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Risk Management Strategies and Portfolio Analysis for Electricity Generation Planning and Integration of Renewable Portfolio Standards

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Risk Management Strategies and Portfolio Analysis for Electricity Generation Planning and Integration of Renewable Portfolio Standards

by

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Dedication

To Mom and Dad

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Abstract

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Renewable Portfolio Standards (RPS) require electricity providers to supply a minimum fixed percentage or total quantity of customer load from designated renewable energy resources by a given date. These policies have become increasingly prevalent in the past decade as state governments seek to increase the use of renewable energy sources. As a policy tool, RPS provide a cost-effective, market-based approach for meeting targets which promote greater use of renewable energy in both regulated and deregulated markets.

To facilitate the obtainment of Renewable Portfolio Standards, most states allow the trading of Renewable Energy Credits (RECs). RECs represent the environmental attributes of renewable energy generation which are decoupled from the generated power. These credits are created along with the generation of renewable energy, decoupled from

energy generation, tracked by regional systems, and eventually purchased by retail suppliers to fulfill their RPS obligations.

As of April 2010, RPS have been passed into law in 29 states and Washington D.C. and an additional 6 states have non-mandatory renewable portfolio goals however the U.S. government has yet to enact a Federal Renewable Portfolio Standard. Although the final requirements and details of a Federal RPS are undecided, federal standards would be unlikely to preempt or override state programs which are already in place. A key concern regarding the passage of a federal RPS is that a national REC market would result in a shift of wealth from states with few renewable energy resources and limited resource potential to regions richer in renewable resources. Because of the implications that a federal renewable portfolio standard would have on the economy, the environment, and the equitable treatment of all the states, many issues and concerns must be resolved before federal standards will be passed into law.

A theoretical case study for an electric utility generation planning decision that includes obligations to meet Renewable Portfolio Standard is presented here. A framework is provided that allows decision makers and strategic planning teams to: assess their business situation, identify objectives of generation planning, determine the relative weights of the objectives, recognize tradeoffs, and create an efficient portfolio using Portfolio Theory. The case study follows the business situation for Austin Energy as it seeks to meet Texas State RPS and mandates set by Austin City Council and prepares for potential National RPS legislation.

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RENEWABLE PORTFOLIO STANDARDS

Chapter 1: State Renewable Portfolio Standards

INTRODUCTION

Renewable Portfolio Standards (RPS) policies are enacted to promote the economic development of renewable energy resources. RPS policies require electricity providers to supply a minimum fixed percentage or total fixed quantity of customer load from designated renewable energy resources by a given date. Currently 29 states and Washington DC have mandatory renewable portfolio standards and six other states have nonbinding goals for the adoption of renewable energy (Figure 1).

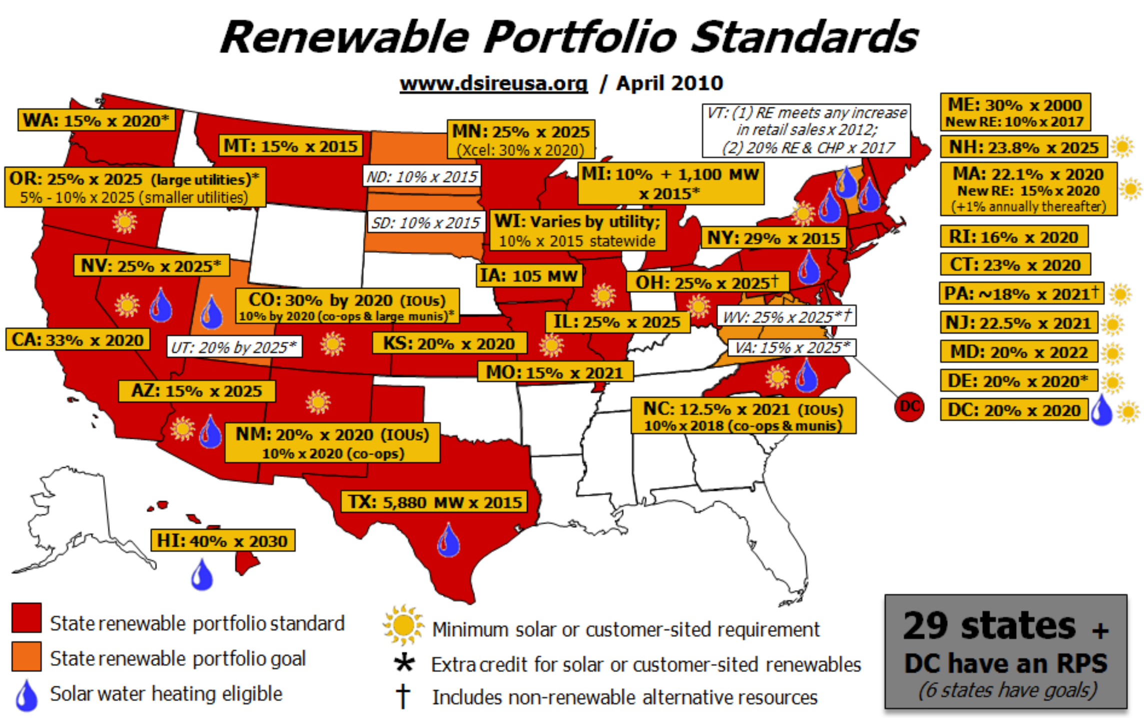

Figure 1: Renewable Portfolio Standards State Programs (United States Department of Energy, www.dsireusa.org)

Every state with RPS has taken a unique approach in the adoption of their standards or goals, and RPS policies vary tremendously among states depending upon the renewable energy potential of the region. Some State RPS policies lay out very stringent and specific requirements while others leave flexibility in the RPS which permits the market to dictate how the targets are achieved, allowing for the most cost-effective and practical solutions to be realized. As a general rule, RPS policies are designed with the expectation that the market will determine which projects and resources are the most cost-effective sources of renewable energy.

CURRENT STATE RENEWABLE PORTFOLIO STANDARDS

Retail Seller Obligations

The requirements posed by RPS are placed on retail sellers. Every state with RPS obligates investor owned utilities to meet the targets set forth in the standards. Municipal utilities and rural cooperatives are sometimes excluded from the obligations for the RPS or might have smaller targets to achieve. To meet RPS requirements, a retailer may either own a renewable energy facility which produces power or may purchase a certain portion of renewable energy generation from other producers through forward contract agreements or on the spot market.

For a retailer seller to receive credit for the renewable attributes of purchased renewable energy generation, electricity generated from the renewable resource may be directly delivered to the retailer. For this transmission to occur, electricity producers and retailers must be connected to the same grid. Any renewable energy used to meet RPS requirements in this way will therefore be in relatively close proximity to the load. Regionally-based renewable resource development would result.

Meeting RPS goals exclusively from generation connected to load is not always possible or practical. To facilitate the transfer of renewable energy that meets RPS when it is impractical or impossible to also transmit power production, renewable energy credits (RECs) may be used. RECs allow the decoupling of environmental attributes of renewable energy from the actual power that is generated. This allows retails who serve load to meet RPS requirements without actually purchasing the energy produced from renewable energy sources. Currently, every state RPS allows trading of RECs with the exception of California and Hawaii. Because RECs have significant implications on RPS, a later section will be devoted to further explanation.

Retail sellers will recover any RPS compliance costs from ratepayers through service rates unless the RPS specifically limits or restricts this practice. Colorado limits the surcharge that utilities may impose on customers as a result of the RPS to 2% of annual electric bills and municipal owned utilities may only charge an additional 1% of annual electric billing rates. Households in Connecticut pay a surcharge of about fifty cents per month to the Connecticut Clean Energy Fund to promote renewable energy generation that will achieve the RPS obligations of the state. After 2011 in Illinois, the net increase paid by retail customers is capped at 2.015% of the amount paid in 2007. Michigan has a monthly rate impact cap set as $3 for residential customers, $16.58 for small commercial customers, and $187.50 for large commercial and industrial customers. Other states like Texas allow retailers to recover RPS compliance costs from ratepayers but forbid retailers from passing on any costs of obtaining RECs. In Delaware, costs associated with penalties for non-compliances and alternative compliance payments are not recoverable through a surcharge on customer bills. Ohio likewise forbids ACP from being recovered through rates.

Renewable Portfolio Standards Design Elements

No two State RPS policies are the same. Each state implements RPS statutes differently with respect to their targets, schedule, resource and technology eligibility, the treatment of existing generation plants, enforcement and penalty systems, restrictions over the tradability of renewable energy credits (RECs), and other eligibility criteria. The Appendix provides a table as an overview of RPS Policy Design Elements by State.

Targets and Schedules

States must decide how large their goals will be by balancing the benefits sought against the costs of reaching a certain target. RPS targets will require either a percentage of energy sales or a fixed quantity (MW) of renewable energy be sold to customers. To keep retailer sellers on track to meet the long-term renewable energy goals by the target date, RPS will often require energy providers to meet yearly objectives. This scheduling feature increases the likelihood that the long-term goals will be achievable, and if they are not, then the regulatory entity designated by the state may enforce penalties for non-compliance or make other accommodations (i.e. make-up periods) to assist retailers in achieving RPS goals for future target dates.

A key distinction of each RPS is how set-asides (also sometimes referred to as "carve-outs") are designed, though they are not always included. Set-asides allow policy designers to promote key renewable energy sources by defining annual or final targets for specific classes of resources. Some resources are listed individually as set-asides, but more commonly resources are grouped in "tiers" or "classes" in order to establish different resource eligibility requirements for multiple sets of renewable energy purchase targets. These measures provide the administrator with more specificity of the realized generation mix than would be achievable without set-asides.

When evaluating the targets and eligibility requirements for any RPS, a notable difference to consider is whether set-asides or carve-outs are a percentage of total sales or are a percentage of the RPS. For example, a set-aside or carve-out for solar might be 1 percent of the RPS. If the RPS is targeted to reach 25 percent of total sales, then the set-aside/carve-out would effectively constitute only one percent of twenty-five percent, or 0.25%, of total sales.

Set-asides are frequently seen for solar resources or other technologies which are currently more costly than other renewable energy sources. New Jersey has one of the nation's most-ambitious solar targets. The set-aside for solar in New Jersey is currently slated to achieve 2.1% of total sales by 2020 (www.dsireusa.org), and is expected to result in 1,500 megawatts of solar capacity. This would represent the largest solar commitment per capita in the nation. Colorado notes its solar goals as a carve-out and as four percent of the RPS. The Colorado RPS is 5% of total sales for investor owned utilities in 2009, so solar generation will effectively comprise 0.002% of total power sales in 2009.

Another approach taken by states to incentivize specific renewable generation sources within a RPS has been to support preferred renewable resources with credit multipliers. When a credit multiplier is assigned to a specific generation source, the power generated from that source is given more weight than power from other resources in the generation portfolio. The quantity of power generated is multiplied by the value of the credit multiplier when determining how much power is applied toward meeting the RPS obligation. The RPS of New Mexico aggressively utilizes credit multipliers. For the New Mexico RPS, a 300% credit multiplier is applied to solar generation and a 200% credit multiplier applies to landfill gas, biomass, fuel cells using renewable sources, and geothermal energy. Generation from these sources would be applied to meeting RPS obligations at 3 and 2 times, respectively, the value of other eligible resources.

Credit multipliers may also be used to promote renewable energy generation on tribal lands or from non-combustible distributed generation by small generators which produce quantities below a certain threshold. Four of the original federal RPS policies under consideration (Bingaman, Markey, Waxman, and Udall) all included such multipliers for distributed generation, and the original Bingaman and Udall bills gave the additional consideration for tribal lands.

Alternatively, fractional credit multipliers may be used to promote certain generation sources at incremental levels. For instance, Michigan's RPS includes a 0.1 credit multiplier for generation from pumped storage during non-peak periods (State of Michigan S.B. 213). This small fractional multiplier promotes peak period generation from pumped storage above that from resources such as fossil fuels, which have zero weighting in the renewable energy portfolio, but to a lesser extent than renewable energy sources which have credit multiplier of greater values.

The effectiveness of any Renewable Portfolio Standard relies upon the creation of a viable and predictable market for a fledgling renewable energy industry. This market can be supported during its development through incremental or annual targets which supply steady growth to the industry beyond what would exist without the RPS in place. RPS policies are used to promote the development of the nascent renewable energy industry and support development that would not yet be economically feasible otherwise. Because RPS are not intended to support the industry indefinitely, schedules might include a sunset date. By this sunset date, the renewable energy industry is expected to be self-sustaining, and if RPS have been successful, renewable energy sources will be cost-competitive with other electricity generation sources.

Eligible Resources

The eligible resources selected for inclusion within each State's RPS are uniquely aligned with the state's political, economic, and environmental goals and limitations. The generic adjective "renewable" has no universal definition within RPS, and every state is free to determine which resources are eligible. To advance the policy goals of the state, eligible resources are selected from those which require financial support to enter or remain in the market. Policy goals which states consider when determining eligible resources include: environmental improvement, resource diversity, technology advancement, economic development, and public preferences (Radar, 2001).

When policy goals are linked to regional economic development, then restrictions for location eligibility are included to foster economic development locally. When resource diversity goals are desired, they will be achieved by specifying the resource types or quantities of generation from each resource. As a general rule, state RPS programs tend to favor renewable energy resources that coincide with the climate and topography of their region. States endowed with rich wind resources tend to favor wind within their RPS, and states with considerable solar radiation lean toward incentivizing solar energy. A quick review of United States maps depicting the allocation of renewable energy resources demonstrates how significant this disparity can be between regions (Figure 2).

