Sustainable Energy Options for Austin Energy

Summary Report

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List of Acronyms and Abbreviations

AC	Alternating current
ACPP	Austin Climate Protection Plan
AE	Austin Energy
AEP	American Electric Power
AES	Allegheny Energy Supply
AMI	Advanced metering infrastructure
Btu	British thermal unit
BWR	Boiling water reactor
CdTe	Cadmium telluride
CAES	Compressed air energy storage
CARROT	Climate Action Registry Reporting Online Tool
CCAR	California Climate Action Registry
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage/sequestration
CCX	Chicago Climate Exchange
CDM	Clean Development Mechanism
CEMS	Continuous emissions monitoring system
CGT	Combustion gas turbine
CH_4	Methane
CHP	Combined heat and power
CIS/CIGS	Cooper indium diselenide
CO_2	Carbon dioxide
Council	Austin City Council
CPP	Critical peak pricing
CREZ	Competitive Renewable Energy Zone
CSP	Concentrated solar power
DC	Direct current
DES	Distributed energy storage
DOD	Department of Defense
DOE	United States Department of Energy

DR	Demand response
DSM	Demand-side management
ECR	Eastern Climate Registry
EEI	Edison Electric Institute
EIA	Energy Information Administration
EPA	United States Environmental Protection Agency
EPIA	European Photovoltaic Industry Association
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EUROBAT	European Storage Battery Manufacturers
FCE	Fuel cell energy
FERC	Federal Electric Regulatory Commission
FPP	Fayette Power Project
g	Gram
GHG	Greenhouse gas
GLO	Texas General Land Office
GRP	General Reporting Protocol
GW	Gigawatts
HAN	Home area network
HEV	Hybrid electric vehicle
HFC	Hydrofluorocarbon
HVAC	Heating, ventilation, and air conditioning
IEA	International Energy Association
IETA	International Emissions Trading Association
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
ITC	Investment tax credit
kg	Kilogram
km	Kilometer
kW	Kilowatt
kWe	Kilowatt electricity

kWh	Kilowatt-hour
LCA	Life-cycle assessment/analysis
LCRA	Lower Colorado River Authority
LFG	Landfill gas
LGOP	Local Governmental Operations Protocol
m^2	Square meter
Mt	Metric ton
MIT	Massachusetts Institute of Technology
MMBtu	Million Btu
MW	Megawatts
MWh	Megawatt-hour
MSW	Municipal solid waste
N_2O	Nitrous oxide
NaS	Sodium sulfide
NCS	New Carbon Finance
NO_x	Nitrous oxides
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NYPA	New York Power Authority
O&M	Operations and maintenance
OTC	Over-the-counter
PFC	Perfluorocarbon
Pm	Particulate matter
PPA	Power purchase agreement
PSEG	Public Service Enterprise Group
PTC	Production tax credit
PUC	Public Utility Commission of Texas
PUP	Power/Utility Protocol
Ppp	Parts per million
PV	Photovoltaic
PWR	Pressurized water reactor
REC	Renewable energy certificate

REPP	Renewable Energy Policy Project
RITE	Roosevelt Island Tidal Energy
SAE	Statistically adjusted end-use
SAIC	Science Application International Corporation
SECO	State Energy Conservation Office of Texas
SEGS	Solar Electric Generation System
SES	Stirling Energy Systems
SF_6	Sulfur hexafluoride
SO_2	Sulfur dioxide
STM	Stirling Thermal Motors
STP	South Texas Project
TCEQ	Texas Commission on Environmental Quality
TEPCO	Tokyo Electric Power Company
TCR	The Climate Registry
TDF	Tire-derived fuel
TOU	Time-of-use
TSTC	Texas State Technical College
TVA	Tennessee Valley Authority
U-235	Uranium-235
US	United States
UTC	United Technologies Company
VCS	Voluntary Carbon Standard
VRB	Vanadium redox battery
VTC	Voluntary carbon market
W	Watt
Wp	Watt peak
WEST	West Energy Systems Technology
WTC	World Trade Center

Foreword

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. This project developed methods to evaluate future power generation options for their feasibility and cost-effectiveness. The 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. 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

This project would not have been possible without the financial support of Austin Energy (AE) and Solar Austin through commissioning the study. Project participants are thankful for the guidance provided by AE, Solar Austin, faculty and staff of The University of Texas at Austin (UT-Austin), and other energy experts in the Austin community.

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. Christopher Smith, Katherine Cummins, and David Eaton, Ph.D., edited this report. Any omissions or errors are the sole responsibility of the authors and editors of this report.

Executive Summary

The City of Austin, on behalf of Austin Energy (AE), and Solar Austin commissioned this Policy Research Project with the Lyndon B. Johnson School of Public Affairs at The University of Texas at Austin to review options for Austin's electric utility, Austin Energy, to achieve sustainable power generation with an interim goal of becoming carbon neutral by 2020. This report describes feasible and cost-effective investments that would allow AE to produce and distribute the electricity it needs while simultaneously achieving zero net CO_2 emissions by 2020 using sustainable energy sources.

The conventional wisdom is that a sustainable energy future will be built around a diverse set of energy technologies that do not pollute as much as current energy systems, along with policy options to reduce energy demand and the use of fossil fuel resources. Rising costs of fossil fuels resulting from increases in worldwide demand and carbon management legislation could make sustainability arguments attractive from an economic or business perspective. Achieving a sustainable electric utility requires citizens to make informed decisions regarding competing power generation technologies. In July 2008, AE unveiled its proposed energy resource plan to Austin. AE has invited its customers to discuss the future power generation mix attributed to their communities. AE hopes that Austin's citizens and elected officials can concur in these decisions. This opportunity exists because the City of Austin controls its own electric utility and AE strives to improve the quality of its service to meet the demands of its customers. By designing a sustainable energy future, AE can become an example for other electric utilities.

Volume II of this report discusses, among other things:

- projected energy needs;
- available and reasonably anticipated technology for energy conservation, energy efficiency, and power generation;
- economic costs of production and distributing electricity as well as CO_2, nuclear waste, and other byproducts of power generation;
- planning and regulatory challenges; and
- other options for community investment.

The goal of this process is to develop a reasonable set of short-term and long-term investments that can become a model for other utilities nationwide.

This report attempts to address difficult issues, many of which do not have ready answers. Some of the issues include:

- the inherently variable nature of some renewable power generation technologies;
- identifying energy storage technologies that enable greater use of such renewable energy sources;

- determining whether CO_2 capture and storage methods provide an interim solution;
- regulatory uncertainties, including the switch to a nodal market and potential carbon legislation;
- "grid" issues, including reliability, transmission, and interconnection;
- the potential for distributed local power generation;
- the uncertainty of projecting future energy requirements;
- the need for AE to remain financially sound and to contribute to the Austin city budget; and
- how to confirm the validity of mitigation strategies that offset any carbon release that is unavoidable.

This report intends to identify obstacles that might inhibit successful implementation of various options and tries to identify potential technical breakthroughs that could enable the achievement of sustainable power generation and reduce AE's CO_2 footprint.

The report encompasses electricity conservation, generation, transmission, and distribution actions that AE can take within its jurisdiction. One of the primary objectives of this report is to evaluate options for generating electricity and identifying the risks and uncertainties associated with these options. In order to compare alternatives, policy research project participants developed a standard simulation model that allows a user to compare costs and risks of alternate energy sources. This model is discussed in detail in Volume III of this report and several different future resource portfolio investment scenarios are evaluated and compared. Volume I of this report is a summary of Volumes II and III.

The project team's assessment of current and future energy options in Volume II of this report 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.

Power generation technologies to be discussed in this report include the following fossil-fueled and renewable resources and their associated technologies:

- coal [pulverized coal power generation, fluidized bed combustion, and integrated gasification combined cycle (IGCC)];
- natural gas (combined-cycle and combustion turbines);
- nuclear;
- hydropower and pumped storage;
- wind;
- solar (photovoltaic power and concentrated solar power);
- biomass;
- geothermal;
- ocean power; and
- hydrogen and fuel cells.

This list of energy sources reflects a reasonable set of future power generation opportunities as of 2009. Further advances in clean coal and other technologies related to increasing efficiency and reducing emissions of fossil-fueled power generation sources will be discussed as potential investments as well as the capabilities of various energy storage technologies that might increase the appeal of wind and solar power generation technologies. Advancements in new technologies continue to occur as concerns for energy security and the environment rises. As new technologies develop, consideration of the costs and benefits of such technologies should be included in discussion of the utility's future power generation mix. By comparing these technologies, citizens can make an informed decision as to which technologies keep costs low, electric reliability high, and reduce AE's carbon footprint. Some of the factors that can be considered include the ability for the technology to meet future load, the cost and time of construction, fuel and marginal operating costs, projected operational life, fuel and plant dependability, maturity of the technology, emissions and other environmental concerns, and security or other potential concerns related to the technology.

This report provides a neutral and comprehensive evaluation of many available options that AE could take to meet future energy demands while satisfying the city's goal of designing a public utility plan that could serve as an example for other utilities to develop a sustainable energy future. This report evaluates impediments towards the usage of alternative electric generation technologies, such as the variable nature of renewable energy (meaning these sources generate electricity variably rather than on demand), various grid issues related to the distribution of renewable energy, the feasibility and risks associated with carbon storage methods, the validity and costs of investments to offset carbon releases, risks associated with adding new nuclear capacity, and challenges for maintaining a financially sound utility. This report considers sustainability as it applies to the energy sector from both economic and environmental perspectives. Options will be analyzed based upon how they affect the financial operation of AE as well as the environment. AE customers will be able to evaluate such options with respect to their personal preferences in working towards a sustainable energy future.

Conclusions and 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 investment opportunities for these technologies. The recommendations that follow are based upon these inferences.

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, the Electric Reliability Council of Texas, 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 money by helping AE trim its peak and reduce overall demand.

If AE wishes to reduce its carbon footprint significantly by 2020 one option is to reduce its reliance on burning coal at the Fayette Power Project (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.

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.

Expansion of natural gas units, 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 power generation capacity creates concern over natural gas price volatility. Increased reliance on natural gas should focus 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 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 carbon capture and storage (CCS) technology would reduce CO_2 emissions, it would also represent a technical risk, as there are no such large-scale plants in routine operation in the United States. 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, liability risks, and CCS still results in CO_2 discharges from parts of the process other than power generation.

AE should monitor the reporting credibility of biomass as a carbon-free source of energy if carbon regulation is passed. 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 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 megawatts (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, onshore wind farms located along the Texas coast, and energy storage facilities coupled with onshore wind can flatten AE's hourly wind supply profile. AE should consider offshore wind, coastal onshore 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 megawatt-hour (MWh) costs of these technologies are expected to fall upon an increase in their market penetration. If centralized photovoltaic (PV) module solar plants (such as the planned 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 as well as increasing the amount of solar PV on roof space in AE's service area. 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 roof space in Austin.

AE could consider creating new incentives to dramatically increase the amount of solar PV on roof space in AE's service area. 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 may need to adjust its business model depending on the amount of PV penetration is expected through 2020 as its current rebate program that does not allow AE part ownership in the PV systems could lead to revenue erosion.

Energy storage could provide a cost-effective way to achieve significant CO_2 reductions if coupled with onshore wind investments. 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 significantly enhance the ability for solar to achieve CO_2 reductions because it is only available during times of typically higher demand, but could allow solar to effectively operate as a baseload power source. 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 Lower Colorado River Authority 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.

Hydropower, ocean energy, hydrogen, and fuel cells do not appear to be viable investment opportunities for AE by 2020. AE should continue to monitor these technologies for future opportunities.

Chapter 1. Introduction: Designing a Sustainable Electric Utility

Energy is an essential component of a prosperous society since its availability and affordability improve a community's quality of life. Current energy systems are built around burning fossil fuels as their relatively low costs and reliable service have been drivers for determining energy fuel sources. The exploitation of fossil fuel sources have always carried economic, health, and environmental risks associated with their extraction, processing, transport, combustion, and use. Increasing concern regarding the potential consequences of current energy usage on future generations, driven by the concern of increased concentrations of greenhouse gases (GHGs) in the atmosphere, has begun to influence electric utility planning. Burning fossil fuels emits large quantities of carbon dioxide (CO_2), the most widely dissipated human-induced GHG. Many scientists agree that human-induced GHG emissions are a cause of global temperature increases.[1] This rise in temperatures, termed global warming, could change the world's climate system and potentially affect the well-being of humans and other species.

The electric utility sector has been targeted as a major potential source of reducing our society's impact on the environment, primarily by reducing CO_2 as well as the impacts of other air, water, and solid wastes. For example, in the United States, 47 percent of total GHG emissions were attributed to the generation of electricity and heat in 2005.[2]

Global warming is only one of many factors influencing electric utility planners to reconsider how to create and distribute electricity to support modern life. Other issues include the future costs and availability of fossil fuels, particularly those that are imported; air and water quality considerations; and the potential availability of affordable renewable domestic energy sources. Power generation providers have been investing in new technologies to generate electricity in a cleaner manner and to increase efficient energy use. Technological advancements to reduce the emission of pollutants from conventional power generation technologies have coincided with advances in alternative technologies that use renewable resources to generate electricity.

The conventional wisdom is that a sustainable energy future will be built around a diverse set of energy technologies that do not pollute as much as current energy systems, along with policy options to reduce energy demand and the use of fossil fuel resources. Rising costs of fossil fuels resulting from worldwide demand increases and carbon management legislation could make sustainability arguments attractive from an economic or business perspective.

Achieving a sustainable electric utility requires citizens to make informed decisions regarding competing power generation technologies. Austin Energy (AE), the electric utility of Austin, has invited its customers to discuss the future power generation mix attributed to their community. AE hopes that Austin's citizens and elected officials can concur in these decisions. This report discusses future power generation options for a sustainable electric utility. This opportunity exists because the City of Austin controls its own electric utility and that organization strives to improve the quality of its service to meet the demands of its customers. By designing a sustainable energy future, AE can become an example for other electric utilities.

On February 7, 2007, City of Austin Mayor Will Wynn unveiled an ambitious plan for the city to address global warming by reducing GHG emissions and Austin's carbon footprint. On February 15, 2007, the Austin City Council passed Resolution Number 20070215-023, outlining the Austin Climate Protection Plan (ACPP) and setting the goal of making Austin "the leading city in the nation in the effort to reduce and reverse the negative impacts of global warming."[3] Components of the plan include a municipal plan, a utility plan, a homes and buildings plan, a community plan, and a "go neutral" plan.

This report focuses on the utility plan component of the ACPP. The ACPP sets forth specific goals and guidelines for the development of the city's utility plan. Specific deliverables outlined by the plan include:[4]

- establishing an upper bound on CO_2 and a carbon reduction plan for all utility emissions;
- achieving carbon neutrality on any new power generation units through lowest-emission technologies, carbon sequestration, and offsets;
- achieving 700 megawatts (MW) in energy savings through energy efficiency and conservation by 2020; and
- meeting 30 percent of all energy needs through renewable resources by 2020, including 100 MW of solar power.

While Mayor Wynn's goals alone appear to be ambitious for an electric utility, the purpose of this particular report is to go one step further: to design a sustainable electric utility with the benchmark goal of reaching carbon-neutrality by 2020. In this report the terms carbon dioxide (CO_2), carbon footprint, and carbon will all be used to convey the same meaning: the weight of GHG releases in terms of CO_2 equivalent.

Background and Purpose of Report

The City of Austin, on behalf of AE, and Solar Austin commissioned this Policy Research Project with the Lyndon B. Johnson School of Public Affairs at The University of Texas at Austin to review options for Austin's electric utility, AE, to achieve sustainable power generation with an interim goal of becoming carbon neutral by 2020. This report describes feasible and cost-effective investments that would allow AE to produce and distribute the electricity it needs while simultaneously achieving zero net CO_2 emissions by 2020 using sustainable energy sources. This report will take into account, among other things: (a) projected energy needs; (b) available and reasonably anticipated technology for energy conservation, energy efficiency, and power generation; (c) economic costs of production and distributing electricity as well as CO_2, nuclear waste, and other byproducts of power generation; (d) planning and regulatory challenges; and (e) other options for community investment. The goal of this process is to develop a reasonable set of short-term and long-term investments that can become a model for other utilities nationwide.

- This report attempts to address difficult issues, many of which do not have ready answers. Some of these issues include:
- the inherently variable nature of some renewable power generation technologies;
- identifying energy storage technologies that enable greater use of such renewable energy sources;
- determining whether CO_2 capture and storage methods provide an interim solution;
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This report intends to identify obstacles that might inhibit successful implementation of various options and tries to identify potential technical breakthroughs that could enable the achievement of sustainable power generation and reduce AE's CO_2 footprint. The report encompasses electricity conservation, generation, transmission, and distribution actions that AE can take within its jurisdiction. One of the primary objectives of this report is to evaluate options for generating electricity and identifying the risks and uncertainties associated with these options. In order to compare alternatives, policy research project participants developed a standard simulation model that allows a user to compare costs and risks of alternate energy sources. This model is discussed in detail in Volume III of this report.

Designing a sustainable electric utility is both a challenge in deciding what exactly that means and how to go about reaching that goal. Sustainability is an inherently subjective term because it reflects human values and the perceived costs and benefits of any particular activity. Energy affects everyone and people have differing perspectives on how it should be utilized. 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, 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 cause of climate change that could have adverse consequences for future generations.

Sustainability was first popularized as a term in 1987 in the report *Our Common Future* published by the World Commission on Environment and Development.[5] This report, commonly referred to as the Brundtland Report, defined sustainable development as, "development that meets the needs of the present without compromising the ability of future generations to meet their own needs."[6] This study adopts "sustainability" as a relative, rather than absolute, gauge of the degree of impact a power generation source has upon the availability of natural resources for future generations as well as the impact of the power generation technology upon the environment. Therefore, wind and solar technologies would be more sustainable than coal and natural gas-based power generation technologies. Nuclear power generation represents a complex source of energy; although nuclear power does not emit GHGs into the atmosphere, 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 power generation technologies based upon this definition is a step for developing potential pathways towards 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 a relative term regarding 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, an 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. This study will evaluate various future power generation mix scenarios in Volume III of this report through a set of four performance measures:

1. does the proposed power generation mix meet projected demand reliably;
2. what are the cost estimates for a particular power generation mix;
3. what are the CO_2 emissions associated with the power generation mix;
4. and what are the risks and uncertainties associated with the energy sources and power generation technologies used?

Measuring sustainability is difficult and determining what factors constitute a sustainable electric utility can create much contention. Placing a value (by assigning an economic cost based on its depletion or impact) on human health, life, and availability of resources is a subjective measurement and can create much debate as well. Measuring the carbon footprint of a power generation mix provides one measurement for determining the relative sustainability of a utility. For the purposes of this report we have identified the interim goal of AE reaching carbon-neutral status by 2020 as a significant step towards becoming a sustainable electric utility. This study will compare power generation technologies based upon carbon emissions per unit of electricity generated.

Restating the goal from “sustainability” to “carbon neutrality” raises the conundrum of defining what “carbon neutral” means. Named the New Oxford American Dictionary’s word of the year for 2006, “carbon neutral” has been defined as: “making no net release of carbon dioxide to the atmosphere, especially through offsetting emissions by planting trees.”[7] 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.

Given the carbon neutrality definition, the next step is to calculate AE’s carbon footprint. This report will describe and assess the methodology used by AE to calculate its carbon footprint as well as baseline projections through the year 2020. 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).[8] These calculations have been verified by a third-party engineering firm and validated by CCAR.

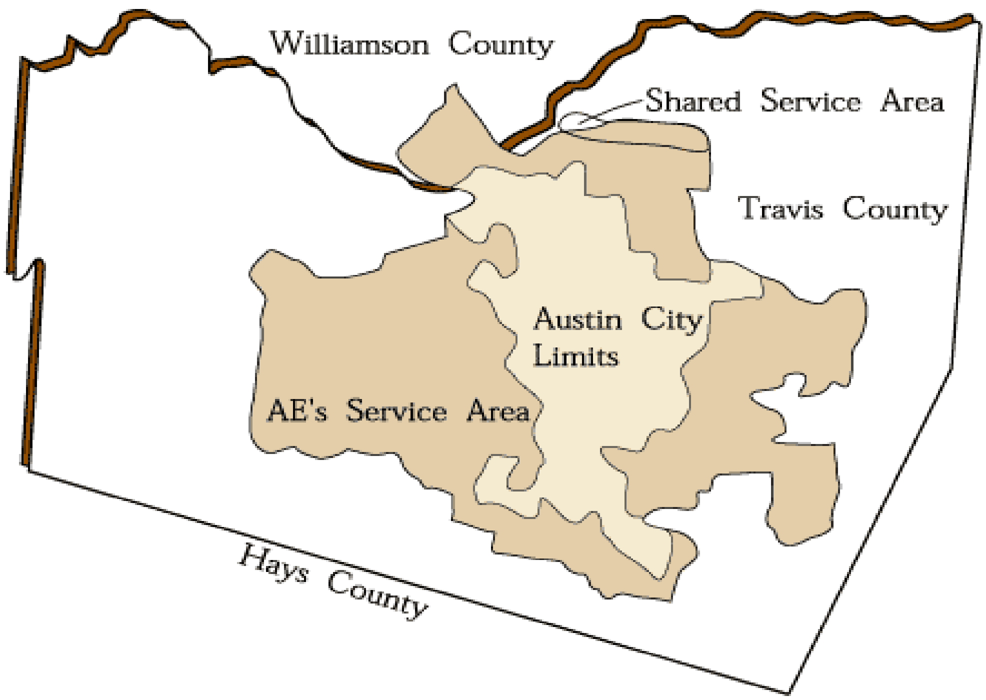
Austin Energy

AE has been owned and managed by the City of Austin since the utility’s creation in 1893. AE as a public utility provider is controlled by its customers through its City Council, which has the authority to set the budget and manage the utility. This status as a public utility allows customers to exert influence over AE and encourage specific or broad actions, such as sustaining a healthy environment.

AE is currently the ninth largest public utility provider in the U.S. by net power generation.[9] AE serves a population of almost one million people, covering 437 square miles.[10] Figure 1.1 shows a map of AE’s service area boundaries, which includes parts of Travis County, a small portion of Williamson County, and the entire City of Austin, totaling 230.7 square miles. A small portion of AE’s service area (about 11 square miles) is shared with the Oncor (formerly TXU) service area.[11] Communities served by AE outside of the City of Austin (totaling about 15 percent of its customers) include Bee Cave, Lakeway, Pflugerville, Rollingwood, Sunset Valley, and Westlake Hills.[12]

In 2001 the State of Texas deregulated the electric utility sector. Municipal utilities in Texas were given an option of whether or not to opt into the deregulated market. As of 2006, AE and all other 73 public utilities in Texas have not opted into deregulation.[13] AE, as a public utility, could decide to do so at any time. Amidst this environment AE has developed a competitive strategy aimed at keeping rates low by reducing operating costs, paying down debt, and paying for electricity through fuel charges when possible, effectively paying for current energy sources at current market costs.

Figure 1.1
Austin Energy Service Area Boundaries



Source: Austin Energy, *Electric Service*. Online. Available: http://www.austinenergy.com/Customer%20Care/Electric%20Service/index.htm. Accessed: July 6, 2008.

The total of AE's rated power generation capacity from its owned or co-owned facilities or power purchased through contractual agreements was 2,762.4 MW as of September 2008.[14] AE continues to use a diverse power generation mix. In 2008 about 30 percent of its energy resources came each from coal, nuclear, and natural gas, with 10 percent coming from so-called "renewable" energy sources (wind, solar, and landfill gas).[15] AE expects to increase the fraction of renewable power generation capacity to 18 percent by 2012.[16] Figure 1.2 details AE's power generation mix as of July 2008.

AE has been recognized nationally for its energy efficiency program. Since 1982 AE has estimated that this program has cumulatively reduced energy use by the equivalent of the annual output of a 700 MW power plant.[17] Through programs ranging from GreenChoice® renewable energy to the utility's free thermostat program (called Power Partner), AE continues to offer customers a wide range of options that lower electric bills and GHG emissions. Rebate programs for solar installations and efficient technologies and recent support for plug-in hybrid vehicles also demonstrate AE's continued efforts to become a sustainable and environmentally-friendly utility.

Figure 1.2
Austin Energy Power Generation Portfolio, July 2008

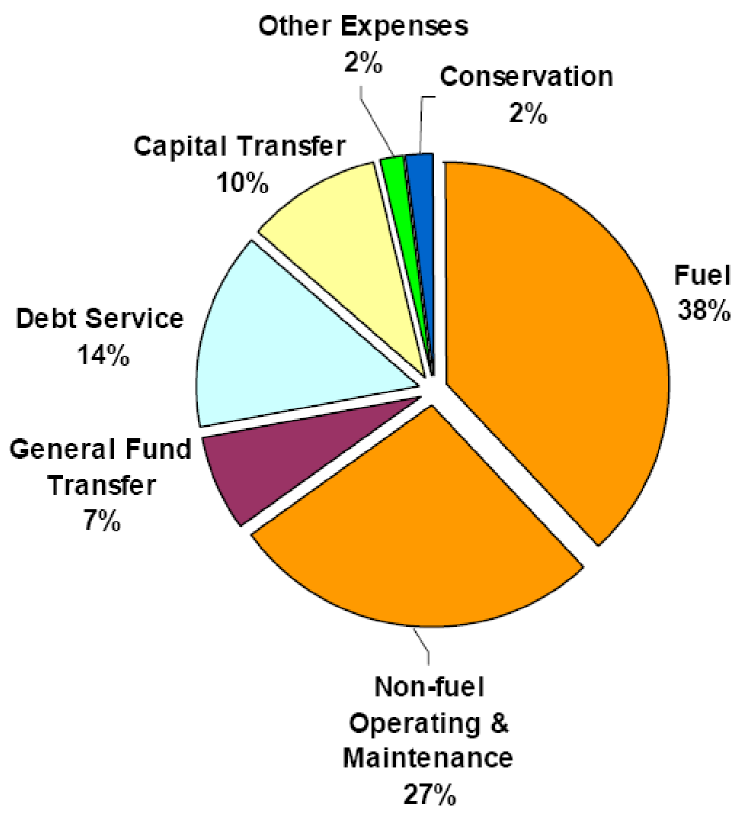
Unit	Nameplate Capacity (MW)	Fuel	Year Installed
Fayette Power Project			
Unit No. 1 (50%)	305	Coal	1979
Unit No. 2 (50%)	302	Coal	1980
Decker Creek Power Station			
Unit No. 1	327	Gas/ No. 2 oil backup	1970
Unit No. 2	414	Gas /No. 1 through 5 oil	1977
Gas Turbines (Units 1 - 4)	193	Gas/No. 1 oil backup	1980
Sand Hill Energy Center			
Gas Turbines (Units 1 - 4)	189	Gas	2001
Combined Cycle	312	Gas	2004
Combined Heat & Power (CHP)			
Domain CHP	4.5	Gas	2004
RMEC CHP (Dell Children's Hospital)	4.5	Gas	2006
South Texas Project Electric Generating Station			
Unit No. 1 (16%)	211	Nuclear	1988
Unit No. 2 (16%)	211	Nuclear	1989
Total Capacity owned by Austin Energy	2473		
Purchased Power			
LCRA Texas Wind Contract	10.0	Wind	1995
FPL Energy Upton Wind I, LP.	76.7	Wind	1999-2001
RES North America Sweetwater Wind	128.0	Wind	2005
Whirlwind Energy LLC	60.0	Wind	2007
Gas Recovery System, Inc	4.0	Landfill Methane	1994-2003
Ecogas Inc. and Energy Developments, Inc	7.8	Landfill Methane	2002-2003
Solar (City, schools and Rebates)	2.9	Wind	Thru 8/2008
Summer Peak Purchases 2008-2010	300	Grid	2008–2010

Source: Austin Energy, *Austin Energy Resource Guide* (October 2008), p. 1. Online. Available: http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf. Accessed: December 19, 2008.

Figure 1.3 details AE's proposed budget for fiscal year (FY) 2009, with approximately $1.27 billion revenues.[18] AE's projected expenditures for FY 2009 are based on all operating requirements, including plant operations and maintenance, conservation initiatives, labor benefits, and administrative support, totaling approximately $943 million.[19] AE manages approximately 392,000 customer accounts classified as residential (89 percent), commercial (11 percent), residential, commercial, and the remainder are classified as industrial, governmental, or street and highway lighting.[20] The 200 largest AE commercial and industrial customers account for about 34 percent of all revenues generated by AE.[21] The approximately 345,000 residential customers provide about the same amount of revenue as the 41,000 business customers of AE.[22] Figure 1.4 provides information on the number of customers for each customer class as well as their respective consumption of energy and revenue generated.

Figure 1.3
Austin Energy's Proposed Budget, FY 2009

Total Budget Requirements: $1,379.7 million



Source: Austin Energy, *Fiscal Year 2008-2009 Proposed Budget.* Online. Available: http://www.ci.austin.tx.us/budget/08-09/downloads/August21BriefingsFINALAE_PW.pdf. Accessed: January 15, 2009.

Figure 1.4
Austin Energy Customer Class Statistics, FY 2007

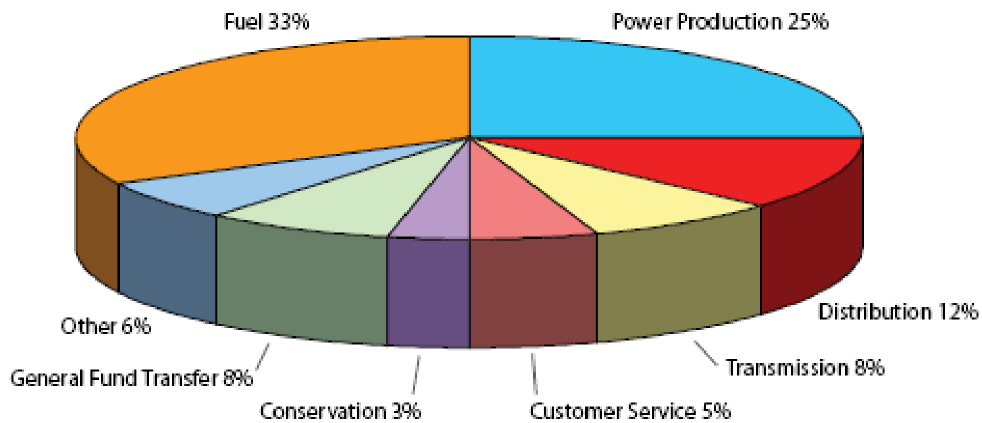
Austin Energy Customer Class Statistics Fiscal Year 2007 (October 2006 - September 2007)			
Customer Class	**Number of Customers**	**Revenue**	**Consumption (kWh)**
Residential	345,197	$ 356,143,000	3,908,318,000
Commercial	41,825	$ 365,991,000	4,350,912,000
Industrial	75	$ 113,248,000	1,930,289,000
Street/Highway	4	$ 8,106,000	47,230,000
Other Government	1,519	$ 73,358,000	1,088,320,000
Total	**388,620**	**$918,846,000**	**11,325,069,000**

Source: AE, *Austin Energy Resource Guide* (October 2008), p. 7. Online. Available: http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf. Accessed: December 19, 2008.

The Austin City Council sets retail service rates through a cost of service study that analyzes the total cost to serve customers, dividing those costs into customer classes. AE's base electric rates (called the Energy Charge on customer electric bills) have been unchanged since 1994.[23] AE revises its Fuel Adjustment Clauses (called the Fuel Charge on customer electric bills) annually as a mechanism to recover the costs of fuel used to generate power as well as fees paid by AE to support the operation of the state's electric grid and power purchases from the Texas wholesale market. No profit is generated from the fuel charge. The Fuel Charge represents about a third of a customer's electric bill and the remainder comes from the Energy Charge.[24] Figure 1.5 details AE operating costs as a percentage of the customer bill.

AE offers an alternative rate program to its residential customers called GreenChoice®. Introduced in 2001, this program replaces the fuel adjustment with a fixed renewable energy rate reflecting AE's long-term contract rate for renewable energy sources.[25] GreenChoice® has been recognized by the National Renewable Energy Laboratory as the leading utility-sponsored renewable energy sales program in the U.S.[26] In contrast to conventional customers, for whom the fuel adjustment clause is readjusted annually to pass on the cost of fuel, customers who opt into GreenChoice® pay a kilo Watt hour (kWh) fee designed to reimburse AE's cost of a power purchase agreement (PPA) for renewable energy.[27]

Figure 1.5
Austin Energy Operating Costs as a Percentage of the Customer Bill



Source: Austin Energy, *Austin Energy Resource Guide* (October 2008), p. 10. Online. Available: http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf. Accessed: December 19, 2008.

AE currently owns outright or has a controlling interest in six power generation facilities with a total of eleven conventional power generating units.[28] AE owns and operates 17,000 miles of lines and 67 transmission and distribution substations.[29] AE has entered into 10 separate PPAs with outside providers, six of which have come into complete commercial operation.[30] A PPA allows AE to hedge risk on capital outlay compared to constructing a plant within the utility, so as to provide predictable energy costs over the contract life. The utility may structure an option to buy the power generation facility into the contract after a set period of time. Given that virtually the entirety of AE's current and projected renewable power generation portfolio is represented by PPAs, it appears that this financing and development strategy may continue to play a significant role as the utility works to achieve its ambitious 2020 goal of achieving 30 percent renewable power generation.

AE finances its operations and capital outlay in part by selling a combination of tax-exempt commercial paper and issuing bonds classified as prior lien obligations and prior subordinate lien obligations on revenue.[31] To service its debts, AE is obligated by contract to maintain rates at a level sufficient to completely cover operations and maintenance requirements. AE is expected to fund reserves for lien obligations at a prescribed level and provide for net revenue which, after meeting the previous two requirements, must exceed the annual debt service obligations for prior first lien obligations by a factor of 1.25 and prior subordinate lien obligations by a factor of 1.1.[32] If these requirements are not met, the City of Austin must take immediate action to alter rates or obtain a statement from a utility system consultant to verify adequacy of the rate structure or suggest restructuring.[33] The City of Austin has authorized AE to trade in futures contracts and swaps of up to $800 million in order to hedge against fluctuations in fuel prices on a five-year horizon.[34] Trading activity is governed by a Risk Oversight Committee. While obligations may be met with commodities or securities, cash payment is standard.[35]

In addition to contractual requirements, the City of Austin maintains a policy for AE to retain a strategic reserve fund. The reserve fund contains an emergency cash reserve equivalent to 60 days of operating revenue, contingency cash reserve equivalent to up to 60 days of operating revenue, and a competitive reserve.[36] AE's books contain separate funds for repair and replacement, conservation rebates and incentives, and performance contracting.[37] Draw-downs from reserves for lien obligations must be immediately replenished with equivalent cash or securities in order to maintain the prescribed level.[38]

In its most recent issuance on July 24, 2008, the City of Austin offered $175 million of revenue bonds, revenue from which was to be immediately applied to $174.6 million of commercial paper debt.[39] The combined utility system currently holds $1.052 billion in parity electric utility obligations, $529.9 million of which is in the form of bonds.[40] In accordance with a master ordinance defining such bond obligations, AE may not at this time assume any debt equivalent to prior first liens or prior subordinate liens. However, AE may obligate itself to other forms of parity electric utility obligations, such as commercial paper, special facilities debt, and credit agreements.[41]

The City of Austin is committed to achieving a Standard and Poor's AA rating on combined utility securities by 2010, improving from its AA- on prior lien obligations and A+ on subordinate lien obligations for combined utility securities and separate lien obligations for the electric utility. Since establishing this goal in 2003 the utility's securities have been upgraded twice.[42] Some of the most important factors which influence an electric utility's bond rating are the consistency of cash flow and the size of the sales margin, the size and population of the service area, the ratio of earnings before interest and taxes to interest expenses, the log of working capital, and the ratio of retained earnings to assets.[43] The current AA- rating indicates that AE's ability to service its debts is largely shielded from being "susceptible to the adverse effects of changes in circumstances and economic conditions."[44] In the matters of these securities AE retains the services of the PFM Group, a national public finance consulting firm.[45, 46]

AE is currently in the midst of a five-year, $1 billion capital improvement plan, of which $347.5 million will be spent in the 2008-2009 FY.[47] This includes $270 million to support peaking capacity at the Sand Hill facility and other electricity delivery initiatives, as well as $55 million to update the Customer Information System and system-wide distribution of automated metering technology.[48]

AE's current business model appears to be sufficient to accommodate the goals outlined by the ACPP. The utility maintains a constant revenue stream well in excess of its operating costs. Capital flows may be managed with the issuance of short-term debt equity, for which AE enjoys a high rating.[49,50,51] The current structure for meeting the requirements of operations and management are sufficient to adjust to a larger share of renewable power sources in AE's energy source portfolio. From the perspective of capital management the optional GreenChoice® rider serves the same function as the fuel adjustment that it replaces by providing revenues directly sufficient to the obligations of the renewable energy PPA.

Planning for the Future

As one of the largest public utilities in the nation, AE seeks to provide continuous reliable and affordable energy to a large customer base. AE continues to plan for the foreseeable future through its strategic planning process. AE released its most recent strategic planning update in 2007, which followed an update in 2006 to the Strategic Plan of 2003.[52] AE's strategic plan identifies the utility's vision, mission, and values and assesses how the changes in the utility environment may affect these goals. AE's vision is for "Austin to be the most livable community in the country."[53] AE's mission is "to deliver clean, affordable, reliable energy and excellent customer service."[54]

An electric utility plans its power generation mix by looking into the future and assessing trends within the sector that can affect the utility's security. Decisions on using a particular generation mix in the future must be made well in advance in order to construct new power generation facilities, plan for decommissioning old facilities, and ensure that supply meets future load forecasts. The decisions AE makes now for its future generation mix will affect the local community, economy, and environment, as well as ensure the future viability of the utility itself. When making decisions on investing in new power generation facilities a utility must consider cost, reliability of service, environmental compliance, and economic development concerns. Meeting future demand involves evaluating new power generation technologies as well as demand-side management (DSM) and conservation programs, and determining how each influences the volume of peak behavior of demand and the scale of power generation capacity.

While AE is primarily accountable to both its customers and the city council, it also must meet energy standards set by state and federal legislation. One electric industry trend appears to be the move towards climate change and carbon legislation. Some analysts expect the federal government to pass some form of climate change legislation within the next few years that would effectively set a "price" on carbon. Several bills related to curbing GHG emissions have been proposed on the federal level, predominately taking the form of a cap-and-trade system to regulate the total quantity of GHG emissions measured by their CO_2 equivalent global warming potential. Within such a system, the United States Congress or a regulating agency would set an upper limit on the total quantity of GHG emissions. Certain sectors and companies would be issued permits to emit up to a particular level of emissions. Permits could then be bought and sold, establishing a market price for CO_2 and other GHGs.

Another potential form of legislation would come in the form of a tax on carbon. Carbon regulation creates an economic incentive to limit $CO_{2,}$ either to avoid or offset fees or taxes or to benefit from the sale of unneeded allowance or offset sales. No matter the form of legislation, AE and many electric utilities have begun to prepare for the impacts of a carbon-constrained market by setting internal goals to reduce GHG emissions. This also creates the need to identify the impacts that such legislation will have on the cost comparisons of various power generation technologies and how these economic expectations could influence AE's future investments. A paradox occurs as utilities anticipate carbon legislation because emission allowan ces will most likely be based on some baseline emissions level. Therefore, there is some incentive for a utility to defer carbon management until a baseline emission level is determined under some future federal legislation.

AE's 2007 Strategic Planning Update identifies an array of regulatory and market trends that it currently faces.[55] While Texas deregulated the electric industry in 1999, reforms of the system continue as new challenges arise. All electric utilities in Texas are regulated by the Public Utility Commission of Texas (PUC) while the state's electric grid is operated by the Electric Reliability Council of Texas (ERCOT). ERCOT is currently designing a new nodal market and is expected to implement this approach at some point in the near future.[56] The nodal market will change the processes and systems of electric transmission and AE must plan and adapt to these changes. AE must further adapt to statewide renewable resource goals and determine how to make use of Texas' electric grid to handle increases in wind and solar development. In July 2008, the PUC approved an agreement to construct transmission lines that could transmit 18,456 MW of energy to metropolitan regions within Texas at an estimated construction cost of $4.93 billion.[57] By addressing transmission barriers the PUC has reduced the barriers to wind or solar resources from West Texas as a future energy generation source for Central Texas.

AE's 2007 Strategic Planning Update identifies several other electric utility trends, including the effect of emerging economies (such as China) on the price of raw materials and fuels used for energy, the expected loss to retirement of many experienced employees in the electric industry, and the increasing trend towards DSM, which looks to promote energy efficiency, reduce and control power usage, and develop technologies for distributed power generation and energy storage.[58] Economic challenges currently facing the U.S. and energy resource pressures caused by fluctuating prices and dependence on foreign oil sources could complicate energy sector investment choices. All of the regulating changes are complicated by technological improvements brought about through research and development. For example, renewable resource technologies and transmission and distribution systems continue to improve at a rapid pace and relative costs of some renewable energy sources may continue to fall compared to traditional fuel sources.

Austin Energy's Proposed Energy Resource Plan

On July 24, 2008, Roger Duncan, AE's Acting General Manager, presented to the city council the utility's preliminary recommendations for meeting energy demand through 2020 while remaining under its proposed CO_2 cap and reduction plan.[59] AE proposed adding 1,375 MW of power generating capacity by 2020, with only 300 MW coming from fossil-fueled resources.[60]

The Austin City Council approved 100 MW of new power generation requests from the addition of a gas combustion turbine at Sand Hill. AE has proposed 200 MW of additional capacity at Sand Hill for 2013 to assist in meeting increasing energy demand. This combined cycle expansion project would provide reliable energy with lower MW-hour carbon emissions than coal. AE is hoping to avoid the prospect of high natural gas prices by locking into pre-paid fuel contracts. AE is expecting this project to cost $160 million and take three years to complete. AE claims that $278 million in projected fuel savings can occur through a pre-pay contract. It has been projected that if this expansion project is completed, CO_2 emissions will be reduced by 1.6 million metric tons through 2020.[61]

On August 28, 2008, the city council approved a biomass project[62] that is expected to be available by 2012 to provide 100 MW of power generating capacity by burning wood waste.[63] Biomass is intended as a baseload source of power generating capacity (similar to that of coal and nuclear) and can provide reliable power during peak demand.[64] This plant has been contracted through a PPA to provide 100 MW of power generating capacity per year over a 20 year time period at a total cost of $2.3 billion. This option will increase AE's renewable resource portfolio to 18 percent by 2012, while locking in fuel costs to provide a reliable energy source. Biomass can hedge against future natural gas price volatility and potential future costs of carbon. AE has recommended an additional 100 MW of purchased biomass power generating capacity for 2016.[65]

AE's primary investment in new power generation capacity is an addition of 1,049 MW of power generating capacity from wind facilities. AE proposed a gradual investment in solar energy to meet the ACPP goal of providing 100 MW of solar energy by 2020. AE's purchase plans to obtain 30 MW of power from a solar facility construction project in Webberville was approved in early 2009. This facility will also dedicate 5 MW of capacity to test emerging solar technologies. AE is planning to invest in covering rooftop space in Austin with photovoltaic systems through public and private partnerships. AE may also consider an investment in a large-scale West Texas solar plant.[66]

Structure of the Report

This report analyzes various future power generation mix scenarios with the goal of designing a sustainable utility that would be carbon-neutral by 2020. The report will consider AE's options for reducing energy usage through DSM and conservation, revising its power generation mix, and reducing CO_2 emissions through new power generation technologies as well as offsetting CO_2 emissions. This report will provide a diverse set of options that AE can use to reduce its carbon footprint. These alternatives could stimulate public involvement from Austin citizens and other AE customers to decide the most desirable, feasible, beneficial, and cost-effective steps for the community as a whole.

One goal of this report is to contribute to a public dialogue that will help AE choose future energy resource investments to meet the goals of the ACPP. On December 13, 2007, the city council passed Resolution Number 20071213-057 directing the City

Manager to "conduct an open, extended Energy Resource Planning Public Participation Process to assist AE with the development of its future resource management plans, including generation planning in line with the Austin Climate Protection Plan."[67] Goals of the public participation process include educating customers on facts, issues, and trends regarding the electric utility industry; informing customers in depth about AE's operations, particularly those involving power production; and obtaining suggestions from its customers and other outside sources for business approaches and proposed solutions designed to meet the future needs of the utility.[68] AE began its public participation process in Fall 2008 through a series of town hall meetings and the release of its resource guide, and resumed these meetings in the first months of 2009.[69] This project included a series of panels of local energy and environmental stakeholders open to the public in conjunction with presenting the final development of this report.

This report describes the potential viability and costs associated with AE reaching the status of carbon-neutrality by 2020. This task begins with a detailed explanation of how AE currently meets demand and calculates the weight of CO_2 equivalent emissions it produces. Scenarios on the "future price of carbon" are included in the evaluation of potential future power generation mixes.

Power generation technologies to be discussed in this report include the following fossil-fueled and renewable resources and their associated technologies:

- coal [pulverized coal power generation, fluidized bed combustion, and integrated gasification combined cycle (IGCC)];
- natural gas (combined-cycle and combustion turbines);
- nuclear;
- hydropower and pumped storage;
- wind;
- solar (photovoltaic power and concentrated solar power);
- biomass;
- geothermal;
- ocean power; and
- hydrogen and fuel cells.

This list reflects a reasonable set of future power generation opportunities as of 2009. Further advances in clean coal and other technologies related to increasing efficiency and reducing emissions of fossil-fueled power generation sources will be discussed as potential investments as well as the capabilities of various energy storage technologies that might increase the appeal of wind and solar power generation technologies.

Advancements in new technologies continue to occur as concerns for energy security and the environment rises. As new technologies develop, consideration of the costs and benefits of such technologies should be included in discussion of the utility's future power generation mix. By comparing these technologies, citizens can make an informed decision as to which technologies keep costs low, electric reliability high, and reduce AE's carbon footprint. Some of the factors that can be considered include the ability for the technology to meet future load; the cost and time of construction; fuel and marginal operating costs; projected operational life; fuel and plant dependability; maturity of the technology; emissions and other environmental concerns; and security or other potential concerns related to the technology.

This report provides a neutral and comprehensive evaluation of many available options that AE could take to meet future energy demands while satisfying the city's goal of designing a public utility plan that could serve as an example for other utilities to develop a sustainable energy future. This report evaluates impediments towards the usage of alternative electric generation technologies, such as the variable nature of renewable energy (meaning these sources generate electricity variably rather than on demand); various grid issues related to the distribution of renewable energy; the feasibility and risks associated with carbon storage methods; the validity and costs of investments to offset carbon releases; risks associated with adding new nuclear capacity; and challenges for maintaining a financially sound utility. This report considers sustainability as it applies to the energy sector from both economic and environmental perspectives. Options will be analyzed based upon how they affect the financial operation of AE as well as the environment. AE customers will be able to evaluate such options with respect to their personal preferences in working towards a sustainable energy future.

Notes

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[12] Ibid.

[13] AE, *Austin Energy Budget*. Online. Available: http://www.austinenergy.com/About%20Us/ Company %20Profile/Budget/Index.htm. Accessed: June 30, 2008.

[14] AE, *Resource Guide* (online), p. 17.

[15] AE, *Resource Guide,* p. 1.

[16] AE, *Future Energy Resources and CO_2 Cap and Reduction Planning* (July 2008). Online. Available: http://www.austinenergy.com/About%20Us/Newsroom/Reports/Future%20Energy %20Resources_%20July%2023.pdf. Accessed: July 24, 2008.

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[28] Ibid., p. 16.

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[30] Ibid., p. 24.

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[32] Ibid., p. 6.

[33] Ibid., p. 6.

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[35] Ibid., p. 24.

[36] Ibid., p. 5.

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[64] AE, *Nacogdoches Biomass Project Town Hall Meeting*, p. 7. August 13, 2008. Online. Available: http://www.austinenergy.com/biomassTownHallAugust2008.pdf. Accessed: August 17, 2008.

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Chapter 2. Austin Energy's Current Power Generation Mix

Summary

Austin Energy (AE) currently employs a diverse mix of power generation sources to meet fluctuating energy demands reliably at a low cost to customers. Austin's energy demand fluctuates over any given day, week, or year and reflects those patterns in AE's investments in particular generation facilities. Future projections of increased demand for energy in AE's service area can be evaluated to determine a range of investment choices that AE can make to ensure reliable, low-cost, and quality service in the future while meeting the goal of developing a sustainable, carbon neutral utility.

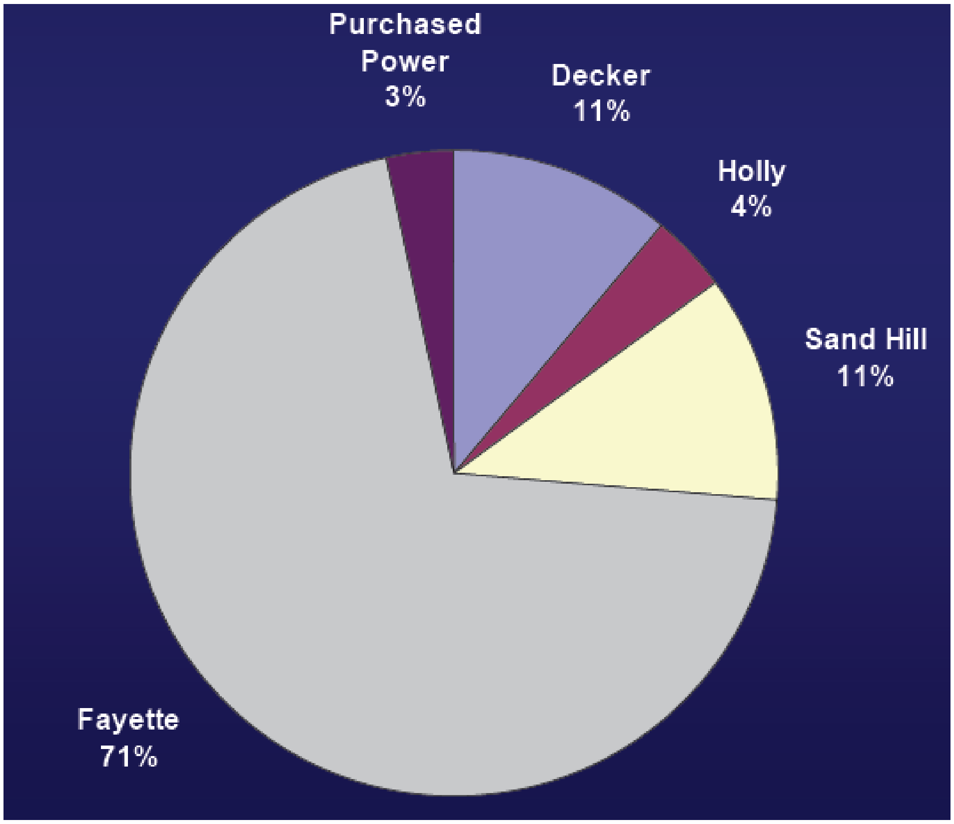
Introduction

Load growth and the age of existing power generation facilities drive the choice of future energy sources. As load, or demand, increases and old plants reach the stage of retirement, new sources of electric power generation are needed to meet future demand. Making accurate projections of future demand is central for the continued well-being of an electric utility. Load forecasting is making accurate projections becomes more difficult as they extend out into the future as future circumstances become difficult to predict. AE currently makes formal load forecasts only through 2020, a horizon of 11 years. Chapter 5 of this report discusses AE's load forecasting methodology and its uncertainties.

After conducting its load forecast AE must evaluate power generation technologies and make appropriate investments to meet future demand. As it takes several years to gain approval and construct new power generation facilities, for a utility often plans many years in advance of new power generation units coming online. Chapters 6 through 19 of this report discuss power generation technology options. Once decision-makers understand the advantages and disadvantages of each power generation technology option, they can evaluate these options under a framework of customer demands.

One interest for this report is the carbon dioxide (CO_2) emissions profile of AE's current and future power generation mix. Figure 2.1 illustrates how the Fayette Power Project, AE's lone coal burning plant, contributes 71 percent of the utility's total CO_2 emissions. This fact alone indicates a potential for significantly reducing AE's carbon footprint by capturing and sequestering this carbon or replacing the coal plant with energy sources that do not release CO_2.

