Sustainable Energy Options for Austin Energy

Summary Report (DRAFT)

A Policy Research Project of
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Forward

The Lyndon B. Johnson (LBJ) School of Public Affairs has established interdisciplinary research on policy problems as the core of its educational program. A major part of this program is the nine-month policy research project, in the course of which one or more faculty members from different disciplines direct the research of ten to thirty graduate students of diverse backgrounds on a policy issue of concern to a government or nonprofit agency. This “client orientation” brings the students face to face with administrators, legislators, and other officials active in the policy process and demonstrates that research in a policy environment demands special talents. It also illuminates the occasional difficulties of relating research findings to the world of political realities.

During the 2008-2009 academic year the City of Austin, on behalf of Austin Energy (AE), and Solar Austin co-funded a policy research project to review options for AE to achieve sustainable energy generation and become carbon neutral by 2020. The summary report evaluates different power generation technology options as well as demand-side management and other AE investment options to discourage future energy use and meet future projected energy demand. This project developed methods to evaluate future power generation options for their feasibility and cost-effectiveness. The project team assessed scenarios of alternate investments that could be made between 2009 and 2020 that would allow AE to produce and distribute the electricity its customers demand at a reasonable cost while reducing carbon dioxide emissions. This report describes a set of short-term and long-term investment options that can help AE, its customers, and be of use for developing sustainable electric utilities nationwide.

The curriculum of the LBJ School is intended not only to develop effective public servants but also to produce research that will enlighten and inform those already engaged in the policy process. The project that resulted in this report has helped to accomplish the first task; it is our hope that the report itself will contribute to the second.

Finally, it should be noted that neither the LBJ School nor The University of Texas at Austin necessarily endorses the views or findings of this report.

Admiral Bob Inman
Interim Dean
LBJ School of Public Affairs

Acknowledgments and Disclaimer

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AE staff members who contributed their time and expertise include: Bob Breeze, Andres Carvallo, Jennifer Clymer, Mark Dreyfus, Christopher Frye, Noreen Gleason, Jerrel Gustafson, Ravi Joseph, Mark Kapner, Richard Morgan, Norman Muraya, Todd Shaw, and Fred Yebra.

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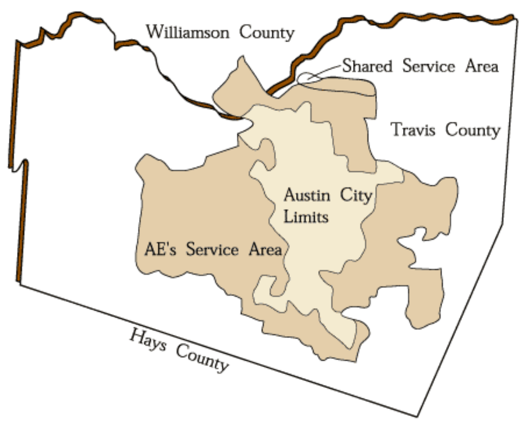
None of the sponsoring units including AE, Solar Austin, the LBJ School of Public Affairs or other units of UT-Austin endorse any of the views or findings of this report. Any omissions or errors are the sole responsibility of the authors and editors of this report.

Sustainable Energy Options for Austin Energy
Introduction

The City of Austin has an educated populace and engaged City Council (Council) concerned with the local and global environments. Austin owns its electric utility, Austin Energy (AE), so its citizens can influence its future operations and energy choices. Over the past several decades AE has exhibited leadership in promoting energy efficiency and conservation programs and investing in sources of renewable energy. AE is arguably one of the most innovative and creative electric utilities in the United States (US) and has a record of environmental stewardship and concern for assuring low-cost and reliable electricity to its customers. Despite previous efforts, AE still has difficult choices to make, as "business as usual" may not be the most sustainable approach to providing electricity to customers.

The Council has adopted a plan to invest in renewable energy sources and reduce Austin's carbon footprint. Austin's elected officials have made a commitment to conserve energy, obtain power from cleaner sources, and continue providing low-cost and reliable electricity to AE customers who live in Austin and the surrounding region (see Figure 1). The following report provides an examination of the options for AE to move beyond the current goals set by Council and achieve a carbon neutral status by 2020 as a step towards sustainability.

Figure 1: Austin Energy Service Area



Source: Austin Energy

The pages that follow summarize two reports prepared by graduate and undergraduate students from The University of Texas at Austin's (UT-Austin) Lyndon B. Johnson School of Public Affairs and other colleges within UT-Austin, including the Cockrell School of Engineering, the Jackson School of Geosciences, the McCombs School of Business, the School of Information, and the School of Architecture. One report details sustainable energy options for AE and the other report provides a detailed analysis of different resource portfolios that AE could adopt by 2020. A spreadsheet-based method was developed to analyze the impacts that investments in power generation and related technologies between 2009 and 2020 could have on four performance measures: system reliability; costs and economic impacts; carbon dioxide emissions; and risks and uncertainties. The purpose of this exercise has been to examine the options and possible outcomes of the choices that AE faces to provide low-cost and reliable electricity for its customers while reducing its carbon footprint.

Drafts of the full-length reports can be accessed online at the following website:
http://www.utexas.edu/lbj/news/story/732/

Background and Purpose of the Report

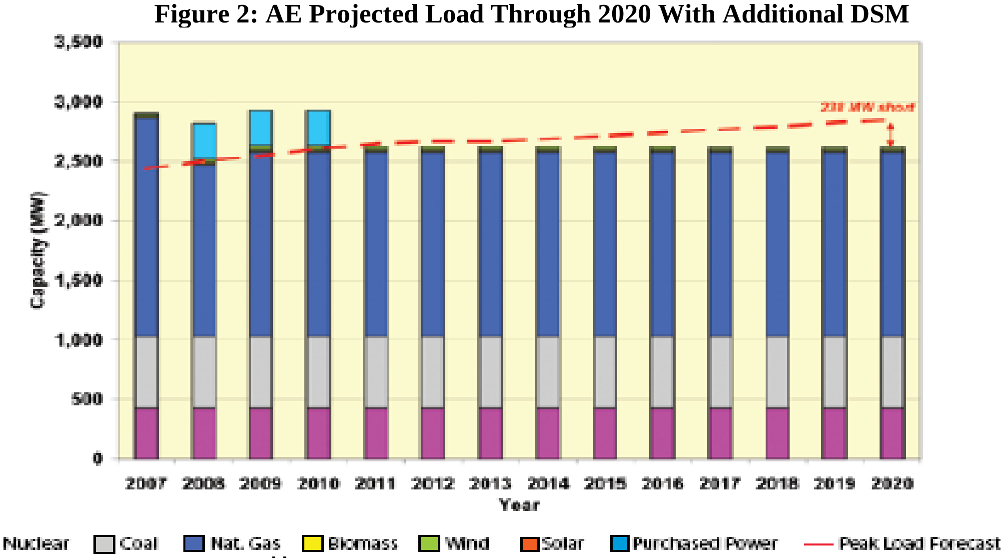
This report summarizes two volumes on "Sustainable Energy Options for Austin Energy," drafted by a policy research project team composed of graduate students from several departments of the University of Texas at Austin through The Lyndon B. Johnson School of Public Affairs. The project was commissioned by the City of Austin (on behalf of AE) and Solar Austin, a Central Texas non-profit renewable energy organization. This report seeks to identify feasible and cost-effective investment opportunities for AE that can help contribute to the creation of a sustainable electric utility. The analysis that follows has set the target of achieving zero net carbon dioxide (CO_2) emissions by 2020 as an interim goal towards achieving a sustainable electric utility. The power generation mix that AE implements in the future will represent a major portion of its cost of service and will be a significant contributor to either increasing or reducing AE's carbon footprint. The resources used and technologies implemented will influence how AE and Austin are perceived as a sustainable utility and a sustainable city, respectively. AE's future energy portfolio will affect customer electricity rates and AE's capacity to contribute assets to the City of Austin budget.

This report takes into account: Austin's published projected energy needs through 2020; available technologies for energy conservation, energy efficiency, and power generation; economic costs of producing and distributing electricity; as well as information available about electric utility planning and regulatory challenges. This summary report is composed of four sections: a brief statement of concerns facing electric utilities, particularly AE; an overview of different power generation technologies and their investment potential; an analysis of eight resource portfolio options; and conclusions and recommendations based upon the project team's analysis. This report includes four appendices for further reference. Appendix A provides information about each power generation and related technology discussed in this report regarding reliability, costs, and CO_2 emissions, among other factors. Appendix B lists advantages and disadvantages of each energy source discussed in this report. Appendix C describes the methodology used by the project team to develop the "Austin Energy Resource Portfolio Simulator." Appendix D is a glossary of key terms used in this summary report.

Key Concerns Facing Austin Energy and the Electric Utility Industry

AE serves a growing population and economy. Despite AE's best efforts to conserve energy to reduce demand, the utility's plan includes an expectation that it must increase its power generation capacity if it wants to assure reliable electric service from its own power system to all its present and future customers. Figure 2 shows AE's projections of energy demand (known as load) through 2020 with additional demand-side management (DSM) savings that AE projects it can meet by 2020.

Figure 2: AE Projected Load Through 2020 With Additional DSM



Source: Austin Energy

As with many contemporary electric utilities, AE does not rely heavily on renewable energy sources. Rather it generates most of its electricity by utilizing the energy embedded in fossil fuels and uranium. Figure 3 shows AE's current power generation mix based on fuel source. Coal, natural gas, and uranium fuels have been plentiful and relatively inexpensive for years in part because some of the external environmental costs associated with their use may not have been included in the commodity cost. As global demand for fuel sources have increased, the market cost for these fuels has fluctuated, leading to uncertainty regarding their price in the future. Burning coal, natural gas, or oil emits CO_2 directly into the atmosphere. The term "carbon footprint" represents the measure of how human activities contribute greenhouse gases (GHGs) to the environment, usually defined as a weight in mass of CO_2 or CO_2-equivalent. It is possible that the US will adopt legislation or regulation to limit CO_2 and other GHG emissions. Such a policy could modify the business model for electric utilities, including AE. AE, in preparation of such regulation, was one of the first electric utilities to adopt voluntarily the California Climate Action Registry's standards for calculating carbon footprint. The majority of AE's emissions come from the burning of fossil fuel to produce electricity (greater than 99 percent), with relatively small amounts of CH_4 and N_2O emitted.

Figure 3: AE Power Generation Mix by Source (FY 2007)

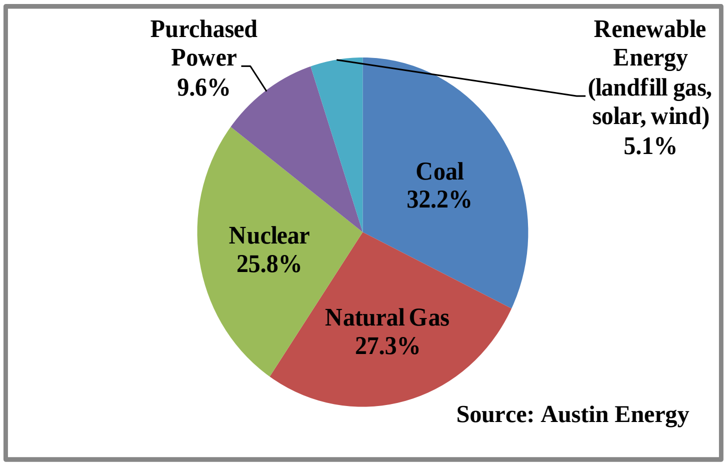
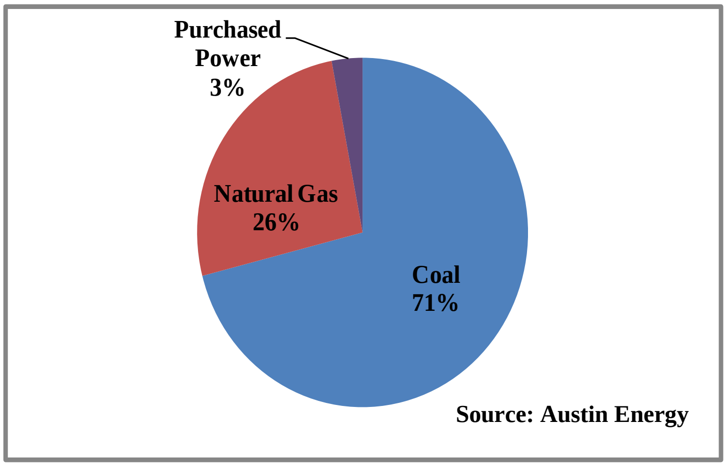


Figure 4 shows the source of AE's CO_2 emissions by fuel type. AE's CO_2 emissions predominately come from the burning of coal at the Fayette Power Project (FPP). While coal only constitutes 32 percent of AE's annual power generation, it accounts for 71 percent of its CO_2 emissions. AE's dilemma is how to plan to meet the energy needs of the public while accounting for changes in emissions regulation, public perception of conventional energy resources, and cost and reliability issues associated with new, less polluting sources of energy. AE is caught between the realities of an effective yet risky business model and a future where energy customers have a vested interest in the source of their power and are served by a utility that is dedicated to environmental leadership and sustainability.

Figure 4: AE CO_2 Emissions by Source (2007)



What is a Sustainable Electric Utility?

Designing a sustainable electric utility is both a challenge in deciding what exactly the term "sustainable" might mean and how to go about reaching such a goal. Sustainability is inherently a subjective term, as it reflects human values and the perceived costs and benefits of any particular activity. Energy affects everyone and people have differing perspectives on how best it should be generated. Debates over whether a particular activity is sustainable often hinge on the tension created by benefits derived from a particular activity and the adverse consequences of that activity. In the energy sector, this debate often comes in the form of economic stability versus environmental consequences. For example, as of 2009 the burning of fossil fuels provides a relatively low cost and reliable source of energy to produce electricity. However, the combustion of these fuels has been associated with the release of CO_2, a potential cause of climate change which could have adverse consequences for future generations.

> **Sustainability** is used in this report to refer to the degree of impact that a particular activity or power generation technology has upon the environment and the availability of resources for future generations.

Sustainability has been defined as "meeting the needs of the present without compromising the ability of future generations to meet their own needs." Some would claim that this definition is far too optimistic or even impossible to meet. It could be argued that even renewable resources utilize some form of material good that is later discarded, whether in the form of metals used for wind turbines or materials used for solar panels. For this reason this study adopts "sustainability" as a relative, rather than absolute, gauge of the degree of impact a resource or technology has upon the availability of natural resources for future generations, as well as the impact of the use of the resource or technology upon the environment. Under this perspective, wind and solar power generation technologies would be more sustainable than power generation based on burning coal and natural gas. Nuclear power generation represents a complex source of energy because nuclear power does not emit GHGs into the atmosphere but the uranium used for nuclear power is a finite resource and its use for power generation produces potentially harmful waste by-products. There also remain risks of nuclear radiation being released from a nuclear accident or terrorist attack. Determining the relative sustainability of a power generation technology in comparison to others is neither transparent nor easy. Some factors for consideration include the costs, capabilities, and limitations of the technology, the context in which it is being used, and how its use can affect the environment and future generations.

Clearly defining sustainability and designing an approach for evaluating technologies based upon this definition is a challenge for developing a sustainable electric utility. This study will adopt an inherently unsatisfying but practical definition for sustainability as it applies to the energy sector. Sustainability is used in this report to refer to the degree of impact that a particular activity or power generation technology has upon the environment and the availability of resources for future generations. Therefore, one activity or technology that poses less adverse consequences for future generations than another activity or technology is more sustainable for the purpose of electric generation.

Measuring the carbon footprint of a power generation mix provides one objective measurement for determining the relative sustainability of a utility. This report uses as a metric an interim goal of AE reaching carbon-neutral status by 2020 as a step towards becoming a sustainable electric utility. This study will compare energy technologies based upon CO_2 emissions per unit of energy generated. This study will define carbon neutrality for an electric utility as reducing CO_2 emissions to the greatest extent possible and then balancing the remaining CO_2 emissions with measurable and reliable CO_2 storage methods or by purchasing offsets.

> **Carbon neutral** status is achieved by reducing CO_2 emissions to the greatest extent possible and then balancing the remaining CO_2 emissions with measurable and reliable CO_2 storage methods or by purchasing offsets.

Given a carbon neutrality definition, the next step is to calculate AE's carbon footprint. AE's carbon footprint measures the amount of CO_2 emissions generated by AE's facilities within a given calendar year. AE has calculated its carbon footprint for the years 2005 through 2007 using the protocols of the California Climate Action Registry (CCAR). These calculations have been verified by a third-party engineering firm and validated by CCAR. This report mimics the methodology used by AE to calculate a carbon footprint based on its baseline energy projections through the year 2020.

Austin Energy's Movement Towards Sustainability

AE has a long history of pioneering sustainability, from energy conservation incentives that began in the 1970's through its green building standards and energy efficiency programs to the award-winning Green Choice® renewable energy pricing plan. AE has become one of the most creative utilities in terms of sustainable practices through its aggressive set of energy efficiency and conservation programs and investments in renewable energy over the past several decades. AE is poised to become one of the first electric utilities in the US to implement an operational smart grid system and has encouraged the adoption of plug-in-hybrid vehicles as a potential means to reduce gasoline-fueled air emissions and as a potential distributed storage venue for electricity. AE's Pecan Street Project now aims to allow Austin to become a testing ground for new energy technologies.

Council passed the Austin Climate Protection Plan (ACPP) in 2007 to reduce Austin's contributions to global warming by 2020. The ACPP directs AE to: (a) establish a cap and reduction plan for all utility emissions; (b) achieve carbon neutrality with any new generation units through low-emission technologies, CO_2 sequestration, and offsets; (c) reduce 700 megawatts (MW) in peak demand through energy efficiency, conservation and DSM by 2020; and (d) meet 30 percent of all energy needs through renewable resources by 2020, including 100 MW of solar power.

In July 2008, AE released its proposed plan for meeting electricity demand through 2020 while meeting the goals of the ACPP. The proposal included a CO_2 cap and reduction plan to limit CO_2 emissions to 2007 levels. Under its proposal, AE would add 1,375 MW of new power generating capacity by 2020, with only 300 MW coming from fossil-fueled resources. Since releasing this plan, AE has made considerable efforts to engage its customers in a public dialogue regarding the proposal and the future energy options for AE. As a public utility, AE considers advice from a variety of stakeholders including Council, Austin citizens, AE customers, AE staff, local industry experts, regulatory officials, and environmental groups. These stakeholders may not agree on the "ideal" power generation portfolio mix to meet demand. For AE to be sustainable it must continue to produce and distribute electricity to serve the needs of the Austin community. AE's public outreach effort, entitled "Austin Smart Energy," has consisted of a series of town hall meetings and meetings with stakeholders to engage the involvement of the public in its investment decisions. The release of AE's "Resource Guide" provides a valuable reference for evaluating the state of its power generation resources and options for future investment. The public participation process and the support of this project are examples of how AE seeks to incorporate diverse perspectives and ideas in the utility's move towards sustainability.

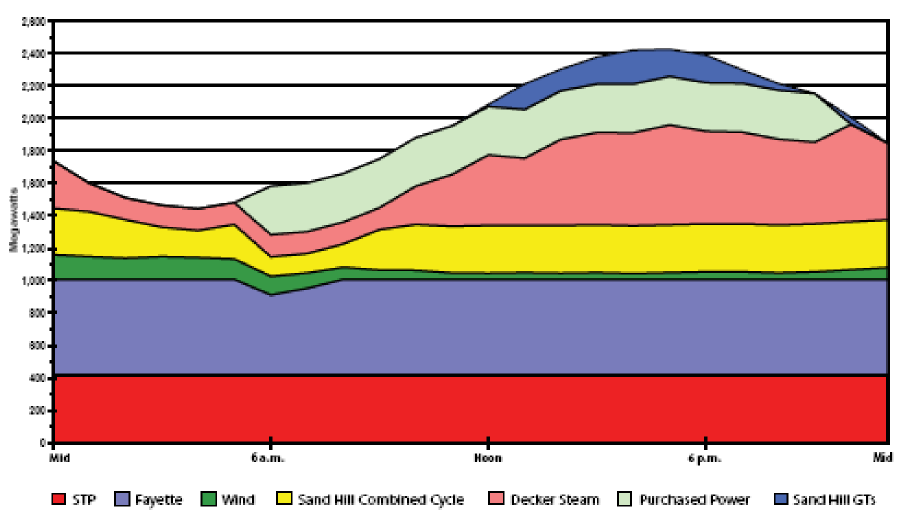
Power Generation Technologies and Other Investment Options

AE makes investment decisions to ensure their power generation mix can meet demand reliably at affordable electric rates for customers. AE provides incentives to replace current power generation facilities with cleaner forms of energy in order to meet its internal renewable energy and carbon reduction goals as well as the goals outlined by the ACPP. New power generation facilities can take many years to site, gain regulatory approval, and construct. Time constraints create a need for long-term planning, consideration of future costs of power generation technologies, and an awareness of the risks and uncertainties that exist in the electric utility and energy sectors. Investing in power generation technologies and facilities benefits a utility by allowing it to control its own assets, reap future returns on investments, and meet regulatory and societal demands. Investing in relatively immature power generation technologies and facilities that use renewable forms of energy (such as biomass, solar, wind or even geothermal) can be made through power purchase agreements (PPA). While such agreements do not allow AE to directly control its own assets, PPAs provide a hedge against cost risks and other uncertainties facing new power generation technologies. It is important for AE to evaluate energy options both in the operational sense as well as for purchase, but such a financial assessment is beyond the scope of this report. This report analyzes the costs of such technologies and facilities based upon current cost estimates for construction and operation of new power generation facilities. In other words, this report assumes for purposes of discussion that under a PPA all real costs will be passed on to AE. Beyond investing solely in power generation technologies, AE also faces opportunities to invest in DSM programs to limit its projected increase in demand, to shift the timing of energy use away from peak use periods, and to invest in infrastructure changes that enhance power system reliability and flexibility.

The project team's assessment of current and future energy options provides the basis for evaluating the integration of future sources of energy into AE's resource portfolio. This report seeks to evaluate the benefits and consequences that these decisions could have for the future of the utility and the Austin community. New technologies continue to improve efficiency and reduce emissions from fossil-fueled and other traditional power generation options. Renewable technologies continue to increase in efficiency, fall in relative costs, and increase in attractiveness as less carbon-intensive sources of energy. New prospects for electric generation and increasing societal pressure to provide clean energy to customers have altered the playing field for power generation investment options. Having a clear and concise understanding of the current state of each electric generation fuel source, as well as the ability to anticipate further advancements to these and other energy-related technologies, is one element for making informed investment decisions. While each power generation technology has proponents and opponents, this report seeks to provide an unbiased perspective by presenting comparative information regarding the advantages and disadvantages of each type of power generation technology (see Appendix B).