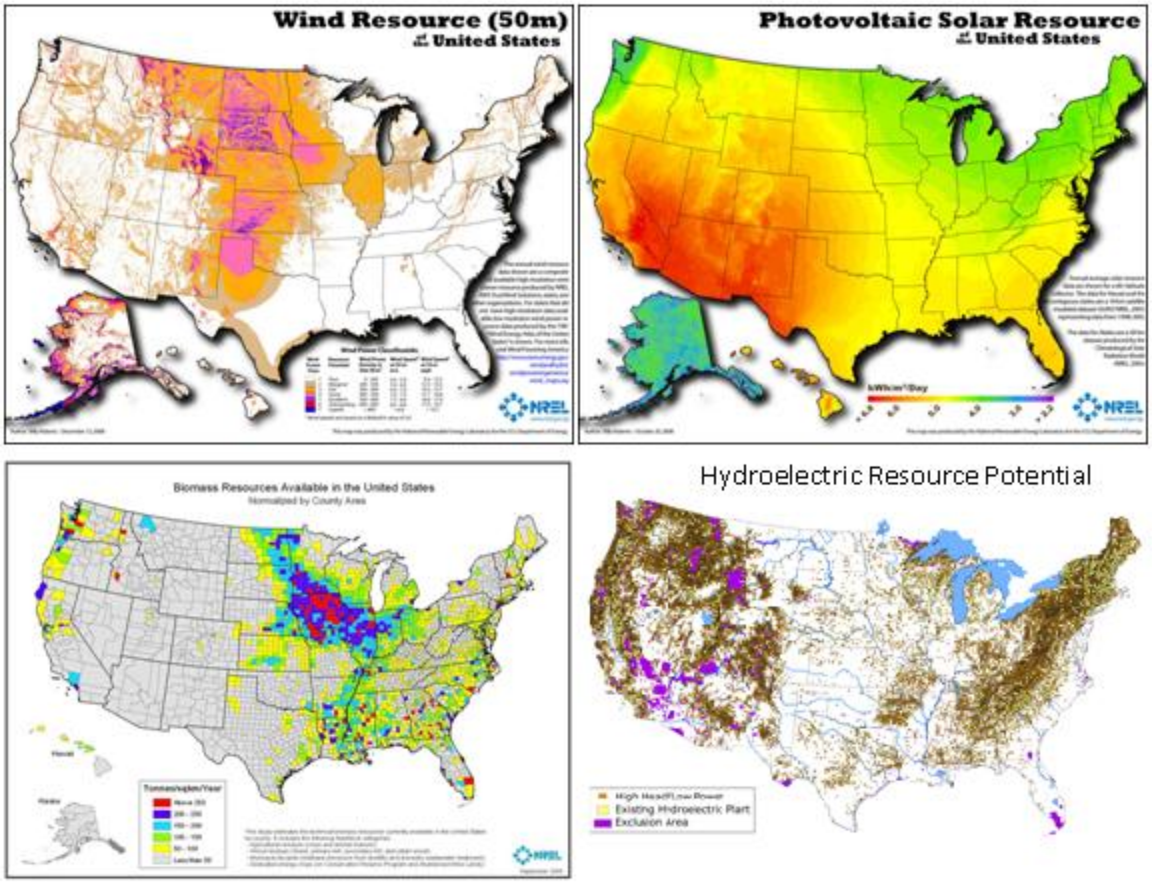

Figure 2: Maps of United States Renewable Energy Resource Distribution (NREL)

The renewable energy technologies eligible to meet state RPS requirements always include wind, solar, geothermal, landfill-gas, biomass, and at least some hydroelectric resources. Hydroelectric resources are not uniformly classified among state standards, and eligibility restrictions for hydroelectric power differ by state based on capacity, age, or design. Generation derived from biomass and municipal solid waste facilities often has eligibility restrictions based on fuel type or specific technology utilized, particularly in mixed-fuel facilities that include coal.

Taking a closer look at the dozens of technologies eligible across the span of state RPS, some of the more-unusual eligible technologies are highly-indicative of regionally economic development goals. These may not coincide neatly with standard environmental aims. Pennsylvania has considerable in-state coal resources, and much to the chagrin of environmentalists, generation from certain coal-derived sources is included in the Pennsylvania RPS. These include waste coal, coal mine methane, and coal gasification. The RPS for West Virginia was enacted in 2009 and the qualifying technologies are still under consideration, but the initial eligible resources include coal-derived resources similar to those permitted in Pennsylvania. Allowing these resources to be eligible for achieving RPS will promote in-state generation for West Virginia despite less-evident environmental gains. The generous inclusion of these coal-derived resources within the Pennsylvania and West Virginia RPS will maximize the ability of the state RPS to promote in-state economic development however this sacrifices some of the environmental objectives that other state RPS achieve.

Other unique qualifying technologies include North Carolina's set-asides for both poultry litter and swine waste. Montana allows all farm-based methane gas. Nevada includes waste tires using microwave induction and solar pool heating. Oregon allows spend pulp liquor. D.C. permits solar space cooling, and the list goes on. For all these resources and for other eligible resources, restrictions may limit the allowable quantity of purchased generation from any particular source and/or geographic locations from which purchased generation may be purchased.

A variation among State RPS is the eligibility requirements of pre-existing renewable energy sources. Age requirements might be placed on resources so that only the most-modern, and expectantly the most-efficient, facilities and new builds are eligible. Those RPS policies which exclude preexisting renewable energy sources presumably do so because these established facilities are already cost-competitive with other resources and future investment would be better-directed toward newer and emerging technologies which will diversity the generation mix.

Hydroelectric power generation demonstrates more variability than any other eligible renewable resource in regards to age requirements and other eligibility requirements amongst state RPS. The restrictions for hydroelectric qualification by state are sometimes in direct contrast with other state qualification requirements. For instance, Montana allows preexisting hydroelectric resources under ten megawatts capacity to qualify, and the Illinois RPS allows all hydroelectric facilities built prior to 2008 to qualify. Conversely, Michigan only allows generation from hydroelectric facilities built after 2008 to qualify, and New Mexico only permits generation from hydroelectric facilities built after July 2007. The difference between these RPS eligibility requirements indicates that Montana and Illinois value the current hydroelectric generation, but since the technology is mature and the industry is established, policymakers do not believe that new generation needs to be incentivized. Michigan and New Mexico on the other hand are interested in making new hydroelectric generation more economic and widespread.

Some programs will even allow a portion of the RPS to be met by investment in measures which avoid additional generation, like energy efficiency or demand site management. Some states which allow demand-side energy efficiency to help meet the requirements of RPS include Hawaii, Nevada, and North Carolina. Alternatively, mandatory energy efficiency standards have been established which are separate from or in combination with renewable portfolio standards for several states including Colorado, Connecticut, Illinois, Minnesota, New Jersey, New Mexico, Pennsylvania, and Texas. Efficiencies on the supply-side, such as electricity or heat from combined heat and power and waste heat recovery facilities, are also eligible for RPS in some states (e.g. Colorado, Connecticut, Hawaii, Illinois, Maryland, Nevada, North Carolina, and Pennsylvania). Fuel cells using non-renewable energy sources are permissible technologies in Arizona, Connecticut, D.C., Maryland, New York, Ohio, and Pennsylvania. Fuel cells using only renewable fuels are eligible in California, Colorado, Delaware, Hawaii, Massachusetts, Montana, New Jersey, New Mexico, Rhode Island, Vermont, and Wisconsin.

Enforcement Provisions

Energy companies which do not demonstrate compliance with RPS on an annual basis may be subject to penalties. RPS could potentially be enforced through many means, including electricity license suspension or revocation and fines. Some states provide allowances when RPS obligations are not met. These allowances may take the form of alternative compliance payments, compliance "make-up" periods, and statutory and discretionary waivers. Most state RPS policies include provisions which allow retailers to comply with the standards despite insufficient RECs and renewable energy generation, thus avoiding the need for agencies to enforce penalties. As of 2008 only two states had taken enforcement action for non-compliance: Connecticut and Texas (Wiser, 2008).

Alternative compliance payments (ACP) are penalties paid by energy companies who fail to comply with RPS obligations. Because the cost associated with an alternative compliance payment is predetermined and defined, an energy company need never pay more than this value to meet RPS obligations. Alternative compliance payments are essentially a cost cap for the upper cost that retailers can expect to pay for renewable energy even when supply shortages might otherwise cause abrupt increases in true cost for renewable energy. If renewable energy costs exceed the value of alternative compliance payments, then retailers will opt to pay the ACP. ACP set a ceiling for the highest expected cost to meet RPS requirements. The funds accumulated from ACP are oftentimes used to further the environmental objectives of the RPS. They may be directed to support renewable energy projects or energy efficiency within the state.

To contain costs, RPS may also specify that interim increases toward the goal be contingent upon the attainment of certain cost targets. For example, the Ohio RPS states that utilities may be released from compliance if renewable power costs more than 3% current market rates. Such clauses prevent the costs of RPS obtainment from increasing too abruptly or dramatically and are intended to protect ratepayers.

Enforcement practices sometimes are lenient, and several states have permitted compliance “make-up” periods. Make-up periods defer any penalty payments owed by retailers and utilities despite failing to meet an RPS target. If afforded such a make-up period, the offending retailer or utility will have as many as several years after failing to meet an annual target to compensate for the previous shortfall. California has a history of allowing utilities several years to make-up RPS obligation shortfalls (Wiser, 2008). In both Arizona and New York, limited funding available for utilities to meet RPS obligations has resulted in curtailed compliance. In some cases, waivers have allowed utilities to repeatedly under-comply with RPS requirements and still avoid any penalty charges. This has been the case in both Nevada and Minnesota.

Language in the Missouri RPS indicates that utilities may be excused from the RPS requirement if they can prove that "failure was due to events beyond its reasonable control that could not have been reasonably mitigated, or that the maximum average retail rate increase has been reached." In Missouri, the 1% rate increase maximum is calculated by comparing the estimated cost of compliance to the cost of energy from traditional sources, "taking into proper account future environmental regulatory risk including the risk of greenhouse gas regulation." With such limitations in place, utilities and consumers are protected from extreme fluctuations in electricity costs for obtainment of the RPS.

Although numerous states have allowed make-ups and issued discretionary waivers, Nevada's experiences with these allowances have been subjected to the most criticism. The two major retailers in Nevada (Nevada Power and Sierra Pacific Power) have repeatedly failed to meet annual RPS obligations (Stanfield, 2008). In 2007, Nevada Power fell short of its solar energy requirements by 42,272 megawatt hours, and Sierra Pacific Power fell short by 18,303 megawatt hours. The state allowed waivers to both utilities because the retailer's efforts to meet the solar portion of the RPS were in "good faith". Similarly, if extenuating circumstances have prevented retailers from meeting the obligations of the RPS, waivers may be issued.

Critics complain that such waivers are too lenient and that RPS obtainment is best achieved by issuing penalties for under-compliance. This may be true in some circumstances however Nevada Power did not cease to invest in renewable energy despite its early struggles meeting the RPS. In 2009, Nevada Power demonstrated in its first quarter compliance filing that it was finally in compliance of both its solar and non-solar requirement under the Nevada RPS.

Benefits and Costs

Renewable Portfolio Standards are designed to achieve many goals simultaneously. Their primary purpose is to stimulate market and technology development of renewable energy sources so that renewable energy sources will eventually be economically competitive with legacy technologies. The market-based policy approach of RPS creates a competitive market for these emerging technologies in renewable energy which might otherwise be too costly to compete with established technologies. Consequently, developers of renewable energy generation facilities and investors in these facilities are provided with some assurance that market demand will exist for their generation.

The Connecticut RPS experience provides some indication of how important this market certainty is for investors. Connecticut's RPS was enacted in 1998 and allowed legislators to amend details within the standard, including the definition of qualifying technologies and geographic extent of generation. This was supposed to give policymakers the opportunity to fine-tune the RPS to maximize its effectiveness, but the continual revisions proved to be a source of vexation for utilities, project developers, and regulators. In 2003 and 2004, prices for RECs hovered between $35 and $45 per REC in Class I (Holt, 2007). Connecticut has a fairly limited supply of in-state renewable energy potential, and presumably to promote in-state generation, two large biomass facilities were approved which use construction and demolition (C&D) waste. In late 2005, Connecticut Class I REC prices plunged to a low of $2 each (Zajac, Oct. 2008). Soon after, legislation was passed (P.A. 06-74) that banned construction and demolition waste, and prices then rose to $9 per for Class I RECs, and by 2007 prices were back up to nearly $30 per Class I REC.

The case of Connecticut's volatile REC market price is indicative of several important considerations when evaluating RPS and their economic impact. Firstly, investors who participate in markets with this much volatility and associated risk would rightfully apply a high discount rate to investments in RECs. Secondly, this emphasizes the significance of eligibility requirements for resources in an RPS. Changing the RPS to include just one more eligible resource, in this case permitting C&D waste facilities in Connecticut, altered the quantities of eligible generation already on the grid so dramatically that REC prices plunged by 95%. The task before policymakers is a challenging one. The decisions they make in creating Renewable Portfolio Standard policies are instrumental to establishment of REC markets, and effective REC markets provide maximum benefit in meeting environmental goals without burdening or hindering economic development.

Another tangential benefit of RPS policies is rural development, since renewable energy facilities are often in rural areas. The struggle with rural development projects for nearly every region of the country is that transmission constraints limit the ability of rural generation to reach urban load centers. Transmission issues complicate the potential of many rural renewable generation projects, and such projects in Wisconsin are no exception. Wisconsin's grid experienced some congestion at its southern border that was alleviated by new in-state renewable and fossil-fueled generation however the addition of new wind projects requires a stronger grid and upgraded transmission lines. Policy-makers in Wisconsin would like to promote this in-state source of renewable energy generation, but the ability to plan projects is a source of conflict because of the overlapping interests of parties including American Transmission Co. LLC (Wisconsin's largest transmission provider), the Federal Energy Regulatory Commission (FERC), Midwest ISO, and Mid-Continent Area Power Pool (Hug, 2009). The Upper Midwest Transmission Development Initiative, which includes members of Iowa, Minnesota, North Dakota, South Dakota as well as Wisconsin, is seeking resolution of these and other related transmission issues.

Since RPS are intended to increase the use of renewable energy sources while displacing fossil fuel generation sources, successful implementation of RPS can achieve air quality benefits. Additionally, increasing the percentage of renewable energy generation that contributes to the US electric power portfolio helps to diversify the nation's generation portfolio and reduces the risk of energy price volatility associated with fossil fuels. The next section of this thesis will elaborate on the significance of fuel price volatility and the significance this attribute can have in generation portfolio planning decisions.

Conclusions from cost-benefit analysis of RPS are varied because most RPS programs are relatively new and most reported studies are sensitive to variables which are highly uncertain. Because of the variations between State RPS policies, methodologies for comparison studies are also difficult to apply. In the states with RPS established as of 2007, a Lawrence Livermore Berkeley report estimated that the expected cost impact to ratepayers as a result of Renewable Portfolio Standards varies from modest energy price increases of 1%-5% and could potentially result in price decreases over the long run. Another RPS cost analysis concluded that ratepayers in a state without readily available renewable energy resources or generation infrastructure could see electricity premiums increase by 25 to 40 percent under the Waxman-Markey Bill, which included a Federal RPS (Hart, Feb. 2009).

Regardless of the ultimate costs imposed on or alleviated for ratepayers, Renewable Portfolio Standards will in principal diffuse compliance costs and benefits among all customers. Advocates cite this as a particularly positive feature of RPS policies. Since the benefits of increased renewable energy generation (i.e. diversified fuel supply, economic development, and environmental gains) are expected to be reaped by all customers, any costs are likewise borne by all customers. And, given that energy generated from renewable energy resources might be cost-prohibitive for customers who are not in closer proximity to these resources, RPS policies diffuse the costs of renewable energy for all customers because the true cost of renewable energy for any one customer might be disproportionally large.

Understanding the costs and benefits of RPS policies would assist policy makers as they design new policies or seek to redesign current policies that will achieve their objectives. To fully comprehend the costs and benefits of Renewable Portfolio Standards, future cost analysis of RPS should include treatment of transmission costs, integration costs, and capacity values. To provide meaningful analysis, a rigorous assessment of both the future costs of renewable technologies and fuel costs for natural gas and coal (with and without carbon legislation) is imperative.

Implementation

The design details of RPS were first discussed in California in 1995 (Wiser, 2007). This ushered in the first wave of State RPS policies in the late nineties. The first RPS enacted in the U.S. was Massachusetts in 1997. When California finally ended the discussion-phase and implemented RPS in 2002, thirteen states had passed RPS mandates into law. Renewable Portfolio Standards gained popularity as policy tools because they do not require an allocation of government funding. Currently, Renewable Portfolio Standards are mandated in 29 states and in DC and an additional six states have renewable portfolio goals. The majority of these were enacted through state legislation however two were established through regulatory channels (Arizona and New York). Both Colorado and Washington RPS were narrowly passed through voters' ballot initiatives. The first ballot initiative RPS was passed in Colorado, and since that time, Missouri and Washington have also enacted RPS through such voter initiatives.