Figure 2.1
Austin Energy's Carbon Dioxide Emissions Profile,
2007 Calendar Year

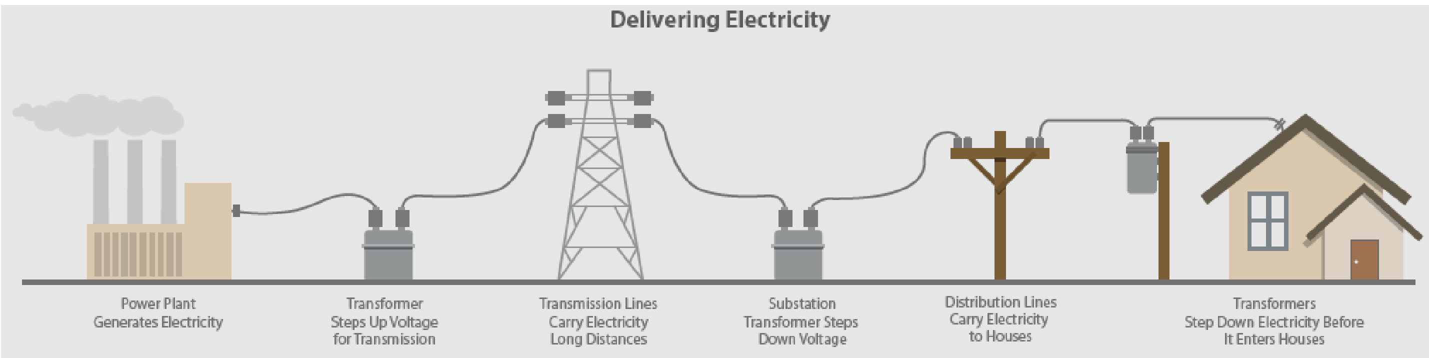


Source: Austin Energy, *Future Energy Resources and CO_2 Cap and Reduction Planning* (July 2008). Online. Available: http://www.austinenergy.com/About%20Us/ Newsroom/Reports/Future%20Energy%20Resources_%20July%2023.pdf. Accessed: July 24, 2008.

How Does a Power System Work?

Electric power systems consist of power generation, transmission, distribution, communication, and other facilities that operate together to produce and deliver electricity to consumers (see Figure 2.2).[1] Dispatch operators at AE, in coordination with the Electric Reliability Council of Texas (ERCOT), work within the electric power system to provide energy from its facilities by moving electricity through a state-regulated transmission network to distribute electricity to customers. Dispatch centers maintain and monitor the electric power system by reporting instantaneous demand and supply. Dispatch centers determine which power plants to cue (dispatch available capacity), track the buying and selling of electricity or capacity, monitor current demand (load), anticipate future demand, and maintain electricity balance demand so that electric flow does not overload the transmission system.[2] Chapter 5 includes a discussion of Texas' state-regulated electricity market.

Figure 2.2
Diagram of a Traditional Power System



Source: Austin Energy, *Austin Energy Resource Guide* (October 2008), p. 8. Online. Available: http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf. Accessed: October 1, 2008.

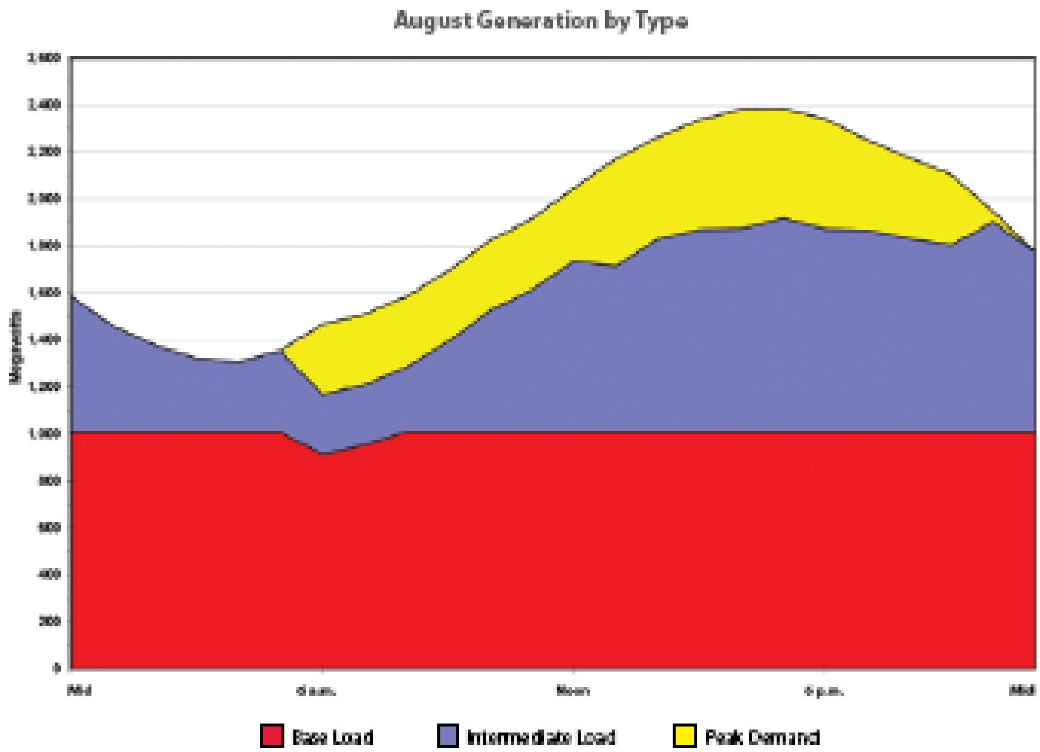
Power Generation

Due to variations in load, only some power generation units are needed at most times during any day, week, or year. Some power generation units are on standby for short notice start-up and are used to account for unexpected drops in supply or sudden rises in demand. Operators determine dispatch schedules based upon the system's lowest marginal cost, expressed as dollars or cents per kilowatt-hour of electricity ($/kWh). Power generating units tend to be designated by their intended usage as base, intermediate, or peak units. Figure 2.3 illustrates energy demand for AE during a typical day in the month of August, the month that usually experiences the heaviest demand due to air conditioning usage.

A baseload power generation plant is typically run at all times, except during repairs or scheduled maintenance. Characteristics of baseload plants are low variable operating costs relative to intermediate and peak plants due to relatively low fuel costs, long ramp-up times (amount of time it takes to bring the unit to full operation for the delivery of power), larger and newer facilities, and greater efficiency. AE's baseload plants are coal-fired and nuclear.[3]

A peakload power generation unit tends to be dispatched only to meet high demands and prevent loss of customer service or system-wide blackout, for example during the middle of a summer weekday afternoon. Peakload plants can range from operating a few hours a day to only a few hours a year. Characteristics of peakload plants are short ramp-up times and higher marginal costs relative to baseload and intermediate plants.

Figure 2.3
Austin Energy Hourly Load Profile, Typical August Day



Source: Austin Energy, *Austin Energy Resource Guide* (October 2008), p. 12. Online. Available: http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf. Accessed: October 1, 2008.

Intermediate or "shoulder" plants fall between baseload and peakload plants in terms of hours of usage, efficiency, and marginal cost per kWh. These plants tend to come online as load grows. Most new intermediate plants use high-efficiency gas turbines. Older plants that are no longer cost-effective may transition to peakload units.[4] AE's peakload units are combustion turbines burning natural gas with diesel oil used as a backup fuel.[5] Reserve or standby power generating units are often available to utilities in the event of an unexpected increase in load or an outage in the system. AE's intermediate plants tend to burn natural gas. Renewable energy assets' transmission congestion costs are negligible and are also used when available, provided that the marginal costs to operate them favor their use.

Transmission and Distribution

The AE transmission and distribution network is a system of conductors, relays, switches, monitoring devices, substations, and easements that deliver electricity from the central station power plants to end-use electricity consumers. The system delivers electricity one-way with a focus on reliability and capacity to transmit power at the time of maximum demand. Table 2.1 lists AE's transmission and distribution assets. Transmission lines are regulated by the Public Utility Commission of Texas (PUC) and are technically owned by the State of Texas. Transmission lines move large amounts of energy at high voltages (96,000 volts or more) so that less power is lost as heat. Transmission lines terminate at substations where the energy is transformed to lower voltages for distribution. Most of AE's distribution system operate at 12,500 volts.[6] Distribution lines are not regulated by the PUC, so AE has full discretion over the installation of distribution lines.

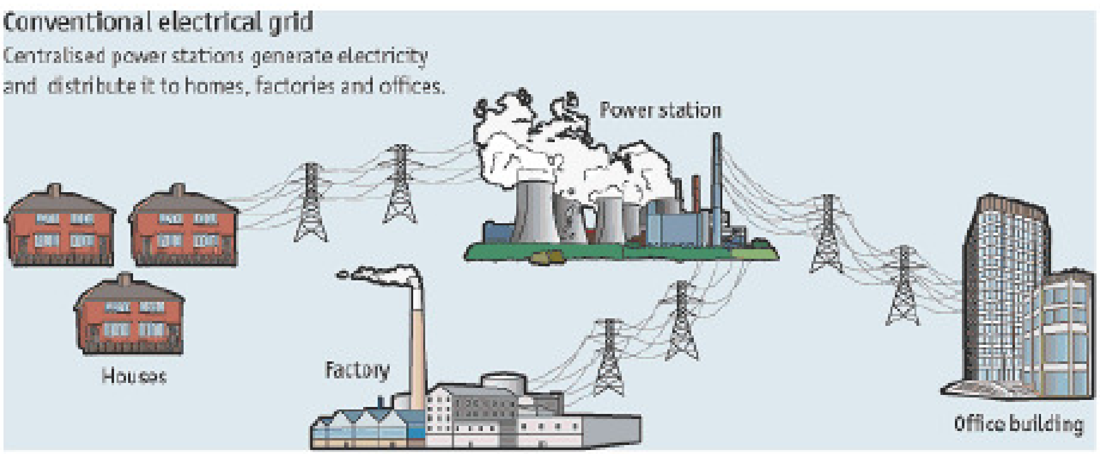
Table 2.1
Austin Energy Electric Delivery Statistics, 2006

Distribution Line Mileage	
Overhead Primary	2,368 miles
Overhead Secondary	3,172 miles
Underground Primary	2,534 miles
Underground Secondary	2,702 miles
Total	10,776 miles
Transmission Line Mileage	
345 kV	269 miles
138 kV	329 miles
69 kV	35 miles
Total	633 miles
Substations	
Distribution	54
Transmission	9
Total	63
Transformers	
Overhead transformers	42,117
Pad-mount transformers	31,120
Submersible transformers	703
Total	73,940
Poles	
Austin Energy poles	141,466
AT&T poles	13,944
Total	155,410

Source: Austin Energy, *Annual Report: 2006*. Online. Available: http://www.austinenergy.com /About%20Us/Newsroom/Reports/annualReport.pdf. Accessed: June 30, 2008.

The Texas transmission grid is unique in the nation because the ERCOT control area is located wholly within the state, so it does not fall under Federal Electric Regulatory Commission (FERC) jurisdiction. As a result, the PUC has the final say on transmission siting decisions and policy. To date, the PUC has chosen to maintain a regulated, open-access grid for the high-voltage transmission network in ERCOT. This network consists of wires, switches, relays, and transformers that passively deliver energy from central power stations to consumers, relying on mechanical switching and central control. The grid is sized to accommodate peak demand, and thus offers excess capacity for most of the year (see Figure 2.4 for a diagram of the conventional electric grid). This means that for 95 percent of the time the system is oversized. Although the location and structure of central station power generation facilities are changing, the transmission system takes time to react because the process of design, approval, and construction of transmission is lengthy. Large pockets of renewable wind power generation in West Texas have tested the reliability of the system.[7] Even with an increase in transmission investment in recent years, the slow pace of transmission line development and aging existing infrastructure means that the network for power delivery in Texas is constantly evolving and at risk.

Figure 2.4
Conventional Electrical Grid



Source: Andres Carvallo, *Austin Energy Smart Grid Program*, p. 6. Austin, Tex. October 1, 2008.

Meeting Current Supply and Demand

The primary responsibility of an electric utility is to balance electricity supply with demand while maintaining a reserve margin of power generation capacity in the case of planned or unplanned fluctuations in both power generation and demand. As a public utility, AE has an important duty to the community to provide reliable energy. This duty means that when a customer decides to turn on a light, she or he can do so at any time and with confidence that the light will turn on. Reliability is important to the daily functioning of Austin and its citizens. Therefore, AE has a vested interest in tracking, responding to, and even influencing the electricity demand of its customers.

Electricity cannot currently be stored easily on a large scale (see Chapter 17 of this report for a discussion of energy storage technologies). As a result, system supply is designed to satisfy demand at any given point in real time. In order to keep power generation costs low, dispatch planners use current information on power generation unit availabilities, outages, operating information, inter-utility contract costs, and fuel costs to determine which power generation units are in operation at a given time. Factors that influence supply at any given time include: unit forced outages; scheduled maintenance of a unit; transmission outages and overloads; changes in inter-utility contract terms; fuel cost updates; and weather impacts on power generation unit and transmission performance.[8]

Other factors can influence available supply at any time, such as when a power generation resource is unexpectedly unavailable at the time of peak demand (which particularly affects wind and solar resources due to the variable nature of these power generation sources) or when demand exceeds forecasts. An adequate reserve margin is needed to ensure service reliability for utility customers during peak demand, the period of highest energy demand. A reserve margin is simply an additional available supply, often measured as a percentage of total power generation capacity that exceeds peak demand.

In 2006 and 2007 AE was able to meet its peak demand through its owned, co-owned, or contracted power generation facilities while ensuring a 20 percent reserve margin. During this time period, AE owned and operated seven power generation facilities, with additional energy provided by wind, solar, landfill gas, and distributed power generation. Figure 2.5 details AE's power generation mix as of July 2008. Total rated power generation capacity from facilities owned or co-owned by AE and power purchased through contractual agreements was 2762.4 MW as of September 2008.[9]

The Holly gas turbine plant was decommissioned in 2007 and AE has since replaced its lost capacity with 300 MW of purchased power through the ERCOT wholesale market. As a result, AE was able to provide a 14 percent reserve margin in 2008. In 2009 a new gas turbine at Sand Hill will provide 100 additional MW of energy for AE, increasing AE's reserve margin to 16 percent. AE currently purchases power from a third-party source to assure an adequate reserve margin. The resulting deficit its power generation facilities face for meeting supply requirements indicates that AE needs to invest in new power generation facilities if it wishes to balance demand with internal supplies.

Figure 2.5
Austin Energy Power Generation Portfolio, July 2008

Unit	Nameplate Capacity (MW)	Fuel	Year Installed
Fayette Power Project			
Unit No. 1 (50%)	305	Coal	1979
Unit No. 2 (50%)	302	Coal	1980
Decker Creek Power Station			
Unit No. 1	327	Gas/ No. 2 oil backup	1970
Unit No. 2	414	Gas /No. 1 through 5 oil	1977
Gas Turbines (Units 1 - 4)	193	Gas/No. 1 oil backup	1980
Sand Hill Energy Center			
Gas Turbines (Units 1 - 4)	189	Gas	2001
Combined Cycle	312	Gas	2004
Combined Heat & Power (CHP)			
Domain CHP	4.5	Gas	2004
RMEC CHP (Dell Children's Hospital)	4.5	Gas	2006
South Texas Project Electric Generating Station			
Unit No. 1 (16%)	211	Nuclear	1988
Unit No. 2 (16%)	211	Nuclear	1989
Total Capacity owned by Austin Energy	2473		
Purchased Power			
LCRA Texas Wind Contract	10.0	Wind	1995
FPL Energy Upton Wind I, LP.	76.7	Wind	1999-2001
RES North America Sweetwater Wind	128.0	Wind	2005
Whirlwind Energy LLC	60.0	Wind	2007
Gas Recovery System, Inc	4.0	Landfill Methane	1994-2003
Ecogas Inc. and Energy Developments, Inc	7.8	Landfill Methane	2002-2003
Solar (City, schools and Rebates)	2.9	Wind	Thru 8/2008
Summer Peak Purchases 2008-2010	300	Grid	2008–2010

Source: Austin Energy, *Austin Energy Resource Guide* (October 2008) p. 18. Online. Available: http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf. Accessed: October 1, 2008.

Current Power Generation Facilities

AE determines in advance of construction whether a plant will serve as a baseload, peakload, or intermediate facility. The economics of such decisions tend to be based on the relative cost of its fuel (along with operations and maintenance costs) as well as the relative efficiency of a plant. The relative efficiency of operating plants is measured by calculating thermal efficiency, or the ability to convert the energy content of fuel into electricity. Heat rate is expressed in British thermal units (Btu) per net kilowatt hour (kWh) of electricity and is used to measure thermal efficiency of a power plant. The lower the plant's heat rate the higher its efficiency, because the plant requires fewer units of fuel input to produce a kWh of electricity.[10]

Three measurements aid in AE's decision as to the frequency to dispatch a particular power plant: its capacity factor, availability factor, and load factor. Capacity factor is the kWh of energy a facility generates in a year divided by the total amount it could generate if it ran at maximum output.[11] Availability factor is the ratio of the number of hours a power generating unit is mechanically able to produce power versus the number of hours in the period.[12]

Dispatchers determine which unit to bring online as loads increase or which unit to take offline as load falls by taking into account the marginal cost of available power generation units. Figure 2.6 includes information on the power generation units currently owned by AE as well as the power generation facilities from which AE receives power through contractual agreements, by fuel types. Each facility is described below.

Figure 2.6
Austin Energy's Power Generation Mix

Austin Energy Generation Mix by Fuel Type
Fiscal Year (October - September)

Fuel Type	FY 2003	FY 2004	FY2005	FY2006	FY2007
Coal	40.5%	37.8%	34.6%	29.7%	32.2%
Natural Gas & Oil	21.4%	20.2%	25.2%	27.9%	27.3%
Nuclear	19.4%	31.2%	27.9%	27.3%	25.8%
Renewable Energy	2.6%	2.6%	4.3%	5.7%	5.1%
Purchased Power	16.1%	8.2%	8.0%	9.4%	9.6%

Source: Austin Energy, *Austin Energy Resource Guide* (Oct. 2008), p. 17. Online. Available: http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf. Accessed: October 1, 2008.

Decker Creek Power Station (natural gas, fuel oil as alternative)

The Decker Creek Power Station, located in Northeast Austin, uses natural gas as its primary fuel source with oil as an alternative. Total power generating capacity at Decker Creek Power Station is 926 MW.[13] Unit 1 was constructed in 1971 with a generating capacity of 321 MW (summertime capacity of 320 MW). Unit 2 was constructed in 1977 with a power generating capacity of 405 MW (summertime capacity of 404 MW). Units 1 and 2 both burn natural gas to drive steam turbines, with fuel oil supplies available as an alternative fuel source.[14] These units are used as intermediate power sources. Decker Creek Power Station also operates four combustion gas-fired turbines (with jet fuel as an alternative fuel source) that each has a power generating capacity of 51.5 MW (summertime capacity of 52 MW). These four combustion gas-fired turbine units, constructed in 1988, are primarily used to meet peak demand.[15]

Fayette Power Project (coal-fired)

The Fayette Power Project (FPP), also known as the Sam K. Seymour Generating Station, is a coal-fired power plant located on a 10 square mile site near La Grange, Texas, in Fayette County, about 60 miles southeast of Austin.[16] AE owns 50 percent of Units 1 and 2 of this plant, which is operated and co-owned by the Lower Colorado River Authority (LCRA). The Fayette units are used by AE as baseload units. FPP is comprised of three power generation units. Unit 1 was completed in 1979 with a power generating capacity of 615 MW (summertime capacity of 598 MW), Unit 2 was completed in 1980 with a power generating capacity of 615 MW (summertime capacity of 598 MW), and Unit 3 was completed in 1988 with a power generating capacity of 460 MW (summertime capacity of 445 MW).[17] Units 1 and 2 are both sub-supercritical designs with a Combustion Engineering boiler and General Electric 4-flow steam turbine. These units burn low sulfur coal shipped from the Powder River Basin in Wyoming with a heating value of 8,000-9,000 Btus per pound and a sulfur content of up to 1 percent.[18]

The two units at FPP have an average capacity factor of 93 percent with a 35 percent efficiency level (the amount of electricity generated from a unit of fuel).[19] The primary form of coal used is sub-bituminous coal, with lignite used as a back-up fuel source. Cooling water is supplied from a freshwater reservoir in Fayette County. LCRA has taken many steps to reduce emissions, primarily focusing on reducing nitrous oxide (NO_x) and sulfur dioxide emissions.[20] AE will pay $225 million by 2010 to install scrubbers to reduce sulfur oxide emissions from FPP.[21] AE maintains the non-nuclear Plant Decommissioning Fund to provide for the retirement of non-nuclear power plants.[22] The cost of retirement is determined by a special study, and revenues are dedicated to the fund at least four years in advance of the retirement.[23]

Sand Hill Energy Center (natural gas, combined cycle)

The Sand Hill Energy Center is a relatively new power generation facility built and operated by AE in part to replace the decommissioned Holly plant. Located in Del Valle, Texas, Sand Hill has a total power generating capacity of 480 MW.[24] Sand Hill is located in a remote area next to the South Austin Regional Wastewater Treatment Plant off State

Highway 71.[25] Four natural gas-fired combustion turbines were constructed in 2001, each with a power generating capacity of 51.4 MW (summertime capacity of 47.3 MW). In 2004 two additional units were constructed at Sand Hill. A combined cycle combustion turbine was installed with a power generating capacity of 198 MW (summertime capacity of 161 MW) and a combined cycle steam turbine was installed with a generating capacity of 190 MW (summertime capacity of 151 MW).[26] The combined cycle units are primarily used for intermediate energy needs while the combustion turbines are used as peaking units. The peaking units comprised the first peaking facility of its kind in Texas to be constructed with selective catalytic reduction pollution control equipment to reduce NO_x emissions by 80 percent.[27] Sand Hill reuses wastewater at its facilities and uses solar panels and solar thermal collectors to operate its facilities. Additional gasification turbines to be installed by 2009 will add 100 MW of power generation capacity to the Sand Hill facility.

South Texas Project (nuclear)

AE owns 16 percent of the South Texas Nuclear Project (STP), located on a 12,200 acre (49 square kilometer) site on the Colorado River in Matagorda County, southwest of Bay City, Texas. STP, the first nuclear power plant built in Texas, provides a power source of about 400 MW of energy output for AE. The two pressurized light water reactors at STP are operated by the STP Operating Company and have provided power continuously for almost four years, except for brief refueling periods. STP is the most productive nuclear power plant in the world with a capacity factor of more than 90 percent in years in which refueling occurs and 100 percent otherwise. This facility also has one of the lowest unsubsidized production costs for a nuclear power plant in the United States.[28] Ownership is divided among Reliant Energy HL&P (30.8 percent), San Antonio Public Service Board (28 percent), Central Power & Light (25.2 percent), and AE (16 percent or 400 MW of energy output).[29] Constructed in 1988, Unit 1 has a power generating capacity of 1,264 MW with a capacity factor of 61.2 percent. Constructed in 1989, Unit 2 has a generating output of 1,265 MW with a capacity factor of 80 percent. STP was designed with one additional emergency core cooling system, or one more than most nuclear reactors, to reduce risks posed by the nuclear plant. The operating license for both units expires in 2027.[30] The cost of decommissioning a nuclear power plant in the U.S. ranges from $300 million to $500 million,[31] and AE has established a trust to pay for its share of decommissioning STP.[32] The two reactors at STP are licensed through 2027 and 2028, after which the operators may apply for a 20-year extension; as of 2008 no decision had been made as to the future of the plant after 2027.[33]

In 2007, NRG Energy, a wholesale power generation company headquartered in Princeton, New Jersey, announced a $6 billion expansion to STP that would add 2,700 MW of generating capacity and two advanced boiler reactors to the plant. NRG Energy filed its application for a license to construct the new reactors with the Nuclear Regulatory Commission in 2007, the first such application filed in the United States since 1979.[34] As of March 2009 the City of Austin has decided not to participate in the expansion of STP based upon recommendations from AE.

Renewable Energy Assets and Other Facilities

AE currently holds assets in wind, solar, and landfill gas to meet intermediate and peak demand energy needs and provide clean, renewable energy to its customers through the GreenChoice® Program. Currently, AE receives wind energy through contractual agreements with wind farms located in McCamey and Sweetwater, Texas.[35] The McCamey turbines have been in operation since summer 2001 and the Sweetwater turbines since December 2005. In 2007, AE held assets of 214 MW of power generating capacity from wind energy. In 2008, this number increased by 60 MW and at least 126.5 MW of additional wind capacity is expected to be added in 2009. These capacity increases will come from commitments to purchase the output from two new Texas wind farms, the 60 MW Whirlwind Energy Center and the 165 MW Hackberry Wind Project.[36] AE estimates that it will receive about 8.1 percent of the power from the total energy output of its wind farm facilities during peak demand hours; some energy losses inevitably result because of transmission and distribution losses, dispatch issues, and fluctuating reliability of wind due to its variable nature.

AE currently yields 2.89 MW of installed solar capacity through the solar rebate program and solar photovoltaic cells located on city-owned facilities.[37] AE projects 20 percent operating efficiency during peak hours for these solar panels after factoring in line losses and reliability issues.

AE produces electricity from three landfill gas projects located in Austin and San Antonio, which burn methane gas produced by decaying garbage sanitary landfills.[38] The Tessman Landfill Biogas Project, east of San Antonio, was developed for the purposes of AE, while purchases are made from the other two landfill gas projects.[39] These projects supply about 12 MW of renewable energy for the utility.

AE also owns and operates two recently built combined heat and power facilities that use small-scale natural gas turbines to provide distributed power generation. One facility is located at the former Robert Mueller Airport on the campus of the Dell Children's Hospital and has a power generation capacity of 4.6 MW. The other facility is located in Austin at the Domain development and has a power generation capacity of 4.5 MW.[40]

Meeting Future Demand

The ability of AE to continue meeting the various levels of energy demand—peak, base, and intermediate loads—from a diverse array of sources, affordably and within the goals set by Austin Climate Protection Plan's (objective of 30 percent renewables by 2020, requires planning and balancing of power generation supply sources. The utility considers the effects of possible significant changes in the regulatory environment that will require reassessment of its current portfolio. Nuclear, coal, and even natural gas may become problematic due to potential carbon regulation affecting fossil fuels and economic uncertainties affecting a new nuclear reactor. In the future AE may pursue renewable options that cost more per kWh. Initiatives such as the Pecan Street Project (an alliance of local government, academic, and commercial entities) suggests the possibility of a distributed energy environment that could stimulate efficiencies in how we generate and consume energy, propelled by the implementation of smart grid options.[41]

AE has signaled a commitment to modernize its energy production in a way that emphasizes environmental stewardship and clean energy sources despite these real constraints. For example, the prospect of carbon regulation could encourage AE to sell or lease it stake in Fayette Power Plant by 2020. AE is seeking a low-cost mix of energy sources to hedge its ability to produce uninterrupted and reliable power with a methodical replacement of one type for another, such as renewables like wind and solar incrementally replacing older sources. The responsibility of planners is to ensure continuity of service during the overlap periods as new power generation platforms come on-line and old ones are decommissioned. Detailed methodological studies such as this report aim to provide sufficient data analysis, comparative consideration of options, and the provision of specific, realistic alternatives to AE and its customers to enable the concurrent achievement of these challenging goals.

Notes

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[4] Ibid.

[5] Ibid.

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[8] Arthur Mazer, "Electric Power Planning for Regulated and Deregulated Markets" (John Wiley & Sons, Inc., Hoboken, NJ: 2007), p. 83.

[9] AE, *Austin Energy Resource Guide* (October 2008), p. 17. Online. Available: http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf. Accessed: October 1, 2008.

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[11] Ibid., p. 9.

[12] Ibid.

[13] AE, *Power Plants* (online).

[14] EIA, *Existing Electric Generating Units in United States, 2006*. Online. Available: http://www.eia.doe.gov/cneaf/electricity/page/capacity/capacity.html. Accessed: July 18, 2008.

[15] Ibid.

[16] Lower Colorado River Authority (LCRA), *Fayette Power Project*. Online. Available: http://www.lcra.org/energy/power/facilities/fayette.html. Accessed: July 18, 2008.

[17] Ibid.

[18] City of Austin, *Audit Report: Fayette Power Project Scrubber Costs*. October 3, 2006. Online. Available: http://www.ci.austin.tx.us/auditor/downloads/au06113.pdf. Accessed: July 18, 2008.

[19] AE, *Resource Guide* (online), p. 23.

[20] LCRA, *LCRA and the Community's Right to Know*. Online. Available: http://www.lcra.org/energy/power/air_quality/righttoknow.html. Accessed: July 18. 2008.

[21] City of Austin, *Official Statement, Electric Utility Revenue Refunding Bonds, Series 2008A*, (July 24, 2008), p. 17. Available: http://www.ci.austin.tx.us/finance/downloads/os_ae_rfg_08a.pdf. Accessed: December 1, 2008.

[22] Ibid., p. 29

[23] Ibid.

[24] AE, *Power Plants* (online).

[25] AE, *Austin Energy, Enron Announce Completion of Sand Hill Energy Center Project* (July 11, 2001). Online. Available: http://www.austinenergy.com/About%20Us/Newsroom/Press%20Releases/Press%20Release%20Archive/2001/shComplete.htm. Accessed: July 18, 2008.

[26] EIA, *Existing Electric Generating Units in United States, 2006* (online).

[27] AE, *Austin Energy, Enron Announce Completion of Sand Hill Energy Center Project* (online).

[28] AE, *Resource Guide* (online), p. 24.

[29] EIA, *U.S. Nuclear Plants: South Texas Project*. Online. Available: http://www.eia.doe.gov/cneaf/nuclear/page/at_a_glance/reactors/southtexas.html. Accessed: July 19, 2008.

[30] Ibid.

[31] Nuclear Energy Institute, *Nuclear Statistics*. Online. Available: http://www.nei.org/resourcesandstats/nuclear_statistics/costs/. Accessed: November 29, 2008.

[32] City of Austin, *Official Statement* (online), p. 29.

[33] Ibid., p. 18.

[34] Tina Seeley and Greg Chang, *NRG Files First Full Application for U.S. Reactor* (September 24, 2007). Online. Available: http://www.bloomberg.com/apps/news?pid=20601087&sid=a_Kp1BDPL6ZE&refer=home. Accessed: July 19, 2008.

[35] AE, *Green Choice Program*. Online. Available: http://www.austinenergy.com/Energy%20Efficiency/Programs/Green%20Choice/programDetails.htm. Accessed: July 19, 2008.

[36] The Green Power Network, *Green Pricing: Austin Energy*. Online. Available: http://www.eere.energy.gov/greenpower/markets/pricing.shtml?page=2&companyid=50. Accessed: July 19, 2008.

[37] AE, *Resource Guide* (online), p. 26.

[38] AE, *Green Choice Program* (online).

[39] Ibid.

[40] City of Austin, *Official Statement* (online), pp. 16-17.

[41] Katherine Gregor, "The Pecan Street Project: Austin and AE form high tech partnership for the next big challenge in clean energy," *Austin Chronicle* (October 3, 2008). Available: http://www.austinchronicle.com/gyrobase/Issue/story?oid=oid:681436. Accessed: February 15, 2009.

Chapter 3. Demand-Side Management

Summary

This chapter describes the variety of demand-side management (DSM) options available to Austin Energy (AE) and concludes with specific options for enhancing the effectiveness of an integrated DSM program. These options include exploiting the range of non-conventional demand response (DR) alternatives, such as price signaling based on a smart distribution grid; expansion of the existing energy efficiency programs, particularly targeting lighting and HVAC modernization; and maintaining an aggressive public participation process to continue to broaden public and customer support.

Background

The cost of power generation facilities is one of a utility's most expensive activities. If a utility can defer construction of generation facilities, it and its customers can save money. AE has been committed to cost-effective DSM efforts over the past several decades to improve energy efficiency, conserve energy, and apply various DR activities, such as load shifting, to achieve further efficiencies. In its recently published *Resource Guide: Planning for Austin's Future Energy Resources,* for example, AE notes that reductions in peak demand can be efficiently achieved through energy efficiency and load shifting.[1] AE has found that it spends about $350 per kilowatt of peak demand avoided through DSM efforts, which is far below the costs of adding new power generation units.[2] The Austin City Council passed a resolution in 1999 that stated "cost-effective conservation programs shall be the first priority in meeting new load growth requirements of AE,"[3] because DSM programs provide the least cost option for meeting increased energy demand. AE's practice is to invest in any type of rebate program that they determine can be justified on a cost-benefit basis for reducing demand or shifting peak demand.[4] AE is constantly presented with new technologies claiming to increase the operating efficiency of heating and cooling units, appliances, or other forms of residential and commercial equipment. AE evaluates these new technologies to ensure that the costs and benefits presented by the producer of the technology are accurate. A cost-benefit analysis is conducted to determine the appropriate rebate that should be provided to customers for purchasing and operating such equipment.

AE uses efficiency and demand controls for reducing overall electricity demand. Energy efficiency focuses on decreasing demand by improving the efficiency of technology. Demand response actions by the utility refer to interventions at a centralized or utility level to achieve aggregate energy demand reductions. Conservation initiatives (considered as a component of DSM in this study) seek change in actual behavior or reduction in demand by removal, downsizing, or turning off electricity-consuming equipment.[5] Making homes and buildings more energy efficient can be an inexpensive alternative to invest in power generation to meet future energy demand. DSM programs save energy by "greening" buildings and providing rebates for energy efficient heating and cooling systems and appliances, renewable technologies, and other technologies that contribute to energy savings. Energy efficiency and conservation programs can reduce carbon dioxide (CO_2) emissions, increase energy security, prevent fossil fuel depletion, and contribute to a sustainable, carbon neutral energy future.

Since 1982 AE has developed and enhanced one of the nation's most extensive and comprehensive DSM programs to reduce as much as 800 MW of load prior to 2008.[6] AE commonly touts that these demand savings have prevented construction of a new baseload power plant.[7]

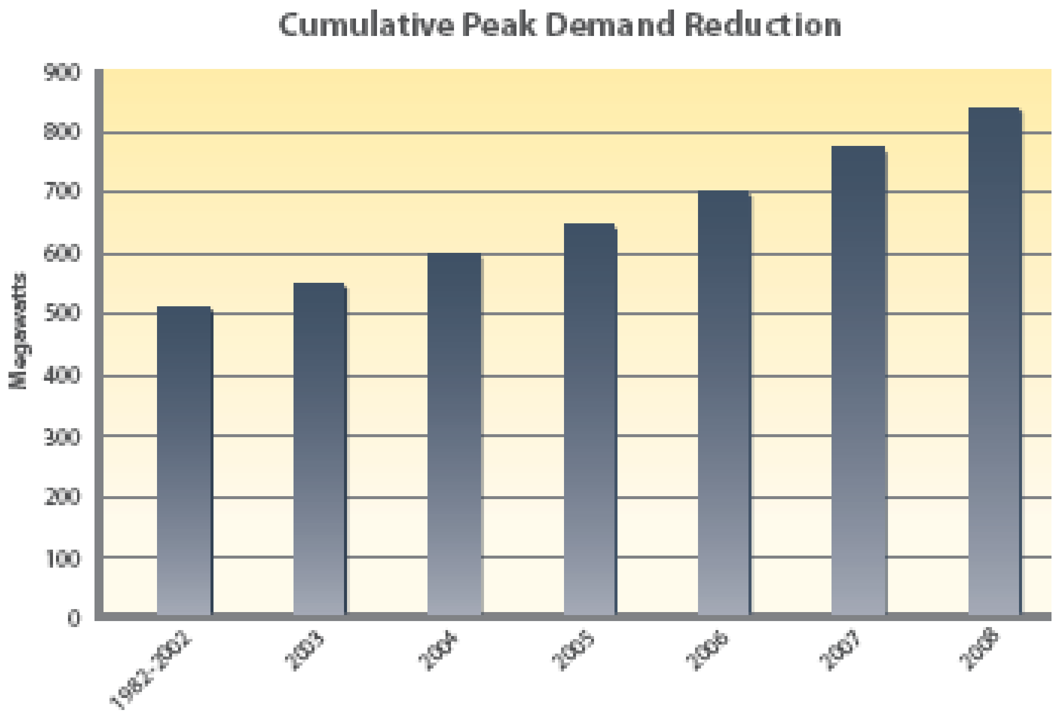
Table 3.1 lists AE's current DSM programs while Figure 3.1 depicts "Austin Energy's Cumulative Peak Demand Savings," the projected power reductions that can be achieved through continued aggressive DSM programs. The Austin Climate Protection Plan set the ambitious goal of achieving an additional 700 MW of savings through energy efficiency and conservation by 2020.[8] AE feels confident that their programs can achieve these goals. However, there remain challenges and uncertainties concerning future conservation projections, as the development of new technologies and their continued adoption by customers is difficult to predict. AE has sought to promote new technologies and energy efficiency and conservation programs to achieve the 700 MW goal. This chapter will identify the types of DSM and DR strategies, and energy efficiency programs that AE already participates in or could adopt to achieve even greater demand savings.

Table 3.1
Austin Energy's Demand-Side Management Programs

Power Saver Commercial	Power Saver Residential	Green Building Program
Municipal and Commercial Power Partner Programs	Power Partner Program	Residential Program
Solar Rebate Program	Solar Rebate Program	Commercial Program
Green Choice Program	Green Choice Program	Multi-Family Program
Commercial Energy Management Services Rebates and Incentives	Home Performance with Energy Star	Residential Code
The Multi-Family Partnership Program	Air Conditioner Rebates	Commercial Code
Multi-Family Program	Duct Diagnostic and Sealing	Multi-Family Code
Load Profiler	Compact Fluorescent Lighting	
Energy Miser Vending Products	Free Home Energy Improvements (Weatherization)	
On-site Commercial Energy Audit	Refrigerator Recycling	
Small Business Rebate and Incentive Programs	Solar Loan Program	
Online Energy Audit	Online Energy Audit	
Commercial Energy Product Guide	Water Heater Timers	
Appliance Efficiency Program	Appliance Efficiency Program	
	Clothes Washer Rebate	
	Cycle Saver	

Source: Austin Energy, *Energy Efficiency*. Online. Available: http://www.austinenergy.com/Energy%20Efficiency/index.htm. Accessed: July 26, 2008.

Figure 3.1
Austin Energy's Cumulative Peak Demand Savings



Source: Austin Energy, *Austin Energy Resource Guide* (October 2008), p. 19. Online. Available: http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf. Accessed: December 19, 2008.

Demand-Side Management: Energy Efficiency, Conservation, and Demand Response

DSM refers to "measures taken by a utility to encourage conservation of electric usage or to reschedule electric usage for more uniform usage…Such efforts are intended at minimizing the size and number of generating facilities or designing strategic load growth."[9] According to Freb Yebra, who manages AE's DSM programs, DSM consists of "utility initiatives which modify the level and pattern of electricity use by customers."[10] Clark Gellings, a leading DSM analyst, has defined DSM as "the planning, implementation, and monitoring of those utility activities designed to influence customer use of electricity in ways that will produce desired changes in the utility's load shape, i.e., changes in the time pattern and magnitude of a utility's load. Utility programs falling under the umbrella of DSM include load management, new uses, strategic conservation, electrification, customer generation, and adjustments in market share."[11] However one defines it, the overall objective of DSM operations is to reduce the burden on the utility to provide uninterrupted power to its customers. AE has utilized DSM for approximately two decades in one form or another, even when other utilities neglected it because of cost efficiency pressures following the deregulation of energy markets in the mid-1990s.

Because AE's electricity load varies during any day, week, and season, DSM can target reducing peak demand when energy supply systems face the greatest constraints. Therefore, DSM applications do not necessarily conserve energy, but instead might preclude the need for investments in additional power generation facilities. It is important to note the difference between "energy savings" and "demand savings." While "demand savings" reduces both the kilowatt hour (kWh) that AE needs to produce as well as the need for additional generation sources, "energy savings" reduces the total amount of pollution, including greenhouse gas (GHG) emissions, that is released into the atmosphere from generation. Gellings and DSM researcher Kelly Parmenter note that "because DSM programs can postpone the need for new power plants, the costs and emissions associated with fossil-fueled electricity generation are avoided. DSM programs also tend to generate more jobs and expenditures within the regions where the programs are implemented, boosting local economies. Moreover, DSM programs can help reduce a country's dependence on foreign oil imports, improving national security."[12]

Gellings and Parmenter note that "DSM encompasses a process that identifies how customers will respond, not how they should respond."[13] In other words, DSM is not simply a program intended to cause customers to conserve energy by actions such as reducing one's thermostat setting during the winter to avoid running the heating system excessively. Rather, DSM constitutes efforts to elicit change, often in the form of specific structural or physical modifications, that affect when and how customers use energy. As a utility responds to demand it seeks to assure more capacity than use. Any flattening of an energy peak means that some power generating capacity can be deferred.

Table 3.2 shows AE's current DSM programs and their associated costs to implement. AE's Power Saver Program provides residential and commercial energy management services to its customers by offering free energy audits and other forms of assistance to identify opportunities to conserve energy and save money by reducing customer electricity bills. Financial incentives such as rebates are offered for installation of qualifying equipment. The Green Building Program provides similar assistance to building professionals who seek to have their projects evaluated based on energy efficiency measures. The "green" building code enforces certain requirements for new homes and buildings. These programs help to drive energy demand down while increasing customer satisfaction. Many of these programs also stimulate the economy and increase employment in Austin by developing the local energy efficiency industry.

Table 3.2
Austin Energy Demand-Side Management Initiatives

Program Description	Program Cost ($ per peak kW reduction)
Duct sealing	890
Home energy performance loan	720
Commercial power partner	630
Refrigerator recycling	600
Appliance efficiency rebate	530
Home performance rebate	510
Washing machine rebate	450
Residential power partner	340
Water heater direct load control	310
Thermal storage	310
Multi-family efficiency	290
Commercial energy management (CEMP)	290
Vending machine mizer	260
Compact fluorescent lighting	240
Small business energy management	210
Green building	50
Load co-operation	20
All DSM programs average	260

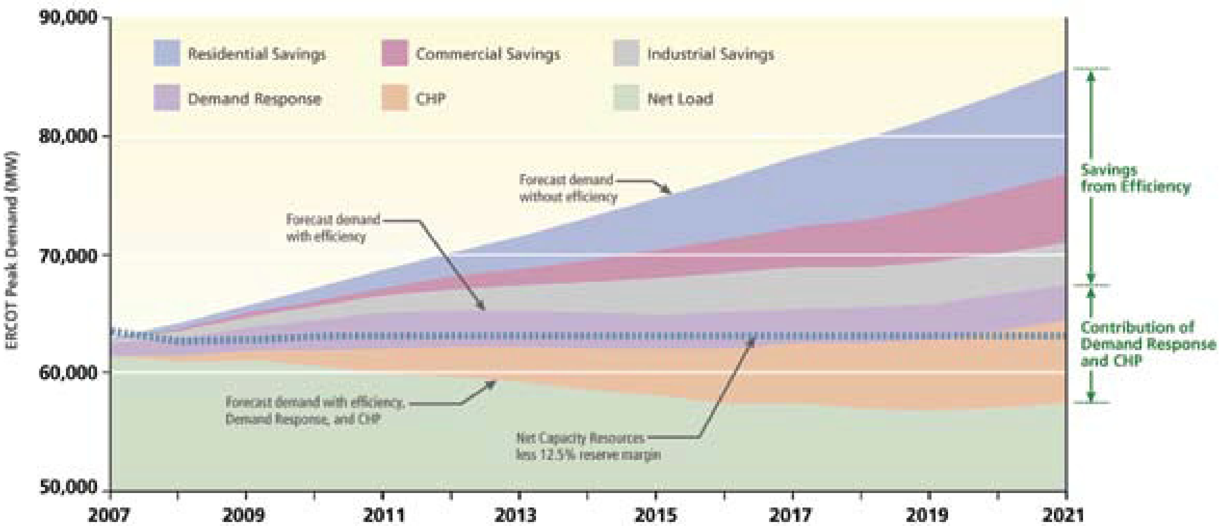
Source: Fred Yebra, *Investing in Energy Efficiency: Assessing the Costs and Benefits* (presentation made at Lyndon B. Johnson School of Public Affairs, Austin, Tex., October 2008).

Energy Efficiency Programs

Among the three major DSM approaches, energy efficiency programs have received the most attention. For example, a January 19, 2009, editorial pointedly titled "Energy Inefficiency" in the *New York Times* emphasizes how Americans can "wring savings from modest efficiency gains in products we already use," citing examples such as "insulating homes, improving fuel efficiency, and switching to concentrated laundry detergents to reduce packaging and transport costs."[14] Also in January 2009, the PBS program *NOVA* aired a segment on California's aggressive commitment to reducing its dependency on traditional sources of energy, called "The Big Gamble," in which the commentator highlighted how that state would achieve reduced CO_2 emissions. The program cited projections that "20 percent of cuts [in carbon emissions] will come from increasing energy efficiency in homes and offices" and "profiles corporate efforts to become more energy efficient."[15] These examples highlight a growing media and public commentator drumbeat to increase public awareness of the virtues of energy efficiency programs.

Even though the State Energy Conservation Office (SECO) of Texas does not formally consider energy efficiency a renewable energy resource, their 2008 publication of the *Texas Renewable Energy Resource Assessment* devotes an entire chapter to energy efficiency. [16] Pam Groce, the director of renewable programs at SECO, touted energy efficiency as the most effective means of achieving energy goals in the coming years, preferable to all other forms of renewable energy such as solar, wind, geothermal, and hydropower.[17] She highlighted the new manual's claim that "Avoiding the consumption of energy through energy efficiency measures provides a clean energy resource that is immediately available. There is abundant energy savings potential available at a low cost through energy efficiency measures in all economic sectors in Texas."[18] Figure 3.2 depicts the projected energy savings SECO envisions achieving through energy efficiency measures, while Table 3.3 highlights some of the specific energy efficiency applications SECO sees being employed within Texas, including some that are already in effect such as rebate programs offered by AE.

Figure 3.2
Projected Energy Savings



Source: State Energy Conservation Office, "Effect of Efficiency, Demand Response, and CHP on Demand Forecasts," *Texas Renewable Energy Resource Assessment 2008* (December 2008), p. 5.

Table 3.3
Examples of Energy Efficiency Strategies

New Home Construction
• More stringent building construction code • Voluntary programs for home builders • Austin Energy's Green Building program • Energy Star New Home program (developed by the U.S. EPA and implemented by many of Texas' investor-owned utilities)
Improve Performance of Existing Residential Dwellings
• Standard Offer programs: Programs administered by the state's investor-owned electric utilities to provide financial subsidies to energy services companies and other organizations who perform weatherization activities. • Energy audits • Proposed programs to provide homebuyers with greater information about the energy performance of homes being sold • Federal Weatherization Assistance Program: designed for low-income families and implemented by Texas Department of Housing and Community Affairs
Air Conditioning and Heating Systems
• Rebate programs (e.g., Austin Energy's program) • Improve installation practices of equipment installers (e.g., Oncor's AC Installer Training program). • Education about GHPs, programs of municipal community purchase and leasing of ground loops. • Encourage AC distributors to stock more efficient equipment (e.g., Oncor's AC Distributor market transformation program).
Lighting
• Buy down programs for compact fluorescent (CFL) bulbs • The Mayors' Challenge program (organized by Environmental Defense and involving the mayors of the state's four largest cities). • CFL give-away programs in lower-income neighborhoods (e.g., Houston in Summer 2008).
Photovoltaic Cells
• Federal tax credits. • Rebate programs (e.g., Austin Energy) • Net metering policies that credit solar power injected into the grid • PV installer training programs
Hybrid, Plug-in Hybrid, and Electric Vehicles
• Federal tax credits • Greater access to HOV lanes on highways • Commercial parking incentives (i.e., retailer proximity)

Source: State Energy Conservation Office, *Texas Renewable Energy Resource Assessment 2008,* p. 5. Online. Available: http://www.seco.cpa.state.tx.us/publications/renewenergy/enduseenergy efficiency.php. Accessed: January 29, 2009.

Bestselling author and *New York Times* opinion writer Thomas Friedman advocates for the role of energy efficiency programs in his 2008 book, *Hot, Flat, and Crowded.*

Friedman contends that "it is impossible to stress how important improving energy efficiency is and how great an impact it can have on mitigating climate change and reducing our energy bills—now."[19] AE continues to use aggressive rebate strategies to encourage adoption of energy efficient technologies, claiming that their rebate programs can reduce the electricity cost to customers by between 20 and 30 percent of the purchase of materials to improve efficiency, among many other alternatives to achieve demand reduction.[20] Gellings and Parmenter identify AE as an exemplar utility that has achieved noteworthy demand savings through its multi-family residential program and its Green Building Program.[21] AE currently operates over 20 energy efficiency programs that can be divided into programs that save residential and commercial power and green building programs. Table 3.1 shows the various DSM programs AE has used.

New opportunities should arise as technologies continue to be developed that improve the efficiencies of power generation, electrical appliances, or electrical devices. For example, Satesh Sainsi, an engineering developer, writes that technologies such as Web-based communication systems, as well as methods like E-mail, cellphones, pagers, and other remote control devices, constitute a range of technology improvements that can dramatically improve energy efficiency.[22] Sainsi claims DSM measure such as these can "be achieved at one-tenth the cost of building new power plants."[23] Gellings and associates Greg Wikler and Debyani Ghosh, in their report "Assessment of U.S. Electric End-Use Energy Efficiency Potential" present meta-analysis of 11 reports the opportunities for energy efficiency-driven savings across three categories: technical, economic, and achievable potential. The categories have viable targets of 33 percent, 20 percent, and 24 percent reductions, respectively, when extracted from programs across the country between 2000 and 2003.[24] Their article argues for increasing pressure on policy developers to promote the potential of such energy reductions.

Conservation Programs

Conservation differs from energy efficiency in that it seeks to eliminate an energy need altogether, rather than simply changing the mode of consuming energy to a more efficient, less demand-intensive means. Although the terminology is sometimes elusive, AE has consistently differentiated how it sees "conservation" acting as a method of reducing demand as opposed to "energy efficiency." In "Putting Energy Efficiency to Work," Fred Yebra includes programs such as Total Home Efficiency, Small Business Efficiency, Green Building Program, Free Weatherization, Municipal Conservation, and Air Duct Sealing, among others, as examples of initiatives that achieve conservational impacts.[25]

Sometimes, conservation is achieved through market forces. For example, during summer 2008 as gasoline prices throughout the U.S. exceeded $4 per gallon, some automobile drivers reduced transportation activities where possible, resulting in a reduction in oil consumption and eventually a corresponding drop in the price of oil. This instance from recent memory serves as a vivid example of how the price of an essential energy commodity can alter behavior and induce conservation. Utilities strive to induce customers to adopt less energy intensive behaviors before a crisis occurs, whether because of resource depletion or cost inflation. Often, these actions require voluntary participation by the customer. For example, efforts to encourage commercial businesses to turn off their lights in Austin high-rise complexes and business-dense skyscrapers constitutes such as an instance in which energy requirements are reduced, thereby lowering demand on the grid. Energy education programs can encourage customers to reduce "phantom" electric use, such as removing cell phones and computers from outlets or using central power-saver turn-off switches when these items are not needed. Such voluntary action decreases overall energy usage, potentially resulting in cost savings to the customer, and serves as a model for individual conservation action.

Table 3.4 details residential energy habits in the U.S. Space conditioning provides the bulk of home energy use at 43 percent. Therefore, programs that improve the heating and cooling efficiencies of a home and decrease the use of air conditioning and heating units can conserve energy. AE programs related to space conditioning include air conditioning improvement rebates, programmable thermostats, weatherization techniques, home performance with Energy Star, duct diagnostic and sealing, and the Green Building Program.

Table 3.4
United States Residential Energy Consumption

End-Use	Amount of Energy Used (% of total)
Space heating	30.7
Space cooling	12.3
Water heating	12.2
Lighting	11
Refrigeration	7.5
Electronics	7.4
Wet clean	4.8
Cooking	4.5
Computers	1.1
Other	3.8
Adjustments	4.7

Source: United States Department of Energy, *Buildings Data Book*, Section 1.2.3 (September 2007). Online. Available: http://buildingsdatabook.eren.doe.gov/docs/1.2.3.pdf. Accessed: August 6, 2008.

Another effective method of conserving energy occurs by providing real-time price feedback to customers regarding their energy use. Using monitors that provide real-time energy use and pricing information could stimulate changes in behavior that could help to conserve energy usage and decrease electric bills. Educating customers on how their energy use at home affect electric bills and the environment could also lead to conservation savings. Stand-by appliances and electronic equipment that is plugged in but not in use accounts for 5 to 10 percent of home electricity consumption. Indeed, three-fourths of the electricity used to power home electronics is consumed while the products are not in use, called "phantom load."[26] Technologies that look to reduce or eliminate phantom loads could also be a method of increasing energy conservation.

