Decarbonization of the U.S. electricity sector: Are state energy policy portfolios the solution?

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Abstract

State governments have taken the lead on U.S. energy and climate policy. It is not yet clear, however, whether state energy policy portfolios can generate results in a similar magnitude or manner to their presumed carbon mitigation potential. This article seeks to address this lack of policy evidence and contribute empirical insights on the carbon mitigation effects of state energy portfolios within the U.S. electricity sector. Using a dynamic, long-term electricity dispatch model with U.S. power plant, utility, and transmission and distribution data between 2010 and 2030, this analysis builds a series of state-level policy portfolio scenarios and performs a comparative scenario analysis. Results 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 difference in decarbonization potential between isolated state policies and larger, more coordinated policy efforts is due in large part to carbon leakage, which is the export of carbon intensive fossil fuel-based electricity across state lines. Results also confirm that a carbon price of $50/metric ton CO_2e can generate substantial carbon savings. Although both policy options—an energy policy portfolio or a carbon price—are effective at reducing carbon emissions in the present analysis, neither is as effective alone as when the two strategies are combined.

Keywords**:** Electricity markets, Energy policy, Carbon dioxide, Climate policy

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1. 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 single 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 clusters of instruments, which may not produce significant effects individually but, when combined, have the potential to provide compounding 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 single instruments because they have the potential to target multiple externalities at once and achieve carbon reductions at a lower overall cost than a single policy (Fisher and Newell, 2008).

There is a great need—in both the policy realm and the energy literature—for information on how well state policy 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 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 intent 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 decarbonization 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.

2. 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 policy scenarios in which 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 (2007) 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 single 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, no studies have modeled energy policy instruments or portfolios at the state level and tracked the dynamics among and between states. Yet, to date, the majority of U.S. decarbonization efforts are concentrated in the states. National policy modeling, as is the norm in the literature, allows for a general comparison 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.

3. 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, largely overlooked in the energy modeling literature. Second, building on the efforts of Fisher and Newell (2008) and others, this analysis focuses on policy portfolios, not just single 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 national energy sector model (Chen et al., 2007). AURORAxmp is frequently used by state utility commissions and electric utilities in both regulated and non-regulated states to simulate short-term resource dispatch based on competitive wholesale electricity market prices. [1] 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 logic 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 benefit minus cost basis—are selected for deployment in a given zone in a given hour.[2] 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—which are collected every fourth hour, four days a week on alternating weeks—are combined in an iterative process until the model is able to extract the resource mix that is most economically efficient 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,

[1] Many NERC regions, such as the Western Electric Coordinating Council, the unit of analysis in the present study, have service territories that are regulated primarily at the retail level; however, utilities and utility commissions within these regions often rely on competitive wholesale power markets to inform rate cases, create integrated resource plans, or inform dispatch and operations that account for opportunities from the wholesale power market. Additionally, despite not having a central clearing market and region-wide independent system operator, as is common in the Northeast and Texas, many regions with regulated retail sales still have several market hubs that are fairly liquid in their wholesale power trades. Utilties and planning commissions within these regions, therefore, still use models such as AURORAxmp for both short-term and long-term energy planning.

[2] A resource's capability is determined in the following process: the model reads the system capacity, and then reduces it by forced outage assumptions, maintenance outage assumptions, reserve withholdings, and commitment assumptions (i.e., fulfilling a minimum up or down time). One could further restrict the capability of various resources—wind energy, for instance—by assuming hourly or monthly shaping factors; however, given the sampling methodology of the present analysis, in which dispatch decisions over the long-term are made during a selected sample of dispatch hours, dispatch decisions will be more accurate if the shaping factor is set to zero but the capability is still refined according to the process described above.

selects resources for deployment based on hourly market values and reserve margin requirements, and tracks transmission exchanges between states and regions.

Electricity trading is determined in the following manner. Locations are divided into zones that resemble individual or clusters of traditional service territories; these zones are not necessarily delineated according to state lines. As part of the dispatch logic, the model identifies trading opportunities on an hourly basis between zones based on differences in the marginal cost of energy to meet demand in each zone. For instance, if one zone has a marginal cost of electricity of $40/MWh and additional resource capacity at $45/MWh, and a neighboring zone has a marginal cost of electricity of $50/MWh, the neighboring zone will be more likely to import the less expensive $45/MWh generation from the first zone than dispatch its own local resource stack. Incremental amounts of electricity are imported and exported from zone to zone in an iterative process until the model eventually settles on the export-import amounts that leave no further opportunity for trade, which is generally the case when the difference in zonal marginal prices is at its minimum.

AURORAxmp allows one to set reserve margins at both the zonal and pool level. We assume no restrictions at the zonal level but a 12 percent reserve margin at the pool level for all WECC pools.

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, capacity size, start-up times, heat rates, minimum up- and down-times, forced outage requirements, and peak load multipliers; a list of existing resources or forced builds; planning reserve requirements; emissions prices and emissions rates for each fuel type; transmission links between zones and regions; and 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) (NC Solar Center, 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. Although the sample selection does not employ an advanced sampling methodology, the selection of states is guided by several criteria. First, I choose states based on the immediacy of the decarbonization policy issue in each state. This criterion requires that I select states that recently drafted climate action plans, the results of which recently or are currently informing policy debates over the adoption or revision of various energy policies.[3] Second, I omit California from the selection process because California's energy generation and policies make the state non-representative of other states. I additionally omit states that border California because California is the biggest importer in the country and, as a result, surrounding states' exporting behavior may be non-representative of average conditions. Third, I select states that have differences in energy resource potential, generation portfolios, and demand projections, so that results are based on a broader range of state-level electricity conditions. Finally, I select states that share a border, so as to monitor trade between the two states. Utah and Arizona match all of these criteria and are selected to serve as the research sample.

Using these data, I build various policy scenarios. 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, save a national investment tax credit for wind and solar.[4] 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,

[3] Utah drafted an advisory report on climate change policy options in 2007 (Utah Governor's Blue Ribbon Advisory Report, 2007) subsequently passed RPS legislation in March of 2008 (NC Solar Center, 2010). Utah has also commissioned a report that explores the state's carbon mitigation options (Gumerman and Daniels, 2009). Arizona drafted a climate action plan in 2006 (Arizona Climate Change Advisory Group, 2006). Arizona passed RPS legislation well before the publication of their climate action plan, first adopted in 1999, but revised their RPS policy in 2006 from a renewable energy mandate of 1.1 percent of all generation by 2007 to 15 percent by 2025 (NC Solar Center, 2010).