Over the past decade, most state renewable portfolio standards have undergone major revisions which have increased and strengthened the renewable energy requirements. To further incentivize renewable energy, state and local governments and utilities have orchestrated numerous financial instruments, programs, and perks.

Depending upon the jurisdiction of the administering body, tax credits and deductions can be found for personal, corporate, sales, and property taxes. Rebates are also common. Grants, loans, and industry support provide stimulus for the private industry, and issuing bonds provides government entities the initial investment they need to develop renewable energy resources and promote distributed generation. To encourage owners of renewable energy generation facilities to produce electricity, production incentives are commonly in place. Other incentives include leasing and lease purchase programs, utility rate discounts, and goodwill.

Chapter 2: Renewable Energy Credits

Renewable Energy Credits as Compliance Mechanisms

The obligations set by RPS policies must be met by retail sellers and are dependent upon the criteria and restrictions set forth by the policy of the state. Most states allow retailers to trade renewable energy credits (RECs) which represent the generation of energy from renewable energy sources. Until recently California did not allow interstate REC trading, but currently, Hawaii is the only state which does not permit trading of out-of-state RECs. Other distinctions among state RPS regarding REC include the tradability of RECs, the verification scheme used to verify compliance within tradable and non-tradable programs, and the flexibility afforded to retailers in meeting their obligations.

States routinely govern the geographic extent of REC trading by either incentivizing in-state generation or by placing qualifiers on RECs which limit the tradability of credits. RECs increase the efficiency of RPS programs by relieving retailers of the need to own their own renewable energy facilities or purchase electricity directly from a renewable energy facility. RECs effectively allow retail electricity sellers to meet RPS requirements without actually purchasing the electricity generated from renewable resources.

In REC regimes, retailers may meet their requirements by buying and retiring easily-transferable credits. RECs effectively decouple renewable energy generation from the renewable energy attributes. This decoupling allows greater latitude in how energy and renewable energy credits may be bought and sold. By allowing retailers to trade their obligations, retailers are given the flexibility of purchasing tradable credits which verify that another producer has generated the required amount of renewable energy. This provides retailers greater flexibility in development and maintenance of their energy portfolios.

RECs are differentiated by the characteristics of the generation source which they represent and are sold as different products based on these attributes. RECs carry with them the attributes of the generation source and these attributes distinguish whether the RECs are eligible for meeting Renewable Portfolio Standard obligations. Similar to the eligibility rules governing renewable resource qualification, RECs must meet the technology, geography, age requirement, and size restrictions of the state RPS.

Additionally, RECs are distinguishable based on whether they are bundled with power, deliverability of power through the grid, and the bankability or vintage of the REC. The vintage of an REC is the date that the power was generated. RECs often have a shelf life that limits how long the credits may be banked. RECs have a three-year lifespan for RPS compliance in Maryland, Michigan, Missouri, Pennsylvania, Texas, and D.C. Renewable Energy Credits can be traded for up to four years in Minnesota and Wisconsin and five years under Ohio RPS. North Carolina RECs must be purchased within 3 years from being generated and used within 7 years of being acquired by the utility.

Since some sources of renewable energy generation are given extra weighting using credit multipliers (i.e. solar, distributed generation), RECs from these sources are sold at a premium. The price range for an REC has ranged from $0.10 to $692. RECs are virtually worthless in some states like Texas which has wind generation in excess to meet RPS. RECs for solar generation to fulfill the New Jersey RPS have been among the highest valued in the nation. Connecticut REC prices have been highly volatile historically because legislation may easily change the eligible technologies for the RPS and this affects the REC market.

Renewable Energy Credit Markets

Participants

Three primary entities are involved in functions related to the implementation of renewable portfolio standards: energy generation companies, retailers, and program administrators. Energy generation companies are those which produce electricity and sell it wholesale to retailers. If these companies are producing electricity from renewable energy sources in a state that includes REC trading as part of the RPS policy, then the generator will receive renewable energy credits for production. Retailers purchase power from these generators and then sell and distribute energy to consumers at the industrial, commercial, and/or residential level. It is the retailers who are mandated to retire RECs each year to meet RPS.

Tracking Systems

Program administrators are responsible for overseeing transactions and tracking RECs trading. Administrators rely on tracking systems to track renewable energy generation from units registered in the system. These systems allow data to be verified for the creation of RECs which characterize this generation. Most tracking systems in the U.S. are regional and are computerized to ensure that participants meet their RPS obligations while complying with RPS regulations and prevent RECs from being counted toward more than one State RPS. Tracking systems are most effective when they cover large regions. The larger the region and the more state RPS included in the tracking system, the more complex the systems might become. For tracking systems to be effective, they must accommodate the most inclusive state program within their region.

Currently seven such regional tracking systems have been established (Figure 3). Texas established the first tracking system in 2001. The system is managed by the

Electric Reliability Council of Texas, also known as ERCOT (https://www.texasrenewables.com/). New England Pool – Generation Information System (NEPOOL – GIS) was the second tracking system and began in 2002. NEPOOL – GIS covers Maine, New Hampshire, Massachusetts, Connecticut, and Rhode Island (http://www.nepoolgis.com/). In 2005 PJM-Environmental Information Services (PJM-EIS) began operating the Generation Attribute Tracking System (GATS) (http://www.pjm-eis.com/index.html). GATS handles environmental and emission reporting and tracking renewable energy credit trading for Delaware, Maryland, New Jersey, Pennsylvania, Ohio, and the District of Colombia. Nevada has its own tracking system known as Nevada Tracks Renewable Energy Credits (NTREC) established in 2007. Two other tracking systems were initiated in 2007 as well: the Western Renewable Energy Generation Information System (WREGIS) (http://www.wregis.org/) and Midwest Renewable Energy Tracking System (M-RETS) (http://www.mrets.net/). WREGIS covers the same region as the Western Electricity Coordinating Council (WECC) and includes all or part of fourteen western states, two Canadian provinces, and a portion of Baja California in Mexico, and M-RETS is designed for North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, and Illinois and part of Canada. The most recent tracking system was created in October 2009 and is the Michigan Renewable Energy Certification System (MIRECS) for the state of Michigan.

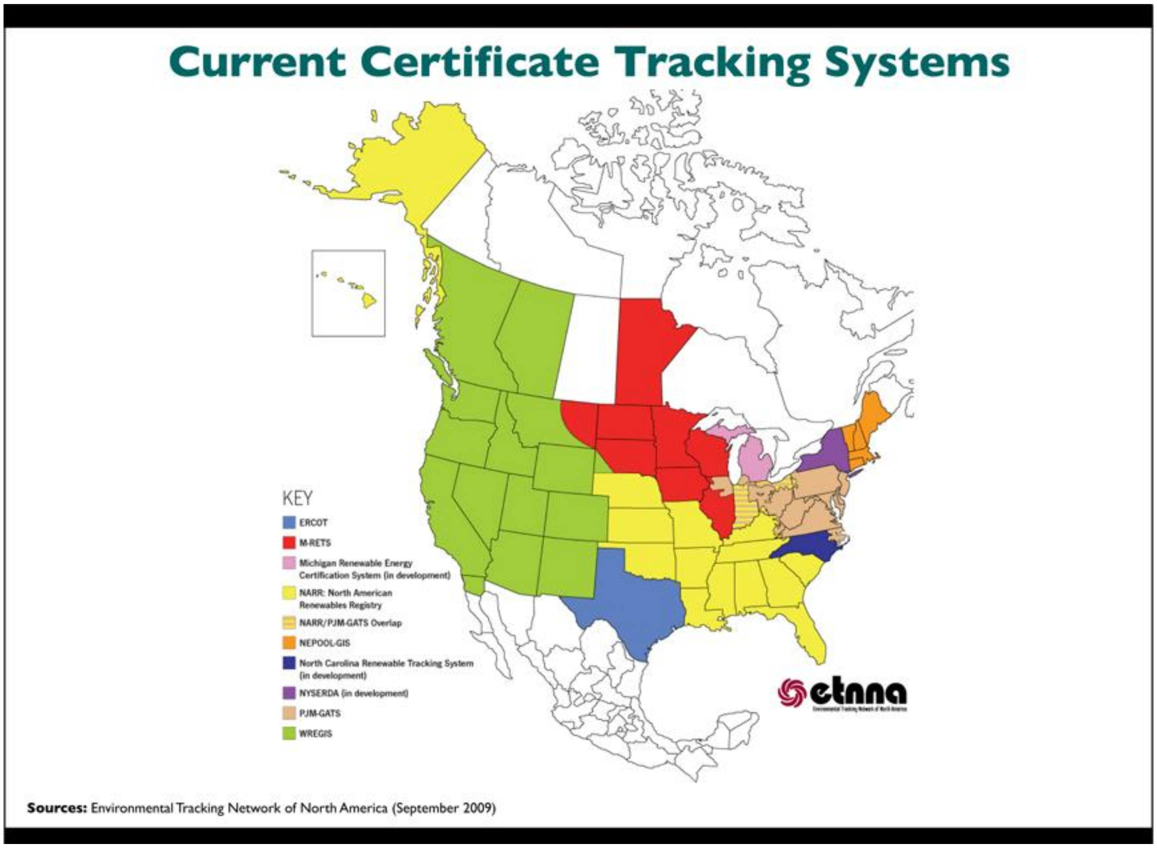

Figure 3: Map of Current Renewable Energy Credit Tracking Systems of North America

Five of these tracking systems use market infrastructure provided by one company, APX Inc. (Zajac, Feb. 2009). These five REC markets include: PJM (GATS), ISO New England (NEPOOL GIS), WECC (WREGIS), Upper Midwest (M-RETS), and ERCOT (Texas REC). APX Inc. is currently working on an additional tracking system for areas of the US not covered by other REC markets. This includes southeast and central states as well as Alaska and Hawaii. This tracking system is known as the North American Renewables Registry (http://narenewables.apx.com/). With this additional market coverage, all of North America will have a tracking system in place. APX is clearly anticipating the passage of a federal RPS or additional state RPS by taking strides to enhance the likelihood that they will ultimately provide market infrastructure for a national or continental tracking system. Linking all these systems would be a next step toward this goal.

Renewable Energy Credit Trading

In states where RPS policies allow REC trading, other entities may be involved in these markets. Brokers can facilitate REC transactions by offering a one-stop shop for market participants. Additionally, in an effort to increase the demand for RECs, environmental groups or foundations may purchase RECs themselves, thereby removing these credits from the market. These market participants vie for purchasable RECs along with retailer suppliers who supply power from generation sources not eligible under RPS and are therefore required to buy RECs from a broker or another generator to meet their obligations under the State RPS.

RECs are traded in long term contracts, shorter term contracts, or through spot purchases. For regulated utilities, these excess costs may be recovered through standard ratemaking proceedings (Chen, 2007). Less certainty for cost-recovery is available in unregulated markets, though excess costs would be expected to be passed on to electricity consumers unless regulations strictly prohibit this practice. For example, Texas is one state that explicitly precludes retail electric providers from simply "passing on" costs for RECs, and Delaware and Missouri do not allow ACP fees to be passed on to customers through rates. Because it is more difficult for deregulated utilities to recoup costs associated with RPS, the financial risks associated with RPS could deter investment in deregulated markets.

Some utilities are trying to recoup costs associated with fulfilling RPS obligations during the project development phase. In September of 2009, E.ON's Kentucky utilities sought to recover contract and transmission costs associated with a 109.5 megawatt wind power purchase agreement through a rider on customer bills (Bleskan, 2009). The request was complicated by the fact that ratepayers would be subject to this fee prior to the delivery of any electricity from the power purchase. The fee would not represent a profit or finance charge to benefit E.ON but would allow the utility to establish a tracking mechanism for the pass-through recovery of costs. E.ON's attorney Kendrick Riggs claims this would be a "single, extraordinary and volatile expense." This case brings to light the struggles faced by investors who want increased assurance of return on investment for renewable energy projects in any market, and the difficulties that utilities face obtaining this cost recovery through rates.

Regulated markets provide investors with more certainty in cost recovery, and deregulated markets may not drive sufficient investor activity to support generation investment in renewable capacity development. President and CEO of Duke, Jim Rogers, expressed belief that deregulated markets are less-suitable to renewable energy development and overall carbon emission reduction when he spoke in early December 2009 during a climate conference in Dallas sponsored jointly by the National Association of Regulatory Utility Commissioners and the National Council on Electricity Policy. Rogers asserted that states which are deregulated need to consider reregulation. His concern is that meeting clean air goals (with or without RPS) is a challenge that is best met by regulated utilities (Boshart, December 2009). He claimed that new generation is generally being built in regulated states where generators have more assurance that they can recover costs. Additionally, Rogers voiced that if policy makers are interested in reducing carbon emissions, this can be better achieved not by setting RPS but rather by setting low-carbon standards that can be met by a broader range of portfolio sources, including natural gas and nuclear. Worth-noting is that Duke is heavily invested in

Southeastern U.S. energy markets and relies on nuclear and natural gas generation. This region of the U.S. has limited regional renewable capacity.

RECs and Carbon Emission Regulation

Because RECs carry with them the attributes of the power generated, a dilemma arises concerning the double-counting of RECs to also meet carbon compliance regulations. Before any national cap-and-trade legislation is passed this important issue of REC trading will need to be addressed. The primary issue is whether emissions allowances should be retired under state RPS. Those who argue for the retiring of emissions allowances under RPS assert that many states expect RPS policies to provide environmental benefits including decreased emissions. With the retirement of allowances, emissions are incrementally reduced. Those who favor the exclusion of emissions allowances from a REC and from RPS compliance would like emissions to instead be freely traded should a cap-and-trade regime be established. With these emission allowances available (but not required by RPS), renewable generators would be free to sell the allowances and earn additional revenue (Holt, 2009).

Two regions have begun to address the issues of double-counting of renewable energy attributes toward both RPS and carbon obligations. Both the Western Region Electricity Generation Information Systems (WREGIS) and Regional Greenhouse Gas Initiative (RGGI) prevent the double-counting of REC generated through state RPS to also count toward carbon compliance (Zajac, Feb. 2009). The WREGIS tracks REC trading in the western US, and a separate organization the Western Climate Initiative (WCI) addresses carbon objectives for seven of these same western states and four Canadian provinces. The RGGI is an initiative in ten Mid-Atlantic and Northeast states (http://www.rggi.org/home).

By not allowing utilities and industry to strip-out attributes of the REC to meet additional compliance obligations, retailers and industry must buy additional RECs or qualifying power to meet their carbon compliance obligations under the WCI and the RGGI obligations. This represents an additional cost for retailers that will likely be passed through to consumers. This precedent might not be politically palatable in other regions if the cost of meeting both renewable and carbon objectives is a significant expense for ratepayers in the region.

