performed using a chronological dispatch algorithm. Resources with optimum net benefits—on a pure cost minus benefit basis—are selected for deployment in a given zone in a given hour. Resources that are not cost-competitive are retired. The resulting balance of resources determines the market-clearing price for each zone in each hour. These hourly dispatch decisions are combined in an iterative process until the model is able to extract the resource mix that is most cost-effective over the life of the analysis. As part of the resource optimization logic, AURORAxmp tracks capacity expansion and facility retirements, performs lifecycle analyses, considers a range of new supply resources, selects resources for deployment based on hourly market values, and tracks transmission exchanges between states and regions.

AURORAxmp's long-term optimization model requires the following inputs:

- electricity demand growth rates;
- annual load growth;

- generation capacity characteristics, such as fixed and variable costs, start-up times, capacity factors, and efficiency factors;
- a list of existing resources or forced builds;
- emissions prices and emissions rates for each fuel type;
- transmission links between zones and regions;
- new resource options.

Aurora generates outputs on an hourly, daily, monthly, and annual basis. For a long-term study, I am interested in the annual estimates. Standard annual outputs include total generation by fuel type, electricity price by area, inter-area and inter-regional transactions, emissions estimates, and imports and exports figures. The model provides greenhouse gas (GHG) emissions but does not break them down by type of greenhouse gas. Therefore, it is necessary to use the GHG output as an indication of the carbon mitigation potential of policy portfolios.

The data used in this analysis come from a variety of sources. Retail and wholesale electricity cost figures are compiled from EIA data, and represent those figures reported in the 2009 Annual Energy Outlook (*AEO2009*). Other sources of cost estimates include Federal Energy Regulatory Commission (FERC) data, Electric Power Monthly, and Natural Gas Week. Locational data of power plants come from EIA-860 database. Demand data come from the Federal Energy Regulatory Commission's Form 714, which contains data on historical annual load-shapes for selected utilities. Emissions rates come from the Environmental Protection Agency's "Clean Air Markets" database (EPA, 2009). Resource information is primarily taken from the North American Electric Reliability Corporation's (NERC) Electric Supply & Demand database (NERC, 2009). The state policy data that inform the various policy scenarios come from each state's enabling legislation, the Database for State Incentives for Renewables and Efficiency (DSIRE, 2009), and supporting literature.

AURORAxmp databases are divided according to NERC regional boundaries, which necessitates that I draw a research sample at the region level. However, the research intent is to draw results that can be generalized to the national level. As a result, research efforts are focused on the Western Electric Coordinating Council (WECC), which is the largest and most diverse of all NERC electric regions, and has the greatest generalizability potential. Much of the WECC is also actively involved in planning for future climate change policy at the regional level via the Western Climate Initiative; and multiple WECC states recently passed state-level legislation for climate action plan policies. The WECC includes 14 U.S. states, as well as Baja, Mexico, and Alberta and British Columbia, Canada. While the analysis is focused on the WECC, the electricity dispatch model still tracks transmission and distribution links between WECC and other NERC regions and, thereby, still captures all retail and wholesale electricity trades among regions. With an objective to track policy effects from state-specific policy portfolios, it is necessary to select states from within the WECC on which to model policy scenarios. I select two states for this purpose, Utah and Arizona.

Using these data, I build various policy scenarios in AURORAxmp. I begin with a business as usual case, which represents electricity dispatch decisions given current energy trends and in absence of any state policy legislation. The output of this case is hereafter referred to as the "baseline". Next, I model a series of policy portfolio scenarios in Utah and Arizona, respectively, then across the entire WECC, and compare model results. Finally, I run the same policy portfolio scenarios first at the state level and then at the regional level, but this time include a national carbon price. Policy portfolios are assumed to become effective on January 1st, 2010, and run through December 31st, 2030. All scenarios are run between 2006 and 2035; but only data from 2010 and 2030 are extracted and reported. This step is generally recommended for long-term electricity dispatch modeling, because it removes any “kinks” that might occur in early or late years of the iterative, dynamic optimization procedure. All cost and price data are in 2006-dollar values.

Similar to other electricity dispatch models (Chen et al., 2007), AURORAxmp calculates electricity prices based on short-term supply curves that reflect marginal costs of operations. When one models a policy by forcing a resource online at a certain time (for instance, if one forces 100 MW of wind power online in 2010 as a result of an RPS policy), the overnight capital costs of that resource are not included in the electricity price. Yet it is unrealistic to believe that utilities will not have to pay these fixed costs and recover their investments over time via rate increases. To deal with this issue, I calculate the additional annual cost associated with all forced resources outside of the model, and then factor this additional cost into the retail price of electricity. For all new supply-side resources, I calculate the additional annual cost with the following equation:

$$Cost_t = CC_{rt} * CRR_r,$$

where CC is the total capital cost of the resource, r is the type of resource in year t, and CRR is the capital cost of recovery. The CRR is calculated with the following equation:

$$CRR_r = d/1\text{-}(1+d)^{-n},$$

in which d is the discount rate and n is the number of years over which the investment is amortized.

Modeling Parameters

Baseline

All generation capacity in the model is categorized as either existing capacity or a "new resource," available for deployment if it is economically efficient to do so. Existing capacity is documented at the power plant level, and includes all generation facilities that are currently in operation or planned for deployment in future years. The new resource types and generating characteristics that are included in the model are listed in Table 4.1. All generation characteristics are extracted from the *AEO2009*, and represent the average cost estimates to build a power plant in a typical region of the country. Because there is some variation in the manner in which different electric providers count expenses as either fixed or variable operations and maintenance (O&M), I apply an adjustment factor to these two variables. I take 20 percent of the fixed O&M, spread over the assumed lifetime of the power plant, and add this value to the variable O&M. The remaining 80 percent is classified as fixed O&M.[18]

[18] This assumption is made per advice from AURORAxmp's management team. Without this adjustment, AURORAxmp dispatches plants too often.

Table 4.1. New Resource Option Parameters included in Baseline Scenario

New Resource Type	Heat rate (BTU/kWh)	Capacity (kW)	Variable O&M ($/MWh)	Fixed O&M ($/MW/wk)	Forced outage (%)	Annual Max per State (# units)	Total Max per State (# units)	Leadtime (years)	Fuel Price ($/mmBTU)
Geothermal	33,729	50,000	3.66	4,599	5	10	50	4	1.74
Solar Photovoltaic	10,022	5,000	0.27	11,047	45	5	100	2	0.00
Biomass	9,646	80,000	7.96	6,721	5	1	2	4	0.05
Municipal Solid Waste/Landfill	13,648	30,000	2.55	5,346	5	1	3	3	1.16
Wind	0	50,000	0.65	3,298	60	2(UT), 0(AZ)	10(UT), 0(AZ)	3	0.02
Scrubbed Sub-Critical Pulverized Coal	8844-8600*	600,000	5.03	3977-3784*	7.5	1	2 (AZ), 0 (UT)	4	1.45-1.66*
Integrated Gasification Combined Cycle	8309-7200*	550,000	3.68	4702-4343*	7.5	0(UT), 1(AZ)	0(UT), 1(AZ)	4	1.45-1.66*
Advanced Gas-Oil Combined Cycle Combustion Turbine	6682-6333*	400,000	2.57	1869-1738*	4	10	100	3	0.17
Advanced Simple Cycle Combustion Turbine	9043-8550*	230,000	4.6	1270-1159*	6.5	5(UT), 10(AZ)	50(UT), 150(AZ)	3	0.00

* indicates that variable ranged in the model over time. The number on the left is the 2008 value and the number on the right is the 2050 value.

Demand projections are exogenously determined, and manually entered into AURORAxmp. I use the default demand growth projections for Utah, Arizona, and all other states within the WECC. Utah’s annual demand growth rate is 1.8 percent and Arizona’s is 2.5 percent between 2010 and 2030. Both of these growth rates represent actual demand growth over the past five years, as documented by the EIA. The average annual growth rate in demand across the WECC is 2.0 percent.

The baseline contains a number of additional assumptions as well. First, the price of GHG emissions is set to zero, which indicates that there are no restrictions on GHG emissions, and reflects current conditions. Second, I assume that SO_2 emissions are regulated and capped, according to the 1990 Clean Air Act Amendments. Third, I assume that NOx is regulated according to the 1990 Clean Air Act Amendments as well. Fourth, I assume no investment tax credit or production tax credit adjustments for any technologies. Finally, all states are modeled as energy-policy free; that is, no state has a pre-existing energy policy that could potentially increase renewable energy or energy efficiency, or decrease fossil fuels.

Baseline Sensitivity Analysis

I additionally run five-baseline sensitivity analyses. The first two represent scenarios in which the prices of both natural gas and coal in the WECC region are higher; the first scenario assumes a 15 percent increase in natural gas and coal resource prices across the study period and the second scenario assumes a 25 percent increase. These scenarios attempt to account for the fact that many long-run electricity forecasts tend to underestimate the cost of natural gas, (Palmer and Burtraw, 2005) as well as coal.

The third baseline sensitivity analysis represents cost improvements of renewable resources due to technological innovation. Given the nature of AURORAxmp's linear optimization logic, the model cannot endogenously determine the cost of technologies that experience improvements due to learning and experience. In order to capture these improvements, I apply "learning parameters" to the fixed operations and maintenance costs of wind, solar photovoltaic, landfill, and geothermal systems, and enter the new cost streams into the model as exogenous parameters. The learning parameters are extracted from the *AEO2009* and include a one percent improvement in the cost of wind by 2025, twenty percent in solar, five percent in landfill, and ten percent in geothermal. Each percentage improvement parameter is a conservative figure, designated by the *AEO2009* as the minimum total learning by 2025 (EIA, 2009).

The final two sensitivity analyses adjust demand growth rates for Utah and Arizona, respectively. Demand assumptions can have significant consequences on the performance of energy models. Because it is possible that the growth rate for Utah in the *AEO2009* is too low and Arizona's is too high, the final two sensitivity analyses adjust each state's demand growth rates. The first of these scenarios increases Utah's demand growth rate from 1.8 to 2.1 percent; and the second decreases Arizona's growth rate from 2.5 to 2.2 percent.

Policy Portfolios

As discussed above, each state traditionally chooses unique combinations of different policy instruments to include in their portfolios. For the purposes of this analysis, I build a portfolio that includes policies that: 1) are found in most states' climate action plans; 2) represent a range of different energy policy instruments; and 3) are modeled at the national level in supporting literature. Guided by these criteria, I include renewable portfolio standards, demand-side measures, tax incentives, and carbon capture and sequestration in the state portfolio scenarios. A description of each policy instrument, and a discussion of the parameters used to operationalize these instruments, is outlined below.

Renewable Portfolio Standards

A renewable portfolio standard (RPS) requires that a minimum level of a state's overall electricity generating capacity must come from renewable energy. Typically, states mandate that a specific percentage of renewable energy must be deployed by a terminal year, e.g., 25 percent by 2025.[19] States tend to select low renewable energy percentage benchmarks for the first few years of RPS operations, which allows utilities and private energy organizations to make initial investments and the long-term renewable energy credit market to develop. The standards then rise by a few percentage points each year until they hit their goal. Common eligible energy resources under RPS legislation include wind, solar photovoltaic, solar thermal, wave, tidal, ocean thermal, biomass, hydroelectric, geothermal, and waste recovery or waste heat capture energy. Some states allow all of these renewable energy sources, while others allow only a few.[20] Non-voluntary RPS programs are currently active in 27 states and the District of Columbia. Nine of these states implemented their RPS program in 2007 (DSIRE, 2007).

The RPS policy scenario in the present study is operationalizated as a 20 percent renewable energy mandate by 2025. I assume that this percentage requirement will grow at a constant rate from zero percent on the eve of policy adoption, in year 2009, to 20 percent by 2025, and then remain constant at 20 percent from 2025 to 2030. The benchmarks for each five-year increment are as follows:

- 1.25% by 2010
- 7.50% by 2015
- 13.75% by 2020
- 20% by 2025

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[19] Under the majority of state RPS programs, each utility's obligation is tradable in the form of Renewable Energy Credits (RECs). Each credit of which a utility falls short is subject to charge. This analysis does not explicitly model REC transactions because renewable energy certificates do not exist in AURORAxmp's dispatch logic.

[20] Some states also allow energy efficiency or advanced coal generation to count toward their RPS requirements.

To determine the total amount of Megawatt-hours of renewable energy needed on an annual basis, I take the baseline total generation for each year, multiply it by the percentage benchmark, and then subtract out existing renewable capacity from all baseline and previous year-RPS renewable energy sources. I then calculate the total system capacity needed for each renewable resource by taking the total renewable MWh needed from the previous step and dividing it by the product of the resources' capacity factor and the total number of hours in a year. These steps are combined, and expressed with the following equation:

$$[(G_n * RPS_n)\text{-}\Sigma\, RE_n]/(CF_i * 8760),$$

where n is the year, G is the total Megawatt-hours of generation in year n, RPS is the percentage benchmark, RE is the total renewable energy that is deployed in the baseline, i is the fuel type, 8760 is the number of days in a year, and CF is the capacity factor for each fuel type. I assume a capacity factor of 36 percent for wind energy.

The present study assumes that 100 percent of all new generating capacity intended to meet RPS requirements—i.e., the renewable capacity needed beyond that which already exists in the baseline—will be met with wind energy. I consider the following energy sources from the baseline as RPS-eligible: wind, solar, geothermal, biomass, hydroelectric, and municipal solid waste. In addition to these assumptions, it is also the case that no renewable energy credits are traded among states; each state must satisfy their own RPS mandates and cannot purchase them from neighboring states.

After I calculate the total annual capacity of wind energy needed to satisfy the RPS requirements, I force this amount of capacity online throughout the study period. Because a RPS is a mandatory regulation, it is fair to assume that utilities will not decide whether or not they want to deploy new renewable energy units, they will instead be mandated to do so. As a result, the utilities will need to decide how to redistribute resources to comply with demand, availability, and fiscal constraints. I therefore force the renewable energy capacity online, as opposed to allow the optimization logic to choose renewable energy when it is cost-efficient. In calculating the annualized capital cost of RPS wind power, I assume a discount rate of 10 percent, which is appropriate for a private sector investment, and an investment payback period of 30 years.

One would expect an RPS policy to increase the retail price of electricity, reduce total carbon dioxide emissions, force the retirement of some natural gas plants and displace new natural gas capacity, since both natural gas and wind serve intermediate loads.

Demand Side Management

Demand side management (DSM) refers to any program or policy that alters electricity demand, either via changes in the pattern of electricity use or in the total quantity. A variety of policy instruments can be considered under the umbrella of DSM, including but not limited to the following: lighting standards, building codes and standards, energy efficiency portfolio standards, public benefit funds, weatherization programs, and loans, grants, and rebates for energy efficiency. States have adopted different combinations of these DSM instruments over the years.

In the present study, I conceptualize a DSM policy as a gradual increase in the percentage of energy savings over time. I assume that the percentage of savings starts at one percent in 2010 and rises by one percentage point each year, until it hits 20 percent in

2029. To operationalize this policy scenario, I convert these savings into changes in demand escalation. For instance, instead of a 1.8 percent growth in demand between year *t* and year *t*+1, as is the case for Utah's baseline, Utah instead experiences a 0.7 percent demand growth in the DSM scenario.

Similarly to all forced supply-side resources, AURORAxmp does not include the cost of demand-side programs in the model. The annual cost of DSM programs, therefore, must be calculated outside of the model, and then factored into the retail cost of electricity. To perform this calculation, I assume that the cost of a DSM program is 3.4 cents/kWh, a cost-effectiveness figure estimated by a Resources for the Future study (Gillingham et al., 2004) for DSM programs. I additionally assume that all DSM program costs are paid in full during the year in which the DSM savings are realized.

A DSM program will likely decrease total carbon emissions, and prolong the need for new power plant builds.

Tax Incentives

There are a variety of tax incentive mechanisms among which states can choose that alter the cost of alternative energy and, as a result, make alternatives more cost-competitive with conventional energy sources. Tax incentives generally reduce the initial, or overnight, cost of an alternative energy system by a specific percentage. The most common tax incentive mechanisms include the personal income, sales, corporate income, and property tax incentives. Most states have at least one of these incentives currently in place.