[4] These cost savings are factored into the fixed cost parameters of both wind and solar.

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.[5]

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.[6] 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.

4. Modeling Parameters

4.1 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 1. All new generator characteristics are extracted from the *AEO2009*, and represent the average cost estimates and other performance characteristics for these energy resources 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.[7]

I also assume a maximum number of energy system builds per year and in total in each state. These figures impose restrictions on the selection of energy systems based on other criteria, such as political or social feasibility. For instance, I restrict the model to one IGCC power plant build per year and per state, and two new IGCC power plants over the entire study period. The model may select IGCC as the most economically efficient

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[5] 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.

[6] Note that in reality, in the WECC, electricity prices at the retail level are generally based on average costs, not marginal costs. If AURORAxmp instead based electricity prices on average costs, one might expect less volatility in hourly prices, and more stability in prices over on-peak and off-peak horizons. However, given that this analysis averages retail prices over an annual basis, the difference should be negligible.

[7] This assumption, or calibration exercise, is made per advice from AURORAxmp's management team. Without this adjustment, AURORAxmp dispatches plants more often than one would realistically observe.

new energy resource but it is improbable to assume that will be politically feasible to build more than one IGCC power plant per state; and so by limiting the maximum number of power plant builds, one can control the rate at which the model selects IGCC plants.[8]

[Insert "Table 1. New Resource Option Parameters included in Baseline Scenario" here]

Despite the ability to control the number of new power plants, it is more difficult to specify when specific power plants that are already operational at the beginning of a study period will be retired. As a result of this complication, no retirement bounds are placed on already existing power plants.[9]

Demand projections are determined exogenously, 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 in the *AEO2009*. 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. 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.

4.2 Baseline Sensitivity Analysis

I run a number of baseline sensitivity analyses to test the sensitivity of the model outputs to variations in primary fuel costs, technological improvements, and demand growth projections. The first two sensitivity analyses 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. 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

[8] It is important to note, however, that these optimization bounds are rarely met. As is discussed in the Results section, the only restriction that is encountered is Arizona's IGCC annual limit in one scenario run.

[9] Each power plant that has already been declared destined for retirement or is well past its functional age, however, does have a specified retirement date in the model. All other plants are eligible for retirement based on the economic performance of the plant.

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 set of sensitivity analyses adjusts demand growth rates for Utah and Arizona, respectively, because demand assumptions can have significant consequences on the performance of energy models. Because it is possible that the growth rates are either too low or too high, I run two demand growth sensitivity analyses for both of the states, which results in four additional sets of outputs. For these sensitivity analyses, I adjust the demand growth rate parameter by .3 above and below the *AEO2009* assumptions.

4.3 Policy Portfolios

As discussed above, each state traditionally chooses unique combinations of different policy instruments to include in their carbon mitigation 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.

4.3.1 Renewable Portfolio Standards

A renewable portfolio standard (RPS) requires that a minimum level of either a state's overall electricity generating capacity or its retail sales 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.[10] 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.[11] 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 (NC Solar Center, 2009).

[10] 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.

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

The RPS policy scenario in the present study is operationalized as a 20 percent of state generation[12] 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

To determine the total amount of incremental 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:

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

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, based on a value that the Department of Energy found for commercial wind operations for turbines installed after 1998, and documented between 2004 and 2005 (DOE, 2008).

This study assumes that 100 percent of all new generating capacity intended to meet RPS requirements—i.e., the renewable generating capacity needed beyond that which already exists in the baseline—will be met with wind energy.[13] I consider the

[12] To date, there is no leading or consistently adopted RPS policy design (Wiser and Barbose, 2008). One of the many design features that vary across state RPS policies is whether the renewable energy percentage mandate applies to a utility's retail sales or its generation and, additionally, whether the percentage mandate is based on a calculation of in-state sales or generation, or both in-state and out-of-state sales or generation. The present analysis calculates the RPS percentage requirements according to total state electricity generation, after adjustments as outlined in the text, which is the equivalent of an in-state plus out-of-state retail sales minus transmission and distribution losses. It is important to note that this assumption requires that more renewable energy is forced online in the model than if I instead calculate the mandated renewable energy using retail sales or exclusively in-state generation as a base for calculation. For states that are net exporters, the greater the difference between exports and imports, the greater would be the difference between the amount of renewables necessary for an RPS under the present specification and under an RPS based on retail sales specification. For states that are net importers, the difference between the amount of renewables needed under different specifications should be minimal, since most generation and sales occur in-state.

[13] The assumption made in this analysis of 100 percent wind energy is mostly in keeping with past trends. Between 1998 and 2007, 93 percent of the total new renewable energy that was deployed in RPS states came from wind energy; the remaining four percent came from biomass, two percent from solar, and one percent from geothermal (Wiser and Barbose, 2008). Solar or distributed generation set-asides are, however, becoming more common; as of 2007, 12 states out of 26 with mandatory RPS policies had a solar or distributed generation set-aside of some type (Wiser and Barbose, 2008). One could make a claim, therefore, that the RPS modeled in this analysis should include other resources, such as solar or distributed generation. The intent of this modeling exercise, however, is not to accurately predict the exact renewable

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 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.

4.3.2 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. [14]

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energy mix that each state or region will deploy as a result of an RPS, which would necessitate additional assumptions about the technical, political, and economic feasibility of various renewable energy sources in different states; instead, the objective is to simplify the modeling parameters and apply consistent scenario assumptions across states and regions for the sake of comparison and generalizability of trends. The author encourages readers to bear these simplifying assumptions in mind when interpreting model results. In particular, on should exhibit caution in the interpretation of cost estimates for scenarios that include RPS policies, since the costs may be lower than one would realistically observe, due to higher initial costs of solar energy and distributed generation relative to wind energy.

[14] The assumption of 20 percent reduction employed in this analysis does not translate into a 20 percent reduction from 2010 demand by 2029. Instead, the percentage DSM savings are applied to the baseline demand projections on an annual basis so that, by 2029, a state will have demand that is 20 percent lower than the baseline 2029 demand. This distinction is important because the former conceptualization, a 20 percent reduction from 2010 demand by 2029, would result in much larger demand savings—perhaps even unrealistic savings—than the latter conceptualization of demand savings.

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. Because it is reasonable to assume that the cost of DSM programs will rise after the lowest hanging demand-side fruit is exhausted, I assume that the price of DSM programs rises to 6.8 cents/kWh after 10 percent—half the savings—have been achieved, which occurs in 2019. I 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.