As other regions which include state RPS begin to address carbon concerns using cap-and-trade systems, they will need to assess how best to track and permit attributes from renewable energy generation toward meeting obligations set forth by multiple standards or initiatives. The same is true for any federal RPS legislation under consideration. An “additionality test” has been used by regulators to assess whether the cap-and-trade legislation and the incentives of the carbon market led to the additional generation with a reduction of carbon emissions. To achieve maximum environmental benefit from both RPS and carbon markets, the additionality test assures that these policies are incentivizing new generation to come online and will reduce overall carbon emissions into the atmosphere. This is easier to explain in theory than to implement in practice.

To test for additionality, project financing can be examined to determine of the project would have been undertaken without the carbon or renewable market incentives in place (Zajac, Feb. 2009). This can be clearly assessed in projects like coal mine methane capture, which would never be undertaken without the incentives of a carbon market. For wind energy projects, the additionality test is less straight-forward to interpret because no carbon reduction occurs at the wind generation site but rather the replacement of fossil fuel generation results in reduced carbon emissions per megawatt of energy output. Therefore a wind project would not get double-credits (both renewable and carbon credits) but only a renewable generation credit in WIC or RGGI regions.

Any federal RPS will need to be explicit in establishing a standard for handling RECs and carbon credits. The issues associated with additionality testing and double-counting have been drawn out because clear winners and losers will emerge once rules are set in place. A federal RPS will work best if it dovetails with current state and regional programs and policies, and tracking systems must be compatible with the most inclusive state policies. California has the most-stringent RPS, and the WIC precludes the double-counting of generation toward carbon and renewable obligations.

Regional Greenhouse Gas Initiative

The first mandatory US cap-and-trade program was launched in 2008 and is known as the Regional Greenhouse Gas Initiative (RGGI). The goal of RGGI is to reduce carbon dioxide emissions from electricity generation in ten Mid-Atlantic and Northeastern states by offering a cap-and-trade program for fossil fuel-fired electric power plants generating 25 megawatts or more annually. The program is administered by RGGI Inc., a non-profit corporation established to provide services to the RGGI participating states and achieve an objective of ten percent carbon dioxide emission reduction by the power sector by 2018 (http://www.rggi.org/home).

The ten eastern states which participate in RGGI are Connecticut, Delaware, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. These states have control over how their allowances are issued. The majority of allowances are offered through quarterly auctions. States offer all or a percentage of their allowances at auction and allocate remaining allowances to other special interest groups and carbon emitters.

Auctions are open to members of the energy, financial, and environmental sectors. The auctions start at a reserve price, as determined by an independent market monitor Potomac Economics. The reserve price is set at eighty percent of the then current market price of allowances. The auctions are held in a sealed-bid, uniform-price format. This is conducted by having a single-round of sealed bids, and the clearing price for the auction is the value of the highest rejected bid. The highest bids are satisfied first until all credits are allocated. The price is then set at the highest priced unsatisfied bid, which is the price paid by the winning bidders.

In the first RGGI auction for carbon dioxide allowances, over twelve and a half million credits were sold at a price of $3.07 per short ton of carbon dioxide. The price peaked at the third auction in March 2009 when over 31.5 million credits were sold at a clearing price of $3.51 per ton of carbon dioxide. The number and price of credits steadily declined for the remainder of 2009, and in early December 2009 just over 28.5 million credits were sold at a clearing price of just $2.05 per short ton of carbon dioxide (http://www.rggi.org/co2-auctions/results).

Standardization

Currently, generation and tracking to meet state RPS policies are coordinated using one of seven regional tracking systems. Should a federal RPS be enacted, a national tracking system would most-likely need to be developed that could incorporate the entire continent. Power transmitted across international borders from Canada and Mexico would also be tracked using the system. A system would need to track REC generation, trading, and retirement using a standardized format. The standardization of RECs poses a dilemma. Credits sold by the RGGI only differentiated by vintage and delivery so standardization is simple, the market is highly liquid, and price transparency is maintained. This standardization is achievable because convoluted policy tools such as multipliers and allocations are not incorporated in this market, allowing the products (which are the carbon credits themselves) to be easily transferrable.

RECs have yet to be standardized because of the unique criteria of each state RPS which differentiates the RECs used to meet each state's obligations. The fragmented RECs markets allow customizable credits to be traded that meet state RPS policy objectives, but this limits the liquidity and transparency of REC markets. Brokerage shops facilitate the liquidity of REC markets, but with so many characteristics differentiating REC products, the seven regional REC markets covering thirty state RPS policies will require significant modifications before broader-reaching tracking systems can be used which mimic the RGGI or SO2 markets. Linking these REC markets through tracking systems and implementing national RPS will be challenging, and the effects of any regulatory changes devised to create a patchwork system will impact existing markets, and this poses a source of uncertainty for investors and utilities.

DORMANT COMMERCE CLAUSE

In an effort to promote in-state and regional economic development, states have adopted various measures and restrictions on REC trading. Policy makers who wish to promote economic development using RPS will often do so by placing geographic location restrictions on permissible generation resources. These eligibility rules have significant implications for REC markets and could potentially give rise to objections that some RPS policies violate the Interstate Commerce Clause, also known as the Dormant Commerce Clause.

States vary in their approach to promoting in-state and in-region development, as well as in their interpretation of the Interstate Commerce Clause. States that enact RPS policies typically prefer that new resource development occur within their own state or region. If transmission of renewable electricity is required for RPS compliance rather than unbundled RECs, then the electricity must be delivered from generator to retailer and then on to consumer. This transmission of electricity necessitates that the energy source be connected through the grid to the end user. This would guarantee that the supplier and end-user are in relatively close proximity and most-likely in the same state or region. This would coincide with in-state and regional economic development goals.

For practicality's sake, no state requires that electrons are tracked in such a manner and every state except Hawaii allows the trading of RECs to represent the renewable energy attributes. For states that permit RECs trading, the electricity and RECs are unbundled. This allows retailers to purchase RECs without any geographic constraint and without location limitations if the generation is otherwise eligible under the state's RPS policy.

The Renewable Portfolio Standard in California is distinct in many respects. Despite being connected to other states through the Western grid, until recently California's RPS did not permit REC trading. California was the only state to prohibit REC markets other than Hawaii. The California RPS has been in transition for many years. Previously targeted to obtain 25% renewable energy by 2020, Senate Bill 14 and Assembly Bill 64 have together been introduced to raise the standard to 33% renewable energy by 2020 (Finerty, 2009). This is the most ambitious target in the United States and would have been virtually impossible to obtain with the previous restrictions precluding REC trading. To make the objective easier to achieve, the companion bills created a market for RECs which is a boon for utilities obligated to meet the RPS.

The California Public Utilities Commission (CPUC) struggled for over five years to unbundle energy and RECs sold under contract. As of March 2010, tradable renewable energy credits (TRECs) may now satisfy the California RPS. No more than 25% of any utilities renewable procurement obligation may be satisfied with TRECs and TRECs will remain under a price ceiling of $50 per credit (Stanfield, 2010). The new rule will expire at the end of 2011, but the CPUC can then reevaluate the rules and consider whether to renew, modify, or eliminate them.

Since energy suppliers in the state can now source RECs from out-of-state REC markets, some stakeholders are concerned that this policy will inhibit new in-state job growth in the green energy sector. With the successful implementation of a liquid interstate REC market, RPS compliance costs will be reduced however investment in renewable generation may be transferred to adjacent states with lower costs for renewable projects. From a regional perspective, the environmental benefits gained by RPS are achieved regardless of the location of the generation though in-state economic development benefits may not be as apparent with the interstate REC market in place.

A variety of policy tools have been adopted by other states to incentivize in-state generation of renewable resources. Colorado applies a credit multiplier to in-state generation. Michigan has applied an unusual 1/10 multiplier to renewable energy generated from equipment that was made in the state. Washington DC dictates that solar requirements met through the purchase of RECs from resources that are not connected to the district's grid can only be purchased after the supplier exhausts all opportunity to meet this requirement via projects that are connected to the grid (Hart, 2008). The District currently imports 98% of their electricity, and would like to see more generation sourced locally. Because restrictions in Washington D.C. limit the height of buildings to thirteen stories, interest in rooftop solar has gained some momentum (Harrington, November 2008). North Carolina limits out-of-state generation eligibility to only 25% of the total sales to fulfill RPS requirements. Out-of-state generation facilities must be first approved by the New Jersey Department of Environmental Protection to be eligible for the New Jersey RPS. It is not infrequent for state RPS to dictate that out-of state generation may only be pursued and purchased after all in-state renewable generation resources have been exhausted.

Only states which have sufficient in-state renewable energy potential can consider placing requirements on in-state generation however, even if a state has renewable energy potential, if the generation is unable to reach market because of transmission limitations it cannot contribute to achieving RPS goals. As noted earlier, transmission constraints for rural renewable generation projects are an obstacle facing many regions of the nation. Rural renewable generation that spurs rural development may be a positive characteristic of increasing the renewable generation requirements through RPS, but if rural power cannot reach load centers then this power will not contribute to achieving the other goals implicit in RPS.

FEDERAL RENEWABLE PORTFOLIO STANDARD

National RPS Status

Although RPS have been passed into law in 29 states and Washington D.C. and an additional 6 states have non-mandatory renewable portfolio goals, the U.S. government has yet to enact a Federal Renewable Portfolio Standard. The U.S. Senate has passed a renewable electricity standard bill on three occasions between 2002 and 2007. The House of Representatives passed a compromise standard as an amendment to a larger energy bill in 2007. A filibuster in the Senate blocked the RSP from being included in the final energy bill. Had the House RPS passed, it would have set standards to 15 percent by 2020 and allowed utilities to meet up to 4 percent of the requirement through energy efficiency investments.

With Democrats currently in control of both The Senate and The House, RPS legislation has many proponents in congress. The House of Representatives and Senate began reviewing new legislation in early 2009 that included renewable portfolio standards as part of the Waxman-Markey Bill. The Waxman-Markey Bill passed in the House by a narrow margin, but the bill is unlikely to clear the Senate without major modifications. Now that President Obama has successfully passed healthcare legislation, he has the ability to turn his attention to other public concerns, including climate legislation. As of late April 2010, climate legislation is being developed by Senators John Kerry, Joe Lieberman, and Lindsey Graham however the passage of comprehensive national carbon legislation in the form of cap-and-trade or a carbon tax, with or without additional RPS, is more likely in 2011 than 2010 (Lum, 2009).

Although the final requirements and details of a Federal RPS are undecided, it is unlikely that federal standards would preempt or override state programs which are already in place. States will always have the authority to adopt or enforce state RPS which are more stringent than federal policies, but all states will be responsible for meeting federal regulations regardless of state policies. The stringency of RPS can include the spectrum of utilities and retailer sellers which are covered, resource eligibility, and target percentages and dates.

Proposals for Federal RPS have generally assumed that RPS would replace the Federal Production Tax Credit. Generation applied to state RPS requirements would presumably also count toward federal targets, unless states make different arrangements. Established State RPS would be maintained given the complexity of the programs and state-specific considerations.

During the third quarter of 2009, the year-on-year third quarter financial allocation toward state and federal lobbying efforts of California's largest electric utility

Pacific Gas and Electric Co. (the utility subsidiary of PG&E Corp.) quintupled as the company lobbied for climate legislation (Lehman, 2009). California already has the most ambitious RPS targets in the nation which is a 33% target by 2025, and PG&E is responsible for meeting this standard set by the state. If a federal RPS is passed that has a smaller renewable energy target, then PG&E would have excess federal RECs. These federal RECs could then be sold to areas of the nation which have less renewable energy generation resources and provide PG&E with a steady source of additional profit. Clearly, PG&E has much at stake in the national and statewide debates over climate legislation and receiving federal allocations for relevant projects.

Additional Considerations

National

Before any federal legislation passes, concerns regarding the intermingling of a potential federal REC program with preexisting state and regional programs must be addressed. Proponents of a federal program attest that a national market for RECs would reduce the cost of renewable energy technologies by creating a national market to promote the most cost-effective renewable energy sources. Opponents claim that a federal RPS would unfairly disadvantage states with limited renewable resource potential (see Figure 2) and that the trading of RECs in a national program would effectively constitute a tax burden on states with minimal renewable potential to states with more renewable energy resources and the infrastructure for REC markets already in place. Resistance is particularly strong in the Southeast, where policymakers worry that the region's lack of wind and hydroelectric resources could make it expensive to meet any standard.

Clearly, because of the implications that a federal renewable portfolio standard would have on the economy, the environment, and the equitable treatment of all the states, many issues and concerns must be resolved before federal standards will be passed into law. Policymakers must balance the cost of a renewable energy mandate that spans regions with dissimilar renewable resource availability. This inequitable distribution of resources is a pressing concern that must be remedied to allow for the passage of a federal RPS.

Few states in the Southeast have adopted State RPS. This is indicative of the relatively low income of these states and the lack of resources which provide the most cost-effective renewable energy generation: hydroelectric and wind. Although the Southeast has adequate solar potential, solar energy technology is still relatively costly compared with the other dominant energy resource technologies. The Southeast has considerable nuclear energy already online, but currently no state RPS allows nuclear generation to meet RPS obligations. Since the actual generation of energy from nuclear fission does not emit any carbon dioxide, it can be argued that nuclear energy should be included in a Federal RPS. This argument assumes that limiting carbon dioxide emissions is a key goal of Federal RPS however other objectives are also important drivers of RPS policy adoption.

Since states vary considerably in their designation of hydroelectric power eligibility, a national RPS would likely exclude some hydroelectric resources that are included within some state RPS unless all hydroelectric power is deemed eligible. Additionally, the inclusion of non-generation measures such as energy efficiency and demand-side management must be defined and established.

One of the most crucial aspects of a national RPS will be defining how aggressive the mandate will be. These details include the total percentage of renewable energy required and the schedule for obtainment of incremental and final goals. President Barack Obama has called for ensuring that 10% of the nation's electricity comes from renewable resources by 2012, with 25% from renewable resources by 2025. The final bill adopted by Congress however is still uncertain. The Bingaman Bill, by Senate Energy and Natural Resources Committee Chairman Jeff Bingaman, Democrat of New Mexico, would create a 20% by 2021 standard, with 5% coming from increased energy efficiency (Hart, March 2009). The Waxman-Markey Bill, by House Representative Edward Markey, Democrat of Massachusetts, calls for 25% of the nation's electricity to come from clean energy sources by 2025 (Hart, Feb. 2009). Neither of these bills has yet to clear both the House and Senate and considerable negotiation will occur before policymakers sign off on any such plan.

International

International concern is growing about climate change and this is encouraging nations to take measures which reduce carbon emissions. A recent study by the U.S. Environmental Protection Agency found "overwhelming" evidence that carbon dioxide emissions threaten public health, and the EPA is advocating that the US congress pass legislation in conjunction with EPA regulatory oversight that will mitigate carbon dioxide emissions in the US (Hart, 7 Dec. 2009). The EPA Administrator Lisa Jackson acknowledges that U.S. action alone will not impact world carbon dioxide levels but believes that the US should take steps to mitigate emissions regardless. Critics attest that the lack of international agreement on steps to abate carbon dioxide will hinder the US if it takes further carbon dioxide abatement measures without similar steps taken by all nations.