I build a tax incentive scenario in which a reduction of 35 percent of the overnight capital costs is applied to the following new renewable energy deployment options: wind, solar, geothermal, biomass, and municipal solid waste/landfill. The new overnight capital cost is then added to the other fixed 0&M costs, and the resulting estimate, the total fixed O&M, is entered into the model. Table 4.2 summarizes the changes in fixed cost parameters between the baseline and the tax incentive scenarios.

Table 4.2. Fixed Operations and Maintenance Costs for Baseline and Tax Incentive Scenarios

New Resource	Baseline Fixed O&M ($/MW-wk)	Tax Incentive Scenario Fixed O&M ($/MW-wk)
Wind	2,837	2,025
Geothermal	4,599	3,852
Solar Photovoltaic	11,047	7,244
Biomass	6,721	4,706
MSW/Landfill	5,346	4,074

Tax incentives will reduce the cost of renewable energy and, thereby, make renewable resources more cost-competitive with conventional fossil fuel resources. As a result of lower prices, one can predict that more renewable energy systems will be constructed and dispatched throughout the study period, which will displace, at least in part, the construction of new coal and natural gas systems, and reduce the total greenhouse gas emissions throughout the study period.

Carbon Capture and Storage

Carbon capture and storage (CCS) is the process of collecting carbon dioxide that is produced at power plants or during fossil fuel processing, compressing it for storage and transportation, and injecting it into deep underground geological layers. Carbon capture technologies are commercially viable in the petroleum processing industry and technologically proven for small-scale gas-fired and coal-fired boilers. Capture technologies are not yet demonstrated, however, for large-scale power plant applications (Rubin et al., 2007). The sequestration and storage aspect of CCS is demonstrated on a large-scale in three separate counties (IPCC, 2005; Rubin et al., 2007). Despite the recent advances made in CCS technological development, a variety of regulatory and legal barriers continue to prohibit wide-scale deployment of CCS technologies.

CCS policies are not typically formed at the state level, but are more conducive to regional or national level policymaking. Yet a variety of states have included CCS policies in their climate action plans. Utah, for instance, has identified CCS policies as a top priority option, which they describe as the following:

> Some of the key questions to be addressed in the development of a consistent regulatory framework for carbon capture and sequestration (CCS) are: immunity from potentially applicable criminal and civil environmental penalties; property rights, including the passage of title to CO_2 (including to the government) during transportation, injection and storage; government-mandated caps on long-term CO_2 liability; the licensing of CO_2 transportation and storage operators, intellectual property rights related to CCS, and monitoring of CO_2 storage facilities. Regulatory barriers may include revisiting the traditional least-cost/least risk regulatory standard or mitigating added risks and financing challenges of CCS projects with assured, timely cost-recovery (Utah Governor's Blue Ribbon Advisory Report, 2007).

For the purposes of the present analysis, a CCS policy is defined as that which removes the regulatory barriers to CCS deployment and defines a legal framework that monitors and regulates CCS developments. I assume that these efforts will eventually render CCS as technologically viable and available for widespread commercialization. I additionally assume that CCS will be deployed in conjunction with advanced, efficient fossil fuel operations, such as integrated gasification combined cycle (IGCC-CCS) or natural gas combined cycle plants (NGCC-CCS), with cost and performance characteristics outlined in the *AEO2009*, and an 86 percent improvement in carbon emissions' rate over conventional, non-CCS plants. I assume that both plants experience technological improvements throughout the study period, as is typical of most new generation technologies. To represent technological improvement, I reduce the overnight capital costs and heat rate of IGCC-CCS and NGCC-CCS plants, respectively, throughout the study period. Table 4.3 displays these assumptions.

Table 4.3. Carbon Capture and Storage Technological Improvement Model Assumptions

	IGCC-CCS		NGCC-CCS	
Year	Heat rate (BTU/kWh)	Fixed O&M ($/MW/wk)	Heat rate (BTU/kWh)	Fixed O&M ($/MW/wk)
2007	10781	8612	8613	4594
2010	10074	8532	8226	4550
2015	9191	8373	7951	4464
2020	8307	8142	7652	4339
2025	8307	7920	7652	4219
2030	8307	7702	7652	4101

This CCS "policy," therefore, is modeled as an electric generation resource option, which a utility in a CCS policy state can choose, among other resource options, to build and deploy. According to these assumptions, I build the CCS policy scenario by including IGCC-CCS and NGCC-CCS as new resource options. Beginning in 2012, these technologies become available—deployable on a commercial scale—but require eight years of permitting and construction time before the plant is up and running. Thus, the first year in which a CCS plant can dispatch power online is 2020. Table 4.4 shows the CCS plant characteristics, as entered in AURORAxmp.

Table 4.4. Carbon Capture and Storage Policy Scenario Parameters

New Resource	Capacity (MW)	Variable O&M ($/MWh)	Year available	Construction time (years)	GHG rate (lb/mmBTU)	Forced outage (%)	Annual Max per State (# units)	Total Max per State (# units)
IGCC-CCS	380	7.09	2012	8	28.7	7.5	1	2
NGCC-CCS	400	3.62	2012	8	16.7	4	2	5

Assuming that the cost and performance parameters render CCS technologies cost-competitive with other sources of electricity generation, one should expect CCS technologies to displace new coal and natural gas power plant builds, resulting in a reduction of total GHG emissions over the course of the study period.

Policy Portfolios

I combine these four policy instruments into two policy portfolio scenarios. The first scenario is a strong portfolio, in which I do not adjust for any overlap in policy objectives and merely combine and run all four instruments as-is. Under this scenario, one should expect more renewable energy deployment than that which is mandated by the RPS, since the tax incentive will encourage additional renewable energy dispatch. In the second scenario, the moderate portfolio scenario, I adjust for overlap in renewable energy deployment. Under this moderate portfolio scenario, I subtract the renewable energy that is dispatched as a result of the tax incentives from the total amount of energy that I force online as a result of the RPS policy. The difference between the strong and weak scenarios, therefore, is the amount of total wind energy that is forced online: the strong scenario has more wind energy and the weak scenario has less. As explained above, I first model these two policy portfolio scenarios in isolated states, Utah and

Arizona, respectively, and then model the portfolio scenarios across the entire WECC region.

Carbon Price Scenarios

In the last series of runs, I add national carbon prices of \$25/metric ton CO_2e and \$50/metric ton CO_2e, respectively, and compare the results to the non-carbon price scenarios. As described above, due to limitations in the modeling software, it is not actually possible to model a price on CO_2 exclusively; instead, the price must be placed on all greenhouse gases.[21] It is fair to assume that a state would respond to a GHG price in the same manner in which it would respond to an exclusively CO_2 price. I hereafter refer to the GHG price as the "carbon price," although all tables and graphs present GHG emissions and savings.

Pre-carbon price policy adoption, I assume that the cost of carbon is zero dollars. Beginning in 2012, for the \$25 carbon cost run I assume that the cost of carbon rises steadily from \$1 to \$15/metric ton CO_2e in the first year, and \$15 to \$25/metric ton CO_2e in the second year. Similarly, the \$50 carbon cost run has an increase in the cost of carbon from \$1 to \$25/metric ton CO_2e in the first year, and from \$25 to \$50/metric ton CO_2e in the second year. Once the cost hits its maximum value, at \$25/ metric ton CO_2e and \$50/ metric ton CO_2e, respectively, it remains steady at that value throughout the duration of the study period.

I additionally run two carbon price sensitivity analyses that allow for the more realistic assumption that demand is elastic and will decrease in response to a rise in the

[21] Carbon dioxide is the second most abundant gas, behind water vapor, in the composition of greenhouse gas.

price of electricity from a carbon price. In effort to capture these effects, I decrease demand growth rates across the entire WECC region. In the \$25/metric ton CO_2e case, I cut demand growth rates by one-sixth, beginning in the first year in which a carbon price is imposed. In the \$50/metric ton CO_2e case, I cut demand growth rates by one-fourth. The average growth rate across the WECC is 0.9 in the baseline scenario, and ranges from 0.77 and 0.55 in the \$25/metric ton CO_2e sensitivity scenario and 0.7 to 0.61 in the \$50/metric ton CO_2e sensitivity scenario.

When emission costs are included in dispatch decisions, AURORAxmp adjusts variable costs for each energy resource according to the following equation:

$$VOM = R * HR * P \,/\, 2\text{x}10^6,$$

where *VOM* is variable operations and maintenance costs for the energy resource (measured in \$/MWh), *R* is the unit emissions rate (measured in lb/mmBtu), *HR* is the unit heat rate (measured in Btu/kWh), and *P* is the emission price (measured in \$/Ton).

Results of Scenario Analysis

Baseline

Figures 4.1 and 4.2 below display the mix of total generation resources in Utah and Arizona, respectively, between 2010 and 2030. Utah's generation mix is heavily concentrated with coal, and grows increasing more so throughout the study period, from 85.9 percent in 2010 to 90.5 percent in 2030. Utah also generates natural gas, hydroelectricity, and biomass. Natural gas generation declines throughout the study period, while the generation of hydroelectricity and biomass remain relatively steady. Although it is not visible in figure 4.1 below, Utah also has 23 MW of geothermal capacity, which it dispatches in 2010 and 2011, but retires by 2012. Utah has no nuclear energy. Utah adds no new generation between 2010 and 2030 and, instead, slightly decreases generation, almost entirely via natural gas plant retirements. In order to satisfy in-state electricity demand, Utah decreases exports and slightly increases imports throughout the study period.

Arizona's generation mix is a bit more varied, with roughly one-third coal, one-third natural gas, and one-third a combination of nuclear and hydroelectricity. Arizona also has solar photovoltaic and landfill in its generation mix, although in such minor concentrations that it is not visible in Figure 4.2. Arizona adds new generation from coal and natural gas early in the study period, beginning around 2016. By 2021, Arizona maintains a steady generation of coal but continues to increase natural gas generation to satisfy its rising electricity demand. Eventually, Arizona generates more natural gas than coal. Arizona also adds new biomass generation, although a relatively minor amount compared to the other energy resources. Both nuclear and hydroelectric generation remain steady throughout the study period.

Figure 4.1. Utah Baseline Generation

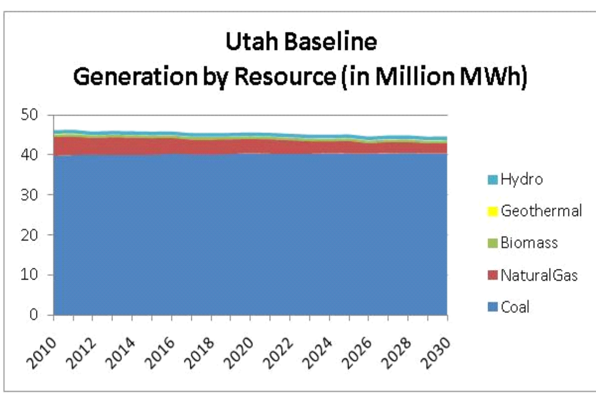
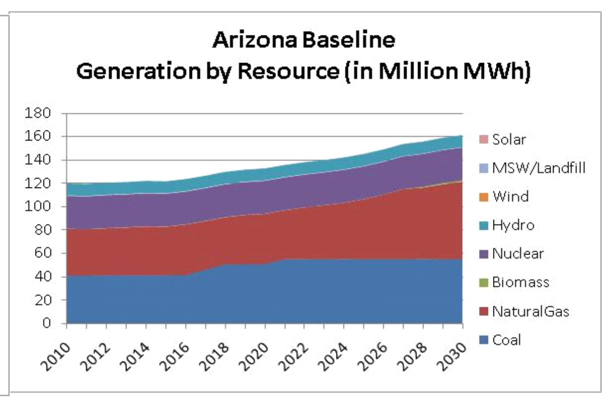


Figure 4.2. Arizona Baseline Generation



Arizona generates significantly more electricity than Utah. In 2020, Arizona generates roughly 37 percent more electricity than Utah. By 2030, Arizona generates 28 percent more electricity. In the beginning of the study period, Arizona and Utah generate roughly the same total amount of coal, although the percentage of coal out of the total respective generation mix is not even.

Table 4.5 presents additional model results. Total GHG emissions remain relatively steady in Utah, around 41 million metric tons. Arizona’s emissions rise throughout the study period, from roughly 59 million metric tons in 2010, to 69 in 2020, and to 80 in 2030. The average electricity price is roughly equivalent across the two states, both of which rise by over 150 percent between 2010 and 2030. Both Arizona and Utah are net electricity exporters. As mentioned above, Utah’s exports drop significantly over the course of the study period and its imports rise slowly; by 2030, Utah’s exports and imports nearly converge. Arizona also demonstrates decreasing exports and increasing imports, albeit to a lesser degree than Utah.

Table 4.5. Baseline Scenario Summary Results for Utah and Arizona, 2020 and 2030

	Utah Baseline		Arizona Baseline	
Year	2020	2030	2020	2030
GHG emissions (tons)	42,817,980	42,330,430	68,982,250	79,998,250
Average electricity price (2006$/MWh)	$59.69	$94.74	$60.58	$94.73
Total generation (MWh)	45,677,199	44,626,119	132,678,868	161,227,928
Coal	40,420,559	40,370,177	51,091,534	55,276,935
Natural gas	3,620,296	2,623,095	42,723,130	65,847,285
Nuclear	0	0	28,005,315	28,005,315
Hydroelectric	964,879	963,217	10,334,871	10,310,864
Wind	0	0	0	0
Solar PV	0	0	40,437	40,327
Geothermal	0	0	0	0
Biomass	671,464	669,630	245,754	1,510,027
Landfill/MSW	0	0	237,827	237,177
Total New Generation (MWh)	0	0	12,096,511	59,193,580
Coal	0	0	9,343,980	13,587,788
Natural gas	0	0	2,752,531	44,103,671
Wind	0	0	0	0
Solar PV	0	0	0	0
Geothermal	0	0	0	0
Biomass	0	0	0	1,264,944
Landfill/MSW	0	0	237,827	237,177
Electricity demand (MW)	4134	4931	12634	16164
Exports (MW)	1,781	1,037	2,927	2,762
Imports (MW)	748	923	491	577

Sensitivity Analysis: Cost Parameters

The results of the five baseline sensitivity analyses are presented in Table 4.6 and Table 4.7. Beginning with the first sensitivity analysis, the increase in the price of coal makes both states produce slightly less of it; although neither state retires any coal plants. As a result of a 15 percent increase in natural gas and coal, respectively, both states generate more natural gas power and less coal, and increase both exports and imports, albeit only slightly. These results reveal that the increase in the cost of coal offsets the effect of an increase in natural gas and so, despite the higher cost of natural gas, these states replace some coal generation with natural gas. The retail price of electricity rises accordingly. Neither state, however, replaces coal or natural gas with renewable energy;

therefore, the increase in fossil fuel price was not enough to make renewable energy cost-competitive across comparable load level, i.e. base load, intermediate, or peak.

Utah responds to a 25 percent cost increase in natural gas and coal with a reduction of both sources of fossil fuel, and a resulting overall decrease in total generation and GHG emissions. Utah also reduces both exports and imports, and experiences an increase in the retail price of electricity. With an effect similar to the 15 percent cost increase scenario, Arizona decreases coal generation, slightly increases natural gas generation, decreases both exports and imports, and experiences a rise in the price of electricity.