4.3.3 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 2 summarizes the changes in fixed cost parameters between the baseline and the tax incentive scenarios.

[Insert "Table 2. Fixed Operations and Maintenance Costs for Baseline and Tax Incentive Scenarios" here]

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.

4.3.4 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 countries (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 3 displays these assumptions.

[Insert "Table 3. Carbon Capture and Storage Technological Improvement Model Assumptions" here]

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 shows the CCS plant characteristics, as entered in AURORAxmp.

[Insert "Table 4. Carbon Capture and Storage Policy Scenario Parameters" here]

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.

4.3.5 Policy Portfolios Scenarios

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 moderate scenarios, therefore, is the amount of total wind energy that is forced online: the strong scenario has more wind energy and the moderate 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.[15]

In all state policy scenarios, only the specific state that is the unit of analysis, is assumed to have a policy portfolio. All surrounding states are modeled as though they do not have any energy policies, even if, in reality, energy policies exist in these states. This assumption is made so that states' policy efforts can be analyzed in isolation, and the model results can be attributed to the isolates states' policy efforts and not confounded by surrounding states' policy actions. In the regional scenarios, all states within a region are assumed to have the same portfolio of energy policy instruments.

4.4 Carbon Price Scenarios

In the last series of runs, I add national carbon prices of $25/metric ton GHG equivalent and $50/metric ton GHG equivalent, respectively, and compare the results to the non-carbon price scenarios. 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 GHG in the first year, and $15 to $25/metric ton GHG in the second year. Similarly, the $50 GHG cost run has an increase in the cost of carbon from $1 to $25/metric ton GHG in the first year, and from $25 to $50/metric ton GHG in the second year. Once the cost hits its maximum value, at $25/

[15] One could additionally run a third series of model adjustments in which the amount of renewable energy that is forced online via an RPS is adjusted further for direct demand reductions from the DSM policy scenarios and indirect demand adjustments from the carbon price scenarios. However, recalling that this analysis assumes that RPS policies are based on total generation, as opposed to retail sales or electricity loads, a change in in-state demand still may not affect the total renewable energy mandate if states increase their exports as a result of in-state demand reductions. I decide, therefore, to restrict the output to only two series of model adjustments—the "strong" and "moderate" scenarios—to improve the focus of the results' discussion.

metric ton GHG and \$50/ metric ton GHG, respectively, it remains steady at that value throughout the duration of the study period.[16]

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 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 GHG 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 GHG 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 GHG sensitivity scenario and 0.7 to 0.61 in the \$50/metric ton GHG 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).

A summary of modeling scenarios is presented in Table 5.

5. Results of Scenario Analysis

5.1 Baseline

Figures 1 and 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 electricity using 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 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 capacity 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 they are not visible in Figure 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

[16] One could argue that these "ramp-up" carbon price rates are too strong and, in reality, it would take several additional years for carbon price to ramp-up to its full value. It is possible that the assumptions made in the present analysis also affect the model outcomes; if, for instance, a state has a decade to ease into carbon price restrictions, it may pursue different electricity resource options than it does under the two-year transition that is modeled in this analysis.

compared to the other energy resources. Both nuclear and hydroelectric generation remain steady throughout the study period.

[Insert "Figure 1. Utah Baseline Generation" here]
[Insert "Figure 2. Arizona Baseline Generation" here]

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 6 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, which is expected given the optimization and electricity trading logic, as discussed in the previous section, 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.

[Insert "Table 6. Baseline Scenario Summary Results for Utah and Arizona, 2020 and 2030" here]

5.2 Sensitivity Analysis: Cost Parameters

The results of the baseline sensitivity analyses are presented in Table 7 and Table 8. 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.

[Insert "Table 7. Utah Baseline Sensitivity Analysis Summary Results, 2030" here]
[Insert "Table 8. Arizona Baseline Sensitivity Analysis Summary Results, 2030" here]

5.3 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 generation 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.

5.4 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. A lower demand growth rate for the state of Utah results in a very slight decrease in coal generation, but an increase in natural gas generation from existing plants. Total generation rises, therefore, as do GHG emissions and the price of electricity, despite the decrease in in-state demand. Utah exports the additional generation and, as a result, exports increase significantly in this scenario relative to the baseline. Imports decrease as well, which makes Utah the largest net exporter in this scenario, relative to all Utah baseline scenarios.

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 increase and its imports decrease. Both GHG emissions and the price of electricity decrease as a result of Arizona's demand growth adjustment sensitivity scenario. With a higher demand growth rate, Arizona increases total generation, mostly from new natural gas units, which increases GHG emissions and the price of electricity. Given additional new resource capacity that is greater than Arizona's in-state needs, Arizona increases exports; imports remain roughly the same.

It is evident that resource dispatch decisions and export-import behavior are sensitive to demand parameter assumptions; export-import and dispatching decisions, in turn, affect total generation and GHG emissions. The direction of the relationships among these variables is difficult to predict a priori. For instance, one cannot assume that just because demand decreases, total generation and GHG emissions will decrease. Instead, it may the case that, due to a decrease in demand growth, the price of excess natural gas or coal generation falls, and, as a result, surrounding states will demand more of the first state's natural gas or coal generation due to the difference in the marginal costs of electricity between the two states.

5.5 Policy Portfolio Scenarios

As discussed in section 4.3, each states' 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, "strong" and "moderate". Refer back to section 4.3.5 and Table 5 for an explanation of these scenario assumptions. The results of these portfolio analyses in year 2030 are summarized in the tables below.[17] 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.

5.5.1 Policy Portfolio Scenarios: Utah

Beginning with Utah's results in Table 9, 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 strong regional coordination portfolio scenario has a lower 2030 retail price of electricity than the isolated state scenario. Figures 3 and 4 present these two variables, Utah's GHG emissions and retail electricity price over time.

[Insert "Table 9. Utah Portfolio Scenario Results in 2030" here]
[Insert "Figure 3. Utah GHG Emissions" here]
[Insert "Figure 4. Utah Retail Price of Electricity" here]

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 exact 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 Utah's dollars associated with the regional coordination scenario is evident in Figure 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 10 below shows the difference between GHG

[17] 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.