Demand Response Programs

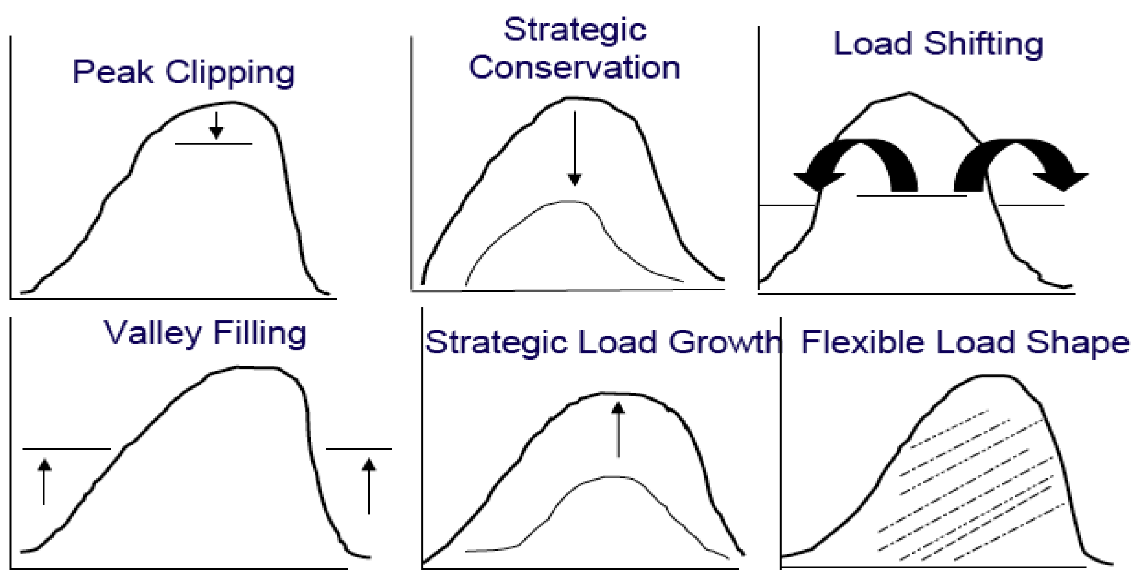
Demand response (DR) programs and another major type of DSM activity. DR is sometimes referred to as load management, load shaping,[27] or load shifting.[28] DR is the ability of a utility to counteract the need for new supply resources by reducing load during a period of relative high consumption. According to one DSM analyst, "Of all the utility DSM programs, load management programs provided the clearest benefits since they directly reduced demand during the time of highest cost."[29] In a 2004 report to the U.S. Senate, the General Accountability Office noted that "demand response programs have saved millions of dollars and could save billions of dollars more, as well as enhance reliability in both regulated and competitive markets."[30]

Generally, DR methodologies are utility-controlled activities, meaning that their application results from a centralized energy control capability to influence how energy is consumed at the end point. The utility's need to oversee the entire system gives it particular advantage in identifying when critical peak periods occur, and to shift aggregate energy consumption directly through strategic intervention. Although this description reflects the traditional model of DR, in the future DR programs might assume a much more decentralized, customer-oriented mode of application. Recently in Austin, AE, The University of Texas at Austin, Environmental Defense, and various commercial participants began the cooperative Pecan Street Project to redesign the energy grid in Central Texas into a "smart grid" that could allow real-time energy price allocation. Among other ambitions, the project seeks to "make the city of Austin into America's clean energy laboratory." A key component lies in modernizing the grid from a centralized energy-to-consumer system into one emphasizing the role of distributed energy, and using cutting-edge technology to allow the utility to price its dispatch based on prior agreements based on price signals.[31] A primary objective is to find innovative ways of increasing how distributed generated renewable energy is fed into the existing energy grid, with a defined goal of achieving 300 MW of locally renewable power generator. By early 2009, several major commercial entities, such as Freescale Semiconductor and Applied Materials, committed to the project, and a series of public "Eco-Series" discussions were conducted to familiarize the Austin with the initiative.[32]

Load shifting refers to programs that move electric usage from peak demand hours, such as weekday afternoons, to a time of day that has lower electric demand.[33] In order to shift load, the utility can either control load directly or offer incentives to encourage users to change their energy usage behavior. AE has applied a range of techniques to achieve load shifts. Figure 3.3 depicts six generic applications through which utilities have modified energy demand to reduce peak loads. These methods include peak clipping, strategic conservation (or strategic load growth), load shifting, valley filling, and flexible load shape. Several technologies can shift loads, such as AE's chillers at the Robert Mueller Energy Center that serves the Dell Children's Hospital. These chillers make ice overnight during the summer and store it in a tank until the next afternoon. The chillers are then turned off allowing the chilled water from the melted ice to provide air conditioning.[34]

While DR programs for commercial and industrial customer classes abound in the Electric Reliability Council of Texas (ERCOT) market, few opportunities for residential customers exist. As far back as the mid-1970s, utilities have conducted studies to measure the effects of how central systems can cycle residential water-heater and air-conditioner load to reduce and/or shift peak demand without sacrificing customer satisfaction.

Figure 3.3
Types of Load Management Techniques



Source: State Energy Conservation Office, "TPPA Energy Efficiency Working Group, Texas Forecasts," *Renewable Energy Resource Assessment 2008* (December 2008), p. 5.

Note: Other versions of this same slide describe this approach as "Demand Response" rather than "Peak Clipping" and "Strategic Conservation" rather than "Strategic Load Growth."

Table 3.5 lists the findings of several of these studies, which demonstrate that consumer energy consumption patterns can be prodded to change at various price point-driven thresholds. New applications of wireless communications have the potential to integrate DR devices into a seamless load control network that offers not only peak demand reduction but also ancillary services like regulation, voltage, and frequency control. When used in conjunction with accurate price signals, a customer could save money without sacrificing reliability or quality of service. Financial benefits accrue to the market as a whole when expensive power plants are not built. In the long run, DR programs should lower the capacity requirement in an electricity market. A recent federal report advocates fully integrated, incentive-based demand response programs.[35]

Table 3.5
Demand Response Program Performance

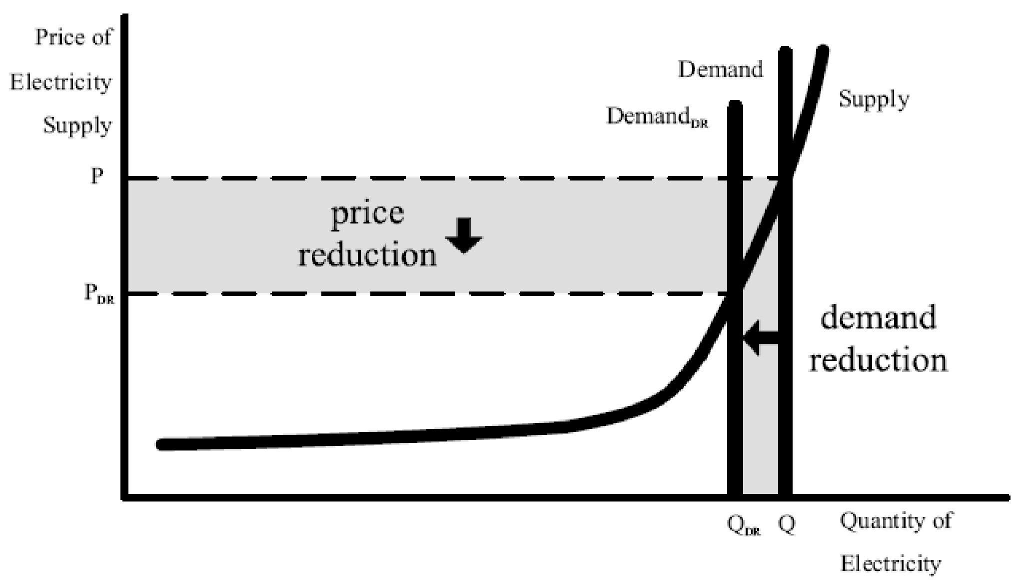
Description	Vendor	Application	Cost ($ million)	Energy Value
Load as resource: ERCOT LARs Program	n/a	ERCOT	n/a	1300 MW, 12.4% peak kW
Interruptible load service: ERCOT EILS Program	n/a	ERCOT	n/a	Unlimited
Forecast DR capability ERCOT- 2023	n/a	ERCOT	427	Unlimited 13,241 MW,[36]
Smart Grid – Broadband over power lines	GridPoint	n/a	n/a	12.5%[37] peak kW n/a[38]
Smart Grid – San Diego study of DOE Modern Grid	Various	SDG&E	490 (capital), 24 (annual op)	n/a
Commercial network power management	Powerit	n/a	n/a	15 – 17%[39] peak kW
Demand control grid-friendly appliance project	GridWise – BPA, PG&E	Yakima, Portland	n/a	n/a
Demand response Market-based, price response	AutoDR	LBNL	$57.62 kW	951 kW, 13.4% peak kW

Sources: R. Neal Elliott, et al., "Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas' Growing Energy Demands," *American Council for an Energy Efficient Economy* (March 2007, p. 16). Online. Available: http://www.aceee.org/pubs/e073.pdf. Accessed: October 10, 2008; Gridpoint, "Gridpoint in Smart Grid Platform." Online. Available: http://gridpoint.com/smartgrid/overview/. Accessed: September 6, 2008; and Powerit Solutions, Intelligent Demand Control. Online. Available: http://www.poweritsolutions.com/FAQs.shtml. Accessed: September 6, 2008; and see endnotes.

Historically, DR has taken the form of direct load control whereby a system operator could "interrupt" service in exchange for some incentive such as a reduced rate structure or an availability payment. The interruptible tariff was usually calculated based on some average avoided cost of capacity represented by the amount of load-shedding capability, but rarely tied to the actual marginal cost of a given service interruption. More recently, ERCOT has encouraged several load participation programs including the bid-based ancillary service Load Acting As a Resource and the contract-based Emergency Interruptible Load Service. ERCOT provides customers (via a qualified scheduling entity) the opportunity to bid their load curtailment into the balancing energy market in the Balancing Up Load program. This program has not been successful and has only one subscriber to date. Many of the potential subscribers to these programs are large industrial consumers that formerly had been on a direct load control tariff. A new paradigm in direct load control is the short-cycle load control that can be provided by many small loads working in aggregate to respond to market and system disturbances. Distributed DR can be seamless and imperceptible to even the smallest consumer if automatic control devices are installed on the major appliances in homes and businesses. Drawbacks to controlled DR include the inability of the consumer to override the control signal and the inability of the utility to fully quantify the capacity available during a given event. Automated direct DR likely has a place in the future distributed active grid by providing load-based ancillary services to increase reliability.

DR can involve the active participation of consumers in the electricity market if incentives to participate are based on pricing or some other agreement. Figure 3.4 demonstrates the typical demand-supply relationship for electricity consumption. The demand for electricity is commonly represented as fully inelastic, but studies have shown significant substitution elasticity based on pricing alone (see Table 3.6). When combined with smart metering and usage information displays, the energy value gained from either shifting from peak to off-peak or eliminating consumption altogether can be much higher.[40] AE could provide its customers the price signals they need to make such substitutions.

Figure 3.4
Electricity Pricing Supply and Demand Curves



Source: United States Congress, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them*, Report prepared by the Department of Energy pursuant to Section 1252 of the Energy Policy Act of 2005 (Washington D.C., February 2006, pp. v–viii. Online. Available: www.oe.energy.gov/DocumentsandMedia/congress_1252d.pdf. Accessed: November 3, 2008.

Table 3.6
Elasticity of Substitution for Price-Based Demand Response

Application	Pricing	Customer Class	Elasticity
Niagra Mohawk	Real-time	Commercial/retail	0.05
Niagra Mohawk	Real-time	Government/education	0.11
Niagra Mohawk	Real-time	Health care	0.03
Niagra Mohawk	Real-time	Manufacturing	0.17
Niagra Mohawk	Real-time	Public works	0.01
Niagra Mohawk	Real-time	Average of all accounts	0.11
Carolina Power & Light	Time-of-use	Residential	0.19
Connecticut	Time-of-use	Residential	0.1
Los Angeles	Time-of-use	Residential	0.11 - 0.19
Southern California Edison	Time-of-use	Residential	0.14 - 0.16
Wisconsin	Time-of-use	Residential	0.13
Norway	Time-of use	Residential	0.15
	Time-of-use	Residential	0.14
Midwest Power Systems	Time-of-use	Residential	0.18
	Time-of-use	Residential	0.173

Source: Charles Goldman, Lawrence Berkely National Laboratory, *Does RTP Deliver Demand Response?: Case Studies of Niagra Mohawk RTP and 43 Voluntary Utility RTP Programs* (December 2004), presented at Mid-Atlantic Demand Response Initiative Meeting, slide 16.

Pricing offers an opportunity to align consumer incentives and utility costs. Other agreements, like bid-based or contract-based load shedding, have a tendency to average costs over time and therefore distort the true cost of the event. Price signals, when properly designed, give a consumer a clear behavioral choice. If a utility cannot communicate to a customer the marginal value of producing a kilowatt-hour of energy it is hard to realize the behavioral shifts from price-minimizing customer choice. As long as the prices paid for energy production and the prices charged for energy consumption are averaged among customer classes and among daily time periods, there will be either a consumer or a producer surplus, and likely some dead-weight loss to the system. Pricing schedules have been devised as an attempt to relate the marginal cost of consumption to the consumer. AE could incorporate time-of-use, real-time, or critical peak pricing tariffs at the residential level in conjunction with smart metering and distributed power generation to maximize the efficiency of the distribution grid.

AE currently charges a fixed rate for connection to the distribution network, a steeply inclined block rate for its base energy charge, and a constant fuel charge for all energy purchased. While the block rate may capture the differences between baseload and peaking plant operations cost, the fuel price is simply an average of the many different fuel costs used in AE’s power generation mix. Under such a system, a consumer has no incentive to reduce peak load and therefore lower total cost.

A basic time-of-use (TOU) rate structure attempts to partition the day into time-based price blocks, where the cost for a specific block reflects the utility's costs of service at that time. For example, the costs of delivering electricity during the daytime peak demand period is higher than the costs of electricity during the night or off-peak hours. Time-of-use rates have the potential to lower system demand if a sufficient price signal is applied appropriately to each time block. Table 3.7 lists findings from several studies that have considered the effectiveness of TOU pricing. While TOU pricing more accurately allocates cost than a constant price, the costs within a time block are still averaged and do not necessarily provide a real-time price signal. TOU pricing has been implemented with large commercial and industrial customers that have been outfitted with advanced meters that can record differentiated consumption within the time block.

Table 3.7
Time-of-Use Pricing Programs

Description	Application	Energy Value
Time-of use pricing	Puget Sound, WA	1.3%[41] - 6%[42] peak kW
Commercial time-of-use tariff	Pacific Gas & Electric	.6% total kWh
Residential time-of-use tariff	Southern CA Edison	5%[43] total kWh
Residential time-of-use tariff	AK	11% - 26%[44] total kWh
Residential time-of-use tariff	CT	13%[45] total kWh
Residential time-of-use tariff	LADWP	7.3%[46] total kWh
Residential time-of-use tariff	NC CPL	13%[47] total kWh
Residential time-of-use tariff	Wisconsin	16%[48] total kWh

Sources: See endnotes.

Real-time or dynamic pricing is a structure that applies actual cost of service in small measured increments, such as hourly consumption. Some tariffs may pass through the market-clearing price in the wholesale electricity market, while others may be based on the utility's actual marginal cost for that hour (system lambda). Customers can be made aware of the prices ahead of time, with the method of communication being crucial to the success of the program. Real-time pricing could shift consumption from peak to off peak, or even reduce total consumption. Table 3.8 lists the findings of several studies that have assessed the effectiveness of real-time pricing on both peak demand reduction and total energy conservation.[49,50,51,52]

Table 3.8
Commercial Real-Time Pricing Programs

Description	Application	Energy Value
RTP with hourly day-ahead price signal	Niagra Mohawk, NY	10% peak kW
RTP Day ahead and hourly pricing	Georgia Power	1,000 MW
RTP	Public Service of Oklahoma	18% peak kW
RTP	Duke Power	33% peak Kw, 4% total kWh
RTP	Exelon	22% peak kW
RTP	New Jersey Central Power & Light	57% peak kW
RTP	FL Power & Light	20% peak kW
RTP	KS City Power & Light	54% peak kW
RTP	Otter Tail Power Company	30% peak kW
RTP	Pacific Gas & Electric	15% peak kW
RTP – hour ahead price signals	GA Power	30%
RTP – day ahead price signals	GA Power	12%
RTP	Gulf Power	15%
RTP with indicator lamps warning of high prices	Finland	71% peak kW
RTP with hourly day-ahead price signal	Niagra Mohawk, NY	10% peak kW
RTP Day ahead and hourly pricing	Georgia Power	1,000 MW
RTP	Public Service of Oklahoma	18% peak kW
RTP	Duke Power	33% peak Kw, 4% total kWh
RTP	Exelon	22% peak kW
RTP	New Jersey Central Power & Light	57% peak kW
RTP	FL Power & Light	20% peak kW
RTP	KS City Power & Light	54% peak kW
RTP	Otter Tail Power Company	30% peak kW
RTP	Pacific Gas & Electric	15% peak kW
RTP – hour ahead price signals	GA Power	30%
RTP – day ahead price signals	GA Power	12%
RTP	Gulf Power	15%
RTP with indicator lamps warning of high prices	Finland	71% peak kW

Source: Charles Goldman, Lawrence Berkely National Laboratory, *Does RTP Deliver Demand Response?: Case Studies of Niagra Mohawk RTP and 43 Voluntary Utility RTP Programs* (December 2004), presented at Mid-Atlantic Demand Response Initiative Meeting, slide 16.

Energy costs are currently driven by the most expensive unit power plant deployed at a given time. Power generation in the ERCOT market is priced at the wholesale level on the marginal cost to serve the next unit demanded. At times of very high demand, or critical peak, the price to serve the next megawatt hour can be extremely high. At times of extreme power shortage, ERCOT spot market prices may be capped but may reach fifty times larger than the incremental cost of AE's baseload plants. A critical peak pricing (CPP) pricing program is an event-driven hybrid of the TOU and the RTP. When a "critical peak" occurs, the normal peak time period in a TOU rate structure is replaced by a very high price that reflects the marginal cost of supply during that event. Table 3.9 lists the results of several critical peak pricing assessment programs. CPP could help AE defer some of its wholesale market risk in the ERCOT market. If AE were to lose some power generation capacity during a shortage event, they might be exposed to such high market pricing which would be very costly. The ability to avoid such "critical peak" costs could be very valuable to AE.[53]

A price-based demand response program pricing could be implemented prior to the complete installation of advanced metering,[54] but will require restructuring AE's billing system. Such restructuring could take several years to implement such a program.

Table 3.9
Residential Critical-Peak Pricing Programs

Description	Vendor	Application	Energy Value
CPP with automated thermostat		California	5.7 – 8.7%[55] total kWh
Smart Power – CPP– Automated Metering Infrastructure interactive energy management	Sensus AMI	AL Power – Birmingham	2 -3 kW per customer[56]
CPP with automated thermostat		Gulf Power	6.9%[57] total kWh
CPP with automated thermostat		General Public Utilities	4.8%[58] total kWh
TOU tariff		California	4.1%[59] peak kW
Fixed CPP tariff		California	12.5% peak kW
Variable CPP price tariff		California	34.5% peak kW
CPP–Low-use, low-income		CA state-wide pricing pilot	.01 peak kW
CPP - Low-use, med-income		CA state-wide pricing pilot	0.056 peak kW[60]
CPP – Low-use, high-income		CA state-wide pricing pilot	0.009 peak kW[61]
CPP – High-use, low-income		CA state-wide pricing pilot	0.057 peak kW[62]
CPP – High-use, med-income		CA state-wide pricing pilot	0.402 peak kW[63]
CPP – High-use, high-income		CA state-wide pricing pilot	0.185 peak kW[64]
CPP single hottest day tariff		California	47.4%[65] peak kW
CPP with automated thermostat		Central and South West	0.8%[66] total kWh

Sources: See endnotes.

Communications Program

Coinciding with the release of its October 2008 *Resource Guide*, AE implemented a public participation process, which it describes as "designed to engage the community in the Utility's planning process."[67] During the early days of DSM, program analysts frequently referred to the marketing aspect of DSM.[68] AE's DSM programs cannot be effective if consumers choose to participate; they are more likely to do so if they are informed about the programs and their potential benefits. AE already demonstrates its commitment to community outreach as part of its general DSM, and in its energy efficiency programs identifies such outreach as a discrete task.[69]

Options for Austin Energy

In order to achieve its ambitious goal of achieving an additional 700 MW of peak demand savings through conservation by 2020[70] AE will not only have to maintain DSM initiatives it has already put in place, but will also need to implement new programs and initiatives to accelerate savings. In 2007 AE projected that it annually saved 65.4 MW of annual required power plant peak demand through its energy efficiency programs. These demand savings (not energy savings) help to delay the construction of new power generation facilities by deferring increased loads. AE projected that its DSM programs equaled 119,000 MWh of energy savings in 2007. The estimated annual power plant emission reductions associated with these savings include 70,100 metric tons of CO_2, 53.7 metric tons of nitrous oxides, 48.6 metric tons of sulfur dioxide, and 37.3 metric tons of carbon monoxide.[71] In projecting demand and energy savings for a given year, AE takes the expected lifespan savings that a particular customer will receive through their participation in a particular program at time of initial participation.[72]

AE's 700 MW goal of additional demand savings by 2020 is based upon assumptions that new technologies, code regulation enforcement, automatic meter reading (enabled by the smart grid system), and adjustments to the billing system will be available in the future. It is an open question whether AE's customers will continue to adopt new technologies that increase efficiency or shift demand. Aggressive information campaigns have the potential for increasing voluntary enrollment in AE DSM programs. Additional price-based DR programs could also reduce demand and should be considered as AE continues to develop its "smart grid" and evaluate its billing system. Data from investor-owned utilities (IOU) in Texas suggest that further significant demand reductions are achievable. For example, according to a September 2008 report presented to the Texas Senate by the Association of Electric Companies of Texas, energy efficiency programs hosted by IOUs in Texas achieved approximately 170 MW of peak demand reduction in 2007 alone, exceeding their goals by 23 percent.[73]

Enforcement of Austin's green building code can contribute to energy demand savings estimates. In 2007, Austin adopted the 2006 International Energy Conservation Code with amendments. This was the first step towards reaching zero-energy capable homes through the Zero Energy Homes Initiative passed by City Council in 2007. Future changes expected to be made in 2009, 2012, and 2015 will enable new homeowners to build zero-energy homes by adding solar technology or other clean technologies to their homes. Homes built after 2015 are expected to use 70 percent less energy than homes built before the 2007 code was adopted if these codes are enforced as expected.[74]

AE and the City of Austin have multiple options to increase DSM programs ability to help reach the stated 2020 goals. AE could pursue rollout of technological advances toward realizing the smart grid to apply price signaling to decrease demand. Price signaling efforts should exploit RTP, TOU, CPP, and other load shaping DR opportunities.

The utility can expand and accelerate existing energy efficiency programs. These include residential and commercial retrofit initiatives, particularly those that target lighting and HVAC modernization for buildings that have not previously been upgraded.

Communications outreach and innovative means of increasing public participation are vital components to any long-term success in raising DSM savings. AE could continue to capitalize on its ongoing public participation process in order to broaden public support and prepare Austin citizens for likely increases in energy prices. Aggressive and regular communication can alleviate or prevent resistance to change. Austin should consider hosting one of the more prominent DSM conferences held annually, such as the International Energy Association (IEA) DSM Summit, or similar high-visibility seminars, and enable as many Austin citizens to attend as express interest.

Austin could identify and implement a wider range of direct incentives, such as residential rebate programs for retrofit and promotion of a range of energy demand reduction actions. For example, the city could actively support state initiatives like the Energy Star Sales Tax Holiday, which encourages state citizens to purchase the most efficient models of home appliances that meet the standards of Energy Star energy efficiency, such as the one offered in May, 2008 on a trial basis.[75] The residential point-of-sale ordinance presents a model for improving public participation in retrofitting residential structures, with enormous potential enhancement of energy efficiency, and should broaden the ordinance's applicability to commercial and government structures.

AE consistently cites its objective of saving 700 MW of avoided power generation by 2020 but avoids explicitly detailing how it plans to achieve this goal. Although specifically itemizing its tactical plan for achieving that objective would undermine its competitive strength vis-à-vis other Texas utilities, this target remains a generally conservative estimate of achievable DSM savings, the 700 MW does not reflect fully the anticipated role of continued technology improvements, incentives provided by carbon legislation, and the potential effect of a shift in public expectations regarding energy usage.[76] The most elusive component of what can be achieved beyond the 700 MW goal is the enormous potential suggested by behavioral change. Fred Yebra noted how previous energy research has typically been unable to adequately quantify the vagaries of how shifts in consumer behavior offer possible energy efficiency opportunities. According to the Energy Information Administration, the "greatest impacts of cost-effective [energy efficiency] programs often coincide with periods of peak usage."[77] Therefore, modulating consumer behavior, both residential and commercial, to preclude the placement of demand on the system at its most vulnerable periods (such as the prototypical late summer afternoon period) offers the most rewarding window for trying to alter behavior, thereby perhaps beginning to alter the peak load demand model that undergrids AE's generation assumptions.

Austin, as a city of atypical government and civil administration employment, has a dense network of 8-to-5 employment, such as the high number of state activities (legislative offices, administrative departments, etc.), state and city academic employment (The University of Texas at Austin, Austin Community College, etc.), and federal governmental employment (Internal Revenue Service regional processing, Camp Mabry military installation, etc.). These civil servants present energy planners with a sizable body of AE consumers whose behavior can be altered or modified to reshape aggregate consumption demand patterns. Although behavior modification, especially at a level that requires such complicated legal and regulatory intervention, remains a difficult variable in the range of options to manipulate, given the impetus of public will and political determination, it nevertheless presents a considerable opportunity for reducing demand beyond the 700 MW objective. Fred Yebra concurred that the potential for emerging research data to support the viability of achieving significant savings by 2020 is real and worthy of serious analysis.[78]

AE may be able to exceed its 700 MW goal by 2020 of DSM-induced energy reductions through behavioral modification. According to Yebra, Austin's uniquely dense concentration of governmental power consumers presents an opportunity to influence demand patterns, especially by avoiding the traditional periods of peak demand by voluntary and mandated changes to work schedules to avoid the typical surges on particularly hot days.[79] Behavioral modification programs are relatively unexplored, yet they represent a means that can be quickly adopted for changing energy consumption patterns.

Notes

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[22] Satish Sains, "Conservation v. Generation: The Significance of DSM," *ReFocus* (May/June 2004), p. 52.

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Chapter 4. Calculating Austin Energy's Carbon Footprint

Summary

This chapter provides an overview of the methodology Austin Energy uses to calculate its carbon footprint and discusses the options available for electric utilities for validating greenhouse gas (GHG) emissions calculations. The chapter begins with a discussion of the meaning of the term "carbon footprint." This is followed by an overview of various standards for calculating and verifying GHG emissions and details the methodology currently used by AE. AE's current and future projected carbon footprint is presented and a discussion of the merits of a life-cycle assessment of GHG emissions is presented.

Background: What is a "Carbon Footprint"

Burning coal, natural gas, or oil emits carbon dioxide (CO_2) directly into the atmosphere. When CO_2 emissions cannot be captured they accumulate in the atmosphere, which many climatologists recognize as a significant contributor to global warming.[1] The threat of the potential consequences of global warming has led to local and global efforts to reduce the amount of GHG emissions released into the atmosphere. Recognizing that an electric utility presents a significant opportunity for GHG emission reductions, the City of Austin included carbon control as a utility plan component within its 2007 Austin Climate Protection Plan (ACPP).[2]

The term "carbon footprint" represents the measure of how human activities contribute GHGs to the environment, usually defined in terms of a mass of CO_2 or CO_2-equivalent. Calculating an entity's carbon footprint is an attempt to measure and verify an entity's impact upon the environment in terms of CO_2-equivalent emissions. The entity can then track, set limits, and reduce its emissions over time. For example, Austin Energy can establish benchmarks, set quantitative targets for future emission reductions, and evaluate alternative future activities.

There is not one standard for calculating a carbon footprint, as multiple standards have been established. A recent literature review on "carbon footprint" in 2007 found that, "the term 'carbon footprint' has become widely established in the public domain albeit without being clearly defined in the scientific community."[3] The approaches proposed for calculating a carbon footprint range from simple online calculators to sophisticated life-cycle analysis or input-output-based methods.[4] Questions have been raised pertaining to what types of emissions should be included within a carbon footprint measurement and at what point in time within the power generation process these emissions should be measured.[5]

One issue is how to include all types of GHGs emitted rather than only CO_2. With the goal of reducing an entity's impact on global warming (as is stated in the ACPP),[6] one approach is to include as many GHGs as possible that can be quantified with accuracy and reliability. The six GHGs subject to the Kyoto Protocol are CO_2; methane (CH_4);

nitrous oxide (N_2O); and three groups of fluorinated gases: sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).[7] Non-CO_2 GHG emissions can be converted to a CO_2 equivalent to provide a measurement of mass units within a time period, typically in terms of tons of CO_2 equivalent. While not all GHGs are carbon-based, for the purposes of this report the term "carbon footprint" will be used hereafter to refer to the measurement of all GHGs.

A second question in calculating a carbon footprint is what emissions should be quantified. Should carbon footprint include only direct emissions from fuel combustion or should it also include indirect emissions incurred in upstream production and transportation processes? The answer to the question relates to whether a so-called "life-cycle impact assessment" is needed to assess the overall impact of the use of particular products and processes on the environment.[8] While the majority of emissions for a given entity will be direct (on-site and internal emissions), other emissions could be indirect (off-site, external, embodied, offstream, or downstream). A recent consultant's report stated: "The carbon footprint is a measure of the exclusive total amount of carbon dioxide emissions that is directly and indirectly caused by an activity or is accumulated over the life stages of a product."[9] This definition recommends the inclusion of indirect emissions in an entity's carbon footprint.

Current carbon accounting systems are silent as to whether an electric utility should calculate so-called life-cycle emissions that would measure the carbon footprint from the earliest point of extraction (coal from a mine, natural gas or oil from a reservoir, or uranium ore from the earth), through energy production processes, transport, burning, and end uses. It is not easy in theory or practice to assess the life-cycle impacts of supplies or products, particularly if the process involves the combustion of fuels for energy embedded in products or services purchased or sold. For these reasons this study will not attempt to calculate life-cycle emissions in the evaluation of various power generation mix scenarios. However, if analysts have quantified life-cycle carbon emissions, such figures will be reported. Table 4.1 provides a list of steps identified in this report as an overview of the steps in calculating AE's carbon footprint.

Table 4.1
Steps for an Electric Utility's Carbon Footprint Reporting

Step 1:	Determine the types of greenhouse gases to include in calculations.
Step 2:	Determine what types of emissions qualify (direct, indirect, etc.).
Step 3:	Choose a protocol to submit and verify your carbon footprint calculation.
Step 4:	Define organizational, operational, and geographical boundaries.
Step 5:	Quantify your emissions.
Step 6:	Verify your emissions calculations with a third-party.
Step 7:	Submit your emissions report to an approved entity to validate your emissions.

Adapted from: California Climate Action Registry, *General Reporting Protocol, Version 3.0* (April 2008). Online. Available: http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April 2008_FINAL.pdf. Accessed: July 7, 2008.

Methodology for Calculating Carbon Footprint

Although there is no generally acceptable methodology for measuring an entity's GHG emissions within the U.S., there are several protocols that have become well-established and are likely to be considered acceptable if federal legislation is passed requiring private firms and governments to inventory GHG emissions. The Greenhouse Gas Protocol (the GHG Protocol) produced by the World Resources Institute and the World Business Council for Sustainable Development was developed in 1998 to guide entities in reporting emissions and developing emission-reduction strategies.[10] The GHG Protocol's supporters claim that it is "the most widely used international accounting tool for government and business leaders to understand, quantify, and manage greenhouse gas emissions."[11] Its founders have produced three documents: the GHG Protocol Corporate Accounting and Reporting Standard;[12] the GHG Protocol for Project Accounting;[13] and the Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects.[14] Each of these documents is designed to help users quantify carbon footprints and can be accessed free-of-charge online. These protocols have served as a basis for other standards and reporting programs.

In 2005, the International Organization for Standardization (ISO) established ISO 14064 to guide carbon footprint calculations and emissions reporting procedures.[15] I SO 14064 standards must be purchased online. ISO 14064 is similar to the GHG Protocol, but also offers entity certification for project-specific compliance rather than just project certification. ISO 14064 aids entities in developing GHG inventories by defining standards for quantifying, monitoring, and reporting project-level GHG emissions and emission reductions. It also establishes requirements for entities conducting GHG emission reduction, validation, and verification.[16]

Within the U.S., the California Climate Action Registry (CCAR) Reporting Protocol has become a commonly used and acceptable standard for reporting and verifying GHG inventories.[17] The CCAR General Reporting Protocol is based on the GHG Protocol but also provides additional sector-specific protocols, including the Power/Utility Reporting Protocol.[18] The California State Legislature accepted CCAR in 2001 as a standard for the tracking of GHGs and for certifying procedures that could later be used to track compliance with any California or federal GHG regulations.[19] AE has adopted the CCAR standards for the reporting of its emissions. AE began submitting an emissions inventory to CCAR in 2006 (for 2005 emissions reporting) and has continued to do so annually. The 2005 through 2007 emissions reports can be accessed online.[20]

In an attempt to develop a national reporting protocol, The Climate Registry (TCR) has been developed following the CCAR and the Eastern Climate Registry (ECR) reporting protocols.[21] TCR is intended to support voluntary and mandatory GHG markets throughout the U.S. and any future federal GHG regulation. Members of CCAR and the ECR will be integrated into TCR when it comes online. Some entities participating with the CCAR may shift procedures over a two-year period to TCR to ensure uniformity among U.S. protocols. As a member of CCAR, AE is expected to transition to the use of the TCR in the near future. TCR guidelines are expected to closely mimic those of the

GHG Protocol and ISO 14064. AE will be reporting as part of the City of Austin to TCR, as Austin is a TCR Founding Reporter. Austin is an unusual case because not many cities in the U.S. have their own electric utilities. Therefore, Austin may appear to have significantly higher emissions per capita than other cities as its utility emissions are included in the city's GHG reporting.

CCAR provides a voluntary registry of GHG emissions for companies and organizations nationwide. Reporting of GHG emissions under CCAR includes the measurement of both direct emissions under an entity's control and indirect emissions controlled by others. Therefore, electricity generated by an off-site power source is considered to be an indirect emission that must be included within the entity's inventory. For the first three years of participation with CCAR an entity is only required to report CO_2 emissions. Participants are encouraged to report the remaining five Kyoto Protocol GHGs (CH_4, N_2O, SF_6, PFCs, and HFCs) and are required to do so after three years.[22] The CCAR developed the General Reporting Protocol (GRP) to support consistent and accurate reporting of an entity's GHG inventory. The third and most recent version of the protocol (Version 3.0) was developed in 2007. The GRP guides participants through CCAR's reporting rules, emissions calculation methodologies, and the Climate Action Registry Reporting Online Tool (CARROT). CARROT is used to calculate and register emissions, provide third-party certification, help an entity manage and track data, and store open records of all data for the general public. The CCAR developed an industry-specific protocol for electric utilities in 2005 as an appendix to the GRP, entitled the Power/Utility Protocol (PUP). While the GRP provides general entity-wide emissions guidelines, the PUP provides much stricter guidelines for electric utilities.

This study will report AE's carbon footprint figures as calculated through the PUP and GRP methodologies. The PUP sets reporting standards for how electric power generation and utility entities (including electricity transmission and distribution) are required to compile, report, and certify their entity-wide GHG emissions when submitting their annual emissions inventory to CCAR.[23] AE is required to use the PUP. The city will use the Local Governmental Operations Protocol (LGOP), which has just been developed and adopted by CCAR's board. The LGOP was developed jointly by CCAR, TCR, Local Governments for Sustainability, and the California Air Resources Board.[24] Austin will use the LGOP to develop the city's inventory to be reported to TCR starting in 2009 for AE's Calendar Year 2008 emissions. Both AE and the City of Austin will use CARROT to report their findings.

Defining Boundaries

A first step in the reporting of emissions under the PUP is to define organizational, operational, and geographic boundaries. Entities have the option of reporting based on management control and/or equity share. The process can become complicated as electric power and utility companies participate in diverse ownership and management control arrangements for power generation facilities, transmission and distribution assets, and the fuel commodities themselves. Due to the varying number of ownership scenarios (seven are listed in the PUP), the guidance document "strongly recommends" that an entity calculate and report their GHG emissions using the equity share method which AE currently uses.[25] No matter what method is chosen by an entity, the same method ought to be used consistently for all facilities. While entities typically have joint ownership of assets (such as AE's 16 percent share of the South Texas Project nuclear facility), contracts set the terms of the distribution of ownership among parties. Therefore, an entity's equity share will typically be the same as the ownership percentage. If an entity chooses to report using the management control method, documentation from partners in ownership must be provided regarding who will be reporting the emissions from a given facility. The PUP provides an outline for reporting emissions under equity share and management control approaches based on types of organizational relationships.[26]

Defining an organization's boundaries becomes further complicated because this process requires defining the entity's direct and indirect emissions. Direct emissions are "those emissions from sources that are owned or controlled by the organization in question."[27] Within the power/utility sector, direct emissions come from: stationary combustion from onsite production of heat; steam or electricity; fugitive leaks or venting; processes such as emission control technologies and other activities; and mobile combustion from non-fixed sources. The PUP provides guidance for calculating and reporting direct emissions from stationary combustion from: the onsite production of heat, steam, or electricity; fugitive emissions from electricity transmission and distribution; and process emissions from sulfur dioxide (SO_2) scrubbers. However, the GRP must be used for calculating and reporting mobile combustion, fugitive emissions from air conditioning or refrigeration systems, and fugitive emissions from fire suppression equipment.[28] Indirect emissions are defined as "those that occur because of the organization's actions, but are produced by sources owned or controlled by another entity."[29] Indirect emissions include electricity, steam, and heating and cooling purchased and consumed and transmission and distribution losses.

Geographic boundaries are determined based on the location of an entity's facilities, broken up between California facilities and other U.S. facilities. An entity also has the option of establishing a baseline year to develop a standard annual emissions profile.[30] AE's baseline year is 2005 while the city's baseline year will be 2007.

Quantifying Emissions

The next step in reporting emissions is applying the methodology to quantify four types of emissions: direct emissions from stationary combustion; direct emissions from processes; direct fugitive emissions; and indirect emissions from energy purchased and consumed. The majority of a power/utility company's emissions will come from the stationary combustion of hydrocarbons in the form of CO_2, CH_4, and N_2O, although CO_2 emissions will typically make up the largest percentage of an entity's GHG inventory.[31] To limit burdensome quantification of emissions, entities are only required to report 95 percent of their total emissions. Each entity can declare up to 5 percent of their total emissions as so-called "de minimus." De minimus emissions must be estimated and reviewed by the certifier, but they are not required to be publicly reported. These estimates must be conservative, verifiable, and appropriately documented. Any assumptions and estimations must be provided for review.[32]

The PUP identifies measurement-based and fuel use calculation-based methodologies that power and utility companies can use to quantify their GHG emissions. Some utilities already have continuous emissions monitoring systems (CEMS) in place. Sometimes fuel use data are used to calculate emissions. All of AE's facilities have CEMS in place to measure CO_2 emissions except for the combustion gas turbine units at the Decker Creek Station. Fuel use data are used to calculate emissions from these units. If separate facilities have different measurement capabilities, a combination of these methodologies may be used. The United States Environmental Protection Agency (EPA) provides requirements for installing, certifying, operating, and maintaining CEMS for measuring and reporting CO_2, SO_2, NO_x, O_2, opacity, and volumetric flow.[33] Guidelines for applying a fuel use calculation-based methodology are available and include the following seven steps:

1) identifying the annual consumption of each fossil and non-fossil fuel;
2) converting fossil fuel use from physical units to energy units;
3) applying or deriving an appropriate CO_2 emission factor for each fuel;
4) applying CH_4 and N_2O emission factors for each fuel;
5) calculating each fuel's CO_2 emissions and converting to metric tons;
6) calculating each fuel's CH_4 and N_2O emissions, if any, and converting to metric tons; and
7) converting CH_4 and N_2O emissions to their CO_2 equivalents and sum totals.[34]

In addition to stationary combustion emissions several processes lead to direct GHG emissions. These include SO_2 scrubber emission control technologies, NO_x emission control technologies, coal gasification at clean coal facilities, and hydrogen production. CEMS sometimes report CO_2 emissions from the use of scrubber technology, but if this is not the case, specific methods for calculating these emissions are available.[35] The PUP does not currently include guidance for calculating and reporting CH_4 and CO_2 emissions from natural gas transmission, storage, and distribution systems,[36] so the GRP can be consulted to determine methodology for reporting these emissions.[37]

Fugitive emissions are classified as unintentional releases of GHGs. These include SF_6 from electricity transmission and distribution systems, CH_4 from fuel handling and storage, HFCs from air conditioning and refrigeration systems, and PFCs and HFCs from fire suppression equipment. Methodologies for quantifying fugitive emissions from electricity transmission and distribution systems and from fuel handling and storage are available.[38] The GRP has procedures to calculate direct fugitive emissions from air conditioning and refrigeration systems and fire suppression equipment.[39] Sometimes fugitive releases can be classified as de minimus emissions and therefore are not required to be reported.

One set of indirect emissions can be quantified from energy purchased and consumed, including electricity resold to end-users that is consumed by transmission and/or distribution systems through line losses. Methodology for reporting indirect emissions associated with transmission and/or distribution losses is available.[40] The GRP has GHG calculation methods related to purchased electricity, steam, or heat for a utility's own consumption. It is common for power and utility providers to track the data used to report such transmission and distribution losses for the Federal Energy Regulatory Commission.

CCAR requires certain industry-specific efficiency metrics to be reported in order to provide a basis for consistent comparison across the utility/power industry, track carbon intensity performance over time, and complement the entity-wide absolute emissions reporting.[41] As entities may have to increase their power generating capacity in order to meet growing electricity demand, these metrics allow entities to monitor their efficiency at generating electricity and compare their own efficiency to others within the power industry. Three efficiency metrics are mandatory for the electric power and utility sector: 1) total electricity generation; 2) fossil fuel electricity generation; and 3) total electricity deliveries. Guidelines exist for quantifying these metrics.[42]

CCAR encourages entities reporting so-called "scope 3," or optional emissions to provide information beyond the minimum required, such as emissions associated with employee commuting, business travel, and product movement. An entity can submit additional information about its environmental goals and programs related to meeting those goals to create a public record of internal environmental goals that complements an entity's emissions inventory. Recommended but not required additional reporting categories include indirect emissions from extraction, production, and transportation of fuels used for generation of electricity, heat, or steam; purchases and sales of tradable renewable certificates; annual energy efficiency savings; purchases and sales of GHG emission offset projects; and contractual agreements assigning liability. Optional efficiency metrics that can be included are energy output, natural gas deliveries, fuel or facility, electricity by customer type, and natural gas by customer type.[43] AE does not currently report any optional (scope 3) emissions.

All annual reports submitted by a participating CCAR entity must first be verified by an approved third-party to ensure the credibility and accuracy of emissions data prior to CCAR approval. Once an approved verifier confirms an entity's data, the emissions report is reviewed by CCAR and accepted into a database open to the public. The GRP provides guidance on the process of verifying a GHG emissions report. Included within these guidelines is information on how to obtain the services of a verification provider and what information must be provided to the verifier. The GRP Protocol lists 12 steps involved in the verification process.[44] The CCAR Power/Utility Verification Protocol provides additional guidance for conducting verification activities and documenting verification.[45] Annual emissions reports must be submitted by June 30 of the following year and verification must be approved by October 31 of that year in order to be included in the registry.

Austin Energy's Carbon Footprint

AE emissions for 2005 through 2007 can be accessed on the CCAR website.[46] The majority of AE's emissions come from the burning of fuel to produce electricity with some indirect emissions generated from purchased electricity as well as mobile sources, SF_6, fire suppression equipment and air conditioning systems. The majority of AE's reported emissions are CO_2 releases (greater than 99 percent), with relatively small amounts of CH_4 and N_2O emitted. CH_4 and N_2O have been converted into their CO_2 equivalent to represent the total global warming potential of all GHGs emitted by AE.

In 2005, AE emitted 5,559,473.52 metric tons of CO_2 equivalent emissions from stationary combustion and 15,219.72 metric tons from transmission and distribution losses from purchased electricity. In 2006 emissions were slightly lower: 5,443,917.08 metric tons of CO_2 equivalent emissions attributed to stationary combustion and 23,193.95 metric tons of CO_2 equivalent emissions attributed to transmission and distribution losses from purchased electricity. In 2007 emissions increased to 6,082,984.48 metric tons of CO_2 equivalent from stationary combustion and 16,254.95 from transmission and distribution losses from purchased electricity. De minimus emissions for AE were included in the 2005 through 2007 reports, accounting for 0.34 percent of AE's total GHG inventory in 2005 0.28 percent in 2006, and 0.41 percent in 2007. All emission reports were verified by Tetra-Tech EM, Inc., a third-party engineering firm. No optional emissions were reported, but information is included in the reports regarding AE's goals set prior to and after implementation of the ACPP. Emissions efficiency metrics were used as the primary calculation methodology and information regarding electricity deliveries, net generation, and net fossil generation are included.

Life-Cycle Assessment

Life cycle assessment (LCA) represents a set of tools used to conduct an environmental analysis of activities related to products and processes, such as the delivery of electricity to consumers by an electric utility or the GHG "content" of goods or services purchased by an entity. A LCA of the electricity generation process could compute the following: impacts of using a particular fuel source; the extraction treatment or processing of the raw material, the transportation of the material to generation facilities, storage of the fuels, the impact of the facility upon the environment, the emissions generated by the burning of the fuel source, and the recycling and/or disposal of any of the by-products of the fuel burning process or the retirement of the facilities. Conducting a life cycle analysis is often referred to as taking a "cradle to grave approach." This approach looks at the complete supply chain of the electricity generation process, plus its use and end-of-life treatment.[47]

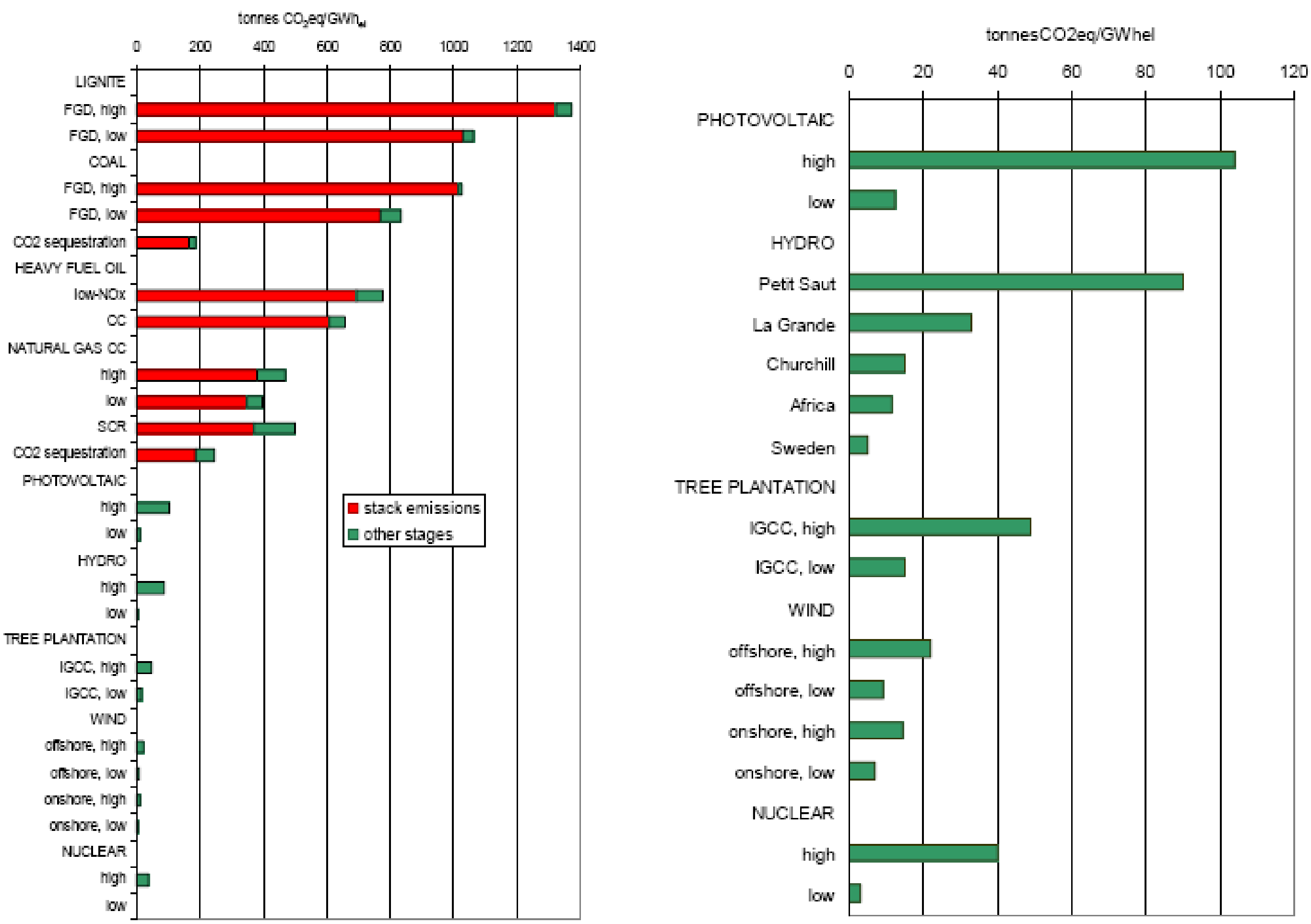
AE's primary source of GHG emissions comes from stationary combustion. Measuring direct emissions from power generation sources is straightforward. Additional electric utility sector emissions can be attributed to upstream and downstream activities related to the process of electricity generation. For instance, when conducting a life-cycle assessment of the environmental impact of a coal plant, it is possible to consider the impact of extracting coal from the earth, washing the coal to remove sulphur or other impurities, emissions related to the building and maintenance of a coal-fired power plant, the transportation of coal and employees to the plant, as well as the impacts on the climate from decommissioning a coal plant. AE has not and does not plan to conduct a full life-cycle analysis of the climate and environmental impacts of their current fuel mix.

ISO 14000 Standards represents an initial effort to establish an internationally accredited guidance for conducting a LCA for products and processes.[48] The LCA process detailed by ISO 14040 is a systematic approach consisting of four stages: definition of goals and scope, inventory analysis, impact assessment, and interpretation.[49] The parameter typically used to measure the global warming potential of electricity generation is to measure the CO_2 equivalent of emissions related to the electric generation process. In July 2004 the World Energy Council produced a report entitled, "Comparison of Energy Systems Using Life Cycle Assessment."[50] Figure 4.1 compares the life-cycle emissions of various power generation technology options. AE's current standard for reporting emissions from a particular power generation source reflects the actual combustion of the fuel. Although this will likely be acceptable for conducting a GHG inventory for the purposes of future state or federal regulation of GHG emissions, by definition and by design it would not provide a comprehensive comparison of the true impact fuel sources and/or power generation technologies have upon the environment. Fossil-fueled energy sources tend to have a higher carbon footprint (up to 1,000 grams of CO_2 equivalent per kilowatt-hour) than non-fossil fuel based technologies (typically lower than 100 grams of CO_2 equivalent per kilowatt-hour) due to emissions created from the burning of the fuel.[51] Even if nuclear energy, biofuels, or other renewable energy sources are referred to sometimes as "carbon-free" or "carbon neutral," this is not true because each source of power for electric generation technologies emits CO_2 at some point during its life cycle.[52] For instance, AE's nuclear power generation does not currently contribute to the utility's GHG emissions. However, a life-cycle assessment of nuclear energy would consider the impacts of mining the uranium, stages of processing the uranium into fuel rods, transportation of products and employees to the plant, emissions related to the construction and maintenance of the plant facilities, and environmental risks associated with the disposal of nuclear waste. One reason an entity might seek to develop a LCA of a nuclear power plant would be to report on the overall climate impact of that particular fuel source or power generation technology.