Table 4.6. Utah Baseline Sensitivity Analysis Summary Results, 2030

	Baseline	15% Cost Increase	25% Cost Increase	Technological Innovation	Demand Growth Adjustment
GHG emissions (tons)	42,330,430	42,437,190	42,243,450	42,422,220	42,717,550
Average electricity price (2006$/MWh)	$94.74	$96.62	$95.68	$96.28	$97.00
Total generation (MWh)	44,626,119	44,893,176	44,486,517	44,826,394	45,515,386
Coal	40,370,177	40,353,105	40,324,914	40,368,471	40,380,297
Natural gas	2,623,095	2,907,224	2,528,755	2,825,076	3,502,241
Nuclear	0	0	0	0	0
Hydroelectric	963,217	963,217	963,217	963,217	963,217
Wind	0	0	0	0	0
Solar PV	0	0	0	0	0
Geothermal	0	0	0	0	0
Biomass	669,630	669,630	669,630	669,630	669,630
Landfill/MSW	0	0	0	0	0
Total New Generation (MWh)	0	0	0	0	0
Coal	0	0	0	0	0
Natural gas	0	0	0	0	0
Wind	0	0	0	0	0
Solar PV	0	0	0	0	0
Geothermal	0	0	0	0	0
Biomass	0	0	0	0	0
Landfill/MSW	0	0	0	0	0
Demand	4,941	4,941	4,941	4,941	5,241
Exports	1,037	1,106	928	929	847
Imports	923	963	827	787	931

Table 4.7. Arizona Baseline Sensitivity Analysis Summary Results, 2030

	Baseline	15% Cost Increase	25% Cost Increase	Technological Innovation	Demand Growth Adjustment
GHG emissions (tons)	79,998,250	80,223,270	80,160,130	79,155,510	79,776,490
Average electricity price (2006$/MWh)	$94.73	$95.02	$95.14	$95.65	$94.20
Total generation (MWh)	161,227,928	161,825,800	161,695,971	159,311,296	160,701,503
Coal	55,276,935	55,275,848	55,276,152	55,268,571	55,270,228
Natural gas	65,847,285	66,446,243	66,316,109	63,464,662	65,485,684
Nuclear	28,005,315	28,005,315	28,005,315	28,005,315	28,005,315
Hydroelectric	10,310,864	10,310,864	10,310,864	10,310,864	10,310,864
Wind	0	0	0	0	0
Solar PV	40,327	40,327	40,327	40,327	40,327
Geothermal	0	0	0	0	0
Biomass	1,510,027	1,510,027	1,510,027	1,510,027	877,555
Landfill/MSW	237,177	237,177	237,177	711,531	711,531
Total New Generation (MWh)	59,193,580	59,318,188	59,762,314	57,255,392	61,013,478
Coal	13,587,788	13,587,788	13,587,788	13,587,788	13,587,788
Natural gas	44,103,671	44,228,279	44,672,406	41,691,130	46,081,687
Wind	0	0	0	0	0
Solar PV	0	0	0	0	0
Geothermal	0	0	0	0	0
Biomass	1,264,944	1,264,944	1,264,944	1,264,944	632,472
Landfill/MSW	237,177	237,177	237,177	711,531	711,531
Demand	16,163.68	16,163.68	16,163.68	16,164	15,243
Exports	2,762	3,214	2,544	2,177	3,248
Imports	577	978	287	220	211

Sensitivity Analysis: Technological Innovation Parameters

In the technological innovation sensitivity analysis, Utah and Arizona demonstrate consistent, albeit complex trends. In the case of Utah, the innovation-based renewable energy cost parameters are not significant enough to induce the state to build new renewable capacity, which is not surprising given that Utah does not build any new capacity in the baseline scenario either. The technological innovation parameters do, however, cause surrounding WECC states to increase landfill/MSW and wind energy, and retire some older coal and natural gas plants. These resource changes result in a decrease of surrounding states' exports, which, in turn, affects Utah's imports and causes

Utah to retain some of the generation that it would otherwise export. Utah also responds to these changes in imported supply by ramping up its natural gas generation by roughly 200,000 MWh. In the case of Arizona, the technological innovation cost adjustments make landfill energy more cost-competitive with natural gas; as a result, Arizona builds more landfill/MSW and less natural gas in the technological innovation scenario, relative to the baseline scenario. Arizona does not replace natural gas with landfill/MSW on a one-for-one basis and so it does not have as much excess capacity to export to surrounding states, including Utah. In summary, both states decrease inter-state electricity trades as a result of the technological innovation sensitivity analysis.

Sensitivity Analysis: Demand Parameters

A higher rate of demand growth causes Utah to increase coal and natural gas generation, which results in an increase of GHG emissions and an increase in the price of electricity. Utah does not, however, build any new power plants to provide for this greater demand; besides ramping up coal and natural gas plants, Utah reduces its exports and increases its imports. By 2030, Utah is a net importer of electricity in the demand growth adjustment sensitivity scenario.

As a result of a lower rate of demand growth, Arizona builds and deploys half as much biomass generation and slightly decreases coal generation. Arizona's exports rise and its imports fall. Both GHG emissions and the price of electricity decrease as a result of Arizona's demand growth adjustment sensitivity scenario.

Policy Portfolio Scenarios

As discussed above, each state's policy portfolio includes an RPS, a DSM program, renewable energy tax incentives, and a CCS policy. Portfolio policies were modeled as "isolated state" scenarios and as "regional coordination" scenarios, with two variants of policy strength. The results of these portfolio analyses in year 2030 are summarized in the tables below.[22] In effort to focus the conversation on broader trends, I only present results from the strong policy portfolios in the corresponding graphs. I do, however, present the moderate portfolio results in the summary tables for the sake of comparison. Overall, moderate and strong portfolios produced similar results.

Policy Portfolio Scenarios: Utah

Beginning with Utah's results in Table 4.8, the top two rows reveal that each portfolio scenario reduces GHG emissions and increases the retail price of electricity in Utah relative to baseline projections. The two isolated state scenarios have slightly lower emissions than the baseline. The regional coordination scenarios have lower GHG emissions than both the isolated state scenarios and the baseline. The lowest retail price in 2030 is in the strong regional coordination portfolio scenario. Figures 4.3 and 4.4 present these two variables, Utah's GHG emissions and retail electricity price, over time.

[22] I also modeled each individual policy in isolated states and across the region. Results of the individual policy scenarios are not presented in this analysis but can be obtained via personal request.

Table 4.8. Utah Portfolio Scenario Results in 2030

	Baseline	Moderate Isolated State Portfolio	Strong Isolated State Portfolio	Moderate Regional Coordination Portfolio	Strong Regional Coordination Portfolio
GHG emissions (tons)	42,330,430	42,012,020	42,020,000	41,138,700	40,224,960
Average electricity price (2006$/MWh)	$94.74	$121.92	$123.80	$112.36	$111.46
Total generation (MWh)	44,626,119	49,284,319	50,212,348	48,462,353	48,177,891
All Coal	40,370,177	40,314,138	40,319,958	39,453,392	38,619,945
IGCC CCS	0	0	0	0	0
All Natural gas	2,623,095	2,018,306	2,034,780	1,967,137	1,700,337
NGCC CCS	0	0	0	0	0
Nuclear	0	0	0	0	0
All renewables	1,632,847	6,951,874	7,857,609	7,041,823	7,857,609
Hydroelectric	963,217	963,217	963,217	963,217	963,217
Wind	0	5,319,027	6,224,762	5,408,976	6,224,762
Solar PV	0	0	0	0	0
Geothermal	0	0	0	0	0
Biomass	669,630	669,630	669,630	669,630	669,630
Landfill/MSW	0	0	0	0	0
Total New Generation (MWh)	0	5,319,027	6,224,762	5,408,976	6,224,762
All Coal	0	0	0	0	0
IGCC CCS	0	0	0	0	0
All Natural gas	0	0	0	0	0
NGCC CCS	0	0	0	0	0
All renewables	0	5,319,027	6,224,762	5,408,976	6,224,762
Wind	0	5,319,027	6,224,762	5,408,976	6,224,762
Solar PV	0	0	0	0	0
Geothermal	0	0	0	0	0
Biomass	0	0	0	0	0
Landfill/MSW	0	0	0	0	0
Electricity demand (MW)	4931	3,953	3,953	3,953	3,953
Exports	1,037	2,283	2,254	2,227	2,273
Imports	923	637	496	682	763

Figure 4.3. Utah GHG Emissions

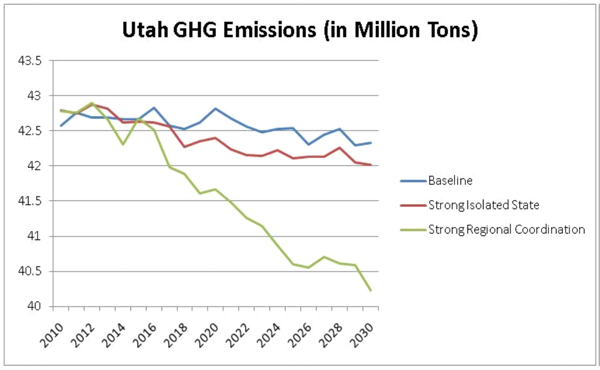
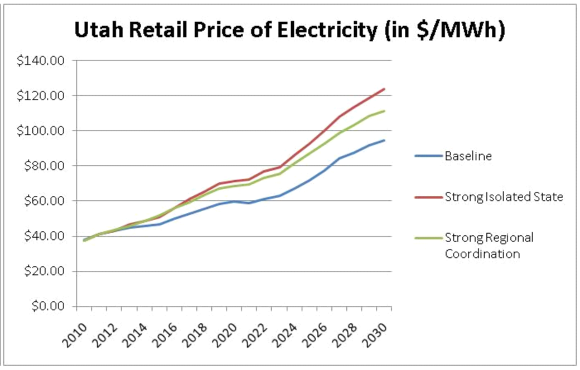


Figure 4.4. Utah Retail Price of Electricity



These graphs reveal that the Utah-only policy portfolio has minor carbon mitigation effects. Regional policy portfolio coordination, however, has a relatively substantial effect on carbon mitigation. The isolated state scenario requires the same total Utah investment as the regional coordination scenario—both the state and regional scenarios have the same new RPS wind resources, demand curtailment, policy incentives, and CCS technology options—yet the total GHG savings of the two scenarios significantly differ. The greater "bang-for-your-buck" of the regional coordination scenario is evident in Figure 4.4, which demonstrates that both portfolio scenarios will increase the total retail price of electricity in Utah, but the isolated state portfolio will increase retail prices more than $10/MWh over the regional coordination portfolio by 2030. Table 4.9 below shows the difference between GHG emissions in the baseline scenario and GHG emissions in the state and regional scenarios, respectively. These estimates reveal that, for the same investment from the state of Utah, a regional portfolio has 2.7 times the decarbonization potential than a state portfolio in 2020, and up to 6.8 times by 2030. If one considers cumulative GHG emissions over the entire study period, the regional coordination portfolio has roughly 5.1 times greater decarbonization potential as the isolated state portfolio.[23]

Table 4.9. GHG Emissions Difference between Baseline and Portfolio Scenarios, Utah

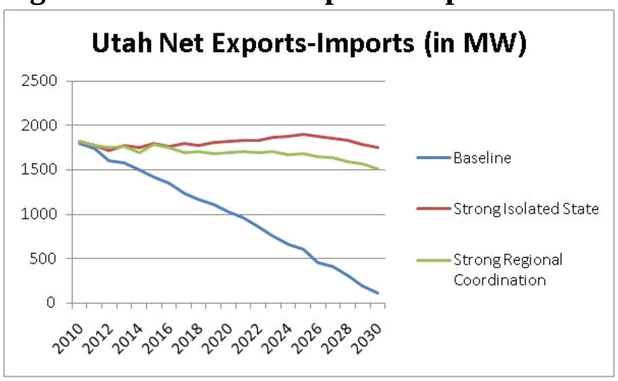
	State Portfolio	Regional Portfolio	Factor of Difference
Year 2020	424,250	1,155,650	2.7
Year 2030	310,430	2,105,470	6.8
Cumulative 2010-2030	3,967,960	20,325,700	5.1

[23] It is worth noting that a regional scenario will result in a greater bang for Utah's buck but will also require surrounding states to make policy investments as well.

Which factors contribute to the greater decarbonization potential of regional portfolios for the case of Utah? Returning to Table 4.7, other model results lend insights on this issue. As a result of all portfolio scenarios, Utah experiences a reduction in total in-state electricity demand, as one would expect given its DSM efforts. Utah also uses less natural gas, and even retires a few natural gas plants, as a result of the new wind generation. Hydroelectricity and biomass remain unaffected, relative to the baseline scenario. Yet total generation rises in all four scenarios. In the case of the isolated state scenarios, coal generation rises rather substantially; the combination of new wind power and increased coal generation—note that Utah does not actually build new coal plants, it simply ramps up generation at existing plants—causes total generation to rise. It is only the retirement of natural gas plants that causes the isolated state portfolio scenarios to experience a reduction—albeit, recall, minor—in GHG emissions vis-à-vis the baseline scenario.

If electricity demand in Utah, however, is 20 percent below a business as usual case, why would Utah generate *more* coal power than it would in the absence of a policy portfolio? The reason is that Utah can export its relatively inexpensive coal-based electricity to neighboring states, a phenomenon referred to as "carbon leakage" in the literature. In the absence of their own renewable energy, energy efficiency, or carbon dioxide legislation, neighboring states will take advantage of the opportunity to purchase Utah's excess coal. In the case of the regional coordination scenario, however, neighboring states also have to meet demand-side and supply-side regulations of their own and, therefore, purchase less of Utah's excess fossil fuel generation. These trends are evident in Figure 4.5, which displays net exports minus imports over time. The baseline scenario experiences converging values for exports and imports. Both the state and regional scenarios experience an increase in exports and a decrease in imports, relative to the baseline. The isolated state scenario has the largest net export-import difference, which indicates that Utah is the biggest exporter of electricity when it is the only state with a policy portfolio.

Figure 4.5. Utah Net Exports-Imports



Policy Portfolio Scenarios: Arizona

Arizona's results are summarized in Table 4.10. As this table reveals, all four policy scenarios reduce GHG emissions significantly below baseline projections. Similarly to Utah, the regional coordination scenarios result in the lowest total GHG emissions. There are, however, only minor differences between GHG emission savings in the isolated state portfolios and the regional coordination portfolios. The retail price of electricity also rises in all four cases but the strong regional coordination scenario has the lowest price by 2030. Figures 4.6 and 4.7 display Arizona's GHG emissions and retail price over time, respectively, as a result of the portfolio scenarios.

Table 4.10. Arizona Portfolio Scenario Results in 2030

	Baseline	Moderate Isolated State Portfolio	Strong Isolated State Portfolio	Moderate Regional Coordination Portfolio	Strong Regional Coordination Portfolio
GHG emissions (tons)	79,998,250	67,111,291	66,415,066	66,467,080	64,743,290
Average electricity price (2006$/MWh)	$94.73	$118.64	$121.35	$110.59	$108.09
Total generation (MWh)	161,227,928	139,614,563	139,977,049	140,997,418	141,001,189
All Coal	55,276,935	58,182,910	58,161,484	54,558,253	53,248,062
IGCC CCS	0	2,950,491	2,950,491	0	0
All Natural gas	65,847,285	25,353,731	24,236,932	30,393,390	29,606,316
NGCC CCS	0	0	0	0	0
Nuclear	28,005,315	28,005,315	28,005,315	28,005,315	28,005,315
All renewables	12,098,395	28,072,607	29,573,318	28,040,460	30,141,496
Hydroelectric	10,310,864	10,310,864	10,310,864	10,310,864	10,310,864
Wind	0	15,737,036	17,870,219	15,467,712	17,331,571
Solar PV	40,327	40,327	40,327	40,327	40,327
Geothermal	0	0	0	0	0
Biomass	1,510,027	1,510,027	877,555	1,510,027	1,510,027
Landfill/MSW	237,177	474,354	474,354	711,531	948,708
Total New Generation (MWh)	59,193,580	36,965,103	38,465,814	31,057,574	33,117,805
All Coal	13,587,788	16,538,279	16,538,279	13,587,788	13,470,185
IGCC CCS	0	2,950,491	2,950,491	0	0
All Natural gas	44,103,671	0	0	25,600	102,398
NGCC CCS	0	0	0	0	0
All renewables	1,502,121	17,476,334	18,977,045	17,444,187	19,545,223
Wind	0	15,737,036	17,870,219	15,467,712	17,331,571
Solar PV	0	0	0	0	0
Geothermal	0	0	0	0	0
Biomass	1,264,944	1,264,944	632,472	1,264,944	1,264,944
Landfill/MSW	237,177	474,354	474,354	711,531	948,708
Demand	16164	12,873	12,873	12,873	12,873
Exports	2,762	3,267	3,301	3,625	3,620
Imports	577	264	254	466	570

Figure 4.6. Arizona GHG Emissions

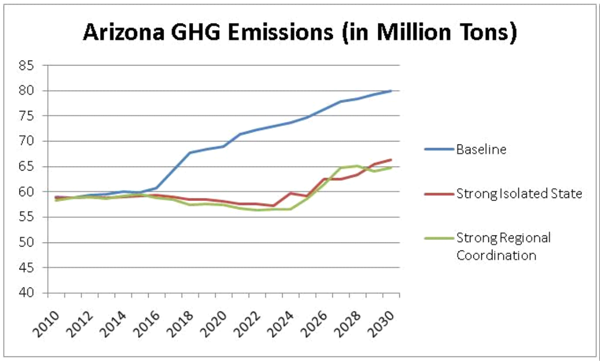


Figure 4.7. Arizona Retail Price of Electricity

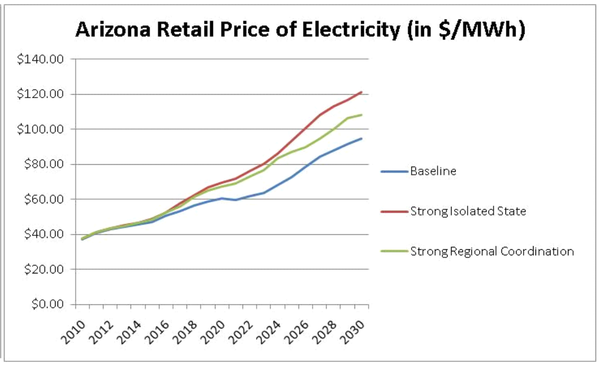


Figure 4.6 demonstrates that the regional portfolio has slightly lower GHG emissions throughout the study period, with the exception of the years between 2026 and 2028. The retail price of electricity in the regional scenario is, however, consistently lower than it is in the state scenario, as displayed in Figure 4.7. Table 4.11 provides Arizona's decarbonization potential factors. The regional coordination policy is 1.1 times more effective at reducing GHG emissions—per Arizona dollar spent on policy portfolios—than the state portfolio, which is the case at 2020, 2030, and cumulatively across the entire study period.