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.[18] If one considers cumulative GHG emissions over the entire study period, the regional coordination portfolio has roughly 5.1 times greater decarbonization potential for the state of Utah as the isolated state portfolio.[19]

[Insert "Table 10. GHG Emissions Difference between Baseline and Portfolio Scenarios, Utah" here]

Which factors contribute to the greater decarbonization potential of regional portfolios for the case of Utah? Returning to Table 8, 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 absence of a policy portfolio? The reason is that Utah can export their relatively inexpensive coal-based electricity to neighboring states, a phenomenon referred to as "carbon leakage" in the literature. In 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 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 exports (exports minus imports) difference, which indicates that Utah is the biggest exporter of electricity when it is the only state with a policy portfolio.

[Insert "Figure 5. Utah Net Exports-Imports" here]

5.5.2 Policy Portfolio Scenarios: Arizona

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[18] These decarbonization potential estimates are not to be confused with cost-effectiveness estimates.
[19] It is important to note 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.

Arizona's results are summarized in Table 11. 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 6 and 7 display Arizona's GHG emissions and retail price over time, respectively, as a result of the portfolio scenarios.

[Insert "Table 11. Arizona Portfolio Scenario Results in 2030" here]
[Insert "Figure 6. Arizona GHG Emissions" here]
[Insert "Figure 7. Arizona Retail Price of Electricity" here]

Figure 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 7. Table 12 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.

[Insert "Table 12. GHG Emissions Difference between Baseline and Portfolio Scenarios, Arizona" here]

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 11, 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 8, 9, and 10 display which decisions Arizona makes.

[Insert "Figure 8. Arizona New Generation" here]
[Insert "Figure 9. Arizona Generation, State" here]

[Insert “Figure 10. Arizona Generation, Regional” here]

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. 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—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.

[Insert “Figure 11. Arizona Net Exports-Imports” here]

5.6 Carbon Price Scenarios

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 13 and Table 14. These tables also include the demand growth sensitivity scenarios.

[Insert “Table 13. Utah Carbon Price Portfolio Results, 2030” here]
[Insert “Table 14. Arizona Carbon Price Portfolio Results, 2030” here]

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 GHG causes both states to make relatively small reductions in coal generation and large reductions in natural gas generation. A carbon price of $50/metric ton GHG 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 12 and 13 display each state's total GHG emission savings, relatively 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, given the parameter assumptions made in this analysis. Beginning around 2015, a carbon price of $50/metric ton GHG and a regional coordination portfolio cuts Utah's emissions by almost one-half, and Arizona's emissions by one-third.

[Insert "Figure 12. Utah Carbon Price Scenarios" here]
[Insert "Figure 13. Arizona Carbon Price Scenarios" here]

5.6.1 Carbon Price Sensitivity Analyses

The demand sensitivity scenarios represent a decrease in the rate of demand growth across all WECC states, which should more realistically capture 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 plants. 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.

5.6.2 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 14 presents the summary findings. WECC greenhouse gas emissions increase throughout the study period in the baseline scenario. The $50/metric ton GHG 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 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, given the specifications of the present analysis, neither is as effective in isolation as they are when combined.

[Insert "Figure 14. WECC GHG Emissions" here]

5.7 GHG Emissions: Combined Scenarios

The GHG emission savings from all strong isolated state, regional coordination, and GHG price modeling scenarios are included in Table 15. The values in this table represent the difference between baseline GHG emissions for each respective area and the GHG emissions from each scenario. This table reveals that, despite the presence of carbon leakage, which makes the isolated state scenarios less effective at reducing carbon emissions in each respective state, some of the leakage is offset by GHG emission savings in other WECC states. These offsets do demonstrate that state level policy portfolios can produce some GHG savings outside of the state that implements the policy portfolio; however, additional savings are not great enough to improve significantly the decarbonization potential of isolated state policy portfolios, relative to regional coordination policy efforts. Table 16 provides additional insights into the differences between isolated state and regional coordinated policy efforts. This table presents program costs—the costs necessary to implement all policies within a portfolio, based on the assumptions presented in section 4—divided by GHG savings for the isolated state and regional coordination scenarios.[20] The table reveals that isolated state policy portfolios cost substantially more per ton of GHG saved than regional coordination policy portfolios. Due to the offset of some carbon leakage at the WECC-wide level, program costs per GHG emissions are slightly lower when one considers the region as a whole.

[Insert "Table 15. GHG Emissions Difference between Baseline and Portfolio Scenarios, All Scenarios" here]

[Insert "Table 16. Program Costs (in $/GHGe ton saved)" here]

6. 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 single 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 state policy actions. The difference in decarbonization potential between

[20] Note that this estimate only includes direct program costs, and not indirect costs associated with new resources that are built as a result of the policy portfolios, or other indirect costs.

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). It is important to note, however, that an RPS policy may have a greater effect on fossil fuel generation and GHG emissions if the renewable energy that is deployed as a result of an RPS is from solar or biomass, since these energy resources have the ability to serve base loads and, thus, replace coal generation. 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. 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. 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 GHG can generate substantial carbon savings. Although both policy options—energy policy portfolio or a carbon price—are effective at reducing GHG emissions, neither is as effective alone as when the two strategies are combined. These results are, however, contingent on the assumptions and specifications of this modeling exercise.

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 between regulated and non-regulated areas as a result of emissions' regulations. 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, and the tendency for emissions' regulated states to transfer relatively inexpensive fossil fuel generation to non-regulated states. Thereby, despite the efforts made —and costs incurred—to reduce GHG emissions by the regulated state, emissions in that state may not decrease much at all. 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 power 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 additional 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.

7. 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.

7.1 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 or are well beyond their age limit. Many of remaining 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. Alternatively, a utility may simply update or retrofit their coal plants every so often, which would also increase the costs of electricity but result in indeterminate changes in 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.

7.2 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 may not have even been included in these scenario models. 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. On the other hand, some RPS policies may also include carve-out provisions for additional energy resources, such as solar or distributed generation; the failure to accurately model carve-out provisions of this variety alternatively could have resulted in cost estimates that are too low. It was also necessary to make simplifying assumptions about the capacity factor for the RPS wind energy that was forced into the model. In reality, capacity factors vary by location; and a 36 percent may be too high for the majority of locations. In this event, the amount of wind energy forced into the model may be too low, which would result in cost estimates that are too low.

In recognition of the inherent limitations of modeling analyses 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. Variations in carbon price and demand growth rates were found to be some of the most sensitive modeling inputs.