Each power generation technology helps meet AE's demand in different ways, incurs varying types of costs, and produces various environmental impacts. Determining the role a particular power generation technology or facility will have in meeting demand, or load, is an element for determining the applicability of the technology for future energy needs. As utilities are limited in their capability to store electricity, load must be met at any given time through the available supply at that time. Some technologies have the ability to provide energy at any time that the plant is in operation. The term baseload power plant refers to one run at all times, except during repairs or scheduled maintenance. Other technologies, such as wind and solar, can only generate electricity during certain periods of the day due to the variable nature of the energy source. A peakload power plant tends to be dispatched

Figure 5: AE Power Generation by Source (typical August peak



Source: Austin Energy

only to meet high demand and prevent loss of customer service or system-wide failure. Figure 5 demonstrates the use of AE's current power generation sources to meet energy demand on a typical August day. Baseload sources are at the bottom of the figure, intermediate in the middle, and peaking at the top. Intermediate power plants fall between baseload and peakload plants in terms of hours of usage and efficiency. These plants tend to come online as load grows. Technology reliability can be measured using its capacity factor or its availability factor. Capacity factor is the measure of actual energy production to total hours in a given period. Availability factor is the percentage of hours in a given period that a plant or technology is available to produce power. Unavailability may be caused by scheduled or unscheduled maintenance or the variable nature of the power source. If a power plant becomes unavailable for whatever reason, it can create costs for a utility, including: removing a power plant owner's revenue stream; requiring owners with sales obligations to customers to pay penalties for contract breach; obligating utilities to purchase higher cost power in the spot market; or even placing a strain on other components of the interconnected power system.

Costs are also a major component of making power generation investment decisions. This report segments costs into five categories: overnight capital costs; fixed operation and maintenance costs; variable operation and maintenance costs; fuel costs; and levelized costs. This report weighs the advantages and disadvantages of alternative energy sources based on load service function, availability and capacity factors, technological maturity, CO_2 emissions, and other costs, benefits, or risks. This analysis of future options includes technologies available for purchase today (2009) and some options that appear viable in the immediate future. Energy sources that cannot be purchased anywhere in the market are treated as unavailable to AE by 2020.

Appendix A lists costs and characteristics of power generation technologies identified in this report. Much of the information on characteristics of these technologies was based on a 2007 report by the National Regulatory Research Institute comparing power generation technologies and data from the Energy Information Adminsitration (EIA), an independent statistical agency within the US Department of Energy. The majority of capital cost estimates come from a report released by the Congressional Research Service (CRS) in November 2008. The CRS estimates are based upon a database of 161 recent power projects. Capital costs are represented in dollars per kilowatt of power generation capacity ($/kW). A potential range of values is provided based upon the maturity of the technology (expected values are in parentheses). Fuel cost and operation and maintenance cost estimates are based primarily upon EIA data converted to 2008 dollars. A range of fuel costs is provided based upon historical price fluctuations and potential changes in fuel prices without carbon regulation imposed. The majority of the levelized costs figures are derived from a 2007 study conducted by the California Energy Commission (CEC) to compare costs of central station electricity generation technologies. A potential range of values is provided based upon the maturity of the technology, with the expected values in parentheses. It should be noted that the capital cost estimates used by the CEC do not reflect those used by the CRS.

Coal

Burning coal produces electricity through a steam turbine. Coal is pulverized into fine dust, air-fed into a boiler, and burned to create steam. The steam spins a turbine to generate electricity. The type and quality of the coal and the intended operating steam pressure and temperature influence the specific design of a pulverized coal power generation plant. There are four types of coal which contain different carbon and moisture contents. Coal with the highest carbon and lowest moisture content has the highest heat value and therefore is the cleanest burning. The Fayette Power Project (FPP), AE's coal burning power plant, accounts for 71 percent of AE's CO_2 emissions, but only 32 percent of AE's annual power generation.

FPP burns a low sulfur-emitting coal from the Powder River Basin in Wyoming, which produces less GHGs than other forms of coal per kilowatt-hour (kWh) of electricity generated.

Integrated Gasification Combined-Cycle (IGCC) power plants could convert coal to a synthetic gas and burn it in a combined-cycle power plant to generate electricity efficiently. Scientists believe that IGCC is the best opportunity to capture the carbon in coal from the feedstock (as opposed to the waste stream) and store that carbon through sequestration methods to eliminate the majority of the CO_2 emissions attributed to traditional coal-based power generation. As no large-scale IGCC with carbon capture and storage technology facility exists in the world, it is unclear when this technology can be purchased on the market and its costs are expected to be high.

The supply of coal in the US is large and inexpensive in comparison to other fossil fuels. Many analysts predict it will continue to be the main staple of the US power generation fuel mix. Mining and transportation costs are rising. If the federal government establishes a carbon cap and trade system or a carbon tax, coal plants are likely to become less attractive compared to other energy sources, as fees for the use of carbon could impose high incremental costs on the utility. The advantages of coal are its relatively low costs, ability to provide baseload power, and reliability. The disadvantages of coal are its environmental impacts, including high CO_2 and other GHG emissions, other air and water pollutants, and large water requirements. Coal also faces uncertainties with regards to fuel price (although less so than natural gas) and the potential impacts of carbon regulation.

For AE to reduce its CO_2 emissions significantly it could divest itself of FPP and find a suitable base-load replacement with low carbon emissions or it could convert FPP to a clean coal plant by retrofitting FPP with a method for removing and then sequestering at least some of the CO_2 emissions. The cost of capturing and storing FPP's CO_2 emissions would increase the plants marginal cost by a considerable amount. As the geology of the land around FPP is not favorable to the most common form of geologic carbon sequestration, AE would have to invest in a CO_2 pipeline to store CO_2 from FPP. Another option for AE is to innovate by investing in a new IGCC power project with carbon capture and storage technology to take advantage of the significant reductions in CO_2 emissions such a facility could achieve.

Natural Gas

There are two common types of turbines that burn natural gas to produce electricity: combustion gas turbines (CGT) and combined cycle turbines (CCGT). A CGT is similar to a jet engine; large fan blades draw in ambient air which is passed through an air compressor, the gas is then burned to heat the air in a combustion chamber and the heated pressurized air expands through a large turbine which is connected to a generator to produce electricity. A CCGT is a CGT with a steam turbine attached to the end of the process. It uses hot exhaust from the CGT cycle to make steam, which is then run through a steam turbine. CCGTs are more efficient than CGTs, with a lower heat rate. AE burns natural gas to provide both intermediate and peaking capacity. The intermediate resources operate with a capacity factor that ranges between 35 and 55 percent. AE currently operates 1,444 megawatts (MW) of natural gas-fired generation capacity. There are two large natural gas-fired plants operated by AE: the Decker Creek Power Station, which is a combustion turbine facility, and the Sand Hill Energy Center, which contains combined cycle units as well as several combustion turbines. AE also owns the Domain and Mueller Energy Plants, each of which have combined heat and power (CHP) units in operation at a combined capacity of 9 MW.

Compared to baseload facilities such as coal and nuclear plants, natural gas facilities are used for intermediate energy needs and require much lower capital construction costs. CO_2 emissions from natural gas are lower per kWh compared to other fossil fuels, producing 30 percent less CO_2 per MWh than oil and almost 45 percent less than coal. Fuel cost is the primary concern for natural gas-fired plants due to erratic fluctuations natural gas prices. Natural gas was once perceived as having three comparative advantages: relatively low capital costs, fewer and less damaging environmental impacts, and low costs per kWh. In the early 1990s, gas-fired power plants became the fuel of choice for electricity generation in the US, with 90 percent of new power generation capacity coming from natural gas plants during that decade. However, with the rise in gas prices and its associated volatility, investment in natural gas plants tempered by 2000, a trend that continues today. Since 2000, it has become increasingly difficult to forecast future natural gas prices.

AE has the capacity to expand the Sand Hill Energy Center to include an additional CCGT. As natural gas turbines can be turned on quickly, natural gas can be used as a backup fuel source to variable renewable energy sources (solar and wind). Expansion of wind and solar power generation capacity coupled with natural gas expansion may relieve some of the risks associated with the variable nature of solar and wind.

Nuclear

Nuclear power generation is similar to most fossil fuel powered electric plants in that it makes steam which turns a generator to produce electricity. The steam pressure needed to turn the turbines comes from the heat of a controlled nuclear fission of uranium-235. Two types of nuclear reactors are licensed by the Nuclear Regulatory Commission to operate in the US: pressurized water reactors and boiling water reactors. There are six components that are common to most nuclear power reactors: fuel, a moderator, control rods, coolant, a pressure vessel, and a steam generator. Nuclear energy generates about twenty percent of the electricity needs of the US. All nuclear power plants are constructed with a containment system that is designed to capture any radiation, typically a re-enforced concrete system at least one meter thick to contain any unlikely malfunction. Safeguards against catastrophic incidents include steel-lined, reinforced concrete containment structures, exclusion zones around the plant, redundant plant shutdown systems, and various other mechanisms to contain radiation in the event of an attack or other incidents. Uncertainties exist regarding the costs of nuclear power plants, as no new plants have been built since 1996. Capital cost estimates for proposed plants continue to escalate. Capital costs estimates range from $2,000-$10,500 per kilowatt (kW) of power generation capacity. The primary advantages of nuclear energy are that it provides a baseload power source with low fuel costs and no direct carbon emissions. Primary disadvantages are high capital cost risks, construction delays, risks of catastrophic incidents, and continued uncertainty regarding the permanent storage of hazardous wastes.

AE currently owns a 16 percent share of the South Texas Power (STP) nuclear facility near Matagorda Bay in Texas. In 2007, NRG Energy, the operator of STP, announced a $6 billion expansion that would add two advanced boiler reactors (2,700 MW of new power generation capacity) to the plant's facilities. In February 2008 and February 2009 Council voted not to participate in the STP expansion proposal.

While it is unlikely that AE will commission its own nuclear power plant, there should be other joint ownership opportunities in the future. AE may have the option to purchase capacity from any of the new plants currently applying for approval in Texas as well as new capacity from the potential expansion of existing plants like STP. Nuclear energy provides a proven baseload power source that does not emit CO_2 and can be available on a large-scale. AE could reconsider the possibilities of adding additional nuclear power to its energy portfolio. Council has previously determined that buying into the proposed new units at STP was not attractive due to the cost and risk of the design and construction. However, if nuclear power plant builders address the uncertainties and the federal government imposes carbon taxes in the near future, the costs and risks of nuclear power may become more attractive relative to alternative sources of electricity.

Hydropower and Pumped Storage

Hydropower creates electricity by converting the kinetic energy of falling water into electric energy. Conventional hydroelectric power is created by damming a river; the resulting reservoir releases water through turbines which spin generators to produce electricity. Pumped storage can be used in conjunction with hydropower facilities to store potential energy by pumping water up between lakes and later releasing the water to produce energy. New hydroelectric investment is unlikely in Texas due to the potential environmental impacts associated with any new large reservoirs and the lack of additional large bodies of water that flow year-round and can be used as hydro-electric resources.

The Lower Colorado River Authority (LCRA) owns and operates six hydroelectric dams, with a combined capacity of 281 MW of power and storage capacity of up to 81 billion gallons of water. Two LCRA lakes, Lake Buchanan and Inks Lake, were once plumbed with a back unit for pumped storage, though they have not been operated as such for many years. The Buchannan Dam is a viable location for the implementation of a pumped storage unit. AE could seek collaboration with LCRA for the implementation and joint use of a pumped storage unit. The implementation of pumped storage at LCRA dams could provide a rapid source of electricity that could be valuable as a source of energy to respond to daily peak demand. As Lake Buchannan and Inks Lake were once plumbed with a pumped storage unit, the incremental costs to create a pumped storage unit at these lakes would be the cost of construction and installation of a pump and its operation. Wind energy, typically available at night in excess of demand, could be used to pump water from a lower reservoir to a higher reservoir so the water could then be dispatched to generate electricity during periods of peak demand.

Wind

Wind power generation is a reliable and low cost renewable energy source. Wind power generation achieved prominence in Texas due to its abundant availability in West Texas and support from state subsidies. Wind power is becoming cost-competitive with traditional power generation technologies without state subsidies. The greatest concern of heavy reliance on wind power is its variable nature. Onshore winds are strongest in the early morning off-peak hours and only can be relied on to generate at about 8-9 percent nameplate capacity during peak demand. Offshore wind turbines are more costly and rare than onshore wind turbines (currently no wind turbines exist off the coast anywhere in the US), but they could generate much more power than onshore wind turbines during peak demand hours.

Wind power generation converts the motion of wind into electricity through the use of a turbine and its blades. A drive shaft is attached to the blades, which rotates the electric generator to produce electric power. The capacity of a wind turbine is related to its height, the area swept by the blades, and the speed of the wind. Wind farms include many wind turbine structures that convert wind into electricity. Most wind farms require wind speeds of at least 14 to 15 miles per hour. AE’s resource portfolio currently includes 440 MW of wind-powered electricity, generated from five sites across West Texas and the Panhandle.

The primary advantages of wind are relatively low capital costs, no fuel costs, and few environmental impacts. The primary disadvantage is its unreliability due to the variable nature of wind and distance from population centers.

The Public Utility Commission of Texas is investing five billion dollars to build transmission lines from West Texas to reach load centers in Texas' major metropolitan areas, including Austin. This investment should allow and encourage the construction of more Texas wind farms. AE can continue to enter into PPAs with new on-shore and off-shore wind projects and renew older contracts. Off-shore wind projects cost more, but may provide much more valuable peak power than on-shore wind sources. Off-shore wind projects can complement on-shore wind due to complementary wind profiles. West Energy Systems is planning to construct an off-shore wind farm near Galveston that may produce 150 MW of electricity. Energy storage technologies could complement on-shore wind projects by shifting excess power produced during off-peak hours to peak demand times.

Solar

Solar energy converts sunlight into electricity. Solar energy is a renewable and accessible resource that can be used to generate light, heat, and electricity. This report evaluates three types of solar-based power generation technologies: concentrated solar power (CSP) systems, photovoltaic (PV) solar technologies, and solar water heating technologies. Concentrated solar power technologies focus direct radiation to create heat and produce hot fluids or gases. Photovoltaic cell systems and other solar technologies convert diffused radiation with electricity directly without hot fluid or gas. Solar plants could potentially serve as baseload facilities if solar energy generated and stored when the sun shines could be dispatched for use during off-peak periods.

CSP technologies (such as parabolic troughs, power towers, and solar dish/engines) collect and concentrate sunlight to transform it into thermal energy to drive an engine and generate power. Parabolic trough systems use curved u-shaped mirrors to concentrate the sun's energy to 30 to 60 times its normal intensity. The thermal energy heats a transfer fluid producing steam, which moves a turbine, generating electricity. A collector field is formed with many parallel rows of troughs connected in a series. The rows can be oriented north to south to allow the collectors to track the sunlight east to west by focusing the energy on a receiver pipe. Parabolic trough CSP systems are currently the lowest-cost solar systems and have been built to the largest capacity; to keep calculations straightforward this report assumes future CSP investment will be in parabolic trough systems as a surrogate for any CSP system. Dish/engine systems consist of parabolic curved mirrors that face the sun and direct and concentrated light to heat gaseous hydrogen or helium, which in turn causes an electric motor to spin, generating electricity. There are also CSP systems that use parabolic dish mirrors to focus light on a cluster of PV cells. An alternative disk/engine technology uses solar radiation to heat pipes in which the boiling and condensing of an intermediate fluid is used to transfer heat from the receiver to an engine. Power tower systems use large mirrors to concentrate the sun's energy at the top of a tower to heat a fluid such as molten salt, which flows through the receiver to generate electricity through a steam generator.

PV technologies convert the energy contained in photons of light into electrical voltage and current. PVs produce direct current power. Electricity from PV cells is converted into alternating current power before it can be transmitted and distributed. Two types of PV solar panels, silicon-based and thin film, differ in manufacturing materials, cost, and efficiency. Most PV arrays are residential or commercial, though larger PV power plants can provide several MW of power generation capacity.

Solar water heating technologies use sunlight to heat water or a heat-transfer fluid in a solar collector. The heated water is then stored for later use. Solar water heating systems can be either “active” or “passive.” Active systems, the most common type used in the US, rely on pumps to circulate water. Passive systems rely on gravity and the tendency for water to circulate naturally when heated. Solar thermal energy systems have industrial and household applications, such as the provision of hot water for the home or industry, or heating of swimming pools.

One advantage of solar is that its availability tends to correspond with peak demand. Additional advantages include the lack of direct GHG emissions and negligible water pollution and solid and hazardous waste generation. The disadvantages of solar energy are relatively high capital costs, the unreliable nature of the source (sunlight), and the inability to serve as a baseload power source unless a storage technology is applied. Additional disadvantages are that solar technologies tend to have a low capacity factor, require substantial land use per kW (although lower than wind farms), and may require additional transmission infrastructure if the solar site is not at the load center.

The ACPP has directed AE to increase its solar energy power generation capacity to 100 MW by 2020. AE has demonstrated considerable interest in PV systems through its solar rebate program. However, solar panels in Austin only constitute about 1-2 MW of AE’s current power generation mix. AE has plans to construct 100 MW of distributed solar capacity on rooftops alone through the Pecan Street Project, but it is unclear whether it can meet this ambitious goal. In order to meet its 100 MW goal AE may need to invest in utility-scale PV or CSP plants. Council recently approved a proposal by AE to cover about 200 acres of the city-owned “Webberville tract” near Manor with PV solar panels to generate a total capacity of 30 MW of power. Currently, the largest centralized PV solar plant in the US provides 25 MW of power generation capacity. AE could look at investing in a CSP system in West Texas to provide a substantial amount of power during peak demand. The largest existing CSP system in the US has a nameplate capacity of 100 MW. CSP projects ranging in size from 200-550 MW are currently in the planning and construction stages. Currently no CSP system exists in Texas. Solar thermal systems have diverse applications for residential and industrial uses. Thermal storage systems can operate at large-scale commercial, industrial and manufacturing centers based on the unique needs of their customers. These systems can stand alone or work in concert with combined cooling and heating systems. AE currently operates a home energy solar rebate program and could expand it, but it is unlikely that enough homeowners would invest in PV systems in order for home PV systems to contribute significantly to reducing AE’s energy demand.

Biomass

Biomass power refers to electric power generated from the burning of organic, bio-degradable feedstock or waste such as wood wastes or gas generated from refuse. Biomass is used as a fuel in turbines, engines and coal-fired burners. Biomass can be burned in a furnace and the resulting heat can boil water, creating steam, which turns a turbine to generate electricity. Biomass is often considered a renewable energy source because it uses vegetation and natural waste that exists in the carbon cycle. Biomass can also be tapped at a landfill, wastewater treatment plant (anaerobic sludge digestion), or animal feedlot (using anaerobic digestion of the manure). This methane can be shipped through pipelines to a power plant. Animal feedlots can utilize methane in a similar way to produce energy for a farm. Turning landfill gas into power is considered a clean energy source because it captures methane, a GHG that is 21 times as potent as CO_2.

AE has contracted to receive wood-fired biomass energy through a PPA with Nacogdoches Power that is expected to begin providing electricity in 2012. This 100 MW biomass facility located in East Texas will be among the largest currently in operation in the US. In order to reduce its environmental impact, the boiler will be fitted with systems to control nitrogen oxide emissions. AE currently has two PPAs with a combined capacity of 12 MW landfill gas power plants that currently provides some of the power generated for AE's Green Choice® customers.

Biomass power can serve as a "renewable" energy source that can provide baseload power at costs lower than solar energy. Technologies exist to capture some air pollutants from burning biomass before they enter the atmosphere. Co-firing biomass with coal could reduce CO_2 emissions from FPP. Biomass power is a relatively mature technology with few risks. Disadvantages are the limited supplies of biomass and the fact that biomass power generates air and water pollution and solid waste. Carbon regulation may discourage biomass use for generating power, including co-firing with coal (despite reductions in emissions) depending on how CO_2 and other GHGs are defined and regulated. Co-firing coal with a 15 percent mix of biomass at FPP provides an option for AE to reduce its CO_2 emissions from the facility that constitutes 71 percent of its total CO_2 emissions.

A biomass combustion plant can provide a source of reliable, relatively clean baseload power. The Nacogdoches biomass plant was the lowest-cost biomass combustion plant available to AE at the time Council approved its contract. It was less costly per kWh than solar, while also achieving objectives of the ACPP and improving the diversity of power generation technologies in AE's portfolio. If the Nacogdoches plant proves to be cost-competitive and as reliable as a coal baseload power plant, there is potential for replicating such plants. Future biomass plants also might be located in East Texas where logging residue is readily available. Future plants comparable in size to the Nacogdoches plant may come down in costs as familiarity with construction practices and technology improvements occur. Although the City of Austin has banned landfill construction within city limits, if new landfills are constructed in or near Austin, they could generate additional small increments of power by burning landfill gas as a clean energy source.

Geothermal

Geothermal power plants tap into heat stored beneath the earth's surface to produce electricity that can serve as a baseload power source for electric utilities. The three main types of geothermal plants are dry steam, flash steam, and binary-cycle plants. Dry steam plants, the oldest form of geothermal power generation, use steam directly to turn conventional turbines, much like a conventional coal plant, but without the need for fossil fuels. Flash steam plants use a high-temperature geothermal fluid that is injected into a low-pressure tank, causing the fluid to vaporize and turn a turbine. Secondary flash tanks can be constructed to vaporize or "flash" the remaining high-temperature liquid. Binary-cycle plants utilize the geothermal fluids to heat another liquid with a much lower boiling point than water. The secondary liquid is then vaporized as in a flash steam plant.

The US is the global leader in geothermal energy accounting for approximately 30 percent of the world's total geothermal power production capacity. In 2007, geothermal power accounted for 3,000 MW of total US electricity generation, or 4 percent of total renewable energy-based production. Geothermal power accounts for 5 percent of the California's power needs (2.4 million households).

Although geothermal sources have been used for some time in Texas for spas and heating, there are currently no large-scale (50 MW of more) geothermal plants that generate electricity in Texas. Ground source heat pumps are currently used throughout the state to heat and cool residences, commercial buildings, and schools. The Texas State Energy Conservation Office and Southern Methodist University's Geothermal Laboratory estimate that Texas could develop between 2,000 and 10,000 MW of geothermal generation capacity in the next ten years by taking advantage of oil and gas drilling sites, thereby reducing the cost of exploration. Although Texas geothermal areas are primarily less than 100 degrees Celsius near the surface, there are areas accessible through existing deep oil and gas wells with temperatures of 180 degrees Celsius in West Texas and 200 degrees Celsius in East Texas. These locations provide a good potential for future geothermal power generation through either current or abandoned oil and gas wells.