Table 4.11. GHG Emissions Difference between Baseline and Portfolio Scenarios, Arizona

	State Portfolio	Regional Portfolio	Factor of Difference
Year 2020	10,819,110	11,622,010	1.1
Year 2030	13,583,184	15,254,960	1.1
Cumulative 2010-2030	185,011,874	195,898,470	1.1

These factors of difference are based on the premise that both the state and regional scenarios will require the same policy expenditures made by the state of Arizona but will have different effects on total GHG emissions. The policy costs are factored into the retail price of electricity; but the retail price also includes other investment decisions made throughout the study period. It is instructive to consider, therefore, why the isolated state scenario results in a higher electricity price than the regional coordination scenario, despite the small difference in total GHG emissions. It is additionally important to consider why Utah has such a significant difference between regional and state scenarios yet Arizona's difference is minor.

Returning to Table 4.10, it is evident that Arizona is forced to make more complex resource decisions than Utah as a result of the policy scenarios. Whereas Utah has relatively steady demand and ample coal resources to satisfy its base load, Arizona has an increasing demand growth rate and needs to build new power plants throughout the study period to satisfy this demand. In the baseline scenario, Arizona primarily builds new natural gas plants to satisfy increasing demand, but also builds coal, biomass, and landfill generating units. In the policy scenarios, Arizona is forced to make new investment decisions regarding which resources to build. Figures 4.8, 4.9, and 4.10 display which decisions Arizona makes.

Figure 4.8. Arizona New Generation

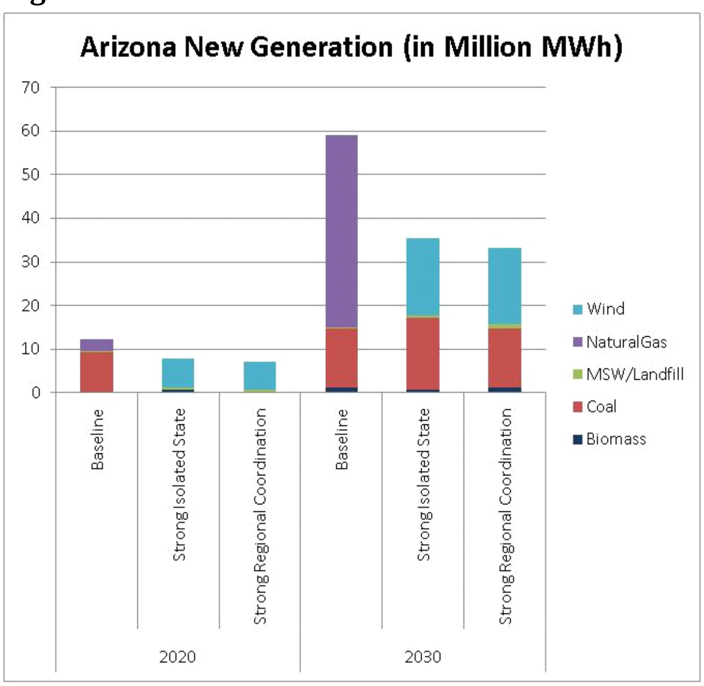


Figure 4.9. Arizona Generation, State

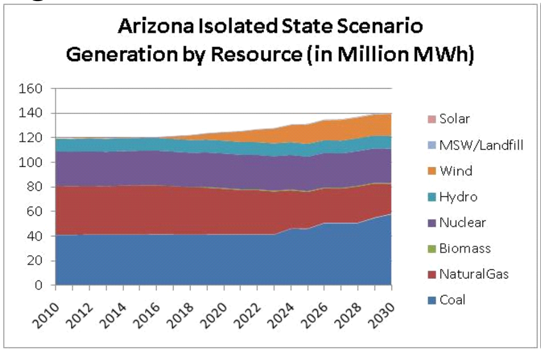
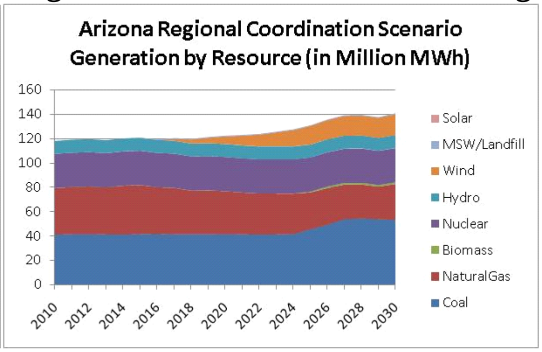


Figure 4.10. Arizona Generation, Regional

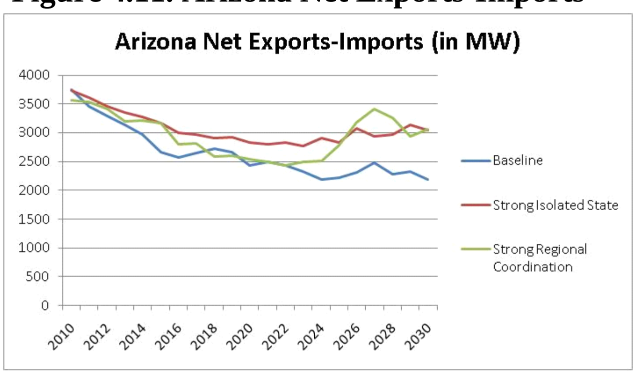


Collectively, these graphs reveal that Arizona reduces total generation as a result of the policy scenarios. This reduction in generation is a significant factor in Arizona's large GHG emissions savings across all policy scenarios. Arizona still has to build new generation to satisfy rising demand, which it does with new coal and RPS wind. The new wind generation entirely displaces the new natural gas builds that occur in the baseline scenario. Arizona still needs to satisfy growing base load demand, however, which it cannot do exclusively with wind power, since wind is a better intermittent load resource than a base load resource. The wind that Arizona deploys allows the state to postpone the construction of new coal plants in both the state and regional scenarios, until it eventually needs to build the additional base load coal generation. Once Arizona builds these coal plants, it has excess coal-based energy, which it can then export to surrounding states until Arizona requires the entire load for itself.

Arizona has to build new coal power plants earlier in the isolated state scenario because it cannot import as much base load generation from other states. Once surrounding states have their own portfolio policies, as is the case with the regional coordination scenarios, they have excess base load coal generation—a small amount of which is from IGCC-CCS[24]—to sell to Arizona, which allows Arizona to further postpone the construction of new coal plants until 2025. Beginning in 2026, Arizona has excess coal power, generated with the most advanced and efficient coal technologies, which it sells to surrounding states.

These trends are evident in the export-import graph below. Both policy scenarios cause Arizona to export more power, relative to the baseline, over the course of the study period. Imports rise in the regional coordination scenario, beginning around 2016, exactly when Arizona postpones its first coal plant build. Imports fall again and exports rise when Arizona builds its regional coordination scenario coal plant in 2025. Between 2026 and 2028, Arizona exports more coal power in the regional scenario than in the state scenario. Save these years, Arizona has a higher net export-import value in the isolated state portfolio scenarios, which are the only years in which the regional portfolio is more cost-effective than the state portfolio.

Figure 4.11. Arizona Net Exports-Imports



Carbon Price Scenarios

[24] Arizona builds an IGCC-CCS plant only after it exhausts its IGCC with no CCS limit of one power plant and its scrubbed sub-critical pulverized coal limit of two power plants. These trends indicate that IGCC with no CCS and sub-critical pulverized coal power plants are preferred to IGCC-CCS in the absence of a carbon price.

The final set of models combine portfolio with carbon price scenarios. The results from the strong regional portfolios combined with the carbon price scenarios are presented in Table 4.12 and Table 4.13. These tables also include the demand growth sensitivity scenarios.

Table 4.12. Utah Carbon Price Portfolio Results, 2030

	Baseline	Regional Portfolio & $25 GHG	Regional Portfolio & $50 GHG	Regional Portfolio & $25 GHG with Demand Sensitivity	Regional Portfolio & $50 GHG with Demand Sensitivity
GHG emissions (tons)	42,330,430	37,548,740	25,710,150	38,636,930	25,958,750
Average electricity price (2006$/MWh)	$94.74	$129.25	$164.86	$132.19	$167.61
Total generation (MWh)	44,626,119	45,785,514	37,490,244	47,134,922	36,533,035
All Coal	40,370,177	36,134,930	23,336,549	37,002,228	23,508,173
IGCC CCS	0	0	0	0	0
All Natural gas	2,623,095	1,614,157	4,616,155	2,094,504	4,988,047
NGCC CCS	0	0	0	0	0
Nuclear	0	0	0	0	0
All renewables	1,632,847	8,036,426	9,537,540	8,038,190	8,036,815
Hydroelectric	963,217	963,217	963,217	963,217	963,217
Wind	0	6,224,762	6,224,762	6,224,762	6,224,762
Solar PV	0	0	0	0	0
Geothermal	0	180,426	181,058	181,477	181,237
Biomass	669,630	668,021	1,931,325	668,733	667,599
Landfill/MSW	0	0	237,177	0	0
Total New Generation (MWh)	0	6,405,188	7,907,942	6,224,762	6,224,762
All Coal	0	0	0	0	0
IGCC CCS	0	0	0	0	0
All Natural gas	0	0	0	0	0
NGCC CCS	0	0	0	0	0
All renewables	0	6,405,188	7,907,942	6,224,762	6,224,762
Wind	0	6,224,762	6,224,762	6,224,762	6,224,762
Solar PV	0	0	0	0	0
Geothermal	0	0	0	0	0
Biomass	0	0	1,264,944	0	0
Landfill/MSW	0	0	237,177	0	0
Demand (MW)	4,931	3,953	3,953	3,863	3,822
Exports	1,037	1,840	1,022	2,086	845
Imports	923	595	725	596	518

Table 4.13. Arizona Carbon Price Portfolio Results, 2030

	Baseline	Regional Portfolio & $25 GHG	Regional Portfolio & $50 GHG	Regional Portfolio & $25 GHG with Demand Sensitivity	Regional Portfolio & $50 GHG with Demand Sensitivity
GHG emissions (tons)	79,998,250	55,974,080	41,122,600	53,720,590	40,693,920
Average electricity price (2006$/MWh)	$94.73	$125.40	$151.16	$128.36	$155.41
Total generation (MWh)	161,227,928	134,433,978	130,982,117	130,308,993	123,473,138
All Coal	55,276,935	48,807,496	28,316,060	45,344,357	25,959,029
IGCC CCS	0	2,950,373	5,891,468	2,946,480	2,943,482
All Natural gas	65,847,285	25,741,120	42,786,073	27,292,553	40,475,608
NGCC CCS	0	0	0	0	0
Nuclear	28,005,315	28,005,315	28,005,315	28,005,315	28,005,315
All renewables	12,098,395	31,880,046	31,874,669	29,666,768	29,033,186
Hydroelectric	10,310,864	10,310,864	10,310,864	10,310,864	10,310,864
Wind	0	17,331,571	17,331,571	17,331,571	17,331,571
Solar PV	40,327	40,327	40,327	40,327	40,327
Geothermal	0	0	0	0	0
Biomass	1,510,027	2,774,223	2,768,846	1,509,653	876,072
Landfill/MSW	237,177	1,423,062	1,423,062	474,354	474,354
Total New Generation (MWh)	59,193,580	33,028,352	32,311,089	26,277,061	21,381,878
All Coal	13,587,788	11,743,832	5,891,468	7,206,193	2,943,482
IGCC CCS	0	2,950,373	5,891,468	2,946,625	2,941,125
All Natural gas	44,103,671	0	5,135,100	0	0
NGCC CCS	0	0	0	0	0
All renewables	1,502,121	21,284,521	21,284,521	19,070,869	18,438,397
Wind	0	17,331,571	17,331,571	17,331,571	17,331,571
Solar PV	0	0	0	0	0
Geothermal	0	0	0	0	0
Biomass	1,264,944	2,529,888	2,529,888	1,264,944	632,472
Landfill/MSW	237,177	1,423,062	1,423,062	474,354	474,354
Demand (MW)	16,164	12,873	12,873	12,328	12,058
Exports	2,762	2,624	2,618	2,905	2,345
Imports	577	201	582	415	343

The carbon price scenarios produce predictable results: the price of electricity rises; GHG emissions fall; total generation decreases in all cases, save the Utah $25 GHG scenario; and renewable energy deployment increases and displaces carbon-intensive fossil fuels. A carbon price of $25/metric ton CO_2e causes both states to make relatively small reductions in coal generation and large reductions in natural gas. A carbon price of

\$50/metric ton CO_2e has the opposite effect: major coal reductions and minor natural gas reductions, as is the case for Arizona, or natural gas additions, as is the case for Utah.

In the low carbon price scenario, Utah increases total generation; this increase is due to new RPS wind and the ramping up of Utah's geothermal operations. Utah also reduces coal generation, although not substantially, as well as natural gas, and increases exports and decreases imports. The price of carbon is significant enough in the high price scenario to cause Utah to deploy new biomass and landfill energy, and cut total coal generation nearly in half. Given that natural gas is the least carbon intensive fossil fuel, and also has the ability to serve as base load power, Utah builds new natural gas plants in the high carbon price scenario to replace a portion of its coal-generated base load. In total, Utah generation decreases, imports increase, and exports decrease in order for Utah to provide enough electricity to meet its consumers' electricity demands at minimal cost. These conditions make the retail cost of electricity rise.

In Arizona's low carbon price scenario, the state retires a substantial amount of coal generation, but replaces much of it with new IGCC-CCS and sub-critical scrubbed pulverized coal units. Arizona also retires more than half of its natural gas plants and replaces them with new renewable energy systems, including biomass, landfill, and RPS wind. The high carbon price causes Arizona to take more drastic measures: it retires over half of its coal plants; replaces a fraction of the coal with IGCC-CCS; decreases natural gas and replaces a portion of that power with renewable energy generation; and increases imports.