One reason why an entity might not want to develop a LCA is that there is no consistent and clear methodology for conducting such an analysis. A second reason is that there is no clear way to trace the GHG content and release from various inputs and outputs. For these reasons, among others, in 2009 AE made no plans to develop LCA methods for its reporting purposes. There is no simple way to envision or conduct a true LCA, as it would have to account for all environmental impacts of fuel sources, power generation technologies, and generation end uses of energy, as well as products or services associated with all stages of the electric power cycle. In accordance with this reality, this report follows AE's practice of not evaluating the current power generation mix of AE or future power generation mix scenarios with such a LCA.

Figure 4.1
Life-Cycle Carbon Emissions of Power Generation Options

(in tons produced)



Source: World Energy Council, *Comparison of Energy Systems Using a Life Cycle Assessment* (July 2004, p. 4). Online. Available: http://www.worldenergy.org/documents/lca2.pdf. Accessed: July 13, 2008.

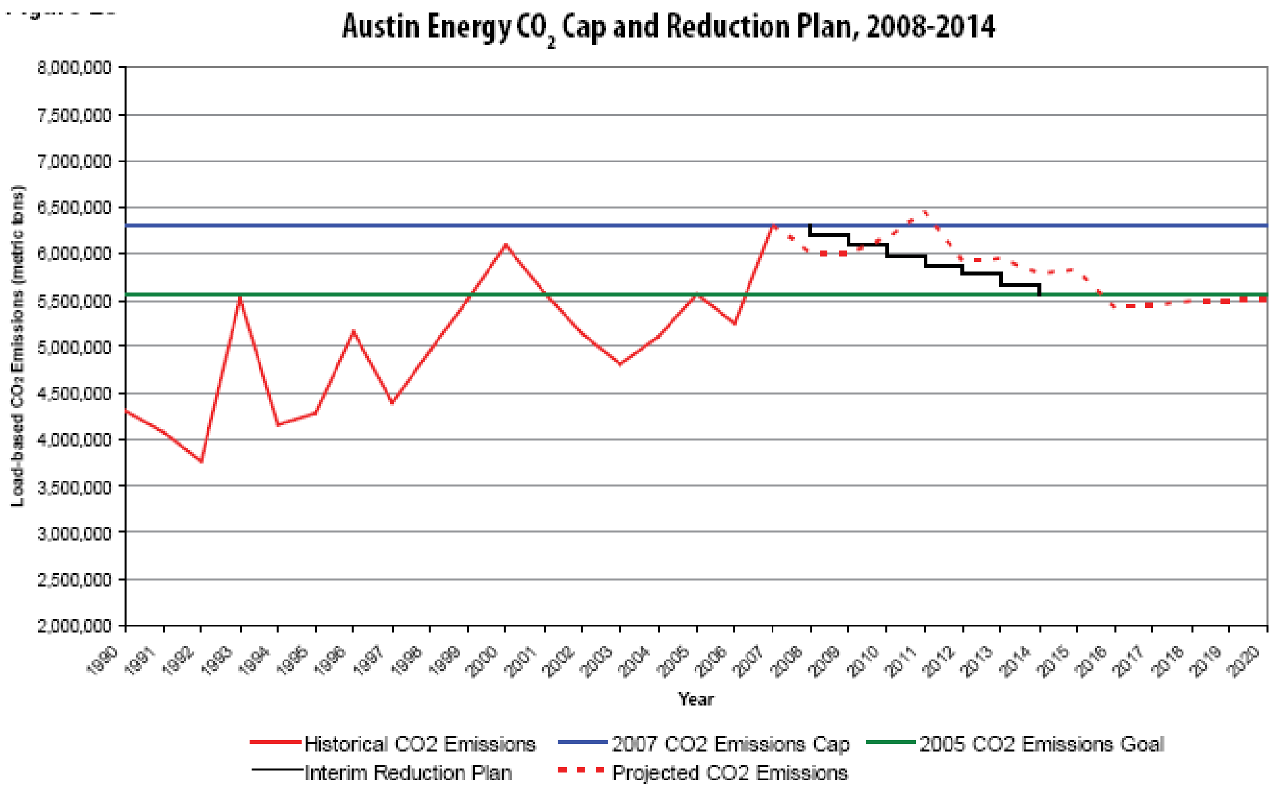
Austin Energy's Future Carbon Footprint

AE has taken the initiative over the past several years to compute and allow a third party to verify their GHG emissions through CCAR. It appears that AE's current reporting standards will be acceptable under future state and federal carbon regulation. Although most emissions generated by fossil-fueled sources are accounted for during the operation of the plant (as currently reported), raw material extraction and power plant construction also plays a role in the environmental impact of these power sources. On the other hand, nuclear and renewable energy sources produce indirect and life-cycle GHG emissions that result from stages other than the operation of facilities, emissions not currently being accounted for by AE.

On July 24, 2008, Roger Duncan, AE's Acting General Manager, presented to the Austin City Council the utility's proposed CO_2 upper limit (cap) and reduction plan through 2020.[53] AE plans to cap its CO_2 emissions at 2007 emission levels and gradually reduce emissions to 2005 levels by 2014 (see Figure 4.2). Most current carbon-related bills propose setting an initial goal of reducing economy-wide GHG emissions to 2005 or 2006 levels in the first year of implementation, typically 2014. AE's CO_2 emissions in 2007 were roughly 6.1 million metric tons and in 2005 were roughly 5.6 million metric tons. AE will need to reduce its emissions by 745,000 million metric tons over a seven-year period while energy demands gradually rise. Their goal is to gradually reduce emissions by about 100,000 metric tons in a stair-step fashion. It should be noted that while no current carbon regulation exists, many bills have been proposed by the U.S. Congress over the past several years. Many of these bills propose a cap-and-trade system that would give away allowances for regulated entities for free in order to ease the regulatory burden. However, these allowances are typically based upon recent historical emissions so a voluntary program for curbing CO_2 emissions could reduce the number of allowances AE receives in the future.[54]

AE has stated that given current economic and political considerations, the best option for reducing its carbon footprint is to generate electricity from its current sources and purchase offsets in the short-term for emissions that exceed the cap and/or replace coal-based generation with natural gas.[55] If the federal government or the State of Texas were to adopt comprehensive GHG regulations, AE would be able to make a more informed decision on these options. AE projects that costs to offset CO_2 emissions by 2014 would be $18.8 million dollars, while replacing coal generation with natural gas would cost $253.3 million.[56]

Figure 4.2
Austin Energy's Proposed Carbon Dioxide Cap and Reduction Plan



Source: Austin Energy, *Austin Energy Resource Guide* (October 2008), p. 35. Online. Available: http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf. Accessed: December 19, 2008.

Table 4.2 lists AE's projected carbon footprint through 2020, based on load generation for both a business-as-usual scenario and a proposed future generation mix scenario. Both scenarios include megawatt-hour projections that assume AE meets its 700 MW energy demand savings and 30 percent renewable energy goals by 2020. The business-as-usual scenario factors in the expansion of AE's Sand Hill Power Plant to include an additional 100 MW of natural gas generation, which is already budgeted for and under construction. The proposed scenario includes the 100 MW expansion at Sand Hill as well as an additional 200 MW of combined-cycle gas generation to come online in 2013. The latter scenario is known as AE's "strawman proposal," presented to the city council in July 2008 and is under public discussion as part of AE's public participation process.[57]

Table 4.2
Austin Energy's Projected Carbon Dioxide Emissions by Year

Year	Load-serving Generation (MWh)	Business-as-usual CO_2 Emissions (metric tons)	Proposed CO_2 Emissions (metric tons)
2000	11,002,593	6,090,098	6,090,098
2001	10,399,301	5,571,205	5,571,205
2002	9,688,085	5,135,223	5,135,223
2003	9,399,018	4,807,361	4,807,361
2004	10,314,232	5,105,404	5,105,404
2005	11,088,756	5,557,322	5,557,322
2006	11,406,483	5,247,038	5,247,038
2007	12,544,349	6,301,582	6,301,582
2008	12,629,121	6,006,655	6,006,707
2009	12,958,920	5,992,548	5,992,548
2010	13,495,659	6,163,800	6,163,800
2011	13,801,942	6,453,446	6,453,446
2012	14,007,549	5,913,366	5,913,366
2013	14,101,319	6,140,617	5,946,251
2014	14,302,476	5,989,090	5,771,571
2015	14,511,159	6,010,942	5,817,770
2016	14,747,987	5,592,617	5,412,448
2017	14,921,395	5,632,788	5,438,171
2018	15,103,856	5,676,071	5,479,951
2019	15,332,179	5,690,716	5,480,394
2020	15,582,008	5,698,270	5,508,076

Source: Austin Energy, "Austin's Projected Carbon Dioxide." Accessed: 2008. (Slide Excerpt.)

Notes

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Chapter 5. Planning for the Future at Austin Energy

Summary

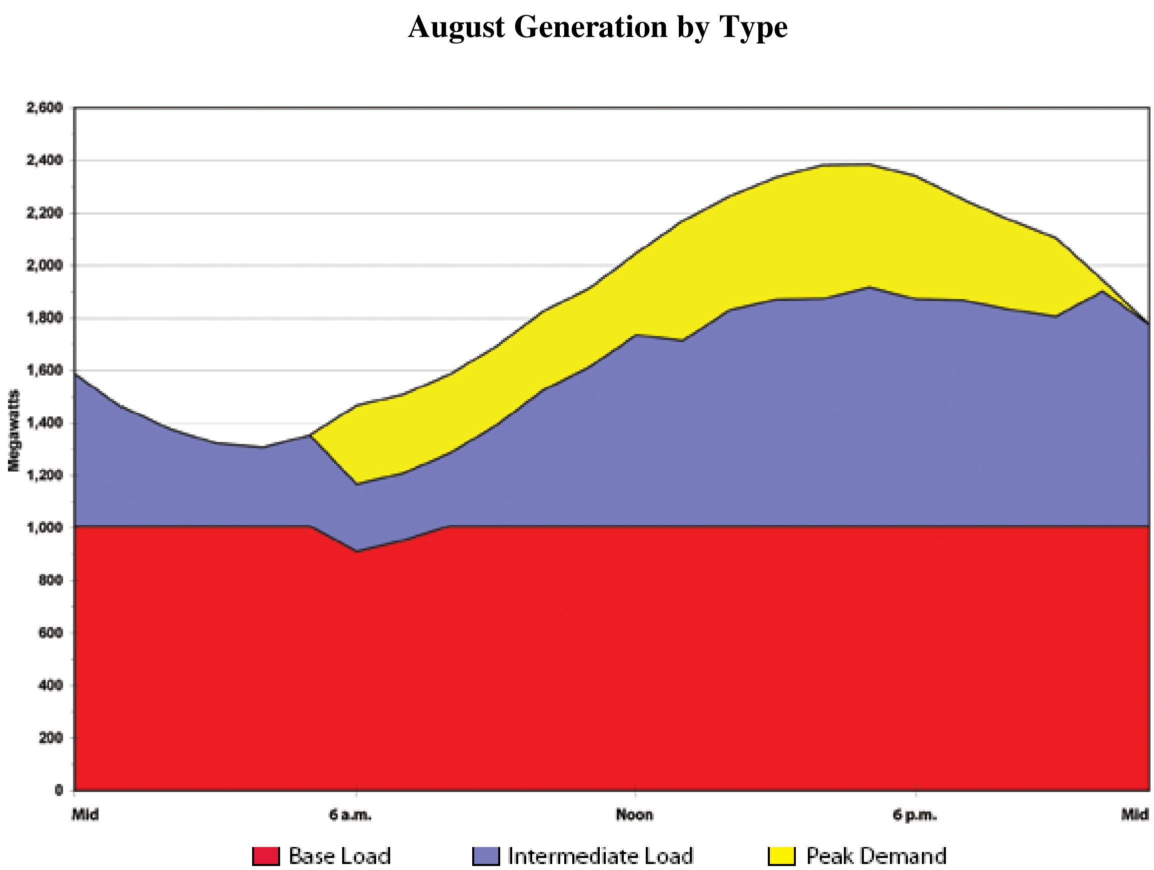
This chapter provides an overview of the considerations that Austin Energy must take into account when making investment decisions on future power generation capacity. It begins with an introduction of the methods used to predict future energy demand and various techniques that could be used to meet that demand. It then discusses AE's proposed energy resource plan, detailing elements of the plan including development of a smart grid and investments in transmission and distribution infrastructure. The chapter then discusses some additional factors that need to be considered when making investments, such as regulatory issues and future carbon pricing policies. It concludes by noting that while current economic data suggests that traditional (i.e., fossil fuel-based) technologies may continue to be the best financial investments, uncertainties about technological advances, legislation, and carbon pricing may make renewable technologies a more attractive long-term investment.

Background

The primary function of an electric utility company is to provide an adequate supply of electricity to meet the fluctuating demands of customers. Demand for electricity is primarily driven by electric consumption behavior in response to weather patterns. Load is a term used in the electric industry to identify the demand of electricity at a given point in time. Load forecasting is the method used to project future demands an electric utility will face. Accurate load forecasts allow for investment decisions in new power generation facilities to be made in a timely fashion to ensure future demand is met. Load shapes demonstrate power requirements over a given period of time, typically represented as daily, weekly, and seasonal patterns. Electric load has a strong correlation with weather due to the relation of weather and electric cooling (air conditioning) and heating systems. Over the course of a typical day afternoons tend to have the highest peak demand for electricity. Weekdays tend to have higher peak demand than weekends due to business operation schedules. The summer and winter months tend to have the highest demand during a year, with highest annual demand occurring on the hottest day of the summer. Figure 5.1 shows the hourly load shape for AE on a typical hot summer day in August. AE currently forecasts load through 2020.[1]

Load forecasting methods use statistical techniques such as regression modeling, neural networks, fuzzy logic, and expert systems to forecast future demand based on estimated demand patterns.[2] Long-term forecasts take into account historical load and weather data, the number of customers in various customer classes, appliances in the area and their characteristics including age, economic, and demographic data and their forecasts, and appliance sales data, among other factors.[3] Long-term load forecasting is dependent upon accurate projections of future changes in an area's demographics as well as technological progress. The longer out a forecast is made, the more opportunity there is for such forecasts to be disrupted by unforeseeable circumstances. Therefore, long-term forecasts at best are estimates of future electricity demand based on historical use patterns extended into the future.

Figure 5.1
Austin Energy Hourly Load Profile



Source: Austin Energy, *Austin Energy Resource Guide*, p. 12. Online. Available: http://www.austin smartenergy.com/downloads/AustinEnergyResourceGuide.pdf. Accessed: December 19, 2008.

Austin Energy's Load Forecasting Methodology

AE currently uses a statistically adjusted end-use (SAE) model. This model is updated yearly to account for any changes in local trends as well as trends within the energy market. SAE modeling is an econometric modeling approach that allows for a multitude of factors to be taken into account to determine future energy demand. This type of modeling technique focuses on the end-uses of electricity and the reasons for consuming electricity over a given period of time. Since people do not consciously "decide" how much energy they plan to consume on a given day or time period, it makes sense to base an energy forecast model upon the factors that influence electric usage behavior. Historic billing data, weather patterns, and future projections of demographic changes within the AE customer base area are some of the many factors utilized to make future projections of energy demand. Regression modeling is used within the model to break future demand into residential, commercial, and industrial customer classes. It is important to subdivide in this way due to large variations in end-use electric usage behavior patterns exhibited by these three customer class groups. Further separating the model into additional end-use categories for electricity usage can increase the analytical abilities of the model.[4]

AE's SAE model process builds upon the Energy Information Administration Annual Energy Outlook and appliance stock projections to incorporate national trends related to energy consumption and efficiency. Short and long-run fuel price impacts are accounted for by using a energy utilization engineering model. Once estimates are made related to future energy market trends a regression model is utilized to account for historical data related to AE customer classes as well as economic and demographic projections for AE's customer base. Future reductions in demand through demand-side management (DSM) are also incorporated into the model. Projections of the impact of DSM programs assume that customers will continue to enroll in AE's current and future DSM programs, more efficient technologies will continue to emerge, and building code standards will continue to be enhanced and adopted by Austin's City Council.[5]

The historical weather pattern data used is from the past 10 years.[6] Although 30 year weather trends have traditionally been used for making load forecasts, recent increases in temperatures associated with global warming have led to the shorter time frame being used. However, the possibility of further increases in temperature is not included in AE's load forecast model.

AE's load forecast model is able to project annual and monthly energy sales, power generation needs, and peak demand forecasts as well as make long-term hourly load forecasts. The further out the time span for the load forecast the less confidence there is in the accuracy of the projection. It is difficult for such modeling to predict future changes in human or industry behaviors that could occur based on factors such as fuel price increases or carbon regulation. One advantage of using SAE modeling is that this method allows forecasters to incorporate future events such as the introduction of carbon legislation or new technological breakthroughs into the model by making assumptions as to how the change could affect demand patterns.

Future Demand

Even if large reductions occur in energy demand per capita through DSM, electricity demand within the AE service area is expected to continue to rise through 2020 driven by population and industrial growth. The 2008 peak demand forecast for 2020 is 2,845 megawatts (MW), an increase of 17 percent from 2006 peak demand of 2,430 MW. The decommissioning of the Holly Plant in fall of 2009 will remove 397 MW of generating capacity, for which AE substituted 300 MW of power purchase agreements that run through 2010. New gas turbines at the Sand Hill Energy Center will produce an additional 93 MW of energy in 2009.

If AE meets its conservation goal of 700 MW of demand savings by 2020, it is projected that the utility will need an additional 238 MW of power generation capacity to meet peak demand in 2020 while without such savings AE faces a shortfall of 627 MW of power generation capacity in 2020 (see Figure 5.2). The utility may need to increase its generating capacity even more to provide a reserve margin in case demand is higher than projected and to ensure capacity exists when planned or unplanned outages occur. In order to meet a 20 percent reserve margin AE must supply about 569 MW of additional energy by 2020 to meet peak demand if projected DSM savings are met. Recommending where this energy will come from is one objective of this report.

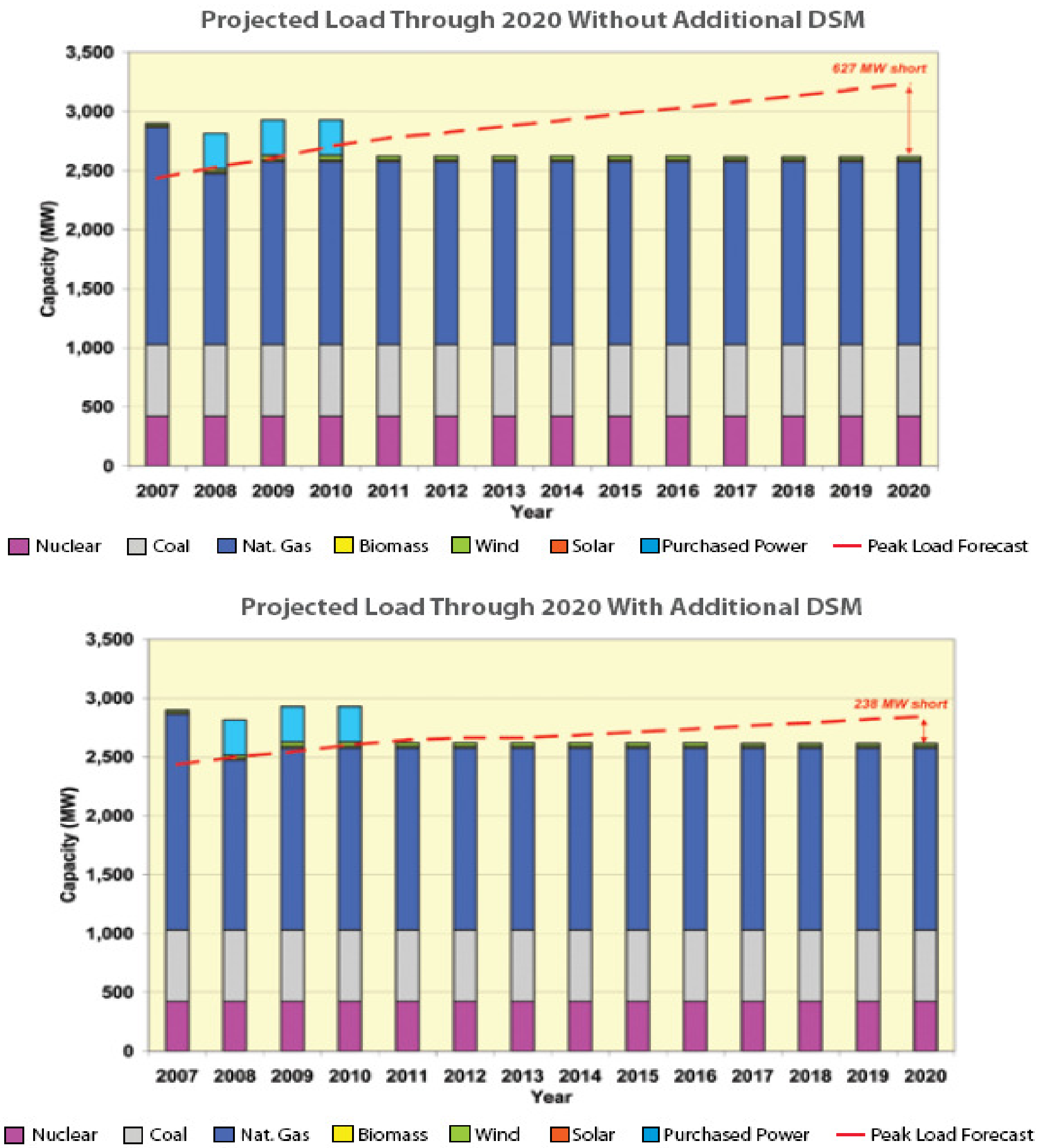
This shortfall, or "gap," poses both a need and opportunity for AE to make investments in future power generation sources. Before the development of renewable energy sources, increases in demand were primarily met by investing in new baseload and intermediate facilities (typically coal-fired, natural gas, or nuclear). Natural gas turbines have recently been added to help meet peak demand, but these units provide relatively small amounts of power generation capacity. Advances in renewable energy technologies have increased the economic feasibility of these technologies. AE's commitment to renewable energy technologies to bridge this gap would help it evolve into a more sustainable electric utility. By investing in renewable technologies the utility could facilitate the development of a local renewable energy industry which could create jobs and stimulate the local economy by increasing tax revenues for the city.

Austin's Climate Protection Plan (ACPP) states that all new power generation facilities must achieve carbon neutrality through lowest-emission technologies, carbon sequestration, and offsets. As a result, this project assumes that AE will seek to meet its future energy demand through least cost options that consider environmental residuals and benefits to the local economy. Some of the factors that will be considered in this report include the costs and benefits of various power generation technologies; how each technology affects the environment; and how a particular investment affects the local economy, within the context of the utility moving towards carbon-neutral status.

AE has been committed to cost effective DSM efforts over the past several decades to improve energy efficiency, conserve energy, and achieve load shifting.[7] DSM and conservation programs provide the least cost option for meeting increased energy demand. For detailed information on DSM, AE's previous and current DSM programs, and potential opportunities for further investment in DSM programs, see Chapter 3.

Figure 5.2
Austin Energy Projected Demand Through 2020

With and Without Demand-Side Management Projections



Source: Austin Energy, *Austin Energy Resource Guide*, p. 12. Online. Available: http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf. Accessed: December 19, 2008.

Meeting Demand

For a utility to ensure that future demand is met they must design a future power generation mix that guarantees reliable service at all times of the day and year. Energy demand fluctuates considerably during the course of a day, week, and year. In order to ensure that demand is met on the hottest and coldest days of the year a utility must have access to electric generating capacity that meets peak demand while maintaining a reserve margin that ensures reliable service in the case of unexpected outages. The consequence of these requirements is that much of a utility's power generation capacity is not needed for a considerable amount of time during the course of a year. The capability of a particular power generation technology to consistently meet demand influences the function of the generation source in meeting load requirements. As discussed in Chapter 2, power generation plants or technologies are typically classified as baseload, intermediate, or peak demand plants. Some power generation technologies simply cannot currently be relied upon to provide baseload power. For example, if a utility's entire resource portfolio consisted of wind and solar power, energy could not be supplied when the sun is not shining and the wind is not blowing. While resources such as wind and solar have high availability factors (the percentage of time that a technology is capable of operating), they tend to have relatively low capacity factors (the ratio of the actual output of a plant or technology over the course of a year to the output the plant or technology would have produced if it operated at nameplate capacity during that year). The dilemma posed by these environmentally attractive technologies is an issue of reliability of service. Since reliability of service is a primary goal of an electric utility, the extent of investment in renewable technologies has been curtailed by the load-service function dilemma.

The load-service function dilemma creates the need to compare power generation options based upon their load service capabilities. However, future power generation investments should also consider that technological advancements in energy storage could dramatically reduce peak demand by shifting energy from low demand to peak demand periods of the day. By flattening load curves energy storage could make wind and solar technologies much more attractive for meeting load at all times of the day. Generally, geothermal, coal, hydropower, nuclear, and biomass plants can be operated as baseload plants because they provide cheap and reliable energy at all times other than during scheduled maintenance or unexpected outages. Baseload plants tend to have the lowest cost per unit of electricity because they are operated continuously at their maximum level of efficiency. Table 5.1 provides a comparison of baseload power generation technologies.

Table 5.1
Comparison of Baseload Power Generation Technologies

Technology	Overnight Cost (2006 $/kW)	Fuel Cost (2006 $/MWh)	Time to Construct (years)	Operating Life (years)	Fuel Depend-ability	Availability Factor (%)	Maturity
Pulverized coal	1,235-1,350 (2,270 with CO2 capture)	14.02	3-4	30-50	High	72-90	Mature
Fluidized bed (coal)	1,327-1,480	15.08	3-4	30	High	90	Develop-ing
IGCC (coal)	1,431-1,490 (1,920 with CO2 capture)	13.17	3-4	Not available	High	88	Newly operat-ional
Combined cycle (gas/oil)	500-620	50.37	3-5	25-30	Medium	90	Mature
Nuclear	1,510-1,849	4.89	9	40-60	Medium	90-97	Mature
Biomass	1,759-2,160	1.55-49.19	4	Not available	High	90	Mature
Geothermal	1,400-2,270	0	4	30	High	92	Mature
Fuel cells	4,015	Not available	3	Not available	Not available	Not available	Develop-ing

Source: The National Regulatory Research Institute, *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria*, pp. 18-19. Online. Available: http://nrri.org/pubs/electricity/07-03.pdf. Accessed: March 16, 2009.

Intermediate and peaking plants are operated at the discretion of utility dispatch controllers to meet rising energy demand over the course of the day, week, or year. Natural gas plants provide reliable service to meet rising demand, but wind, solar, and ocean energy provide much cleaner forms of energy. The marginal costs per kilowatt-hour for bringing a particular power generation plant or technology onto the grid are the primary determinant of which plant or unit is dispatched and at what time. However, when making a dispatch decision, a utility might want to consider the environmental benefits of using renewable technologies if the utility seeks to reduce its carbon footprint. Constraints on transmission and distribution capacity can limit the abilities of such technologies to meet demand at any given time. Table 5.2 compares intermediate and peak power generation technologies.

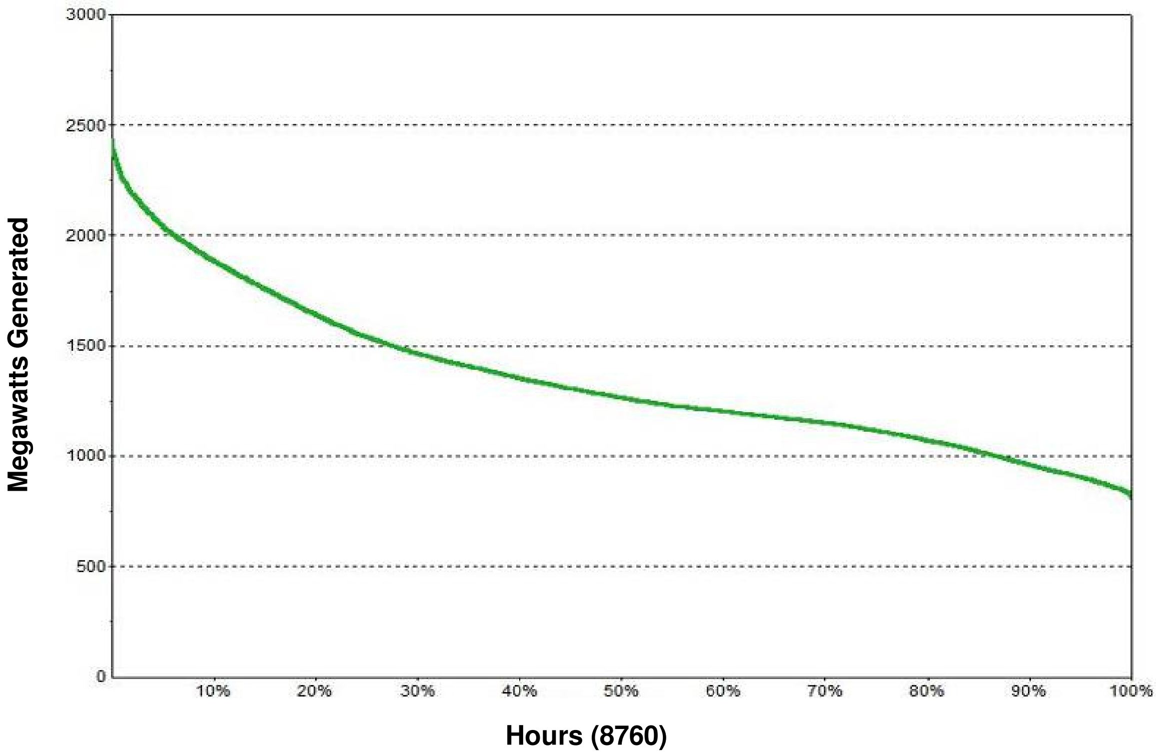
Table 5.2
Comparison of Intermediate and Peak Power Generation Technologies

Technology	Overnight Cost (2006 $/kW)	Fuel Cost (2006 $/MWh)	Time to Construct (years)	Operating Life (years)	Fuel Depend-ability	Availability Factor (%)	Maturity
Combined cycle (gas/oil)	500-620	50.37	3-5	25-30	Medium	90	Mature
Combustion gas	411-433	75.60	< 1	25-30	Medium	95	Mature
Wind	1,510-1,849	0	3	20	Low	98	Mature
Pumped-storage hydro	2,379	Existent cost of electricity	4-5	50-60	High	90-95	Mature
Photovoltaic	4,222	0	2	20-40	Low	99	Mature
Concentrated solar	2,745-3,410	0	3	30	Low	Not available	Mature
Barrage and ocean current	Not available	0	Not available	Not available	High	Not available	Develop-ing
Fuel cells	4,015	Not available	3	Not available	Not available	Not available	Develop-ing

Source: The National Regulatory Research Institute, *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria*, pp. 18-19. Online. Available: http://nrri.org/pubs/electricity/07-03.pdf. Accessed: March 16, 2009.

An electric utility's load profile is a graph of the variation in the electrical load over a certain period of time. For example, AE's load profile over the course of the day, week, and year can be used to indicate how much baseload power is required and how much energy is demanded from intermediate and peaking plants. A load duration curve can be used to illustrate how much power generating capacity is needed at any time over the course of a year. Figure 5.3 shows AE's load duration curve for 2006. AE's minimum electricity demand is approximately 1,000 MW at all times over the course of the year as compared to its maximum load requirement of about 2,400 MW.

Figure 5.3
Austin Energy's Load Duration Curve, 2006



Source: Class Presentation by Fred Yerba, Austin Energy, "Investing in Energy Efficiency: Assessing the Costs and Benefits," at the Lyndon B. Johnson School of Public Affairs, Austin, Texas, October 14, 2008, p. 12.

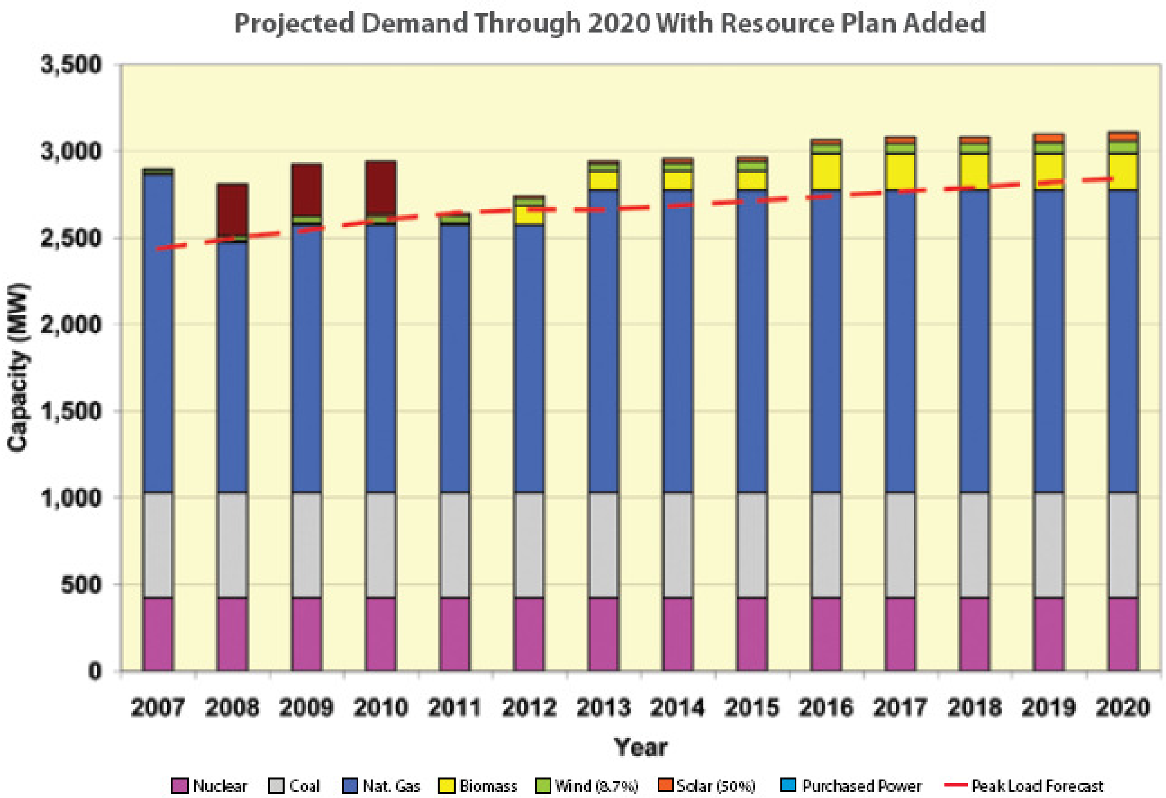
This report will consider future power generation mix scenarios to analyze how various combinations of baseload, intermediate, peaking plants, and technologies can meet future goals of carbon-neutrality and sustainability, and what the associated costs would be. Although certain power generation technologies emit no greenhouse gases (GHGs) they can be limited by resource availability and load service function capabilities. The load service function dilemma arguably presents the greatest hurdle to developing a sustainable utility. However, future technological advancements could change the load service function of certain power generation technologies and reshape the problem posed by a utility's load shapes.

Austin Energy's Proposed Energy Resource Plan

On July 24, 2008, Roger Duncan, AE's acting General Manager, presented to the Austin City Council on the utility's preliminary recommendations for meeting energy demand through 2020 while remaining under its proposed carbon dioxide (CO_2) cap and reduction plan (see Figure 5.4).[8] AE proposed adding 1,375 additional MW of generating capacity by 2020, with only 300 MW coming from fossil-fueled resources.[9]

Figure 5.4
Austin Energy Projected Supply and Demand Through 2020

(Assuming AE's Resource Plan is Implemented)



The 8.7 percent wind and 50 percent solar reflect the amount of capacity that can be counted on during peak demand hours.

Source: Austin Energy, *Austin Energy Resource Guide*, p. 16. Online. Available: http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf. Accessed: December 19, 2008.

100 MW of energy has already been approved with the addition of a gas combustion turbine at Sand Hill. 200 MW of additional power generation capacity at Sand Hill has been proposed for 2013 to assist in meeting increasing energy demand. This combined cycle expansion project would provide reliable energy with lower MW-hour carbon emissions than coal. AE is hoping to avoid the prospect of high natural gas prices by locking into a pre-pay fuel contract. AE is expecting this project to cost $160 million and take three years to complete. AE claims that $278 million in projected fuel savings can

occur through a pre-pay contract. It has been projected that CO_2 emissions will be reduced by 1.6 million metric tons through 2020 if this expansion project is completed.[10]

The city council approved a 100 MW biomass project on August 28, 2008.[11] This project is expected to be available by 2012 and provide 100 MW of baseload power generating capacity by burning wood waste.[12] Biomass has a power generating capacity similar to that of coal and nuclear and can provide reliable power during peak demand.[13] This power generating capacity has been contracted through a power purchase agreement (PPA) to provide 100 MW of energy per year over a 20-year time period at the total cost of $2.3 billion. This will increase AE's renewable resource portfolio to 18 percent of its total resource capacity by 2012. This agreement seeks to lock in fuel costs to provide a reliable energy source. Biomass can hedge against future natural gas price volatility and potential future costs of carbon. An additional 100 MW of purchased biomass power generating capacity has also been recommended for availability in 2016.[14]

AE's primary investment in new power generation capacity is an addition of 1,049 MW of generating capacity from wind facilities. AE proposed a gradual investment in solar energy to meet the ACPP goal of providing 100 MW of solar energy by 2020. AE has approved plans to purchase 30 MW of power from a solar facility to be constructed in Webberville, just outside of Austin. This facility would also have 5 MW of capacity to test emerging solar technologies. AE is planning to invest in covering rooftop space in Austin with photovoltaics through public and private partnerships. AE may also invest in a large-scale West Texas solar plant.[15]

Electric Grid of the Future

AE is poised to become one of the first utility companies in the United States to institute a fully integrated smart grid system. AE began building its smart grid system in 2003 and plans for the system to be fully online sometime in 2009 or 2010. Figure 5.5 compares the conventional electric grid with the capabilities of the smart grid. While many energy companies have been hesitant to invest in the costly infrastructure of a smart grid system, AE has determined that the potential savings for the utility company offset the costs of the system, negating the need to charge customers for implementing the new system.[16] Furthermore, the City of Austin could benefit economically by being the first to develop a large-scale smart grid system in the U.S. Companies developing smart grid technologies and renewable technologies that can be used for distributed power generation, particularly solar, could be drawn to Austin as a test market for their products.

The smart grid system allows for more sophisticated responses to supply and demand fluctuations and personal needs of customers through real-time monitoring. By creating a two-way communication mechanism both the utility and its consumers have greater control over power consumption. Smart grid is the union of an advanced distribution infrastructure, distributed energy resources, distributed energy storage, demand response, and the pricing, billing, and financial settlement of transactions between the utility and its customers, as well as among the customers themselves.

Figure 5.5
Conventional Electric Grid Versus a Smart Grid

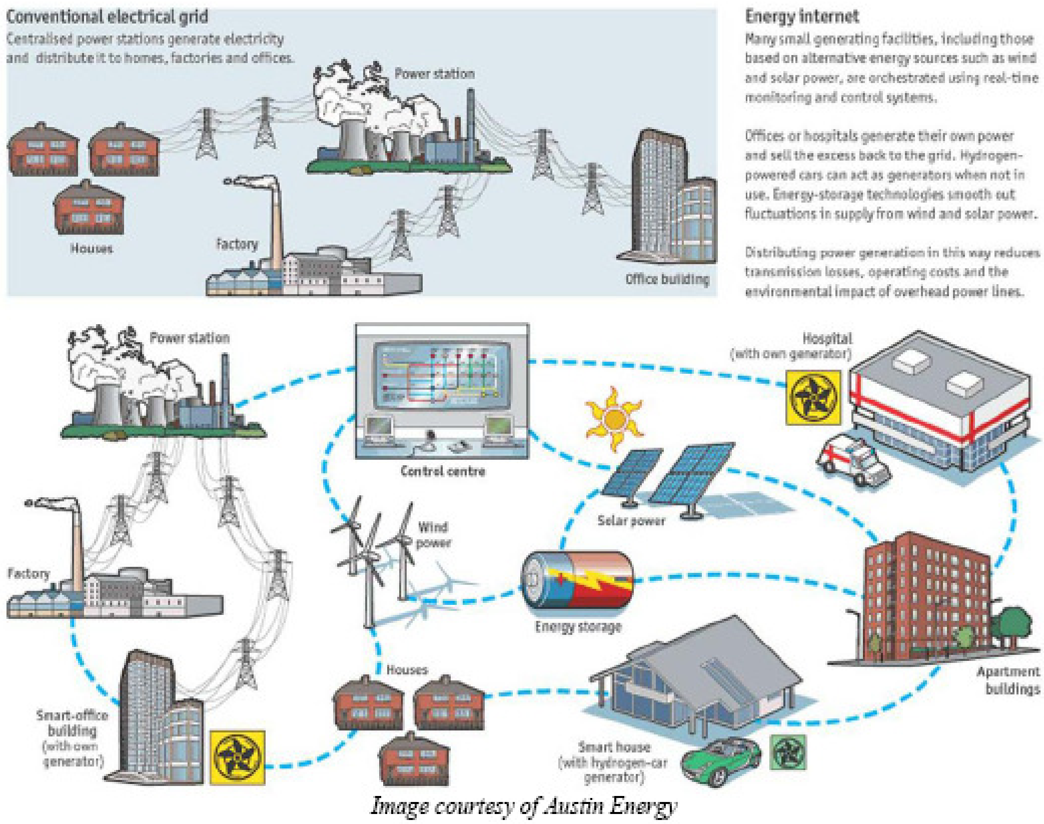


Figure 18: The future Smart Grid will include distributed power generation and interconnections.

Source: Austin Energy.

A smart grid can reduce electricity production and transmission capacity needs, lower fixed and variable costs, and help meet the growing demand for energy in an efficient and sustainable manner. Think of the smart grid as the nervous system of the electric utility: the brain, the communication platform, the wires, and the sensors that allow operators or automation to meet the needs of the system in real time. According to Andres Carvallo, AE's Chief Information Officer, "The smart grid is the seamless integration of an electric grid, a communications network, and the necessary software and hardware to monitor, control, and manage the generation, transmission, distribution, storage, and consumption of energy by any customer type."[17]

One of the most immediate benefits of the smart grid system is the ability to signal the cost of electricity (based upon supply and demand) in real-time and allow smart devices (including air-conditioning units, vehicles, diesel generators, refrigeration plants, and smart appliances) to operate only at times when electricity costs reach a certain level.

This provides a sophisticated mechanism for conserving energy and reducing demand when it is at its peak. Rebate programs will be needed as an incentive for customers to purchase smart appliances. The hope is that this will, in turn, increase technological developments that utilize smart grid capabilities. The rate at which other utilities convert their systems will be a major factor in determining the timeframe in which smart appliance technology is developed.

The potential to promote adoption of local renewable energy through distributed generation is another key characteristic of the smart grid. Small-scale renewable energy technologies, primarily photovoltaic solar energy modules, can connect to the grid, allowing consumers to sell energy back to the grid when personal supply exceeds consumption. As solar energy tends to be highest during peak demand this could help to reduce peak demand and provide an incentive for consumers to invest in renewable technologies that reduce GHG emissions.

Demand management systems implemented over a smart grid could automatically reduce a customer's power consumption to prevent outages and reduce peak demand. Smart grid technology also allows AE to restructure its billing system using variable pricing schemes. Under a variable pricing scheme electricity rates could be higher when demand is highest (for more detail on the potential impacts of price-based demand response programs see Chapter 3). This should decrease peak demand and contribute to meeting future energy conservation goals. Although variable pricing could discourage energy usage during peak demand it is not known whether variable pricing would be approved by state regulators. Variable pricing is not just an efficiency issue, as there are social equity concerns as well. For example, should low-income, disabled, or elderly consumers (who cannot easily afford upgrading the energy efficiency of their residences or whom spend more time at their residence during the peak hours) be exempt from such pricing mechanisms?

One attraction of a smart grid system is the so-called "vehicle-to-grid" system. The idea behind the vehicle-to-grid system is that plug-in hybrid vehicles could serve as temporary storage devices to shift energy from off-peak demand hours to peak-demand hours. AE is one of the main proponents of this concept and is already beginning to test its potential. In January 2008, AE announced that it would partner with V2Green's Connectivity Module to test its automation equipment with two plug-in hybrids.[18] The idea behind this technology is that the vehicle-to-grid system can control the timing and extent to which the vehicles are charged and when energy is sold back onto the grid. By charging a vehicle at night, when demand is low, and selling back energy when the vehicle is plugged in during the day, when demand is at its peak, plug-in customers can make money from the electricity produced while the utility can effectively shift demand away from peak hours to off-peak periods. This process would effectively store energy for the utility to reduce peak demand. Vehicle to grid technology could stabilize electrical grids by consuming power when electricity is abundant and selling electricity back to the grid when electricity is in highest demand.

The amount of emissions related to a plug-in hybrid is dependent upon the utility's power generation mix or the power generation technology linked to a particular plug-in vehicle. If solar power were used to recharge a vehicle, emissions attributed to the vehicle would be much lower than if the energy were attributed to the utility's overall power generation mix. Furthermore, wind energy tends to be abundant during the early morning hours (2 to 6 am) when supply could be greater than demand. Prices for such energy could be very cheap for plug-in customers and provide clean energy for the powering of their vehicles. If this energy is sold back onto the grid later clean energy will have been stored for the electric utility by the vehicle's battery storage. However, plug-in hybrids need to be able to penetrate the market for this type of technology to make a sizeable difference. Toyota is set to bring the first plug-in hybrid into the market in 2009 and other manufacturers are in the development stages of plug-in vehicles as well. However, prices of plug-in hybrids will most likely be high and subsidies may be needed as an incentive to purchase such vehicles. Incentives could be provided by the government or by the utility company through agreements that the customer will provide a certain amount of electricity back to the utility during certain hours of the day when demand is the highest.

A smart grid is an enabling technology framework for AE to move from its current state of a static, centrally-controlled, one-way utility to a distributed, self-aware, two-way, dynamic and sustainable energy system. AE is poised to implement a smart grid because of its vertically-integrated structure and relative regulatory freedom as a municipal utility that has chosen not to participate in retail competition.

Investing in Transmission and Distribution Infrastructure

The transmission and distribution infrastructure assets owned and managed by AE are aging and provide an opportunity for new technology installation through attrition. AE could take advantage of its low cost-of-capital to invest in promising new breakthroughs in conductor technologies and methodologies (such as carbon nano-tubes, direct-current microgrids, and distributed-energy minigrids) that maximize fuel efficiency and minimize energy losses in the wires. An advanced transmission and distribution infrastructure with increased sensing, monitoring, and control capabilities via advanced metering could enhance the development of distributed and renewable power generation, energy storage, demand response, and electric transmission solutions.

Transmission Infrastructure

Advanced metering infrastructure (AMI) is a key to the smart grid because the meters are the communication link between the consumer and the utility. Meters that can record consumption in the same interval as market prices and utility costs will allow a better alignment of consumption and energy cost. Although advanced metering unit costs have been high, new technologies are reducing the cost to implement AMI.[19]

Advanced meters (or smart meters) differ from conventional meters because they are able to record consumption in small time intervals, such as hours, and have communications capabilities to transmit consumption information in real time and on-demand. Table 5.3 lists some features and benefits of AMI. AE predicts they will have 270,000 new smart meters installed by June 2009.[20] That would mean a 50 percent penetration rate of advanced metering (100 percent of their residential rate class) compared to an industry average of about 6 percent.[21] Central to the smart meter infrastructure is the information technology needed to implement an enterprise architecture that integrates data management throughout the company and allows operators to manage an "information grid" in the same way that the utility operates the power grid. The increase in data sophistication provided by the meter data management system could enable new demand-side applications that contribute to AE's goal of 700 new MW of peak of demand savings by 2020.[22]

Table 5.3
Advanced Metering Infrastructure Functions and Benefits

Function	Benefit
15 minute interval data collection	Dynamic pricing, customer reporting
Remote connect/disconnect	Lower utility cost
Remote software upgrade	Lower utility cost, more timely upgrades
Demand response dispatch	Peak demand reduction, energy conservation
Outage notification	Lower utility cost, increased customer service
Remote meter reading	Lower utility cost
Remote power quality reading (voltage, frequency)	Lower utility cost, increased customer service
Memory to support longer reading cycle	Lower utility cost, increased customer service
Prepay metering	Lower utility cost, increased customer service
Integration with meter-data management system	Lower utility cost, increased customer service
Integration with home-area networks	Peak demand reduction, energy conservation

Source: Federal Energy Regulatory Commission, *2007 Assessment of Demand Response and Advanced Metering* (staff report, September 2007). Online. Available: http://www.ferc.gov/industries/electric/indus-act/demand-response.asp. Accessed: November 3, 2008.

A smart grid need not be limited to the residential meter. It can include the interconnection and communication with various home appliances to automate demand response capacity without loss of convenience to the consumer. Critical to that goal are appliance controllers and thermostats that can communicate with the meter and/or directly with the utility to cycle and respond to price signals and events. Appliance manufacturers such as Whirlpool are investigating consumer reactions to advanced technology like automatic appliance controls and in-home energy use displays. In a 2006 study Whirlpool found that consumers do not want to monitor their energy use continuously and consider time-of-use pricing negatively if it forces a noticeable change in lifestyle.[23] Whirlpool concluded that consumers must experience the demand response function effortlessly and without a loss of convenience to perceive a net benefit. The study did not address how the utility would receive the desired settings from the consumer, or remotely control the appliances.[24] Communication between the utility and the end-use loads remains a hurdle, with several competing methods and technologies including wireless networks, broadband over power lines, and fiber optics. Low-cost, low-energy, low-bandwidth wireless networking is emerging as the technology of choice, but issues remain regarding standardization and protocols. It is clear that the seamless flow of data between producer and user is the key to the full utilization of the demand response capabilities of the smart grid, but that data must first be collected and transmitted.

A home area network (HAN) is a wireless network managed by a network controller device that can integrate and control the electronic devices in a home. The HAN relies on the Institute of Electric and Electronics Engineers 802.14.5 standard to communicate among components. Leveraging current networking technologies, a HAN can gather data from as many as 65,000 remote devices at once. The HAN is the communications bridge between the AMI and the end-use appliances. A communications protocol known as ZigBee is being developed by a group of AMI vendors, along with common applications and functions for the network. Several installations of ZigBee-capable smart meters are being installed in the U.S.[25]

Tapping into Wind Energy

Advancements in wind energy technologies over the past several decades have made wind energy cost competitive with traditional power generation technologies. As of early 2008, Texas holds a wind power generating capacity of 4,356.35 MW.[26] This accounts for 25 percent of all wind power generation in the U.S., far exceeding any other state.[27] A further 1,238.28 MW of wind power capacity is currently under development.[28] With a potential capacity of 136,100 MW, Texas has the second highest potential capacity in the U.S.[29] The biggest hurdle for expanding wind energy capacity for AE and around the state is the building of new transmission lines.

While it only takes about a year to build a wind farm it can take up to five years to build transmission lines.[30] Therefore, a paradox occurs in which wind power developers do not want to build power generators where transmission lines do not already exist and utility companies do not want to build transmission lines prior to power generators being built. Texas Senate Bill 20, passed in 2005, attempted to promote proactive development of transmission lines in areas that would lead to the greatest generating capacity. The Electric Reliability Council of Texas (ERCOT), in charge of operating the state's electric grid, was identified to target Competitive Renewable Energy Zones in order to develop a transmission infrastructure that facilitates the use of wind energy and other renewable energy sources. In October 2006, Governor Rick Perry announced the commitment of $10 billion from private companies to increase wind power generating capacity in the state by 7,000 MW, contingent on the approval by the Public Utility Commission (PUC) of additional construction of transmission lines to windy areas of the state.[31] In July 2007, the PUC approved construction of additional transmission lines that could deliver 10,000 more MW of renewable power by 2012.[32] However, these commitments did not focus on the transmission of power to the largest cities in the state where the energy demand is highest.