It was necessary to make 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. Despite the large number of states, and the diversity and heterogeneity of state conditions within the WECC, it is possible that the WECC is not the most representative population for the other NERC regions, particularly those that have primarily market-based retail pricing, such as Northeastern states, as opposed to the regulated pricing found throughout the WECC.[21] This study does not presume that all regions, or all states, will respond to

[21] As discussed above, the Northeastern states have identified the problem of carbon leakage in RGGI operations and are currently seeking methods of mitigating this leakage (RGGI, 2007). One may conclude,

policy portfolios or carbon prices in exactly the same fashion as the WECC, or 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. Furthermore, it is indeed 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. 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 and each NERC region. Future studies could additionally seek to identify empirically which factors are associated with improved or reduced cost-effectiveness of carbon mitigation policy portfolios. Future studies could also consider the differences in decarbonization effects between states that are regulated and those that are not.

8. Conclusions

This study sought to explore whether state policy portfolios can be 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 can be the most effective carbon mitigation option out, given the assumption and specifications employed in this analysis.

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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therefore, that the results of the present analysis are applicable, at least to some degree, to the Northeastern states' experiences, and vice versa, despite the differences in retail price regulation.

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Table 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)	Peak Credit Multiplier (%)a	Fuel Price ($/mmBTU)
Geothermal	33,729	50,000	3.66	4,599	5	10	50	4	1	1.74
Solar Photovoltaic	10,022	5,000	0.27	11,047	45	5	100	2	0.6	0.00
Biomass	9,646	80,000	7.96	6,721	5	1	2	4	0.6	0.05
Municipal Solid Waste/Landfill	13,648	30,000	2.55	5,346	5	1	3	3	0.6	1.16
Wind	0	50,000	0.65	3,298	60	2(UT), 0(AZ)	10(UT), 0(AZ)	3	0.1	0.02
Scrubbed Sub-Critical Pulverized Coal	8844-8600*	600,000	5.03	3977-3784*	7.5	1	2 (AZ), 1 (UT)	4	1	1.45-1.66*
Integrated Gasification Combined Cycle	8309-7200*	550,000	3.68	4702-4343*	7.5	1	2	4	1	1.45-1.66*
Advanced Gas-Oil Combined Cycle Combustion Turbine	6682-6333*	400,000	2.57	1869-1738*	4	10	100	3	1	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	1	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 2030 value.
a. Peak load multiplier is the proportion of a unit's input capacity that can count toward the reserve margin criteria.
Source of data: *AEO2009*

Table 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

Table 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

Table 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

Source of data: *AEO2009*

Table 5. Summary of Modeling Scenarios

	Isolated State	Regional Coordination	$25 GHG Price	$50 GHG Price	Isolated state and Carbon Price	Regional Coordination and Carbon Price
Policy instruments included	RPS Tax incentives DSM CCS	RPS Tax incentives DSM CCS	None	None	RPS Tax incentives DSM CCS	RPS Tax incentives DSM CCS
Price of carbon	$0	$0	$25/ton GHG equivalent	$50/ton GHG equivalent	$25 and $50/ton GHG equivalent	$25 and $50/ton GHG equivalent
"Moderate" version	Adjustment for renewable energy	Adjustment for renewable energy	N/A	N/A	Adjustment for renewable energy	Adjustment for renewable energy
"Strong" version	No adjustment for renewable energy	No adjustment for renewable energy	N/A	N/A	No adjustment for renewable energy	No adjustment for renewable energy

Figure 1. Utah Baseline Generation

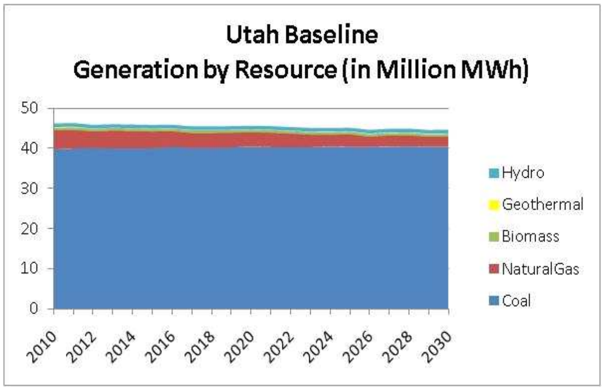

Figure 2. Arizona Baseline Generation

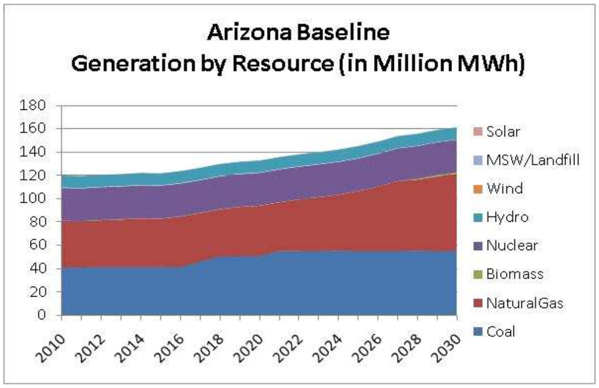

Table 6. Baseline Scenario Summary Results for Utah and Arizona, 2020 and 2030

	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

Table 7. Utah Baseline Sensitivity Analysis Summary Results, 2030

	Baseline	15% Cost Increase	25% Cost Increase	Technological Innovation	Decreased Demand Growth Adjustment	Increased Demand Growth Adjustment
GHG emissions (tons)	42,330,430	42,437,190	42,243,450	42,422,220	42,419,830	42,717,550
Average electricity price (2006$/MWh)	$94.74	$96.62	$95.68	$96.28	$96.04	$97.00
Total generation (MWh)	44,626,119	44,893,176	44,486,517	44,826,394	44,819,593	45,515,386
Coal	40,370,177	40,353,105	40,324,914	40,368,471	40,367,390	40,380,297
Natural gas	2,623,095	2,907,224	2,528,755	2,825,076	2,819,356	3,502,241
Nuclear	0	0	0	0	0	0
Hydroelectric	963,217	963,217	963,217	963,217	963,217	963,217
Wind	0	0	0	0	0	0
Solar PV	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0
Biomass	669,630	669,630	669,630	669,630	669,630	669,630
Landfill/MSW	0	0	0	0	0	0
Total New Generation (MWh)	0	0	0	0	0	0
Coal	0	0	0	0	0	0
Natural gas	0	0	0	0	0	0
Wind	0	0	0	0	0	0
Solar PV	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0
Biomass	0	0	0	0	0	0
Landfill/MSW	0	0	0	0	0	0
Demand	4,941	4,941	4,941	4,941	4,652	5,241
Exports	1,037	1,106	928	929	1,277	847
Imports	923	963	827	787	855	931