The primary advantages of geothermal energy are no fuel costs, negligible GHG emissions, no solid waste, low energy costs relative to other renewable resources, and its ability to serve as a baseload power source. There are no major economic or financial risks associated with this technology other than source exploration which occurs at the outset of project development. These risks have been lowered in recent years due to rich data regarding potential sites gathered by both government entities in Texas and the oil and gas industry. The primary disadvantage of geothermal technologies are relatively high overnight costs as deeper wells needed to reach some geothermal sources lead to higher construction costs. Geothermal power is accessible and price competitive close to locations where hot water or steam can be tapped. The release of geothermal fluids on the surface can affect both surface waters and groundwater, though it is common practice to re-inject the fluids back into the well from which they came, reducing this impact.

Transmission costs and energy losses could diminish any cost advantages of using geothermal energy located in West Texas for power production in Central Texas. However, transmission lines currently under construction to tap into the vast West Texas wind potential could be used to deliver geothermal energy from West to Central Texas. Given that Texas' Public Utility Commission is investing $5 billion in transmission lines for West Texas, there may be opportunity for use of geothermal power for AE in the future depending on the costs associated with the proposed facility. There is also much potential to develop geothermal resources located in East Texas near the Gulf of Mexico.

Ocean Power

Wind, wave, and tidal technologies produce energy from the ocean. Oceans cover more than two-thirds of the earth's surface and represent a vast resource of renewable energy. Three ocean energy generation technologies have been developed: tidal barrages, wave power generation, and underwater turbines. Tidal barrage generators act like underwater dams by utilizing the flow of water between high and low tides. Wave power generation uses the ebb and flow of waves to move hydraulic rams back and forth through waves to create energy. Underwater turbines essentially work the same as underwater wind farms, using water currents instead of wind. These systems can be designed for larger bodies of water depending on the velocity of currents in the area. Ocean currents and tidal flows create high-energy yields because water is 1000 times denser than air. Ocean energy sources produce variable power as the amount of energy production fluctuates depending on currents, tides and waves. All ocean power technologies are classified as experimental, but there are operating examples of each identified technology. The output of each approach varies by location and is dependent on the strength of tidal flows, water currents, and wave height.

Advantages of ocean power include no fuel costs, GHG emissions, or solid waste produced. Transmission lines established along the Texas coast could be lower in construction costs than other ocean sites. Disadvantages of ocean energy include high construction costs, unknown impacts on ocean ecosystems and fish populations, harsh corrosive environment of the sea and, extreme weather, such as hurricanes. Currently, there are no federal or state tax breaks for ocean wave/tidal energy projects.

There are no existing ocean power projects in Texas or the southeast US. Texas coasts along the Gulf of Mexico do not possess ideal conditions for low-cost or high-performance ocean-based renewable energy. High construction and maintenance costs, as well as the costs of transmission lines or cables, represent a cost risk. Tidal and wave energy levels around Texas are too low to utilize existing technologies in an economically viable renewable energy program. Areas of the world with much greater ocean energy potential are more likely sites for developing commercially viable ocean power generation technology. Given these considerations, ocean energy is not likely to become an option for AE to provide power by 2020.

Energy Storage

Energy storage that absorbs low-cost off-peak electricity to yield electricity during peak-use periods could increase the value of solar, wind, or other variable renewable energy sources. Energy storage technologies could improve the quality and reliability of power to users during peak demand, provide low-cost electricity to customers, and reduce CO_2 and other GHG emissions. Energy storage has the potential to avoid the need for costly peaking power plants and can be used to arbitrage the costs of electricity over time. Storage technologies can be classified by size: Large-scale or utility-scale bulk storage is usually recognized as having as storage capacity between 10 and 500 MW, medium-scale is between 100 kWs and 10 MW, and small-scale is between 1 and 100 kWs, also called distributed energy storage. Large-scale storage technologies include pumped hydroelectric storage and compressed air energy storage (CAES). Medium and small scale technologies include everything from batteries and flywheels to ultra-capacitors and even electric cars. The key difference between utility scale and medium/small scale energy storage is that utility scale storage can provide electricity that can be managed and dispatched. Medium and small scale storage technologies are better adept at providing grid support, power conditioning, and demand reduction at the consumer delivery point.

Utility-scale energy storage technologies could mitigate the variable nature of renewable resources such as solar and wind and make them more reliable sources of energy. Energy storage could also provide a sink for excess energy from base-load plants at times of very low demand when it is not favorable to curtail coal or nuclear resources. Disadvantages of energy storage technologies are the immaturity of the technology and the difficulty to anticipate how such technologies could best be implemented.

AE has already identified CAES (which uses compressed air to increase the efficiency of a simple-cycle natural gas generator) as a viable technology for immediate implementation. Coupling energy storage with wind power production may be the most valuable way to utilize a large-scale storage system given the hours at which solar and wind generate power. Excess wind capacity, which blows strongest during off-peak hours, could be shifted to peak hours to provide a less costly peak power source. AE is currently evaluating the investment potential of a large CAES system (in the range of 200 MW), a small distributed power generation CAES system where the storage device is above ground, and a novel compressed energy storage plant using stored thermal energy from a solar collector field that would circumvent the need to burn natural gas. Further investments in thermal energy storage, flywheels, and battery technologies could provide opportunities to reduce peak demand, balance the intermittent renewable resources in AE's portfolio, and reduce AE's carbon footprint.

Demand Side Management

AE reports that demand side management (DSM) programs have reduced peak demand by 600 MW since 1982. DSM is a term that refers to a myriad of programs, technologies, and techniques that lower electricity demand. Conservation, load-shifting, peak-smoothing, demand response, direct load control and pricing schedules can encourage reductions in energy use which can defer the need for capital investment in new power plants or avoid the costs of serving load at a demand peak. DSM is commonly cited as cheaper than investing in new power generation sources.

AE offers voluntary opportunities to its consumers to reduce their energy consumption and hopes to achieve an additional 700 MW of peak demand savings through 2020. It is unclear whether AE can reduce energy demand beyond this goal or even meet the goal due to the uncertainty involved regarding new technologies becoming available that can increase efficiency and reduce demand. Pricing methods such as time-of-use and real-time pricing, adoption of smart grid enabled technologies, and voluntary behavior change programs have been identified by this report as significant opportunities for AE to help meet or exceed their demand reduction goal.

Future Resource Portfolio Analysis

The primary goal of AE is to ensure that its power generation mix can meet demand reliably at affordable electric rates for customers. AE is now faced with additional goals set forth by the ACPP to increase the amount of renewable energy resources used and reduce the amount of CO_2 emitted into the atmosphere that can be directly attributed to its resource mix. While the benchmarks set by the ACPP aim to reduce dependence on traditional fossil fuels and limit CO_2 emissions, this report seeks to take these goals further by evaluating the impacts of moving toward a sustainable AE. The primary goal of this research project is to evaluate sustainable energy options for AE with the interim goal of reaching carbon neutrality by 2020. Four criteria were identified as critical to the evaluation of the relative merits of different future energy options given the project goal: *system reliability; costs and economic impacts; carbon reductions, and risks and uncertainties*.

In order to assess power generation resource portfolio options, the project team designed a user-friendly spreadsheet relying on Microsoft Excel to automate calculations and displays. This simulator allows the user to compute the consequences of a selection of power generation and energy storage technology additions and subtractions made to AE's resource mix between 2009 through 2020. A user can select an investment plan and run it quickly. Inputs include potential power generation and associated technology investments and the associated availability factors, capacity factors, capital costs, fuel costs, and levelized cost of electricity associated with these technologies. The user can manipulate the investments in different technologies, the characteristics of these technologies, and the cost data to align with their assumptions or preferences. The software produces a series of charts and graphs that allow the user to compare different resource portfolio scenarios along the four identified criteria. Appendix C details the methodology, major assumptions made, and limitations of the model.

The report evaluates a diverse set of options from more coal and nuclear energy to a future resource portfolio based primarily on renewable power generation sources including biomass, geothermal, solar, and wind. Seven primary scenarios were tested to demonstrate the diversity of investment opportunities along with a base case for comparison, AE’s proposed energy resource plan. Scenarios include:

- AE’s proposed energy resource plan;
- nuclear expansion;
- a high renewable energy investment;
- an expected available renewable energy investment;
- an expected available renewable energy investment with energy storage capacity;
- natural gas expansion;

- addition of integrated gasification combined cycle coal-fired facility enabled with carbon capture and sequestration technology to replace current coal facility (FPP); and
- high renewable energy investment to replace both coal and nuclear.

The eight scenarios recognize and assess the impacts of different and distinctive approaches to reducing AE's carbon footprint. The evaluation of these eight scenarios is not intended to preclude the consideration or evaluation of other potential AE investment plans.

The following portion of the report describes the eight scenarios. A discussion of the advantages and disadvantages of the eight scenarios then follows. The range of outputs are presented for three of these scenarios: AE's proposed energy resource plan; nuclear expansion; and high renewable energy investment).

Portfolio Option 1 (Baseline Scenario): Austin Energy's Proposed Energy Resource Plan

In July 2008 AE released a proposed energy resource plan for meeting energy demand through 2020 while remaining under a proposed CO_2 cap and reduction plan (see Table 1). AE proposed adding 1,375 additional MW of power generating capacity to its current resource mix by 2020, with 300 MW coming from fossil-fueled resources. The wind and natural gas planned additions for 2009, planned wind additions for 2011, the proposed centralized photovoltaic (PV) module system for 2010, and the biomass project expected to be available by 2012 have been included in all potential scenario runs as all have been approved by Council.

Table 1: AE Resource Plan Scheduled Additions

Schedule of power generation additions and subtractions (net MW)													
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	607	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	422	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 1-4	189	100	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 5	312	0	0	0	0	200	0	0	0	0	0	0	0
Natural Gas - Decker 1 & 2	741	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker CGT	193	0	0	0	0	0	0	0	0	0	0	0	0
Wind	274	165	0	23	0	0	50	100	0	74	0	50	110
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	100	0	0	0	100	0	0	0	0
FPP w/ biomass co-firing	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas	12	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV - Centralized	0	0	30	0	0	0	0	0	0	0	0	0	0
Solar PV - Distributed	1	0	0	0	0	0	20	0	0	20	0	0	0
Concentrated Solar	0	0	0	0	0	0	0	0	0	0	0	30	0
IGCC w/ CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
IGCC w/o CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0
Accelerated Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0

AE's plan includes 200 MW of additional capacity at the Sand Hill Energy Center, proposed for 2013. This would be a combined cycle expansion project that would provide reliable energy with lower megawatt-hour carbon emissions than coal. An additional 100 MW of purchased biomass generating capacity has also been recommended for 2016. AE's primary investment in new generation capacity is an addition of 775 MW of generating capacity from wind facilities. AE's existing contracts for 77 MW and 126 MW of current wind generating capacity are set to expire in 2011 and 2017, respectively. AE may be able to renew these contracts at that time. AE has also proposed a gradual investment in solar energy to meet the ACPP goal of providing 100 MW of solar capacity by 2020. AE has not stated whether the solar capacity additions for the years 2014, 2017, and 2019 are expected to come from distributed solar PVs, centralized PV systems, or concentrated solar facilities. For the purposes of this analysis, it has been assumed that the 2014 and 2017 additions are cumulative investments in distributed PV systems up to that year and the 2019 addition will be a concentrating solar facility.

Portfolio Option 2: Nuclear Expansion Scenario

The nuclear expansion scenario aligns with AE's proposed energy resource plan while replacing all of AE's coal resources with nuclear (see Table 2). Additional nuclear capacity allows coal to be replaced with a reliable and emission-free baseload power source. Nuclear energy raises security and environmental concerns related to nuclear waste and large coolant water requirements.

Table 2: Nuclear Expansion Scenario Scheduled Additions

Schedule of power generation additions and subtractions (net MW)													
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	607	0	0	0	0	0	0	0	0	0	-607	0	0
Nuclear	422	0	0	0	0	0	0	0	0	0	422	0	0
Natural Gas - Sand Hill 1-4	189	100	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 5	312	0	0	0	0	200	0	0	0	0	0	0	0
Natural Gas - Decker 1 & 2	741	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker CGT	193	0	0	0	0	0	0	0	0	0	0	0	0
Wind	274	165	0	23	0	0	50	100	0	74	0	50	110
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	100	0	0	0	100	0	0	0	0
FPP w/ biomass co-firing	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas	12	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV - Centralized	0	0	30	0	0	0	0	0	0	0	0	0	0
Solar PV - Distributed	1	0	0	0	0	0	20	0	0	20	0	0	0
Concentrated Solar	0	0	0	0	0	0	0	0	0	0	0	30	0
IGCC w/ CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
IGCC w/o CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0
Accelerated Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0

Under this scenario 607 MW of coal (the current power generating capacity of AE's stake in FPP) is replaced in 2018 by a doubling of current nuclear energy capacity (422 MW). It is assumed that the additional units proposed for expansion at STP and other expansion proposals would come to fruition by that time to provide available nuclear capacity that could be purchased by AE beginning in 2018. While AE may not be directly involved in the funding of the construction of the facility from which this nuclear power would be purchased, it is assumed that the costs of capital will be accounted for in the levelized cost of electricity. This scenario and some other scenarios include the divestment of all or a portion of AE's stake in FPP. No analyses attempts to infer a monetary value from reducing or removing coal or any other resource from AE's resource portfolio, as the methods for evaluating how much AE could receive for such a sale or lease are beyond the scope of this report. Such removal may help to alleviate the additional costs to electricity accrued from resource additions.

Portfolio Option 3: High Renewable Resources Scenario

The high renewable resources scenario presents an ambitious and optimistic implementation of renewable energy resources through 2020 to replace the use of coal by AE (see Table 3). Investments are made gradually, assuming expansion in both renewable power generation technologies and Texas' electric grid. Utility-scale solar, geothermal and biomass power plants are limited in size by expected resource availability and facility capacity constraints. Wind expansion is assumed to be unconstrained by capacity limitations.

Table 3: High Renewables Scenario Scheduled Additions

Schedule of power generation additions and subtractions (net MW)													
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	607	0	0	0	0	0	-305	0	0	0	0	0	-302
Nuclear	422	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 1-4	189	100	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 5	312	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker 1 & 2	741	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker CGT	193	0	0	0	0	0	0	0	0	0	0	0	0
Wind	274	165	0	100	0	0	100	200	0	526	0	100	220
Offshore Wind	0	0	0	0	50	0	50	0	50	0	50	0	105
Biomass	0	0	0	0	100	0	0	0	100	0	0	0	90
FPP w/ biomass co-firing	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas	12	0	0	0	0	0	0	0	15	0	0	0	0
Solar PV - Centralized	0	0	30	0	0	0	50	0	0	70	0	100	0
Solar PV - Distributed	1	0	5	5	5	5	5	5	5	5	5	5	5
Concentrated Solar	0	0	0	0	0	0	305	0	0	0	0	0	302
IGCC w/ CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
IGCC w/o CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	50	0	0	0	50	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0
Accelerated Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0

Biomass and geothermal power plants can provide baseload power that is available continuously in the same manner as coal, hydroelectric, and nuclear facilities. Therefore, biomass and geothermal plants provide a reliable source of energy as long as supplies are available. In addition to the biomass project that will begin operation in 2012, AE has proposed an additional 100 MW biomass project to come on-line in 2016. This scenario includes an additional 90 MW of biomass generation capacity to be added in 2020. Although no geothermal power plant currently exists in Texas, there appears to be potential for geothermal power production. This scenario proposes a total of 100 MW of geothermal energy to be added to AE’s resource portfolio, with 50 MW additions occurring in 2014 and 2020, respectively. An addition of 15 MW of landfill gas power in 2016 provides an additional source of local baseload power.

Wind and solar resources provide a carbon-neutral source of energy, but these resources are variable in nature. AE is currently proposing an aggressive expansion of wind and solar assets (to 1,029 MW and 101 MW of power generation capacity, respectively). The high renewables scenario invests in more wind and solar assets (to 1,990 and 913 MW of wind and solar power generation capacity, respectively). Solar additions include the construction of two utility-scale concentrated solar plants (CSP) that use parabolic trough methods (currently the most advanced and least cost option for CSP), accelerated investments in local distributed power generation from solar photovoltaic (PV) panels on rooftops, and gradual investment in centralized PV systems. Onshore wind energy investments under this scenario are almost double that proposed by AE through 2020. In this scenario a gradual addition of 305 MW of offshore wind power generation capacity is included to tap into a wind source available during peak hours.

Resource Portfolio Option 4: Expected Available Renewable Resources Scenario

The expected available renewable resources scenario is a compromise between AE’s proposed resource plan and the high renewable resources scenario that provides a more realistic outlook on the availability and practicality of renewable resources (see Table 4).

Table 4: Expected Renewables Scheduled Additions

Schedule of power generation additions and subtractions (net MW)													
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	607	0	0	0	0	0	0	0	0	0	-305	0	0
Nuclear	422	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 1-4	189	100	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 5	312	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker 1 & 2	741	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker CGT	193	0	0	0	0	0	0	0	0	0	0	0	0
Wind	274	165	0	23	0	0	50	100	0	74	0	50	110
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	100	0	0	0	100	0	0	0	0
FPP w/ biomass co-firing	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas	12	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV - Centralized	0	0	30	0	0	0	50	0	0	0	0	50	0
Solar PV - Distributed	1	0	1	1	1	1	1	1	1	1	1	1	1
Concentrated Solar	0	0	0	0	0	0	100	0	0	0	0	0	100
IGCC w/ CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
IGCC w/o CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0
Accelerated Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0

Under option 4, AE eliminates half of its coal use by 2020. To account for lost coal baseload power, this scenario maintains the investment schedule proposed by AE for wind, natural gas, and biomass additions by 2020 and adds greater solar investments (341 MW versus 100 MW in AE's plan), which is two-thirds less than the solar investment included in scenario 3 for high renewables. In addition to the currently scheduled 30 MW centralized solar installation scheduled in 2010, scenario 4 installs two 50 MW centralized solar PV facilities (one in 2014 and another in 2019) and two 100 MW concentrating solar parabolic trough facilities in 2014 and 2020. Distributed solar PV installation is assumed to occur at a rate of 1 MW per year beginning in 2010 (since a typical residential installation is about 3 kW and 1 MW equals 1,000 kW, this would translate into the installation of about 333 residential PV systems per year). AE has no plans as of 2009 to acquire any geothermal or offshore wind sources. Scenario 4 does not include any.

Portfolio Option 5: Expected Available Renewable Resources with Energy Storage Scenario

This scenario incorporates possible energy storage capacity into the expected available renewable resources scenario (see Table 5). This scenario strives to address the two primary failings of portfolio option 4: a failure to meet the peak daily demand by 200 MW and the divestment of AE's remaining coal resources (302 MW).

Table 5: Expected Renewables with Energy Storage Scheduled Additions

Schedule of power generation additions and subtractions (net MW)													
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	607	0	0	0	0	0	0	0	-305	0	0	0	-302
Nuclear	422	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 1-4	189	100	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 5	312	0	0	0	0	200	0	0	0	0	0	0	0
Natural Gas - Decker 1 & 2	741	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker CGT	193	0	0	0	0	0	0	0	0	0	0	0	0
Wind	274	165	0	23	0	0	0	0	0	24	0	0	10
Wind + CAES	0	0	0	0	0	0	50	100	0	50	0	50	100
Biomass	0	0	0	0	100	0	0	0	100	0	0	0	0
FPP w/ biomass co-firing	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas	12	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV - Centralized	0	0	30	0	0	0	50	0	0	0	0	50	0
Solar PV - Distributed	1	0	1	1	1	1	1	1	1	1	1	1	1
Concentrated Solar	0	0	0	0	0	0	100	0	0	0	0	0	100
IGCC w/ CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
IGCC w/o CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	50	100	0	50	0	50	100
Accelerated Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0

This scenario introduces several additions of compressed air energy storage (CAES) facilities that could combine to store a capacity of 350 MW by 2020. CAES was chosen as the most viable energy storage technology in the short-term due to its relatively low capital costs and reliability at utility-scale. In principle, pumped storage on the Colorado River could be used as a form of energy source, but AE has yet to discuss such an option with the Lower Colorado River Authority so its is not considered as an option in option 5. As electricity demand peaks during afternoons in the summer when solar output is producing near its maximum and wind is producing near its minimum, CAES is paired with wind facilities. This scenario permits the CAES system to capture excess nighttime electricity generated by paired wind facilities to be dispatched during peak afternoons and evenings when demand is at its peak.

Portfolio Option 6: Natural Gas Expansion Scenario

The natural gas expansion scenario represents a strategy of gradually replacing coal with natural gas (see Table 6). While burning natural gas releases CO_2, it is less carbon-intensive than coal.

Table 6: Natural Gas Expansion Scheduled Additions

Schedule of power generation additions and subtractions (net MW)													
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	607	0	0	0	0	0	-305	0	-302	0	0	0	0
Nuclear	422	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 1-4	189	100	0	0	0	0	0	0	302	0	0	0	0
Natural Gas - Sand Hill 5	312	0	0	0	0	0	305	0	0	0	0	0	0
Natural Gas - Decker 1 & 2	741	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker CGT	193	0	0	0	0	0	0	0	0	0	0	0	0
Wind	274	165	0	23	0	0	0	0	0	0	0	0	0
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	100	0	0	0	0	0	0	0	0
FPP w/ biomass co-firing	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas	12	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV - Centralized	0	0	30	0	0	0	0	0	0	0	0	0	0
Solar PV - Distributed	1	0	0	0	0	0	0	0	0	0	0	0	0
Concentrated Solar	0	0	0	0	0	0	0	0	0	0	0	0	0
IGCC w/ CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
IGCC w/o CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0
Accelerated Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0

This scenario proposes an addition of 607 MW of natural gas to replace the two units that AE owns at FPP by 2016. The 2014 addition would be a combined cycle expansion at Sand Hill Energy Center. In 2016 several advanced gas combustion turbine units would be added to Sand Hill. This scenario includes all scheduled resource additions through 2012, but does not include any other investments through 2012. This scenario would essentially use natural gas as a baseload power source to replace lost coal-fired baseload capacity at FPP. Investments in energy resources beyond natural gas are consistent with AE's proposed resource plan. This scenario demonstrates the impact and costs of replacing coal with natural gas to reduce CO_2 emissions.

Portfolio Option 7: Cleaner Coal Scenario

The cleaner coal scenario seeks to replace FPP with an integrated gasification combined cycle (IGCC) coal plant equipped with carbon capture and sequestration technology (see Table 7).