This problem may have been recently resolved when the PUC approved a multi-billion dollar investment plan for transmission lines to tap into West Texas wind energy. This plan focuses on bringing renewable energy to the most-densely populated cities of Texas, including Austin. The PUC identified areas in Texas with the highest potential for expanded wind power generation facilities and further ordered ERCOT to design transmission routes to move between 5,100 MW to 17,500 MW of energy to the state's largest cities.[33] Four scenarios were proposed ranging from 12,053 MW to 24,859 MW of transmission lines installed at the cost of between $2.95 and $9 billion.[34] Studies showed that building new transmission lines for wind power could lead to $100 million in savings each year due to increased efficiencies.[35] Furthermore, each $1 billion of investment in transmission lines would only increase a residential bill by an estimated 73 to 85 cents per month.[36]

In July 2008, the PUC approved construction of power lines that could transmit 18,456 MW of energy to metropolitan regions within the state of Texas at an estimated construction cost of $4.93 billion. This is expected to raise residential electric bills by about $4 a month and the new lines are expected to be completed within 4 to 5 years.[37] This commitment by the PUC to construct new transmission lines greatly enhances the ability for AE to make large investments in West Texas wind energy. Furthermore, new transmission lines should also make investments in large-scale solar plants more attractive as most of the best locations for solar energy in Texas are in West Texas as well.

Distribution Infrastructure

Several new opportunities exist to improve the distribution grid and incorporate demand response, distributed generation, and distributed reliability services. The wires that "distribute" energy are lower voltage, have higher line losses, and require more maintenance than their transmission counterparts. The distribution system includes the substations that transform the high-voltage electricity into lower, more manageable voltages that can be carried safely on smaller "feeder wires." The distribution network is a trunk and branch system, with limited looping and almost no ability to isolate or "island" specific users. Direct current microgrids and distributed energy minigrids offer opportunities for AE to enhance system reliability while improving service to major power users.

Direct current (DC) has benefits at low voltages as well as high, and is a good choice for incorporating small-scale renewable power generation. B ecause DC is not as vulnerable to power quality issues as alternating current (AC), it can be used in small isolated pockets to interconnect similar users as a group. For example, a DC grid could link up to the AC grid at substations with inverters. Because many digital devices and renewable generators actually run on DC power, building DC microgrids would remove an unnecessary layer of transformation and inversion.[38]

Minigrids are self-contained combinations of load control, distributed generation, advanced metering, and electricity management software that work together to manage the electricity needs of a localized group of customers with complimentary demand. A typical minigrid may contain one or more combined heating, cooling, and electricity generation plants, several types of small-scale renewable generators, large industrial customers with interruptible load, and a mix of residential and commercial customers with non-coincident load peaks and the ability to store electricity or to defer use until the system has sufficient capacity. Central to the development and operation of the minigrid is the ability for all components in the system to communicate with one another. AE is attempting to develop a minigrid at the former airport, centered around the Mueller Energy Center and the Dell Children's Hospital. The combined heat and power facility that serves the hospital electric load also sells steam recovered from the turbine exhaust and uses that steam to chill water for the air conditioning via an absorption chiller. The demand for waste products doubles the fuel efficiency of the turbine alone, and provides the foundation for additional steam and chilled water customers at the site.[39]

One type of minigrid called a "power park" should be attractive to AE because it is designed around the high reliability needs of high-tech industry. Power parks are basically interconnected minigrids with reliability as the core goal. Many data centers and semi-conductor manufacturing plants require completely uninterruptible load service. Microgrids can meet their needs by offering storage and power quality buffers like flywheels, battery banks, and ultracapacitors. Distributed generation would often be used as the primary power source with grid backup in place.[40]

Distributed Generation

One of the greatest benefits of an enhanced electrical power distribution system through the smart grid is the capability for interacting with local distributed generation. Distributed generation is the creation of electricity from small local power generation units. Historically, electricity has been generated from large, centralized power plants to provide cheap, reliable power. Coal-fired, natural gas-fired, nuclear, and hydroelectric plants have typically been constructed away from cities due to local effects on air quality. Electricity then has to be transmitted over distances where transmission losses occur. Distributed generation has the benefit of low transmission losses because the power generation technology is tapped directly into the electric grid. However, some of these technologies have relatively low energy efficiencies and high production costs, preventing many of these technologies from being cost competitive with large-scale power plants. AE's smart grid system should help to alleviate the high costs of installing small-scale residential and commercial power generation technologies by enabling customers to sell energy back to the utility during peak demand. This will enable customers to sell energy that they are not using during peak demand when the price of electricity is highest. They could then use energy during the off-peak hours at much lower cost, further reducing electric bills to increase the economic appeal of small-scale, renewable generation technologies.

One common form of distributed generation currently is solar photovoltaic panels on rooftops. With government subsidies and rebates provided by AE, solar rooftop panels continue to decrease in cost. As solar panel power generation technology continues to advance, increasing its efficiency and lowering its cost to produce, solar panels themselves will become more appealing for customers. If solar panel installations continue to increase in Austin the scale of operations could lower the unit cost for installation and maintenance. Having one of the first smart grid systems in the U.S., Austin has the potential to attract solar companies both from the investment and the production and installation sides.

Another available small-scale distributed generation technology is small-scale wind turbines. These turbines take up more space than solar panels, but could provide a competitive form of energy in windy areas of the city. Wind energy can complement solar energy because wind tends to be highest during the late night or early morning hours (2 to 6 am). Smart grid technology reduces the necessity of battery storage for excess power generation. It should be noted that this does not mean that these power generation technologies can store energy, it simply means that the smart grid can allow for load shifting that would conserve energy by reducing demand during peak hours and shifting load away from GHG emitting power generation sources.

Another emerging distributed generation technology is distributed cogeneration sources which tend to use natural gas burned in microturbines or reciprocating engines to turn generators. Hot exhaust can then be used for space or water heating or can drive an absorptive chiller for air condition. Cogeneration sources offer a low pollution alternative to large-scale facilities, but still face some reliability issues. Cogeneration facilities are appealing because most large buildings already burn fuels and cogeneration can extract greater value from the fuel. Some larger facilities use combined cycle power generation, such as the Mueller Energy Center in Austin. These plants have the highest known thermal efficiencies, in principal capable of exceeding 85 percent and in one large scale test exceeding 75 percent on a regular basis. Cogeneration facilities are most appealing for large facilities or buildings.

As discussed earlier, smart grid technology could also help facilitate movement towards the use of plug-in-hybrid vehicles to shift loads. Similar to methods of load shifting for small-scale power generation technologies like solar panels and small-scale wind turbines, vehicle-to-grid technology will allow customers to sell electricity during high-demand hours when prices for electricity are higher, and consume electricity when it is cheapest.

Carbon Legislation and Regulatory Issues

Regulatory responses to changing societal demands related to energy usage could spur energy market shifts that make renewable technologies and new emission reduction technologies more cost-competitive. With several different bills currently appearing in the U.S. Congress related to GHG emissions and climate change it appears highly likely that some form of carbon legislation will be passed in the near future. Most likely coming in the form of a carbon cap-and-trade system, a future price of carbon would be generated through market mechanisms. Charges to emit CO_2 could both stimulate the economy of renewable technologies as a competitive alternative to traditional power generation technologies as well as increase the appeal of nuclear energy and carbon capture and storage. Predicting when such legislation will be passed and what effective price this would put on carbon is uncertain. Further regulatory responses could also increase the appeal of less traditional electric generation technologies. Renewable portfolio standards in Texas continue to increase the amount of energy within the state that must be generated by renewable resources. More drastic regulatory actions could occur at any point, creating the potential for an uncertain energy market for the future AE.

Carbon legislation could affect AE's investment decisions because individual utilities are less likely to consume fossil fuels that emit GHGs when it is no longer convenient or cheap to do so. This concern could be addressed in a few different ways: using a so-called "cap and trade" mechanism that issues permits to limit GHG emissions to a specific quantity and allows trading of such permits; placing a tax on GHG emissions (carbon tax); or enacting regulations that limit emissions or restrict energy consumption.[41]

Under a cap and trade mechanism, the government sets a maximum limit, or cap, on an entity's GHG emissions. This entity is then issued an "emissions permit" for every ton of CO_2 equivalent that it releases into the atmosphere. Entities that emit less than their allowance can sell their extra permits to entities that are not able to reduce their emissions to meet their cap. This system provides an overall reduction in GHG emissions, rewards the most efficient entities, and ensures that the cap can be met at the lowest possible cost to the economy.

A carbon tax is a tax on the carbon content of fossil fuels, such as a tax on the GHGs emitted from burning fossil fuels. Some economists argue that a carbon tax would be the most efficient way to reduce emissions by using price signals to change behavior.[42] Such a tax could generate revenues that could be used to lower other taxes or be invested in energy efficiency, a concept called a "green tax shift." A green tax shift taxes any entity that emits GHGs, rather than taxing good behavior.

Regulatory restrictions on emissions could be imposed on different sectors of the economy. Examples of these restrictions include: fuel economy standards for cars, emissions standards for power plants, building energy codes, and renewable energy portfolio standards. These restrictions or requirements can assist in lowering GHG emissions, but they do not offer incentives for companies to make reductions beyond regulatory requirements.

Both the PUC and ERCOT have some regulatory authority over AE's facilities and activities. The PUC regulates all electric utilities in Texas, provides oversight to ERCOT, and adopts and enforces rules related to retail electric competition. PUC has jurisdiction over rates and quality of service of transmission and distribution utilities, sets wholesale transmission rates, and oversees wholesale and retail competitive markets. As a municipally-owned utility, AE is not subject to the PUC's retail rate and service quality jurisdiction, but is subject to wholesale transmission rate jurisdiction and wholesale power generation market oversight. Austin City Council sets the budget and electric rates for AE.

ERCOT operates the electric grid in Texas that serves about 75 percent of the state, overseeing 70,000 MWs of power generation capacity and 37,000 miles of transmission lines that make up the statewide electric grid.[43] As a member of ERCOT, AE pays 4 percent of ERCOT's costs to operate the state's power grid, as it represents 4 percent of the statewide power generation load.[44] ERCOT also facilitates the operation of the retail competitive market by managing transmission congestion and ensuring all power generators have equal access to the electric grid. Although AE does not participate in retail deregulation, it does participate in the ERCOT wholesale market. AE conducts the following types of transactions with ERCOT: sale of electricity; purchase of electricity; sale of ancillary services (e.g. reserve capacity, load following and frequency control); submission of transactions negotiated with other entities for approval; and ERCOT-required transactions, when necessary, to maintain system reliability or to relieve transmission congestion.[45]

In September 2003, the PUC ordered ERCOT to transition from a zonal to a nodal market.[46] The purpose of the switch was to improve price signals, improve dispatch efficiency, and assign congestion costs to market participants responsible for the congestion.[47] Although the transition was originally scheduled for completion in December 2008, ERCOT announced in May 2008 that it would not meet the target date.[48] The nodal market grid is expected to consist of more than 4,000 nodes, replacing the current congestion management zones of the zonal market.[49] Although the nodal market will not affect all of ERCOT's current processes and systems, several major components will be added: day-ahead markets; reliability unit commitment; real-time or security constrained economic dispatch; and congestion revenue rights.[50] Day-ahead markets will provide a centralized market for parties to conduct power transactions for delivery the next day.[51] Reliability unit commitment is a system that can be used to ensure that sufficient power generation capacity is being provided, while also leveraging offline resources to relieve load and transmission congestion.[52] Security constrained economic dispatch will be used to determine economical load dispatch across the grid by calculating actual shift factors.[53] A congestion revenue right is a financial instrument that ERCOT will be auctioning monthly and annually, where revenues will be returned to loads.[54]

The switch to a nodal market will affect AE's future resource planning, even though only 5 to 10 percent of AE's power sources are currently traded through the ERCOT market.[55] Under the nodal market, all power will be bid into and purchased out of the market. Under the zonal market, AE contracts to buy or sell power from other parties through bilateral contracts. With the switch to the nodal market, these bilateral true supply contracts will become ERCOT instruments that provide guaranteed prices.[56] Besides a significant change in the way power transactions are completed, AE will have to ensure the infrastructure is able to perform in the nodal market.[57] Another consideration relevant to the scope of this report is that the nodal market is based on the operating idea of reliability and cost, rather than environmental responsibility.

Offsetting Carbon Emissions

An increasingly popular method of reducing an entity's GHG emissions is to purchase carbon offsets. If the federal government is going to charge utilities for emitting CO_2, AE will want to analyze costs to purchase offsets for their remaining CO_2 emissions. A GHG offset or carbon credit is defined as a "tradable instrument representing a verified reduction of GHG emissions."[58] In other words, a carbon offset is a financial instrument that allows entities to receive credit for purchases of activities that offset GHG emissions. Carbon offsets are measured in metric tons of carbon dioxide-equivalent (Mt CO_2e). The ability to purchase a carbon credit to offset the equivalent of one metric ton of CO_2 is a method that some organizations or nations are using or may use for reducing an entity's or country's carbon footprint.

The global market for carbon offset trading is divided into two segments: a regulatory or compliance market and a voluntary carbon market (VTC). The compliance market is a cap-and-trade market that allows companies to buy carbon offsets to meet caps set on the total amount of CO_2 they are allowed to release. The compliance market cap-and-trade market evolved out of the ratification of the Kyoto Protocol (Kyoto). One option instituted by the United Nations under Kyoto to achieve emission reduction goals is the Clean Development Mechanism (CDM). CDM offers carbon offsets or Certified Emissions Reductions to developed countries for sponsoring projects in developing countries. Although the U.S. did not ratify Kyoto, entities in the U.S. are able to purchase renewable energy credits on the voluntary market. CDM is the model which most VTC market registries seek to emulate. The VTC market offers entities the opportunity to purchase offsets to balance GHG emissions. The VTC market can be broken down further into two segments; the Chicago Climate Exchange (CCX) and the Over-the-Counter (OTC) market. CCX is a voluntary cap and trade system, whereas the OTC market consists of a highly variable set of transactions not driven by an emissions cap.

Currently there is no universally accepted set of standards for carbon offsets traded on the VTC market. There are however four characteristics which are shared by all of the standards: requiring offsets to be permanent, additional, independently verified, and enforceable. GHG emission reductions must be permanent and not be reversible. Projects that pose a risk of reversibility of reductions must provide safeguards to ensure that the risk is minimized and that the reductions will be replaced or compensated. GHG emissions reductions must go beyond what an institution had planned or the expected emissions of a business-as-usual scenario had the project not occurred. Any GHG emission reduction project must be verified by an independent, accredited, third-party entity. Projects must disclose real information about GHG emissions and be measurable using recognized tools. Finally, any GHG reduction project must be enforceable or, in other words, backed by legally recognized contracts or agreements that define their creation, provide for transparency, and ensure exclusive ownership.[59]

In the U.S. several standards (such as those of the CCX, the Gold Standard, the Voluntary Carbon Standard, and the California Climate Action Registry) have emerged for certifying carbon offset projects on the voluntary market. Each protocol has its own methodology for calculating GHG reductions. As a result, an organization seeking an offset would find it difficult to compare projects and to gauge if one credit purchased actually equals a reduction of one metric ton of CO_2e or if one project is better than another based on some performance measure.

The CCX is a voluntary GHG cap and trade system that allows members to trade offsets from qualifying emission reduction projects. In addition to being a standard, CCX is also a registry for recording emissions, holdings, and transfers on the CCX electronic trading platform.

In the OTC market, the leading standards are the Gold Standard and the Voluntary Carbon Standard (VCS). The Gold Standard is a labeling standard which certifies renewable energy and energy efficiency projects that offer sustainable development benefits to the local community. Emission reduction projects are subject to third party validation and verification. Gold Standard credits thus far have been slightly more expensive than projects from other standards.[60] VCS has emerged as the leading standard in the voluntary market. It validates and certifies emission reduction projects worldwide. VCS was founded by the Climate Group, the International Emissions Trading Association (IETA), the World Business Council for Sustainable Development, and the World Economic Forum. VCS is a global standard based on benchmarks set by the International Standards Organization (ISO) and Greenhouse Gas Protocol. VCS works with registries, like the Gold Standard and the California Climate Action Registry (CCAR) to track and record emission reductions.

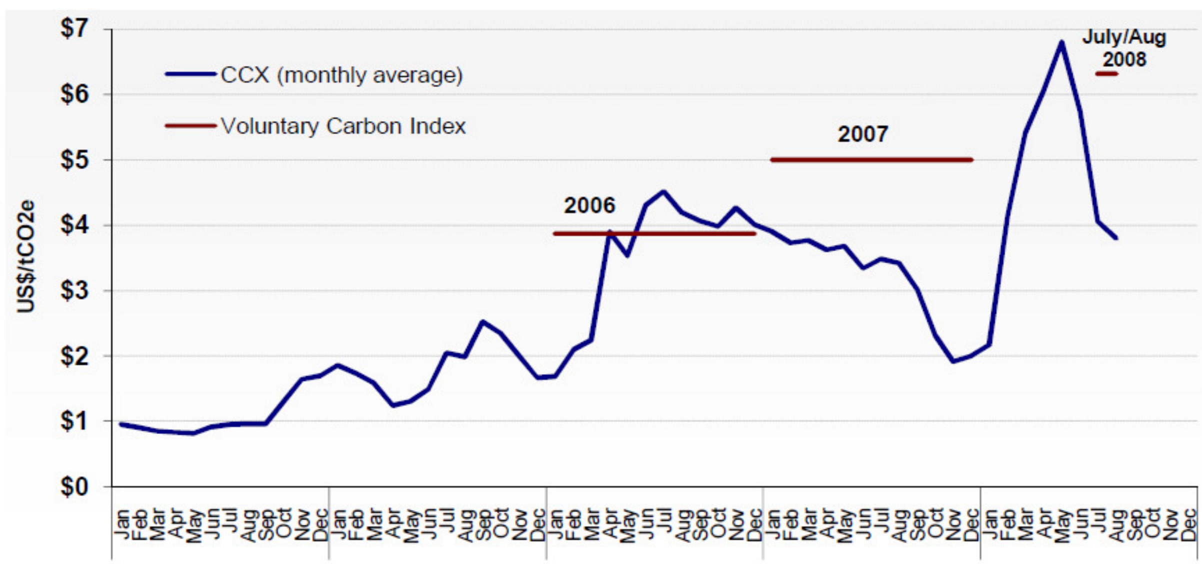
CCAR is a non-profit organization that certifies and registers projects associated with GHG reductions. In 2008, VCS approved CCAR as its first recognized, independent GHG offset program. VCS approval of CCAR is a step towards establishment of global carbon offset standards and opens up the U.S. market to international trading.[61]

There is a need for the development of universally recognized standards in order to ensure credibility, accuracy, and uniformity in evaluation. In the U.S. there are over 600 organizations that develop, market, and sell carbon offsets in 40 states. Emission reduction projects vary from reduction programs to changes in energy production and use. Programs that reduce the amount of GHGs in the atmosphere include methane gas capture and storage, the destruction of agricultural byproducts or industrial pollutants, reforestation, and geological sequestration. Programs that change energy practices and use include fuel switching, power plant upgrades, and renewable energy projects, like solar, wind, biomass, and hydropower. In 2007, almost half of the offsets were generated from projects that reduced the emission of methane. A third of the supply of carbon offsets came from projects in Texas and Virginia.[62]

Pricing of carbon credits varies widely by month, project, standard, and market. The most readily available information on pricing regarding the VTC market is from New Carbon Finance (NCF) and the Chicago Carbon Exchange (CCX). In September 2008, NCF, the carbon market analysis division of New Energy Finance, launched the Voluntary Carbon Index to track intra-annual price developments in the OTC market and to increase transparency in the market.[63] CCX emissions, holdings, and transfers are measured in standardized emission units called Carbon Financial Instruments which are equal to 100 Mt CO_2e.[64] According to data from NCF, the average price of voluntary carbon credits rose 26 percent in the first quarter of 2008 to \$6.3 per Mt CO_2e. Figure 5.6 illustrates the fluctuation in price of voluntary carbon credits sold on the OTC and CCX markets.

Figure 5.6
Carbon Offset Prices, 2004-2008

Historical Prices for NCF's Voluntary Carbon Index (OTC market) and the Chicago Climate Exchange



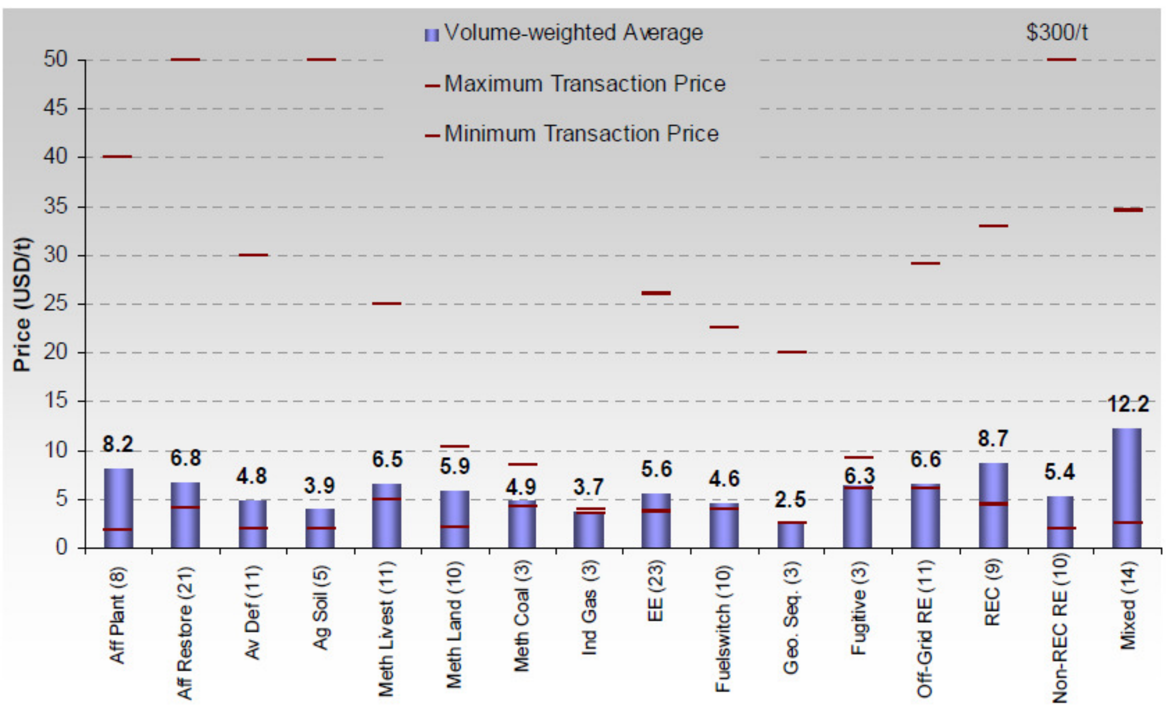
Notes: prices shown are the average closing prices (averaged across vintages) for the quarter and volumes are total traded CFIs in metric tonnes of CO_2e. Source: New Carbon Finance based on CCX data

Source: New Carbon Finance, *New Carbon Finance's Voluntary Carbon Index (VCI)*, First Edition. Online. Available: http://www.newcarbonfinance.com/?p=about&i=freereports. Accessed: November 2, 2008.

Since 2006, the demand for carbon offsets has increased. Carbon offsets can provide a cheap alternative for reducing an entity's emissions without investing in new clean energy power generation technologies or replacing existing power generation sources with cleaner energy sources. In 2006, 23.7 million Mt CO_2e were traded on the VTC market in the U.S., on the order of one-tenth of a percent of the 1.8 billion Mt CO_2e traded in the European Union market.[65] In 2007, 65 million Mt CO_2e were traded on the VTC market.[66]

Of the registered carbon offset projects, industrial gas and geological sequestration projects offered the least expensive credits in 2007.[67] Both projects are high-volume, low cost means of offsetting carbon emissions. Since industrial gas produces high levels of GHG emissions, emission reduction projects are relatively cost effective. These projects, however, may be less desirable because many consumers prefer to spend their money on "green" projects, such as renewable energy. Thus far in 2008, the most voluntary carbon credits traded on the VTC market in terms of number of offsets and pricing have been for methane projects. Like industrial gas sequestration, methane projects are relatively inexpensive to develop and prevent large volumes of GHG emissions.[68] Figure 5.7 shows the variations in price of carbon offset by project type in 2007.

Figure 5.7
Carbon Offset Voluntary Market Prices



Source: Katherine Hamilton, et al., *Forging a Frontier: State of the Voluntary Carbon Markets 2008* (New Your, NY: Ecosystem Marketplace & New Carbon Finance, May 2008), p. 39.

If AE should choose to purchase carbon offsets in order to meet carbon reduction goals it would want to be sure that the credits obtained are certified and valid. As AE is already a member of CCAR and since CCAR is now approved by VCS (currently the leading standard), utilizing CCAR's registry to seek out verified projects would be a feasible option. As a large number of carbon offsets are being produced in Texas, AE could seek out certified projects in the region. If the ultimate goal is not just to achieve a sustainable AE but more broadly a sustainable City of Austin, AE could consider regionally-based

GHG emission reduction projects within the Austin or Central Texas region. Texas is the second largest agricultural state in the nation, providing a basis for a wide variety of methane capture projects and agriculture soil carbon projects, such as prairie restoration or conservation tillage.

Another option is for AE to adopt a customer-based emission reduction program similar to ClimateSmart™. ClimateSmart™ is a voluntary program of the California Public Utilities Commission that enables customers to neutralize the GHG emissions associated with their energy use by purchase of carbon offsets. Customers who enroll in the ClimateSmart™ program pay a separate amount on their monthly utility bill which is determined by the number of pounds of GHG emissions associated with the customer's electricity usage.[69]

Conclusions

One of the greatest challenges for AE in planning its future power generation mix is considering uncertainty. Uncertainties exist in forecasting future demand and in making financially sound investment decisions. Load forecasting is based upon predictions of the future. Therefore, it is possible that there will be much more or much less demand for energy than is currently predicted. However, forecasts tend to be fairly accurate and even the peak demand forecast for 2020 should provide a reasonable prediction of energy demand. Unforeseeable circumstances that could affect future load forecasting would include local, regional, and national economic recessions or booms, major advances in appliance technologies, and shifts towards new technologies (such as electric vehicles) that would increase energy demand.

Furthermore, there are major uncertainties that exist with regard to which power generation options will actually have the lowest costs in the future. Investments in power generation units with long projected lifespans create financial commitments to these technologies for several decades. While some technologies may be low-cost options in 2009, technological improvements and increased efficiency of renewable technologies, increased fuel prices, and improvements to the electric grid could lead to renewable technologies becoming the most economically attractive investments by 2020. As the use of renewable technologies continues to expand and further investments are made in research and development, it is highly likely that increases in efficiency will be reached through technological improvements, and economies of scale will be reached through increased production and usage of these technologies.

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Chapter 6. Comparing Future Power Generation Options

As a municipal electric utility, Austin Energy makes investment decisions to deliver power reliably and at a low cost in response to consumer energy demands. AE has developed renewable energy and carbon reduction goals that could lead to the replacement of current power generation facilities with cleaner forms of energy. As it can take many years to site, gain regulatory approval for, and construct new power generation facilities, decisions on future sources of energy will reflect projections of future costs and capabilities of new power generation technologies, as well as uncertainties that exist in the electric utility and energy sectors. Investing in new power generation technologies and facilities benefits a utility by allowing it to control its own assets, control future costs, and meet regulatory and societal demands. For 30 years AE has invested in demand-side management (DSM) programs to constrain increases in demand. Despite such efforts, expected future demand increases must still be met with new power generation units. By developing a strategy for determining its future power generation mix or energy resource portfolio, AE and its customers can make informed decisions based on the benefits and consequences that these decisions could have for the future of the utility and the community.

AE's objectives include its financial stability as a utility, providing low-cost energy to its customers, lowering emissions to protect the environment, meeting regulatory requirements, and satisfying political and public demands. Any one power generation technology may satisfy some of these objectives at the expense of other objectives. For example, while coal-fired power plants provide relatively inexpensive and reliable energy at most times, this comes at the cost of higher rates of greenhouse gas emissions and other pollutants per kilowatt-hour (kWh) of energy produced. While wind energy may be cost competitive with coal-fueled energy and does not emit pollutants, it provides a source of energy that varies with the wind and is subject to transmission constraints, creating reliability of service concerns. A so-called "portfolio" approach allows decision-makers to weigh the tradeoffs of different objectives and determine what set of options best achieves AE's multiple objectives,[1] and identify ways in which power generation technologies can complement each other within a power generation mix.[2]

Table 6.1 compares several power generation technologies based upon costs, average size, construction time, and heat rates. Table 6.2 compares the carbon dioxide emissions of some of these technologies. These technologies include hydrocarbon-based energy resources (coal, natural gas, or oil), non-renewable traditional energy resources (nuclear), as well as renewable sources of energy (wind, hydropower, solar, biomass, geothermal, and ocean tidal/current). Some technologies also have the capability to store energy, such as fuel cells. The Energy Information Administration published their data as "expected" cost estimates to build a plant or facility in a "typical" region of the country. Heat rate (expressed in British thermal units per net kilowatt-hour of electricity) is used to measure thermal efficiency of a power plant. The lower the plant's heat rate, the higher its efficiency because the plant requires fewer units of fuel input to produce a kWh of electricity.[3]

Table 6.1
Power Generation Technologies: Cost and Performance

Technology	Size (MW)	Construction Time (years)	Total Overnight Costs (2006 $/kw)	Variable O&M Costs (2006 $/kw)	Fixed O&M Costs (2006 $/kw)	Heat Rate (2007 Btu/kWh)
Scrubbed Coal New	600	4	1,534	4.46	26.79	9,200
Integrated Coal-Gasification Combined Cycle (IGCC)	550	4	1,773	2.84	37.62	8,765
IGCC with Carbon Sequestration	380	4	2,537	4.32	44.27	10,781
Conventional Gas/Oil Combined Cycle (CC)	250	3	717	2.01	12.14	7,196
Advanced Gas/Oil CC	400	3	706	1.95	11.38	6,752
Advanced CC with Carbon Sequestration	400	3	1,409	2.86	19.36	8,613
Conventional Combustion Turbine (Gas)	160	2	500	3.47	11.78	10,833
Advanced Combustion Turbine (Gas)	230	2	473	3.08	10.24	9,289
Fuel Cells	10	3	5,374	46.62	5.5	7,930
Advanced Nuclear	1350	6	2,475	0.48	66.05	10,400
Distributed Generation-Base	5	2	1,021	6.93	15.59	8,900
Distributed Generation-Peak	2	3	1,227	6.93	15.59	9,880
Biomass	80	4	2,809	6.53	62.70	8,911
Municipal Solid Waste-Landfill Gas	30	3	1,897	0.01	111.15	13,648
Geothermal	50	4	1,110	0	160.18	33,729
Conventional Hydropower	500	4	1,551	3.41	13.59	10,022
Wind	50	3	1,434	0	29.48	10,022
Wind Offshore	100	4	2,872	0	87.05	10,022
Solar Thermal	100	3	3,744	0	55.24	10,022
Photovoltaic	5	2	5,649	0	11.37	10,022

Source: Energy Information Administration, *Assumptions to the Annual Energy Outlook 2008* (June 2008), p. 89. Online. Available: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf. Accessed: March 16, 2009.

Table 6.2
Carbon Dioxide Emissions From Power Generation Technologies

Technology	CO_2 Emissions (metric tons per MWh by 2010-2015)
Pulverized Coal	0.80 for supercritical plant without CO_2 capture (0.052 with capture)
Fluidized Bed Coal Combustion	0.87
Integrated Gasification Combine Cycle (coal)	0.86 without capture (0.156 with capture)
Combined Cycle (gas)	0.39
Combustion Gas	Not available
Nuclear	None
Wind	None
Pumped Storage Hydropower	Not applicable
Photovoltaic (solar)	None
Concentrated Solar	None
Biomass	0.10
Geothermal	None
Barrage and Ocean Current	None
Fuel Cells	Not available

Source: The National Regulatory Research Institute, *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria*, pp. 18-19. Online. Available: http://nrri.org/pubs/electricity/07-03.pdf. Accessed: March 16, 2009.

The power generation technologies to be discussed in this volume of the report include: coal [pulverized coal generation, fluidized bed combustion, and integrated gasification combined cycle (IGCC)]; natural gas (combined-cycle and combustion turbines); nuclear; hydropower and pumped storage; wind; solar (photovoltaic power and concentrated solar power); biomass; geothermal; ocean power; and hydrogen and fuel cells. This list reflects a reasonable set of future power generation opportunities as of 2009. Improvements in clean coal technologies and other technologies related to increasing the efficiency and reducing the emissions of fossil-fueled generation sources are discussed as other potential investments. Energy storage technologies to increase the appeal of wind and solar are considered as well.

Comparative Criteria

By comparing the costs and benefits of the generation options, utility managers and their customers can make an informed decision as to which technologies best meet future electricity loads. Criteria used for comparison include: the cost and time of construction; fuel costs and marginal operating costs; projected operational life; fuel and plant dependability; maturity of the technology; emissions and other environmental concerns; and security or other potential concerns related to the technology.

This report provides a neutral and comprehensive evaluation of available power generation options for AE through 2020. It evaluates barriers limiting electric generation technologies, such as: the variable nature of renewable energy (meaning these sources cannot generate electricity "on demand"); various grid issues related to the distribution of renewable energy; the feasibility and risks associated with carbon storage methods; the validity and costs of investments to offset carbon releases; and challenges for maintaining a financially sound utility. This report considers "sustainability" as it applies to the energy sector from both economic and environmental perspectives. Options will be analyzed based upon how they affect the financial operation of AE as well as the environment. AE customers will be able to evaluate such options with respect to their personal preferences in working towards a sustainable energy future. Some of the specific factors are considered below.

Load-Service Function

Electric utility service providers must meet certain load requirements. Some technologies have the ability to provide energy at any time that the plant is in operation (called baseload power facilities). 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. Power generating technologies also vary in costs to start-up and operate. These costs determine which plants and technologies are used to meet baseload, intermediate, and peak demand needs.

Construction Time

Any proposed power plant will take time to plan, build, and be connected to the electric grid. Construction time refers to the estimated length of time to construct the plant. However, it also takes time to site the plant and gain regulatory approval for its construction. Construction time can affect the capital costs of a particular plant or technology because the length of time from the decision to build to the point of power generation affects any project's financing.

Construction Cost

Construction costs can be measured in different metrics, depending upon how financing interest is considered. This report uses the category "overnight costs." Interest expenses are not stated separately, as these are included within overnight costs. Overnight costs describe what the plant costs would be if it were built and paid for overnight, requiring no time-dependent expenses;[4] in effect future discounted costs are converted to present values. Overnight construction costs include all material and labor costs associated with the main contractor and sub-contractors. Construction costs could vary over time depending on the fluctuating prices of various commodities used in constructing a particular facility, waste disposal fees, and transportation costs to a particular construction site. Construction costs can also be affected by factors such as future environmental regulations requiring installation of emissions control equipment, whether the plant is new or an expansion of an existing facility, and the size of the plant.[5]

Variable Costs

The term "variable costs" includes all costs that are incurred on a regular basis during the operation of the plant or power generation equipment. For traditional technologies, fuel costs tend to make up the majority of variable costs. Renewable technologies tend to have lower variable costs. Operation and maintenance costs, emission allowances, and transmission interconnection costs are additional variable costs. These costs are difficult to estimate because there is high variability within each type of plant and technology, and location will influence variable costs.

Operational Life

Operational life refers to the average amount of time that a plant or technology is able to operate mechanically, and may differ from the length of time a power generation unit or technology is economically attractive for an owner. As a plant requires more maintenance and can become less reliable as it ages, a plant may not be used for its entire operational life.

Fuel Dependability

Fuel dependability is based upon the apparent strengths and weaknesses of its availability. A fuel's dependability may be questioned based on access to transportation networks (which can be site-specific), competition for a fuel within the energy sector, or competition for a fuel for purposes other than power generation. If a plant has the capability to burn multiple fuels this increases its fuel dependability. Future fuel dependability can be difficult to predict because future pricing can affect how a fuel is supplied and the volume of future demand.

Plant or Technology Reliability

Plant or technology reliability can be measured using its capacity factor or its availability factor. The capacity factor is a ratio of "actual hours of energy production/total hours" for a given period.[6] The availability factor is the percentage of hours in a given period that a plant or technology is "available" to produce power.[7] 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, the hiatus in power generation can create costs for a utility including: reducing the owner's revenue stream; requiring owners with sales obligations to customers to pay penalties for a contract breach; requiring the utility to pay higher costs for fuel or energy on the spot market; or even placing a strain on other components of the interconnected power system.[8]

Maturity of the Technology

Maturity of the technology is a subjective measurement based on the level of use and proven viability of the technology. The maturation of a technology often lowers its costs and factors into the willingness of investors to invest in the technology. The four stages of maturity are: under development; newly operational; mature; and fully mature.

Greenhouse Gas Emissions and Other Pollutants

It is useful to separate levels of GHG emissions from other pollutants or environmental concerns because of this report's emphasis on reducing AE's carbon footprint. Carbon dioxide emissions may soon have an economic cost if federal or state governments pass carbon legislation; a carbon tax, fee, or fine would add cost for fossil fuels.

Other Environmental Concerns

Other environmental concerns exist for any particular technology during its life-cycle from the time the fuel is extracted, through its processing or transport, to its burning or other use, up to the point that a plant is decommissioned. Mining of particular fuels can cause environmental degradation, including but not limited to the pollution of waterways, disruption of ecosystems, release of particulate matter or harmful effluents into the air, not to mention the health risks to miners. Transportation of fuels requires energy that releases emissions and pollutants into the atmosphere. Wastes, such as nuclear waste, created during a plant or technology's operation are also of environmental concern, and the costs associated with appropriate disposal represent part of a utility's responsibility. Some technologies, such as wind turbines, may cause death for bats and birds that fly in the area, or affect the visual appearance of an area.

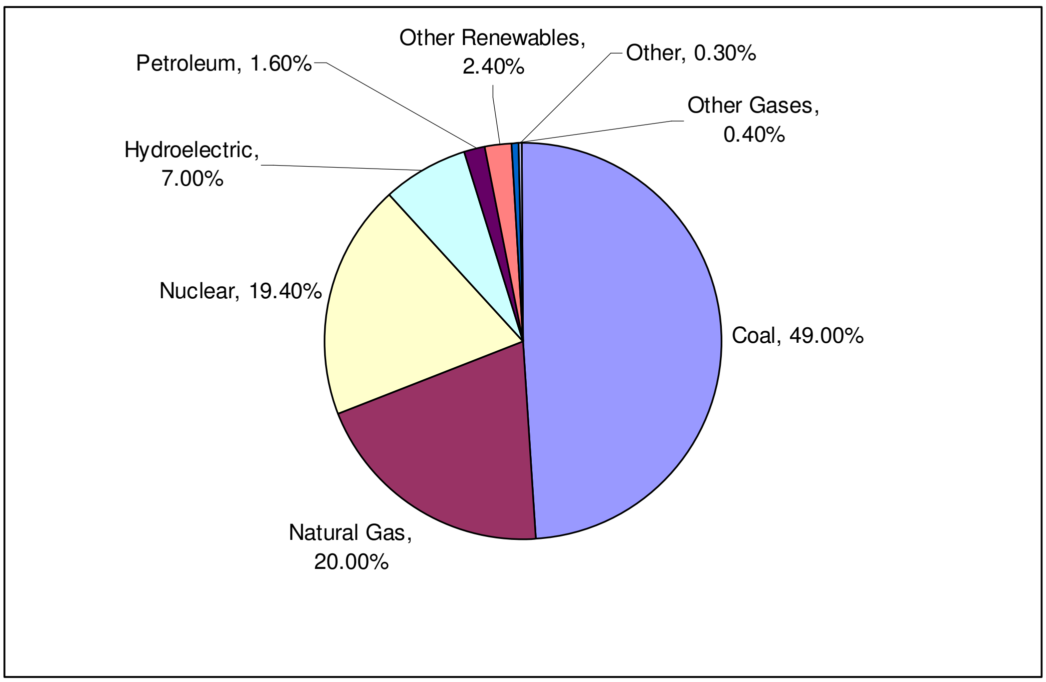
Risks, Uncertainties, and Externalities

Risks, uncertainties, and externalities encompass a wide range of issues regarding the potential viability, security, and liability of a particular plant or technology. For technologies such as hydrogen fuel cells that are yet to be proven to be as efficient or reliable as other technologies, one set of risks is financial: can a utility recoup its investment? Other risks include fluctuations in future fuel pricing and transmission reliability. Security risks are posed by plants or technologies that could harm the welfare of the surrounding area. Of particular concern are the threats of terrorist attacks on power generating facilities or meltdowns at nuclear facilities. Liability and future environmental concerns complicate the choice of some technologies. The unknown state of future legislation on carbon emissions is of particular concern from both a liability and financial standpoint. Another concern is the risk of requirements for carbon capture and sequestration for fossil-fuel plants. The determination of the party assuming liability for carbon sequestration may affect the financial viability of this technology.

Future Power Generation Options

Electricity has traditionally been generated at a power station by a heat engine through the process of combusting fossil fuels or through the fission of nuclear energy, utilizing energy sources such as coal, oil, hydropower, natural gas, and nuclear. Electric power generation in the United States predominantly comes from these traditional energy sources (see Figure 6.1). In 2006, 49 percent of electricity generation came from coal, 20 percent from natural gas, 19.4 percent from nuclear and 7 percent from hydroelectric.[9] AE uses less coal power than national averages and no hydropower, generating about an equal amount of energy from nuclear, coal, and natural gas.[10] These technologies and fuel sources have dominated the electric power generation industry because of their relatively low marginal costs and high supply reliability. Non-traditional or so-called renewable energy sources include wind, solar, ocean currents, and geothermal energy. Despite the many benefits presented by these technologies, the availability to use these technologies may be limited to specific times of day or locations. Chapters 7 through 17 present information on how these different generation and energy storage technologies work, the current states of these technologies, current costs, and the potential benefits and risks.

Figure 6.1
United States Electric Power Generation, 2006



Source: Energy Information Administration and Department of Energy, *Energy Information Sheets: Electricity Generation*. Online. Available: http://www.eia.doe.gov/neic/infosheets/electric generation.html. Accessed: July 28, 2006.

Notes

[1] National Regulatory Research Institute, *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria*, p. 62. Online. Available: http://nrri.org/pubs/electricity/07-03.pdf. Accessed: March 16, 2009.

[2] Ibid., pp. 64-65.

[3] Ibid., p. 8.

[4] Ibid., p. 12.

[5] Ibid.

[6] Ibid., p. 9.

[7] Ibid.

[8] Ibid., p. 15.

[9] Energy Information Administration and the United States Department of Energy, *Energy Information Sheets: Electricity Generation*. Online. Available: http://www.eia.doe.gov/neic/infosheets/electricgeneration.html. Accessed: March 16, 2009.

[10] Austin Energy, *Austin Energy Resource Guide* (October 2008), p. 17. Online. Available: http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf. Accessed: December 19, 2008.

Chapter 7. Coal

Summary

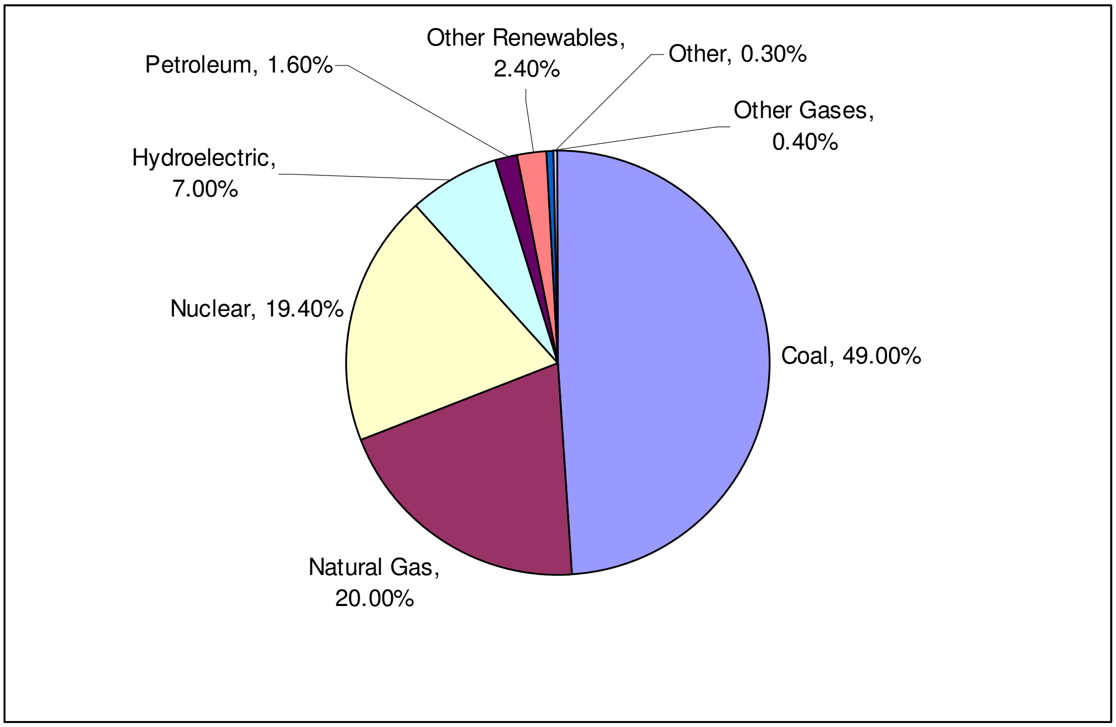
This chapter considers Austin Energy's options for future coal generation as part of its 2020 carbon neutrality goal. AE currently operates 607 MW of pulverized coal-fired electricity generation which contributes the overwhelming majority of the utility's CO_2 emissions. Replacing this coal generating capacity with an integrated gasification combined cycle (IGCC) plant with carbon capture and sequestration (CCS) technology would allow AE to significantly reduce its emissions without reducing coal-powered electricity generation. CCS technology is not considered feasible or mature for utility-scale use. If other utilities were to install and test CCS prior to 2013, AE could consider it an option for its 2020 energy portfolio, but such a circumstance is unlikely. AE will meet its 2020 goal of carbon neutrality either by shifting generating capacity away from coal or by purchasing offset credits.

Background

Coal is a major fuel used for electric power generation in the United States due to high local availability and low price compared to other energy sources. In 2006 utilities burned coal to produce 39 percent of the world's electricity, 49 percent of U.S. electricity, and 36.5 percent of Texas' total electricity (see Figure 7.1).[1] World coal reserves are greater than one trillion U.S. tons, which is sufficient for at least 190 years of current world rates of consumption.[2] Coal is found in 70 countries worldwide with the largest reserves located in the U.S., Russia, China, and India. The U.S. holds the world's largest known coal reserves with about 268 billion recoverable U.S. tons, estimated to last at least 236 years at current U.S. usage rates.[3] There are four major types of coal containing varying carbon and moisture contents. Coal with the highest carbon and lowest moisture contents has the highest heat value and therefore burns cleaner. In order of highest to lowest carbon content, the four types of coal are anthracite, bituminous, sub-bituminous, and lignite.[4] These coal types have heat rates of 25, 24, 17-18, and 13 million British thermal units (Btu) per ton, respectively (see Table 7.1).[5]

There are several coal-combustion technologies used to produce energy, including pulverized coal, fluidized bed combustion, and IGCC. Table 7.2 summarizes the characteristics of these technologies, including costs estimates and environmental impacts.

Figure 7.1
United States Electric Power Generation by Source



Source: Energy Information Administration and United States Department of Energy, *Energy Information Sheets: Electricity Generation*. Online. Available: http://www.eia.doe.gov/neic/infosheets/electricgeneration.html. Accessed: July 28, 2006.

Table 7.1
Energy and Carbon Content of Coal Types

	Coal Property	
Coal type	**Average energy content** (kJ/kg)	**Average carbon content** (weight by percent)
Anthracite	30,750	80
Bituminous	27,900	67
Sub-bituminous	20,000	49
Lignite	15,000	40

Source: Massachusetts Institute of Technology, *The Future of Coal: Options for a Carbon-Constrained World* (2007), pp. 39, 111. Online. Available: http://web.mit.edu/coal/The_Future_of_Coal.pdf. Accessed: August 8, 2008.

Table 7.2
Characteristics of Coal Power Generation Technologies

	Technology Type		
Technology characteristics	**Pulverized coal**	**Fluidized bed**	**IGCC**
Load service function	Baseload	Baseload	Baseload
Fuel dependability	High	High	High
Maturity	Mature	In development	Newly operational
Time to construct (years)	3-4	3-4	3-4
Operational life (years)	30-50	30	Not available
Cost to construct ($/kW)	1,235	1,327	1,431
Fuel cost (2006 $/MWh)	14.02	15.08	13.17
Fixed operation and maintenance costs ($/kW)	Not available	Not available	37.62[6]
Variable operation and maintenance costs ($/kW)	Not available	Not available	2.84[7]
Availability factor (percent)	72-90	90	88
Capacity factor (percent)	80[8]	40 (Nucia CFB Demo)[9]	80[10]
GHG emissions (metric tons of CO_2 equivalent per MWh)	0.80 for supercritical plant without CO_2 capture (0.052 with capture)	0.87	0.86 without CO_2 capture (0.156 with capture)

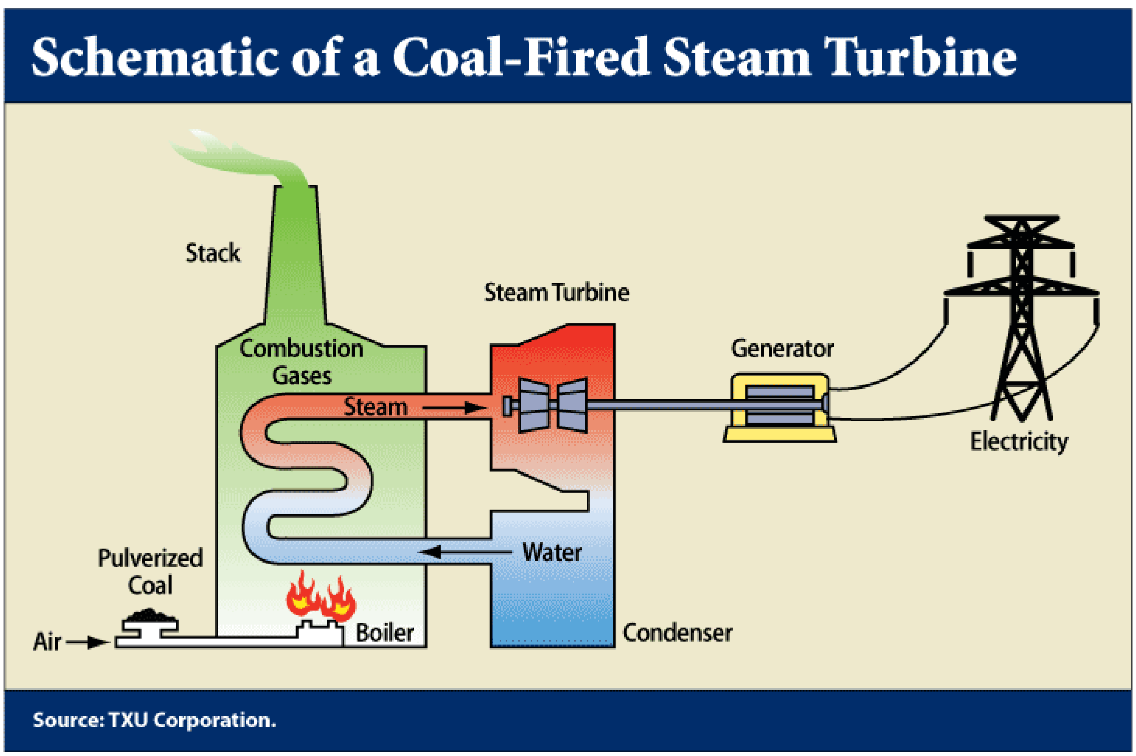
Source: The National Regulatory Research Institute, *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria* (2007), p. 18. Online. Available: http://www.nrri.org/pubs/electricity/07-03.pdf. Accessed: July 16, 2008. (See endnotes for additional sources.)