Table 8. Arizona Baseline Sensitivity Analysis Summary Results, 2030

	Baseline	15% Cost Increase	25% Cost Increase	Technological Innovation	Decreased Demand Growth Adjustment	Increased Demand Growth Adjustment
GHG emissions (tons)	79,998,250	80,223,270	80,160,130	79,155,510	79,776,490	83,211,670
Average electricity price (2006$/MWh)	$94.73	$95.02	$95.14	$95.65	$94.20	$95.81
Total generation (MWh)	161,227,928	161,825,800	161,695,971	159,311,296	160,701,503	169,432,580
Coal	55,276,935	55,275,848	55,276,152	55,268,571	55,270,228	55,276,286
Natural gas	65,847,285	66,446,243	66,316,109	63,464,662	65,485,684	73,815,408
Nuclear	28,005,315	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	10,310,864
Wind	0	0	0	0	0	0
Solar PV	40,327	40,327	40,327	40,327	40,327	40,327
Geothermal	0	0	0	0	0	0
Biomass	1,510,027	1,510,027	1,510,027	1,510,027	877,555	1,510,027
Landfill/MSW	237,177	237,177	237,177	711,531	711,531	474,354
Total New Generation (MWh)	59,193,580	59,318,188	59,762,314	57,255,392	61,013,478	65,928,075
Coal	13,587,788	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	50,600,989
Wind	0	0	0	0	0	0
Solar PV	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0
Biomass	1,264,944	1,264,944	1,264,944	1,264,944	632,472	1,264,944
Landfill/MSW	237,177	237,177	237,177	711,531	711,531	474,354
Demand	16,164	16,164	16,164	16,164	15,243	17,137
Exports	2,762	3,214	2,544	2,177	3,248	2,928
Imports	577	978	287	220	211	787

Table 9. 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	$128.25	$130.18	$118.28	$117.39
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 3. Utah GHG Emissions

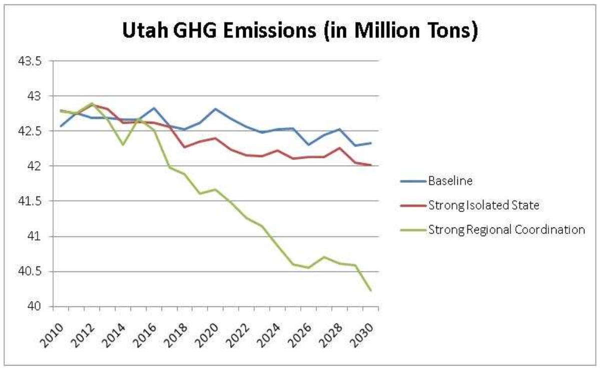

Figure 4. Utah Retail Price of Electricity

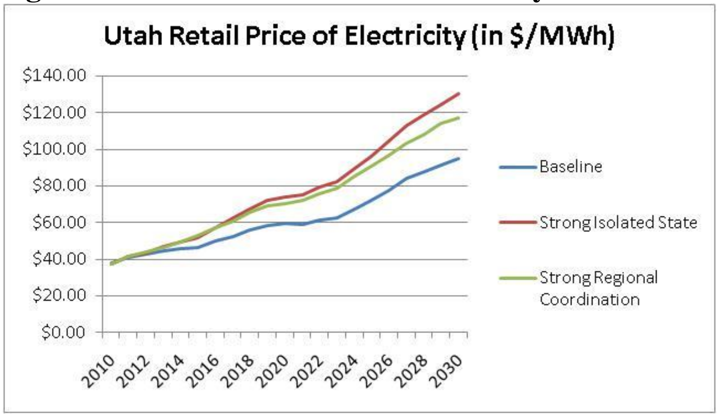

Table 10. GHG Emissions Difference between Baseline and Portfolio Scenarios, Utah

	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

Figure 5. Utah Net Exports-Imports

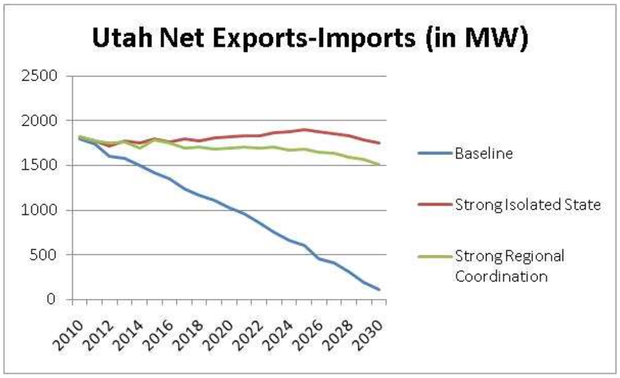

Table 11. Arizona Portfolio Scenario Results in 2030

	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	$124.52	$127.47	$116.12	$113.48
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 6. Arizona GHG Emissions

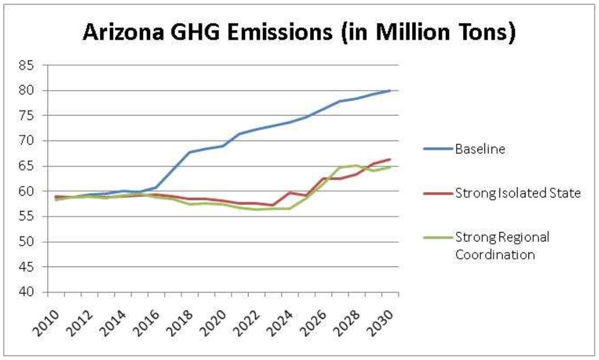

Figure 7. Arizona Retail Price of Electricity

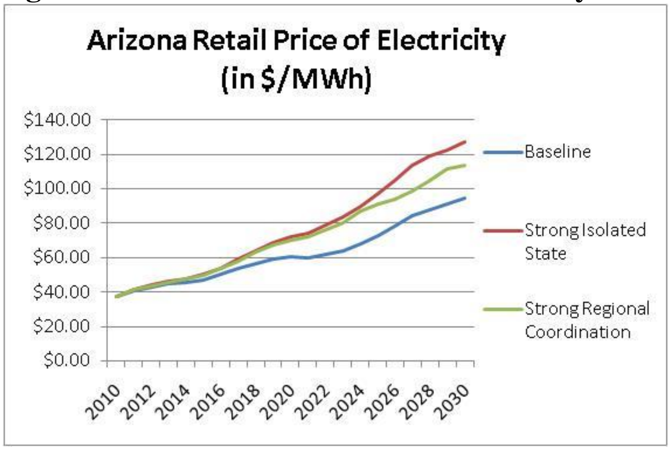

Table 12. GHG Emissions Difference between Baseline and Portfolio Scenarios, Arizona