Table 7: Cleaner Coal Scheduled Additions

Schedule of power generation additions and subtractions (net MW)													
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	607	0	0	0	0	0	0	0	0	0	0	0	-607
Nuclear	422	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 1-4	189	100	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 5	312	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker 1 & 2	741	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker CGT	193	0	0	0	0	0	0	0	0	0	0	0	0
Wind	274	165	0	23	0	0	0	0	0	0	0	0	0
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	100	0	0	0	0	0	0	0	0
FPP w/ biomass co-firing	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas	12	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV - Centralized	0	0	30	0	0	0	0	0	0	0	0	0	0
Solar PV - Distributed	1	0	0	0	0	0	0	0	0	0	0	0	0
Concentrated Solar	0	0	0	0	0	0	0	0	0	0	0	0	0
IGCC w/ CCS	0	0	0	0	0	0	0	0	0	0	0	0	607
IGCC w/o CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0
Accelerated Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0

This scenario would sustain the use of coal while reducing CO_2 emissions from this source. Cleaner coal plants can provide a baseload source of power. An IGGCC power plant with carbon capture and storage technology produces energy at the same magnitude as a traditional pulverized coal plant at a much higher efficiency while releasing much less CO_2 per MWh. However, the process of capturing and sequestering CO_2 costs much more due to the increased energy and infrastructure required to operate the carbon capture process and transport CO_2 to an available storage site. Investments in energy resources beyond a new coal facility are consistent with AE's proposed resource plan. This scenario demonstrates the impact and costs of replacing FPP an IGCC plant with CCS technology.

Portfolio Option 8: High Renewables Replacing Coal and Nuclear Scenario

The schedule for this scenario is identical to the schedule for the high renewables scenario with three exceptions (see Table 8).

Table 8: Renewables Replacing Coal and Nuclear Scheduled Additions

Schedule of power generation additions and subtractions (net MW)													
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	607	0	0	0	0	0	0	0	0	-302	0	0	-305
Nuclear	422	0	0	0	0	0	0	0	-422	0	0	0	0
Natural Gas - Sand Hill 1-4	189	100	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 5	312	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker 1 & 2	741	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker CGT	193	0	0	0	0	0	0	0	0	0	0	0	0
Wind	274	165	0	100	0	0	100	200	0	526	0	100	220
Offshore Wind	0	0	0	0	50	0	50	0	50	0	50	0	105
Biomass	0	0	0	0	100	0	0	0	100	0	0	0	90
FPP w/ biomass co-firing	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas	12	0	0	0	0	0	0	0	15	0	0	0	0
Solar PV - Centralized	0	0	30	0	0	0	50	0	0	70	0	100	0
Solar PV - Distributed	1	0	5	5	5	5	5	5	5	5	5	5	5
Concentrated Solar	0	0	0	0	0	0	305	0	0	0	0	0	302
IGCC w/ CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
IGCC w/o CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	100	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0
Accelerated Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0

Option 8 divests 422 MW of nuclear power (the generating capacity of STP) from AE's resource portfolio. This scenario includes a slight acceleration in the addition of geothermal capacity as well as a delay in divestment in coal while keeping all other renewable investments the same as in option 3. With the loss of its stake in a coal and nuclear plant AE would no longer receive energy from a baseload power source of significant capacity, but would rather be reliant on power sources whose yields varies with the wind and the sun. Rather,

Portfolio Comparison

These eight scenarios have been created to compare realistic but different approaches to reducing AE's carbon footprint. These scenarios provide a diverse set of options by focusing on different types of energy technologies for power generation or storage. The intent of the comparison of these eight scenarios is to provide the reader of this report with an overview of a range of investment and divestment opportunities along with information on the impact of these investments. Almost every power generation or energy storage technology that has been identified by the project team as a feasible investment opportunity between 2009 and 2020 is included in one or more scenario. Each reader can consider the estimated consequences of investing in her or his preferred technologies. Each user can use the raw data to design an AE resource portfolio that she or he prefers.

The project team accepts that there is no easy way to compare these eight scenarios or others that could or should be developed to explore AE's diverse potential energy portfolios. The project's approach is to compare alternate scenarios based on four criteria: system reliability, costs and economic impacts, CO_2 emissions, and risks and uncertainties. The tradeoffs among criteria are clear (as discussed below), so it is important to construct a transparent comparison process as other analysts may wish to use different metrics of comparison. It is possible for AE to reach close to carbon neutrality by 2020 using any of the eight scenarios by using different approaches. The following paragraphs compare the logic involved in these tradeoffs.

In some scenarios (high renewables) AE will spend a lot of money buying new renewable energy sources in order to relieve current carbon-intensive fuels from service. Such options may be more "sustainable" in the sense that renewable resources are carbon neutral. If the US were to develop federal carbon regulations AE may be able to avoid CO_2 fees and even earn significant revenues by selling CO_2 allowances. Fuel costs would drop, so the savings in fuel would eventually balance out the increased capital expenses. However, no private-sector investor would embrace the disproportionate investment required to achieve the high renewables scenario, as the substantial annual fuel savings would require many years to compensate AE for the capital investments.

The nuclear expansion option that allows AE to retire coal incorporates a different value judgment: replace carbon with nuclear fission. Nuclear expansion can yield low-cost power and a zero carbon footprint with the potential for carbon offset payments to morph into carbon allowances that earn money for AE. The issue is whether the public is willing to accept the risks associated with nuclear energy. Risks include very high capital costs and possible construction delays. In Austin there would also be the issue of nuclear energy per se: what are the sustainable merits or risks of nuclear energy due to the production of radioactive wastes. As no new nuclear power plant has been built in the US for several decades it is hard to assess whether estimated capital costs will fall within "expected" values or be even more expensive per kWh than solar power. Any tradeoffs involving unintended risks versus expected costs represent a choice that only elected officials have the right to make.

The third example of tradeoffs among scenarios comes from AE's base case, its resource plan, where carbon neutrality could only be reached through an annual payment of carbon offsets. It is an open question whether the purchase of carbon offsets to achieve carbon neutrality could constitute a sustainable electric utility. While AE's resource plan has the lowest incremental capital costs per kWh of the eight scenarios, it also makes the least progress towards carbon neutrality. AE's base case accepts the existing coal source and actually expands reliance on natural gas as a complement to variable solar and wind resources.

The problem with this conceptual comparison among scenarios (which could be expanded to all eight scenarios or others) is that is not easy to analyze such marginal changes without making value judgments. As a result, the project team has attempted to evaluate the scenarios by identifying performance measures of interest to AE's customers. These measurements relate to certain criteria that have meaning both to electricity customers and electric utility managers. Table 9 lists the criteria used to evaluate the eight primary scenarios identified by this report. For each criterion multiple measurements are used to compute an ordinal ranking of the eight resource portfolio scenarios under each criterion.

Table 9
Criteria and Measures for Evaluating Resource Portfolios

Criteria	Measures
Criteria #1: System Reliability in 2020	• Reliable power generation capacity (based on MW capacity of non-variable resources) • Ability to meet peak demand on the peak day in 2020 • Ratio of available natural gas capacity to solar and wind capacity. • Reliance on natural gas (based on yearly MWh) • Infrastructure requirements (based on MW capacity of biomass, geothermal, solar and wind)
Criteria #2: Carbon Profile in 2020	• Direct carbon emissions (metric tons of CO_2) • Annual cost of offsets • Annual costs or profits of allowances
Criteria #3: Costs and Economic Impacts Through 2020	• Total expected capital costs • Total expected fuel costs • Expected increase in levelized cost of electricity in 2020 • Economic development in Austin and surrounding 10 counties
Criteria #4: Risks and Uncertainties	• High estimate of total capital costs through 2020 • High estimate of total fuel costs through 2020 • High estimate of increase in levelized cost of electricity in 2020 • Fraction of total demand met with variable resources in 2020 • Technological maturity subjective ranking

Table 10 ranks the eight resource portfolio options by assigning equal weight to each comparative measure within each criteria and then assigning equal weight to each criteria to compute an average order ranking across the four criteria. While such a measure has no absolute meaning whatsoever, it is an index of indices added together and represents a means to compare scenarios. Of all the ways that multiple criteria can be aggregated, this approach is used because it is transparent and simple. A multi-criteria weighting that emphasizes costs would yield a different ordinal ranking, as would other weighting preferences. Users can adopt their own multi-criteria measures.

The AE proposed energy resource plan receives the highest overall ranking despite achieving the lowest reductions in carbon because it received the highest ranking for system reliability, costs and economic impacts, and risks and uncertainties. The nuclear expansion scenario is ranked second because of the significant reductions the scenario makes in CO_2 emissions. The high renewables scenario receives a higher ranking than the expected available renewables, natural gas expansion, cleaner coal, and expected available renewable with energy storage scenarios. The high renewables without coal and nuclear scenario has by far the lowest average ranking of the eight scenarios. It appears that the nuclear expansion scenario and AE's resource plan receive comparable rankings when the factors of system reliability, carbon reductions, costs and economic impacts, and risks and uncertainties are all assigned equal weight. AE's resource plan is less costly, more reliable, and faces lower risks and uncertainties than the nuclear expansion scenario, but fails to make significant reductions in carbon emissions. The implication of this result is that if a user is comfortable with nuclear power's costs, risks and uncertainties (as compared to the value of reducing CO_2), then nuclear expansion would be favored to replace coal. If a user is trouble by nuclear energy's risks and is willing to accept the high costs and risks if relying on renewable energy sources, then the high renewables scenario appears to be the best option. The following sections include details on the measurements used to obtain scores for the four identified criteria: system reliability, costs and economic impacts, carbon reductions, and risks and uncertainties. Outputs generated by the model for three of these options (AE's plan, nuclear expansion, and high renewable investment) are included in each criteria section.

Table 10
Comparative Ranking of Resource Portfolio Options

Portfolio Rankings	System Reliability Score	Carbon Emissions and Associated Carbon Costs Score	Costs and Economic Impacts Score	Risks and Uncertainties Score	Total Score (Average Ranking)
Portfolio 1-AE Resource Plan	7 (1)	24 (8)	10 (1)	7 (1)	48 (2.75)
Portfolio 2-Nuclear Expansion	19 (4)	6 (2)	20 (5)	16 (2)	61 (3.25)
Portfolio 3-High Renewables	23 (5)	3 (1)	17 (2)	27 (6)	70 (3.50)
Portfolio 7-Cleaner Coal	9 (2)	9 (3)	20 (5)	26 (5)	64 (3.75)
Portfolio 6-Natural Gas Expansion	12 (3)	18 (6)	18 (4)	18 (3)	66 (4.00)
Portfolio 4-Expected Renewables	29 (7)	21 (7)	17 (2)	20 (4)	87 (5.00)
Portfolio 5-Renewables with Storage	24 (6)	15 (5)	20 (5)	28 (7)	87 (5.75)
Portfolio 8-High Renewables Without Nuclear	36 (8)	12 (4)	21 (8)	33 (8)	102 (7.00)

System Reliability

Table 11 summarizes the quantitative and qualitative system reliability indicators. Figures 6 through 8 show the following outputs related to system reliability for three of the portfolio options (AE's plan, nuclear expansion, and high renewable): power generation capacity by resource by year through 2020; electricity delivered by resource by year through 2020; and the hourly load profile by resource during peak demand in the summer of 2020.

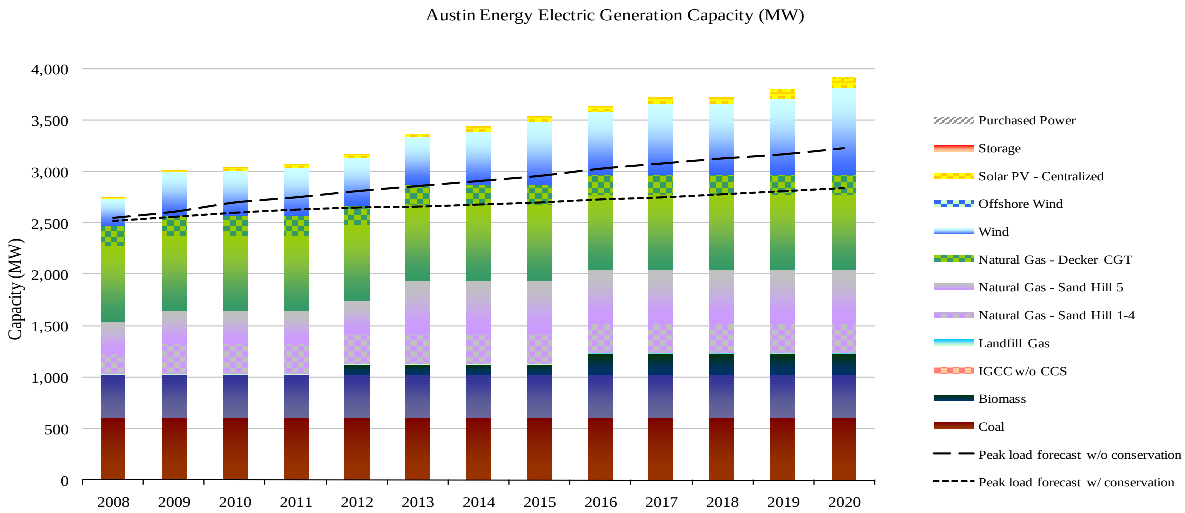
Based upon the measurements used in this analysis, AE's energy resource plan emerges as the leading candidate for ensuring system reliability. Only three of the scenarios are unable to meet peak demand without purchasing power from the electric grid: the nuclear expansion scenario, the expected renewables scenario, and the high renewables to replace coal and nuclear scenario. The nuclear expansion scenario comes close to being able to meet peak demand by doubling current nuclear capacity (from 422 MW to 844 MW) to replace the 607 MW of power generation capacity attributed to coal. If AE were to substitute all of the current coal power generation supply with nuclear (a 607 MW addition of nuclear power generation capacity), it would be able to meet peak demand in 2020 and would ensure system reliability similarly to AE's proposed resource plan. None of the scenarios falls dramatically short of meeting peak demand. The two high renewable scenarios appear to be the only two scenarios that face serious risks due to reliance on unreliable variable energy resources, wind and solar. Under the high renewables scenario, it appears that even if all of the expected wind and solar resources were unavailable, 50 percent of the nameplate capacity would be supported by available natural gas capacity. Since wind and solar capacity factors are already low, natural gas capacity may be able to account for the complete loss of wind and solar availability even under the high renewable scenario. The high renewables scenarios could only occur if Texas' proposed new transmission infrastructure is built. Texas is currently investing 5 billion dollar to build extensive transmission lines in West Texas to deliver electricity from wind farms to the most populous cities in Texas. It is unclear whether these investments would be able to transmit such a large investment in West Texas wind and solar resources to AE. The feasibility of the high renewables case could depend on the amount of investment by other utilities in wind and solar resources.

Table 11
Measures of System Reliability (in 2020, rankings in parentheses)

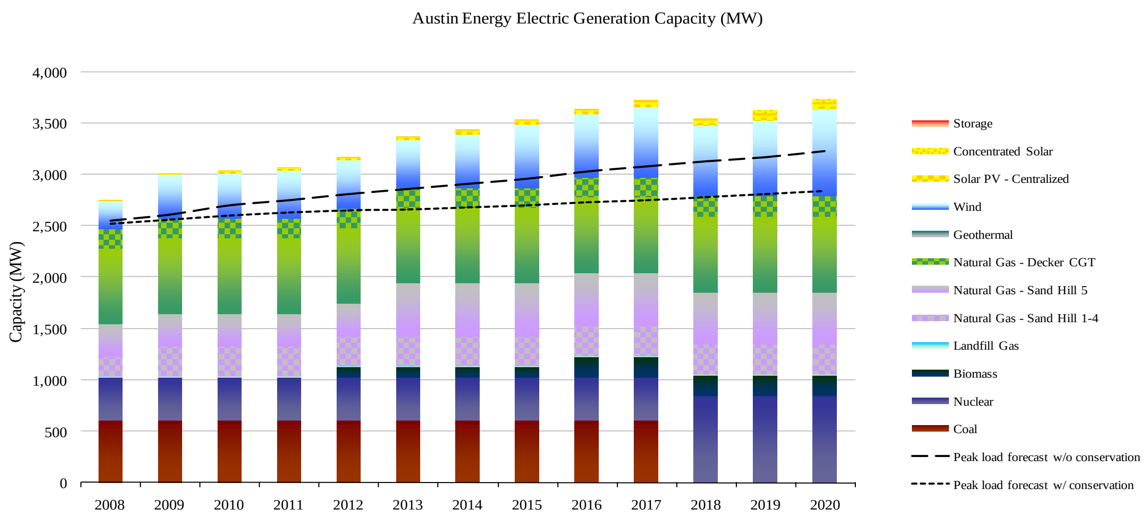
	Total Power Generation Capacity of Non-Variable Resources (MW)	Fraction of Peak Hourly Demand Met (%)	Ratio of Unused Natural Gas Capacity to Wind and Solar Capacity	Fraction of Total Demand Met with Natural Gas (%)	Total Power Generation Capacity of Biomass, Geothermal, Solar and Wind (MW)
Portfolio 1-AE Resource Plan	2,976 (1)	100% (1)	1.58 (2)	14.6% (2)	1147 (1)
Portfolio 2-Nuclear Expansion	2,791 (4)	98.8% (6)	1.41 (4)	24.6% (4)	1147 (1)
Portfolio 3-High Renewables	2,374 (7)	100% (1)	0.50 (7)	4.6% (1)	3293 (7)
Portfolio 4-Expected Renewables	2,471 (6)	93.5% (8)	0.95 (5)	25.7% (5)	1388 (5)
Portfolio 5-Renewables with Storage	2,719 (5)	100% (1)	0.92 (6)	41.5% (7)	1388 (5)
Portfolio 6-Natural Gas Expansion	2,976 (1)	100% (1)	1.65 (1)	48.4% (8)	1147 (1)
Portfolio 7-Cleaner Coal	2,976 (1)	100% (1)	1.57 (3)	15.6% (3)	1147 (1)
Portfolio 8-High Renewables Without Nuclear	1,952 (8)	97.3% (7)	0.38 (8)	26.7% (6)	3293 (7)

Figure 6: Comparison of Power Generation Capacity (MW)

AE Resource Plan



Nuclear Expansion Scenario



High Renewables Scenario

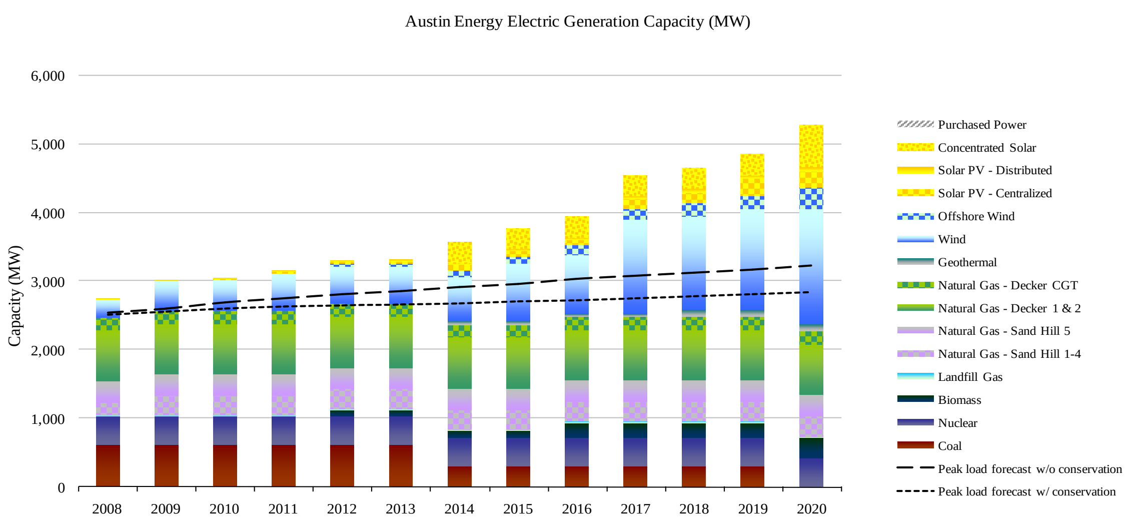
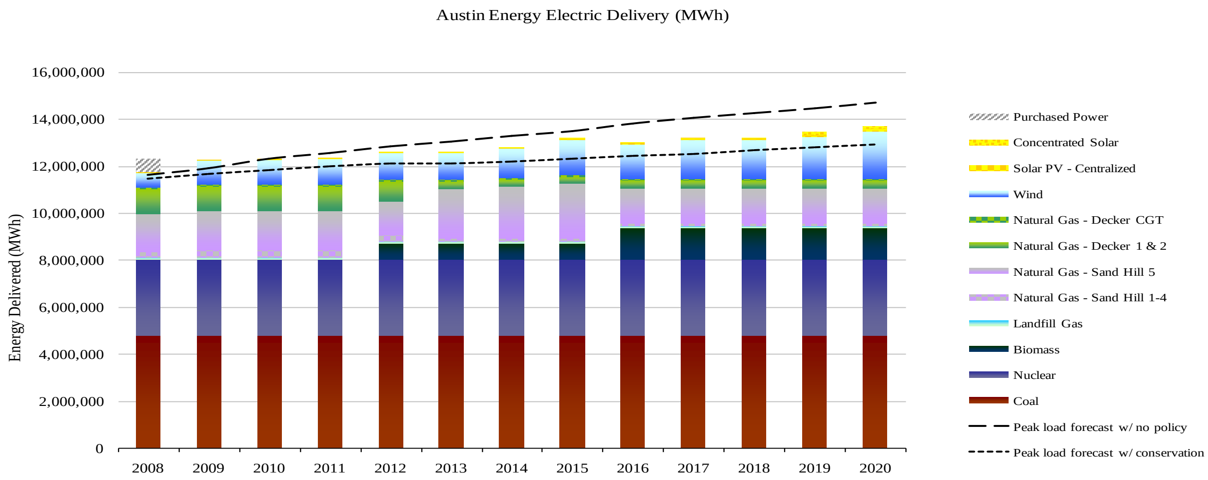
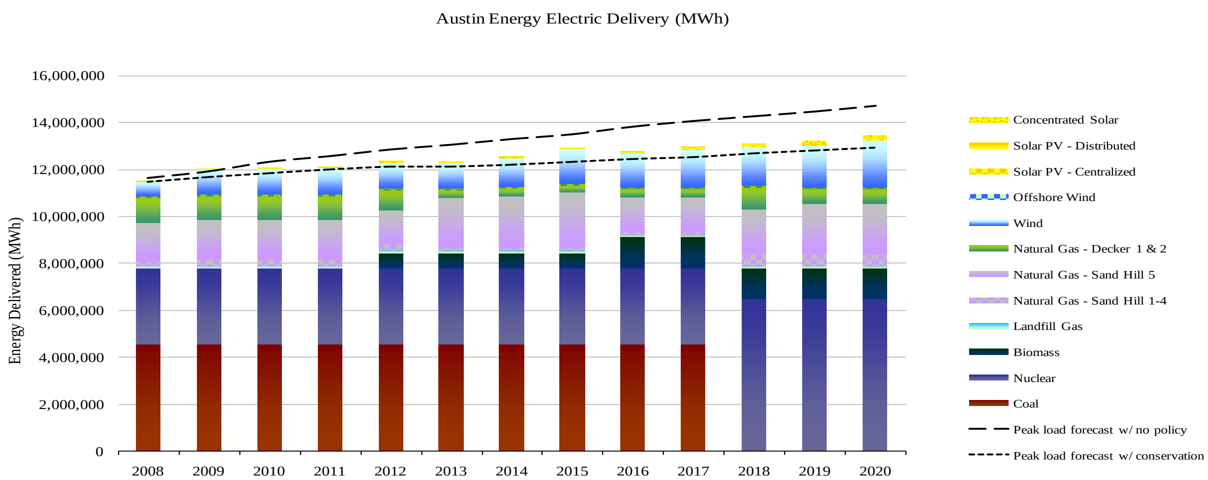