Pulverized Coal Plants

Pulverized coal generation accounts for approximately half of all U.S. electricity generation, as it is a mature, commercially viable technology.[11] To produce energy through pulverized coal combustion, chunks of coal are crushed into a fine powder, mixed with air, and blown into a combustion unit where the coal is burned. The burning coal heats water, creating steam, which spins turbines to generate electricity. Both the type and quality of the coal and the intended temperature and operating steam pressure influence the specific design of a pulverized coal power plant (see Figure 7.2).[12]

Pulverized coal plants are typically operated for baseload electricity generation because the technology has a lower cost per kWh than any other fossil fueled plant and the plants are considered highly reliable.[13] The steam systems currently used at pulverized coal plants operate at different efficiencies, from subcritical or conventional (the least efficient), to supercritical, to ultra-supercritical (the most efficient).[14] Ultra-super-critical pulverized coal power plants may attain greater than 43 percent efficiency, while the average efficiency of U.S. coal power plants is 33 percent.[15] Improved power generating efficiency results in lower carbon dioxide (CO_2) and criteria pollutant emissions per kilowatt-hour (kWh) of electricity generated.[16] The efficiency of a coal plant is often referenced by its "heat rate", which indicates the amount of combustion heat required to produce a given amount of electricity, and which is often measured in British thermal units per kilowatt hour (Btu/KWh). The heat rate for average pulverized coal plants varies from subcritical technology with 9,950 Btu/KWh without carbon capture technology and 13,600 Btu/kWh with carbon capture, to ultra-supercritical technology with 7,880 Btu/KWh without carbon capture technology and 10,000 Btu/kWh with carbon capture.[17]

Figure 7.2
Diagram of a Pulverized Coal Plant



Source: Texas Comptroller of Public Accounts, *The Energy Report 2008* (May 2008), p. 94. Online. Available: http://www.window.state.tx.us/specialrpt/energy/. Accessed: October 8, 2008.

The projected operational life of pulverized coal generation units is between 30 to 50 years.[18] The majority of units in the U.S. range from 35 to 55 years old, with the fleet averaging 35 years old.[19] Plant design, energy output, emissions, and efficiency achieved by a plant depend its age.[20] Plants 30 to 35 years of age were constructed as the Clean Air Act was becoming law and were grandfathered under that legislation.[21] While these units produce more emissions than newer plants, most are nearing the end of their projected operational lives.[22] Existing pulverized coal plants have nameplate power generation capacities ranging from 100 megawatts (MW) to 1300 MW.[23]

Fluidized Bed Combustion Plants

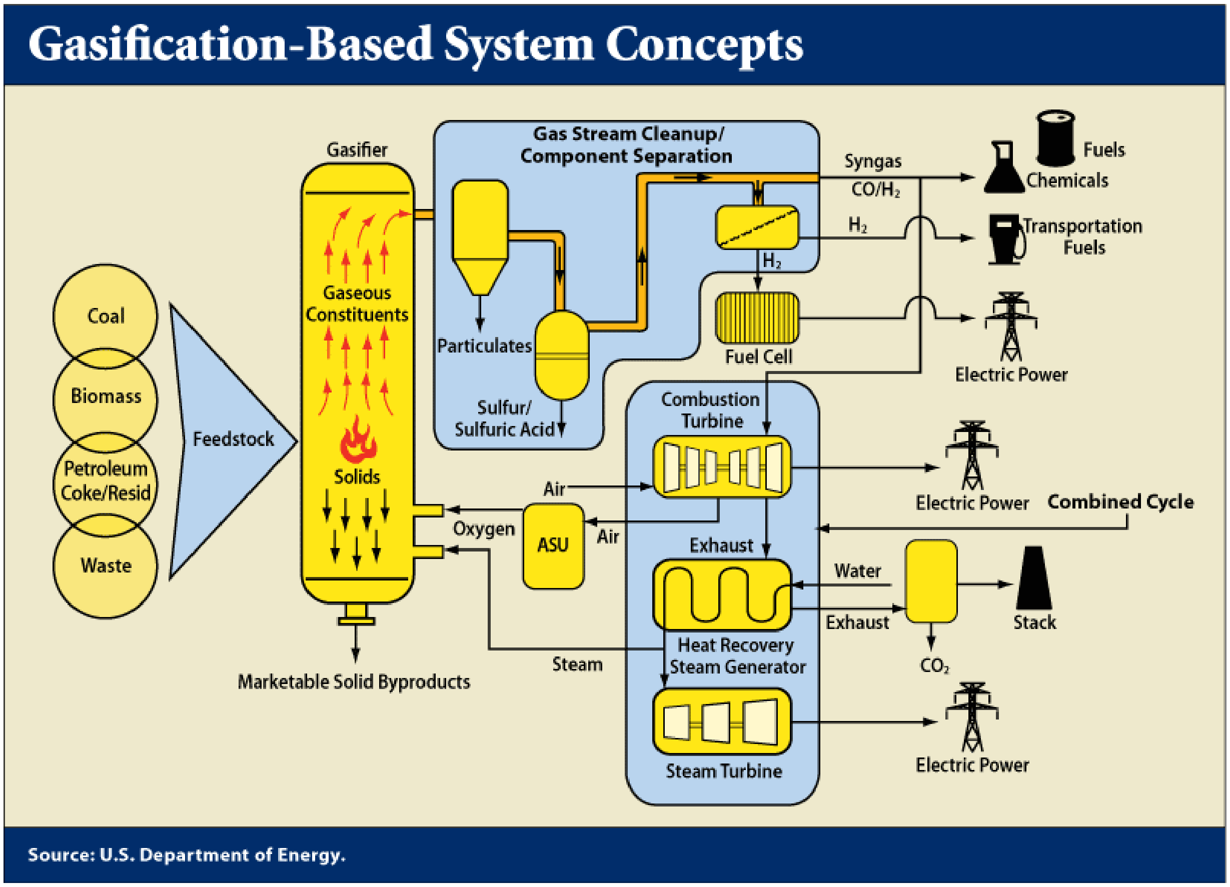
Fluidized bed commercial units can operate at competitive efficiency and cost compared to pulverized coal plants.[24] Fluidized bed technology still uses pulverized coal, but suspends the coal in the furnace by blowing jets of air during the combustion process, resulting in a mix of gas and solids. There are two types of fluidized bed combustion technologies: atmospheric fluidized bed and pressurized fluidized bed. Atmospheric fluidized bed systems combust fuel under atmospheric pressure. Pressurized fluidized bed systems have a reactor vessel that is pressurized to produce flue gas energy to drive a gas turbine in conjunction with a steam turbine in a combined cycle.[25] Atmospheric fluidized bed combustion technology can burn lower-grade fuels than pulverized coal combustion technology (including municipal waste), resulting in a greater set of fuel options.[26]

Fluidized bed combustion technology could be used to meet baseload energy demand, as operating plants have an availability factor of 90 percent.[27] The heat rate is 9,810 Btu/KWh without carbon capture technology and 13,400 Btu/kWh with carbon capture.[28] Although the U.S. Department of Energy has been testing fluidized bed combustion for over 30 years, it is a fairly immature technology and operational life is uncertain. Given the limited commercial application (there is currently only one fluidized bed combustion plant in operation in the U.S.), it is hard to know whether a plant's operational life would extend past 30 years.[29,30] The demonstration plant has been tested with various coals, high sulfur petroleum coke, and coal-coke blends; it appears to operate about as reliably as a pulverized coal plant. Research is also being conducted to determine the viability of integrating carbon capture systems into fluidized bed combustion plants.[31]

Integrated Gasification Combined Cycle Plants

In an Integrated Gasification Combined Cycle (IGCC) power plant, coal is fired in an atmosphere of steam and oxygen and the combustion produces a synthesis gas (syngas) containing a mixture of carbon monoxide, CO_2, and hydrogen.[32] This gas can then be burned within a gas turbine to produce electricity. The hot exhaust from the gas turbine can be routed to a heat recovery steam generator, producing steam to power a steam turbine (see Figure 7.3). Electricity is produced from both a gas turbine and a steam turbine; hence the name Integrated Gasification Combined Cycle. IGCC plants can be powered by coal, petroleum coke, or biomass. IGCC plants typically have somewhat lower rates of nitrous oxides (NO_x), sulfur dioxide (SO_2), and mercury than traditional pulverized coal plants.[33] Of particular interest, CO_2 can in principle be captured before combustion in IGCC, as opposed to after combustion in a pulverized coal power plant, which could greatly reduce the price of CCS.[34] There are currently two DOE-assisted IGCC plants in the U.S., in Florida and Indiana (Table 7.3 compares the two plants).[35]

Figure 7.3
Diagram of Integrated Gasification Combined Cycle Technology



Source: Texas Comptroller of Public Accounts, *The Energy Report 2008* (May 2008), p. 95. Online. Available: http://www.window.state.tx.us/specialrpt/energy/. Accessed: October 8, 2008.

Table 7.3
Integrated Gasification Combined Cycle Plant Operational Examples

	Operational plants	
Characteristics	**Wabash plant**	**Polk County, Florida plant**
Total project cost ($)	438 million	303 million
Availability (percent)	70	80
Heat rate (Btu/kWh)	8,910	9,350
Sulfur dioxide emissions	Below 10% of permitted limits	Reduction of 95%
Particulate emissions	Extremely low	Very low

Source: Global Change Associates, *An Analysis of the Institutional Challenges to Commercialization and Deployment of IGCC Technology in the U.S. Electric Industry: Recommended Policy, Regulatory, Executive, and Legislative Initiative*, vol. 2 (March 2004), pp. 6-7. Online. Available: http://204.154.137.14/energy-analyses/pubs/FinalReport2-20Vol1.pdf. Accessed: November 24, 2008.

IGCC plants can generate baseload or load-following power, however current IGCC plants have little practical experience with operating in a load-following mode.[36] As there has been limited experience with IGCC operations, its availability factor is lower than for other coal plants, but availability would increase as utilities gain familiarity with the technology of adding a spare gasifier as a backup.[37] Estimations of availability factor for IGCC plants range from 80 to 88 percent.[38] However, IGCC plants may experience a lag of three to five years to reach an availability factor of 80 percent.[39] A recent Energy Information Administration (EIA) estimate of the heat rate for IGCC plants is 8,765 Btu/kWh and an estimate of the heat rate for IGCC plants with CCS is 10,781 Btu/kWh[40] Table 7.4 summarizes similar estimates from an MIT study.

Table 7.4
Integrated Gasification Combined Cycle Plant Characteristics

	Technology	
Characteristics	**IGCC**	**IGCC with carbon capture**
Power generating capacity (MW)	500	500
Heat rate (Btu/kW-h)	8,891	10,942
Generating efficiency (percent)	38.4	31.2
CO_2 emissions (kg/h)	415,893	51,198
Amount CO_2 captured at 90% (kg/h)	0	460,782
CO_2 emissions (g/kW-h)	832	102

Source: Massachusetts Institute of Technology, *The Future of Coal: Options for a Carbon-Constrained World* (2007), p. 30. Online. Available: http://web.mit.edu/coal/The_Future_of_Coal.pdf. Accessed: August 8, 2008.

Carbon Capture and Sequestration

Although coal provides a relatively cheap and abundant local source of energy for the U.S., any production and use of coal generates adverse environmental impacts, including the release of CO_2 and other GHG emissions. Carbon Capture and Sequestration (CCS) technologies (sometimes referred to as “clean coal technologies”) have been developed to limit coal’s release of CO_2. CCS is the process of capturing carbon from fossil-fuel plants before it enters the atmosphere and then storing the carbon within some type of geological reservoir. This technology has the capacity to reduce GHG emissions from baseload and intermediate power plants that use coal and natural gas as a fuel source. A study conducted by the Massachusetts Institute of Technology (MIT) on the future of coal stated that "CO_2 capture and sequestration is the enabling technology that would reduce CO_2 emissions significantly while also allowing coal to meet the world's pressing energy needs."[41] CCS provides a mechanism for controlling CO_2 emissions, though the technology has yet to be used on a large-scale.

One of the primary challenges for implementing CCS technology is the difficulty of moving CO_2 from the point of capture to a site for storage. Although CO_2 can be transported in three states (gas, liquid, or solid), the least costly option is to convert gaseous CO_2 into a liquid for transport either by pipeline or by ship.[42] Pipeline transport involves the compression of CO_2 at the upstream end to about 4.8 to 9.6 million pascals (MPa) for low and high pressure pipelines, respectively, to drive the flow over moderate distances.[43] In some circumstances, dependant on geography and distance, additional intermediate compression systems may be necessary to keep the CO_2 as a liquid. Moisture in CO_2 is corrosive to pipelines and therefore the CO_2 must be dried before compression to maintain the integrity of the pipelines.[44] In transporting small gas volumes (less than a few million metric tons CO_2) or over very large distances (more than 1,000 km), ships could be an alternate method. Shipping CO_2 is analogous to shipping liquefied petroleum gas, as the CO_2 would first be converted to a liquid.[45]

The three major cost elements for pipeline transport are construction costs (material, labor, etc), operation and maintenance costs (monitoring, maintenance, etc.), and other costs (insurance, design, right-of-way). Construction and operating costs are largely dependent on the length and diameter of the pipeline, the volume of CO_2 to be transported, and the quality of the CO_2. Pipeline construction costs range between $0.1 million and $1.5 million per mile.[46] Transport costs to move CO_2 range between $1 and $8 per metric ton CO_2 per 250 kilometer (km) traveled, depending on pipeline diameter.[47] Terrain is also an important cost determinant, as onshore pipeline costs can increase by 50 to100 percent when the route passes through heavily populated locations or congested regions. Offshore pipelines are often between 40 to 70 percent more expensive than land lines. Pipeline transport is considered to be a mature industry.[48]

Potential storage sites for captured CO_2 include: geologic formations such as oil and gas fields, non-mineable coal beds, and deep saline formations.[49] Oil and gas reservoirs and saline formations, both onshore and offshore, have been targeted as potential storage targets because their high porosity rock characteristics enable them to hold fluids such as liquefied CO_2. Coal beds have also been proposed as potential storage sites for CO_2 with a dual purpose of enhancing methane production. About 30 million metric tons (Mt) of CO_2 is injected annually into oil and gas reservoirs for enhanced oil recovery, mostly in west Texas.[50] CO_2 storage in oil and gas deposits or deep saline reservoirs is expected to occur at depths greater than 800 meters. For geologic sequestration, a well-sealed cap rock over the storage reservoir can ensure that the CO_2 remains underground.[51] CO_2 injection would involve many of the same technologies developed by the oil and gas extractive industry. Well drilling, injection technology, pipeline, and computer simulation of reservoir modeling are common technologies utilized by the petroleum industry that can be adapted for carbon storage.[52] The Intergovernmental Panel on Climate Change (IPCC) estimates that geological storage will cost $0.6 to $8.3 per metric ton CO_2.[53]

A second possibility for CO_2 storage is direct injection into the deep ocean. Either a pipeline or ship could inject CO_2 at depths greater than a kilometer below the ocean surface so as to disperse it throughout the water column or consolidate it within basins to form CO_2 lakes. Fixation of carbon into solid inorganic carbonates by way of chemical reaction or industrial consumption of CO_2 are two other methods for managing CO_2.[54]

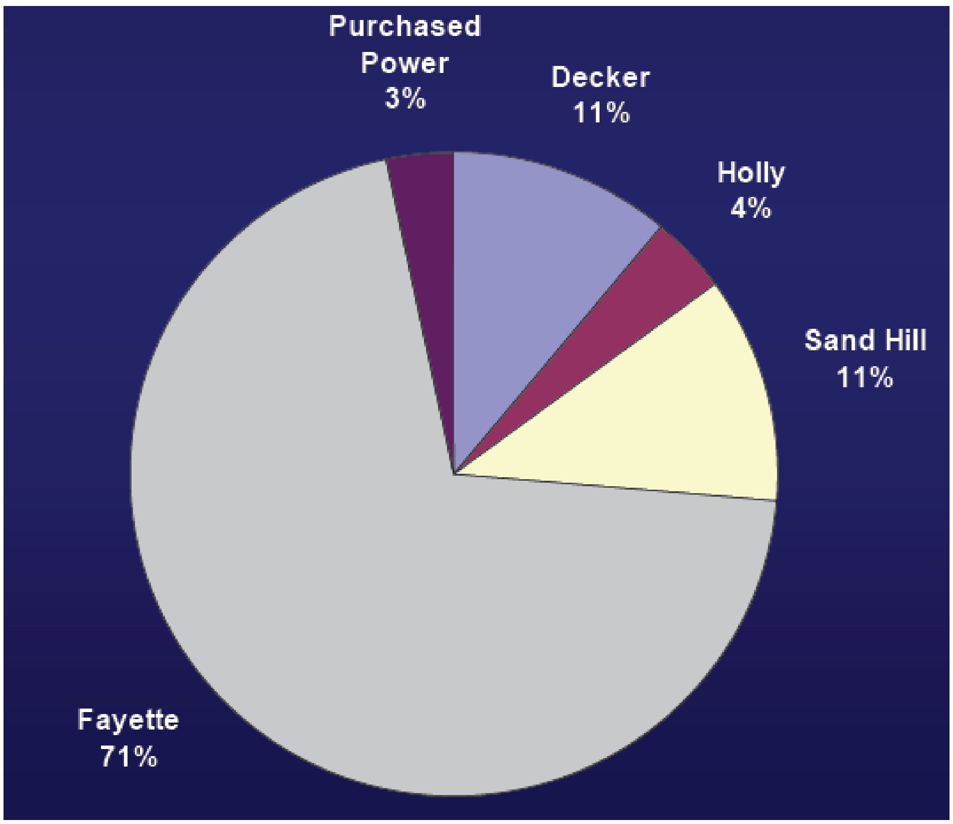
Operating Examples

The Fayette Power Project (FPP), also known as the Sam K. Seymour Generating Station, is a coal-fired power plant located on a 10 square mile site near La Grange, Texas, in Fayette County, about 60 miles southeast of Austin.[55] AE owns 50 percent of Units 1 and 2 of the plant, which is operated and co-owned by the Lower Colorado River Authority (LCRA). The Fayette units are used by AE for baseload power. FPP is comprised of three power generation units. Unit 1 was completed in 1979 with a power generating capacity of 615 MW (summertime capacity of 598 MW), Unit 2 was completed in 1980 with a power generating capacity of 615 MW (summertime capacity of 598 MW), and Unit 3 was completed in 1988 with a power generating capacity of 460 MW (summertime capacity of 445 MW).[56] Units 1 and 2 are both sub-supercritical designs with Combustion Engineering boilers and General Electric 4-flow steam turbines. These units burn low sulfur coal shipped from the Powder River Basin in Wyoming with a heating value of 8,000-9,000 Btus per pound and a sulfur content of up to 1 percent.[57]

The two units at FPP used by AE have an average capacity factor of 93 percent with a 35 percent efficiency level (the amount of electricity generated from a unit of fuel).[58] These units are designed to burn both lignite and sub-bituminous coal, although primarily they now burn low-sulfur coal from the Powder River Basin.[59] Cooling water is supplied from a freshwater reservoir in Fayette County. LCRA has taken many steps to reduce emissions, primarily focusing on reducing nitrogen oxides (NO_x) and sulfur dioxide emissions.[60] AE will pay $225 million by 2010 to install scrubbers to reduce sulfur oxide emissions from FPP.[61] AE maintains a Non-nuclear Plant Decommissioning Fund to provide for the retirement of non-nuclear power plants.[62] The cost of retirement is determined by a special study, and revenues are dedicated to the fund at least four years in advance of the retirement.[63] FPP provides about 30 percent of AE's energy needs, yet accounts for 71 percent of the utility's carbon dioxide emissions (see Figure 7.4).[64]

U.S. coal reserves are concentrated in specific geographical areas, and the delivery of coal reserves to power plant sites located far from the mines incurs costs. One informal survey of Texas utilities that import coal from the Powder River Basin suggested that rail costs can comprise two-thirds to three-quarters of the overall cost of coal supply.[65] In 2006, 71 percent of U.S. coal by weight was shipped by rail, 11 percent by truck, 10 percent by river barges, and 7 percent by short distance means such as tramways, conveyers, or slurry pipelines.[66] AE currently has a long-term contract with Union Pacific Railroad under which the utility pays about $20 million per year to have coal shipped to FPP for their use.[67] Union Pacific plans to transition to a new pricing system that will no longer rely on long term contracts, which could increase AE's coal transportation costs for 2010.[68]

Figure 7.4
Austin Energy's 2007 Calendar Year Carbon Dioxide Emissions Profile



Source: Austin Energy, *Future Energy Resources and CO_2 Cap and Reduction Planning* (July 2008). Online. Available: http://www.austinenergy.com/About%20Us/Newsroom/Reports/Future%20 Energy%20Resources_%20July%2023.pdf. Accessed: July 24, 2008.

There are currently two IGCC power plants in the U.S., one in Florida and the other in Indiana. Given this limited experience with IGCC plants, it is hard to estimate their projected operational life expectancy. The Polk facility in Florida is a 250 MW plant and the Wabash River plant in Indiana is a 262 MW plant (see Table 7.4). The Wabash Plant is a renovated, 1950s vintage conventional coal-fueled plant that has successfully operated as a baseload and load-following plant. It has a heat rate of 8,910 Btu/kWh.[69] The Tampa Electric Polk Power Plant was the first commercial scale IGCC power plant in the U.S., and was constructed with DOE financing (the Wabash Project was also supported by the DOE). The unit uses a Texaco gasifier and started up in 1996. The total plant cost, by EIA estimates, was about $1,800/kW of power generation capacity.[70] Many features have since been added to the unit, such as a hot-gas clean up system, and some of the initial features have been simplified, removed from the unit, or left unused. Accounting only for components required for the current plant configuration, the plant would cost roughly $1,650/kW of power generation capacity.[71] The Wabash Plant in Indiana (262 MW power generating capacity) had a total overnight cost of $438 million, which represents a cost of $1,672 per kW of power generating capacity.[72] An MIT study estimates that cost savings could decrease an IGCC plant's cost to $1,430 per kW (in 2001 dollars) with economies of scale, component standardization, or advances in design and technology.[73] The cost of IGCC plants is much debated, however, and a more recent estimate cites overnight construction costs for IGCC plants as $3,359 per kW, or $4,774 with CCS technology added.[74] The availability of these IGCC plants was low for the first several years of operation due to a range of problems. The Polk plant's gasifier started up in 1995 and is now available for operation over 82 percent of the time, at an efficiency of 35.4 percent.[75]

Economic Outlook

Coal is currently less expensive than oil or natural gas for producing electricity. Table 7.5 lists the costs and performance characteristics of various coal-fired power generation technologies. Costs vary among pulverized coal combustion power plants dependent upon the type of coal used, the cost of the coal and its transportation, environmental requirements for a particular plant location, and the operational life of the plant. Table 7.6 lists the costs associated with pulverized coal plants with and without CCS technology.[76] Table 7.7 lists the costs and CO_2 emissions associated with fluidized bed combustion plants with and without carbon capture technology.[77] Table 7.8 lists the costs associated with IGCC plants with and without carbon capture technology.[78]

Table 7.5
Coal Power Generation Technology Characteristics

	Technology		
Characteristics	**Scrubbed coal new**	**IGCC**	**IGCC with carbon sequestration**
Construction time (years)	4	4	4
Reference size (MW)	600	550	380
Total overnight cost (2006 $/kW)	1,534	1,773	2,537
Variable operations and maintenance cost (2006 $/kW)	4.46	2.84	4.32
Fixed operations and maintenance cost (2006 $/kW)	26.79	37.62	44.27
Heat rate in 2007 (Btu/kW-h)	9,200	8,765	10,781

Source: Energy Information Administration, *Assumptions to the Annual Energy Outlook 2008: World Projections for 2030* (June 2008), p. 79. Online. Available: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2008).pdf. Accessed: November 24, 2008.

Table 7.6
Costs of Pulverized Coal Plants

	Costs		
Technology	**Fuel cost** (cents per kW-h at $1.50/MMBtu)	**Total plant cost** (dollars per kW)	**Operations and management cost** (cents per kW-h)
Pulverized coal	1.49	1,280	0.75
Pulverized coal with carbon capture	2.04	2,230	1.60

Source: Massachusetts Institute of Technology, *The Future of Coal: Options for a Carbon-Constrained World* (2007), p. 35. Online. Available: http://web.mit.edu/coal/The_Future_of_Coal.pdf. Accessed: August 8, 2008.

Table 7.7
Fluidized Bed Coal Combustion Plant Characteristics

	Technology	
Characteristics	**FBC w/o carbon capture**	**FBC with carbon capture**
CO_2 emissions (kg/h)	517,000	70,700
Amount of CO_2 captured at 90% (kg/h)	0	36,000
CO_2 emissions (g/kW-h)	1030	141
Total plant cost ($/kW)	1330	2270
Fuel (cents/kW-h)	0.98	1.34
Operations and maintenance costs (cents/kW-h)	1.00	1.85
Cost of electricity (cents/kW-h)	4.68	7.79

Source: Massachusetts Institute of Technology, *The Future of Coal: Options for a Carbon-Constrained World* (2007), p. 19. Online. Available: http://web.mit.edu/coal/The_Future_of_Coal.pdf. Accessed: August 8, 2008.

Table 7.8
Integrated Gasification Combined Cycle Plant Costs

	Technology	
Costs	**IGCC**	**IGCC with carbon capture**
Total plant cost ($/kW)	1,430	1,890
Fuel costs (cents/kW-h)	1.33	1.64
Operations and maintenance cost (cents/kW-h)	0.90	1.05

Source: Massachusetts Institute of Technology, *The Future of Coal: Options for a Carbon-Constrained World* (2007), p. 30. Online. Available: http://web.mit.edu/coal/The_Future_of_Coal.pdf. Accessed: August 8, 2008.

Table 7.9 provides future cost projections for pulverized coal and IGCC power plants.[79] IGCC has high initial capital costs relative to pulverized coal power plants. Texas currently has no IGCC plants operating or planned. AE has reviewed the possibility of an IGCC plant but concluded that it would not yet be economical to invest in one.[80] The technology is expensive, making it hard to compete with traditional pulverized coal plants. If IGCC costs come down in the future it would become a more attractive and viable option, especially if federal carbon legislation were to be implemented.

CCS technology represents a way to lower CO_2 carbon emissions. The world's largest sequestration project stores one million tons per year of CO_2 from the Sleipner gas field into a saline aquifer under the North Sea.[81] The IPCC estimates total costs per metric ton of CO_2 for CCS to range from $30 to $70 for pulverized coal plants and from $20 to $70 for IGCC plants.[82] One study estimated that the construction of a carbon capture and enhanced oil recovery project in Texas would take two years, with $60 million in expenditures during the first year of operation and $90.5 million the second year.[83] Table 7.10 presents estimates of cost and energy requirements for CCS technology. Table 7.11 and Table 7.12 summarize cost of electricity and total costs by power plant type with and without CCS technology installed. Table 7.13 lists CCS system components and their costs.

Table 7.9
Coal Costs: Pulverized Coal Versus IGCC Plants

	Costs		
Technology	**Capital costs** ($/kW)	**Operation and maintenance cost** (cents/kW-h)	**Cost of energy** (cents/kW-h)
Advanced pulverized coal	1330 (total plant cost)	0.75	4.78
Future pulverized coal	1370	0.89	5.00
IGCC	1429	0.90	5.13
Future IGCC	1440	0.92	5.16

Source: Massachusetts Institute of Technology, *The Future of Coal: Options for a Carbon-Constrained World* (2007), p. 143. Online. Available: http://web.mit.edu/coal/The_Future_of_Coal.pdf. Accessed: August 8, 2008.

Table 7.10
Cost and Energy Requirements Associated with Fossil Fuel Technologies

	Energy requirements and cost	
Technology	**Energy requirement (kWh/T CO_2)**	**Capture cost ($/T CO_2)**
Pulverized coal	317	49
IGCC	194	26
Natural gas combined cycle	354	49

Source: Lyndon B. Johnson School of Public Affairs, *Creating a Carbon Capture and Storage Industry in Texas,* Policy Research Report Series, no. 154 (Austin, Tex., 2006), p. 27.

Table 7.11
Electricity Costs with and without Carbon Capture and Sequestration

	Cost of Electricity (cents per kWh)	
Technology	**Without carbon capture**	**With carbon capture**
Pulverized coal	4.4	7.7
IGCC	5.0	6.7
Natural gas combined cycle	3.3	4.9

Source: Lyndon B. Johnson School of Public Affairs, *Creating a Carbon Capture and Storage Industry in Texas,* Policy Research Report Series, no. 154 (Austin, Tex., 2006), p. 28.

Table 7.12
Costs for Carbon Dioxide Capture and Storage

	Natural Gas Combined Cycle Plant	Pulverized Coal Plant	IGCC Plant
COE without capture ($/MWh)	37	46	47
Power Plant with Capture			
COE with capture only ($/MWh)	54	73	62
Increase in COE with capture ($/MWh)	17	27	16
Percent increase (%)	46	57	33
Power Plant with Capture and Storage			
COE with capture and geologic storage ($/MWh)	60	80	75
Electricity cost increase ($/MWh)	23	34	28
Percent increase (%)	62	74	60

Source: Intergovernmental Panel on Climate Change, *IPCC Special Report: Carbon Dioxide Capture and Storage* (September 2005), p. 28. Online. Available: http://www.ipcc.ch/ipccreports/srccs.htm. Accessed: November 24, 2008.

Table 7.13
Carbon Capture and Storage Costs by Component

Carbon Capture Storage System Component	Costs ($ per metric ton CO_2)
Capture from coal or gas plant	15-75
Transportation	1-8
Geologic storage	0.5-8
Geologic storage - monitoring and verification	0.1-0.3
Ocean storage	5-30
Mineral carbonation	50-100

Source: Intergovernmental Panel on Climate Change, *IPCC Special Report: Carbon Dioxide Capture and Storage* (September 2005), p. 28. Online. Available: http://www.ipcc.ch/ipccreports/srccs.htm. Accessed: November 24, 2008.

Environmental Impacts

Mining, processing, transporting, and burning coal has significant environmental impacts, ranging from air and water pollution to land damage and occupational health risks of employees. The burning of coal creates numerous air emissions, including sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury, other trace metals, ash, and volatile organic compounds.[84] As federal and state governments have passed air quality legislation, plants have been retrofitted with equipment that reduces some of those emissions. Combusting lower sulfur coals can also reduce emissions. Coal emits much higher levels of greenhouse gas (GHG) emissions per unit of energy than other fossil fuels. For example, conventional coal combustion plants emit more than twice as much CO_2 per megawatt-hour (MWh) as natural gas combined cycle units.[85] Of the 5.5 billion tons of CO_2 per year emitted in the U.S. in 2004, 35 percent of that total can be attributed to electrical generation plants.[86] Coal power plants are responsible for nearly 80 percent of the emissions from electrical generation plants.[87] Table 7.14 lists CO_2 emissions from a pulverized coal combustion plant (500 MW of power generating capacity) with and without carbon capture. Table 7.15 provides estimates for the costs of capturing and storing CO_2 emitted from pulverized coal plants.

The Environmental Protection Agency (EPA) estimates that coal plants are responsible for 13 to 26 percent of total annual mercury emissions in the U.S.[88] Pennsylvania, the state with the second-highest anthropogenic mercury emissions in the U.S. (Texas is first), approved a 90 percent phased-reduction plan for mercury emissions in 2006.[89] This law was recently struck down on a technicality, which has raised public awareness and puts the burden for action on a federal administration that has already sought to limit environmental mercury.[90,91] Mercury is a health concern and exposure to mercury has been associated with neurological complications.[92] The financial risks of cleanup costs or litigation resulting from shifting public and political opinion on mercury emissions from coal plants may move utilities to investigate alternative energy generation strategies.

Table 7.14
Carbon Dioxide Emissions From 500 MW Pulverized Coal Plant With and Without Carbon Capture and Storage

	Technology	
Amount of CO_2 emitted or captured	**Pulverized coal**	**Pulverized coal with carbon capture**
Emissions (kg/h)	466,000	63,600
Amount captured at 90% (kg/h)	0	573,000
Emissions (g/kW-h)	931	127

Source: Massachusetts Institute of Technology, *The Future of Coal: Options for a Carbon-Constrained World* (2007), p. 19. Online. Available: http://web.mit.edu/coal/The_Future_of_Coal.pdf. Accessed: August 8, 2008.

Table 7.15
Cost of Carbon Capture and Storage for Typical Pulverized Coal Plant

	Cost Metric and Value	
Type of cost	**Metric**	**Value**
Annual energy capture cost	MMBtu/year	4,108,433
Hourly energy cost	MMBtu/hour	514
Fuel cost	$/MMBtu	6
Capture energy cost	$/ton CO_2	25
Annual capture energy cost	$/year	24,672,000
Annual capture plant maintenance cost	$/year	3,600,000
MEA regent and water costs	$/year	2,260,000
Total annual capture costs	$/year	30,532,000
Capture costs	$/ton CO_2	30.53

Source: Lyndon B. Johnson School of Public Affairs, *Creating a Carbon Capture and Storage Industry in Texas,* Policy Research Report Series, no. 154 (Austin, Tex., 2006), p.75.

Coal power plants also affect water quality and land use.[93] Coal plants use water to generate steam for producing power and for cooling. By one estimate, an average supercritical plant uses 1,042 gallons of water per MWh, while IGCC plants may use 25 to 30 percent less water per MWh than a supercritical plant.[94,95] Most of the water extracted from a water source is used and then returned to the source. Once the water is used, the wastewater typically has a higher temperature than the source water to which it returns and may have trace levels of ammonia, harmful metals, or other chemicals.[96]

Both types of coal mining—underground and surface—damage land, and coal mining remains one of the most hazardous professions.[97] Underground coal fires in abandoned mines, acid mine drainage, and land subsidence remain risks associated with coal mining. Burning coal in combustion plants produces waste ash. Typically, utilities either sell the ash for use in concrete or deposit it in landfills.[98] For example, AE sells its ash to be made into such products as cement, road base, and building materials.[99]

AE currently uses a verifiable registry to report its GHG emissions, but it does not conduct a full life-cycle assessment of the environmental impacts of its current fuel mix (see Chapter 4). A life-cycle assessment of the environmental impact of a coal power plant would take into account the impact of extraction, processing, and transportation of the coal, emissions related to the building and maintenance of the power plant, the transportation of employees to the plant, or even the impacts associated with decommissioning a coal plant.

Several "clean coal technologies" have been developed with the purpose of lessening the environmental impacts of coal-fired power generation. Such technologies include (a) physical or chemical processes to wash minerals and impurities from coal; (b) combustion processes that separate effluents before they can become pollutants; (c) equipment that reduces SO_2 or NO_x emissions created from coal plants; and (d) equipment designed to capture the CO_2 released at a coal plant.[100,101] Scrubber technologies reduce the volume of residual products of the combustion process that get into the air by capturing harmful pollutants.[102] At FPP, work began in 2007 to install scrubbers on units one and two to reduce SO_2 emissions from the two units by approximately 97 percent.[103] Installation of both scrubbers will be complete by 2010.[104] Retrofitting pulverized coal-fired combustion plants for carbon capture would be another clean coal technology. As discussed above, carbon capture may be the most effective clean coal technology for reducing air pollutants, but it is expensive to implement.

Fluidized bed combustion plants have the same fuel characteristics as pulverized coal plants. Costs to construct a fluidized bed combustion plant are about 5 to 10 percent more than pulverized coal plants without emission reduction equipment for SO_2 and NO_x emissions.[105] With such emission equipment installed however, pulverized coal boilers are about 8 to 15 percent more expensive than fluidized bed combustion boilers.[106]

IGCC technology improves the efficiency of burning coal for electric generation while reducing the volume of pollutants.[107] IGCC plants with CCS technology installed allow the operator to separate CO_2 from syngas. Once captured, the CO_2 could be injected underground for sequestration. When the syngas hydrogen is used to produce power, carbon emissions are lowered but not eliminated.[108]

Future Outlook

The supply of coal in the U.S. is large and relatively inexpensive and many analysts predict it will continue to be a staple of the U.S. power generation mix.[109] There are questions regarding the future of carbon regulation that could increase coal's price relative to other fuels. Mining and transport costs have increased over the years and are likely to continue to do so. Eighty-six coal power plants have been canceled or postponed since January 2007, illustrating the increased risk and uncertainty perceived by the public with coal power generation.[110]

Many questions surround CCS technology, making an IGCC plant with CCS technology a risky investment option for AE prior to 2020. The industry may mature rapidly in the coming years given the federal government's demonstrated support and interest, and the low price and high availability of American coal. Current evidence suggests the addition of CCS equipment to IGCC plants would lower operating efficiency by 7.2 percent and require an increase in the coal feed rate of 23 percent.[111] Sub-critical pulverized coal plants like FPP could expect a 9.2 percent drop in efficiency and an increase in coal feed rate of 37 percent when CCS technology is added to the end of the combustion process.[112] CCS technology increases the cost of electricity for pulverized coal plants and IGCC plants by 58 to 84 percent and 33 to 52 percent, respectively, according to an MIT review of recent estimates.[113] This is due in large part to the costs involved with capture, transportation, and storage of CO_2.

There is significant uncertainty over the timeframe for the emergence of a viable, utility-scale CCS industry. The MIT CCS study states that "there do not appear to be unresolvable open technical issues" with developing utility-scale geological sequestration of CO_2 by 2050, but no studies were found which addressed the likelihood of a viable storage market for CCS being available by 2020.[114] U.S. sequestration capacity estimates range from 2 to 3747 gigatons, according to the MIT meta-review, with most estimates in the range of 10 to 1000 gigatons.[115] While this number is undoubtedly large enough to serve AE's potential CCS demands, the timeline for sequestration development facilities, and marketplace competition for CCS storage as capacity develops, yields considerable uncertainty over the future price of CCS per ton of CO_2.

Options for Austin Energy

AE has multiple options for reducing or eliminating CO_2 emissions attributed to the burning of coal. One option would be for AE to invest in retrofitting FPP with CCS technology. A CCS system at FPP would reduce CO_2 emissions but it would also require significant energy to operate the capture process and significant costs to transport CO_2 to an available storage site. For example, AE's share of the FPP power plant produces approximately 4.4 million tons of CO_2 emitted annually.[116] If a capture system were to be implemented it is estimated that this would result in an 87 percent emissions reduction, capturing 3.8 million tons of CO_2 annually based upon current emissions rates at FPP for AE.[117] Powering the CCS equipment for FPP would reduce the production capability of FPP by about 36 percent.[118] Thus AE would be required to increase its share of nameplate generating capacity at FPP from 607 MW to approximately 950 MW to deliver the same amount of power to its customers. It should be noted that whole generating units at FPP would have to be upgraded with CCS equipment; this fractional analysis is only justified on the grounds of representing the cost-sharing burden that AE would likely incur from such a move. The cost of CCS retrofit is estimated to be $2,192 dollars per kW of power generating capacity, or a capital cost increase of $2,082 million for a 950 MW pulverized coal unit.[119] Total overnight costs would depend on the price at which AE could purchase additional stake in FPP, or whether expansion of the facility would be required. Assuming a base 2008 cost of $2485/kW of capacity, the roughly 343 MW expansion would cost an additional $852 million.[120] According to an MIT review, a CCS retrofit on a subcritical PC plant like FPP could increase the electricity costs by 4 cents per kWh (in 2001 dollars).[121]

AE could instead build a new IGCC plant equipped with CCS technology to replace FPP. For an IGCC power plant equipped with CCS technology to have a final output of 607 MW, AE would need to invest in 730 MW of IGCC power generating capacity.[122] Capital costs for such an IGCC plant with CCS technology installed would, at the recently estimated rate of $4,774 per kW, amount to $3,485 million.[123] Replacing subcritical PC units at FPP with IGCC power generating units with CCS technology installed could increase electricity costs by 1.5 cents per kWh (in 2001 dollars).[124]

Another option for AE could be to sell or lease all or part of its stake in FPP. The amount the utility would receive for the sale or lease of one or two half-units at FPP would depend on the market for coal-fired power generation at the time. Selling or renegotiating AE’s contract with LCRA prior to the implementation of carbon legislation may result in a higher value. While this option would reduce AE’s emissions, FPP provides 30 percent of the power the utility produces. The utility would have to change its power generation mix, supplementing the loss of baseload power generation by other means. Replacing the coal plant with nuclear power (another baseload power source) could provide system reliability but nuclear power entails its own risks and uncertainties (which are described elsewhere in this report). There are other baseload power options (biomass, natural gas, etc.) but each has its own risks and the per MWh cost of electricity will likely be much higher than current costs at FPP.

Conclusions and Recommendations

Austin Energy has multiple options for reducing or eliminating coal power generation from its utility mix, and thus reducing its CO_2 emissions. AE could of course do nothing about FPP, and by extension maintain that 71 percent of its total annual CO_2 emissions. AE could add 40 percent additional pulverized coal power generating capacity to FPP, and install CSS technology, to reduce emissions by roughly 3.8 million metric tons per year while increasing electricity costs at FPP by 4 cents per kWh. O r AE could replace FPP with an IGCC plant with CCS technology installed and sufficient additional power for carbon capture (roughly 730 MW nameplate capacity) to reduce emissions by roughly 3.8 million metric tons per year while increasing electricity costs at FPP by 1.5 cents per kWh.

AE should decide whether it is prepared to be an early adopter of IGCC power generation and CCS technology or whether it prefers to wait for a viable CCS market to emerge in the U.S. To ready an IGCC power plant with integrated CCS to replace FPP by 2020, AE would need to begin construction on such a plant by 2013.

As an alternative policy, AE could purchase offsets for FPP's emissions while continuing to operate pulverized coal generation. AE could instead sell or lease some or all of its stake in FPP and replace its baseload power generating capacity with biomass, natural gas, increased demand-side reduction, nuclear or a combination of variably available renewables (wind, solar) coupled with energy storage technologies. The emergence of a domestic utility-scale carbon sequestration industry, carbon regulation, or efficiency and reliability gains in renewable energy technology will determine which of the outlined options most economically allows AE to achieve significant reductions in CO_2 by 2020.

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Chapter 8. Natural Gas

Summary

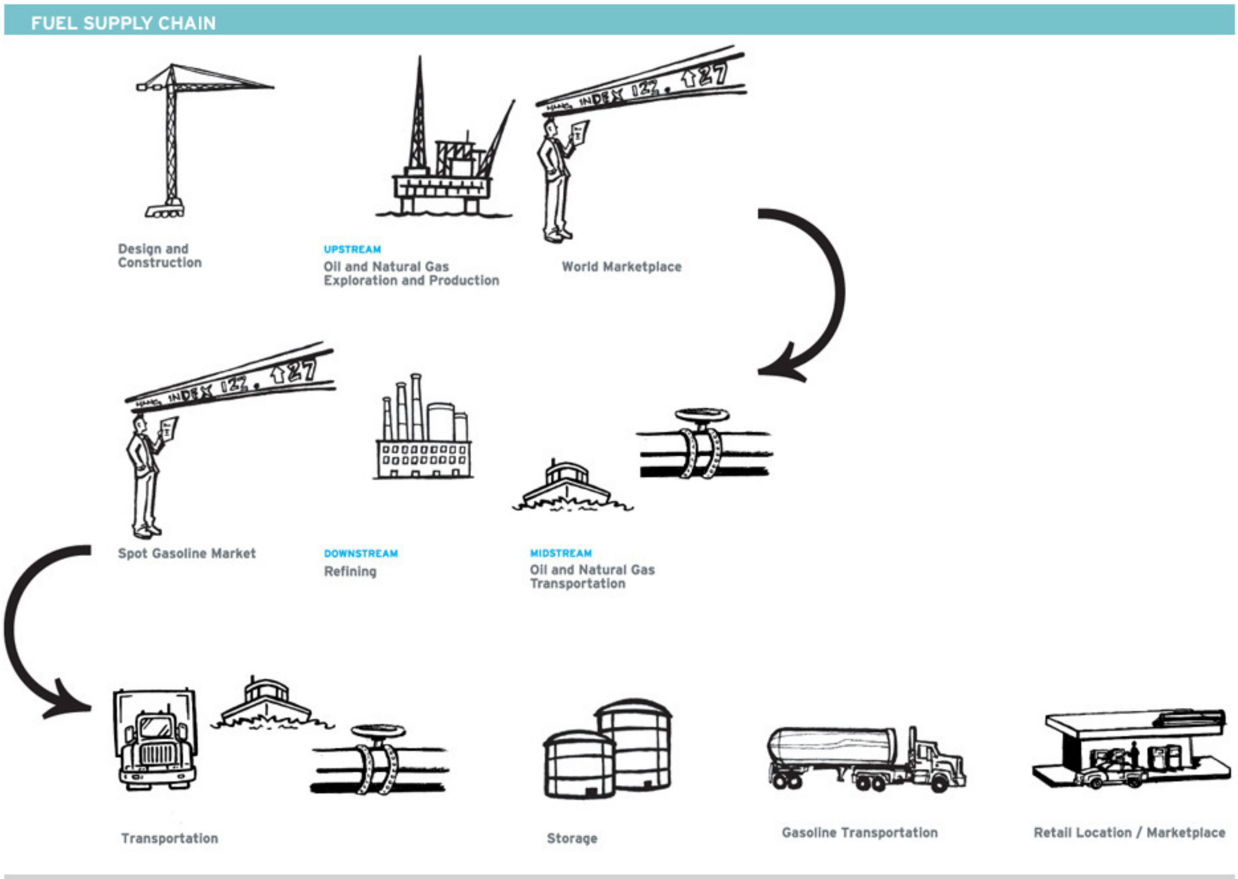
This chapter considers the potential for new natural gas electricity generation to contribute to Austin Energy's 2020 portfolio. AE currently operates 1,444 MW of natural gas power generating capacity, which accounts for approximately one quarter of its carbon dioxide (CO_2) emissions.[1] Natural gas can provide a substitute for coal and can serve as a backup power source for solar or wind power generation when the sun isn't shining or the wind isn't blowing. AE's greatest opportunity for reducing direct CO_2 emissions, as detailed in the previous chapter, is reducing its use of coal. AE could build additional natural gas power generating capacity before 2020 to replace the burning of coal for power production and to provide rapid backup power for future renewable power generating capacity.

Background

In the early 1990s, gas-fired power plants became the fuel of choice for electricity generation in the United States, with 90 percent of new power generating capacity coming from natural gas plants during that decade.[2] However, with the rise in gas prices and its associated volatility, investment in natural gas plants tempered by 2000, a trend that continues today.[3] According to the Energy Information Administration (EIA), the proportion of gas-fired power generation to total new power generating units will continue to decline in the U.S., reaching 37.6 percent of new units by 2010, down from 73.1 percent in 2006.[4] In Texas, natural gas accounts for more than 70 percent of power generating capacity and half of its annual power generation.[5]

Natural gas is a fossil fuel that consists primarily of methane (CH_4), four hydrogen atoms attached to a carbon atom. Natural gas is produced by microorganisms in many locations, especially swamps and landfills. The most abundant commercial source of natural gas comes from underground reservoirs often associated with petroleum. Natural gas can be produced from conventional oil wells (gas comes to the surface dissolved in the oil) or by itself. Oil wells have distinct natural gas, oil, and water layers. If crude oil is passed through a chamber of reduced pressure, the gas streams separate out. Some wells in the U.S. contain natural gas without crude oil. Every natural gas stream must be cleaned before it is used, as raw gas from the ground may contain impurities, such as heavier gases, oils, CO_2, water, or hydrogen sulfide. Processing plants designed for this purpose remove these impurities. Once cleaned, natural gas is usually transmitted or distributed via pipeline. Natural gas coming from overseas can be shipped using a liquid natural gas tanker which requires specialized facilities to compress and decompress the fuel. Figure 8.1 illustrates the process of transferring gas from a reservoir to its use for generating electrical power.

Figure 8.1
Diagram of Natural Gas Production Process



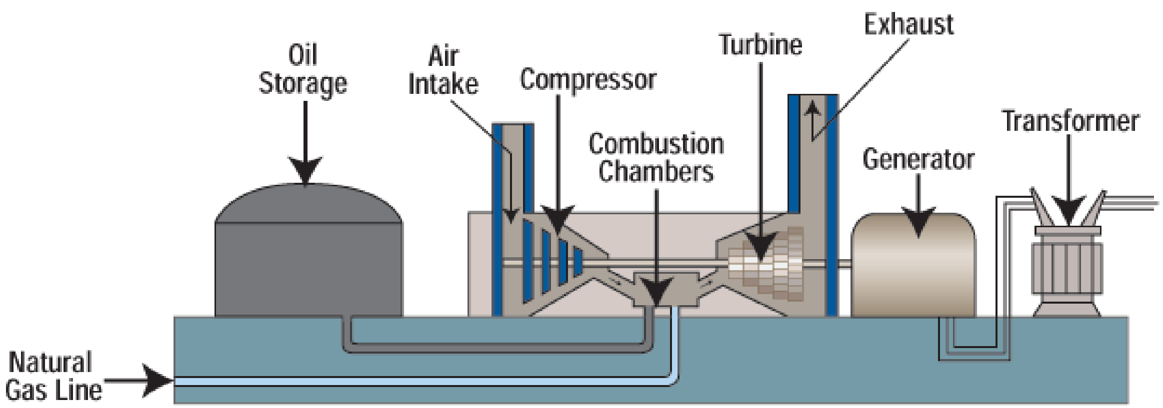
©2005 Chevron Corp.

Source: The Price of Fuel, *How Fuel is Produced*. Online. Available: http://www.thepriceoffuel.com/howfuelisproduced/. Accessed: December 11, 2008.

Fuel cost is the primary concern for the economics of natural gas-fired plants due to high and unpredictable fuel prices along with limited supplies. According to various estimates, including the EIA and the Oil and Gas Journal and World Oil publications, global natural gas reserves are around 175.4 trillion cubic meters (tcm).[6] The largest proven reserves are located in Russia, with 44.65 tcm or more than 25 percent of the world's supply, followed by Iran and Qatar with 15.3 and 14.6 percent of proven world reserves, respectively.[7] The U.S. has 3.4 percent of total proven natural gas reserves.[8]

There are two common types of turbines that burn natural gas to produce electricity, combustion gas turbines (CGT) and combined cycle gas 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 (see Figure 8.2). Table 8.1 compares cost and performance characteristics of CGT and CCGT technologies.

Figure 8.2
Diagram of a Combustion Gas Turbine



Source: Ira A. Fulton School of Engineering, *Fossil*. Online. Available: http://www.eas.asu.edu/~holbert/eee463/FOSSIL.HTML/. Accessed: December 11, 2008.

Table 8.1
Cost and Performance Characteristics of Natural Gas-Fired Power Generation Plants

	Technology Type	
Technology Characteristics	**Combined Cycle Gas Turbine**	**Combustion Gas Turbine**
Load service function	Base load, intermediate peak	Peak
Fuel dependability	Medium	Medium
Maturity	Mature	Mature
Time to construct (years)	3-5	<1
Operational life (years)	25-30	25-30
Cost to construct ($/kW)	565-620	411-431
Fuel cost ($/MWh)	50.37	75.60
Fixed O&M costs ($/kWh)	0.0061	0.0061
Variable O&M costs ($/kWh)	0.0321	0.0671
Availability factor (%)	90	95
Capacity factor (%)	30-40	10-15
GHG emissions (metric tons of CO2 equivalent per MWh)	0.39	Not available

Source: The National Regulatory Research Institute, *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria* (2007), p. 18. Online. Available: http://www.nrri.org/pubs/electricity/07-03.pdf. Accessed: October 09, 2008.