	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

Figure 8. Arizona New Generation

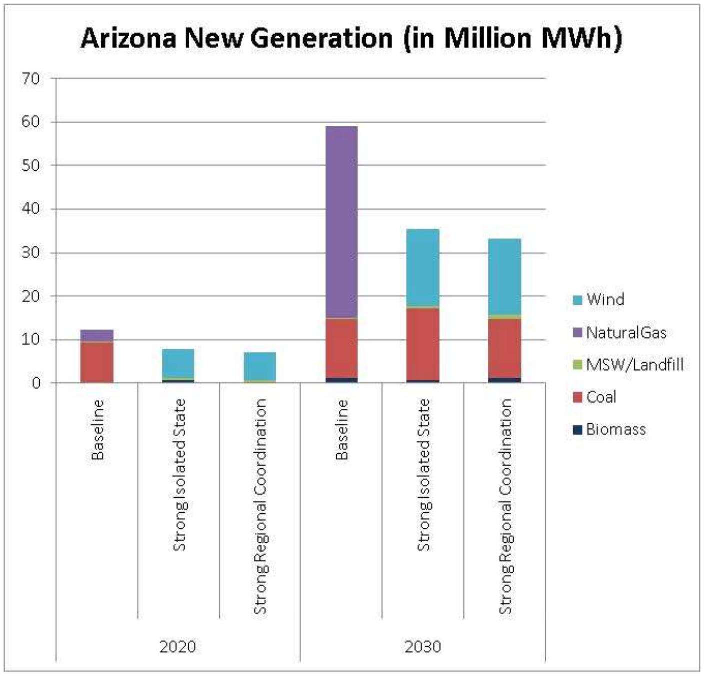

Figure 9. Arizona Generation, State

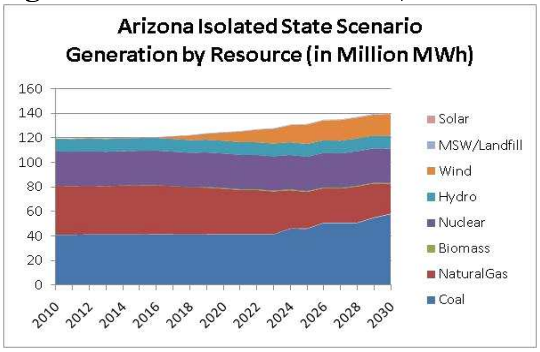

Figure 10. Arizona Generation, Regional

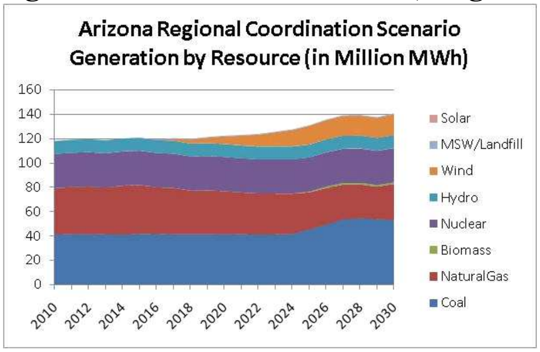

Figure 11. Arizona Net Exports-Imports

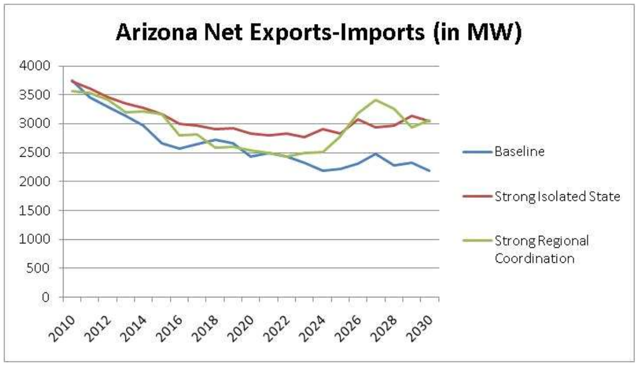

Table 13. Utah Carbon Price Portfolio Results, 2030

	Baseline	$25 GHG	$50 GHG	Regional Portfolio & $25 GHG	Regional Portfolio & $50 GHG	Regional Portfolio & $25 GHG with Demand Sensitivity	Regional Portfolio & $50 GHG with Demand Sensitivity
GHG emissions (tons)	42,330,430	41,403,110	30,750,730	37,548,740	25,710,150	38,636,930	25,958,750
Average electricity price (2006$/MWh)	$94.74	$115.36	$139.27	$133.57	$169.82	$136.47	$172.72
Total generation (MWh)	44,626,119	46,826,431	43,823,229	45,785,514	37,490,244	47,134,922	36,533,035
All Coal	40,370,177	39,733,807	25,063,982	36,134,930	23,336,549	37,002,228	23,508,173
IGCC CCS	0	0	0	0	0	0	0
All Natural gas	2,623,095	2,250,267	13,566,489	1,614,157	4,616,155	2,094,504	4,988,047
NGCC CCS	0	0	0	0	0	0	0
Nuclear	0	0		0	0	0	0
All renewables	1,632,847	4,842,358	5,192,758	8,036,426	9,537,540	8,038,190	8,036,815
Hydroelectric	963,217	963,217	963,217	963,217	963,217	963,217	963,217
Wind	0	1,051,200	1,401,600	6,224,762	6,224,762	6,224,762	6,224,762
Solar PV	0	0	0	0	0	0	0
Geothermal	0	181,836	181,836	180,426	181,058	181,477	181,237
Biomass	669,630	1,934,574	1,934,574	668,021	1,931,325	668,733	667,599
Landfill/MSW	0	711,531	711,531	0	237,177	0	0
Total New Generation (MWh)	0	3,027,675	12,148,550	6,405,188	7,907,942	6,224,762	6,224,762
All Coal	0	0	0	0	0	0	0
IGCC CCS	0	0	0	0	0	0	0
All Natural gas	0	0	8,770,475	0	0	0	0
NGCC CCS	0	0	0	0	0	0	0
All renewables	0	3,027,675	3,378,075	6,405,188	7,907,942	6,224,762	6,224,762
Wind	0	1,051,200	1,401,600	6,224,762	6,224,762	6,224,762	6,224,762
Solar PV	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0
Biomass	0	1,264,944	1,264,944	0	1,264,944	0	0
Landfill/MSW	0	711,531	711,531	0	237,177	0	0
Demand (MW)	4,931	4,941	4,941	3,953	3,953	3,863	3,822
Exports	1,037	1,084	575	1,840	1,022	2,086	845
Imports	923	713	534	595	725	596	518