Figures 4.12 and 4.13 display each state's total GHG emission savings, relative to baseline values, as a result of the portfolio and carbon price scenarios. These graphs demonstrate that carbon prices, coupled with portfolio policies, have significant potential to reduce GHG emissions over the long run. Beginning around 2015, a carbon price of $50/metric ton CO_2e and a regional coordination portfolio cuts Utah's emissions by almost one-half, and Arizona's emissions by one-third.

Figure 4.12. Utah Carbon Price Scenarios

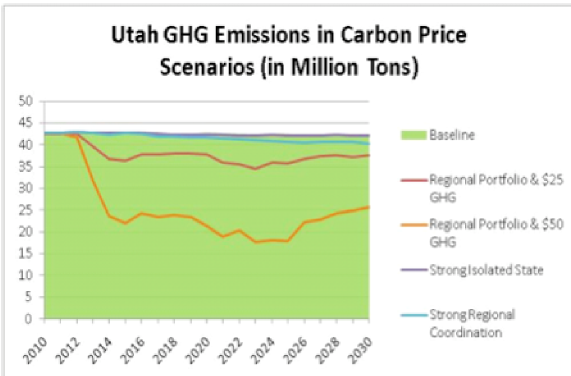
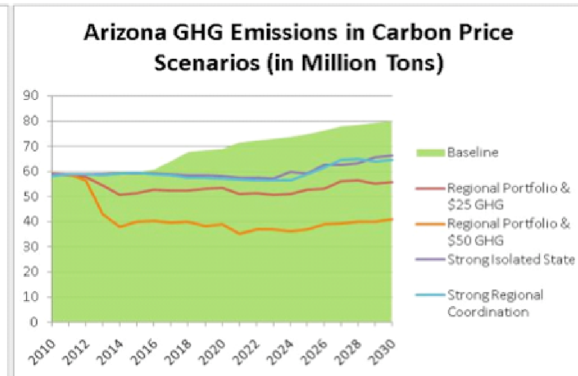


Figure 4.13. Arizona Carbon Price Scenarios



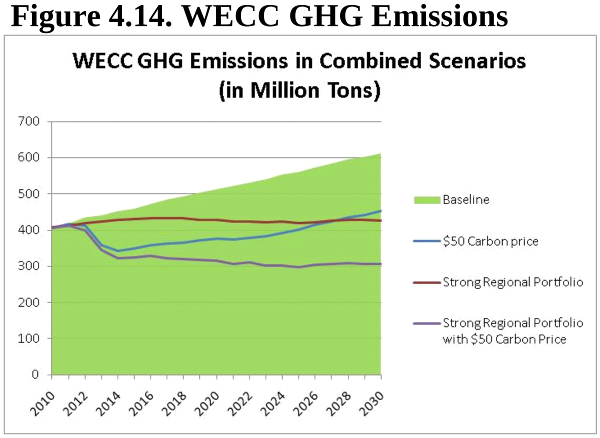
Carbon Price Sensitivity Analyses

The demand sensitivity scenarios represent a decrease in the rate of demand growth across all WECC states that more realistically captures the elasticity of demand that accompanies a carbon price. The sensitivity results once again highlight the intricacies of state level electricity dynamics, in which states make different dispatch decisions based on each state's mix of generation resources, its export and import constraints, and the activities made in surrounding states. Vis-à-vis the baseline scenarios, both Utah's and Arizona's outputs from the sensitivity scenarios are consistent with those from the carbon price scenarios, as outlined above. When one instead compares the sensitivity scenarios with the carbon price scenarios, a couple of differences are worth noting. First, a lower rate of demand growth leads both states to cut back on the amount of new renewable generation, particularly biomass and landfill, that each needs to build. Arizona also cuts back on new coal power plant builds. Second, given that there is less new generation in WECC states but there is still a need for electric supply that can match demand in these states, both Utah and Arizona ramp up generation from their natural gas plants. Utah also increases coal and geothermal generation, although not significantly. Both states find it advantageous to increase their already existing capacity—primarily from less carbon-intensive fuel sources—instead of building new generation. Third, some of this increase in already-existing generation is to satisfy in-state demand and the rest is for out-of-state demand. In states with relatively low demand and high capacity, such as Utah, net exports are the greatest. Utah is able to significantly increase exports and decrease imports in the $25 carbon price with demand sensitivity scenario. Utah's total generation is actually higher in the demand sensitivity scenarios than it is in the carbon price scenarios because it is able to deploy this already-existing generation and sell it to surrounding states; although this results in a greater amount of GHG emissions and a higher retail price of electricity in Utah. Given that Arizona has less existing capacity to ramp up, and also cuts back on the new capacity that it builds, Arizona needs to import a greater amount of generation in the $25 carbon price with demand sensitivity scenario. Finally, both states cut back on new power plant builds, and decrease both imports and exports, as a result of the $50 carbon price with demand sensitivity scenario.

Regional Models

I additionally modeled a series of carbon price and portfolio scenarios at the regional level to track the differences in carbon mitigation effects of various energy and climate policies. Figure 4.14 presents the summary findings. WECC greenhouse gas emissions increase throughout the study period in the baseline scenario. The $50/metric ton CO_2e scenario causes the WECC to experience two years of rapid transition, or a tighten-the-belt period, in which it must quickly shift from carbon intensive fuels to more efficient and less carbon-intensive sources. After those two years, emissions continue to rise at a rate that is similar to, if not slightly smaller, than the baseline scenario. In the presence of a coordinated regional or national energy policy portfolio, but without a price on carbon, the WECC is able to roughly stabilize emissions at 2010 levels and generate a "stabilization triangle" (refer to the area above the red line in figure 4.14; Pacala and Socolow, 2004). The combination of the energy policy and the climate policy—the regional portfolio and the carbon price—causes the WECC to once again tighten its belt for a few years, but also has the combined effect of a change in the overall rate of GHG emissions growth. The new rate of growth is close to zero and, at times, slightly negative. These results confirm that both energy portfolio policies and climate policies have the potential to reduce GHG emissions significantly; but neither is as effective in isolation as they are when combined.

Figure 4.14. WECC GHG Emissions



Discussion

Results from the combined set of analyses confirm that: 1) spreadsheet projections of the climate mitigation effects of state energy policy efforts are not adequate; and 2) national level policy analyses—focused on both singular and portfolio policies—cannot be generalized to the state level. Regarding the former, the present results reveal that the electricity sector cannot be captured easily in a linear spreadsheet projection, in which tracking state-by-state electricity trade exchanges, transmission constraints, and utility cost minimization decisions is immensely difficult. Regarding the latter, all national level modeling analyses reviewed above demonstrate the potential cost-effectiveness of policy efforts that are heterogeneous and continuous across states. Previous national level findings are akin to the regional level results generated in the present study, which conclude that a coordinated policy strategy has significant carbon mitigation potential. In short, both state level spreadsheets and national modeling projections overestimate the effectiveness of state energy policy portfolios on carbon mitigation because they do not account for—or have the resolution to identify—changes in inter-state exporting behavior, the potential for carbon leakage, the retirement and building of new power plants, or changes in the relative price of electricity between states as a result of policy variation across state borders.

A summary of the model results is as follows. State energy policy portfolios have the potential to reduce GHG emissions over the long run. Coordinated energy policy portfolio efforts, as facilitated across multiple states, a region, or the nation, can produce minor (e.g. Arizona) to significant (e.g. Utah) improvements in the decarbonization potential of policy actions. The difference in decarbonization potential between isolated state policies and larger, more coordinated policy efforts is due to in large part to carbon leakage, which is the export of carbon intensive fossil fuel-based electricity across state lines.

The difference between the GHG mitigation potential of state efforts versus larger, coordinated efforts depends on the individual circumstances of each state. The present study considered two states, Utah and Arizona, and identified which factors contributed to the states' GHG savings over time. In the case of Utah, which has a low demand growth rate and an abundance of coal generation, an isolated state policy portfolio causes Utah to decrease natural gas generation and export all excess coal generation to neighboring states. A regional coordination portfolio, on the other hand, reduces the neighboring states' demand for inexpensive base load power, and Utah is forced to retire some of its older, less efficient coal power plants. The difference in decarbonization-effectiveness between the two scenarios, therefore, is large. In the case of Arizona, which has a high rate of electricity demand growth and a variety of different electricity resources, both an isolated state and a regional coordination portfolio cause Arizona to make significant changes to its resource portfolio mix. Both portfolio scenarios force Arizona to reduce total generation and delay new fossil fuel power plant builds. The regional coordination portfolio has greater decarbonization potential because Arizona builds less new coal generation, and thereby has lower carbon leakage, relative to the isolated state scenario.

It is additionally instructive to consider the behavior of the individual policy instruments that are included in the energy portfolios. First, the RPS policy increased wind generation, which tended to displace new or replace existing natural gas generation.

The scenarios in this analysis confirm that an RPS policy can effectively increase renewable energy deployment, but it has limited ability to control fossil fuel generation, reduce demand, or control GHG emissions, as the literature has recently discussed (Rabe, 2008; Carley, 2009). Second, DSM policies were found to decrease in-state electricity demand, but, as was the case with Utah, not necessarily cause total in-state production to decrease accordingly.

Third, tax incentives of a 35 percent capital cost reduction had minimal effects on total renewable energy generation in all non-carbon-price policy scenarios. Tax incentives did not affect Utah’s dispatch behavior, but they did cause Arizona to deploy extra landfill instead of new fossil fuel generation. These results reveal that a 35 percent capital cost tax incentive is not enough to make most renewable resources cost-competitive with conventional energy sources. With an incentive, landfill energy is able to compete with other new resources, but not existing resources. In the combined carbon price and portfolio scenarios, the tax incentive helps improve the cost-competitiveness of landfill, geothermal, and biomass resources.

Finally, the CCS policy had noteworthy results. No state in the WECC built NGCC-CCS technologies in any of the policy scenarios. Utah did not deploy a power plant with CCS technology; but this is not surprising, given that Utah had no need to add extra base load generation at any time during the study period. Arizona deployed IGCC-CCS generation in the isolated state scenarios, beginning in 2030, after the state exhausted its IGCC with no CCS and scrubbed sub-critical pulverized coal power plant builds. Arizona did not deploy any IGCC-CCS in the regional coordination policies, although surrounding states did. This result is due to the timing of Arizona’s power plant construction needs, and the lack of overlap between its needs and the availability of CCS technologies. In the high carbon price and regional coordination portfolio scenario, 100 percent of Arizona's new generation capacity was supplied by IGCC-CCS. These collective results reveal that, given current EIA cost and performance characteristics, IGCC-CCS technologies have the potential to be cost-competitive and more than carbon-competitive with other coal generating units, but only in the presence of carbon restrictions. Scenario results indicate that IGCC-CCS will not realize this potential, however, until 2027 or beyond.

The final results of this analysis revealed that energy policy portfolios have carbon mitigation potential, and that larger, coordinated policy efforts have enhanced potential. Results also confirmed that a carbon price of \$50/metric ton CO_2e can generate substantial carbon savings. Although both policy options—energy policy or climate policy—are effective, neither is as effective alone as when the two strategies are combined.

Returning to the discussion of carbon leakage, this analysis is by no means the first to document this phenomenon. Many studies have used this term to classify the migration of carbon-intensive firms or industries from regions of carbon regulation to those without regulation. In other words, as a result of a climate policy, emissions increase outside of the policy-enforcing region. Numerous examples of international emissions leakages associated with cap-and-trade policies have emerged in recent years. Rabe (2008) has identified the problem of carbon leakages in the U.S. as well, which accompany the Regional Greenhouse Gas Initiative (RGGI). Rabe and Bushnell and his colleagues (Bushnell et al., 2007) extend the notion of carbon leakages, or "reshuffling" as Bushnell et al. refer to it, to include the transfer of relatively inexpensive electricity from a regulated area to a non-regulated area. The consequences of this type of carbon leakage is that it increases the price of electricity—the incidence of which is more often than not passed along to the consumer—and costs the government financial resources that could be used for other public purposes, all for minor or potentially negligible savings of global greenhouse gas emissions. As Rabe (2008) explains, “the impact of significant leakage could be to neutralize any potential carbon reduction of RGGI and even create substantial sinks that could accentuate the attractiveness of electricity produced in nonregulated states and provinces.” In keeping with these observations, both the European Union and RGGI have recently raised this concern, and facilitated working groups to study the extent of the problem and ways in which it can be addressed (RGGI, 2007; EU, 2009).

The supporting literature to date has focused exclusively on the climate policy-carbon leakage connection. The present study additionally identifies the connection between energy policies and carbon leakages. These findings are pertinent because U.S. climate change efforts are, to date, primarily state-run energy policy efforts, and the likelihood that leakage is already present is high. It is possible that states that appear to be U.S., and even global, leaders in climate change efforts may have a minimal, if not a negligible, effect on global greenhouse gas emissions.

In the continued absence of national climate change legislation, the cost-effectiveness of state decarbonization policies can be improved with efforts to coordinate energy and climate policy action across state borders, via either state partnership agreements or regional policy coordination. Assuming that the primary objective of a climate action plan, or energy policy portfolio, is to reduce GHG emissions over the long run, individual states can also make concerted efforts to align the policy objectives, and therefore the policy design features, of the various policy instruments in their climate action plans. Several studies have also confirmed that policy instrument coordination can increase the effectiveness of energy and climate policy efforts (Sorrell and Sijm, 2003; Gonzalez, 2007). Furthermore, individual states can add stipulations to their renewable energy and energy efficiency legislation that additionally regulates the amount or percentage of fossil fuel generation that can be produced and consumed in-state. Or, alternatively constructed, states can mandate that new RPS renewable energy capacity or DSM "negawatts" must be matched one-for-one across comparable load levels with carbon-intensive fossil fuel plant retirements.

It is worth noting, however, that each energy policy instrument that is included in a state portfolio is designed to address a fundamentally different market failure than just GHG emissions. For instance, RPS policies address the market failures associated with renewable energy market penetration. It is important to note that energy policy instruments can have some effect on GHG mitigation—and they can be optimally designed and coordinated so as to maximize total GHG mitigation potential, as argued above—however, energy policy instruments are not the same thing as climate policy instruments; and each type of instrument is associated with a different set of objectives, market failures, and mechanisms for policy action.

This analysis raises issues regarding the potential effectiveness of a "progressive federalism" approach. It is not yet clear how much authority the national government will grant states to maintain their own energy and climate policies, in the event that national climate change legislation is passed in coming years. The proposed Waxman-Markey bill, "H.R. 2454, the American Clean Energy and Security Act of 2009," provides some insights on the possibility of federal preemption. The bill mandates that all states must comply and cannot interfere with the federal cap-and-trade during the first five years of operation, 2012-2017. After 2017, the bill allows states to set their own cap limits, so long as the state caps are more stringent than the federal caps. The bill offers few additional details regarding the authority of state governments, which suggests that the bill will likely preserve states' authority to enact and maintain state level energy policy portfolios. However, many of the major policies that are currently found in state climate action plans are proposed as national regulations in the Waxman-Markey bill. For instance, the bill proposes a national RPS as well as an efficiency portfolio standard. Therefore, if the bill is enacted as proposed, any state with energy policies that match or are less strict than the national policy will be forced to abandon previous state regulations and instead comply with national standards.

While some states, such as many in the Southeast, object on economic grounds to the national government setting energy policy regulations in addition to carbon regulations, this analysis finds evidence that a national policy portfolio could have a larger effect on global greenhouse gas emissions than state-led efforts. A combined federal cap-and-trade and national policy portfolio has the potential to produce the greatest carbon savings.

Limitations

There are a number of limitations to this type of modeling analysis. The first set of limitations is associated with the choice of model, and with modeling analyses more generally. The second set of limitations includes those that are due to the methodological approach of the present study.

Modeling Limitations

AURORAxmp is a bottom-up electricity model and, similar to other bottom-up models, it tends to demonstrate overly optimistic technology diffusion behavior. This is because a model such as AURORAxmp neglects to account for non-standard economic conditions in its optimization equation, such as transition costs, market uncertainties, and market imperfections. As a counter-balance to this trend, however, AURORAxmp bases its optimization logic purely on a cost-minimization equation, and thereby neglects to consider that some market actors deploy new energy systems due to non-cost factors. For instance, homeowners may install solar photovoltaic panels on their roofs because they believe that it is worth spending extra money on electricity in order to have minimal impact on their environment.