Additionally, the Competitive Enterprise Institute (CEI) intends to file suit against the EPA endangerment findings claiming that global climate change models are not holding up. A senior fellow of CEI Marlo Lewis has attested that EPA regulation of carbon dioxide emissions would “trigger costly and time-consuming permitting for tens of thousands of previously unregulated small businesses under the Clean Air Act” (Hart, 7 Dec. 2009).

Late in 2009, a scandal surfaced that scientists from the UN’s Intergovernmental Panel on Climate Change allegedly manipulated global climate data (Hart, 2 Dec. 2009). Several years of emails were hacked from U.K. Climatic Research Unit at the University of East Anglia and posted online. Some of the e-mails suggest that prominent climate researchers were manipulating scientific data to support their theory. The concern is that key studies were compromised, laws were broken, and climate change research deliberately obscured or manipulated.

Senator James Inhofe, Republican of Oklahoma, asked Barbara Boxer, Democrat of California, who is the committee chairman of the Senate Environment and Public Works Committee, to hold hearings to investigate the issues involved and the implications for proposed cap-and-trade legislation. Inhofe argued that the e-mails could have,

> far-reaching policy implications, affecting everything from (to name a few) cap-and-trade legislation, state and regional climate change programs, the Environmental Protection Agency's 'Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act,' the US Global Change Research Program, global climate models used by federal agencies, the Department of Interior's coordinated strategy to address climate change impacts, and international climate change negotiations.

Regardless of whether emails by climate change scientists contain indications of any misrepresentation of data, the animosity that is evoked by these allegations is significant. It is not clear whether these allegations will affect or potentially diminish the passage of climate change policies however the impassioned response stirred by these allegations is indicative of how contentious the debate regarding climate change policies has become for parties involved on the international stage.

Other Obstacles to RPS Obtainment

Renewable energy resources such as wind and solar energy are dependent on intermittent weather patterns. The availability of energy derived from these sources is subject to the unpredictability of weather. Because energy demand must be met in real time and large scale storage technology is not very limited, renewable energy resources further complicate economic dispatch modeling used by system operators to match supply and demand in real time. If renewable energy technologies are improved in tandem with storage technologies, renewable portfolio standards will provide maximum benefit and system reliability can remain unimpaired.

FINAL REMARKS ABOUT RPS

Renewable Portfolio Standards offer policymakers an attractive approach to increasing renewable energy generation with only a minimal outright expenditure by governments. Because RPS policies are based on a market approach, they have become a popular policy tool implemented by state governments, and over half of the US is currently under a RPS policy. State Renewable Portfolio Standards are relatively new policies and few states have more than a decade of experience with RPS. Because most state RPS are only a few years old and given the variations between the qualifying technologies, targets, and other factors among state RPS, comparative analysis between policies and conclusive cost/benefit analysis are difficult to assess. Most state legislators agree that implementing a market for Renewable Energy Credits allows RPS to achieve maximum effectiveness, and the only state with a RPS that precludes REC trading is Hawaii. Regional REC markets are under transition as increasing numbers of states implement state RPS policies and establish REC trading within RPS. Efforts are underway to create a continental tracking system to incorporate the many state RPS policies and provide a one-stop shop for REC trading. A national REC market would need to be established should a federal RPS policy be instituted.

The popularity of RPS as a regulatory instrument that incentivizes renewable energy generation and promotes benefits associated with these resources seems to be gaining momentum. With democrats in control of both the House and Senate, a Federal RPS is again under consideration and could pass as early as 2010 or 2011. Because of the implications a federal renewable portfolio standard would have on the economy, the environment, and the equitable treatment of all the states, many issues and concerns must be resolved before federal standards are likely to be passed into law.

PORTFOLIO ANALYSIS

This section introduces and describes a conceptual framework which could be used by utilities, policy decision-makers, and researchers of power systems to assess and compare generation portfolios for long-term electric generation planning. This methodology is an integration of decision analysis, Portfolio Theory Analysis, an Integrated Resource Planning (IRP) study by the LBJ School of Public Affairs (Eaton, LBJ, 2009), and a five-step process devised by the National Regulatory Research Institute (NRRI) for evaluation of generation portfolios. To demonstrate the rational for and the insight provided by this methodology, it is applied to a theoretical case study for a municipal electric utility contemplating how to minimize the cost and risk associated with meeting Renewable Portfolio Standard obligations.

The National Regulatory Research Institute devised a five-step strategy to evaluate generation portfolios that provides state commissioners and other decision-makers with a method to assess and analyze long-term generation portfolio and procurement options while utilizing the benefits offered by Portfolio Theory. This procedure offers a simplistic, standardized method for reviewing generation portfolios. By using that framework and then adding decision analysis techniques to a deterministic IRP study completed by LBJ students, a methodology is developed and demonstrated here that allows Portfolio Theory Analysis to be applied to a Renewable Portfolio Standard obligation decision. This technique is a value-creating strategy for generation portfolio selection.

This section demonstrates how the strategic planning team of a municipal electric utility would use this decision analysis process to: identify objectives and conduct a business assessment, develop alternatives, evaluate the alternatives using Portfolio

Theory, and develop plans for action. The portfolio approach allows the strategic team to identify ways in which generation technologies can complement each other within a generation mix. This in-turn allows decision-makers to be better equipped to weigh the tradeoffs of different objectives and determine the alternative that best achieves the utility's objectives.

NRRI applies the following five-step procedure for determining an appropriate generation portfolio. It can be easily adapted to review and analysis of Renewable Portfolio Standards. Each step would be subject to a regulator's judgment and discretion but simply stated are as follows:

- Identify the objectives of generation planning
- Determine the relative weights of the objectives
- Identity the inherent characteristics of individual technologies
- Recognize and accept "trade-off" effects
- Create an efficient portfolio using Portfolio Theory.

Applying this methodology to a theoretical case study while integrating decision analysis techniques provides a readily-transferable course of action for policy makers, regulators, and strategic planning teams faced with decisions regarding any generation portfolio decision-making including the creation or adoption of Renewable Portfolio Standard obligations. The approach detailed in this section utilizes the decision analysis cycle which aims to assess the situation, to thoroughly consider alternatives, to illuminate sources of uncertainty, and to create value-driven plans for action. Ultimately, the insight provided through this process and case study could be used by decision to determine if they have an adequate budget to meet their goals and whether the budget is allocated effectively (Matheson, 1989).

Chapter 3: Case Study Austin Energy

BACKGROUND

This application of generation portfolio planning for renewable portfolio standards will be directed to a theoretical case study of Austin Energy. As a municipal electric utility, Austin Energy (AE) has the sole responsibility for servicing the greater Austin area. Since Austin Energy does not compete with any other utilities for customers within this region, AE is a regulated monopoly and must make long-term generation planning decisions that will adequately meet future load growth in the entire region by providing reliable and affordable service to all their customers. As owners and operators of generation assets and purchasers of long-term generation forward contracts, Austin Energy is presented with a unique decision-making opportunity to utilize decision analysis and portfolio analysis tools to maximize the likelihood of procuring a generation portfolio that minimizes costs and risk. The outcomes of AE's decisions regarding long-term generation planning are likely to impact the utility's future profitability, access to customers, customer electricity rates, and continued ability to contribute assets to the City of Austin.

The state of Texas has a Renewable Portfolio Standard that requires 5,880 MW of renewable energy be available for electricity customers by 2015. The Texas State RPS is designed such that every electric provider is obligated to purchase and deliver a fraction of the total 5,880 MW state-wide renewable energy generation. The requirement is for each provider to obtain and deliver renewable energy proportionate to the provider's market share of energy sales for the state. This RPS is predominantly achieved through wind generation, and wind generation has quadrupled since the RPS was established.

The decision before Austin Energy is then how best to develop its generation mix to achieve a portfolio that matches future supply with forecasted demand and reserve margin requirements. AE must also meet the RPS obligations set by the state of Texas and, as a municipal utility owned by the City of Austin, abide by requirements set forth by Austin City Council. As representatives for the citizens of Austin, City Council has responded to public interest in increasing the renewable generation of AE to a standard more-rigorous than set by the state. In responding to public concern, Austin City Council has set a target of utilizing additional renewable energy generation such that 20% of total generation will be from renewable energy sources by the year 2020 and has also stated that all new energy generation will be carbon neutral (i.e. derived from carbon-free sources or off-set through purchase of carbon credits).

To provide a greater percentage of total generation from renewable energy resources, AE may choose to reduce generation from non-renewable energy resources or to increase generation from renewable resources or a combination of both. Although AE is actively pursuing demand-side management practices to reduce the need for additional generation, AE's published demand forecasts indicate that additional generation will be required by 2020 even with demand-side management, conservation, and load-shifting (Austin Energy Resource Guide, 2008).

Austin Energy currently derives energy from several non-renewable and renewable sources: coal, natural gas, nuclear, wind, landfill gas, biomass, and solar. Renewable energy sources (wind, solar, landfill gas, and biomass) currently comprise about 10% of AE's generation mix. In order for AE to meet City Council's objectives and to maintain reliability, they will need to greatly increase their investment in and use of renewable energy and possibly phase out some of their current non-renewable energy sources.

Although increasing the percentage of renewable energy in AE's generation mix is supported at least partially by the public, the realization of this goal is more likely to gain political acceptance if some of the benefits can be quantified. Benefits for the utility and city which result by increasing renewable energy in AE's generation portfolio include: possible cost reductions, decreased price volatility, and positive environmental effects such as reduced carbon emissions. The following procedure offers a practical methodology which makes it possible to quantify these benefits.

IDENTIFY THE OBJECTIVES OF GENERATION PLANNING

The primary responsibility of an electric utility is to balance electricity supply with demand while maintaining a reserve margin of energy capacity in the case of planned or unplanned fluctuations in both generation and demand. Beyond this obligation, many other, secondary objectives are also of importance for long-term generation planning. These objectives might include cost mitigation, environmental responsibility, high power-system reliability, moderation of price risk, service expansion, or other policy goals.

Because of the complexity of generation planning decisions and the implications of their outcomes, a logical decision-focused strategy will create optimal value for the generation portfolio owners. For any electric utility, the strategic planning team has the responsibility to identify the objectives of and alternatives for long-term generation asset procurement decisions. To identify the objectives of generation planning for a particular generation portfolio owner, first the owner's business situation must be assessed.

Assess Austin Energy's Business Situation

This step identifies the issues and challenges Austin Energy faces and provides clarity for plans to later fill-in gaps in information, alternatives, and value trade-offs in the following step. Fully understanding the issues AE is currently facing and the challenges it expects is an important first step in the decision analysis cycle.

As a municipal utility, Austin Energy is mandated to serve all the customers within its region. This provides Austin Energy with many of the advantages afforded to any natural monopoly however AE is regulated by mandates from Austin City Council, and these dictate many of AE's business decisions. AE's strategic plan must strive to meet all the power needs of its customers while taking into account changes in emissions regulation, public interest and perception of the utility's energy resources, and cost and reliability issues that are characteristic of renewable energy sources. Consequently, AE faces some unique issues that must be addressed in the short- and long-term. The issues of concern to AE are primarily Austin City Council mandates, possibility of policy changes, economic and technological uncertainties and/or barriers, and areas for opportunity. A more-detailed assessment of the primary issues facing AE follows:

- Austin City Council has set targets that the City of Austin derive 20% of its electricity from renewable energy sources by the year 2020 and that all new sources of electricity be carbon-neutral (i.e. derived from carbon-free sources or off-set through purchase of carbon credits).
- AE currently relies on the Fayette coal-fired plant for 32% of its load, yet the Fayette coal-fired plant contributes 71% of AE carbon emissions (Eaton, LBJ, p11).
- The current federal administration is considering the passage of federal mandates that may have a direct effect on prices and emission requirements. Possible action could include a tax on carbon emissions or the implementation of a cap-and-trade system. The federal government could also impose federal renewable portfolio standards.
- Safety of nuclear energy generation and disposal make nuclear energy a source of public concern however nuclear energy is currently used for base load generation for AE and constitutes 20 percent of AE's generation portfolio.
- Fuel is required in order to generate energy using either coal or natural gas. Therefore

the cost of generating energy from either of these sources can be highly variable due to the volatility of the price of fuel.

- Wind and solar energy are weather-dependent and weather is neither controlled nor accurately-predicted by humans.
- Transmission constraints limit the availability and reliability of West Texas wind energy for the Austin area.
- Long lead time for construction of new plants (particularly for nuclear and also for coal-fired) and new transmission lines.
- Population and economic growth are uncertain and AE must meet 100% of demand and meet reserve margin requirements as set by ERCOT.
- Impact of new nodal market on pricing and availability.
- Technological advancements in solar and wind energy production, carbon-sequestration, and energy storage have the potential to greatly affect the costs associated with generation from relevant sources.

Create a Decision Diagram and Distill Key Challenges

These issues make long-term generation planning a challenge for Austin Energy. These issues can be further elucidated when displayed in a decision diagram. The decision diagram functions as a tool to help understand the interrelation of identified challenges facing Austin Energy. The influence diagram in this step encompasses external as well as some internal uncertainties and decisions. The influence diagram demonstrates the complexity of matching supply with demand (Figure 4). Note that because of the complexity of the decision diagram, not all relevance arrows are included but only those that are needed to demonstrate the direct relevance between uncertainties, decisions, and calculations.

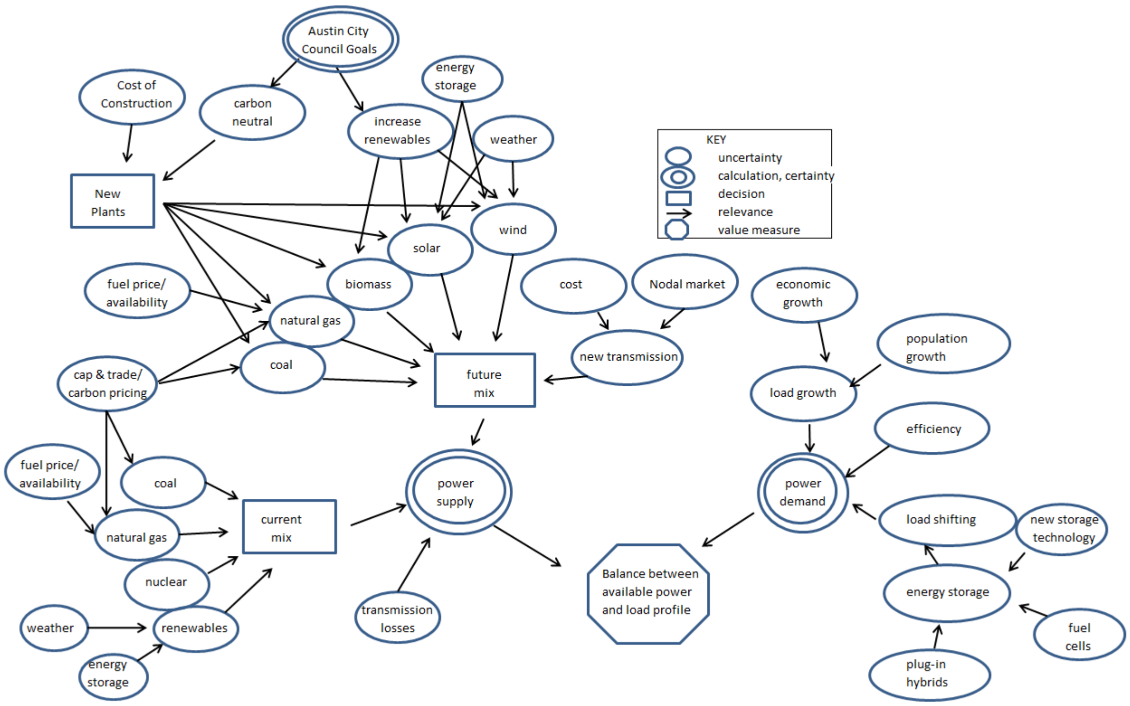

Figure 4: Decision Diagram of Austin Energy long-term generation planning

Using the decision diagram, it is possible to reevaluate the issues facing Austin Energy and to express them now as challenges that address specific needs and opportunities for value creation (Bodily, 1999, p.19). These challenges come from both internal and external sources and include the areas of: policy and regulatory change, technology limitations and improvements, alterations on the demand-side, market structure, and responding to stakeholders (ratepayers, employees, and Austin City Council). Challenges are listed as specific methods of value-creation available to Austin Energy and come from both the internal and external business environment:

- As the sole provider of energy of the Austin area, Austin Energy is responsible for meeting 100% of load for the region and maintaining adequate reserve margins. AE needs to assess the size of the gap between MW production and demand forecasts and when gaps will occur.