Figure 7: Comparison of Electricity Delivered (MWh)

AE Resource Plan



Nuclear Expansion Scenario



High Renewables Scenario

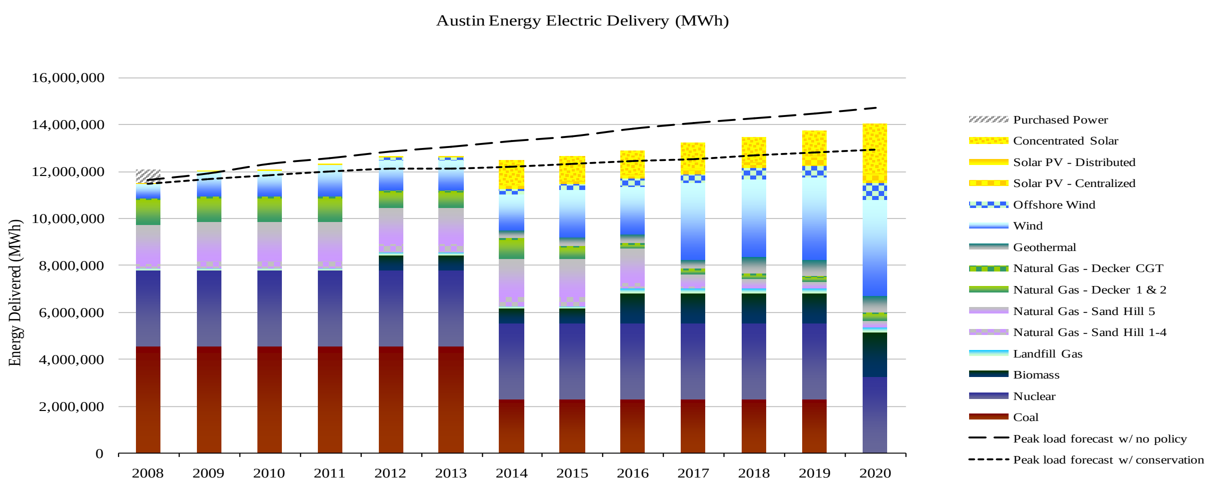
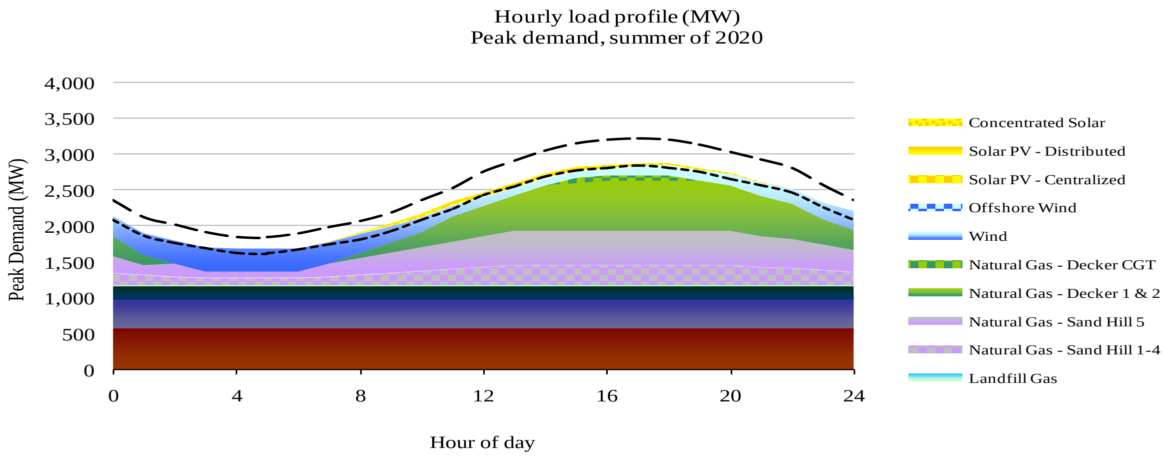
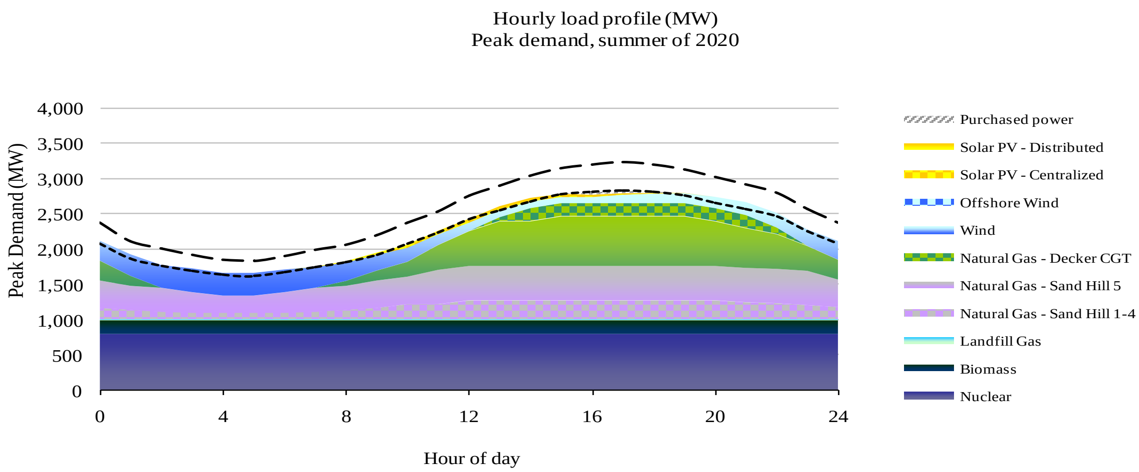


Figure 8: Comparison of Hourly Load Profile for Peak Demand, Summer 2020 (MW)

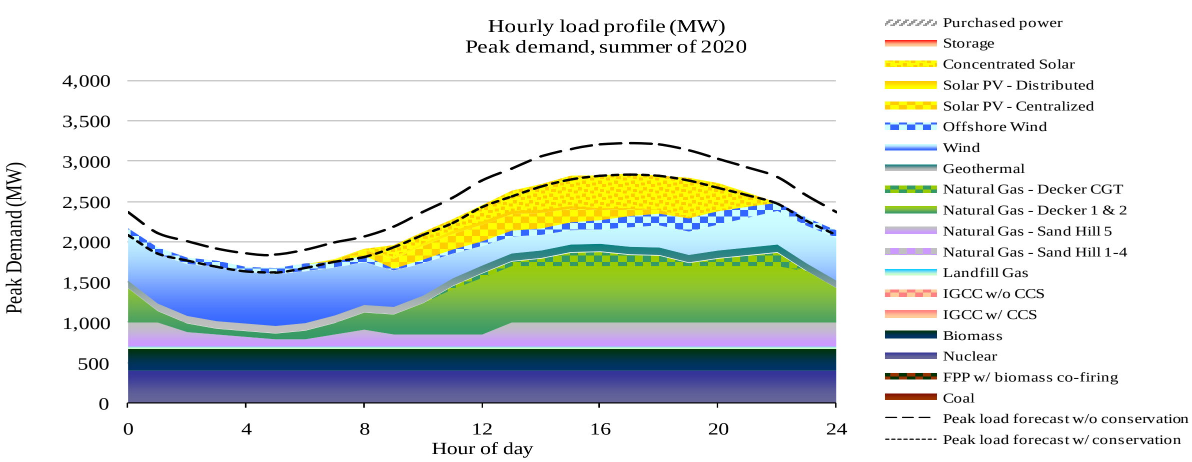
AE Resource Plan



Nuclear Expansion Scenario



High Renewables Scenario



Carbon Emission Reductions

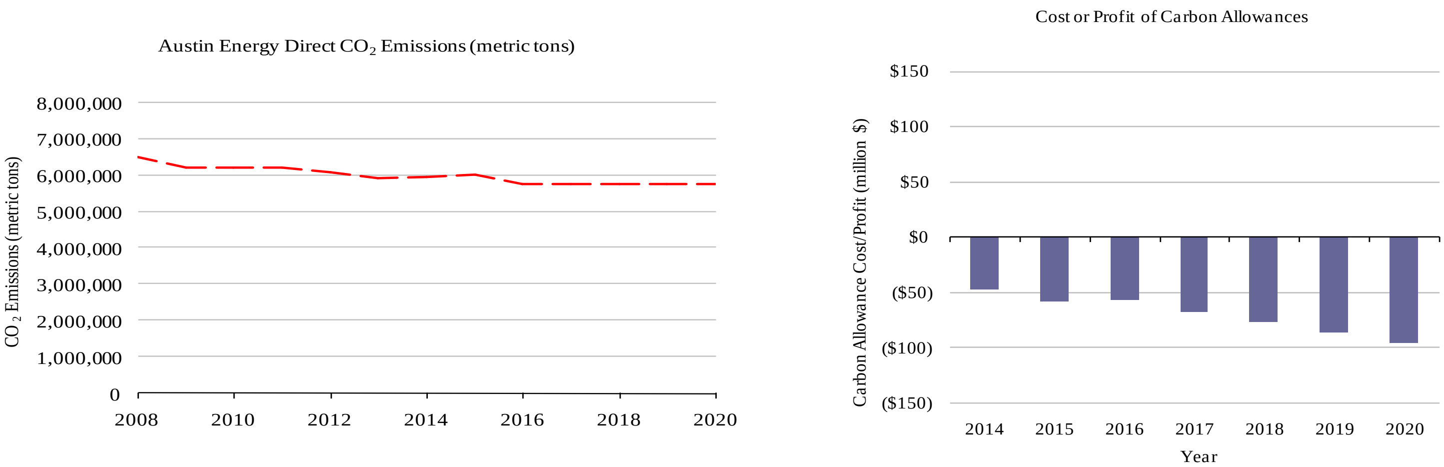
Table 12 summarizes the quantitative and qualitative indicators of CO_2 emissions and associated potential carbon costs. Figure 9 shows the following outputs related to CO_2 emissions and associated costs for three of the portfolio options (AE's plan, nuclear expansion, and high renewable): direct CO_2 emissions by year through 2020 and expected costs or profits from carbon allowances (based upon the proposed Lieberman-Warner Climate Security Act of 2007). The three measurements are related, as the greater the reduction in CO_2 the lower the annual costs of offsets and allowances. The high renewable scenario achieves annual CO_2 reductions of over 5.5 million metric tons of CO_2 by 2020 from 2007 levels (about 6.1 million metric tons), the greatest reduction of all eight scenarios by about 1 million metric tons. The nuclear expansion scenario achieves the second largest reduction in CO_2 emissions by 2020 and the AE resource plan achieves the lowest reduction in CO_2 emissions, reducing between 2007 and 2020 annual emissions by about 300,000 metric tons prior to the purchase of offsets. Under the high renewable scenario, it is estimated that the annual costs of offsetting emissions would be about $14 million by 2020 at an offset cost of $25 per metric ton of CO_2 emitted. The cost of offsetting emissions in the future is unclear due to the uncertainty of carbon regulation in the US. The cost of offsetting emissions is fairly low currently (at about $4-8 a metric ton of CO_2), but would likely rise if carbon regulation is implemented in the US. Under the AE resource plan, this cost would be about $144 million annually. Based upon the carbon regulations proposed by the Lieberman-Warner bill, two of the scenarios would result in the need for AE to purchase allowances in 2020: the AE resource plan (at an annual cost of about $96 million) and the expected available renewables scenario (at an annual cost of about $31 million). The high renewable scenario would generate about $94 million annually through the sale of allowances by 2020. The nuclear expansion scenario would generate about $55 million annually through the sale of allowances. It is expected that the value of allowances would continue to increase each year after 2020.

Table 12
Measures of Carbon Profile (in 2020, rankings in parentheses)

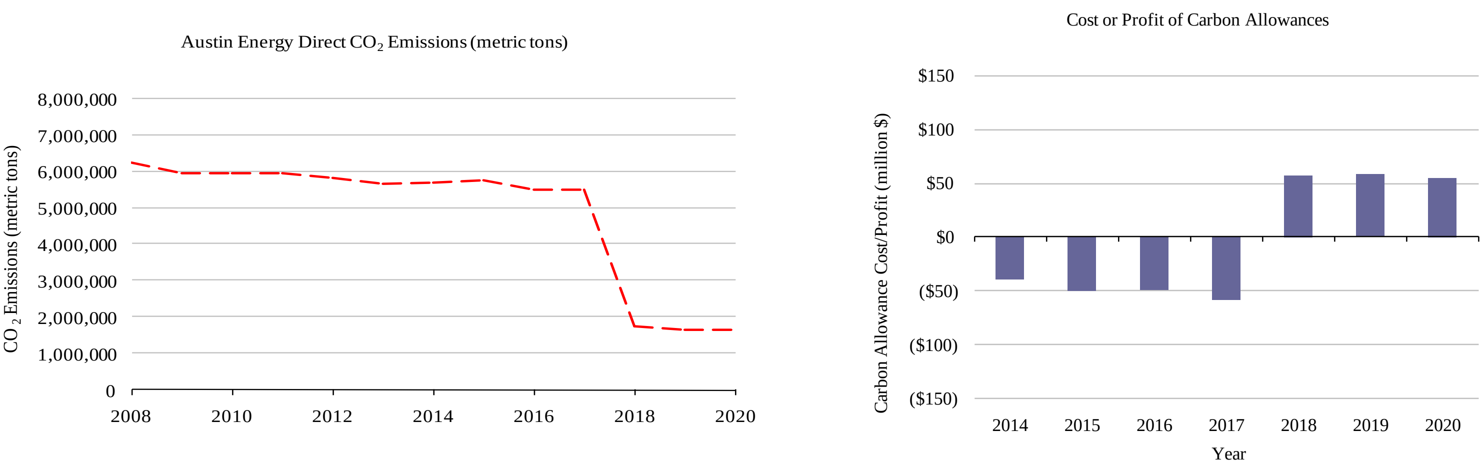
	Direct Carbon Emissions (metric tons of CO_2)	Annual Costs of Offsetting Emissions to Zero ($ million)	Annual Costs or Profits of Allowances ($ million)
Portfolio 1-AE Resource Plan	5,761,000 (8)	144 (8)	-96 (8)
Portfolio 2-Nuclear Expansion	1,646,000 (2)	41 (2)	55 (2)
Portfolio 3-High Renewables	566,000 (1)	14 (1)	94 (1)
Portfolio 4-Expected Renewables	3,993,000 (7)	100 (7)	-31 (7)
Portfolio 5-Renewables with Storage	2,984,000 (5)	75 (5)	6 (5)
Portfolio 6-Natural Gas Expansion	3,021,000 (6)	76 (6)	4 (6)
Portfolio 7-Cleaner Coal	1,791,000 (3)	45 (3)	49 (3)
Portfolio 8-High Renewables Without Nuclear	2,031,000 (4)	51 (4)	41 (4)

Figure 9: Comparison of Carbon Emissions (in metric tons of CO_2) and Associated Costs (in million dollars)

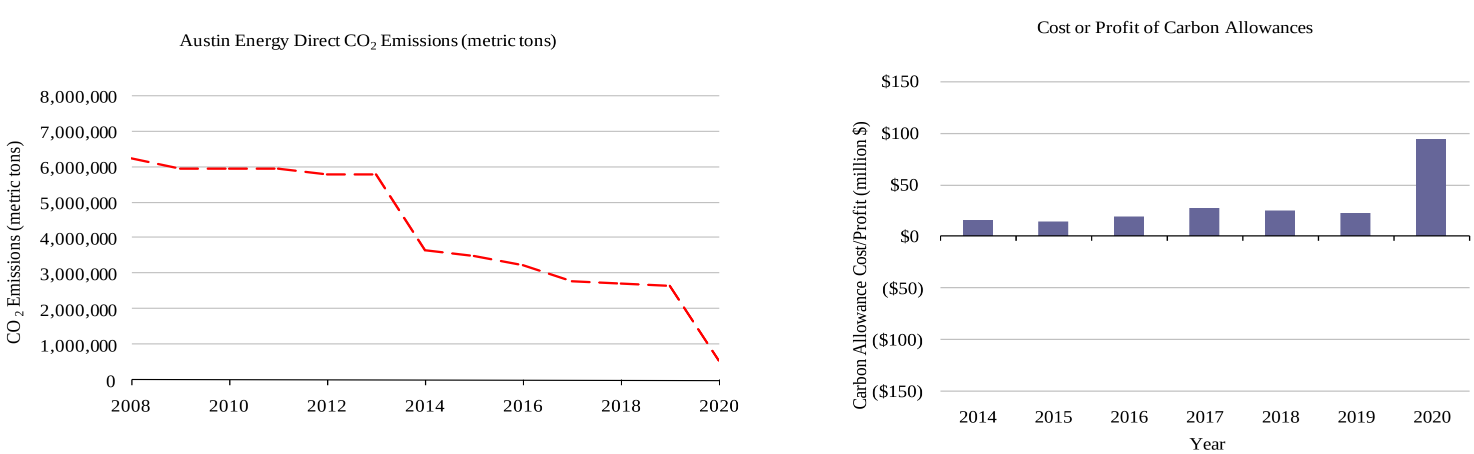
AE Resource Plan



Nuclear Expansion Scenario



High Renewables Scenario



Costs and Economic Impacts

Because this report indicates that making investments with the intent of reducing AE's carbon footprint can entail significant costs, the costs and expected impacts on customer electric rates are another criteria posited by this analysis. To evaluate the total economic impacts of a resource portfolio, various cost indicators are measured along with the projected economic development impacts in Austin and surrounding counties. The total expected capital costs includes the expected capital outlay (measured as total overnight costs) that would be necessary through 2020 for a particular investment plan, which can affect electric rates, AE's credit rating, and AE's ability to finance new projects. Total expected fuel costs measures the reliance on fossil fuels and the risk of volatile fuel prices. Fuel costs may become increasingly volatile as competition for fossil fuels increases with global economic activity. Carbon regulation could also affect fuel prices, as combustion of fuels emits large amounts of CO_2. The expected increase in levelized cost of electricity attempts to capture the actual impact of investments on customer electric bills. It should be noted that throughout this analysis no "value" is imputed to the leasing or selling of AE's share of ownership of any power plant facility in the levelized cost of electricity. The calculators do not attempt to represent the flows of debts or revenues. Any sale or lease of AE's power plant ownership, such as its stake in FPP, could be used to pay for the purchase of other power sources or could contribute to a reduction in electric rates at that time.

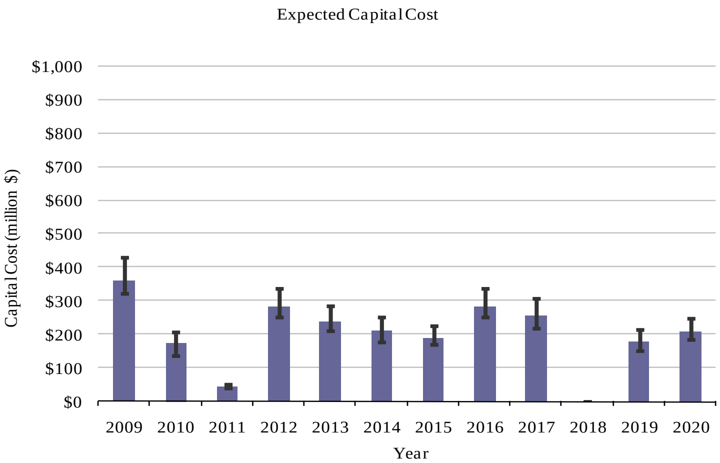
Table 13 summarizes the quantitative and qualitative indicators of costs and economic impacts. Figures 10 and 11 show the following outputs related to costs for three of the portfolio options (AE's plan, nuclear expansion, and high renewable): capital costs (represented by total overnight costs) by year through 2020; fuel costs of AE's entire resource portfolio by year through 2020; and the expected increase in total levelized cost of electricity by year through 2020 as attributed to the cumulative addition of each resource, technology, or facility. The expected capital costs of the high renewable scenarios (about \$8.3 million) exceed that of AE's resource plan (about \$2.2 million) by a factor of almost four. While total expected fuel costs are about \$600,000 lower in the high renewable scenario, lower fuel costs do not offset the capital costs incurred during this time period. Selling or leasing ownership in FPP would offset some of these costs under the high renewable scenario. AE's proposed resource plan would entail the lowest expected capital costs (at about \$2.24 million). The natural gas expansion scenario would have the greatest expected total fuel costs (at about \$4.08 million). Annual fuel costs by 2020 would be the highest under a natural gas expansion scenario. The high renewables scenario would have the lowest annual expected fuel costs by 2020, but it would take several decades for annual fuel costs, at current prices, to offset the high capital costs. The expected increase in levelized costs of electricity attempts to account for the costs of financing power generation projects and all costs that go into the production of electricity including capital and variable costs. The current cost of electricity for AE customers is about 10 cents per kWh, but varies based upon the amount of electricity consumed during a billing period. The expected increase in the cost of electricity is about 2 cents per kWh under AE's proposed energy resource plan. The expected renewables scenario would face an expected increase in cost of electricity of 2.2 cents per kWh, but this does not capture the increased reliance on natural gas that could raise the fuel charge for customers. The high renewable scenario estimates an expected increase in the cost of electricity of about 5.8 cents per kWh by 2020. The cleaner coal scenario also demonstrates a high expected increase in cost of electricity of 5.7 cents per kWh. The natural gas scenario estimates an expected increase of 4.1 cents per kWh, but this may be misleading because much of the natural gas expansion comes in the form of combustion turbines that would be used to provide large amount of electricity. It is not realistic that AE would operate combustion gas turbines at high levels of use. Therefore, costs would likely be lower with the expansion of combined cycle facilities replacing combustion gas turbine expansion to be used for high levels of use. The nuclear expansion scenario provides a middle ground cost of electricity increase between AE's resource plan and the high renewable scenario with an expected increase of 3.9 cents per kWh. However, nuclear investments entail high capital cost risks and the potential for project delays that could push costs higher. The AE resource plan appears to be the least cost option followed by the expected renewable scenario and the nuclear expansion scenario. The value of the sale or lease of FPP could alter this ranking.