Another counter-balance to the overactive diffusion behavior is AURORAxmp's failure to retire coal power plants at a specified terminal year. AURORAxmp does retire some coal power plants, but only those plants that the electric industry has already publicly designated for retirement. The remainder of the coal power plants are already over 30 years old. Yet the only way that these plants will be retired is if they cannot compete with the real annualized net present value of alternative resources. If these plants are already paid off, the chances of retirement are small. By the end of the study period, many of the WECC's coal power plants are well over 60 years old, and some up to 80 years of age. In reality, one should assume that a portion of these coal plants will need to be replaced between 2010 and 2030, which will increase electricity costs and potentially decrease GHG emissions. Considering the case of Utah, it is possible that Utah would make different construction and dispatch decisions if it had to replace a major coal power plant during the study period. Instead of constructing a new coal power plant, for instance, Utah may consider a biomass co-combustion plant.

Non-linear bottom-up models also fail to consider technological change. More advanced, non-linear models make energy resource costs endogenous, which provides more realistic projections of future circumstances. This omission likely affects renewable and alternative energy options the most, since these resources are still experiencing downward trends on their respective marginal cost curves.

Finally, AURORAxmp is an electricity dispatch model, not an integrated micro-economic model such as NEMS or a macro-economic model such as the Applied Dynamic Analysis of the Global Economy model (ADAGE). Therefore, Aurora does not have the ability to find the lowest cost energy solutions across the entire economy; it is merely able to find the lowest cost electricity source given constraints on capacity, transmission and distribution capacities, and costs.

Methodological Approach Limitations

This type of analysis is not rooted in causal inference. It is merely a modeling exercise based on electricity dispatch optimization logic. Model results are predictions based specifically on hypothetical scenarios, and dependent on variables that may be inaccurate projections of future circumstances. Furthermore, some scenarios relied on simplified assumptions; for instance, I assumed that 100 percent of all new RPS renewable energy would come from wind power with no trading of renewable energy certificates (RECs). In reality, an RPS policy will encourage the deployment of a variety of different renewable energy resources, including resources that were not included in these scenario models, such as distributed renewable generation. The trading of RECs across a region will also facilitate a more cost-effective renewable energy deployment pattern. The inability to model these options in the present analysis has likely resulted in cost estimates that are too high.

In recognition of the inherent limitations of modeling analyses, however, I ran a series of sensitivity analyses on the baseline scenario, and modeled variations in policy portfolio strength and carbon price levels. Results across the model variations were fairly consistent, and demonstrated mild sensitivity to model parameters, such as primary resource costs. Variation in carbon price was found to be one of the most sensitive policy parameters.

It was necessary to make additional assumptions concerning the study sample. I selected the WECC region for this sample, and Utah and Arizona as representative states within this region. The intent was to generate descriptive results that have generalizability; that is, the Utah and Arizona results could indicate broader state experiences, the WECC results could suggest national level trends, and the combination could lend insights into the dynamics of electricity sector interactions among states and across regional boundaries. It is possible that Utah and Arizona are poor representations of the average state's characteristics. What is more likely, however, is that there are a few states that have extreme characteristics—for instance, Maine, which shares only one state border and generates 29 percent of its total electricity from hydroelectricity—and simply cannot be represented by any other state. This study does not presume that all states will respond to policy portfolios or carbon prices in exactly the same fashion as either Utah or Arizona. Nor does it presume that a national level coordinated policy portfolio will have the exact same effect as a regional coordination policy. Fortunately, these strong assumptions are unnecessary. Future analyses may choose to improve the generalizability of the present results via a modeling exercise that includes the entire population sample, all 50 U.S. states. Future studies could additionally seek to empirically identify which factors are associated with improved or reduced cost-effectiveness of carbon mitigation policy portfolios.

Conclusions

This study sought to explore whether state policy portfolios are effective decarbonization strategies. The results of a scenario-based electric dispatch modeling exercise revealed the following descriptive trends:

- Regional coordination policy portfolios demonstrate greater potential for decarbonization than do isolated state policy portfolios;
- Some states benefit more from regional policy coordination than others, depending on the state's demand growth, resource mix, and export-import strategy, among other unaccounted for factors;
- Emissions leakage attenuates the effect of isolated state policy portfolios;

- A carbon price coupled with regionally or nationally coordinated policy portfolios is the most effective carbon mitigation option.

The need for further investigation of the effects of state level policy performance, and the federalist implications of state energy and climate policy leadership is immense. As our global society progresses with international climate change agreements, lessons from the U.S. states can provide valuable insights on the performance of energy portfolios, the occurrence of carbon leakage, and the interaction between climate policy and energy policy.

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CHAPTER 5

CONCLUSION: LESSONS FROM THE ERA OF STATE ENERGY POLICY INNOVATION

U.S. energy and climate change policy has evolved from the bottom up, led by state governments and internationally recognized for the use of unconventional and innovative policy instruments. After roughly a decade and a half of state leadership in energy and climate policy, what have we learned about the effects and effectiveness of state policy tools as they relate to the diversification, decentralization, and decarbonization of the U.S. electricity sector? What lessons can be extracted about the use of policies that have shaped the era of state energy policy innovation and what do these lessons suggest about the role of state energy policy in the U.S. electricity sector?

This three-essay dissertation sought to address these questions and, in doing so, empirically evaluate some of the leading policy instruments that states have deployed throughout this era. I first evaluated the effects of RPS policies on states' percentages and total amount of renewable electricity generation. In the second essay, I tested whether policies and regulations that aim to reduce barriers to distributed generation are effective at motivating utilities or utility customers to adopt and deploy distributed generation units. In the final essay, I explored the decarbonization effects, among other effects, of state level policy portfolios. These essays do not provide exhaustive answers to the questions that they seek to answer but they do collectively provide a detailed assessment of various state level policy instrument effects. They provide some insights on which instruments function as intended and which do not, how well various instruments work together, and which policy design features may require further examination.

Each of the three essays provides three contributions to the energy policy literature. First, each essay reveals that previously employed methods used to address related research questions suffer from statistical biases or methodological imprecision that affect the validity of empirical results. Second, each essay extends the current understanding of its respective topic in new directions: the diversification essay advances the RPS literature beyond a discussion of RPS-driven total renewable energy deployment, toward a more accurate consideration of RPS effects on the percentage of renewable energy; the decentralization essay moves the literature beyond a mere definitional consideration of DG, and provides a first attempt to identify the main drivers behind DG trends; and the decarbonization essay introduces the need for state level modeling analyses, and identifies the phenomena of carbon leakage as a result of state energy policies. Finally, each essay provides new conclusions and associated policy implications on the effects and effectiveness of state energy policy instruments.

In this final, concluding chapter, I seek to synthesize the findings from these three essays and, in conjunction with findings from the literature, provide a summary of the current state of understanding of state energy policy instruments and their role within the era of state energy policy innovation. The narrative begins with a narrowly focused discussion on individual policy instruments, including the renewable portfolio standard, net metering policies, interconnection standards, and tax incentives.[25] The discussion in

[25] States use a variety of other policy instruments as well, including demand side management and energy efficiency instruments, various types of subsidies, public benefit funds, and production incentives, among

this section aims to balance a micro and a macro perspective on each of these instruments, without delving too deeply into the intricacies of each instruments' design or assuming a one-thousand-foot aerial view. In order to keep this balance, the discussion focuses on general lessons about how these instruments work and whether they achieve the objectives for which they are intended, and identifies possible policy measures that may improve the efficacy of these instruments in operation. Next, I discuss the potential for complementary use of a variety of these instruments. I conclude with a discussion of broader trends that have emerged in the state energy policy innovation era, and suggest avenues of future research. Before proceeding, it is important to note that this conclusion is by no means a comprehensive review of all policy instruments and policy interactions that have shaped the era of state energy policy innovation. This conclusion, instead, draws heavily on the lessons learned in the present dissertation, with assistance from the supporting literature.

Policy Instruments

Renewable Portfolio Standard

I begin with a discussion of renewable portfolio standards because they are one of the most popular state policy instruments, and they epitomize the complexity and innovativeness that is indicative of modern state energy policy instruments. Additionally, the lessons about the effects and effectiveness of RPS policies lend a great number of insights on the role of public policy in state electricity markets.

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others. The discussion in this conclusion chapter is focused narrowly on the policy instruments that were covered most thoroughly, if at all, in this dissertation. Future iterations of this paper will include a more extensive review of these remaining policy instruments.

The literature to date has documented a variety of RPS effects. Palmer and Burtraw (2005) and Kydes (2006) found that RPS policies effectively increase renewable energy generation and primarily offsets or displaces natural gas generation, for a net total reduction in carbon dioxide emissions. Kydes also found that a national 20 percent RPS mandate raises electricity prices by three percent. RPS effectiveness studies have established that some states are experiencing great success with their RPS mandates (Langniss and Wiser, 2003). Studies that consider the varied experiences of all states conclude that RPS policies are effective drivers of RE development and generation (Menz and Vachon, 2006; Bird et al., 2005) but that not all states are on the path toward meeting their RPS benchmarks (Wiser, 2004; Rabe, 2008).

RPS policies may increase renewable energy generation, but they have been identified by some (Rabe, 2008; Bushnell et al., 2007) as being inefficient in the achievement of other outcomes, such as a reduction in greenhouse gas emissions, a switch from conventional fossil fuels to less carbon-intensive fossil fuel generation sources, or a reduction in energy demand. These findings reveal that RPS policies may not be well suited to achieve multiple policy objectives simultaneously, such as the diversification, decentralization, *and* decarbonization of the electricity sector. Yet RPS policies are currently used by many states as a policy tool to achieve all three of these objectives.

All three essays in this dissertation explored RPS policy effects and effectiveness. The first essay found that RPS policies effectively increase in-state renewable energy generation, but have yet to significantly increase in-state percentages of renewable energy electricity out of total state generation portfolios. These results confirmed others' findings: RPS policies are effective at encouraging RE development, but not all states are able to translate RPS mandates into renewable energy percentage growth. Reasons for these shortcomings include several possibilities: enforcement mechanisms and penalties for noncompliance are too weak; states are not making efforts to decrease or hold steady fossil fuel generation; or states are not making efforts to decrease or hold steady total demand for electric generation. Results reveal that states can improve RPS policies by strengthening enforcement mechanisms, or implementing RPS policies in conjunction with a carbon price or cap-and-trade policy, fossil fuel mandates, or efficiency standards.

It is possible that the inability of RPS policies to increase the share of renewable energy is due to poorly structured design features. It is also possible, however, to interpret the results of the first essay as an indication that, although RPS policies are one of the main drivers of renewable energy generation and consequently electricity diversification, additional factors are needed to actually increase the share of renewable energy generation. Some of the most significant factors in this development involve political capacity and support of energy and environmental policy efforts. Legislative support for environmental policies and bureaucratic capacity in natural resource management both assist in the growth of the percentage of renewable energy. Additionally, strong coal and petroleum interests diminish the pace of renewable energy development.

The second essay found that RPS policies have mixed effects on distributed generation adoption and deployment. The first finding in this essay was that individuals in states with an RPS policy are more likely to adopt distributed generation than individuals in states without an RPS policy, all things equal. The second finding was that, out of all utilities with some distributed generation, those in states with RPS policies deploy less distributed generation than those in states without RPS policies. The latter finding reveals that small-scale energy systems may compete with large-scale renewable energy facilities for utility attention and resources. When a utility is mandated to meet renewable energy benchmarks, it will likely prioritize large-scale renewable energy development over distributed generation development.

The third essay confirmed Palmer and Burtraw's (2005) and Kydes' (2006) findings that RPS policies increase total renewable energy, decrease carbon dioxide emissions, and increase the retail price of electricity. This essay also found, however, that an increase in renewable energy generation does not necessarily translate into a significant decrease in greenhouse gas emissions. I found evidence that, when surrounding states do not have RPS regulations, a state with an RPS may continue to generate its excess, more carbon-intensive fossil fuel power and sell it to neighboring states. In one scenario, the state of Utah actually ramped up its coal generation despite its RPS policy in order to export the excess power to its neighboring, non-regulated states. RPS benchmarks are not designed to perfectly match demand projections. That is, states do not calculate the amount of additional capacity they will need by a certain year, and then mandate that all of that capacity be met by renewable energy. As a result, renewable sources of energy do not simply replace any new capacity that would otherwise have to be built. Nor does it reduce demand for energy. Instead, new renewable energy capacity is intended to replace a portion of fossil fuel capacity that already exists. But are states actually replacing this capacity? Results indicate that, so long as surrounding states do not have similar regulations, retirement of older, less efficient, and more carbon-intensive power plants may not occur. As Bushnell and his colleagues (2007) explain, “although the regulator can force its local firms to buy ‘clean’ products, it can’t keep firms in other states from buying the ‘dirty’ products that the firms in the regulated states used to buy.” These findings reaffirm those made by Rabe (2008), which is that RPS policies may effectively increase total renewable energy generation but are inefficient policy tools for decarbonization objectives.

An RPS is an appealing state policy instrument for a number of reasons. Of notable importance, RPS policies demonstrate great political feasibility (Rabe, 2008): they come with no explicit price tag[26]; the benchmarks start off mild and ramp up over the course of one or two decades; they aim to incentivize renewable energy, not tax the use of fossil fuels; and they are a popular “symbol” (Bushnell et al., 2007) to indicate a concern about business as usual energy and climate trends. RPS policies are often presented as a cost-effective option to help the renewable energy industry grow and help individual technologies become cost-competitive with conventional sources of fossil fuel energy. The essays contained in this dissertation, as well as other studies reviewed above, however, reveal that RPS policies also have several disadvantages. First, having an RPS policy is not enough to significantly increase the percentage of renewable energy generation across states, at least given current RPS designs. Second, an RPS policy that is designed to increase the share of renewable energy generation will have limited ability to achieve multiple objectives simultaneously. Third, and closely related to the last point, RPS policies, as implemented on the state level, are also unable to prevent carbon leakage across state borders.

[26] This is not to say that RPS policies do not incur costs. The actual costs of an RPS are borne by electric utilities, and eventually passed down to consumers. The costs are not, however, the most obvious design feature of an RPS, as they are, for instance, with a carbon tax.

In light of these findings, how could one improve the functionality and efficacy of an RPS policy? Given that an RPS is designed, by its very nature, to increase renewable energy, as well as the percentage of renewable energy out of the total generation mix, it is most constructive to first consider how to improve an RPS policy's ability to affect renewable energy deployment. As the first essay suggests, and as is reaffirmed by Wiser and his colleagues (2004; 2007), possible strategies for improvement include a redesign of the following design features: enforcement mechanisms; the degree of flexibility and number of exemptions granted to utilities; and the ambitiousness of RPS benchmarks.

In the event that a state, or the national government, decides to pursue multiple electricity market objectives simultaneously, one may secondarily consider how to construct "carve-out" provisions in RPS policy design that further incentivize or, more accurately, mandate additional types of resources, such as certain distributed generation units, energy efficiency, or less carbon-intensive fossil fuels.[27] Indeed, many states have done this, including Pennsylvania, which includes waste coal, coal mine methane, and coal gasification in its list of eligible RPS renewable energy sources. Some states have altered their RPS legislation after a couple of years with carve-out provisions, which allows for greater flexibility and an enhanced scope of RPS objectives. However, the more carve-out provisions made to specifically isolate and incentivize other technologies (e.g., poultry waste in North Carolina) or pursue other objectives entirely (e.g., energy efficiency provisions for the sake of decarbonization), the more expensive and less cost-effective—and potentially inefficient—this policy option becomes (Rabe, 2008). Therefore, instead of asking how one can improve the functionality and efficacy of an

[27] States may also consider carve-out provisions as a means to help them comply with RPS benchmarks in the event that they are not as well endowed with renewable energy resource potential.

RPS policy to serve multiple objectives, perhaps one should ask whether there are more efficient policy tools that can compliment an RPS policy, but specifically target a different objective(s), such as decentralization or decarbonization. In this line of reasoning, chapter 4 demonstrates that RPS policies are more effective when implemented in conjunction with a carbon price and other supporting instruments.