- Austin Energy needs to be capable of supplying power to all areas in the region including new development areas with affordable, reliable electricity.
- Federal mandates for a carbon tax or cap-and-trade would impose a financial burden on AE under current conditions, however AE could make choices now that would preemptively minimize risk associated with carbon-related policies in the future. If managed effectively, carbon-related legislation could become an opportunity to potentially provide AE profit with the sale of unused carbon credits.
- Austin Energy has a unique opportunity to promote demand side management (DSM) to reduce need for additional generation. AE's current goal is to reduce demand by 700 MW by 2020 through DSM (Resource Guide, p. 4).
- New generation facilities and transmission take many years to site, gain regulatory approval, and construct; decisions on future sources of energy must be made well in advance to meet expected demand.
- Technologies in solar generation, as well as cleaner coal and energy storage technologies, although not yet mature, could make rapid improvements and cost-advancements. AE could benefit by investing in these high-risk, potentially high return technologies.

Develop Alternatives, Gather Information, and Determine Key Areas of Uncertainty

Alternatives

During this step, alternative strategies to improve the value of AE's decisions regarding generation planning are created and developed. It is only possible to create comprehensive alternatives after having fully distilled the issues and challenges faced by AE in the previous steps. To comprehensively determine what generation planning alternatives AE could pursue, this step begins with brainstorming possible alternatives, being as creative as possible. Leaving critical review for later, the brainstorming stage will illuminate many alternatives, some of which may be infeasible and others of which might later be hybridized to maximize value. It is important initially that judgment of the alternatives and feasibility not limit the scope of creative alternatives. In this way, creative brainstorming illuminates otherwise-overlooked, innovative sources of value for the municipal utility (Bodliy, p.18).

Three alternatives are developed. These strategies include 20% Renewable Energy Generation, No Nuclear, and Carbon Neutrality for All New Generation. The first scenario of 20% renewable energy generation within the generation portfolio is the current target for AE as set by Austin City Council. The no nuclear scenario could become a goal for the city if concern intensifies over the safety and economics of nuclear generation. The third alternative is for all new generation to result in no net increase in carbon emissions.

Gather Information

Data sources for this project were obtained from publicly available sources. Monthly fuel prices for coal, oil, and natural gas were obtained from The US Department of Energy (DOE) Energy Information Administration (EIA) for five years starting in January 2005 through December 2009 (http://www.eia.doe.gov/emeu/mer/prices.html). Historical nuclear input costs were derived from the spot price of uranium. Uranium is not sold on public commodity markets, but spot prices are tracked through several publicly available sources including the website for Cameco, which is a Canadian company and one of the world's largest producers of uranium (http://www.cameco.com/marketing/uranium_prices_and_spot_price/spot_price_complete_history/). Historical solar retail prices were obtained from Solarbuzz, a leader in solar energy news, research, and market data (http://www.solarbuzz.com/solarprices.htm).

Wind energy estimations were taken from a report commissioned by the Chesapeake Climate Action Network and titled, “A Portfolio-Risk Analysis of Electricity Supply Options in the Commonwealth of Virginia" by DeLaquil et al.

Levelized cost assumptions and overnight cost assumptions for oil were taken from the academic study, “Levelized costs for nuclear, gas and coal for Electricity, under the Mexican scenario" (Palacios). Cost and overnight assumptions for the remaining resource types were obtained from an LBJ School of Public Affairs study (Eaton, LBJ, p.22-23, 2009). Authors of the LBJ study reverse engineered data from Austin Energy brochures and publications to extrapolate: demand expectations, capacity factors, and carbon dioxide equivalent emission factors. The cost projections for capital costs are based upon general industry-wide cost data for new power generation plants, rather than the contractual agreements established by AE.

Determine Areas of Uncertainty

This step will reveal gaps in information needed for making decisions. The goal of long-term generation planning for Austin Energy cannot be optimally achieved without adequate information regarding: demand forecasts, capital and fuel costs, and regulations. Although these areas are sources of uncertainty, it is profitable to fill-in gaps in information if this can facilitate a more-comprehensive understanding of value trade-offs for the following step.

Five key sources of uncertainty which are taken into consideration for generation mix planning are identified by NRRI:

- Market Conditions
- Fuel Prices
- Policies and Regulatory Orders

- Fuel Supply and Availability
- Commission Forecasting Processes

Market Conditions: This includes uncertainties in load growth, be it from fluctuations in population, industry demand, or other consumer electricity use. Market uncertainty also includes load profile shape and market prices for power.

Fuel prices: Fuel prices are governed by fluctuations in supply and demand, like any other commodity in the marketplace. Natural gas prices are often cited for their extreme and unpredictable volatility. Natural gas prices are regionally based (unlike crude oil) and are supplies are susceptible to geopolitical conflict, natural disasters and forces, advancements in technology, and storage limitations. Overbuilds in one generation type can also impact fuel prices.

Policies and regulatory orders: This includes legal actions at the national or state level in the form of legislation or regulatory orders. Two policies on the national level that would alter comparisons between generation technologies are National Renewable Portfolio Standards and regulation of carbon.

Fuel supply: Any generation technology relying on fuel is vulnerable to interruptions in fuel supply. The OPEC oil embargo of 1973 is a notable example. Other susceptibilities of fuel supplies include coal deliveries relying on railroad lines, natural gas is delivered through pipelines which can rupture, and hydroelectric generation is dependent on water availability.

Commission forecasting processes: Commissions and regulated utilities revisit their forecasts periodically to try to increase the accuracy by updating information, filling in gaps that were previous areas of uncertainty, or with improved analysis tools. A common analysis tool used is integrated resources planning, but no forecasting method can predict unforeseen events like technological change, construction delays, and cost overruns. It is difficult to create models that are accurate reflections of electricity markets.

Value Measures

This step evaluates the sources of uncertainty and their relative importance. These are used in the formulation of the model to ensure that the model output represents the decision maker's preferences accurately and appropriately. During this step, it is determined when and with what probability uncertainties could occur.

For example, the utility values low cost and low environmental impact. By assigning weights to each of these desires, preferably through quantification (to allow for apples-to-apples comparisons), the tradeoffs and the opportunity costs are made explicit in the following step. This explicitness aids rational decision making in the achievement of business objectives and societal goals.

The strategy team must verify the appropriate value measures for decision criterion, discount rate (if used), risk attitude, and any other value issues. For this theoretical AE generation planning case, these value measures are displayed in the Table 1.

Decision Criterion	Meet 100% demand continually through 2020 with minimized cost and risk
Discount Rate	10 percent (nominal)
Risk Attitude	Risk neutral
Other Value Issues	Portfolios include 20% renewable energy sources by 2020; no nuclear; all new generation be carbon neutral

Table 1: Table with value measures for AE generation planning case.

Upon completing these initial stages, the strategic planning team would be wise to ask the decision-making team the following questions before proceeding with the next phase:

- Should we consider any additional alternatives?
- Have we presented any alternatives you will not consider?
- Should we explore any important value trade-offs during the evaluation, including the key measures we need to use while evaluating the alternatives? (Bodily, 1999, p.23).

Evaluate the Risk and Potential Return of Alternatives

Now that the objectives, information, and uncertainties have been fully illuminated, the strategic planning team will seek to recognize and consider tradeoffs. No single generation technology advances all societal goals by itself. Only with a balanced grouping of the available technologies can the generation planning goals best be achieved. Making changes to the current generation mix will inevitably result in tradeoffs, and these are difficult choices for decision-makers, particularly when they are accountable to public opinion through the City Council's mandates, as in AE's situation.

To quantitatively evaluate the tradeoff effects, the alternatives are evaluated here using an optimization model. Sensitivity analysis is used to quantify the value, risk, and trade-offs associated with each. The model used for this report evaluates three measures for each alternative. These are annual cost, price volatility, and carbon emissions profile.

Create Efficient Portfolios

An efficient portfolio advances the desired objectives at minimum cost. The decision maker has multiple objectives. Some of these objectives are in opposition to each other (i.e. price level vs. price predictability). The optimal decision will minimize the tradeoffs among opposing objectives so that the achievement of one occurs at minimum cost to another. In financial theory, Portfolio Analysis derives an efficient frontier that maps out the set of portfolios with the minimized risk (the dependent variable on the y-axis) for every given expected cost (the independent variable on the x-axis) (Figure 5). Portfolios along the efficient frontier represent the boundary along which both risk and costs are minimized. All other portfolios not along the efficient frontier are either infeasible (those to the upper left, as indicated by the arrow) or inefficient (have greater costs and/or associated risk). A risk-averse decision-maker wants to move in the direction of higher mean and lower standard deviation. That direction is indicated by the arrow on the graph of Figure 5. As a result, the preferred portfolio is represented by the tangent point between the EF and the decision maker's dashed line of indifference (Bjorgan, 1999).

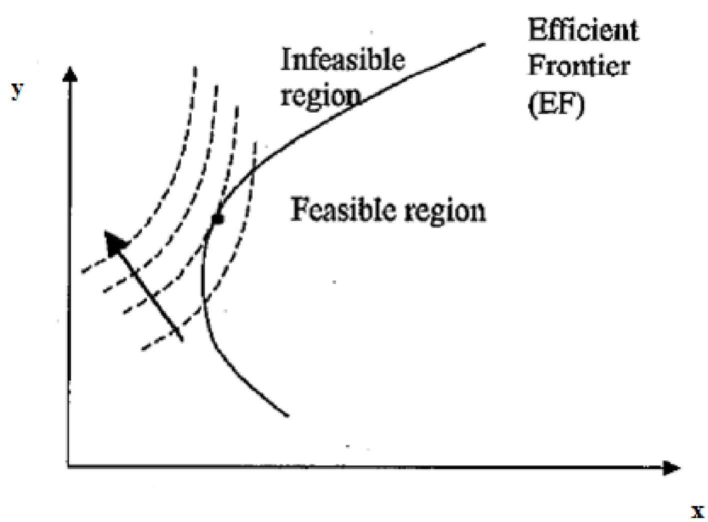

Figure 5: Efficient Frontier

The inputs to the efficient frontier are data: data on costs, reliability, and other possible outcomes, negative and positive. The regulator then has to choose among the options, options which equal each other in efficiency but which differ from each other in terms of the tradeoffs and uncertainties involved. To make this choice, the regulator cannot demand certainty because certainty comes at too high a price. Nor can the regulator defer the decision until certainty arrives. The regulator must use judgment to determine which point on the frontier best advances societal goals and public interest.

To assess the costs and benefits of increasing the percentage of renewable energy generation in AE's portfolio, Portfolio Theory can be applied to find an efficient frontier for renewable energy sources. This section includes analysis of three scenarios and their corresponding energy mixes and captures fuel price variance, expected cost, and carbon emissions for each one. The three scenarios chosen each include one element of the Austin City Council's goals for Austin Energy. Energy mixes were found that satisfied each of the following criteria: 20% generation from renewable energy, no nuclear, and carbon neutrality for all new generation. By minimizing both cost and risk, these scenarios elicit efficient frontiers. From each of these efficient frontiers, the portfolio with the lowest carbon emissions can then be determined.

The Model

To determine the optimal energy mix for Austin a single-period asset allocation model for finding efficient investment portfolios is created. This model is generally of the same structure as an investment portfolio model but different in several key respects. Traditional Investment Portfolio Theory solves for the percentages of each type of investment within a portfolio. This model instead solves for the total megawatt hours of energy generated by each source. Rather than creating a variance-covariance matrix of the investment returns for each given investment, as is done in investment portfolio theory, this model utilizes a variance-covariance matrix representing the volatility of the costs associated with each source of energy.

For generation sources which rely on fuels, the price of fuels is used as the input in the variance-covariance matrix. This data is compiled and normalized such that all values were in units of price per energy output (dollars per million BTUs). These values provide the necessary information to derive a variance-covariance matrix. Some sources of energy do not require fuel, such as solar and wind, so no fuel costs are available.

The objective in Portfolio Theory is to determine the efficient frontier along which both variance and cost are minimized. The variance-covariance matrix provides input for the efficient frontier however determining the total cost of generation requires some assumptions to elicit this necessary input for the model. The model relies on levelized variable cost data (which includes operating expenses and fuel costs where applicable) in dollars per mega-Watt hours. Aggregate annual demand was assumed to be 52% of peak demand, as used in the LBJ study.

Finally, the model required a method to aggregate values for total generation costs by source as a means for comparison between sources though these values are not reflective of true annual costs. The final costs are annualized after incorporating fixed and overnight costs. Fixed and overnight costs are added whenever a change occurs in energy required from a particular source. To derive annual costs, the total variable costs (calculated for each source by multiplying the energy usage for a particular source in 2020 – a number returned by Excel solver – with the levelized cost for that source), are multiplied by 24 and then 365 (to convert the hourly costs to yearly), and then also multiplied by 52% to account the total annual demand as a percent of peak daily demand. Finally, the fixed costs (calculated based on the change in usage from 2008 to 2020) are added to determine the total annual cost. The cost calculations entail several assumptions which are presented in the following section.

Assumptions

The levelized cost estimates for each of the energy sources (used as variable costs in the model) are not entirely realistic because generation costs include both fixed and variable components which are generally averaged together when calculating the levelized cost. The levelized cost represents an average cost per mega-Watt-hour (MWh) that an energy source would incur when operating at a given capacity factor. For fuel-based sources of energy, it also includes costs associated with fuel prices.