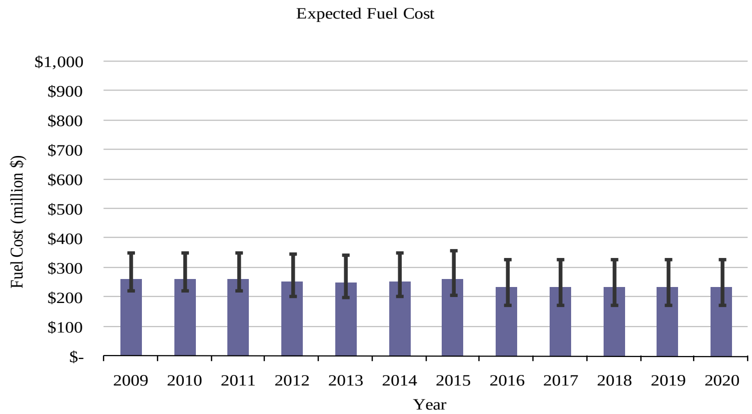
Table 13
Measures of Costs and Economic Impacts (through 2020, rankings in parentheses)

	Total Expected Capital Costs ($million, through 2020)	Total Expected Fuel Costs ($million, through 2020)	Expected Increase in Levelized Costs of Electricity in 2020 (cents/kWh)	Economic Development in Austin and Surrounding 10 Counties (measured in net job years)
Portfolio 1-AE Resource Plan	2,241 (1)	2,977 (3)	2.0 (1)	10,270 (5)
Portfolio 2-Nuclear Expansion	3,889 (4)	3,022 (4)	3.9 (4)	3,507 (8)
Portfolio 3-High Renewables	8,286 (7)	2,398 (1)	5.8 (7)	15,720 (2)
Portfolio 4-Expected Renewables	3,076 (3)	3,142 (6)	2.2 (2)	9,456 (6)
Portfolio 5-Renewables with Storage	4,558 (6)	3,247 (7)	3.6 (3)	11,994 (4)
Portfolio 6-Natural Gas Expansion	2,925 (2)	4,077 (8)	4.1 (5)	14,751 (3)
Portfolio 7-Cleaner Coal	5,318 (5)	2,896 (2)	5.2 (6)	9,063 (7)
Portfolio 8-High Renewables Without Nuclear	8,286 (7)	3,062 (5)	6.0 (8)	20,755 (1)

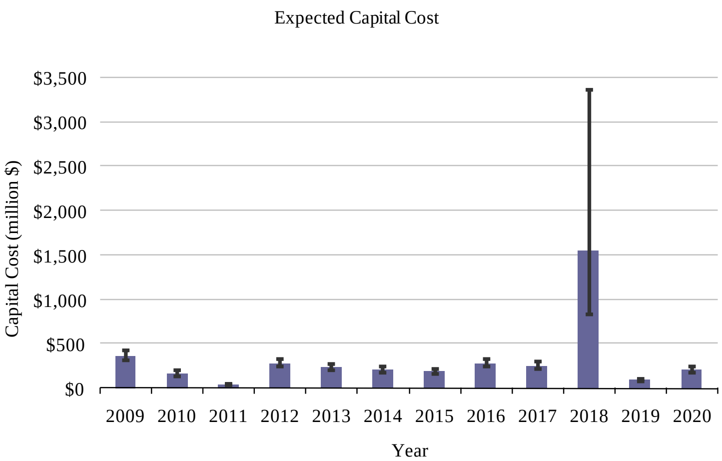
Figure 10: Comparison of Capital Costs and Fuel Costs (in million dollars)

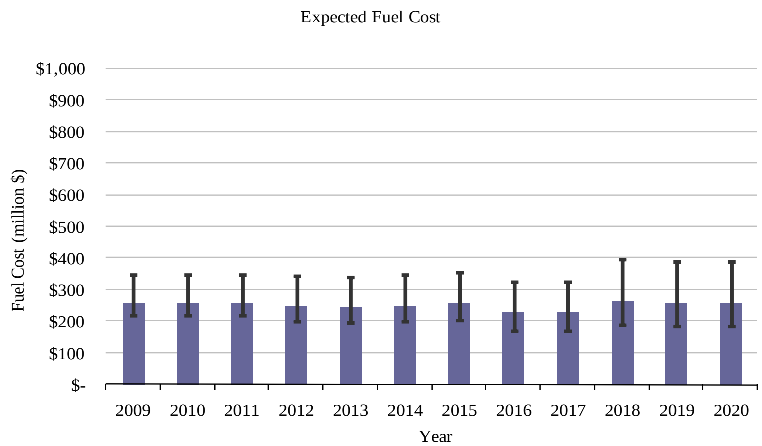
AE Resource Plan



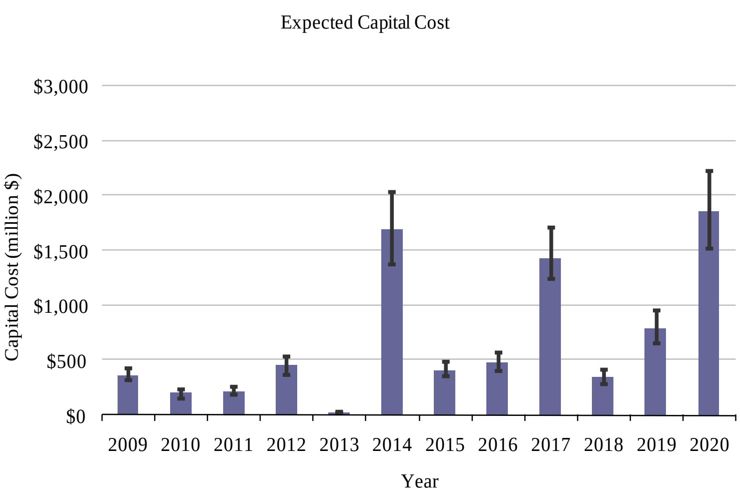


Nuclear Expansion Scenario





High Renewables Scenario



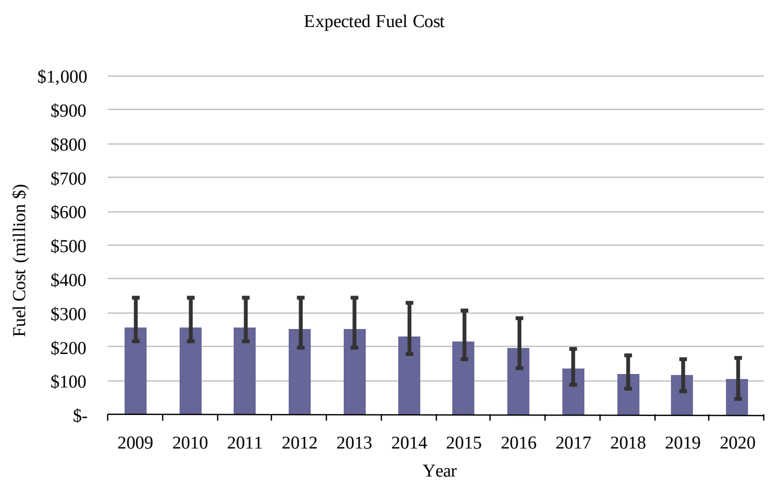
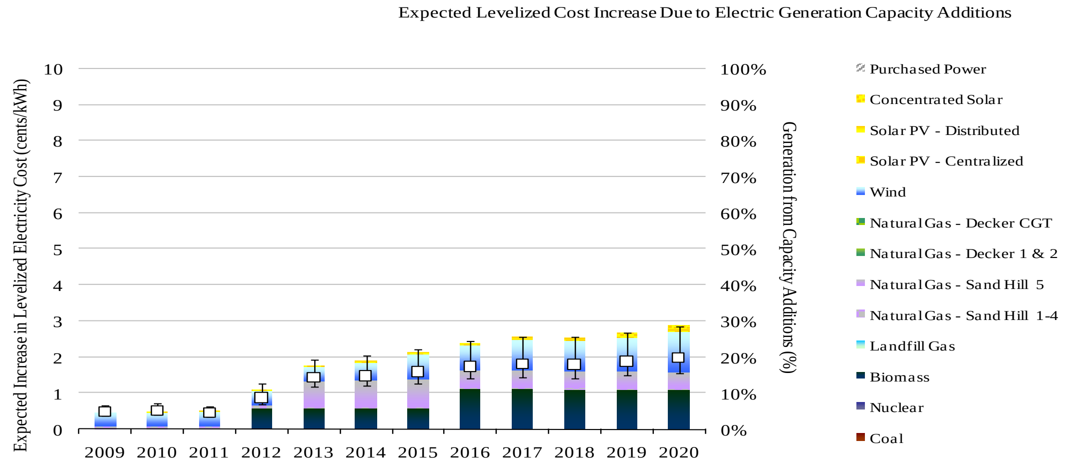
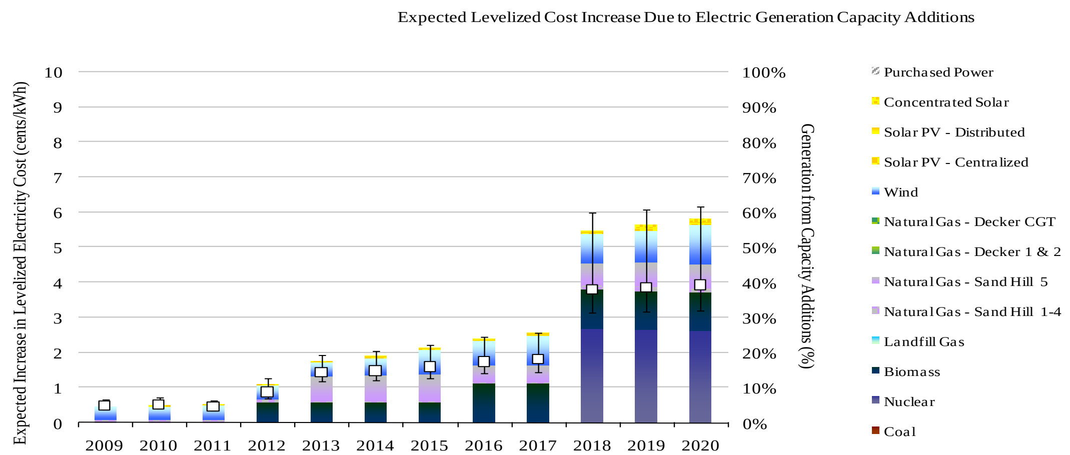


Figure 11: Comparison of Increase in Levelized Costs of Electricity (cents/kWh)

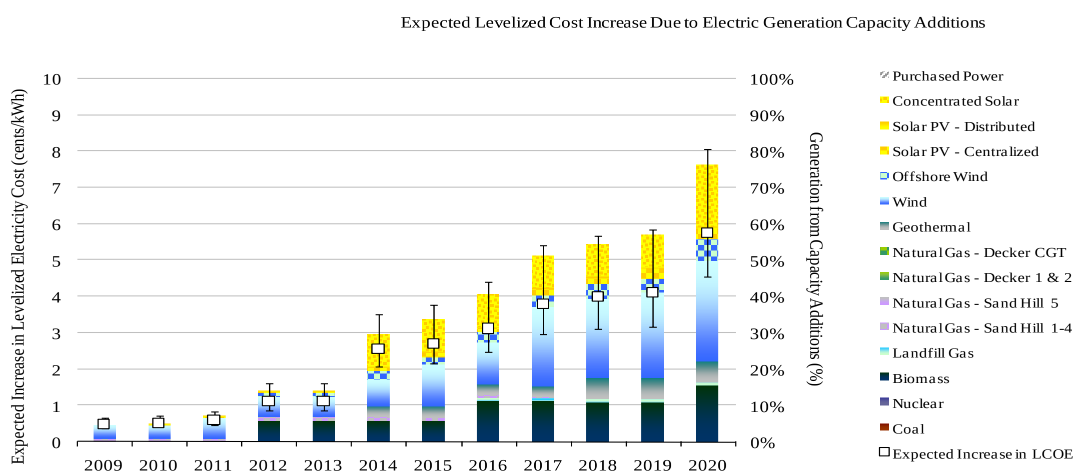
AE Resource Plan



Nuclear Expansion Scenario



High Renewables Scenario



Risks and Uncertainties

Any future is full of uncertainties, starting with the question of whether 2020 electricity demand will be lower or relatively similar than demand in 2008 due to a prolonged depression or whether growth will push 2020 demand at or above AE forecasts. Any portfolio of power sources has risks and uncertainties associated with it. Measurements of risks include uncertain cost estimates and reliance on variable resources or immature technologies. High estimates of capital costs, fuel costs, and increases in levelized cost of electricity represent one criterion of AE cost risks. The fraction of total demand met by energy sources that vary (solar and wind) is an indicator of the risk of relying heavily on sources of energy that are dependent on weather and wind patterns as well as time of day. Reliance on emerging technologies is another type of risk that may affect electricity availability and reliability.

Table 14 lists indicators of risks and uncertainties. Taking the high estimate of total capital costs, fuel costs, and increase in levelized cost of electricity does not alter the ordinal rankings of these scenarios from expected costs. For example, the nuclear expansion scenario faces the greatest capital costs and levelized cost of electricity risks due to the uncertainty of the costs that will be incurred to build the nuclear expansion. The natural gas expansion scenario faces the greatest fuel costs risk. The cleaner coal and natural gas expansion scenarios have the lowest fraction of total demand met with variable resources in 2020. The high renewables scenario places a considerable amount of dependency on variable resources at almost 60 percent of electricity generated (compared to 17 percent under AE's resource plan). No other scenario places more than 24 percent reliance on variable resources in 2020. Risks from immature technologies are greatest under the clean coal scenario, expected renewable with energy storage, and the high renewable scenarios.

Table 14
Measures of Risks and Uncertainties (through 2020, rankings in parentheses)

	High Estimate of Total Capital Costs ($million, through 2020)	High Estimate of Total Fuel Costs ($million, through 2020)	High Estimate of Increase in Levelized Cost of Electricity in 2020 (cents/kWh)	Fraction of Total Demand Met with Variable Resources in 2020 (%)	Technological Maturity (Subjective Ranking)
Portfolio 1-AE Resource Plan	2,905 (1)	4,102 (3)	2.8 (1)	17.0 (1)	1
Portfolio 2-Nuclear Expansion	4,373 (4)	4,259 (4)	6.2 (5)	17.3 (2)	1
Portfolio 3-High Renewables	8,770 (7)	3,382 (1)	8.1 (7)	58.5 (7)	5
Portfolio 4-Expected Renewables	3,560 (3)	4,416 (6)	3.2 (2)	22.8 (5)	4
Portfolio 5-Renewables with Storage	5,072 (5)	4,619 (7)	4.9 (3)	23.2 (6)	7
Portfolio 6-Natural Gas Expansion	3,409 (2)	5,954 (8)	5.7 (4)	17.4 (3)	1
Portfolio 7-Cleaner Coal	5,803 (6)	4,005 (2)	7.3 (6)	17.7 (4)	8
Portfolio 8-High Renewables Without Nuclear	8,770 (7)	4,370 (5)	8.4 (8)	59.3 (8)	5

Costs of Becoming Carbon Neutral

This report seeks to estimate the costs and risks for AE to reach carbon neutrality by 2020. Each energy portfolio has an associated cost for reducing CO_2 emissions. Table 15 provides several categories for comparison that demonstrate the estimated costs to reach carbon neutrality for each resource portfolio. To estimate which scenarios have the best "bang for the buck" for reducing CO_2 emissions, two criteria have been used: metric tons of CO_2 reduced in 2020 from 2007 levels by million dollars invested in capital and by cents per kWh of expected rise in cost of electricity. The nuclear expansion scenario exhibits the greatest efficiency reductions in cents per kWh of expected rise in the cost of electricity, at about 1.14 million metric tons per cent increase (compared to 161,000 metric tons under AE's resource plan). The nuclear expansion scenario achieves the second greatest reductions of dollars of capital invested at 1,141 metric tons per dollar invested (compared to 144 metric tons under AE's resource plan). The natural gas expansion scenario achieves a reduction of 1,534 metric tons of CO_2, but this figure is deceiving because it does not account for the high fuel costs associated with natural gas expansion. It achieves the second least reductions based on metric tons of CO_2 reduced by cent per kWh of expected rise in cost of electricity at 366,800 metric tons. AE's proposed energy resource plan achieves the least reductions in CO_2 based upon these two measurements for the eight scenarios. Expected total costs of offsetting CO_2 emissions to zero through 2020, purchasing allowances, annual costs or profits of allowances, and annual costs of offsets are all lowest for the high renewables scenario, followed by the nuclear expansion scenario. AE's resource plan is last in all of these categories.

Based on a cumulative score from these carbon reduction and cost categories the nuclear expansion scenario has the lowest relative costs for reducing carbon emissions, followed by a large investment in renewables. These results follow the charts in Figures 12 through 14. These charts compare the amount of CO_2 reductions achieved with their associated costs. Scenarios lying on the left side of the axis and equal to a scenario on their right side would be the better investment option as they would meet similar reductions at lesser cost. These charts demonstrate that the AE resource plan comes at the lowest costs, but also achieves the least reduction in CO_2 emissions. The expected renewables scenarios (with and without energy storage capacity) and the natural gas expansion scenario appear to make considerable reductions in CO_2 emissions without drastically raising the cost of electricity, but it should be noted that the model does not take into account the added cost of using more natural gas. The nuclear expansion scenario appears to provide the greatest reductions in CO_2 emissions at the lowest cost if expected cost estimates are achieved. However, the range of potential costs is highest for this scenario demonstrating the risks of high capital costs for nuclear expansion. Given the highest cost estimate for nuclear expansion, the high renewable scenario (at expected costs) would achieve greater reductions in CO_2 emissions at lower cost.

Table 15
Costs of Reaching Carbon Neutrality

	Direct Carbon Emissions (metric tons of CO_2)	Total Expected Capital Costs ($million, through 2020)	Expected Increase in Levelized Costs of Electricity in 2020 (cents/kWh)	Metric Tons of CO_2 Reduced From 2007 Levels by Million Dollar Invested in Capital	Metric Tons of CO_2 Reduced From 2007 Levels by Cent per kWh of Expected Rise in Cost of Electricity	Expected Total Costs of Offsetting Carbon to Zero ($ million, through 2020)	Expected Total Costs or Profits of Allowances ($million, through 2020)	Annual Costs or Profits of Allowances ($million)	Annual Costs of Offsets ($million)	Cumulative Score and Ranking
Portfolio 2-Nuclear Expansion	1,646,000 (2)	3,889 (4)	3.9 (4)	1140.94 (1)	1.137,720 (1)	1,424 (3)	-31 (3)	55 (2)	41 (2)	22 (1)
Portfolio 3-High Renewables	566,000 (1)	8,286 (7)	5.8 (7)	665.77 (6)	951,129 (2)	1,215 (1)	216 (1)	94 (1)	14 (1)	27 (2)
Portfolio 6-Natural Gas Expansion	3,021,000 (6)	2,925 (2)	4.1 (5)	1046.83 (2)	746,825 (6)	1,339 (2)	58 (2)	4 (6)	76 (6)	37 (3)
Portfolio 5-Renewables with Storage	2,984,000 (5)	4,558 (6)	3.6 (3)	679.85 (4)	860,764 (4)	1,516 (4)	-163 (4)	6 (5)	75 (5)	40 (4)
Portfolio 7-Cleaner Coal	1,791,000 (3)	5,318 (5)	5.2 (6)	807.07 (3)	825,382 (5)	1,621 (7)	-297 (7)	49 (3)	45 (3)	42 (5)
Portfolio 4-Expected Renewables	3,993,000 (7)	3,076 (3)	2.2 (2)	679.36 (5)	949,865 (3)	1,611 (6)	-282 (6)	-31 (7)	100 (7)	46 (6)
Portfolio 8-High Renewables Without Nuclear	2,031,000 (4)	8,286 (7)	6.0 (8)	489.02 (7)	675,331 (7)	1,522 (5)	-168 (5)	41 (4)	51 (4)	51 (7)
Portfolio 1-AE Resource Plan	5,761,000 (8)	2,241 (1)	2.0 (1)	143.71 (8)	161,029 (8)	1,786 (8)	-488 (8)	-96 (8)	144 (8)	58 (8)

Figure 12
Metric Tons of CO_2 Reduced From 2007 Levels by Cent per kWh of Expected Rise in Cost of Electricity

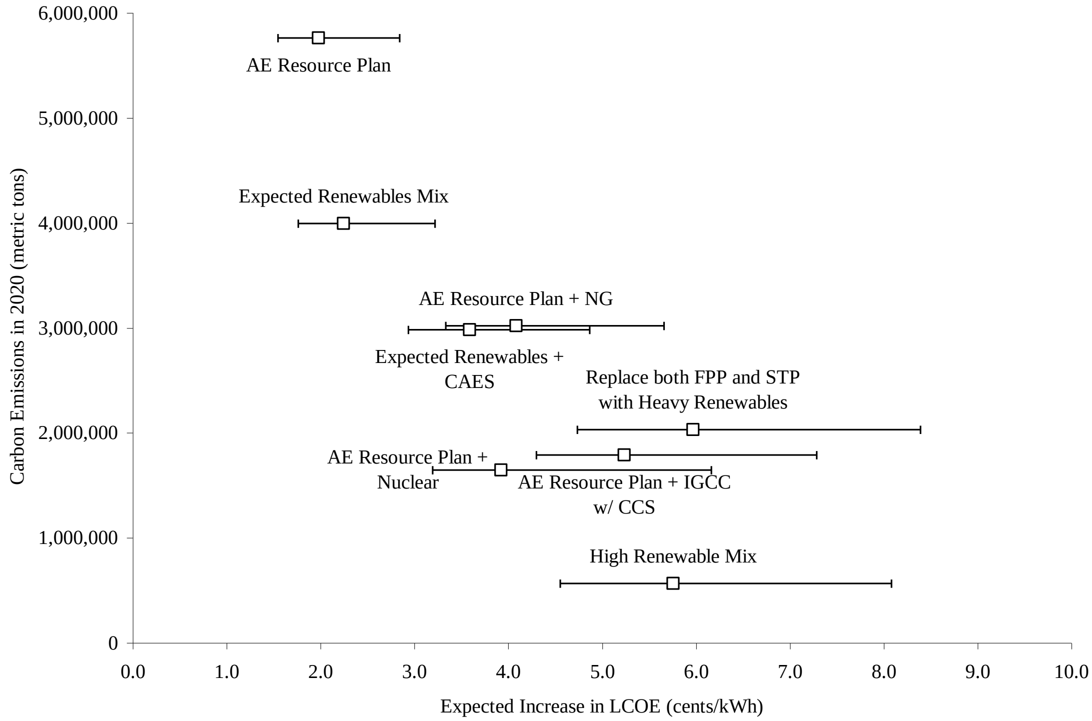


Figure 13
Metric Tons of CO_2 Reduced From 2007 Levels by Million Dollars Invested in Capital