It is highly probable that, even despite the use of multiple policy instruments, each of which is focused on a different market failure, RPS policies will continue to encourage emission leakages across state or regional borders. The cause of leakage is attributable to the scale on which the policy instruments are applied (Bushnell et al., 2007). Electricity transactions—or “power flows”—are not limited to state borders, nor are the effects of greenhouse gas emissions. It should come as no surprise, therefore, that policy instruments that are implemented on the state scale but inconsistent across state borders, no matter how innovative or flexible the instruments, cannot control the leakage of electricity or emissions across state lines. Until states adopt consistent and coordinated regulations, or the national government adopts a federal RPS, state level free-riding will likely continue. A national RPS policy, however, could have the combined benefits of correcting the market distortions associated with carbon leakage and state free-riding, and create uniformity and, in turn, predictability in renewable energy markets across the entire country (Cooper, 2008).[28]

Net metering and Interconnection Standards

[28] While some advocate for a national RPS policy on the grounds just defined, others object to the adoption of a single and uniformly applied RPS. These critics emphasize that natural resource endowments are not consistent across regions. A national RPS may, therefore, result in a net transfer of fiscal resources from the Eastern to the Western hemisphere (Casten, 2009) or, more specifically, from the Southeast and parts of the Northwest to the Midwest, West, and Southwest.

The second essay in this dissertation, chapter 3, considered the role of net metering and interconnection standards in motivating the decision to adopt and deploy distributed generation. The empirical results demonstrated that net metering standards reduce the technical barriers to DG deployment and make DG adoption on the customer side of the meter more likely. Interconnection standards were also found to be a primary motivating factor behind customer DG adoption. These results demonstrate that integrated and consistent protocols for electricity interconnection—including connecting equipment, standard tariff payment schemes, and power quality characteristics—reduce costs and bureaucratic hassles associated with customer DG hook-ups.[29]

The second essay also found that customers that are interconnected to the electric grid via net metering use a greater proportion of renewable energy-based DG than do utilities. Slightly less than half of the customer owners used renewable DG, whereas less than 25 percent of utility owners used renewable DG. These findings indicate that, although both utilities and their customers are involved in the movement toward more decentralized electricity, customer owners play a more prominent role in renewable DG development.

It is clear that state level net metering and interconnection standards are effective decentralization policy instruments. Are these DG policy instruments also able to serve diversification and decarbonization objectives? Both standards effectively help shift the

[29] Net metering and interconnection standards have grown in popularity over the past five years. During the year in which the second essay drew its data, 2005, 39 states had net metering standards and 28 states had interconnection standards. As of January, 2010, all but five states have state-mandated net metering policies, and one of the remaining five has a utility-selected net metering program (North Carolina Solar Center, 2010); 40 states have interconnection standards. The Federal Energy Regulatory Commission has also adopted interconnection standards for DG units that connect at the transmission level. State standards regulate the interconnection of DG units with the distribution level and the FERC regulates the transmission level.

balance of resources—albeit slight in magnitude—toward more decentralized and less centralized sources. Thus, DG policy instruments do perpetuate a diversity of energy technologies and resources. However, when a utility is faced with both an RPS and DG standards, the RPS mandate has the potential to "trump" the DG instruments and reduce their effects on distributed generation adoption. In this case, RPS policies are the main drivers of diversification, and net metering and interconnection standards play a less prominent role in the diversification of the electricity sector. In consideration of the DG instruments' decarbonization potential, it is important to bear in mind which types of fuel DG systems tend to use— distillate oil, natural gas, and various renewable fuels. All of these sources are less carbon-intensive than coal, which is the primary source of electricity in the United States. If DG policy instruments motivate the adoption of DG units, and these systems replace power that would otherwise be generated from more carbon-intensive sources, than one could classify DG instruments as achieving decarbonization objectives. If, on the other hand, net metering and interconnection standards increase customer-owned DG in one location, a neighborhood for instance, only to result in excess generation that is shifted (or "leaked") elsewhere, then DG instruments are not entirely effective at decarbonization. The essays included in this dissertation, however, do not provide enough information to draw any definitive conclusions about these dynamics.

Tax Incentives

This dissertation gave some attention to tax incentives but ultimately provided limited insights about the effects or effectiveness of this type of policy instrument. Before discussing these findings, therefore, it is helpful to consider what the literature has already established regarding the use of energy policy tax instruments, and how well they compliment other tools.

The political appeal to using tax instruments, as well as other types of financial incentives, is that they directly reduce the cost of alternative technologies (i.e. provide a "carrot"), but do not explicitly raise the cost of conventional technologies (i.e. use a "stick"). Tax incentives help the consumer, either an individual or a company, overcome the potential economic barriers associated with large start-up costs. Tax incentives also allow governments to set limits on exactly how much is spent on renewable energy policy. Financial incentives provide a number of additional benefits, including the following: they provide a price signal to the consumer or company, which has the potential to alter behavior even in the absence of regulations; they allow consumers or companies to make their own decisions based on personalized cost-benefit considerations; and they obviate the need for governmental regulatory decisions, as well as possible compliance and enforcement costs associated with such regulations (Gunningham and Grabosky, 1998).

Despite the many advantages to using tax instruments, there are also a number of disadvantages. First, by adjusting the cost of alternative technologies but not conventional technologies, tax incentives do little to discourage the use of carbon-intensive generation or, alternatively, encourage conservation. In fact, on some occasions, financial incentives actually encourage an increase in energy consumption (Newell, 2007). Second, although the amount spent on the incentives can be pre-established, the actual amount of alternative energy that is developed as a result of the incentives cannot be guaranteed. Third, tax incentives may affect the behavior of those who pay taxes, but will have no effect on entities that do not pay taxes. Fourth, the use of tax incentives often requires policymakers to choose favorites among a variety of alternative technologies. As a result, policymakers may devote money to technologies that have little commercial promise or are not in need of additional support. Funding may also continue for too long after a technology becomes commercially mature. Finally, the duration and amount of tax incentives may be unpredictable over time.

In effort to mitigate the last two of these potential problems, policymakers should consider designing tax incentives that are transparent, predictable, and scale back over time as a technology matures (Geller, 2002).[30] It is difficult, however, to construct tax incentives so that they are able to overcome the first two problems—a lack of encouragement to conserve energy and the inability to set renewable energy development levels. These issues are best addressed via the use of other policy tools that can compliment tax instruments, yet make up for their inherent shortcomings (Gunningham and Grabosky, 1998).

The energy policy literature contains few analyses that explore the effects or effectiveness beyond this general understanding of the pros and cons of state tax incentives.[31] In fact, state tax incentives appear to be the least researched, and particularly the least empirically researched, policy instrument of all state policy instruments, save

[30] Some also advocate for the use of production incentives in lieu of tax incentives, because production incentives provide financial compensation for the actual amount of generation output, as opposed to just the upfront costs. Production incentives, in other words, ensure that consumers chose alternative technologies that are promising enough to actually produce electricity (Gouchoe et al., 2002).

[31] The literature on tax incentives for energy efficiency is a bit more extensive but not reviewed in this document.

perhaps the public benefit fund.[32] Tax incentives are likely under-researched due to the immense variation in their design across location, which makes empirical evaluations of their effects difficult. Additionally, tax incentives are often implemented in conjunction with other instruments, which makes it difficult to tease out the effects of one instrument from the effects of the other in empirical evaluations.

Despite the general lack of studies on the topic, a number of recent analyses have presented informative insights on the performance of tax incentives. The predominant finding within this body of research is that tax incentives play mostly an assisting role to other energy policy instruments, but are not the primary drivers of alternative energy development (Bird et al., 2005; Gouchoe et al., 2002; Lewis and Wiser, 2007).

The second major finding is that tax incentives are effective at encouraging small-scale renewable energy development. Although, relating back to the first point, they are still one of several factors that affect renewable energy development and not necessarily the primary driver. A couple of studies have also pointed out that tax incentives are well suited for smaller-scale energy systems and more efficient when used at the sub-national level (Gouchoe et al., 2002; Bushnell et al., 2007). Tax incentive design features generally limit the system size and costs of eligible technologies, which often prevents tax incentives from being used for larger-scale renewable energy development (Gouchoe et al., 2002).

Third, several studies have documented the incidence of free-riding as it relates to tax incentives. Free-riders are those that would have purchased the alternative

[32] This statement is based on my informal assessment of the related literature and is not backed up by sources or quantitative estimates.

technologies regardless of the incentive; and the incentive merely serves as a bonus, or a "seal the deal" factor (Gouchoe et al., 2002; Geller, 2002; Newell, 2007).

Lastly, one study reveals that tax instruments, as well as other types of financial instruments, also have the potential to cause—or at least contribute to—leakage problems (Bushnell et al., 2007). Tax incentives reduce the costs of renewable technologies, which, in turn, increases the demand for renewable energy and decreases the demand for fossil fuel generation. These trends eventually cause the price of fossil fuel generation to decrease, which causes the demand for the excess energy to increase elsewhere. Neighboring regions will then purchase this excess fossil fuel generation; and the carbon-intensive electricity will leak across borders from the region with the incentive to the region without. Although, as Bushnell and his colleagues (2007) point out, financial incentives are less susceptible to leakage than other instruments, such as an RPS or cap-and-trade policy, because the price impacts of financial incentives are relatively small compared to these alternative instruments. In fact, these authors believe that tax incentives are the most efficient state or local policy tool if the policy objective is decarbonization, since other instruments have greater price impacts and, therefore, greater potential for leakage.

The first essay in this dissertation, chapter 2, found that tax incentives are not significant drivers of renewable energy. In light of others' theories regarding the effects of energy tax instruments, possible explanations for these findings may include one or several of the following:

- Tax incentives are used more often for small-scale and less often for large-scale renewable energy systems. In the presence of an RPS, utilities are more inclined to deploy large-scale systems.
- Tax incentives are susceptible to free-ridership, in which consumers develop renewable energy regardless of the incentive, yet still collect the financial outlay.
- The tax incentive variable in the first essay is poorly constructed. Given that there is variation in the design of tax incentives across states, it is likely that the tax incentive scale variable that I used was unable to capture the actual effects of various tax incentive designs. This limitation highlights the difficulty of capturing tax incentive variation in a single model, and provides some insights on why state level energy tax incentives are under-explored in the empirical literature.

The third essay found that tax incentives, as one instrument in a larger state policy portfolio, play a supporting but weak role in achieving decarbonization objectives. A tax incentive of 35 percent reduced capital costs, in absence of any climate policy, only rendered landfill technologies cost-competitive in the assessed regions. Landfill energy is not carbon-neutral, nor is it one of the “cleanest” of all alternative energy technologies. In combination with a carbon price, the same tax incentive leads to a significant increase in landfill, geothermal, and biomass deployment. Thus, one can conclude, tax incentives have a greater effect when used in combination with a regional or national climate policy. It is important to bear in mind, however, that these findings are contingent on a number of modeling assumptions, as reviewed in the third essay.

The third essay also found evidence of carbon leakage that results from inconsistency of energy regulations across states. It is impossible to tease out information on which instruments contribute more or less to leakage. Yet, insofar as the tax incentives modeled in this analysis contributed to the deployment of new renewable energy, the literature provides evidence that the tax incentives may also contribute to leakage but not be the major instigator.

In summary, a tax incentive is a policy instrument that has potential to achieve multiple policy objectives. When adequately designed and paired with other policy instruments, tax incentives have the ability to perpetuate the diversification, decentralization, and decarbonization of the electricity sector. Tax incentives play a smaller role, however, in achieving each of these objectives than do other policy instruments; and as a result tax incentives often play supporting policy roles. Tax incentives have a smaller price impact than other instruments and, due to their relatively small contribution to carbon leakage, are believed by some to be one of the most effective decarbonization tools for state or local energy policy.

Complementary and conflicting policy efforts

Thus far, this conclusion has analyzed how individual policy instruments work, and attempted to identify trends, both planned and not planned, associated with each instruments' use. In the process, I have also reviewed how well various instruments work together, with a particular concern for issues involving federalism and the scale of governmental operations. I do not attempt to identify a single instrument that is the most cost-effective; but, instead, the various findings collectively demonstrate that different instruments serve different purposes or, alternatively phrased, address different market failures.

Because different policy instruments serve different purposes, one cannot conclude that more instruments automatically equate to greater policy effectiveness. In some situations, instruments that hold the same objective can be paired together to enhance the effectiveness of a policy strategy that seeks to achieve a single objective. For instance, renewable energy tax incentives and renewable portfolio standards, both of which aim to increase diversification via renewable energy development, can be combined to produce a potentially greater effect on renewable energy markets than if either worked in isolation. This strategy is endorsed by Gunningham and Grabosky (1998), who refer to the use of multiple instruments for the sake of one objective as “killing one bird with two stones”. Combining two different instruments that are each designed to address a different market failure, however, does not ensure that either market failure will be mitigated with greater effectiveness. For instance, the combination of a renewable portfolio standard and a net metering policy will not necessarily be a more effective decentralization strategy than if the net metering policy was implemented in isolation. As another example, some authors (Sorrell and Sijm, 2003; Gonzalez, 2007) contend that combining a carbon cap-and-trade with an RPS will raise the cost of carbon mitigation efforts but will not necessarily increase carbon savings beyond the cap. These types of instrument combinations have the potential to increase the cost of policy interventions without increasing the effectiveness. Instrument combinations of this variety are only “acceptable” so long as one policy instrument increases the efficiency of the other instrument, or provides other valuable outcomes (Sorrell and Sijm, 2003).

In the event that a state has more than one policy objective (e.g. decentralization *and* decarbonization), it may want to consider more than one instrument, each of which targets a different market failure (Gunningham and Grabosky, 1998; Sorrell and Sijm, 2003; Gonzalez, 2007; Goulder and Parry, 2008). The challenge with this approach is that it requires an optimal alignment of policy instruments so that they work well together and are complimentary, without compromising the effectiveness or efficiency of any specific instrument (Sorrell and Sijm, 2003; Gonzalez, 2007). The potential for various instruments to work together is strong, as discussed in the section above, although an optimal policy portfolio will necessitate that much effort is put into aligning policy objectives and the policy design features of various instruments. Policymakers' must remain explicit about which public policy objectives they seek to attain, and which trade-offs are made among various instrument options (Sorrell and Sijm, 2003). Some researchers also suggest that, when combining multiple instruments, policymakers ought to keep the design of each instrument simple because too much complexity can degrade the synergy between instrument combinations (Gonzalez, 2007).

Trends in the Era of State Energy Policy Innovation

The study of the effects of state energy policy instruments lends a number of insights into broader trends associated with the state energy policy innovation era. This section highlights a number of trends that were identified in previous chapters, but is not meant to be an exhaustive review of all associated trends. This section synthesizes the lessons learned across the previous chapters, identifies limitations of the present analysis, and suggests avenues of future research. Each trend or lesson learned is identified as a separate "note", of which there are nine in total. The notes begin with findings that are specific to policy instruments, then turn to findings that relate to other factors that play supporting roles in state energy policy, and finally considers broader trends that mark the era of state energy policy innovation.

Note 1: Each state has its own combination of different policy instruments.

Each state has selected among a wide variety of different policy instruments, and crafted unique combinations to suit its own needs and objectives. No two state policy portfolios are the same, either in the types of instruments or the design of instruments.

The energy policy literature offers no insights on which factors lead states to adopt different policy combinations, nor does it offer statistical analysis of which types of policy combinations are more prevalent. Future research in this realm could provide valuable information for states that are considering various energy policy options, states that seek to revise previously enacted policies, or the national government as it considers the possibility of a national energy and climate change bill.

Note 2: Some instruments are more effective at achieving their objectives than others.

Net metering and interconnection standards, both of which aim to reduce the barriers to distributed generation market growth and consumer adoption, are successful in both pursuits, but particularly the latter. Policy instruments that aim to increase renewable energy generation demonstrate mixed results. The renewable portfolio standard is able to increase total renewable energy generation, but is less successful at increasing the percentage of renewable energy generation out of all generation sources. Tax incentives contribute to renewable energy growth but are not the major drivers. Policy portfolios that aim to reduce greenhouse gas emissions demonstrate moderate to significant success, dependent on a variety of state level electricity sector factors as well as other unaccounted for factors. State level policy portfolios are not, however, the most effective decarbonization strategy. Regional or national policy coordination is more effective than isolated state policy efforts; and policy coordination in conjunction with a carbon price is more effective than either alternative.