Another type of cost included in the analysis, overnight costs, reflect costs associated with adding capacity other than normal operating costs. These include fuel costs and maintenance costs. Overnight costs represent the costs for adding one kilo-Watt-hour (KWh) of capacity for a given energy type. This includes the construction cost of building and financing a new energy plant. Overnight costs are assumed to be incurred on a per KWh basis when the model recommends a target mix for a given energy source above the 2008 capacity. An additional assumption for this model is that decreasing capacity of an energy source will involve costs that would be similar to plant construction costs. To model the costs of plant closures, overnight costs are incurred for each KWh that is subtracted from existing capacity for that energy source. Overnight costs and levelized cost assumptions are primarily taken from the Austin Energy study performed by the LBJ School (Eaton, LBJ, 2009). Another assumption is that overnight costs will all be charged in the year 2020, which implies that any energy capacity additions would be paid for in 2020.

The model is designed to provide an optimal energy mix to meet peak demand based on forecasted peak demand in 2020. Forecasted peak demand is derived from literature published by Austin Energy which did not consider the potential for energy conservation or demand side management to lessen peak demand (Eaton, LBJ, 2009). To estimate how peak energy generation would correspond to the city's annual energy needs, the Austin Energy study performed by Eaton and LBJ School of Public Affairs estimated that hourly demand is on average 52% of hourly peak energy demand based on empirical data from Austin Energy (Eaton, LBJ, 2009). This model also assumes that annual energy demand will be 52% of peak demand.

The energy generation mix is assumed to remain limited to coal, natural gas, nuclear, fuel oil, solar, and wind. Austin Energy's does not currently buy energy sourced from fuel oil plants, but it is assumed that this type of plant could be added with limited infrastructure problems if needed. The model also does not take into account possible carbon credits that may be available for reducing greenhouse gases in future years. A final assumption is that 100% of the capacity of each energy source can be used to meet peak demand at any given time. A discussion of how these assumptions might limit the model is included in the 'Future Improvements to The Model' section.

Results Discussion

Once the model is built, various sets of constraints can be incorporated. By altering the constraints and running scenarios, it is possible to analyze different options that may be of interest to the city. The first scenario is to meet Austin's stated goal of generating 20% of its energy supply from renewable sources. The later scenarios take into consideration an option with no nuclear energy and finally an option with no increase in carbon emissions.

Option One: Twenty Percent Renewable Option

In order to meet the City's goal of deriving at least 20% of its energy supply from renewable sources, a constraint is added to the model which requires 20% of total generation to be sourced from solar and wind. According to this model, the minimum annual cost that meets this constraint is approximately $3,595,000,000 and has a variance of 25.6. If decision makers were interested in minimizing variance at any cost, the minimum variance that could be obtained was 1.6; however, in order to achieve this level of security (i.e., lack of risk) the annual cost would be around $8,011,000,000. Four evenly-spaced points were plotted between these two extremes, all of which could be considered 'optimal' choices. This efficient frontier is shown in Figure 6.

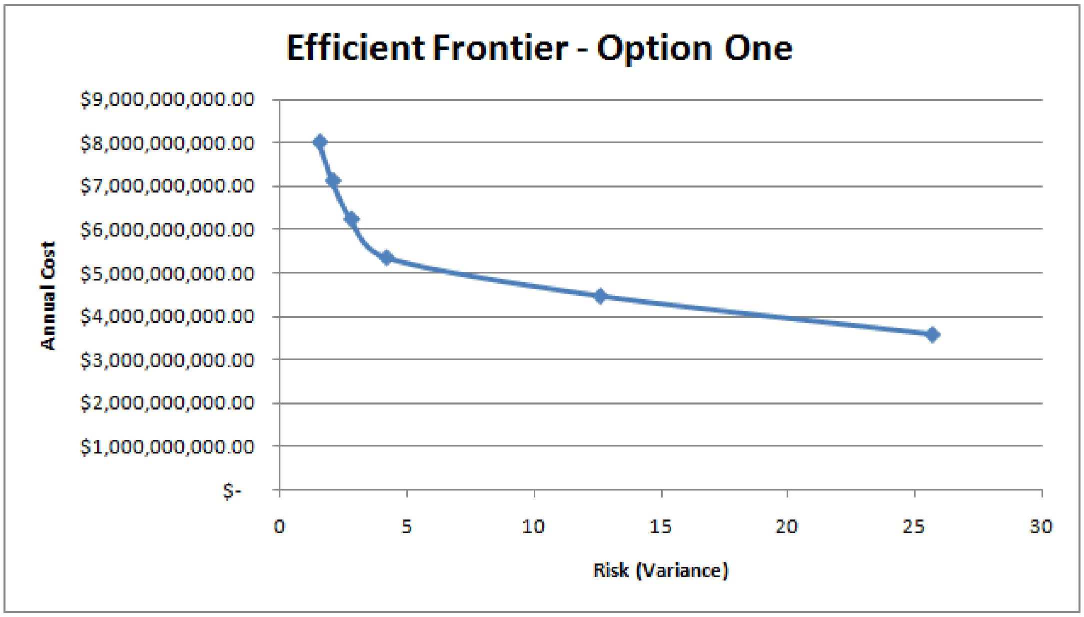

Figure 6: Efficient frontier for Option One – 20% Renewable Energy Portfolio

If Austin Energy was most-interested in minimizing carbon emissions, then the best choice may be the point along the efficient frontier which achieves the minimum amount of carbon emissions. That portfolio would consist of 72% wind, 20% coal, and 8% nuclear, as shown in Figure 7. This portfolio would cost close to $6,245,000,000 and would have a variance of 2.8, while keeping carbon emissions to 2,594,000.

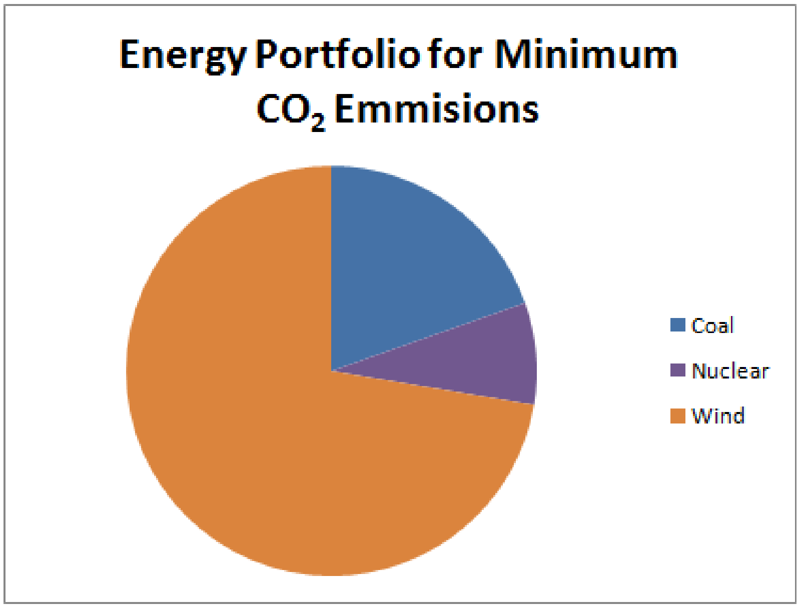

Figure 7: Minimum Carbon Emissions Energy Portfolio for 20% Renewable Option

Option Two: Nuclear Free Option

The nuclear-free scenario could potentially be a goal of Austin Energy because public concern exists over the safety of both nuclear energy generation and nuclear waste disposal. Additionally, nuclear energy enjoys production credits, federal insurance coverage for catastrophic events above a certain threshold, and loan guarantees for some new power plants. Collectively, these raise questions about the true costs of nuclear energy for society. Because of the uncertainties associated with nuclear energy despite the relative maturity of the technology, some citizen groups would like Austin Energy to eliminate nuclear energy from its generation portfolio.

For the nuclear-free model, a constraint is added that sets the level of nuclear generation in 2020 to zero. When the objective is set to minimize expected cost, a minimum cost of roughly $4,779,000,000 is obtained with a variance of about 23. When the objective is set to minimize variance, a minimum variance of 1.95 is obtained with a cost of about $8,455,000,000. Three target costs are evaluated while minimizing variance to obtain values for an efficient frontier for the nuclear-free scenario (see Figure 8). Along the efficient frontier and for the values obtained using this method, carbon emissions are minimized at roughly 2,524,000 when variance is 2.8 and cost is $7,697,000,000. The resulting energy portfolio is shown in Figure 9. This represents a 59% reduction in carbon emissions. Since nuclear generation produces no carbon emissions directly or within this model, it is surprising to find that such a large reduction in carbon emissions is possible even without including nuclear generation in the portfolio. This low carbon emission results from the heavy weight of wind generation in this portfolio; wind makes up 76% of the total energy generated. Given the intermittency of wind generation, reliability issues associated with weather-dependent generation, and lack of energy storage options, it is unlikely that wind would ever constitute this large a percentage in any utility's generation mix.

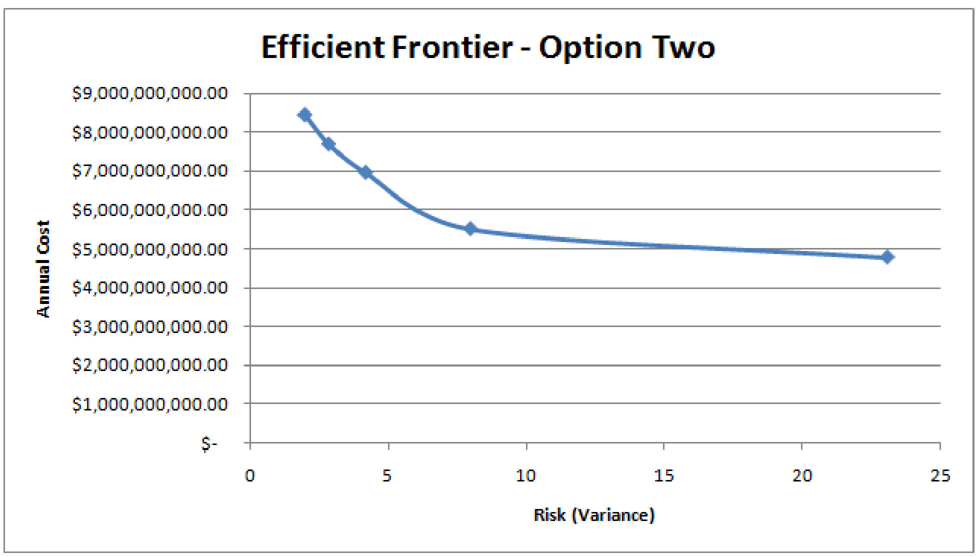

Figure 8: Efficient Frontier for No Nuclear Option

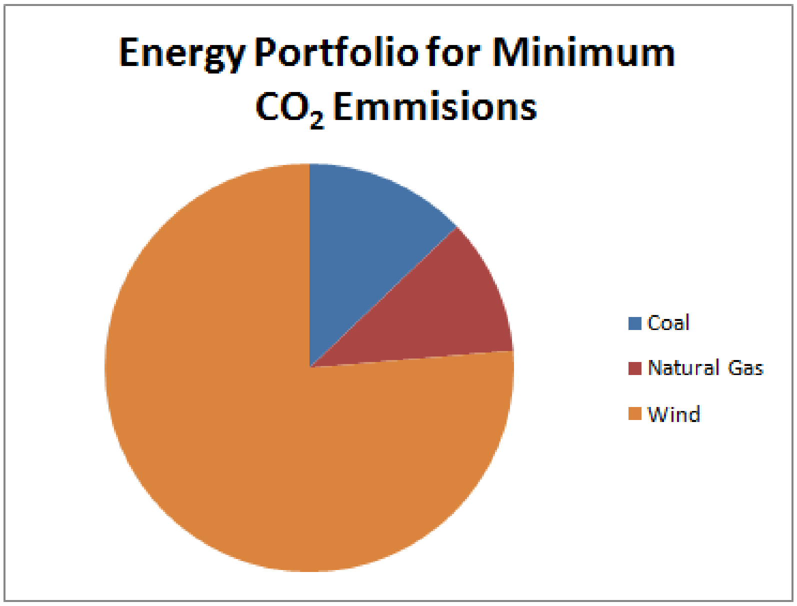

Figure 9: Minimum Carbon Emissions Energy Portfolio for No Nuclear Option

As variance decreased along the efficient frontier, coal and natural gas have incrementally less weight in the generation portfolios and wind generation is increased. The exception to this trend is when the model is used to elicit an absolute minimum variance. For the minimum variance portfolio, coal has an uncharacteristically large weight of 74.4% and wind is 25.6%. This is likely because coal is such a large percentage of the mix in 2008, and there are penalties in the model for eliminating generation resources. These penalties would be quite large if coal were to be eliminated entirely from this minimum variance portfolio.

Option Three: Carbon Neutral for New Generation

The final scenario involves forecasting an efficient frontier of energy mixes based on the constraint that there would be no increase in carbon emissions in the year 2020 from 2008 levels. Six points are forecasted and graphed to create an efficient frontier displaying the minimum cost and minimum variance points for the year 2020. These points are shown in Figure 10. For the minimum cost portfolio, there is little change from the 2008 mix of nuclear, coal, and natural gas in the year 2020. This implies that Austin may not require drastic changes in the energy mix to limit carbon emissions as the city grows. The biggest change in the energy mix of the minimum cost portfolio is the percentage of wind generation, which jumped from about 10% to 20% in the year 2020. A 20% mix of wind energy seems to be feasible since some European countries have successfully obtained this level of energy from wind energy. Denmark, for example, generated 20% of its energy from wind in 2007 (Danish Energy Agency, 2008). In the portfolios closest to the minimum cost portfolio on the efficient frontier, natural gas drops from around 46% of the energy mix to around 30% while coal and nuclear experienced much smaller decreases in the energy mix. A large reason for the drop in natural gas appears to be that the capital charges for reducing plant capacity, reflected in overnight costs, are much lower for natural gas than coal and nuclear. Natural gas also has a larger variance than coal, so it is reasonable that the amount of coal increased as the portfolios approached the minimum variance portfolio. It is interesting to note that many of the portfolios have decreases in carbon that are quite significant even though the carbon constraint only prohibited an increase in carbon emissions. The dramatic decreases in carbon emissions appear to be a result of the high percentage of wind as the efficient frontier approaches the minimum variance portfolio. The increase in wind appears to result from the low variance for wind generation costs. In fact, wind has one of the lowest variances of all the energy sources. The variance in wind energy is calculated based on costs assumptions for constructing new wind turbines and may not accurately reflect the variability of electricity generation from wind (Gotham, 2009).