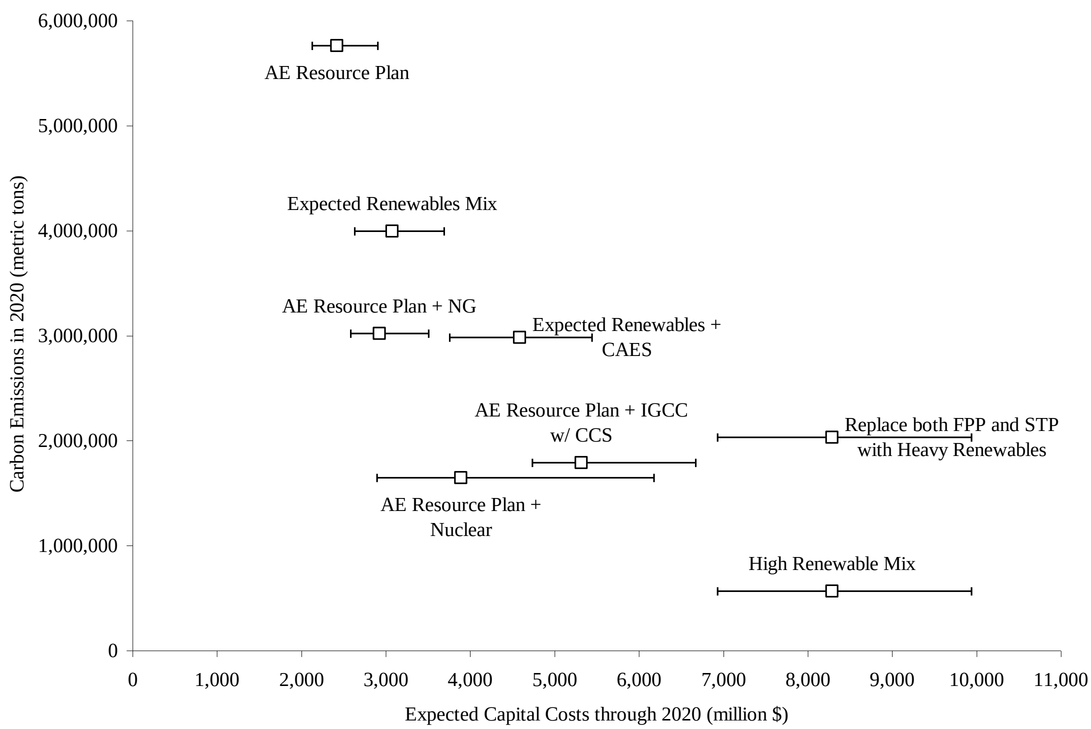
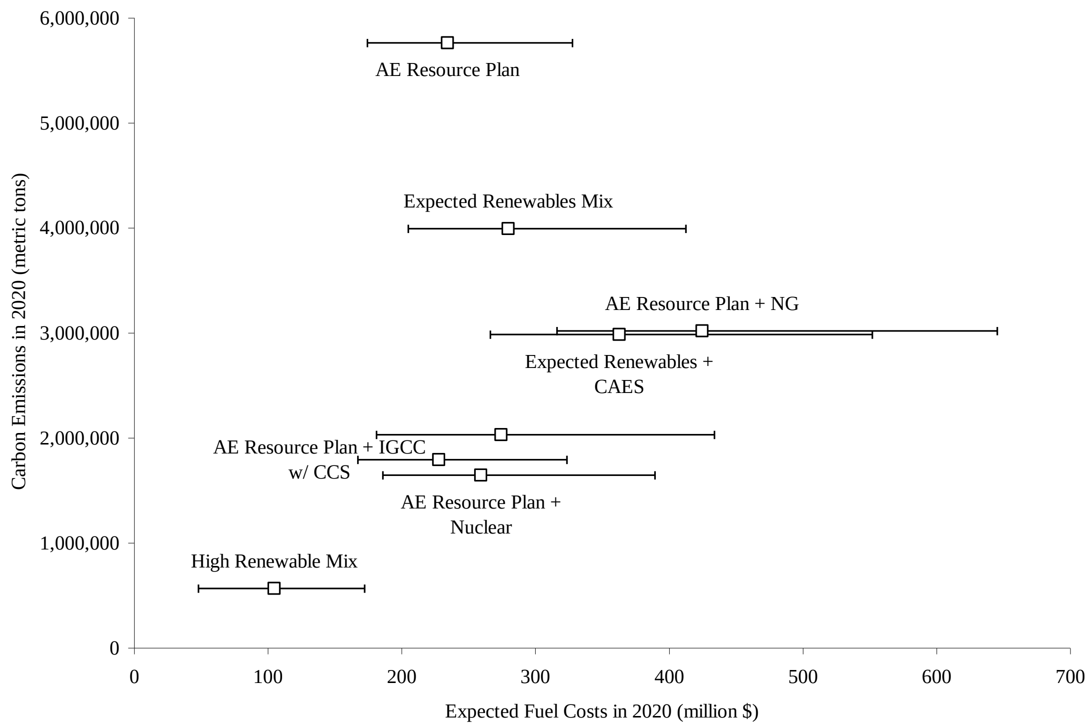


Figure 14
Metric Tons of CO_2 Reduced From 2007 Levels by Increase in Fuel Costs



Discussion

This report discusses a diverse range of choice of fuel sources for electricity in order to encourage Austin's citizens and elected officials to remain the final arbiters of the future based on their value judgments. Each of the eight scenarios allows AE to reach carbon neutrality by 2020 either by reducing direct CO_2 emissions or through the purchase of carbon offsets. However, there are significant differences in costs, risks, and merits of achieving sustainability associated with these options. A number of conclusions are discussed below that reflect the analysis of power generation technologies and the analysis of investment options for these technologies.

AE's proposed resource plan (portfolio option 1) appears to be a reliable, low cost, and low risk investment plan compared to the other seven scenarios. It also reduces direct CO_2 emissions the least because AE continues to burn coal at a constant rate through 2020. AE is not likely to significantly reduce its carbon footprint unless it reduces its coal use.

Several alternative technologies (nuclear, natural gas, integrated gasification combined cycle with carbon capture and storage, biomass, and geothermal power plants) can create opportunities for replacing AE's current pulverized coal-fired baseload generation capacity with cleaner forms of energy, measured in terms of direct emissions of CO_2. Wind and solar resources are not reliable baseload power generation sources due to their variable nature, but may become more reliable with the development of utility-scale energy storage. Biomass and geothermal resources face availability constraints that limit their potential to replace all of AE's current coal baseload power usage. It is not known if AE could build clean coal facilities with carbon capture and storage at the necessary scale to replace FPP on its own by 2020. Additional nuclear energy capacity or natural gas appears to be a feasible means to substitute coal baseload power generation.

Nuclear expansion (portfolio option 2) provides the least expected cost option for reducing CO_2 emissions. However, expansion of AE's nuclear power comes with the largest range of cost risks and uncertainties regarding construction length. Nuclear energy continues to face uncertainty in terms of public acceptance due to concerns related to the management of radioactive waste and safety.

AE's current nuclear capacity allows it to invest in renewable baseload power sources (biomass and geothermal) to replace coal if available to ensure reliable service to customers. It remains uncertain whether AE can purchase and implement reliable additional biomass or geothermal resources prior to 2020.

The cost of investment in the "anticipated" available renewable resources (portfolio option 4) are lower than a high investment in renewables (portfolio option 3), even if option 4 only allows for half of AE's coal use to be replaced with cleaner sources of energy, thus achieving more modest reductions in CO_2. A high investment in renewables entails high expected capital costs as well as high risks and uncertainties. The high renewables scenario may be more sustainable in that the sources once in place can continue to be used without fuel costs. It also reduces CO_2 emissions more than the other options. It may be overly ambitious about where and when these resources could come on-line.

AE must maintain sufficient natural gas capacity to backup wind and solar additions to AE's resource portfolio for any of the increased renewables scenarios. The capital costs of central solar facilities remain hard to estimate. The variability of performance of solar and wind due to when the sun shine and the wind blows means that sufficient natural gas and/or storage are necessary requirements for assuring reliable electricity service.

AE's planned additions for onshore wind under its proposed energy resource plan appear to be reasonable even if these wind resources have low resource availability during peak demand. Potential investments in offshore wind achieve higher rates of reductions in CO_2 emissions by displacing more natural gas use during peak hours than equal investment in onshore wind. Offshore wind currently faces uncertainty in terms of availability and costs.

Solar energy investments permit greater reductions in CO_2 emissions than onshore wind due to higher availability of solar energy during the day, as opposed to onshore wind which is primarily available during the night and morning off-peak hours. Solar investments currently come at much higher cost per kWh than wind.

Energy storage could provide a cost-effective way to achieve significant CO_2 reductions if coupled with onshore wind investments (portfolio option 5). Energy storage allows wind power generation to be temporarily stored and shifted from times of high production (early morning hours) to times of greater demand (late afternoon hours) to displace natural gas. Energy storage does not enhance the ability for solar to achieve CO_2 reductions because it is only available during times of typically higher demand. While energy storage requires additional capital, by shifting wind generated power from off-peak to on-peak hours, storage can serve as a hedge against natural gas prices. Compressed air energy storage facilities appear to be the most mature type of energy storage technology on the market today and have the highest capacities for storing energy. AE could collaborate with the LCRA to construct pumped storage facilities close to Austin. Two uncertainties with storage are what storage capacity would cost and the rules concerning how storage would be operated and dispatched. If storage is not used on a regular basis it could become an expensive way to achieve peak shifting.

Expansion of natural gas units (portfolio option 6), particularly an additional combined cycle unit at Sand Hill, provides a low capital cost investment to displace coal use while achieving some reductions in CO_2 emissions (albeit at much lower levels than nuclear or renewable resources). Added natural gas generation capacity creates concern over natural gas price volatility. Increased reliance on natural gas should be focused on the use of combined cycle units due to the high costs of operating combustion turbines. Additional natural gas capacity can serve as a backup source for additional investments in wind and solar, to be used primarily when these resources become unavailable. The need for natural gas expansion is contingent on the magnitude of complementary wind and solar investments as well as AE's ability to purchase supplementary power from the grid if these resources become unavailable for periods of time due to weather or cloud patterns.

While replacing FPP with an advanced clean coal facility with CCS technology (portfolio option 7) would be a symbolic act of confidence in coal, it would also represent a technical risk, as there are no such large-scale plants in routine operation in the US. As an immature technology, CCS would have high costs and uncertain operating characteristics as a replacement for FPP. Even though the CCS option uses a lower-cost fuel (coal) to enhance CO_2 reductions comparable to a natural gas alternative, the CCS process includes a large demand for energy to capture and sequester carbon, high capital costs, and CCS still results in CO_2 discharges from parts of the process other than power generation.

Removing both coal and nuclear from AE's resource mix (portfolio option 8) is a risky scenario for AE. AE would face significant expansion of natural gas facilities due to the variable nature of wind and solar as well as the uncertainty of availability of biomass and geothermal resources.

One uncertainty affecting each scenario is the question of whether the US will regulate carbon. Carbon regulation could offset some of the costs for cleaner energy technologies by increasing the cost of emitting carbon or allowing an electric utility to generate revenues depending on the type of carbon regulation implemented. Carbon regulation alone will not make solar power generation technologies cost competitive nor will it erase the diurnal cycles of wind and solar availability.

The cost of implementing new renewable power generating technologies, particularly solar technologies, into AE's resource portfolio would need to drop considerably between 2009 and 2020 to make a high renewable investment scenario cost competitive with AE's proposed energy resource plan. Even the optimistic scenarios of solar advocates (30 percent reduction of silicon costs over a decade) cannot make solar a cost-effective source for baseload power.

The expected available renewable resources scenario demonstrates that it is possible to reduce coal use by half and reduce the amount of natural gas expansion necessary through 2020 with utility-scale solar power plant additions at cost similar to AE's proposed energy resource plan. The cost of increased use of its natural gas facilities (not captured by these calculations) could be offset by the selling or leasing of one unit at FPP (not captured by these calculations) and the value of emission reductions under carbon regulation.

Further demand reductions beyond AE's goal of 700 MW of savings through 2020 would delay the need for additional power generation capacity additions. Accelerated DSM demand reductions due to time-of-day pricing tied to the smart grid or peak shifting could ease the transition to a coal-free resource portfolio and lower the costs for replacing this lost source of baseload power.

Remaining Issues

AE has some choices as to when to act and in what energy sources to invest to maintain its record of reliable low-cost electricity service to its customers as it seeks to become a sustainable, carbon-neutral utility. AE has already taken significant risks to move towards sustainability over the past several decades, including the early adoption of energy conservation and efficiency programs, green building regulations, and substantial investment in on-shore wind, and its smart grid deployment.

There are potential advantages and disadvantages to waiting to invest in new sources of power generation or energy conservation programs. AE is already becoming a utility leader in advancing new technologies and investing in cleaner sources of energy. AE is poised to have one of the first fully operational smart grid systems in the US. It will receive 100 MW of power generation capacity from biomass (by 2012) and 30 MW from the largest centralized PV solar plant in the US (by 2010). Should AE also be an initial adopter of other more immature technologies such as utility-scale energy storage, carbon capture and storage, off-shore wind, and geothermal in Texas? An early adopter may take advantage of lower contract costs from vendors eager to establish utility-scale performance. Unfortunately those same vendors may seek delays in construction or demand compensation for cost over-runs if the developing technology does not meet advertised performance measures. Early adoption and investment in immature technologies entails significant risks and uncertainties that AE and Austin citizens may wish to constrain until costs become more stabilized and technologies become more advanced.

Austin citizens ought to consider the balances of risks and costs of nuclear expansion as a sustainable resource relative to a zero carbon footprint. Nuclear energy provides the most reliable and abundant baseload power source to replace fossil fuels from AE's resource portfolio without emitting CO_2.

Despite the expected scale of investment in solar and nuclear technologies it is impossible to predict whether solar costs per kWh will fall significantly over the next decade and whether the next generation of nuclear plants can come on-line under the estimated capital budgets and within the estimated time. It is also difficult to determine when large-scale carbon capture and storage can become cost-effective and accepted by the public. Underlying these choices are many other risks and questions related to: (a) how the US will regulate CO_2 emissions; (b) how the Texas' Legislature and ERCOT will manage its electric industry; and (c) how Austin's citizens will weigh the value of reaching carbon neutrality against its costs and charges versus the electricity people have to pay or the effects upon reliability of service.

Recommendations

There are many ways for AE to reach carbon neutrality by 2020. One key issue is whether AE wishes to reach carbon neutrality by potentially paying hundreds of millions of dollars in carbon fees, taxes, or offsets, or whether it wants to invest in new sources of nuclear or renewable energy that cost more to build than its proposed energy resource plan but less to operate under a carbon regulation regime. A number of inferences can be developed based upon the analysis of power generation technologies and the analysis of investment options for these technologies. The recommendations that follow are based upon these inferences.

If AE wishes to reduce its carbon footprint significantly by 2020 one option is to reduce its reliance on FPP. If AE sells or leases its ownership in two units at FPP, it should target divestment to a year that would allow AE maximum carbon credit if carbon regulation is passed prior to the divestment. If AE divests its coal capacity and it wishes to retain or enhance system reliability, then AE must invest in cleaner forms of baseload power generation capacity such as nuclear, biomass, and geothermal baseload power plants.

Biomass is touted as a carbon-free source of energy even though it requires the burning of carbon. Its low carbon footprint reflects an accounting anomaly that weighs CO_2 emitted from burned organic residues different from energy in coal and gas. AE should monitor the reporting credibility of biomass as a carbon-free source of energy if carbon regulation is passed. AE can evaluate the merits of this resource as a form of clean energy. AE could benefit from any cost-competitive sources of biomass power generation capacity up to 300 MW of power generation capacity if it is considered a verifiable carbon-free source of energy.

AE should investigate the possibilities of investment in geothermal plants in areas of the state where geothermal sources exist. Any geothermal opportunities presented by third parties should be considered for up to 300 MW of power generation capacity. Partnerships for such an investment should be pursued if the relative costs are low and the reliability of the resource is high.

AE should monitor its wind investments as a component of its overall resource portfolio and evaluate the quality of its availability. Wind energy investments are only expected to be valuable up to a point at which infrastructure is in place to transfer wind energy over hundreds of miles from West Texas to Central Texas. Wind is likely to remain a low-cost option to meet off-peak demand (between 800-1500 MW of additional onshore wind investments). Offshore wind and energy storage facilities coupled with onshore wind can flatten AE’s hourly wind supply profile. AE should consider off-shore wind and energy storage to provide wind capacity during peak demand hours. Such investments should be evaluated based upon the value and risks of renewable power capacity at times when electricity is most needed and most costly.

AE should monitor the costs of solar technologies, particularly utility-scale solar power plants, as the marginal per-MWh costs of these technologies are expected to fall upon an increase in their market penetration. If centralized PV module solar plants (such as the proposed Webberville facility) are built in areas close to Austin, the solar industry in and around Austin would develop valuable expertise. AE could make at least 100 MW of investment in centralized PV facilities through 2020.

AE could consider investments in concentrated solar plants (particularly parabolic trough facilities) in West Texas. Opportunities presented by third parties should be considered along with proposed partnerships for such investments. The amount of investment should reflect the marginal per-MWh cost of solar energy. Should concentrated solar energy costs fall rapidly, AE could benefit from at least 200 MW of solar capacity additions and upwards of 600 MW of capacity additions to its resource portfolio by 2020. Increased efforts should be made to add distributed PV systems to roofspace in Austin. As AE’s smart grid is deployed and costs of PV rooftop systems drop AE may be able to increase its investment and efforts for subsidizing PV systems, particularly for commercial entities.

AE’s single best electric sector investment is in conservation, peak shifting, and reducing peak demand through methods such as real-time or time-of-day pricing made possible by a smart grid. AE uses its last 100 MW of peak resources only 43 hours per year. If that peak evaporates the cost savings from not having to build or use 100 MW of peak power are significant. One of AE's top priorities should be to work with the Texas Legislature, the Public Utility Commission of Texas, ERCOT, and other Texas utilities to develop pricing options that reward electricity providers to avoid, prevent, or constrain peak demand.

The design and success of AE's plans through 2020 depend on one critical assumption: that 700 MW can be conserved between 2009 and 2020. It took AE 20 years to achieve 600 MW of demand savings, reflecting 26 different energy conservation investment programs. There are two keys to conservation success, the amount of electricity saved for each conservation investment and the fraction of AE's customer base that participates in such practices and programs. If AE hopes to achieve 700 MW or more in demand savings between 2009 and 2020 it should invest in a community-wide education program to help its customers save themselves money by helping AE trim its peak and reduce overall demand.

Appendix A: Costs and Characteristics of Power Generation Technologies

Table A-1: Costs and Characteristics of Coal Technologies

	Pulverized Coal	IGCC without CO_2 Capture	IGCC with CO_2 Capture
Availability factor	0.95	0.88	0.88
Capacity factor	0.95	0.95	0.95
Technology maturity	Mature	Newly operational	Immature
CO_2 or equivalent emissions (metric tons/MWh)	0.94	0.86	0.16
Load service function	Baseload	Baseload	Baseload
Operational life (years)	30-50	Unknown	Unknown
Overnight capital costs ($/kW)	2,361-2,982 (2,485)	3,023-4,367 (3,359)	4,297-6,206 (4,774.00)
Fixed operation & maintenance costs ($/kW)	28.10	39.46	46.43
Variable operation & maintenance costs ($/kW)	4.68	2.98	4.53
Fuel costs ($/MWh)	13.32-14.72 (14.02)	12.51-13.83 (13.17)	12.51-13.83 (13.17)
Levelized cost of electricity (cents/kWh)	7.4-13.4 (9)	7.5-13.5 (10.4)	12.1-17.4 (13.4)
Current Austin Energy capacity	607 MW	0 MW	0 MW

Table A-2: Costs and Characteristics of Natural Gas Technologies

	Combustion Gas Turbines (CGT) (Advanced)	Combined Cycle Gas Turbines (CCGT)
Availability factor	0.96	0.96
Capacity factor	0.05-0.17	0.63
Technology maturity	Mature	Mature
CO_2 or equivalent emissions (metric tons/MWh)	0.52-0.73	0.36
Load service function	Baseload, intermediate, peak (mainly intermediate)	Baseload, intermediate, peak (mainly peak)
Operational life (years)	25- 30	25- 30
Overnight capital costs ($/kW)	426-568 (473)	1,067-1,423 (1,186)
Fixed operation & maintenance costs ($/kW)	10.74	11.94
Variable operation & maintenance costs ($/kW)	3.23	2.05
Fuel costs ($/MWh)	60.48 -113.40 (75.60)	40.30 -75.56 (50.37)
Levelized cost of electricity (cents/kWh)	22.1-33.4 (24.9)	73-100 (82)
Current Austin Energy capacity (MW)	382 (CGTs)	312 (CCGT), 741 (steam turbines)

Table A-3: Costs and Characteristics of Nuclear Technology

	Nuclear (Advanced)
Availability factor	0.97
Capacity factor	0.92
Technology maturity	Mature
CO_2 or equivalent emissions (metric tons/MWh)	None
Load service function	Baseload
Operational life (years)	40-60
Overnight capital costs ($/kW)	1,980-8,000 (3,682)
Fixed operation & maintenance costs ($/kW)	69.28
Variable operation & maintenance costs ($/kW)	0.50
Fuel costs ($/MWh)	4.65-5.13 (4.89)
Levelized cost of electricity (cents/kWh)	6-12.6 (6.7)
Current Austin Energy capacity (MW)	422

Table A-4: Characteristics of Hydropower and Pumped Storage Technologies

	Conventional Hydropower	Pumped Storage
Capacity factor	0.40-0.50	0.30-0.35
Technology maturity	Mature	Mature
CO_2 or equivalent emissions (metric tons/MWh)	Negligible	Negligible
Load service function	Baseload	Peak
Operational life (years)	50	60
Overnight capital costs ($/kW)	1,700-2,300 (2,000)	2,141-4,000 (2,379)
Fixed operation & maintenance costs ($/kW)	0.03-0.04	14.26
Variable operation & maintenance costs ($/kW)	None	Estimated $3.58; depends on cost of electricity used to pump the water up
Fuel costs ($/MWh)	None	None
Levelized cost of electricity (cents/kWh)	2.4	4.8; depends on the cost of electricity used to pump the water up
Current Austin Energy capacity (MW)	None. LCRA owns and operates 6 dams that can provide up to 281 MW of power and store up to 81 billion gallons of water.	Two lakes, Lake Buchanan and Inks Lake, were once plumbed with a back unit for pumped storage by LCRA, though they have not been operated for many years.