Table 14. Arizona Carbon Price Portfolio Results, 2030

	Baseline	$25 GHG	$50 GHG	Regional Portfolio & $25 GHG	Regional Portfolio & $50 GHG	Regional Portfolio & $25 GHG with Demand Sensitivity	Regional Portfolio & $50 GHG with Demand Sensitivity
GHG emissions (tons)	79,998,250	78,322,080	60,234,120	55,974,080	41,122,600	53,720,590	40,693,920
Average electricity price (2006$/MWh)	$94.73	$115.43	$132.78	$130.97	$156.81	$134.30	$161.69
Total generation (MWh)	161,227,928	159,780,563	162,671,316	134,433,978	130,982,117	130,308,993	123,473,138
All Coal	55,276,935	54,400,005	20,873,594	48,807,496	28,316,060	45,344,357	25,959,029
IGCC CCS	0	0	0	2,950,373	5,891,468	2,946,480	2,943,482
All Natural gas	65,847,285	64,802,495	101,219,659	25,741,120	42,786,073	27,292,553	40,475,608
NGCC CCS	0	0	0	0	0	0	0
Nuclear	28,005,315	28,005,315	28,005,315	28,005,315	28,005,315	28,005,315	28,005,315
All renewables	12,098,395	12,572,748	12,572,748	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	10,310,864	10,310,864
Wind	0	0	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	40,327	40,327
Geothermal	0	0	0	0	0	0	0
Biomass	1,510,027	1,510,027	1,510,027	2,774,223	2,768,846	1,509,653	876,072
Landfill/MSW	237,177	711,531	711,531	1,423,062	1,423,062	474,354	474,354
Total New Generation (MWh)	59,193,580	56,625,322	84,235,638	33,028,352	32,311,089	26,277,061	21,381,878
All Coal	13,587,788	13,587,788	0	11,743,832	5,891,468	7,206,193	2,943,482
IGCC CCS	0	0	0	2,950,373	5,891,468	2,946,625	2,941,125
All Natural gas	44,103,671	41,061,060	82,259,163	0	5,135,100	0	0
NGCC CCS	0	0	0	0	0	0	0
All renewables	1,502,121	1,976,475	1,976,475	21,284,521	21,284,521	19,070,869	18,438,397
Wind	0	0	0	17,331,571	17,331,571	17,331,571	17,331,571
Solar PV	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0
Biomass	1,264,944	1,264,944	1,264,944	2,529,888	2,529,888	1,264,944	632,472
Landfill/MSW	237,177	711,531	711,531	1,423,062	1,423,062	474,354	474,354
Demand (MW)	16,164	16,164	16,164	12,873	12,873	12,328	12,058
Exports	2,762	2,833	2,645	2,624	2,618	2,905	2,345
Imports	577	813	275	201	582	415	343

Figure 12. Utah Carbon Price Scenarios

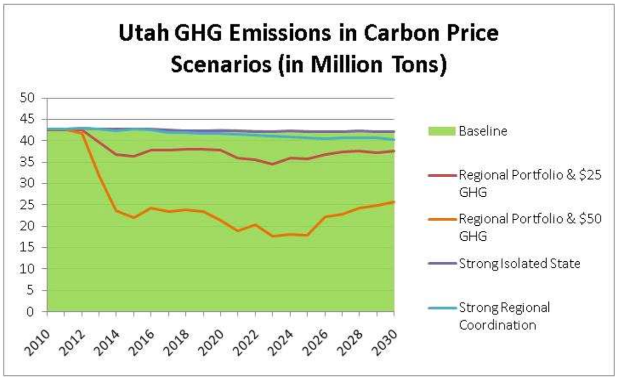

Figure 13. Arizona Carbon Price Scenarios

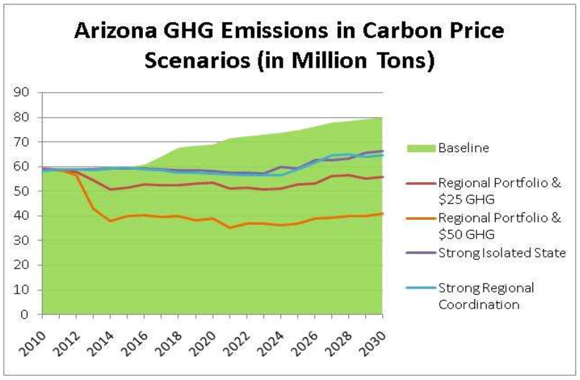

Figure 14. WECC GHG Emissions

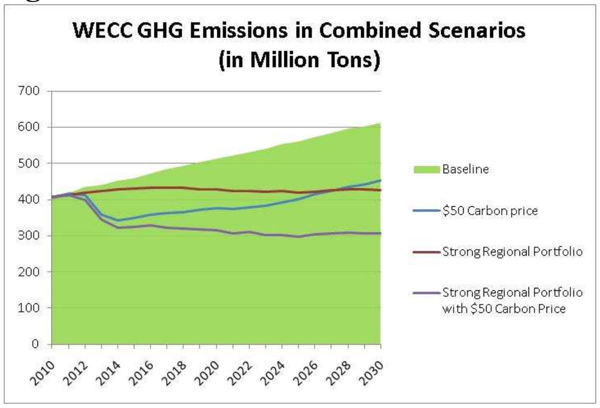

Table 15. GHG Emissions Difference between Baseline and Portfolio Scenarios, All Scenarios

Scenario	Utah	Arizona	WECC
Utah Isolated State Scenario	310,430	-	2,075,774
Arizona Isolated State Scenario	-	14,599,070	20,440,067
Regional Coordination Scenario	2,105,470	15,254,960	185,290,684
$25 GHG Scenario	927,320	1,676,170	46,136,496
$50 GHG Scenario	11,579,700	19,764,130	159,222,955
Regional Coordination and $25 GHG Scenario	4,781,690	24,024,170	226,760,515
Regional Coordination and $50 GHG Scenario	16,620,280	38,875,650	304,105,276

Table 16. Program Costs (in $/GHG equivalent tons saved)

Scenario	Utah	Arizona	WECC
Utah Isolated State Scenario	$2,877	-	$430
Arizona Isolated State Scenario	-	$187	$133
Regional Coordination Scenario	$424	$179	$101