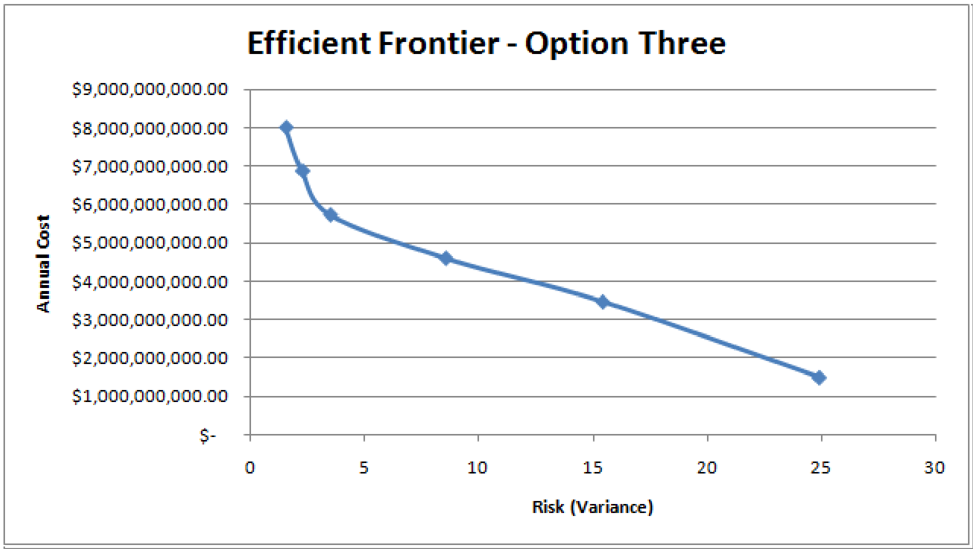

Figure 10: Efficient Frontier for 0% Carbon Increase Option

The point along this frontier which achieves the minimum carbon emissions will have an annual cost of approximately $7,697,000,000 and carry a risk (variance) of only 2.8. Figure 11 shows the portfolio mix will consist primarily of wind with the remainder split between coal (13%) and natural gas (11%) and carbon emissions of 2.5 million.

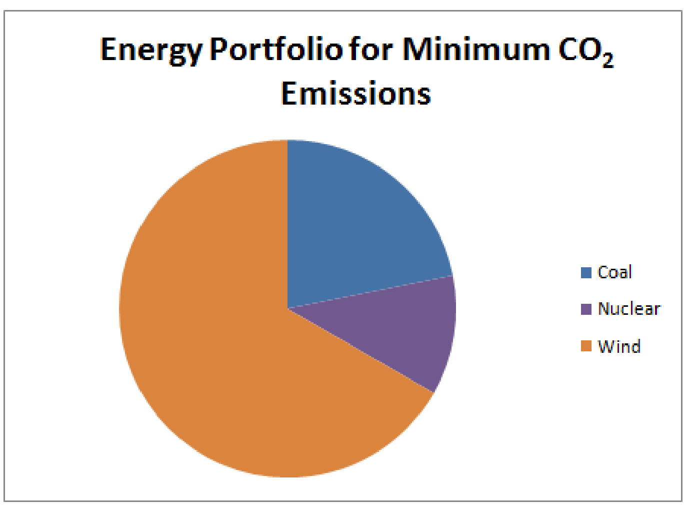

Figure 11: Minimum Carbon Emissions Portfolio for 0% Carbon Increase Option

Future Improvements to the Model

This model includes a number of assumptions which likely limited the accuracy of the results. The model could be improved and made more realistic if it incorporated more parameters to replace some of these assumptions. For instance, overnight costs are all charged in the year 2020, which implies that any energy capacity additions would be paid for in 2020. It may be more realistic to amortize overnight costs over a number of years instead of recognizing capacity additions only in the target year.

Additionally, this model incorporated the Austin Energy study's simplifying assumption that hourly demand is on average 52% of peak demand. Using this assumption, the annual average demand load was calculated by multiplying the estimated hourly peak demand by 52%. This estimate limits the model since it does not accurately take into account how the energy mix will vary in an hourly load profile. A more realistic expression of commercial generation would incorporate the tendency for expensive, peaking plants to only be utilized when load is above a certain threshold.

Another model assumption is that 100% of the capacity of each energy source can be used to meet peak demand at any given time. This is not realistic for wind energy since it is impossible to predict when the wind turbines will be generating energy at full capacity. One way to address this weakness in the model would be to include temporal capacity factors for wind generation in order to address the inherent variability of wind energy.

Additionally, this model does not take into account the possibility of using carbon credits for achieving reductions in greenhouse gases. Incorporating carbon credits would have lowered the expected costs of energy mixes with the highest quantity of renewable energy generation by essentially creating a ceiling for the highest expected cost for achieving low carbon goals. A potential adaptation to this model could include carbon credits as the plug. AE could then set further constraints on the quantity of generation they are capable of generating or purchasing, and Excel Solver would optimize for the value AE should place on carbon credits in order to realize their low carbon emission commitments given the generation constraints.

Finally, an interesting adaptation to this model would include not only fuel prices in the variance-covariance matrix but also the variability of wind and solar inputs. In the same way that fuel prices modulate with the supply, weather-dependent energy sources are subject to natural supply given meteorological conditions. An advanced, regionally-based model could use Weather Service data for solar radiation and wind conditions within the variance-covariance matrix. The variability of weather through the year or over the course of a typical day could then be incorporated into the model as an additional risk.

DECIDE AMONG ALTERNATIVES AND PLAN FOR ACTION AND IMPLEMENTATION

At the conclusion of the decision analysis cycle, decision makers finally have an opportunity to make an informed choice among alternatives given the insight obtained from the previous steps. Now strategic and organizational considerations are weighed along with the financial comparisons of alternatives. The ultimate aim here is to discuss implementation issues associated with the most attractive alternative strategies and to establish a plan for action.

The three scenarios considered demonstrate how Austin Energy might approach an analysis of renewable portfolio standard costs and benefits using Portfolio Theory to elicit minimized costs and risk. These scenarios allow the city to evaluate the various costs and risks associated with meeting several different environmental goals. By reviewing the three scenarios, it is clear that developing an energy mix portfolio without nuclear power would be the most costly alternative. The no nuclear option would cost one to two billion dollars more than simply achieving its goal of twenty percent renewable energy or keeping carbon emissions from increasing. If AE is interested in minimizing carbon emissions, then the least-cost portfolio would be Option Three – zero net increase in carbon. It is worth noting that this option carries a slightly higher risk than the other two options, with a variance of 3.5 as opposed to only 2.8 for the minimum carbon emission portfolio along the efficient frontier for either of the other two options.

CONCLUSION

This strategy provided benefits of clarity and precision in thinking, especially in defining goals for Austin Energy's strategic planning team. As AE makes decisions regarding their long-term generation portfolio alternatives, implementing a strategy such as this could provide them with rationale and quantitative objectivism to direct their decision making efforts. Uncertainty is inherent to most decision making processes, but because of the long-lead times for construction of generation plants and transmission lines and the need for forward contracts, delaying long-term generation portfolio decisions until uncertainties are diminished is simply not a practical option. Decision makers using this strategy would do well to review and adapt this model and their assumptions periodically as more information becomes available in order to minimize uncertainty over time.

This analysis provides a methodology as a starting point for electric utility strategic planning decisions that incorporate RPS goals. Modifications and extensions to the model could bring to bear additional guidance for professionals in the electric utility industry. The area of long-term planning for electric generation portfolios could benefit from further analysis using the decision analysis cycle, and continued research using this method could provide valuable insight for utilities, decision makers, and researchers of power systems.

Appendix: RPS Design Policy by State

State	Enacted	Target Amt	Target Year	Special Provisions	Who's Covered	Qualifying Technologies
Arizona	1996	15%	2025	4.5% by 2012 from distributed energy resources	Utility	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Geothermal Electric, Anaerobic Digestion, ydroelectric, Geo Space Heating and Process Heating, Fuel Cells using Renewable Fuels
California	2002	20%; 33% (two phase)	2010; 2020 (two phase)		IOU; Electric Service Providers; Small and Multi-Jurisdictional Utilities; Community Choice Aggregators	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Geothermal Electric, Municipal Solid Waste, Anaerobic Digestion, Small Hydroelectric, Tidal Energy, Wave Energy, Ocean Thermal, Biodiesel, Fuel Cells using Renewable Fuels
Colorado	2004	20% (IOUs); 10% (coops and munis with > 40,000 customers)	2020	Solar-electric (IOUs only): 4% of annual requirement (0.8% of sales in 2020); half of solar-electric requirement must be located on-site at customers' facilities	Municipal Utility, Investor-Owned Utility, Rural Electric Cooperative, (Only Municipal Utilities Serving 40,000+ customers)	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, "Recycled Energy", Anaerobic Digestion, Fuel Cells using Renewable Fuels
Connecticut	1998	27%	2020	4% Energy Efficiency and CHP by 2010; Class I: 20% by 2020 Class I or Class II: 3% by 2010 Class III: 4% by 2010)	Municipal Utility, Investor-Owned Utility, Retail Supplier	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Fuel Cells, Municipal Solid Waste, CHP/Cogeneration, Low E Renewables, Tidal Energy, Wave Energy, Ocean Thermal
District of Columbia	2005	20%	2020	0.4% solar by 2020	Investor-Owned Utility, Retail Supplier	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells, Municipal Solid Waste, Solar Space Cooling, Cofiring, Tidal Energy, Wave Energy, Ocean Thermal
Delaware	2005	20%	2020	2.005% solar by 2019	Investor-Owned Utility, Retail Supplier	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Anaerobic Digestion, Tidal Energy, Wave Energy, Ocean Thermal, Fuel Cells using Renewable Fuels
Hawaii	2004	40%	2030		Investor-Owned Utility, Rural Electric	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Geothermal Heat
Iowa	1983	105 MW	N/A		Two IOUs: MidAmerican Energy and Alliant Energy Interstate Power and Light (IPL)	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric (including small), Municipal Solid Waste, Anaerobic Digestion
Illinois	2007	25%	2025	Wind (IOUs): 18.75% of sales by 2025; Wind (ARES): 15% of sales by 2025; PV (All): 6% of annual requirement by 2016 and thereafter 1.5% of total sales by 2025	Investor-Owned Utility, Retail Supplier	Solar Water Heat, Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Biodiesel
Massachusetts	1997	15%	2020	Class I (New Resources): 15% of by 2020 and an additional 1% each year thereafter; Class II (Existing Resources): 7.1% in 2009 and thereafter (3.6% renewables and 3.5% waste-to-energy)	Investor-Owned Utility, Retail Supplier	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, Anaerobic Digestion, Small Hydroelectric, Tidal Energy, Wave Energy, Ocean Thermal, Renewable Fuels, Fuel Cells using Renewable Fuels
Maryland	2004	20%	2022	2% solar by 2022	Municipal Utility, Investor-Owned Utility, Rural Electric Cooperative, Retail Supplier, Retail Electricity Suppliers	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, Anaerobic Digestion, Tidal Energy, Wave Energy, Ocean Thermal, Fuel Cells using Renewable Fuels
Maine	1997	40%	2017	10% Class I by 2017	Investor-Owned Utility, Retail Supplier	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells, Municipal Solid Waste, CHP/Cogeneration, Tidal Energy, Other Distributed Generation Technologies
Michigan	2008	10%	2015			Landfill Gas, Wind, Photovoltaics, New Hydroelectric, Biomass, Geothermal, Municipal Solid Waste, Tidal, Wave, Ocean Thermal, Hydroelectric Pumped Storage
Minnesota	1994	25%	2025	Xcel Energy: 25% wind	Utility, Municipal Utility, IOU	Landfill Gas, Wind, Photovoltaics, Small Hydroelectric, Biomass, Anerobic digestion, Hydrogen
Missouri	2007	15%	2020	0.3% solar retail sales by 2021	IOU	
Montana	2005	15%	2015		Investor-Owned Utility, Retail Supplier	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Anaerobic Digestion, Fuel Cells using Renewable Fuels
North Carolina	2007	12.5%	2021	Solar: 0.2% by 2018; Swine Waste: 0.2% by 2018; Poultry Waste: 900,000 MWh by 2014	Municipal Utility; IOU; Rural Electric Cooperative	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Landfill Gas, Wind, Biomass, Geothermal Electric, CHP/Cogeneration, Hydrogen, Anaerobic Digestion, Small Hydroelectric, Tidal Energy, Wave Energy

Appendix (Continued)

New Hampshire	2007	24%	2025	0.3% solar by 2025	Utility; Electricity Supplier	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Small Hydroelectric, Geothermal Electric, Anaerobic Digestion, Tidal, Ethanol, Biodiesel, Fuel Cells using Renewable Fuels
New Jersey	1999	22.5%	2021	2.12% from solar by 2021	Investor-Owned Utility, Retail Supplier	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Resource-Recovery Facilities approved by the DEP, Anaerobic Digestion, Tidal Energy, Wave Energy, Fuel Cells using Renewable Fuels
New Mexico	2000	20%	2020	Wind: 4%; solar: 4%; biomass and geothermal: 2%; distributed renewables: 0.6% by 2020; total 20% by 2020 (IOU only) and 10% by 2010 for rural electric coops	IOU; Rural Electric Cooperative	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Zero emission technology with substantial long-term production potential, Anaerobic Digestion, Fuel Cells using Renewable Fuels
Nevada	1997	25%	2025	1.2% solar by 2015; 1.5% by 2025	Investor-Owned Utility, Retail Supplier	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, Waste Tires (using microwave reduction), Geothermal Hot Water District Heating Systems, Solar Pool Heating, Anaerobic Digestion, Biodiesel
New York	2004	24%	2013	0.154% customer-sited by 2013	IOU	Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Fuel Cells, Anaerobic Digestion, Tidal Energy, Wave Energy, Ocean Thermal, Ethanol, Methanol, Biodiesel
Ohio	2008	25%	2025	12.5% wind and solar; 0.5% solar by 2025; 12.5% generated in-state	Electric Distribution Utilities; Electric Service Companies	Landfill Gas, Wind, Photovoltaics, Hydroelectric, Biomass, Geothermal, Anerobic digestion, Fuel cells
Oregon	2007	25%	2025	Smaller utilities 5-10% by 2025 (depending on size)	Utility	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Geothermal Electric, Municipal Solid Waste, Anaerobic Digestion, Small Hydroelectric, Tidal Energy, Wave Energy, Ocean Thermal, Small Thermal Heat Processes, Hydrogen, Spent Pulp Liquor, Biodiesel, Agricutural Residues, Dedicated Energy Crops,
Pennsylvania	1998	18%	2020	Tier I: 8% by 2021 (includes PV minimum); Tier II: 10% by 2021; PV: 0.5% by 2021	Investor-Owned Utility, Retail Supplier	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells, Geothermal Heat Pumps, Municipal Solid Waste, CHP/Cogeneration, Waste Coal, Coal Mine Methane, Coal Gasification, Anaerobic Digestion, Other Distributed Generation Technologies
Rhode Island	2004	16%	2019		Investor-Owned Utility, Retail Supplier	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Anaerobic Digestion, Tidal Energy, Wave Energy, Ocean Thermal, Biodiesel, Fuel Cells using Renewable Fuels
Texas	1999	5,880 MW	2015	At least 500 MW from renewables other than wind	Investor-Owned Utility, Retail Supplier, (Municipal Utilities and Coops May Opt-in)	Solar Water Heat, Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Geothermal Heat Pumps, Tidal Energy, Wave Energy, Ocean Thermal
Washington	2006	15%	2020		Large Utilities (>25000 customers)	Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Anerobic Digestion, Tidal Energy
Wisconsin	1998	10%	2015		Municipal Utility, Investor-Owned Utility, Rural Electric Cooperative	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Tidal Energy, Wave Energy, Fuel Cells using Renewable Fuels
Six States with Renewable Portfolio Goals: North Dakota, South Dakota, Utah, Vermont, Virginia, and West Virginia						

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