Table A-5: Costs and Characteristics of Wind Technologies

	Onshore Wind	Offshore Wind
Availability factor	0.95	0.95
Capacity factor	0.29	0.29
Technology maturity	Mature	Developing
CO_2 or equivalent emissions (metric tons/MWh)	None	None
Load service function	Peak	Peak
Operational life (years)	20-30	20-30
Overnight capital costs ($/kW)	1,706-2,275 (1,896)	2,010-3,446 (2,872)
Fixed operation & maintenance costs ($/kW)	30.92	91.32
Variable operation & maintenance costs ($/kW)	N/A	N/A
Fuel costs ($/MWh)	None	None
Levelized cost of electricity (cents/kWh)	4.4-9.1 (6.1)	Unavailable, onshore wind estimates used for simulator
Current Austin Energy capacity (MW)	440	None

Table A-6: Costs and Characteristics of Solar Technologies

	Concentrated Solar Power (CSP) – Parabolic Trough	CSP – Power Tower	CSP – Dish/ Engine	Photovoltaic (PV) - Centralized	PV – Distributed Thin Film
Availability factor	0.99	0.99	0.99	0.99	0.99
Capacity factor	0.41	0.41	0.41	0.17	0.17
Technology maturity	Developing	Immature	Immature	Relatively mature	Relatively mature
CO_2 or equivalent emissions (metric tons/MWh)	None	None	None	None	None
Load service function	Peak	Peak	Peak	Intermediate and peak	Intermediate and peak
Operational life (years)	Unknown	Unknown	Unknown	20-40	20-40
Overnight capital costs ($/kW)	2,269-3,403 (2,836)	2,800-4,200 (3,500)	2,995-4,493 (3,744)	4,626-6,938 (5,782)	Dependent on rebates
Fixed operation & maintenance costs ($/kW)	57.94	55.24	55.24	11.93	N/A
Variable operation & maintenance costs ($/kW)	None	None	None	None	None
Fuel costs ($/MWh)	None	None	None	None	None
Levelized cost of electricity (cents/kWh)	14.5-18.6 (15.5)	7.2-108 (9)	25-37.5 (31.2)	9.3-13.9 (11.6)	7.9-12.4 (10.2)
Current AE capacity (MW)	None	None	None	1	None

Table A-7: Costs and Characteristics of Biomass Technologies

	Biomass Combustion	**Biomass co-fired with coal**	**Landfill gas to energy**
Availability factor	0.90	0.95	0.90
Capacity factor	0.80	0.95	0.85
Technology maturity	Developing	Mature	Mature
CO_2 or equivalent emissions (metric tons/MWh)	0.10	Based on amount of biomass blended in coal	0.10
Load service function	Baseload	Baseload	Baseload
Operational life (years)	N/A	N/A	N/A
Overnight capital costs ($/kW)	2,528-3,370 (2,809)	50-500 (275)	1,707-2,276 (1,897)
Fixed operation & maintenance costs ($/kW)	59.19	N/A	116.60
Variable operation & maintenance costs ($/kW)	6.84	N/A	0.01
Fuel costs ($/MWh)	1.55-49.19 (25.37)	1.55-49.19 (25.37)	Unavailable
Levelized cost of electricity (cents/kWh)	5-9.4 (6)	0.3-3.7 (2)	4.3-8.1 (4.8)
Current Austin Energy capacity (MW)	100 by 2012	None	12

Table A-8: Costs and Characteristics of Geothermal Technology

	Geothermal (Binary-Type)
Availability factor	0.92
Capacity factor	0.90
Technology maturity	Mature
CO_2 or equivalent emissions (metric tons/MWh)	None
Load service function	Baseload
Operational life (years)	30
Overnight capital costs ($/kW)	3,231-4,308 (3,590)
Fixed operation & maintenance costs ($/kW)	168.01
Variable operation & maintenance costs ($/kW)	N/A
Fuel costs ($/MWh)	None
Levelized cost of electricity (cents/kWh)	4.2-8.1 (6.7)
Current Austin Energy capacity (MW)	None

Table A-8: Costs and Characteristics of Ocean Power Technologies (Operating Examples)

	Barrage generator – La Rance, France	Wave power – Pelamis, Portugal	Underwater turbine – New York City, NY
Availability factor	Unavailable	Unavailable	Unavailable
Capacity factor	0.40	0.25-0.40	0.77
Technology maturity	Experimental	Experimental	Experimental
CO_2 or equivalent emissions (metric tons/MWh)	None	None	None
Load service function	Baseload		Peak
Current capacity of operating example (MW)	240	2.25	10
Construction cost ($ million)	512	12.55	20
Construction time (years)	7 years	4 years	8 years
Levelized cost of electricity (cents/kWh)	2.6	Unknown	7
Fuel costs ($/MWh)	None	None	None
Current Austin Energy capacity (MW)	None	None	None

Table A-9: Costs and Characteristics of Energy Storage Technologies (Based on Capacity Size)

	Compressed Air Energy Storage (CAES) large, below ground (100-300 MW)	CAES small, above ground (10-20 MW)	Pumped Hydro (1,000 MW)	Flywheel (10MW)	Lead acid battery (10MW)	Sodium sulfur battery (10 MW)
Overnight capital costs ($/kW)	590-730	700-800	1,500-2,000	3,360-3,920	420-660	450-550
Levelized cost of electricity (cents/kWh)	20-102	200-250	100-200	1, 340-1,570	330-480	350-400
Storage Hours	10	4	10	0.25	4	4
Total Capital Cost ($/kW)	600-750	1,000-1,800	2,500-4000	3, 695-4,313	1,740-2,580	1,850-2,150
Application	Bulk- power management	Bulk-power management	Bulk-power management	Grid Support (load shifting)	Ensuring power quality up to grid support	Grid- support (load shifting)
Current Austin Energy Capacity	AE does not own or use an operating energy storage system. AE is ahead of many utilities as it has created and almost fully implemented its smart grid system that allows for utility-scale grid energy storage. With the smart grid system, energy producers can send excess electricity over the electric grid to temporary energy storage sites that become energy producers when electricity demand is greater.					

Appendix B:
Advantages and Disadvantages of Power Generation Technologies

The perceived advantages and disadvantages of each technology are listed below based on their load service function (baseload, intermediate or peak), local viability, risks (economic or other), environmental impacts, and other relevant issues and/or benefits.

Advantages	Disadvantages
Coal	
• Inexpensive and abundant fuel supply • Mature technologies with known risks • Coal is easily stored and transported • Dependable fuel source • Serves as a baseload energy source	• High CO_2 emissions • High emission of other air pollutants • High water use • The more efficient types of coal are less plentiful • High fuel transportation costs
Natural Gas	
• Mature technology • Short construction period • Cheap to construct • Can serve peak, intermediate, and peak load and provide a backup source to variable renewable resources	• High CO_2 emissions (but lower than coal) • High emission of other air pollutants • Variability in fuel costs • Long distance transfer of natural gas requires infrastructure
Nuclear Energy	
• High availability, typically shuts down only to re-fuel • Serves as a baseload energy source • Lower marginal cost of fuel compared to all other power plants that use a fuel source • Low operation and maintenance costs • Nuclear power generation emits negligible GHGs, including $CO2_2$, or other air pollutants • Regulated industry with an excellent safety record • Potential federal subsidies for new power plants may make nuclear power more financially attractive	• High overnight costs • Uncertain capital cost estimates • Potential for construction delays • Approval for construction is a lengthy process, roughly five to nine years • Generates radioactive waste • Uses large amounts of water • No permanent spent fuel storage facilities exist in the US • Potential for catastrophic incidents caused by terrorism or a facility malfunction • Negative public perceptions
Hydropower and Pumped Storage	
• Negligible GHG emissions • Can serve as baseload (conventional) or peak demand (pumped storage) • Mature technologies with few known risks • Pumped storage is the only large-scale	• High overnight costs • Damming impedes the natural flow of a river and alters its ecosystem, including water quality and fish populations • Requires relatively large amounts of land

storage technology currently commercially-available. • National average cost of hydroelectric generation is low • Hydropower projects offer multiple uses, including flood control, maintenance of municipal water supplies, and recreation	• As pumped storage have an efficiency of 70 to 85 percent, some energy is lost in the use of pumped storage, though benefits of peak shifting may outweigh efficiency losses • Limited local availability
Wind	
• Negligible GHG and air pollutant emissions • Few environmental impacts • No fuel costs • Onshore and offshore wind profiles are complementary • Cost-competitive with conventional fossil fuels	• Cannot serve as a baseload energy source • Low capacity factor • Variable power supply • Areas of high wind are rarely located near population centers • Requires transmission infrastructure which is costly • Peak winds typically do not blow during peak electricity demand periods • Requires large amounts of land
Solar	
• Negligible GHG and air pollutant emissions • Few environmental impacts • No fuel costs • Typically available during peak demand • Can serve as an off-grid power source as well as a distributed generation source in which customers sell energy to their electric utility provider through net metering methods	• Low capacity factor • Cannot serve as a baseload energy source • High capital costs • Requires additional transmission infrastructure • Requires viable energy storage capacity to increase availability during peak demand • Requires large amounts of land (less than wind)
Biomass	
• Can be used as a baseload power source • Can be co-fired with coal to decrease CO_2 emissions and other air pollutants • Lower costs than solar energy • Mature technology with few known risks • Biomass energy offsets the natural release of methane (a much stronger GHG as compared to CO_2) • Technologies exist to capture noxious gases before they enter the atmosphere	• Acquisition of a secure and inexpensive supply of biomass fuel can be a logistical challenge • Biomass plants must be fitted with additional systems to avoid GHG emissions • New regime of carbon regulations may discourage co-firing with coal, despite reductions in emissions • Biomass power plants generate air and water pollution as well as solid waste • Negative perception of landfills close to residences for landfill gas
Geothermal	
• Negligible GHG and air pollutant emissions	• Relatively high overnight costs • Geothermal power is only accessible and

• Few environmental impacts • Can serve as a baseload energy source • No major economic or financial risks associated with this technology • The largest economic risk, exploration, occurs at the outset of project development. These risks have been lowered in recent years due to the rich data on potential sites gathered by both government entities in Texas and the oil and gas industry	price competitive close to those locations where hot water or steam can be tapped • Lower below-surface temperatures lead to higher construction costs • The release of geothermal fluids on the surface can affect both surface waters and groundwater, though it is common practice to re-inject the fluids back into the well from which they came, eliminating this impact
Ocean Power	
• Negligible GHG and air pollutant emissions • Transmission lines established along the Texas coast could keep construction costs low • Can provide peak power • Ocean currents create high energy yields and are 1000 times denser than air • Barrage generators have operated since the 1960s. • No fuel costs	• The coast off Texas is too shallow, and tidal velocity and wave power off the coast are too slow and too low to make this an appealing resource in Texas • High construction costs • Unknown impact on ocean ecosystems and fish populations • There are no federal or state tax breaks or subsidies for ocean energy projects

Appendix C: Model Methodology

The Austin Energy Resource Portfolio Simulator (AERPS) performs a series of calculations to generate a series of charts and graphs that demonstrate the impact of changes to AE's resource portfolio made between 2009 and 2020. A user can analyze the ability of a power generation mix to meet annual demand and daily peak demand; evaluate the CO_2 emissions profile of the mix; and determine the anticipated costs of power generation and associated technology investments.

Inputs

The simulation model operates by first scheduling a mix of energy resources to be implemented to serve the electrical demand needs for AE's service area through 2020. The project team analyzed the availability of various energy sources and power generation technologies to determine reasonable investment opportunities through 2020. The following fuel sources and power generation technologies were included as potential inputs in the model:

- Coal (pulverized coal and integrated gasification combined cycle power plants with and without a carbon capture and storage system);
- Nuclear;
- Natural gas (combustion gas turbines or combined cycle gas units);
- Wind (onshore and offshore);
- Biomass (using wood waste);
- Coal co-fired with biomass (using wood waste);
- Landfill gas;
- Concentrated solar;
- Solar photovoltaic (centralized facilities and distributed systems); and
- Geothermal (binary cycle power plants).

A user identifies new sources of energy as inputs to the calculations. The user can add or subtract power producing capacities each year. Long-term planning factors are included. These features allow a user to manipulate assumptions of load forecast, technology characteristics, costs and other factors such as choosing when to introduce new energy resources.

Outputs

After a user determines the appropriate investments that allow AE to meet projected electricity demands along with other concerns, the simulator generates a serious of charts and graphs that demonstrate the impacts of the inputs on system reliability and CO_2 emissions and shows the costs associated with investments. The following outputs are generated automatically:

- Annual power generation capacity from each resource and the overall mix through 2020;
- Annual electricity production from each resource and the overall mix through 2020;
- An hourly load profile for meeting peak demand in 2020 with electricity production from each resource and the overall mix;
- A carbon emissions profile through 2020;
- Potential annual carbon costs or profits due to impending legislation from 2014 to 2020;
- Potential costs to offset remaining carbon emissions;
- Annual capital costs of new facilities added to the mix (represented as total overnight costs);
- Annual fuel costs of the mix; and
- A range of expected increases in the cost of electricity (represented as total levelized costs of electricity) attributed to each resource and the magnitude of additions to the mix.

System Reliability

The purpose of the first set of outputs and calculations is to test whether the user defined a resource portfolio that allows AE to meet its peak load forecasted from 2009 through 2020. These outputs gauge the reliability of the resource portfolio. AE projects that it will be able to meet its goal of an additional 700 MW of demand savings by 2020. However, it is possible that AE will achieve more or less savings. For this reason, both projection lines are included in the system reliability outputs. The scenarios tested so far were designed to meet demand assuming AE's projections for DSM savings are met.

Carbon Reductions and Associated Costs

A linear graph is generated showing AE's direct carbon emissions by year. The estimated annual costs of offsetting AE's CO_2 emissions through the year 2020 is represented as a bar graph with a range of offset costs from $13 to $40. This range is based upon a general review of the price of offsets in voluntary carbon markets in the US and projections of future offset costs if carbon regulation similar to Lieberman-Warner Climate Stewardship and Innovation Act of 2007 were to be implemented. The price of offsets could be influenced by the structure of the allowance market (i.e. percentage of credits versus percentage auctioned). Such a system would bring into question whether any utility participating in the carbon market could purchase offsets or credits in order to claim "carbon neutrality" or "sustainability." The estimated annual costs or profits from the purchasing or selling of allowances is represented as a bar graph for the years 2014 and 2020 and is based upon the projected impacts of the Lieberman-Warner Climate Stewardship and Innovation Act of 2007.

Costs and Economic Impacts

Expected annual capital costs for a particular investment plan is represented by a bar graph that calculates the total overnight costs of all power generation technology investments, summed over a given year. Total overnight cost is the cost that would be incurred if a technology or power plant facility could be built instantly. Capital costs are represented in dollars per kilowatt of power generation capacity ($/kW). Additionally, annual fuel costs are provided. A dual axis bar and box-and-whiskers graph is used to demonstrate the expected increase in levelized cost of electricity by year for the overall mix attributed to investments in new power generation technologies and facilities. The "levelized cost" of electricity is the constant annual cost of electricity that is equivalent, on a present value basis, to the actual annual costs, which are themselves variable. Components of levelized costs estimates include: the total cost of construction including financing; the cost of insuring the plant; ad valorem property taxes; fixed operation and maintenance costs; fuel costs, and variable operation and maintenance costs. By levelizing costs, one is able to compare technologies against one another more easily than by comparing annual costs.

Assumptions of the Model

This simulator is intended to provide a transparent snapshot of the consequences of making investments in power generation technologies to re-shape AE's resource portfolio by 2020. Many assumptions have been made due to data limitations and the goal of designing procedures that can be replicated by a user.

System Reliability

- Future peak demand is assumed to follow AE projections as estimated from AE documents without specific data.
- Future annual electricity generation is calculated based upon AE projections of future peak demand, multiplied by 0.52 – a value determined empirically in the model calibration process. This implies that the average yearly demand for the entire system is on average about half of peak demand.
- Actual energy produced is based upon generation capacity multiplied by capacity factor

multiplied by 8760 (days in a year).
- A 5 percent transmission loss is applied to all resources (except distributed solar photovoltaic modules) in calculating actual energy generated.
- Efficiencies of technologies are assumed constant and based upon current estimates.
- Hourly capacity factors for the following resources are assumed constant: coal, nuclear, biomass, landfill gas, geothermal, and purchased power.
- Hourly capacity factors for the following resources are manipulated as necessary or based upon hourly load profiles: natural gas, wind, solar, and energy storage.
- Capacity additions and subtractions are assumed to occur on the first day of the calendar year (January 1) and CO_2 emissions are reported for each calendar year.
- Peak demand hourly profile shape for 2020 is based upon current peak demand profile shape provided by the Electric Reliability Council of Texas (ERCOT) extrapolated to projected 2020 peak demand projection provided by AE. Furthermore, spot wind and solar profiles (not varying) are used to model hourly availability of these intermittent sources.
- Energy storage is not represented as additional generation capacity, but rather as a mechanism to use excess electricity during a different period of the day. This can be manipulated manually with hourly load profiles.

Carbon Dioxide Emissions and Carbon Costs

- Carbon emission factors are assumed constant and emission factors for current facilities are based upon 2007 AE reporting.
- Costs of offsets are provided as a range of potential values assumed constant through 2020.
- Carbon regulation is assumed to become effective beginning in 2014 and costs or profits of carbon are based upon the Lieberman-Warner Climate Stewardship and Innovation Act of 2014.

Costs and Economic Impacts

- Capital, fuel, and levelized costs are assumed constant and are based upon current estimates. Cost ranges are provided to account for potential cost fluctuations.
- Capital costs are represented as total overnight costs for implementing a new technology or constructing a new power plant facility.
- The value of selling existing facilities (or ownership in existing facilities) is not represented in the model.
- Expected increases in levelized cost of electricity are calculated based upon the percentage of electricity generated from cumulative new additions as a weighted cumulative average of additions.

Limitations of the Model

Due to the simplicity of the model and lack of data, limitations arose during the creation of the model. The following limitations exist in the model:

System Reliability

- Projected demand for actual energy delivered (in MWh, not peak power demand in MW) is not based upon AE projections, but determined empirically.
- Energy storage is only currently modeled to account for the storage of excess electricity (usually wind). Therefore, it is a power supply technology that is not comprehensively modeled as it would be actually used. For example, energy storage may be used to store baseload power sources at night for use during the day due to cost incentives.
- Capacity factors can be adjusted yearly for the output of total electricity generation, but are

particularly difficult to estimate for natural gas sources when they are used as a backup power source for solar and wind or as an intermediate power source.

- The peak demand hourly profile is provided only for the year 2020 and, therefore, does not account for potential failure to meet peak demand in previous years.
- The model only looks at the hourly load profile for peak demand during the summer and does not account for other seasonal fluctuations in demand.
- The model does not specifically deal with probabilistic failures or intermittency of wind and solar resources.

Costs and Economic Impacts

- Capital costs for additions to existing facilities use data for total overnight costs for a new facility.
- All cost projections are based upon current cost estimates and, therefore, do not account for potential future rises or drops in costs for particular technologies that are expected to exhibit such changes as they become more widely adopted or as fuel prices escalate.
- Levelized costs of electricity estimates do not account for current costs of electricity by source, but rather by taking the cumulative weighted average of additions and its expected impact on electric bills based upon percentage of overall energy generated coming from additions.
- Levelized costs of electricity for storage and DSM are not explicitly modeled. Rough storage cost estimates are made by attempting to capture how the additional capital costs, operation & maintenance costs, and any fuel costs would be passed along if storage technologies were built in conjunction with additional wind facilities. The rough estimates come from manipulating inputs to the cost estimation model obtained from the California Energy Commission.

Appendix D: Glossary of Terms

Availability factor	The amount of time a generator is typically out of service for maintenance and repairs divided by the amount of time it is ready for use
Baseload generation	Generation plants that are run constantly to provide the lowest level of instantaneous demand Coal, nuclear, combined-cycle natural gas, and biomass plants are usually operated as baseload plants
Carbon cycle	The natural process of the earth and atmosphere emitting and absorbing carbon and carbon dioxide
Carbon footprint	A measurement of the carbon dioxide and carbon-equivalent emission of an electric utility
Carbon neutral	A state of operation where an electric utility does not emit more carbon dioxide than it offsets or sequesters
Carbon sequestration	The act of taking carbon dioxide out of the waste stream of a power generation facility and permanently removing it from the atmosphere
Capacity factor	The actual energy output of a plant divided by the full capability of the resource A measure of resource utilization Coal plants typically have high capacity factors, while wind farm usually have very low capacity factors
Conservation	Programs or technologies designed to reduce the consumption of energy by using less As opposed to efficiency, conservation strives to do less work by restricting energy consumption
Demand peak	The instant that a utility must serve the highest amount of load for a given time period
Demand-side management	Programs or technologies designed to reduce peak demand by signaling loads to reduce their consumption at a specific time
Direct load control	A generator or dispatch authority program that directly reduces load at the consumer delivery point
Electric energy	Electric energy, measured in Watt-hours (Wh), is the amount of electric power consumed over time
Electric power	Also known as capacity, power is the ability to do work using electricity Instantaneous demand and generation capacity are often referred to in Watts (W), a measure of electric power
Energy efficiency	Programs or technologies that do the same amount of desired work with less electrical energy Compact fluorescent light bulb programs are a common energy efficiency program promoted by utility companies
ERCOT	Electric Reliability Council of Texas, it is the regional independent system operator that oversees the dispatch and clearing of the physical and economic market in which Austin Energy participates.
Fixed operation and maintenance costs	The costs to operate and maintain a power plant that are incurred whether or not the plant generates electricity; administration, overhead, licensing and personnel are such costs
Fuel cost	The direct cost of the fuel source
Intermediate generation	Generation plants that have some responsiveness to changes in demand, but cannot respond to peak demand
Kilowatt	Equal to one thousand watts.

Kilowatt-hour	A unit of energy representing energy delivered by electric utilities.
Levelized cost of energy	The constant annual cost of electricity that is equivalent, on a present value basis, to the actual annual costs. Includes the total cost of construction including financing; the cost of insuring the plant; ad valorem property taxes; fixed operation and maintenance costs; fuel costs, and variable operation and maintenance costs.
Megawatt	Equal to one million watts. A watt measures a rate of energy conservation and is equal to one joule of energy per second.
Megawatt-hour	Equal to one-thousand kilowatt-hours.
Operational life	The expected lifespan of a power plant
Overnight capital cost	The present value of a power plant installation as if the plant were completed "overnight;" does not account for debt service or inflation
Peaking generation	Generation plants that are very responsive, have fast start-up times, and low fixed operating costs Can respond quickly to meet peak demand for short periods
Peak smoothing	A demand-side practice that defers consumption from the peak demand to some other time period
Renewable resources	Generation fuels or energy sources that can be acquired repeatedly and indefinitely
Solar PV	Solar power generation technology using photo-voltaic panels
Variable operation and maintenance costs	The costs to operate and maintain a power plant that vary with the electrical output of the plant; such costs include station load service, emission costs and regulatory compliance