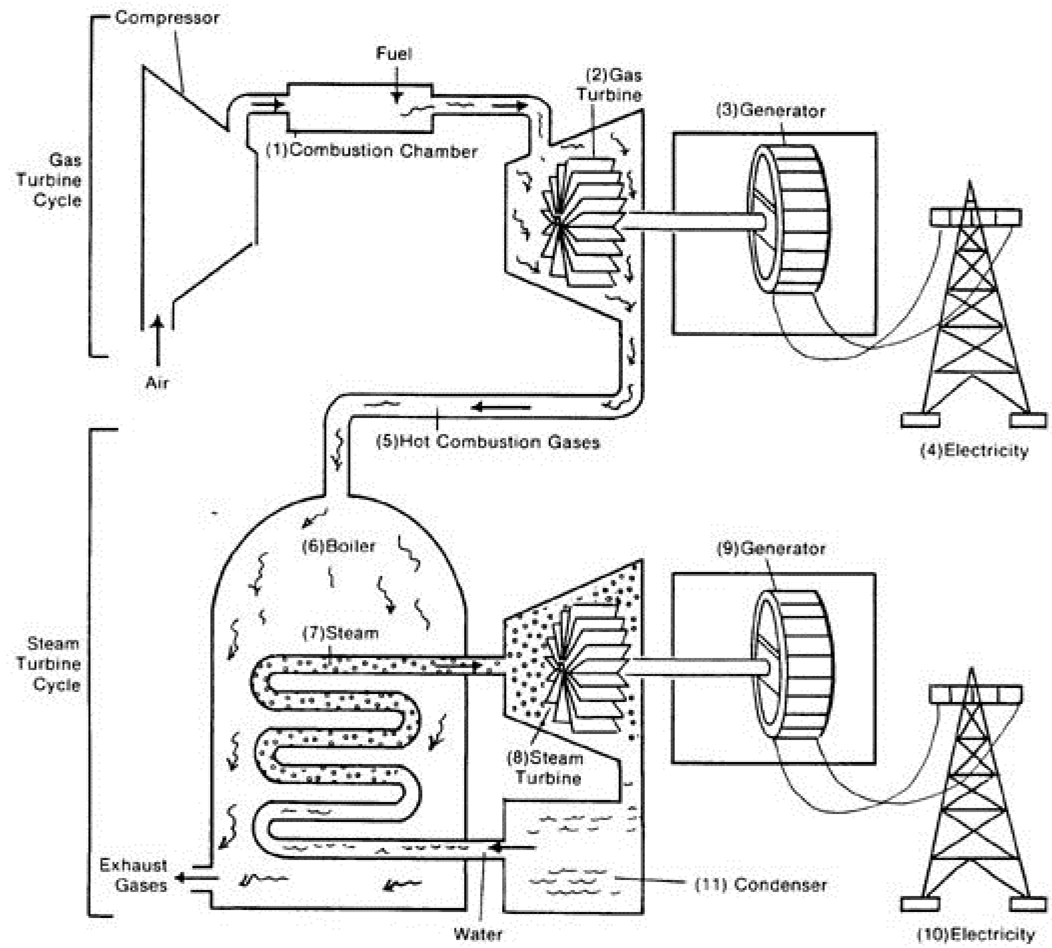
Combustion Gas Turbines

A CGT, also known as a simple cycle gas turbine, uses a rotary engine to compress gas and air, combust the mixture, and extract energy from this process. CGTs are appealing to meet peak demand because they can be powered up in a matter of minutes, meaning they have a high "ramp-up" rate. The heat rate for an average simple cycle plant is 10,807 British thermal unit per kilowatt-hour (Btu/kWh).[9] CGTs operate mainly as peaking facilities. Because CGTs typically serve peak demand, their capacity factors are low (typically between 30 and 85 percent), even though their availability factors are high (typically above 90 percent).[10] Recent studies have estimated the operational life of a simple cycle turbine plant to be 25 to 30 years.[11] Combustion gas turbine plants tend to be highly dependable and are a proven, mature technology.

Combined Cycle Gas Turbines

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 (see Figure 8.3). CCGTs are more efficient than CGTs, with a lower heat rate. A CCGT, like a CGT, can be used for baseload, intermediate, or peak power. CCGTs use both gas and steam-turbine thermodynamic cycles to generate electricity similar to the processes used by integrated gasification combined cycle coal plants.

Figure 8.3
Diagram of a Combined Cycle Gas Turbine



Source: Ira A. Fulton School of Engineering, *Fossil*. Online. Available: http://w ww.eas.asu.edu/ ~holbert/eee463/FOSSIL.HTML/. Accessed: December 11, 2008.

One 2006 estimate of the heat rate for a conventional combined cycle plant was 7,163 Btu/kWh.[12] CCGT plants are no longer novel and are considered a proven, mature technology. Although their life expectancies are not yet known, projected operational life is 25 to 30 years.[13] The price variability of natural gas tends to determine whether a natural gas-fired plant is used for baseload power, intermediate power, peak load, or a combination of these purposes. For AE, CCGTs serve an intermediate load function, while CGTs are used for peak load. The capacity factors of these units tends to fluctuate based on natural gas price. When natural gas prices are high, CCGT plants may operate between 30 and 40 percent of the time. When gas prices are relatively low, the same facilities may operate 80 to 90 percent of the time as an intermediate source of energy.[14] A typical combined cycle turbine has an availability factor of 90 percent.[15]

Operating Examples

AE currently operates 1,444 megawatts (MW) of natural gas-fired power generating capacity[16] through two large natural gas-fired plants, the Decker Creek Power Station, which is a combustion turbine facility, and the Sand Hill Energy Center, which contains a combined cycle unit as well as several combustion turbines. AE also owns the Domain and Mueller Energy Combined Heat and Power (CHP) plants, each of which produce 4.5 MW from natural gas that can be delivered in the form of chilled water, heat, steam, or electricity.

AE burns natural gas to provide both intermediate and peaking power.[17] The intermediate resources operate with a capacity factor that ranges between 35 and 55 percent.[18] Compared to baseload facilities such as coal and nuclear plants, natural gas facilities used for intermediate energy needs require much lower capital construction costs.[19] Decker and Sand Hill each have about 200 MW of peaking power generating capacity[20] with a capacity factor of 5 to 15 percent. While these facilities require relatively low capital costs, with high gas prices they can be the most expensive units in AE's resource portfolio to operate.[21]

The Sand Hill Energy Center is a relatively new power generation facility built and operated by AE in part to replace the decommissioned Holly plant. Located in Del Valle, Texas, Sand Hill has a total energy output of 480 MW.[22] Sand Hill is located in a remote area next to the South Austin Regional Wastewater Treatment Plant off of State Highway 71.[23] Four natural-gas fired combustion turbines were constructed in 2001 with power generating capacities of 51.4 MW (summertime capacity of 47.3 MW) each. In 2004 two additional units were constructed at Sand Hill. A combined cycle combustion turbine was installed with a power generating capacity of 198 MW (summertime capacity of 161 MW) and a combined cycle steam turbine was installed with a power generating capacity of 190 MW (summertime capacity of 151 MW).[24] The combined cycle units are primarily used for intermediate energy needs while the combustion turbines are used as peaking units. These peaking units comprised the first peaking facility of its kind in Texas to be constructed with selective catalytic reduction pollution control equipment to reduce NO_x emissions by 80 percent.[25] Sand Hill reuses wastewater at its facilities and relies on solar panels and solar thermal collectors to operate its facilities. In 2009 AE will add 100 MW of peak power generating capacity to the Sand Hill facility, in the form of two CGT plants rated at 50 MW each.[26]

The Decker Creek Power Station, located in Northeast Austin, uses natural gas as its primary fuel source with oil as an alternative. Total power generating capacity at Decker Creek Power Station is 926 MW.[27] Unit 1 was constructed in 1971 and has a power generating capacity of 327 MW. Unit 2 was constructed in 1977 and has a power generating capacity of 414 MW.[28] Units 1 and 2 both burn natural gas to drive steam turbines, with fuel oil supplies available as an alternative fuel source.[29] These units are used as intermediate power sources. Decker Creek Power Station also operates four combustion gas-fired turbines (with jet fuel as an alternative fuel source) that have a combined power generating capacity of 193 MW.[30] These four combustion gas-fired turbine units, constructed in 1988, are primarily used to meet peak demand.[31]

Economic Outlook

The capital costs for a combined cycle natural gas plant range from $1,000 to $1,500 per kilowatt (kW) of power generating capacity.[32] According to Federal Energy Regulatory Commission data, construction costs for CCGTs have doubled in the last four years because of rising global demand for engineering services and power plant equipment as well as rising costs of raw materials.[33] Fixed operating costs for CCGTs can range from $6.50 to $7.25 per kW per year.[34] The variable operating cost for a combined cycle turbine plant is $2.80/MWh.[35] The cost of running a natural gas-fired power plant fluctuates with natural gas prices. At a natural gas price of $7 per thousand cubic feet, the cost of running a CCGT is estimated to be 5 cents per kWh, or $50.37/MWh.[36] The estimated cost to build a CGT plant is between $414 and $431 per kW of power generating capacity.[37] The cost of running a CGT is estimated to be $75.60/MWh at the price of $7 per thousand cubic feet of gas.[38]

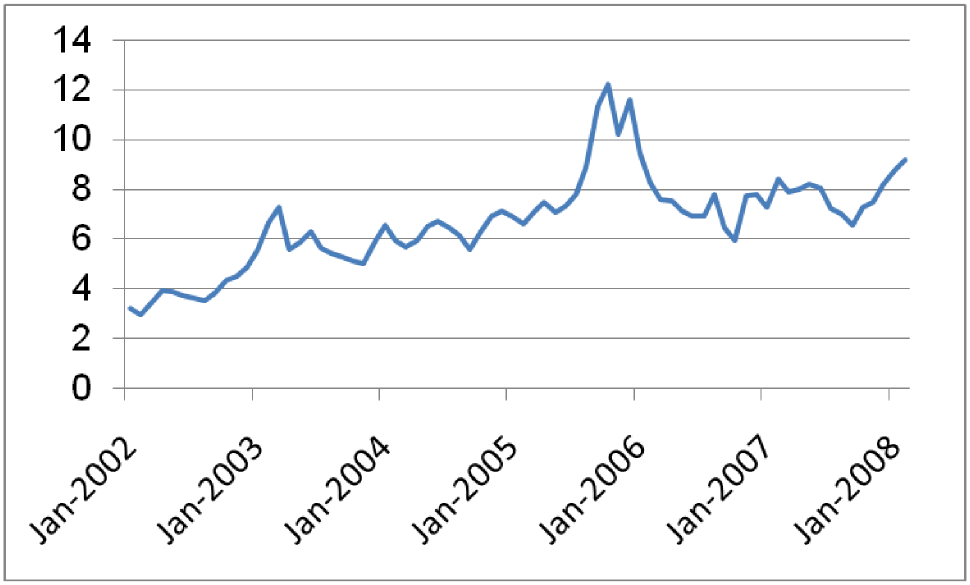
One source of concern about natural gas units is that power production costs depend heavily on natural gas prices which are both volatile and difficult to predict.[39] Every dollar increase per thousand cubic feet of natural gas prices equates to roughly a cent per kWh increase in electricity production costs for CGTs.[40] Every dollar increase in natural gas price would increase the cost of producing power from CCGTs by 0.7 cents per kWh.[41]

Since 2000 it has become increasingly difficult to forecast future natural gas prices, as several factors contribute to price variability.[42] One change is the rise in demand for new natural gas power generating plants in the electricity sector, as about 200 gigawatts of new power generating capacity has been added over the last five years in the U.S.[43] Hurricanes Ivan, Katrina, and Rita created serious supply shortages and price hikes followed.[44] It is difficult to determine how much speculation has also contributed to increasing natural gas prices.[45] Hedge fund activity in the natural gas sphere saw an increase from about $0.3 billion in the early 1980s to over $35 billion in 2000, and then to $132 billion in 2004.[46]

One study released in 2002 suggested natural gas prices would average between $3.77 to $6.72 per million Btu (MMBtu) for the near future.[47] The spot price for natural gas electricity generators, which historically receive the most competitive pricing, has fluctuated from less than $3/MMBtu in 2002 to a peak of over $12/MMBtu in 2005. Prices have averaged well over $6/MMBtu since 2004.[48] Figure 8.4 demonstrates the changing natural gas spot prices for electrical generators from 2002 to 2008.

Figure 8.4
Natural Gas Spot Prices for Electrical Generators

(Dollars per metric cubic foot)



Source: Adapted from Energy Information Administration, *U.S. Natural Gas Electric Power Price*. Online. Available: http://tonto.eia.doe.gov/dnav/ng/hist/n3045us3m.htm. Accessed: November 24, 2008.

To compensate for the volatility and rise in natural gas prices, utilities have begun to use hedging mechanisms.[49] This typically consists of entering contracts for fixed fuel prices for future gas deliveries and may sometimes be accompanied by the acquisition and storage of gas supplies.[50] For AE, natural gas costs represented 54 percent of total fuel costs despite providing just 26 percent of AE's electricity produced in 2007.[51]

Environmental Impacts

CO_2 emissions attributed to the burning of natural gas are lower per kWh compared to other fossil fuels; 30 percent less CO_2 than oil and almost 45 percent less than coal.[52] AE estimates that on average its own CCGT plants emit 360 kg/MWh of CO_2 and its CGT plants produce from 520 to 730 kg/MWh CO_2.[53] CCGT plants occupy about one-tenth of the space of a comparable nuclear or coal plant.[54] Water use tends to be comparable for natural gas versus oil or coal, as it reflects the relative efficiency of the natural gas plant; the waste heat ends up as thermal pollution.[55] Extraction, storage, and transportation of natural gas also pose fewer land-use, effluent, and aesthetic problems, compared to nuclear or coal.

On average, U.S. natural gas-fired power plants produce 1,135 pounds (lbs) of CO_2, 1.7 lbs of nitrous oxides (NO_x), and 0.1 lbs of sulfur dioxide (SO_2) per MWh of electricity generated.[56] CCGT plants produce roughly two-thirds the emissions of these pollutants that CGT plants produce.[57,58] Natural gas power generation produces half the CO_2, less than a third of NO_x, and one percent of sulfur oxides (SO_x) of an average coal plant.[59] Table 8.2 details the emissions from a natural gas combined cycle plant.

Table 8.2
Emissions of a Natural Gas Combined Cycle Plant

Pollutants	Effluent Rate (kg/MWh)
Particulates (PM-10)	0.007
SOx	0.002
NOx	0.039
CO	0.005
Hydrocarbons/VOC	0.0003
Ammonia	0.0000006
CO_2 (baseload operation)	411
CO_2 (full power operation)	429

Source: Northwest Power Planning Council, *New Resource Characterization for the Fifth Power Plan: Natural Gas Combined-cycle Gas Turbine Power Plants,* p. 8. Online. Available: http://www.westgov.org/wieb/electric/Transmission%20Protocol/SSG-WI/pnw_5pp_02.pdf. Accessed: October 9, 2008.

Although natural gas combustion processes do not consume substantial amounts of water, cooling does require significant amounts of water use and waste water is often discharged into lakes or rivers with thermal and chemical pollutants.[60] A CCGT plant produces no large solid waste streams.[61] The extraction of natural gas can also affect soil productivity and wildlife habitats. Fuel production and transportation of natural gas creates additional environmental burdens. According to one life-cycle analysis of a combined cycle system conducted by researchers at the National Renewable Energy Laboratory, the net greenhouse gas (GHG) emissions of a CGGT, when converted to CO_2 equivalents, amount to 499.1 grams (g) per kWh.[62] Roughly 24.9 of all natural gas-related GHG emissions occur during natural gas production and distribution and 74.6 percent of air emissions are produced during power plant operation.[63] Ammonia production and distribution contributes 0.1 percent, and construction and decommissioning of power plants accounts for 0.4 percent of all life-cycle GHG emissions.[64]

Future Outlook

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. Due to fuel price volatility the cost advantages are growing negligible. Natural gas power plants have relatively small land requirements and have a relatively short construction period versus coal or nuclear plants. They also produce lower volumes of CO_2, SO_2, NO_x, and particulate pollution. A utility can build gas-fired power facilities at relatively low costs due to a diversity of available sizes in power generation units in order to respond to changes in energy demand and economic conditions, while still having the capability to increase power generation capacity over time.

Fuel price volatility and the potential implementation of carbon regulation is likely to continue to influence the popularity of natural gas facility investment. CCGTs emit about half the amount of CO_2 per MWh of a pulverized coal plant, making them more attractive as a fossil fuel option in the event of carbon regulation.[65] Fuel prices could also alter the economic attractiveness of natural gas-fired plants in the future. For example, natural gas prices that utility operators paid between 2002 and 2008 changed the economics of natural gas turbines. A once economically feasible power generation source became much more expensive to operate. The volatility in natural gas prices made even the most efficient turbines among the costliest of fossil fuel-powered plants.

Electric utilities are unlikely to rely on natural gas facilities for baseload power generation unless they are assured of stable fuel prices. Implementation of a carbon tax or a cap-and-trade system may affect natural gas power generation costs, even though natural gas is the least carbon intensive of all fossil fuels. A high enough carbon price could create strong economic disincentives to all fossil fuels.

In the absence of carbon legislation, CCGT plants likely will continue in their limited roles of providing peak and intermediate generation at today's prices because gas cannot compete with the marginal costs of producing electricity from coal.[66] The EIA projects that in the absence of compulsory carbon constraints, natural gas will constitute 40 percent of new power generating capacity in the U.S. between 2006 and 2030, accounting for 17 percent of the nation's overall power generation mix in 2030.[67] The Electric Power Research Institute also expects gas consumption in the electric power sector to peak in 2019 and then decline as new coal-fired technology becomes more prominent.[68] In a speech at the July 2007 Texas Public Power Association annual meeting, Barry Smitherman, Chairman of the Public Utility Commission of Texas, expressed concern that Texas is too dependent on natural gas and called for expanding alternate energy sources in the state's power generation mix.[69]

The main uncertainties associated with natural gas are related to price and supply. Natural gas is limited within the lower 48 states and it may become necessary to rely on unconventional gas supplies or natural gas imports to meet future domestic demand. By 2030, EIA projects that unconventional gas supplies (such as Devonian shale, tight sands, and coal-bed methane) could make up 45 percent of total natural gas consumption in the U.S.[70] Although the potential for pipeline and storage failures and terrorist attacks exists, catastrophic risks are not generally believed to be a major deterrent to building new natural gas-fired power plants.

Natural gas power generating technologies have increased in efficiency over the past several decades and are likely to continue to improve. By 2020, a CCGT plant is expected to have an overall operating efficiency above 55 percent and some CHP plants can already operate at over 70 percent efficiency.[71] Table 8.3 compares the cost and performance characteristics for advanced combustion turbines with conventional turbines.

Table 8.3
Conventional and Advanced Combustion Turbine Characteristics

Performance Measure	Metric	Advanced Combustion Turbine	Conventional Combustion Turbine
Construction time	years	2	2
Size	MW	230	160
Total overnight cost	$/kw, in 2006	473	500
Variable O&M	$/kw, in 2006	3.08	3.47
Fixed O&M	$/kw, in 2006	10.24	11.78
Heat rate	Btu/kWh, in 2007	9,289	10,833

Source: Energy Information Administration, *Assumptions to the Annual Energy Outlook 2008* (June 2008), p. 79. Online. Available: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf. Accessed: November 29, 2008.

Microturbines, or smaller gas-fired power generation units, are becoming popular. Currently developed at the 30 to 350 kW capacity range, they can stand alone or provide backup power for customers such as hospitals and office buildings.[72] Recuperators, or internal heat exchangers found in most microturbines, can increase efficiency through the preheating of inlet air.[73]

Options for Austin Energy

AE has already made a strong commitment to gas-fired power generation as it represents 26 percent of AE's 2007 power generating capacity.[74] In addition to a new 100 MW gas combustion turbine at Sand Hill that has already been approved to increase peaking capacity, AE plans to add 200 MW of additional capacity in 2013 to assist in meeting Austin's increasing energy demand and to provide a rapid-starting option as a backup for wind and solar energy resources.[75] This expansion project would provide reliable energy with lower CO_2 emissions than coal. AE is hoping to avoid the prospect of high natural gas prices by negotiating pre-pay fuel contracts. For example, AE argues that it will save $278 million in projected fuel costs through pre-pay contracts.[76] It has been projected that CO_2 emissions will be reduced by 1.6 million tons cumulatively through 2020 if the expansion project is completed.[77] Furthermore, AE has the ability to expand power generating capacity at Sand Hill up to 1000 MW without any further land purchases.[78]

AE is likely to continue to invest in natural gas power generating capacity, both to meet future demand and supply rapid-starting backup power for future wind and solar projects. The attractiveness of expanding natural gas power generating capacity depends on the fuel contracts into which AE is able to enter. An expansion at Sand Hill could be accompanied by a reduction in capacity at Decker, or its decommissioning altogether. To compensate for this reduction in intermediate and peak capacity, there would need to also be an increase in renewable power generating capacity, a step that would further reduce AE's CO_2 emission profile. AE can retain natural gas facilities as a complement and backup power source for wind and solar power as it seeks to reduce CO_2 emissions by 2020.

Conclusions and Recommendations

Natural gas is a key component of AE's intermediate and peak-load power generation sources. AE is likely to continue to rely on the high-efficiency CCGT power generating units as an intermediate power source, while utilizing combustion turbines to back up variable wind and solar energy.

If the U.S. moves to regulate CO_2 emissions, it is possible that decommissioning some of AE's natural gas portfolio could yield carbon offset credits. However, given the high percentage of CO_2 emissions attributed to AE's share in the coal-fired Fayette Power Plant, coal represents a priority target for AE's future CO_2 emissions reduction goals. The current economic situation has analysts cutting natural gas price forecasts for 2009, but this has little bearing upon gas price potentials in 2020.

Further AE investment in natural gas power generating capacity appears likely, either to supply rapid-starting backup power to future wind and solar portfolios, or to offset reductions to baseload capacity if AE decides to reduce its coal power generating capacity in response to federal carbon regulation.

A cost analysis of full or partial decommissioning of Decker and purchasing land parcels adjacent to Sand Hill for further CCGT development is warranted. Decommissioning the Decker facility would require the replacement of 926 MW of intermediate and peak power generating capacity, while Sand Hill has room for 1,000 MW of capacity additions without additional land purchases.

AE should consider expanding the power generating capacity of the Sand Hill facility to meet future demand increases and provide rapid-starting backup power generation needs for future wind and solar power investments. The availability of affordable carbon offset credits, demand side management opportunities, and energy storage technology in which AE invests by 2020 will determine the ratio of additional peaking CGT to intermediate CCGT capacity best suited to AE's needs.

Notes

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Chapter 9. Nuclear

Summary

This chapter describes nuclear fission as a source for electric power and its potential to fit into Austin Energy's 2020 energy resource portfolio. The comparative advantages of nuclear power for AE are its zero direct carbon dioxide (CO_2) emissions compared to fossil fuels and its low operating cost. The risks associated with nuclear power are that the cost and length of time for construction of new power plants are uncertain, there has been no national decision as to a site for the disposal of highly radioactive waste, and there is a public perception of a higher risk of operation than alternative sources. While AE has twice declined the opportunity to invest in next generation nuclear power since 2008, AE should remain informed of the balance of risk and reward, particularly if the United States adopts fees that penalize carbon emitting energy sources.

Background

There is approximately a million times more energy potential per gram of fuel in nuclear fission when compared to the molecular chemical process of traditional fossil fuel burning. Much of the developed world in the early 1950s believed that nuclear power could become a solution for the world's growing power demand. The first nuclear reactor in the U.S. was a small experimental breeder reactor (EBR-1) in Idaho that began producing electricity in December 1951. The first commercial reactor was a pressurized boiler reactor, which successfully ran from 1960 to 1992. During the 1960s the nuclear power industry grew both in the U.S. and world-wide. The industry declined during the 1970s and 1980s as the number of new nuclear power units ordered and brought online fell to nearly zero, reflecting public concerns regarding nuclear safety and financing risks.[1]

Interest in nuclear power has renewed because it represents a source of baseload electricity generation that does not convert carbon fuels into CO_2 and other potentially harmful air pollutants. In the 2005 Energy Policy Act, the U.S. Congress included incentives for new-generation nuclear power reactors.[2] Table 9.1 lists the major cost and performance characteristics of nuclear power generation.

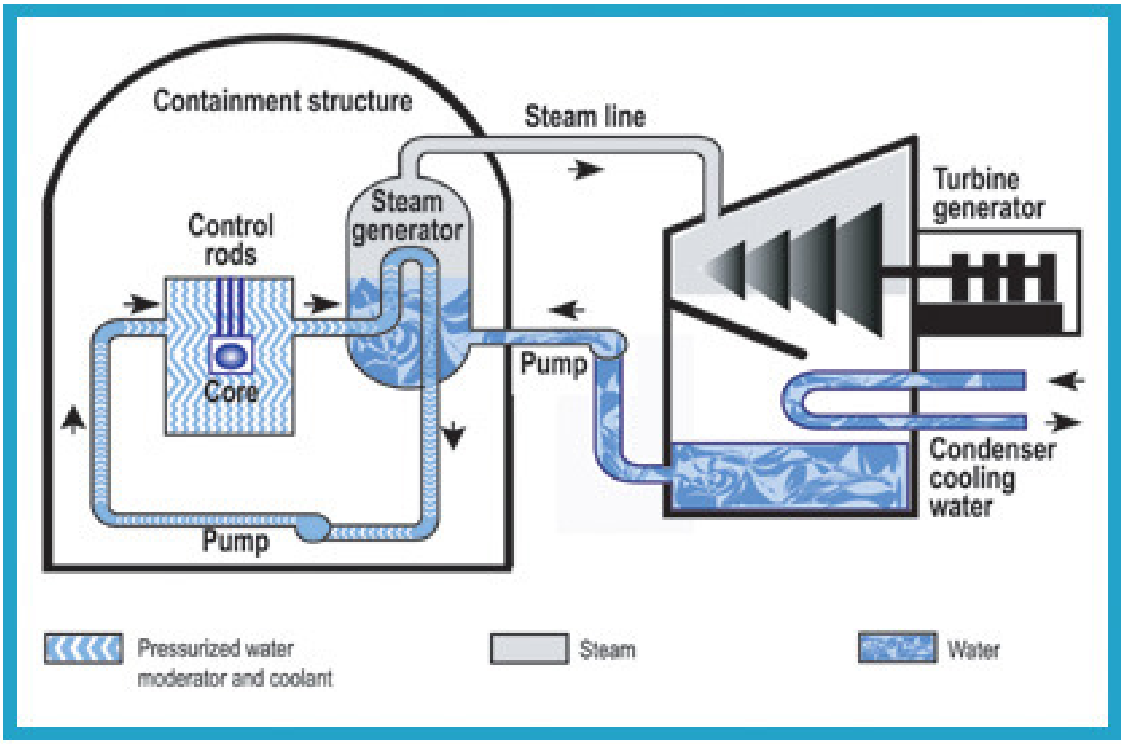
Nuclear reactors are comparable to most fossil fuel powered electric plants in that they generate steam which turns a generator to produce electricity. What differentiates nuclear energy from other sources of electricity produced by steam driven turbines is the fuel used, fission of uranium-235 (U-235). There are six common components to most nuclear power reactors: fuel, a moderator, control rods, coolant, a pressure vessel, and a steam generator (see Figure 9.1).

Table 9.1
Nuclear Power Performance and Cost Characteristics

Technology Characteristics	Nuclear Energy
Load service function	Baseload
Fuel dependability	Medium
Maturity	Mature
Time to construct (years)	9
Operational life (years)	40-60
Cost to construct ($/kw)	1,849
Fuel cost (2006 $/MWh)	4.89
Fixed operation and maintenance costs ($/mWh)	8.00
Variable operation and maintenance costs ($/kW)	Not available
Availability factor (percent)	90-97
Capacity factor (percent)	91.8
GHG emissions (metric tons of CO_2 equivalent per MWh)	None

Sources: The National Regulatory Research Institute, *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria*, p.18. Online. Available: http://www.coalcandothat.com/pdf/35%20GenMixStateToolsAndCriteria.pdf. Accessed: July 16, 2008; Congressional Budget Office, *Framing the Analysis: Base-Case Assumptions and the Effects of Policy*. Online. Available: http://www.cbo.gov/ftpdocs/91xx/doc9133/Chapter2.5.1.shtml#1090614. Accessed: November 2, 2008; and Nuclear Research Institute, *Resources and States*. Online. Available: http://www.nei.org/resourcesandstats/documentlibrary/reliableandaffordableenergy/graphicsandcharts/usnuclearindustrycapacityfactors/. Accessed: December 10, 2008.

Figure 9.1
Diagram of a Nuclear Power Generation Facility



Source: World Nuclear Organization. *Electricity Generation-Nuclear Power Reactors* (1996). Online. Available: http://www.world-nuclear.org/how/npreactors.html. Accessed: October 12, 2008.

Uranium fuel is formed into pellets that are smaller than a thimble, with each one containing the energy of nearly a ton of coal. The pellets are loaded into fuel rods that are bundled together to form fuel assemblies. The control rods are made from neutron-absorbing materials such as cadmium, hafnium, or boron. Approximately 200 assemblies are grouped together to make a reactor's core, which is typically 10.5 feet across and 14 feet high. The moderator is the medium that slows the fission-released neutrons in order to produce further fission. A reaction starts when control rods are withdrawn and fission begins. Rods are inserted into the reactor's core to control the rate of fission or to stop it completely. Coolant is circulated through the core to transfer heat, the heat converts water to steam (see Figure 9.1).[3] The steam turns the turbine to produce electricity and spent steam is fed into a condenser. When the steam is cooled by water from a reservoir and pumped back to the steam generators, the cycle starts again.[4] Nuclear radiation from fission is captured inside the core. All nuclear power plants are constructed with a containment system that is designed to capture any radiation should a major malfunction occur. The typical containment system is a re-enforced concrete vessel at least one meter thick.[5]

Several generations of reactors are commonly distinguished. Generation I reactors were developed in 1950s and 1960s, and outside the UK none are still running today. Generation II reactors are typified by the present U.S. fleet and the most common in operation globally. Generation III (and 3+) are advanced reactors currently in prototype operation in Japan and are under construction or ready to be ordered in other parts of the world including Europe and the U.S. Generation IV designs are still in the development stage and will not be operational before 2020 at the earliest.[6]

Currently there are two types of nuclear reactors licensed by the Nuclear Regulatory Commission (NRC) to operate in the U.S.: pressurized water reactors (PWR) and boiling water reactors (BWR). As of 2008, the NRC has currently licensed 104 nuclear power reactors in the U.S. (69 PWR and 35 BWR) that generate about 20 percent of electricity in the U.S.[7] Nuclear power plants have reliable availability records, typically shutting down only to re-fuel. According to estimates of the U.S. Department of Energy (DOE), the average U.S. nuclear power plant experiences 40 days of shutdown per year. Nuclear power plants in the U.S. range in capacity between 512 megawatts (MW) and 1,314 MW. Table 9.2 details power generation capacity, capacity factor and monthly output for the period of January to June 2008 for all Texas nuclear power reactors.[8] AE currently produces about 27 percent of its electricity from nuclear power.[9]

Table 9.2
Texas Nuclear Reactors Capacity and Output

	Nuclear Reactor					
Capacity and Output	**Comanche Peak 1**	**Comanche Peak 2**	**STP 1**	**STP 2**	**Texas Total**	**U.S. Total**
Net capacity MW(e)	1,150	1,150	1,280	1,280	4,860	100,635
Capacity factor (%)	93.0	96.2	94.6	93.7	N/A	N/A
January (MWh)	874,729	875,910	1,015,428	1,014,997	3,781,064	70,686,448
February (MWh)	733,286	840,452	946,554	947,698	3,447,990	64,936,331
March (MWh)	872,420	747,222	848,366	1,009,014	3,447,022	64,682,802
April (MWh)	843,447	279,814	89,087	970,557	2,182,905	57,281,042
May (MWh)	869,240	869,640	998,223	998,585	3,735,688	64,794,361
June (MWh)	836,727	837,576	956,224	954,847	3,585,374	70,268,406
Year to date (MWh)	5,029,849	4,430,614	4,853,882	5,895,698	20,210,043	392,649,390

Source: Energy Information Administration, *US Generation of Electricity* (June 2008). Online. Available: http://www.eia.doe.gov/cneaf/nuclear/page/nuc_generation/usreact08.xls. Accessed: October 27, 2008.

N/A = not available

In a typical PWR, the nuclear fission in the core of the reactor produces heat. Pressurized water in the coolant loop carries the heat via a heat exchange system to the steam generator. The steam line then directs the steam produced from the heat to the turbine, which turns to produce electricity. Excess steam is collected in a condenser, turned back into water, and returned to the reactor. A typical PWR contains 150 to 200 fuel assemblies.[10]

A BWR differs in the delivery of steam. As the core heats through nuclear fission, coolant water is passed upward through the core, where it is converted into steam. Droplets of water are collected and removed from the steam line, and directed to the turbine, which turns to produce electricity. After being processed through the turbine generators, the steam is collected, condensed, and returned to the reactor to repeat the process. A typical BWR contains 370 to 800 fuel assemblies.[11]

Electric utilities typically use nuclear energy as a baseload power source because a nuclear reactor can produce electricity with lower marginal cost of fuel than all combustion-fired power plants. Nuclear energy is typically not used to service peak load, as it is costly and time consuming to start up and stop the fission process. U.S. nuclear plants have served as reliable power generation facilities with low operation and maintenance costs compared to other technologies. Technological improvements continue to enable nuclear plants to run safer and more efficient. Table 9.3 compares cost and performance characteristics of nuclear, coal, and natural gas baseload power generation plants.

Table 9.3
Baseload Power Generation Technologies Cost and Performance Characteristics

	Characteristics					
Technology	**Construction time (years)**	**Overnight cost (2006 $/MW)**	**Fuel cost ($/mWh)**	**Fixed O&M ($/mWh)**	**CO_2 emissions (Mton/mWh)**	**Heat rate (Btu/kWh)**
Advanced nuclear	6	2,358	8	8	0	10,400
Conventional coal	4	1,499	16	4	1	9,200
Conventional natural gas	3	685	40	1	0.5	7,196
Innovative coal	4	2,471	17	6	0.85	N/A
Innovative natural gas	3	1,388	52	3	0.3	N/A

Source: Congressional Budget Office, *Framing the Analysis: Base-Case Assumptions and the Effects of Policy*. Online. Available. http://www.cbo.gov/ftpdocs/91xx/doc9133/Chapter2.5.1.shtml#1090614. Accessed: November 2, 2008.

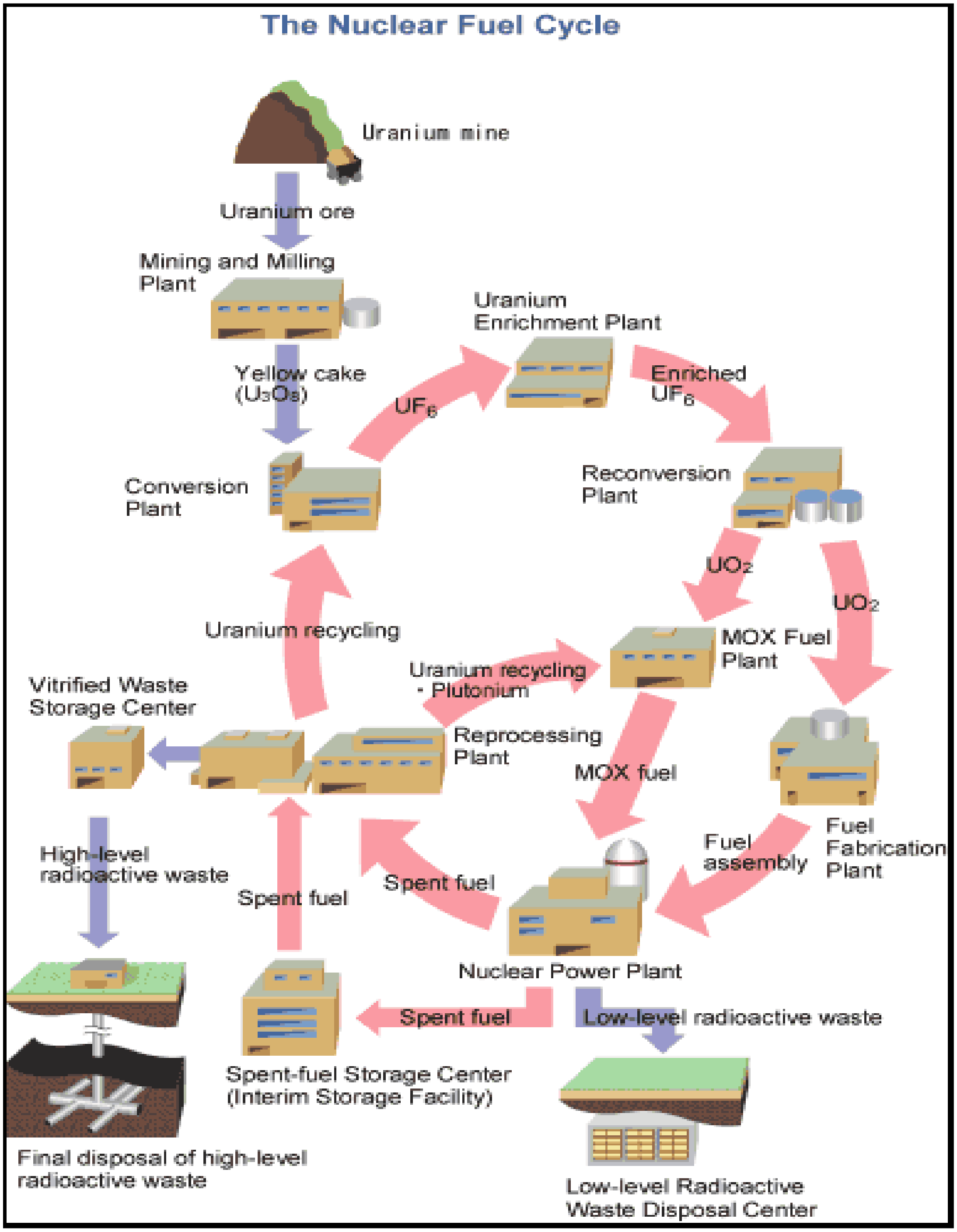
Nuclear power plants have an average life span of between 40 and 60 years. The Atomic Energy Act and NRC regulations limit the length of an operator's license to 40 years but these licenses are routinely renewed for up to 20 years.[12] The South Texas 1 reactor was licensed in March of 1988 (its license expires August 2027), and The South Texas 2 reactor was licensed in March 1989 (its license expires in December 2028).[13]

Nuclear fuel is produced from uranium. Before uranium can be used as fuel in a nuclear reactor it must be processed from raw rock form and enriched. The enrichment process consists of five steps: mining, milling, conversion, enrichment, and fabrication. Uranium either can be mined through traditional mining operations or produced as a by-product of other mineral processing operations. Once uranium is mined, solvents are used to remove uranium from the ore. The remaining uranium oxide (called yellowcake) can then be filtered and dried. Once dried the yellowcake is sent through the conversion process where it is chemically treated to become uranium hexafluoride. This compound is heated into a gas and trapped in cylinders. When it cools, it condenses into a solid form of hexafluoride that contains two types of uranium, uranium-238 and U-235. U-235, the type used for fission, is typically less than one percent of the yield. The U-235 is then enriched to three to five percent and fuel rods are produced from this enriched U-235.[14] Figure 9.2 illustrates the complete nuclear fuel cycle.

Since 2000, the price of uranium has risen, which has spurred private sector investment into renewed uranium mining and enrichment. Current estimates indicate adequate uranium stores in the U.S. and Canada for at least 100 years at current usage rates.[15] In 2005 the Organization for Economic Cooperation and Development and the International Atomic Energy Agency issued a joint report that stated that current uranium reserves are adequate to meet the needs of both existing and projected nuclear reactors worldwide.[16] These estimates do not take into account utilizing weapons-grade plutonium from decommissioned nuclear weapons.[17] According to the Nuclear Energy Administration, sufficient nuclear fuel resources exist to meet the energy demands of current and future generations, even if increased demand requires the construction of new nuclear plants.[18]

Research and history indicate that other than terrorism there are only a few risks associated with storing nuclear fuel assemblies. Nuclear pellets, which form fuel rods, are small and stored easily. Nuclear energy's main unresolved risks involve the storage and disposal of spent nuclear fuel and a public perception (after the Three Mile Island and Chernobyl incidents) of the potential risk of a core meltdown.

Figure 9.2
Diagram of the Nuclear Fuel Cycle



Source: Class presentation by S. Biegalski, Nuclear Engineering Teaching Laboratory, *Nuclear Power Technology,* at the Cockrell School of Engineering, The University of Texas at Austin, February 2008.

Operating Example

AE generates 27 percent of its electricity through the use of nuclear power derived from its 16 percent ownership of the South Texas Project (STP) located in Matagorda County, southwest of Bay City, Texas. STP sits on a 12,220 acre site. Included on this site is a 7,000 acre water reservoir which contains the water used for cooling the nuclear reactors.[19] Providing AE with 422 MW of power generating capacity, STP provides a baseload power source for AE. The two pressurized light water reactors at STP are operated by the STP Operating Company and have provided power continuously for almost four years, except for brief refueling periods. STP is the most productive nuclear power plant in the world with a capacity factor of more than 90 percent in years in which refueling occurs and 100 percent in other years.[20] STP was designed with one more emergency core cooling system than most nuclear reactors in order to reduce the risks posed by the nuclear plant.[21] This facility also has one of the lowest unsubsidized production costs of the nuclear power plants in the U.S.[22]

Ownership of STP is divided among Reliant Energy HL&P (30.8 percent), San Antonio Public Service Board (28 percent), Central Power & Light (25.2 percent), and AE (16 percent or 422 MW of energy output).[23] Constructed in 1988, Unit 1 has a generating capacity of 1,264 MW with a capacity factor of 61.2 percent. Constructed in 1989, Unit 2 has a generating output of 1,265 MW with a capacity factor of 80 percent. Both units are pressurized light water reactors. The operating license for Unit 1 expires in 2027 and the license for Unit 2 expires in 2028 unless a 20 year extension is requested and granted.[24] As of 2009 no decision has been made as to the future of the plant after 2027.[25] The cost of decommissioning a nuclear power plant in the U.S. ranges from $300 million to $500 million.[26] AE has established a trust to pay for its share of decommissioning STP.[27]

In 2007, NRG Energy, a wholesale power generation company headquartered in Princeton, New Jersey, announced a $6 billion expansion to STP that would add 2,700 MW of power generating capacity and two advanced boiler reactors to the plant. NRG Energy filed its application for a license to construct the new reactors with the NRC in 2007, the first such application filed in the U.S. since 1979.[28] As of March 2009 the City of Austin has decided not to participate in the expansion of STP based upon recommendations from AE.

Nuclear energy has several advantages over coal. If the same amount of power as is produced at STP were to be produced by burning coal, AE would emit an additional 6 to 8 million tons of CO_2 per year.[29] Furthermore, nuclear energy is cheaper by 35 percent per kilowatt-hour (kWh) compared to coal, the next lowest cost energy source.[30] Fueling a reactor for one year requires approximately 350,000 pounds of raw uranium in order to produce about 1,000,000 kW of electricity for about 7,500 hours at a rate of approximately 0.04 cents per kWh.[31]

STP has the lowest production costs reported by any nuclear power plant in the U.S. In September 2007, STP's cost to produce energy was 1.356 cents per kWh.[32] STP led all

33 two-unit U.S. plants in output in 2006, generating 21.36 billion kWh of electricity.[33] STP operates the most reliable nuclear power plant in the U.S., setting the record for continuous operation during the period from 2005 to 2008.[34] Unit 1 operated continuously from April 2005 to October 2006 (when it was shut down for refueling) and from November 2006 to March 2008 (when it was refueled again). Unit 2 was continuously online from October 2005 to March 2007, and again from April 2007 to October 2008. During this run, the units generated 32.7 billion kWh and 32.3 billion kWh of electricity, respectively.[35]

Economic Outlook

Construction costs of a nuclear power plant are difficult to predict. Cost estimates range from $1,000 to $5,000 per kW of power generation capacity, or from $1 billion to $5 billion for a 1,000 MW power plant.[36] The variation in the overnight cost estimates is explained by the following three factors: uncertainty of escalation of commodity prices over the length of construction; risk of changes in design work; and experience within the nuclear power industry that early estimates rarely account for all costs.[37] An October 2007 estimate by Florida Power and Light places the range of overnight cost for two new nuclear units at its Turkey Point site at between $3,108 per kilowatt electricity (kWe) and $4,540/kWe based on an earlier study conducted by the Tennessee Valley Authority (TVA) and adjusted for specific conditions of the site.[38]

In November 2008, TVA updated its estimates for Bellefonte Units 3 and 4 for which it had submitted an application for twin AP1000 reactors to generate 2234 MWe. TVA said that the overnight capital cost estimates for the two reactors ranged from $2,516 to $4,649/kW, for a combined construction cost of $5.6 to $10.4 billion. Total cost to the owners would be $9.9 to $17.5 billion. A comparative study published in January 2008 for a Connecticut Integrated Resource Plan listed an overnight capital cost for a nuclear plant of $4,038/kW. Although it was the most expensive plant option, it produced the least expensive electricity (see Table 9.4).[39]

Table 9.4
Comparative Cost Study – Connecticut Integrated Resource Plan

	Overnight capital cost (2008 $/kW)	**Electricity cost (cents/kWh)**
Nuclear	4038	8.34
Supercritical coal	2214	8.65
Supercritical coal + CCS (carbon capture and storage)	4037	14.19
IGCC	2567	9.22
IGCC + CCS	3387	12.45
Gas combined cycle	869	7.60
Gas combined cycle + CCS	1558	10.31

Source: World Nuclear Association, *The Economics of Nuclear Power* (January 2009). Online. Available: http://www.world-nuclear.org/info/inf02.html. Accessed: February 15, 2009.

Construction costs for a new nuclear plant represent a key factor when comparing costs with other energy sources, as nuclear plant operating costs tend to be less than the operating cost of coal and natural gas facilities. If the federal government were to tax carbon emissions, nuclear energy will become even more competitive with coal and natural gas. The social cost of carbon emissions in theory could be internalized through a carbon tax or an equivalent "cap and trade" system. Depending on the level of tax per ton of CO_2 emitted, the levelized electricity cost for coal could increase from 4.2 cents/kWh to 5.4 cents/kWh based on a tax basis of $50/ton CO_2 and to 9.0 cents/kWh based on a $200/ton CO_2 tax rate.[40] A carbon tax in the range of $100 to $200/ton CO_2 would affect the relative cost competitiveness of coal, natural gas, and nuclear electricity generation.[41]

The Energy Policy Act of 2005 (the 2005 Act) created several incentives for developing new nuclear power plants, including a production tax credit of 2.1 cents/kWh for the first 6,000 MWe produced by new nuclear plants in their first eight years of operation (same as for wind power, but without an unlimited availability).[42] The 2005 Act also provided for federal loan guarantees for advanced nuclear reactors or other so-called "emission-free" technologies in an amount of up to 80 percent of the project costs and for a period of 20 years. The 2005 Act supports advanced nuclear technology research and demonstration projects. For example, $1.25 billion was provided by the 2005 Act for an advanced high-temperature reactor capable of co-generating hydrogen, the so-called Next Generation Nuclear Plant at the Idaho National Research Laboratory.[43]

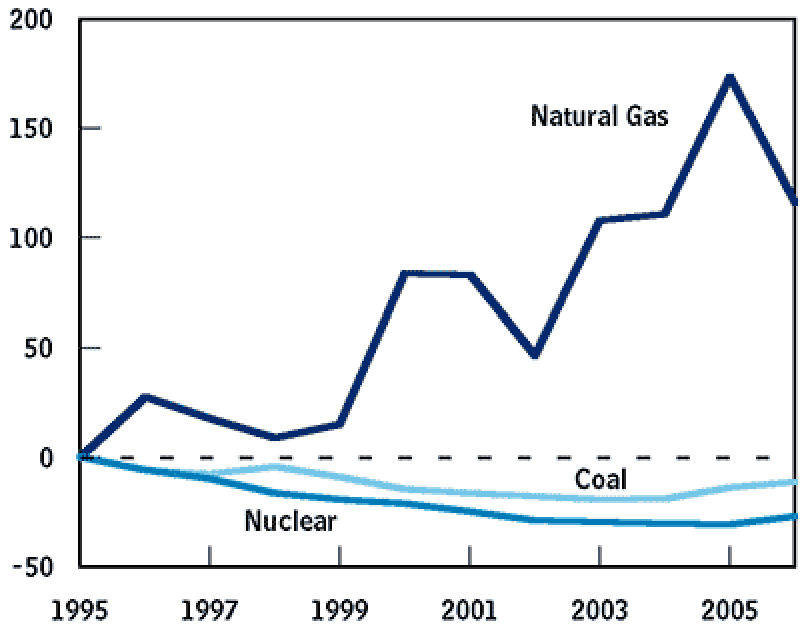
In 2006, the U.S. DOE indicated that the 6,000 MW eligible for production tax credits would be divided pro-rata among those applicants that: (a) file applications for building new nuclear facilities by the end of 2008; (b) commence construction of the advanced plant by 2014; and (c) start service by 2021.[44] In October 2007, the DOE announced that it would guarantee the full amount of loans covering up to 80 percent of the cost of new clean energy projects, including advanced nuclear power plants under the 2005 Act.[45] The first round of loan guarantees will go to renewable energy and advanced natural gas projects. Nuclear subsidies have yet to be authorized by Congress.[46] These federal incentives could make the addition of more nuclear power to AE's mix of energy resources more attractive from a financial perspective due to the incentives it's potential nuclear partners would receive for the construction of new reactors in the future.

Future generation nuclear reactor designs reduce overnight cost with simplified designs and longer operating life. The Westinghouse AP-1000, scaled-up from the AP-600, received final design certification from the NRC in December 2005, the first Generation 3+ type to do so.[47] Overnight capital costs were originally projected at $1200 per kilowatt and modular design is expected to reduce construction time to 36 months.[48] The AP-1000 generating costs are expected to be very competitive and it has a 60 year operating life.[49] China has selected the design for construction and it is under active consideration for building in Europe and Southern U.S. states.

While the cost of construction is difficult to predict, the price of uranium is relatively stable compared to natural gas (see Figure 9.3)

Figure 9.3
Historical Volatility in Nuclear Fuel Prices

(Percentage Change)



Source: Congressional Budget Office, *Nuclear Power's Role in Generating Electricity, Chapter 2* (May 2008). Online. Available: http://www.cbo.gov/ftpdocs/91xx/doc9133/Chapter2.5.1.shtml#1045449. Accessed: April 6, 2009.

Note: The percentage changes are based on prices in 2006 dollars, with adjustments for inflation made using the gross domestic product price index. Prices for all fuels equal the average cost at which those fuels are delivered to power plants, as measured by EIA.

Environmental Impacts

Considering only stationary combustion emissions, nuclear power plants qualify as so-called "carbon-neutral" producers of electricity. Nuclear power generation does not emit green house gases (GHGs) directly, as heat is produced to generate steam through nuclear fission, not through the oxidation of fossil fuels.[50] Nor does nuclear power generation directly produce any of the air pollutants associated with coal, oil, or natural gas, such as sulfur oxides, nitrogen oxides, or particulates. However, as with other power generation methods, some elements of the nuclear power cycle do generate CO_2 and other GHGs and air pollutants (see Table 9.5).

Nuclear power plants and the nuclear power cycle have a significant impact on the environment and pose safety risks. The main risk involves the disposal of high-level radioactive waste, as no permanent spent fuel storage facilities exist in the U.S.

Currently, 60,000 metric tons of spent nuclear fuel is stored in numerous temporary storage facilities across the U.S.[51] The NRC is presently considering a license request from the DOE for Yucca Mountain to begin accepting and storing spent fuel in 2017. The proposed Yucca Mountain repository is located in Nevada and is limited to storing 70,000 metric tons of hazardous waste. While it may be feasible to increase the storage space at Yucca to 120,000 metric tons, current estimates indicate that actual waste could exceed that capacity by 2030.[52]

Table 9.5
Nuclear Power Generation Assisted Greenhouse Gas Emissions

	Life State of Power Plant (grams CO^2 equivalent per KWh)				
Study	**Front-end**	**Construction**	**Operation**	**Back-end**	**Decommissioning**
Andseta et al. (1998)	0.68	2.22	11.90	-	0.61
Barnaby and Kemp (2007)	56.00	11.50	-	-	35.50
Dones et al. (2005)	6.85	1.20	-	0.45	-
Dones et al. (2003)	9.00	1.15	-	0.80	-
Dones et al. (2004)	42.40	1.20	-	0.90	-
ExternE (1998)	-	11.50	-	-	-
Fritsche and Lim (2006)	20.00	11.00	-	33.00	-
Fthenakis and Kim (2007)	16.85	9.10	5.41	2.80	1.30
Hondo (2005)	17.00	2.80	3.20	0.80	0.40
IEA (2002)	4.86	2.55	-	4.86	0.17
ISA (2006)	31.50	7.30	18.55	11.95	0.70
ISA (2006)	29.25	6.80	17.20	11.10	0.65
Rashad and Hammad (2000)	23.50	2.00	0.40	0.50	-
Storm van Leeuwen et al. (2005)	36.00	23.50	-	17.00	34.50
Storm van Leeuwen and Willem (2006)	39.00	24.50	-	17.00	36.00
Storm van Leeuwen et al. (2007)	22.27	20.00	24.40	28.13	44.30
Tokimatsu et al. (2006)	61.95	13.65	21.00	7.35	1.05
Vorspools et al. (2000)	-	2.00	-	-	1.00
White and Kulcinski (2000)	9.50	1.90	2.20	1.40	0.01
Mean	25.09	8.20	11.58	9.20	12.01

Source: Benjamin K. Sovacool, "Valuing Greenhouse Gas Emissions from Nuclear Power: A Critical Survey," *Energy Policy*, vol. 36, no. 8 (2008), pp. 2940-2953. Online. Available: http://ezproxy.lib.utexas.edu/login?url=http://search.ebscohost.com/login.aspx?direct=true&db=egh&AN=32983275&site=ehost-live. Accessed: October 26, 2008.