This dissertation took a detailed look at how several policy instruments operate, both individually and collectively, but omitted a number of additional important instruments. It is worth noting that this dissertation was focused heavily on the supply side and devoted minimal attention to demand-side operations. Future efforts to synthesize the trends and lessons learned from the era of state energy policy innovation should incorporate insights on the effects of various demand-side instruments, such as public benefit funds, energy efficiency standards, building codes, energy efficiency portfolio standards, and a variety of other instruments.

Note 3: The selection of policy objectives requires trade-offs

If state policymakers have multiple policy objectives, the discussion above established that they may want to consider the use of multiple policy instruments. This analysis has also found that various state policy objectives have the potential to work together in concert. But there is some evidence that simultaneous pursuit of multiple objectives is challenging and may require making trade-offs. There are two types of trade-offs in this context: 1) trade-offs involving government resources;[33] and 2) trade-offs involving the resources of the governed. Regarding the former, governments are constrained by budgets, administrative abilities, and political feasibility, all of which require that policymakers carefully weigh the costs and benefits of policy efforts, and compare potential outcomes across a variety of efforts. Regarding the latter, policymakers will need to be mindful of the resource constraints—fiscal, environmental, and other constraints—of the individuals and companies that are governed by these policies. These constraints may require that trade-offs be made between different resource options. For instance, at the intersection of diversification and decentralization objectives, trade-offs may be necessary between large-scale renewable energy and small-scale distributed generation. At the intersection of decentralization and decarbonization, fossil-fuel-based distributed generation and renewable-energy-based distributed generation may stand at odds. At the intersection of diversification and decarbonization, trade-offs may be necessary between advanced, efficient fossil fuels and renewable energy, or demand-side management and renewable energy. Significant efforts are necessary to coordinate policy objectives and, therefore, the design of instruments used to achieve these objectives, so that individuals and companies can respond to multiple incentives and regulations in the most cost-effective and efficient manner possible.

This dissertation focused exclusively on diversification, decentralization, and decarbonization policy objectives. It is possible that I have neglected other significant policy objectives, and the inclusion of which could change, or at least improve, the discussion of policy instrument effects and the trade-offs that may emerge among

[33] Note that there is a third trade-off as well— trade-offs among different decision criteria. For instance, one policy instrument may be the most efficient instrument, but another the most equitable. Policymakers must make trade-offs among a variety of criteria during the selection of policy instruments or efforts.

objectives. For instance, as documented elsewhere (Rabe, 2008), it may be the case that a primary objective for some state policymakers is economic development and job growth. These states may adopt various energy policies, such as an RPS or tax incentives, in efforts to increase manufacturing activities, employment, and competitive advantage in a renewable energy industry. The possibility that I have omitted this policy objective raises several questions about the ultimate intent of state policymakers. Do policymakers seek to increase jobs via the diversification of the electricity sector, or is it to diversify the sector with the help of economic development efforts? Or is an economic development objective being used to improve the political feasibility of energy legislation? This possible omission also raises questions about the conclusions drawn in this dissertation: if the ultimate intent of policymakers is to increase jobs, not electricity diversification or decarbonization, are some policy instruments more or less successful at achieving this objective? I raise these questions to highlight the possibility that there may be additional objectives that guide state energy policy efforts, the evaluation of which may lend greater insights into the effects and effectiveness of energy policy instruments or the trade-offs that are necessary between conflicting or complimentary policy instruments.

Note 4: Energy policies affect different market actors differently

In chapter 3, I found that net metering and interconnection standards are associated with a significant increase in the likelihood that a consumer (i.e., an individual or company that buys its power from a utility) will adopt a distributed generation system. I did not find that these same policies are significantly associated with utility DG adoption; instead, economic factors—including the price of electricity, status of electricity sector regulation, and average household income—appear to be the main drivers of utility DG adoption. These findings highlight the fact that energy policies affect different market actors differently.

The other two essays in this dissertation, chapter 2 and chapter 4, used state level aggregated data. Therefore, these essays did not have the resolution to measure the differences in response to policies among different utilities or other market actors. As a result, this dissertation cannot address how different utilities and renewable energy developers may respond to an RPS policy, or how these same market actors may respond to a policy portfolio. Future studies that focus on these trends will make great contributions to the literature.

Note 5: Location matters…but how much?

Clearly, locational considerations play a factor in a state's adoption of a new energy policy. Locational considerations also set constraints on how much new energy supply a state can pursue, since energy resource potential varies by location; and some states are better endowed with wind, solar, geothermal, or biomass resources than others. Yet states are not evenly divided by location or resource potential in either their policy efforts or their renewable energy outcomes. In chapter 2, I found that both RPS adoption rates and renewable energy development is the greatest in states with average wind energy potential. States with the greatest wind energy potential lag behind the first group, in both RPS adoption rates and renewable energy generation. The last category of states, those with the lowest wind energy potential, also have the lowest RPS adoption rates and the least renewable energy generation. These findings demonstrate that there is currently a mismatch between resource endowment and policy action, and resource endowment and renewable energy development.

In the event that national energy policy legislation is passed, and that it contains a national RPS or some other renewable energy requirement, location and resource endowment will invariably become more important for two reasons. First, those states in regions with poorer energy resource endowments may struggle to meet national standards, and will potentially have to export significant sums of money to other states for renewable energy credits. Second, the same states that will be most compromised by national renewable energy legislation are those that have lagged behind other states in energy policy legislation and renewable energy development, respectively, over the past decade and a half. The failure to jumpstart renewable energy development, attract innovative energy businesses or industrial activity, or develop the political capacity to address energy and climate change issues throughout the era of state energy innovation policy will potentially put these states at a double-disadvantage, and force them to play a potentially expensive game of catch-up.

Note 6: Status of market regulation matters

The interaction between efforts to deregulate or restructure electricity markets and diversification, decentralization, or decarbonization policy interventions is not clearly established in the supporting literature. The empirical analyses presented in chapters 2 and 3 both controlled for states' electricity market deregulation status. The parameters estimates on the deregulation variable in both analyses provided noteworthy findings. In the diversification essay, results revealed that, all else constant, deregulation is associated with an increase in total renewable energy development, but not an increase in the share of renewable energy. In the decentralization essay, I found that deregulation is positively and significantly associated with utility DG adoption, but not consumer adoption, holding all else constant. These findings suggest that deregulation increases competition in the industry and encourages power producers to adopt new and innovative sources of electricity as a response to consumer demand for more diverse and alternative fuel sources. I also found that, although deregulation encourages utility DG adoption, it is not associated with a greater magnitude of DG deployment. Combining the results of both essays, I conclude that the deregulation of a state electricity market does encourage utilities to adopt non-conventional fuel sources and to make some substitutions among fuel types, as is argued by Delmas and her colleagues (2006) and supported by Dahl and Ko (1998) in an analysis that explores natural gas market deregulation. Deregulation is not, however, a significant enough factor to substantially alter the balance of states' generation assets. One possible explanation for this finding is that deregulation does not discourage the continued use of coal generation from amortized power plants (Dahl and Ko, 1998; Hyman, 2006); a transition away from a heavy reliance on coal generation, therefore, will require more policy intervention than deregulation of a state's electricity market (Hyman, 2006).

As indicated in both essays, these results are still preliminary and an interpretation of the parameter estimates is still largely speculative. The literature could benefit from future studies that empirically evaluate the relationship between regulation status and other policy interventions, and between combined policy efforts and electricity market outcomes.

Note 7: Energy policies are not climate policies

Current state public policy efforts employ energy policies for climate policy objectives (i.e. in attempt to abate greenhouse gas emissions). Yet, results from the previous chapters reaffirm findings made by others (Rabe, 2008; Fisher and Newell, 2007; Bushnell at al., 2007; Sorrell and Sijm, 2003; Gonzalez, 2007; Palmer and Burtraw, 2005; Goulder and Perry, 2008), that renewable energy policies are not the most cost-effective policy tool for climate policy objectives. As Rabe (2008) explains, "there appears to be a nearly inverse relationship between those policies that policy analysts tend to endorse as holding the greatest promise to reduce emissions in a cost-effective manner and the political feasibility of respective policy options." Although renewable energy or distributed generation policies provide a number of societal benefits, the most cost-effective carbon mitigation policy is one that explicitly prices the use of carbon-intensive generation. A price on carbon emissions causes utilities to seek alternative, less carbon-intensive fuel options and causes consumers to reduce their electricity use. Thus, energy policies are less cost-effective because they do not directly address the market failures associated with climate change, but also because the manner in which they are currently used is fraught with inefficiencies associated with carbon leakage.

Note 8: Policy coordination across states improves the effectiveness of public policy efforts

Many studies have established the importance of jurisdictional size as it relates to the effectiveness and efficiency of energy policy instruments (Bushnell et al., 2007;

Gonzalez, 2007; Goulder and Parry, 2008; Rabe, 2008). Each of these studies raises concern about the potential problems associated with policies that are not consistent across regulating jurisdictions.

For the sake of illustration, let us consider two contiguous states, $state_1$ and $state_2$. I will also assume that $state_1$ can save X in carbon emissions from its policy agenda (or portfolio) and $state_2$ can save Y. If both states pursue their research agendas, then one should expect total carbon savings of $X + Y$. Some argue that inconsistency in policy efforts across jurisdictions, even if all participating states seek the same objective, makes it difficult to align policy features so as to achieve a desired outcome in the most efficient manner (Gonzalez, 2007). If this statement is true, we should expect total carbon savings to equal $X + Y – A$, where A is the lost carbon savings that results from inconsistent policy efforts across $state_1$ and $state_2$. When one jurisdiction supports an energy policy agenda and a neighboring jurisdiction does not, one would expect that total carbon savings will be less than the potential savings if the two states were to each have their own policy agenda. If $state_1$ is the state with the policy agenda and $state_2$ is the state without, one should expect total carbon savings to be X. As chapter 4 provides evidence, however, the total carbon savings that results from $state_1$ acting in isolation is actually less than X; instead, one should expect total savings to be $X – B$, where B is the lost carbon savings due to carbon leakage across state borders. Assuming that all policy instruments are optimally designed, it is likely that the carbon savings from the case of two policy agendas but with inefficiencies due to inconsistency is greater than the case of the one policy agenda with carbon leakage, or $Y – A > -B$.[34]

[34] I do not, however, have empirical evidence to back up this claim.

One could also identify additional benefits that accrue when two or more states, or an entire region, coordinate policy efforts. Although the literature has yet to devote much attention to this subject and this discussion remains fairly speculative, possible benefits include: greater economic development possibilities from regional competitive advantage strategies; enhanced opportunities to participate in cap-and-trade markets; or improved policy design features of individual states as a result of either peer-pressure or policy diffusion. If additional carbon saving benefits, C, accompany policy coordination, total carbon savings associated with the coordination between state_1 and state_2 is $X + Y + C$, which is the best possible outcome of all reviewed above.[35]

These conclusions are recognized by many state policymakers, as evidenced by recent efforts to coordinate cap-and-trade markets, as well as and renewable energy credit markets, across regional lines.

Note 9: The federalist implications of state leadership in energy policy requires further examination

States are regarded in the federalism literature as “laboratories of democracy.” States can develop policies that are smaller in scale, and better tailored to local conditions and needs. This process may involve experimentation, borrowing lessons from other states, and, perhaps eventually, the identification of policy “winners.” As is often the case, after a period of state experimentation, the national government can craft a policy agenda that employs the best practices and avoids the worst. The disadvantages to state

[35] Given that the focus of this discussion is still on state-by-state coordination, and not national coordination, one should actually expect the total savings to equal $X + Y + C – B/n$, where n is a value that represents an improvement in carbon leakage. As more states join efforts, n increases, B/n decreases, and total carbon savings increase.

policy leadership, on the other hand, include the possibility of duplication of efforts, a lack of regulatory consistency that may affect individuals or companies that cross state lines, budget constraints, inter-state competition, or a “race to the bottom” in policy stringency.

Have developments in the era of state energy policy innovation revealed states to be effective laboratories of democracy? An answer to this question requires that I pose two additional questions: first, have states been effective at devising and implementing energy policies that increase the diversification, decentralization, and decarbonization of the U.S. electricity sector; and, second, have states set a good example for the national government?

In response to the first question, this dissertation highlighted the mixed evidence of the effects and effectiveness of states’ energy policy efforts or, in some cases, lack of efforts to date. Some states have taken minimal action, others substantial action. Out of those states that have crafted energy policy instruments, some have experienced early success in attaining desired outcomes. Others have encountered difficulties with their policy approaches, and gone back to the drawing board to craft new or additional mechanisms, or revise previous ones. A consideration of all states’ experiences with various policy instruments reveals that some instruments are more effective at achieving various objectives, and have fewer unintended outcomes, when used at the state level. Empirical results from previous chapters suggest that state level policy instruments have the potential to achieve all three policy objectives reviewed in this analysis, yet states have experienced greater success in this pursuit with instruments that encourage decentralization than those that encourage diversification or decarbonization. States have experienced some success, but with limitations, with their instruments that aim to diversify the electricity sector. States' ability to use policy instruments that decarbonize the electricity sector, however, have been and will continue to be plagued by limitations, so long as states continue to use energy tools instead of climate policy tools and lack policy coordination across state or regional lines.

Regarding the second question, it is important to note that "good" is subjective. This not withstanding, the states' experiences are exemplary in a number of ways, including but not limited to the following:

- The majority of state governments have demonstrated a concern for energy and climate issues, and translated this concern into policy action.
- Many states have crafted innovative policy tools that combine elements from other market-based instruments as well as from command-and-control instruments, with flexibility mechanisms built in.
- Many states have continually reevaluated their policy portfolios, with particular attention devoted to policy design features of their various tools. These states have demonstrated a tendency to enhance the strength—or "stretch"—of policy instruments over time.[36]
- The majority of states have pursued an open and democratic policy process, with all stakeholders invited to the table (Peterson and Rose, 2006).
- State policymakers have demonstrated a concern for equity across "socioeconomic groups, regions, and generations" (Peterson and Rose, 2006).

[36] Some states have redrafted their policy instruments to mandate greater renewable energy benchmarks, or increase the amount of funding that is devoted to renewable energy, distributed generation, or less carbon-intensive fuels. However, a counter-trend may be occurring simultaneously. Although this phenomena has not yet been identified in the literature, a cursory glance at various states' RPS design features reveals that, as time goes on, new RPS adopters are tending toward weaker design features.

- More recently, as states have begun to form regional partnerships, they have demonstrated a willingness to cooperate with states or jurisdictions that do not necessarily share the same ideology, fiscal resources, or generation assets.

Conclusion

Over the course of the era of state energy policy innovation, states have selected a variety of policy instrument “winners”—or “front-runners”—that they believe to hold the greatest potential to achieve diversification, decentralization, and decarbonization objectives. Yet, the effects and effectiveness of these instruments on the U.S. electricity sector are not entirely understood, as evidenced by the lack of empirical literature on state level energy policies. Nor is there clear understanding in the literature regarding how well these instruments work together, whether multiple objectives can be pursued both effectively and simultaneously, and what are the limits of state leadership in energy and climate policy.

This dissertation sought to address some of the unanswered questions about the era of state energy policy innovation via a series of essays on the effects and effectiveness of different state level energy policy instruments. Each essay addressed a different policy objective with an empirical approach that was tailored specifically to the research question. The conclusion reviewed and synthesized these results, and attempted to further highlight significant trends, necessary trade-offs, potential issues that may warrant public policy concern, and avenues for future research.

The need to address remaining questions and expand on these findings is ever-present. Until the U.S. and its global partners can reduce dependence on fossil fuels, devise advanced, efficient, and clean energy alternatives, and reduce greenhouse gas emissions, the need for optimal policy solutions will remain significant. Policy solutions will require making trade-offs, and a continual reevaluation of progress.

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