While nuclear power plants do not directly generate significant amounts of air or water pollution, other parts of the nuclear fuel cycle do produce air pollution, water pollution, hazardous waste, and radiation. Table 9.5 compares studies which document GHG emissions during the entire life state of a nuclear plant. The life state of a plant can be separated into five stages during which GHG emissions occur: front-end, construction, operation, back-end, and decommissioning. Front-end includes the mining, milling, and enrichment of uranium. Construction includes fabrication of materials used to make the plant, transportation of materials to the building site, and the actual work involved in building the plant. Operation includes the production of the energy required for cooling the nuclear reactors. The back-end of the process includes fuel processing, interim storage, and final sequestration of waste. The decommissioning stage includes both the decommissioning and dismantling of the reactor, as well as reclamation of a used uranium mine.[53]

Nuclear power plants produce solid waste in the form of spent fuel that is highly radioactive and must be disposed of in a manner which protects the environment against radiation leaks. STP replaces about one third of its fuel every 18 months.[54] Spent fuel is stored underwater in specially constructed stainless steel containers placed inside concrete pools. These underwater storage pools provide an excellent shield against radiation. STP has enough storage capacity to hold all the waste generated during the power plant's lifetime, after which the operators plan to dispose of spent fuel at Yucca Mountain.[55]

The NRC regulates the U.S. nuclear industry and the industry has an excellent safety record. However, the potential for a catastrophic accident is much higher at a nuclear power plant than any fossil fuel-powered plant. In the history of the nuclear industry there has been one near-catastrophic accident at the Three Mile Island plant in Pennsylvania in 1979 and a catastrophic accident at Chernobyl in Ukraine in 1988. While both incidents alarmed U.S. citizens, the Chernobyl incident had more adverse impacts.

In 1988, the Number 4 reactor at the nuclear power plant in Chernobyl, Ukraine exploded. The explosion blew off the top of the reactor's containment structure, releasing radiation into the environment. The accident was the result of technicians improperly performing a test, coupled with an inferior design and poor construction of the containment structure. The resulting fallout was estimated to be 400 times the amount released from the atom bomb dropped at Hiroshima. In total, 33 deaths were attributed to the initial explosion and subsequent radiation poisoning.[56] The Soviet (and later Ukrainian) government imposed a 2,600 kilometer exclusion zone around the town.[57] Long-term effects of the tragedy include an estimated 4,000 cases of thyroid cancer in the 20 years since the explosion.[58]

The incident at Three Mile Island occurred in 1979. The accident started in a non-nuclear section of the plant, as main water supply pumps ceased. A series of design errors and equipment malfunctions eventually led to the opening of a pressure release valve in one of the reactors, which released cooling water and caused the reactor to overheat. Approximately one half of the reactor's core melted. Unlike Chernobyl, the containment system at Three Mile Island held and no radiation was released. No injuries or deaths resulted.[59] As a result of the Three Mile Island Incident, the NRC enacted several safety regulations that address equipment upgrades and improvements, training requirements, procedural clarifications, and licensing requirements.

Future Outlook

Several uncertainties will affect the future widespread use of nuclear power in the U.S.: the threat of terrorist attacks or sabotage, spent fuel storage issues, and radiation risks associated with nuclear power plant failure. These legitimate issues, coupled with the potential high costs of new plant construction, have contributed to public concerns towards the further development of nuclear energy in the U.S.[60] While each of these issues represents a valid concern, the nuclear industry and the NRC have implemented safeguards against terrorist acts and catastrophic incidents. These safeguards 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.[61] The terrorist attacks of September 11, 2001, have spurred additional investments in nuclear power plant security; by April 2006 the industry had spent more than $1.25 billion to further protect nuclear power plants.[62]

Many past and currents concerns relative to the use of nuclear power are being addressed through the development of third and fourth-generation reactors. While fourth-generation reactors are in the concept stage and unlikely to be ready before 2030, third-generation reactors are being designed, approved, and constructed around the world today. Table 9.6 lists the advanced reactors being marketed by the nuclear industry today. The greatest departure from second-generation designs is that many third-generation reactors incorporate passive technology which requires no active controls or operational intervention to avoid accidents in the event of malfunction.[63]

Advances in safety, cost and efficiency of third-generation reactors include (a) a standardized design for each reactor to expedite licensing, reduce capital cost and reduce construction time; (b) a simpler and more rugged design, making the reactor easier to operate and less vulnerable to operational upsets; (c) higher availability and longer operating life, typically 60 years; (d) reduced risk of core melt accidents; (e) resistance to serious damage that would allow radiological release from an aircraft impact; (f) higher burn-up to reduce fuel use and the amount of waste; and (g) burnable absorbers (“poisons”) to extend fuel life.[64]

One of the main reasons that nuclear plants can produce electricity at a low cost is that nuclear fuel is relatively concentrated and inexpensive. Even though building a nuclear power plant is costly, such plants can operate efficiently at a low marginal cost. The average lifespan of a nuclear plant is 50 years of operation,[65] which helps amortize the high initial capital outlay over a long time period. The U.S. federal government has sought to subsidize new nuclear plants by guaranteeing loans under the Energy Policy Act of 2005.

Table 9.6
Advanced Nuclear Reactors

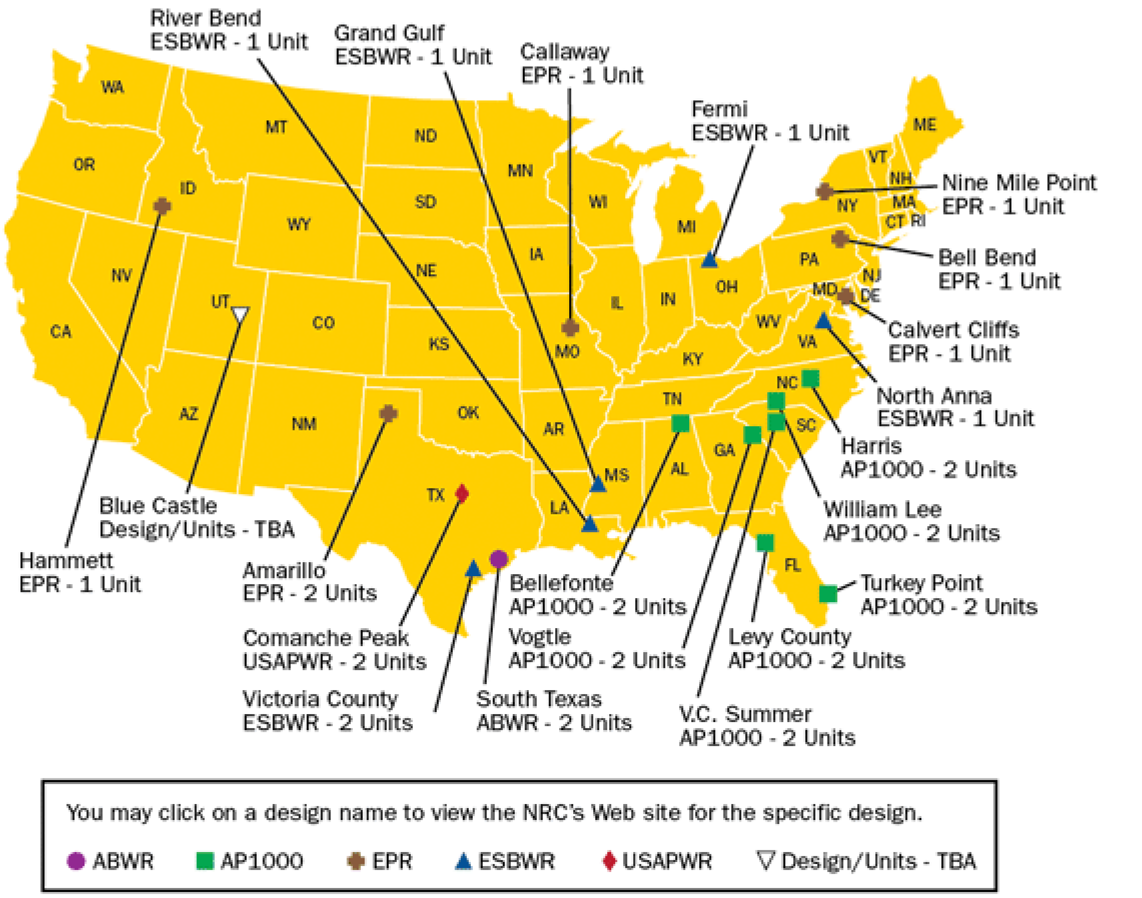
Country and Developer	Reactor	Size MWe	Design Progress	Main Features (improved safety in all)
U.S.-Japan (GE-Hitachi, Toshiba)	ABWR	1300	Commercial operation in Japan since 1996-7. In U.S.: NRC certified 1997, FOAKE	Evolutionary design. More efficient, less waste. Simplified construction (48 months) and operation.
USA (Westinghouse)	AP-600 AP-1000 (PWR)	600 1100	AP-600: NRC certified 1999, FOAKE. AP-1000 NRC certification 2005, many units planned in China	Simplified construction and operation. 3 years to build. 60-year plant life.
France-Germany (Areva NP)	EPR US-EPR (PWR)	1600	Future French standard. French design approval. Being built in Finland and France, planned for China. U.S. version developed	Evolutionary design. High fuel efficiency. Flexible operation
USA (GE- Hitachi)	ESBWR	1550	Developed from ABWR, under certification in USA, likely construction there	Evolutionary design. Short construction time.
Japan (utilities, Mitsubishi)	APWR US-APWR EU-APWR	1530 1700 1700	Basic design in progress, planned for Tsuruga, U.S. design certification application 2008	Hybrid safety features. Simplified Construction and operation.
South Korea (KHNP, derived from Westinghouse)	APR-1400 (PWR)	1450	Design certification 2003, First units expected to be operating c 2013	Evolutionary design. Increased reliability. Simplified construction and operation.
Germany (Areva NP)	SWR-1000 (BWR)	1200	Under development, pre-certification in USA	Innovative design. High fuel efficiency.
Russia (Gidropress)	VVER-1200 (PWR)	1200	Replacement under construction for Leningrad and Novovoronezh plants	Evolutionary design. High fuel efficiency. 50-year plant life

Source: World Nuclear Association. *Advanced Nuclear Power Reactors* (December 2008). Online. Available: http://www.world-nuclear.org/info/inf08.html. Accessed: February 10,2009.

The potential for expansion of nuclear power plants in Texas and in the remainder of the U.S. is promising. The NRC is currently processing applications for 32 new nuclear reactors across the country (see Figure 9.4). Eight of these proposed new reactor units are at four sites in Texas: an evolutionary power reactor near Amarillo; an advanced pressurized-water reactor near Glen Rose; a boiling-water reactor in Victoria County; and the addition of two units of advanced boiling-water reactors at STP.[66]

The City of Austin has elected not to invest in the two new reactors being built at STP based upon recommendations from AE. The city council cited as the primary reasons: the risk of overly optimistic projected costs; permitting and construction schedules; and inherent uncertainties and risks.[67] The additional security and environmental risks associated with hazardous waste generated from nuclear energy were left unstated.

Figure 9.4
Projected Location of New Nuclear Power Reactors in United States



Source: United States Nuclear Regulatory Commission, *New Reactors, Location of Projected New Nuclear Power Reactors.* Online. Available: http://www.nrc.gov/reactors/new-reactors/col/new-reactor-map.html. Accessed: February 10, 2009.

AE's formal recommendation that the City of Austin not participate in the STP expansion proposal was given in February 2008. In November 2008, NRG Energy submitted revised and additional information to AE. In December 2008, AE approved a $241,000 contract with a consulting firm, Worley Parsons, to analyze the proposal. On February 12, 2009, the Austin City Council voted to decline participation in the expansion of the STP as currently proposed.[68] A detailed financial analysis and risk assessment completed by Worley Parsons concluded that the potential return to the City of Austin would not outweigh the potential risks of the expansion project and its $2 billion price tag to the city.[69] The consulting firm argued that the total estimated project cost of $6 billion could potentially exceed $10 billion reflecting STP's history of construction cost over-runs in the past.[70] During the 1970's STP's initial two reactors were estimated to cost close to $1 billion and ended up opening more than five years late at a cost of $5 billion over the initial estimate.[71] Another council concern was that the $2 billion price tag cost could potentially have a negative effect on AE's credit rating, thereby affecting the company's ability to invest in other energy projects.[72]

If AE elects to build or participate in the ownership of a new nuclear power plant, the expected time it would take for new units to be approved and constructed would be five to nine years. This estimate is based on it taking approximately two to three years to receive regulatory approval from the NRC and four to six years for actual construction.[73]

Options for Austin Energy

While it is unlikely that AE will commission its own nuclear power plant, there are several opportunities to hold joint ownership with new plants that are currently applying for approval in Texas or to participate in potential expansions of existing plants such as STP. AE could meet its carbon neutrality goal relatively easily if it were to add additional nuclear power to its energy portfolio. The city council previously determined that buying into the proposed new units at STP is not attractive due to uncertainties relating to costs and schedule delays. However, if the uncertainties are addressed by nuclear power plant builders and if the federal government imposes some form of carbon regulation in the near future, the use of nuclear power may become substantially more attractive. One option that AE could consider would be to double its nuclear capacity with the addition of 422 MW. This nuclear power could be used to replace more than 60 percent of AE's current (607 MW) stake in coal with nuclear energy. This would require, by way of an example, a 15 percent participation in STP's current expansion plan, which includes two new reactors with 1350 MW capacity each.

Conclusions and Recommendations

The recommendations regarding nuclear below are based upon an analysis of the nuclear options available to AE and the most effective role nuclear technology can play in meeting AE's stated goal of carbon neutrality by 2020.

AE should monitor the expansion of nuclear power in Texas and consider the benefits as well as the risks of investing in or contracting for additional nuclear power generating capacity when third-generation nuclear power plants come on-line. There are currently four third-generation nuclear power plants and expansions planned for the State of Texas (see Table 9.7). The sponsoring utilities have been trying to reduce the uncertainties of planning, design, and construction cost and schedules. The expansion projects at STP and Victoria are expected to provide the most attractive future investment opportunities for AE due to their close proximity and the existing transmission line networks. Expansion of its nuclear portfolio could provide AE with its lowest cost option for significantly reducing carbon emissions by 2020.

Table 9.7
Third Generation Nuclear Plants Planned in State of Texas

Location	Applicant	Reactor Type	Application Date
Amarillo	Amarillo Power	EPR (2units)	2009 expected
Comanche Peak	Luminant	US-APWR (2units)	9/19/2008
South Texas Project	NRG Energy	ABWR (2 units)	9/20/2007
Victoria County	Exelon	ESBWR (2 units)	9/3/2008

Source: United States Nuclear Regulatory Commission, *New Reactors, Location of Projected New Nuclear Power Reactors*. Online. Available: http://www.nrc.gov/reactors/new-reactors/col/new-reactor-map.html. Accessed: February 10,2009.

If AE were to delay a decision to invest in or contract for nuclear power until a third-generation nuclear plant operates reliably it could balance the risk and rewards. An operating power plant would provide a clear picture of the actual costs of the new nuclear power, which can be used for a comparison with other power generation options at the time an investment decision must be made. Of course, coming into a power market after the risks are resolved may cost more (a higher ¢/KWh) than an earlier commitment.

An additional value should be accrued to nuclear energy due to its relative merits as a CO_2 emission-free source of energy. According to much of the published technical literature, nuclear power is likely to continue to be cost-competitive with coal. Even though the cost of building a new nuclear power plant is difficult to estimate, nuclear remains an attractive economic proposition even if the “projected” costs are doubled or tripled. AE should be able to utilize nuclear conservatively by comparing it based on a fourfold cost overrun rate, which is quite pessimistic (but not unreasonable given the 1970’s STP cost over-runs).

Notes

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Chapter 10. Hydropower and Pumped Storage

Summary

This chapter examines the potential for hydropower and pumped storage capacity to contribute to Austin Energy's 2020 portfolio of energy sources. The chapter evaluates the current state of the technology and the potential for feasible economic investments in the technology. One conclusion is that it is unlikely that AE will build a new dam for creating a reservoir to generate hydropower. AE should consider cooperating with the Lower Colorado River Authority (LCRA) in development of a pumped storage project using an existing dam on the Colorado River if an appropriate price can be negotiated.

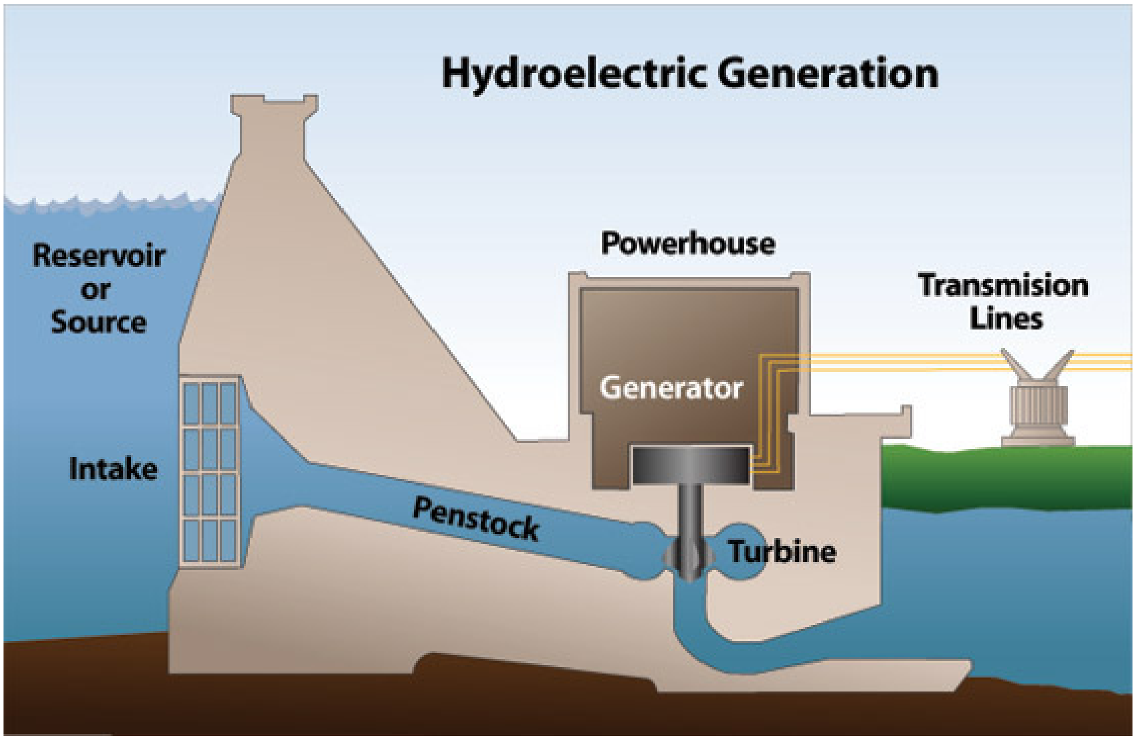
Background

Hydropower works by using the kinetic energy that water gains when it drops in elevation to generate electricity. Hydroelectric power is typically created by damming a river to create a reservoir and releasing the water through turbines and generators that produce electricity (see Figure 10.1). Hydropower projects create multiple uses for the stored water behind a reservoir, including flood control, maintenance of municipal water supplies, and recreation, in addition to the generation of electricity.

LCRA, AE's neighboring electric utility, has generated electricity from hydropower since the 1930s.[1] LCRA's six currently operating dams can provide up to 292 MW of power and form lakes that store up to 81 billion gallons of water.[2] These reservoirs include Buchanan, Inks, Wirtz, Starcke, Mansfield, and Tom Miller, which have power generating capacities of 51.3,[3] 14,[4] 56,[5] 32,[6] 102,[7] and 17.3 MW,[8] respectively. One of the dams (Buchanan Dam) has pre-existing pump-house plumbing that could be used for pumped storage. A second dam (Inks Dam) also may have been designed with a pump-back unit that could be used for pumped storage purposes.

Pumped storage can be used for peak demand energy by pumping water up between lakes at a time when the cost of electricity to the utility is low and allowing the water to flow down during peak energy demand when the cost of electricity to the utility is high. Pumped storage allows stored water's potential energy to be released as electricity (see Figure 10.2). Pumped storage is the only commercially available large-scale energy grid storage technology currently available.[9] Pumped storage can be used as a load management tool by storing water as potential energy during off-peak periods and then releasing it to generate electricity during peak periods. Pumped storage can respond quickly to sudden changes in demand, making it especially valuable for meeting peak demand.[10] A utility system that includes pumped storage could use renewable energy sources such as wind and/or solar energy generated during off-peak periods, or in excess of demand, to pump water that can be stored to be dispatched during peak demand periods when those sources may not be available.

Figure 10.1
Diagram of Hydroelectric Power Generation Process

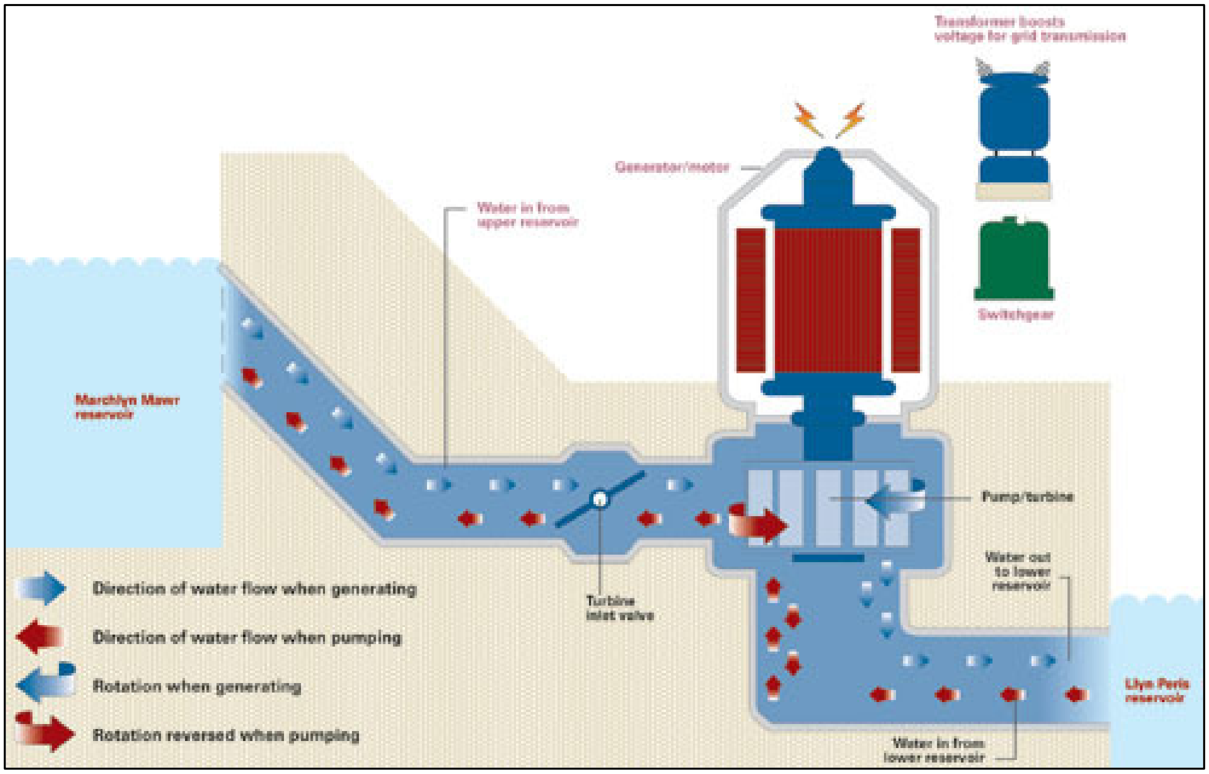


Source: Southern Edison California, *Hydropower: How it Works.* Online. Available: http://www.sce.com/Feature/Archive/hydropowerfeature.htm. Accessed: October 13, 2008.

Conventional hydropower can serve as a baseload power source to replace fossil-fueled power generation technologies.[11] Conventional hydropower has a capacity factor of 40 to 50 percent.[12] he most common role for pumped storage is in response to peak demand because it is easily dispatchable.[13] Pumped storage has a capacity factor of 15 to 35 percent.[14]

Both conventional hydropower and pumped storage are mature technologies with known risks. Pumped storage does depend on the electricity used to store kinetic energy by pumping the water up. If a pumped storage facility depends on electricity generated from natural gas, its relative value would reflect uncertainties in the cost of natural gas. Water in a reservoir has alternative uses to power generation (irrigation, domestic use, etc) and the release of water from the lowest reservoir in sequence means the water cannot be used for power generation. Pumped storage has few opportunity costs if there are multiple reservoirs in sequence and water is reused on a continuing basis for storage and power generation. Conventional hydropower generation and pumped storage facilities tend to be reliable and have an operational life of about 50 and 60 years, respectively.[15,16]

Figure 10.2
Diagram of Hydro Pumped Storage Process



Source: First Hydro Company, *The Principles of Pumped Storage*. Online. Available: http://www.fhc.co.uk/pumped_storage.htm. Accessed: October 13, 2008.

Operating Examples

The Ludington Pumped Storage Plant provides an example of successful pumped storage and hydropower technology (see Figure 10.3). This power plant, located in Ludington, Michigan, is co-owned by Consumers Energy and Detroit Edison and has a power generation capacity of 1,872 MW.[17] The facility cost $327 million to construct and install (1969 to 1973).[18] Ludington functions as a peak demand energy source.[19] When energy demand is low, operators pump water 363 feet up into the Ludington Reservoir. As demand increases, the water is released back down, activating the facility's six turbines.[20] When the reservoir is full, it can provide electricity at full power for eight hours.[21] The power used to pump the water up is provided by the area's energy mix, which includes conventional generation sources such as coal.[22] Consumers Energy and Detroit Edison have taken care to mitigate the facility's effects on its local environment. Each year a two-mile long net is installed to prevent local fish populations from being cycled through the power plant, at a cost of $1.6 million.[23] The net is removed during the winter to prevent damage. Operation and maintenance costs for the facility are $11.6 million a year.[24] Despite these high costs, the total cost of producing energy from

Ludington remains competitive with other conventional power generation technologies. According to its joint owners, "by displacing higher-cost generation, Ludington saves Consumers Energy and Detroit Edison customers millions of dollars a year."[25]

Figure 10.3
Ludington Pumped Storage Power Plant

Source: Consumers Energy and Detroit Edison Energy, *Ludington Pumped Storage Plant* (brochure). Online. Available: http://www.consumersenergy.com/welcome.htm?/content/hiermenugrid.aspx?id=31. Accessed: October 28, 2008.

Economic Outlook

Hydropower does not present any unusual financial uncertainties. The national average cost of hydroelectric power generation is 2.4 cents per kW hour (kWh).[26] These costs are relatively low, reflecting the absence of fuel costs and low fixed costs for operation and maintenance (0.04 cents and 0.03 cents per kWh, respectively).[27] Capital costs are relatively high, with the total overnight cost ranging from $1,700 to $2,300 per kW installed.[28]

The cost per kWh of energy production from pumped storage depends on the cost of the electricity used to pump the water up to storage.[29] If the energy used in conjunction with pumped storage is renewable, the fuel cost is close to zero. One estimate of the total overnight cost for this technology is roughly $2,400 per kW installed.[30] Capital costs for pumped storage plants are high, but their value as reserve capacity and for dispatch during peak demand can be attractive for a particular utility. For example, using off-peak electricity to pump water up to later produce electricity during peak periods could reduce a utility's costs of electricity by reducing the need to purchase additional power from the grid or another utility to meet peak demand.

New sources for hydroelectric power in Texas are unlikely due to high capital costs to construct new dams, in-stream flow requirements to protect local habitats and ecosystems, and the cost of acquiring land to be flooded by hydropower projects. The same issues do not arise when considering the potential for pumped storage in Central Texas using existing dams and reservoirs.

Environmental Impacts

While hydropower does not directly emit any greenhouse gases from electricity production, methane can be released from decaying plants in newly-formed reservoirs.[31] Most analyses evaluating the environmental impact of hydropower consider the amount of air emissions from methane to be negligible, especially when compared to generating electricity from fossil fuels. While some researchers have found the volume of methane released at some locations to be comparable to the greenhouse gas release from burning fossil fuels, others argue that these researchers are not taking into account the amount of methane that would have been released even in the absence of the reservoir.[32]

Water processed through the turbines of a hydropower plant is not polluted as a result, nor is there a solid waste component to hydroelectric power generation.[33] However, damming a river fundamentally alters the river and its local ecosystems. Damming can also affect water quality by changing the amount of dissolved gases in the water or by causing a variation of river temperature.[34] These temperature changes can affect local fish populations and any communities that depend on them.[35]

Hydropower projects require an average of 75,000 hectares of land for 1 billion kW-hours per year produced (Table 10.1).[36] In addition to the above environmental concerns, there are social concerns associated with the flooding of land for reservoirs, as inhabitants of once-arable and non-flooded areas typically are resettled in alternate areas. Careful assessments are often performed to ensure the benefits outweigh the costs for new hydropower projects.

The materials used to construct a dam, such as concrete, represent a source of carbon dioxide (CO_2) emissions in any life cycle analysis. For example, concrete releases higher total CO_2 emissions than earth and rock materials.[37] According to the International Energy Agency, between 4 and 410 grams of CO_2 per kWh is emitted during the life-cycle of a conventional hydropower facility.[38]

Table 10.1
Land Use for Power Plants

Technology	Land Use (hectares)*
Hydropower	75,000
Biomass	200,000
Wind	13,700
Solar photovoltaic	2,800
Geothermal	30
Coal	166
Nuclear	31
Natural gas	134

Source: David Pimentel and Marcia H. Pimentel, *Food, Energy, and Society* (New York: CRC Press, 2007), p. 261.

* Assuming one billion kilowatt-hours of electricity production per year.

Future Outlook

A 1993 study completed by the Idaho National Engineering Library estimated an additional 1,000 MW of potential hydropower capacity in Texas.[39] However, due to environmental challenges and lower economic attractiveness of remaining site locations, utilities have not sought to develop any new hydropower projects in Texas.

Options for Austin Energy

It is possible to develop pumped storage facilities using existing dams and reservoirs. AE does not currently operate any hydroelectric facilities, although the City of Austin owns the Tom Miller Dam, and has leased it to LCRA until December 2020. [40] If LCRA were interested in collaboration with AE in a pumped-storage facility, it is possible that one of their existing reservoirs could be used for pumped storage. For example, Lake Buchannan and Inks Lake were once plumbed with a back unit for pumped storage, though they have not been operated as such for many years. A pump could be installed at a low cost compared to an entirely new project. Any of the other dams owned by LCRA would require a pumped-back unit, which would require a 404 permit from the Army Corps of Engineers. Table 10.2 lists additional information regarding Buchannan Dam and Inks Dam. Given that Lake Buchannan and Inks Lake were plumbed with a pumped storage back unit, the additional costs to create a pumped storage unit at these lakes would be the cost of construction and installation of a pump and its operation.

LCRA's oldest dam, Buchannan Dam, was built in the early 1930s and its associated lake covers 9,039 hectares.[41] It is the most viable location for implementation of a pumped storage unit. The lake has a capacity to store and discharge six inches, which corresponds to a volume of 11,167.5 acre-feet. As pumped storage units have an efficiency of 70 to 85 percent, some energy will be lost in the use of pumped storage, but the benefits of peak shifting may outweigh efficiency losses.[42] There may be some public preferences against pumped storage, as the elevation of any lake utilized for pumped storage will rise and fall with the associated pumping and releasing of water. There are few additional risks or uncertainties associated with installing a pump at Buchannan Dam, as this technology is mature and the risks associated with hydropower occur during dam construction.

Table 10.2
Local Dams with Potential for Pumped Storage

	Dams with Potential for Pumped Storage	
Dam Characteristics	**Buchannan Dam**	**Inks Dam**
Discharge capacity (ft^3/s)	355,000	3,200
Lake area (hectares)	9,039	339
Elevation when full (ft above mean seal level)	1,020.35	888.22
Top of dam (ft above mean sea level)	1,025.35	922
Volume when full (acre-ft)	875,566	15,063
Generating capacity (MW)	51.3	14

Source: Lower Colorado River Authority, *Renewable Energy Leader in Texas.* Online. Available: http://www.lcra.org/energy/power/index.html. Accessed: November 3, 2008.

Given the environmental and social impacts of creating a new reservoir for a hydropower project there is no reason for AE to pursue a completely new hydropower project. However, the capacity for pumped storage at Buchannan or Inks Dam represents a significant source of energy storage. The implementation of pumped storage at one or both of these sites could provide a rapid source of electricity that could be valuable in displacing peak demand. Wind energy, typically available at night in excess of demand, could be used to pump water into these reservoirs, and the water could then be dispatched during periods of peak demand.

Conclusions and Recommendations

There are no practical opportunities for AE to make an investment in hydropower. The lack of suitable resources nearby and the expected increase in the value of water resources makes a new hydroelectric dam an economically, environmentally, and politically unattractive investment.

AE has a potential for investment in pumped storage by working with LCRA to install a pump at the Buchanan Dam. This investment would provide AE with a relatively inexpensive, reliable source of power dispatchable at times of peak demand, with a reduced carbon footprint relative to conventional fossil fuel power generation technologies.

Notes

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[4] Ibid.

[5] Ibid.

[6] Ibid.

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[8] Ibid.

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[14] Ibid., p. 50.

[15] DOE, *Hydropower* (brochure).

[16] NRRI, *What Generation Mix Suits Your State?* (online), pp. 49-51.

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[19] Ibid.

[20] Ibid.

[21] Ibid.

[22] Ibid.

[23] Ibid.

[24] Ibid.

[25] Ibid.

[26] DOE, *Hydropower* (brochure).

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Chapter 11. Wind

Summary

This chapter outlines Austin Energy's options for wind power investment as a mechanism for achieving carbon neutrality by 2020. Given the maturity of wind power generating technology, its relatively small environmental footprint, and availability of high-class winds in the state of Texas, AE could significantly expand its wind power generating capacity by 2020. With proper investment in energy storage and rapid-starting natural gas power generation as backup power sources, AE could double its current wind energy investment schedule of 610 megawatts (MW) of new wind power generation through 2020, as outlined by AE's proposed energy resource plan.[1]

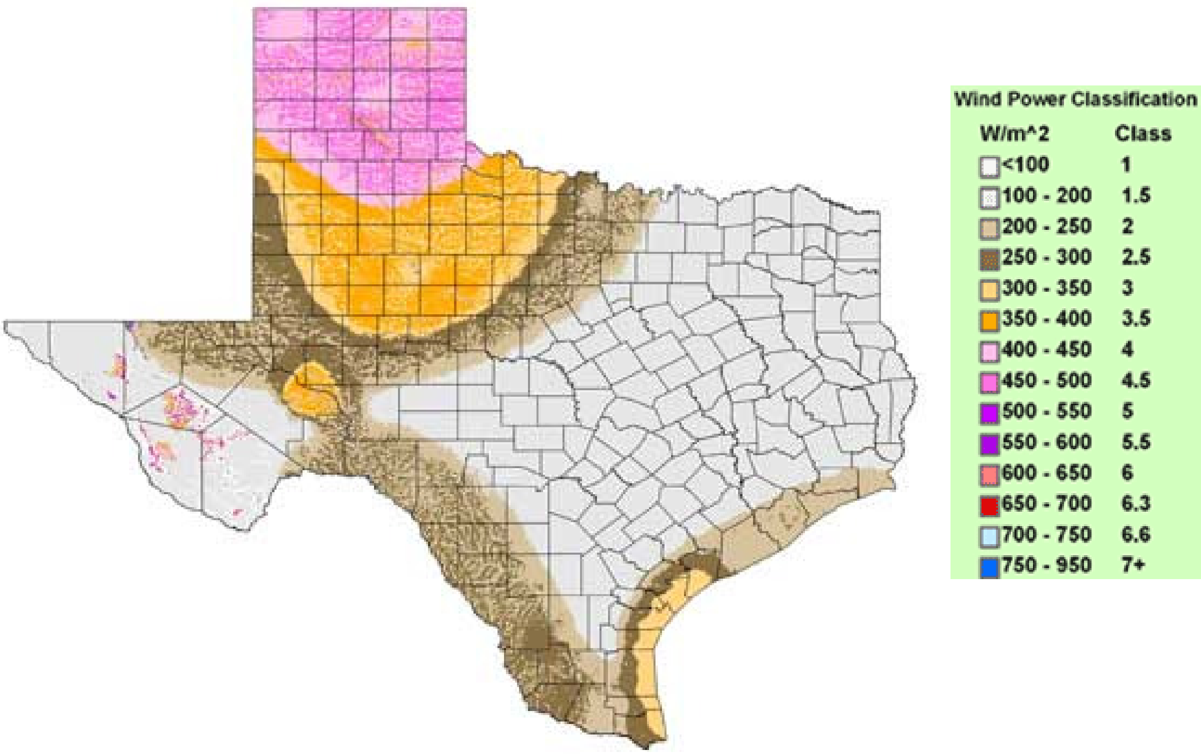
Background

Wind power generation is a reliable and economically attractive renewable energy source available in West Texas (see Figure 11.1) and across the world.[2] Wind power generation is the conversion of wind energy into electricity through the use of wind turbines. This chapter considers three applications of wind power: onshore and offshore utility-scale wind power and small-scale wind power for domestic and commercial use. Onshore wind turbines embody a mature technology with significant market penetration over the past two decades. Offshore wind power is an application of wind power generation that has yet to penetrate the market with widespread use because turbines are costly and difficult to install in offshore locations. Small-scale wind turbines are a form of distributed power generation that has yet to be widely adopted due to noise, aesthetic, and efficiency concerns. Wind power is particularly appealing for AE because Texas has an abundance of wind power that can be converted into energy and transferred to AE's customers as a renewable power source.

Wind power generation converts wind into electricity through the use of a turbine and its blades. Wind farms consist of numerous wind turbine structures that use aeronautically designed blades to convert the kinetic energy of wind to energy in the form of electricity. A drive shaft is attached to the blades which rotates the electric generator to produce electric power. The power capacity of a wind turbine is related to air density, the area that is swept by the blades, and the speed of the wind.[3] Figure 11.2 is a diagram of a typical wind turbine.

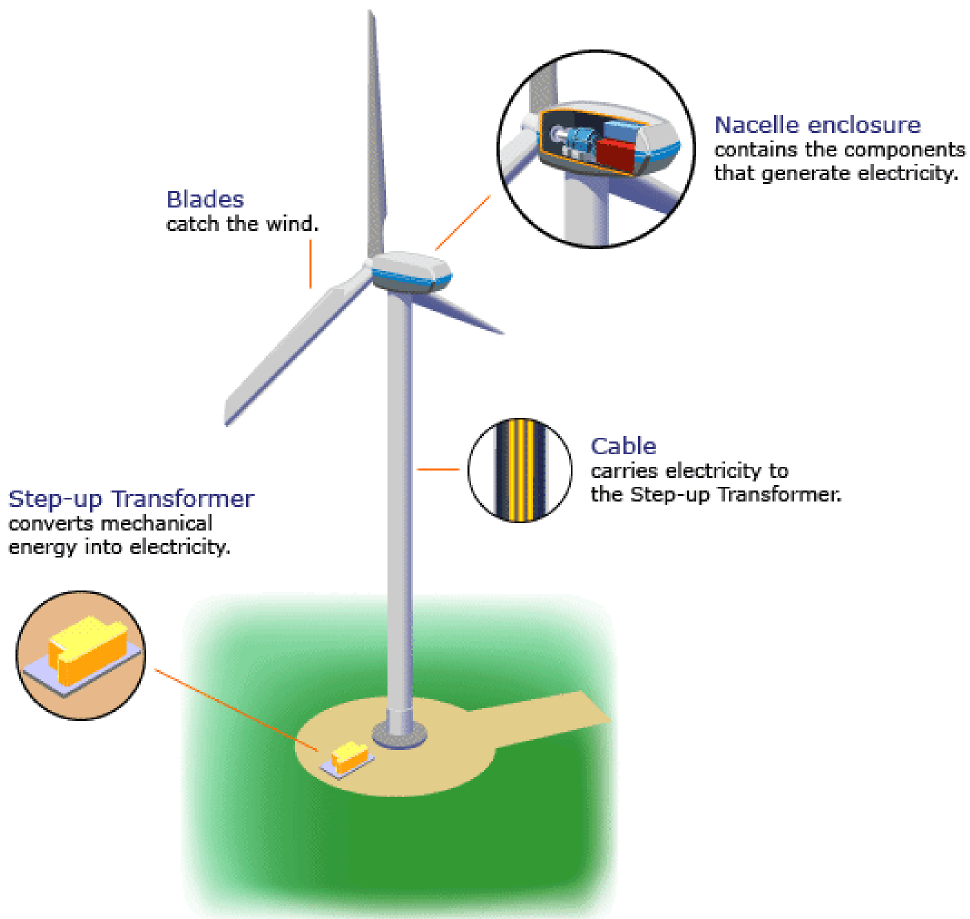
Wind turbines produce power irregularly with variable wind,[4] so the capacity factors for onshore and offshore wind are relatively low (averaging 30 percent)[5], compared to other facilities that have large capital costs and low operational costs. Small-scale wind turbines have a capacity factor of 15 to 20 percent in rural areas and 10 percent in urban areas.[6] Wind turbines have a high availability factor of 98 percent, which means that they are down for maintenance and repair only 2 percent of the time.[7] The expected average operational life for a wind turbine is 20 years, but refurbishment of the turbine generators and equipment can add another 10 years to its lifespan.[8] Onshore wind technology is considered mature since thousands of turbines have produced power over the past several decades. Small-scale wind applications are also considered a mature technology. Offshore wind power is less mature because there is limited experience with the installation and operation of a turbine at sea, particularly with foundations in deeper waters.

Figure 11.1
Wind Energy Classifications in Texas



Source: State Energy Conversation Office, *Wind Energy Maps*. Online. Available: http://www.seco.cpa.state.tx.us/re_wind_maps.htm. Accessed: October 12, 2008.

Figure 11.2
Diagram of a Typical Wind Turbine



Source: WTU Retail Energy, *How Wind Turbines Work*. Online. Available: http://www.wturetailenergy.com/wtu/residential_offers/how_wind_turbines_work.aspx. Accessed: October 12, 2008.

Wind is unpredictable, inconsistent, and often strongest at night. Wind is hard to predict more than a few hours ahead of time which means that minute-to-minute load imbalances can occur.[9] Therefore, a wind farm designed to produce 10 megawatts (MW) of energy may deliver less than 1 MW or even no energy at all depending on location, time of day, seasonal variations, or the whim of nature. According to estimates made by AE and the Electric Reliability Council of Texas (ERCOT), AE's wind power generating facilities are collectively assigned a peak-hour capacity factor of 8.7 percent and an annual average capacity factor of 29 percent.[10,11] Due to concerns regarding inability to meet load, backup power sources are necessary to ensure load can be met when wind turbines are not generating power.[12] Backup power sources are typically rapid-starting peak or intermediate units that run on natural gas combustion. A peaking power plant is normally only run when the demand is at its peak, but as a backup power source would be used at any time that wind power production drops below expected levels. An intermediate unit adjusts its output as demand for electricity changes throughout the day.

Natural gas plants have been used as backup power sources for wind farms so that in the absence of wind, natural gas can be burned to produce electricity. One backup natural gas system built in Minnesota can be started and generate a full load of 51.8 MW in less than 10 minutes.[13] Backup power sources reassure customers that they will receive electricity at all times without disruption. Weighting a utility's power generation mix with power sources such as natural gas combustion turbines that can start and ramp up quickly could lower the "variable cost" of wind. Variable costs may rise if wind energy is overly weighted in a system's power generation mix.[14]

Current technology allows wind farms to be built on locations with class three wind speeds or above, which means that most wind farms require minimum sustained wind speeds near 14 to 15 mph.[15] Wind power generation increases with the cube of the wind speed.[16] For example, increasing average wind speed from 13 to 15 mph can increase electricity output by 50 percent.[17] Wind farms have been constructed with capacities of over 700 megawatts (MW).[18] The total time required to build a wind facility depends on its size, location, weather, and terrain. For example, a 50 MW facility can be expected to take about three years to complete from the time of ordering turbines to completion of construction.[19]

Offshore wind turbines are set further from land where there is less visual impact. Wind speeds tend to be higher offshore, and Texas offshore wind is strongest on average in the late afternoon and weakest in the early morning.[20] This matches AE's average daily electricity demand curve much better than onshore wind, which tends to be stronger in the early morning and weakest in mid-afternoon.[21,22] Thus, average offshore and onshore wind patterns are complementary, and investments in offshore wind power generating capacity may increase the average and peak hour reliability of wind energy in Texas. West Energy Systems Technology (WEST) is in the early stages of building conventional wind turbines on decommissioned oil platforms off the coast of Galveston, Texas (see Figure 11.3).[23] Figure 11.4 shows Galveston, Texas, to have a higher wind speed than the U.S. average. Texas currently maintains control over all submerged lands out to nine nautical miles, or about 10.36 miles.[24] The Texas General Land Office (GLO) is the state entity responsible for this land area and oversees offshore wind power development. The GLO has determined that any royalties derived from offshore wind agreements will contribute to the state's Permanent School Fund to assist in funding for public education. For example, the Galveston project is expected to provide the state with at least $26.5 million over the life of the project.[25]

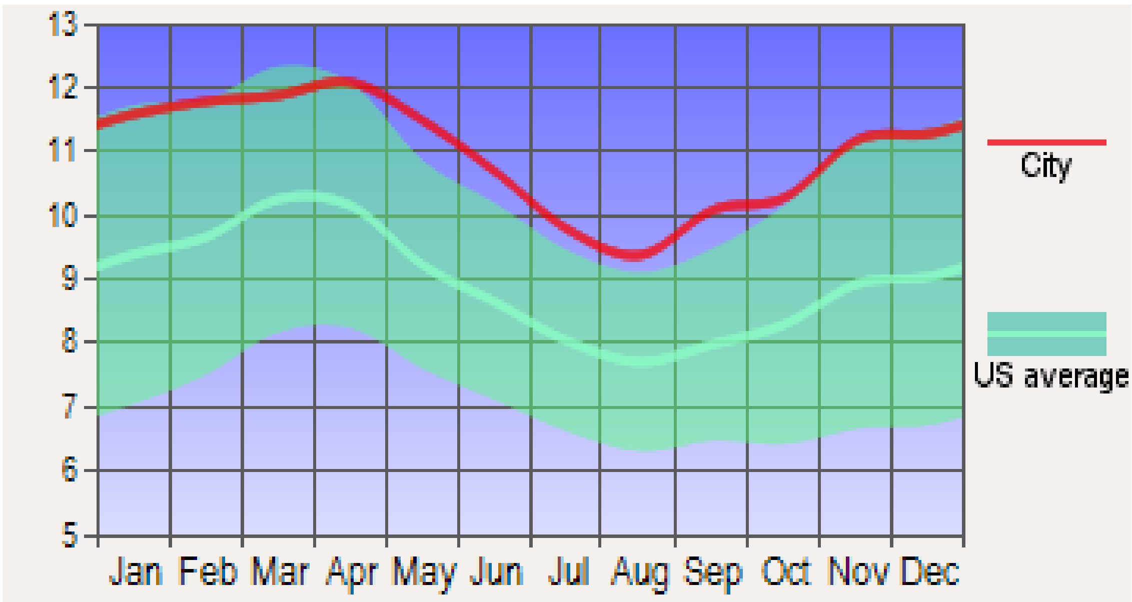
Figure 11.3
Picture of an Offshore Wind Farm

Source: Thomko Petro Chemical Blog, *Texas Plans Nation's Biggest Wind Farm*. Online. Available: http://thomko.squarespace.com/display/ShowJournal?moduleId=209208&categoryId=38230. Accessed: October 12, 2008.

Offshore wind development in Texas' Gulf is closer in proximity to transmission lines compared to the wind farms of West Texas. Since the GLO can lease offshore areas in Texas and the royalties help fund education, wind power expansion directly offshore in Texas has fewer hurdles and opposition than other coastal states. Offshore turbine size is limited by advancement in technology of the turbine and the support structure used. A recurring challenge is to design foundational supports for offshore wind turbines that can survive high winds and waves. Common designs are (a) monopile foundation which has minimal footprint on the seafloor, low stiffness, and a depth limit of about 25 or 30 meters (m), and (b) gravity foundation, with a larger footprint and a stiffer but heavier structure with an unknown maximum depth.[26] Future designs include a tripod fixed-bottom foundation with a larger footprint and depth about 20-90m, and a floating structure with a depth of 40-900 m.[27] Turbines set farther from land may benefit from an increase in wind speed, better siting options, less visual impact, and fewer competing uses for the seabed.

Figure 11.4
Average Onshore Wind Speeds in Galveston, Texas By Month

(in miles per hour)



Source: City-data.com, *Galveston, Texas.* Online. Available: http://www.city-data.com/city/Galveston-Texas.html. Accessed: November 16, 2008.

Winds near the coast of Texas are typically comparable to offshore winds in speed and daily fluctuation.[28] Thus onshore wind farms built near Texas coasts can benefit from proximity to existing transmission lines and offshore wind speeds and daily capacity curve, while still utilizing the familiar technology of land-based turbine installation. The recently completed Peñascal Wind Power Project in Kenedy County is the first example in Texas of this promising "coastal onshore" form of wind power generation.[29]

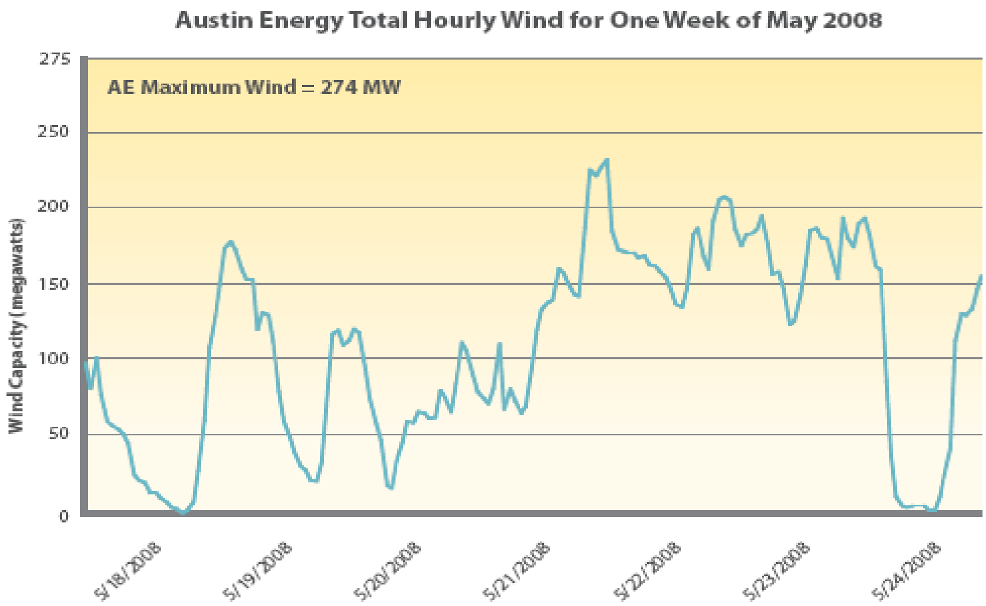
Small-scale wind turbines can be used as a distributed power generation source for residential and commercial use inside city limits closer to the demand load. Small-scale wind turbines connected to the grid are less a source of power to the grid than a source of load reduction.[30] Local wind power generation would decrease the loss of power due to transmission. A small turbine requires almost all the same wind conditions as larger wind turbines, including prevailing wind speeds of at least 12 mph.[31] A small-scale wind turbine is best placed away from turbulent flow that a building or tree might create. The mast of the roof is an ideal place. However, at this height, people will be able to see and hear it even though it is much smaller than an industrial-scale turbine.[32] The overall power benefit of placing one small turbine on the roof is not large enough to permit a building to be completely off the grid, but money can be saved monthly.[33] Small-scale wind turbines (any turbine that is rated less than 50 kilowatts), can weigh as little as 35 pounds.[34,35] Figure 11.5 illustrates a small-scale wind turbine.

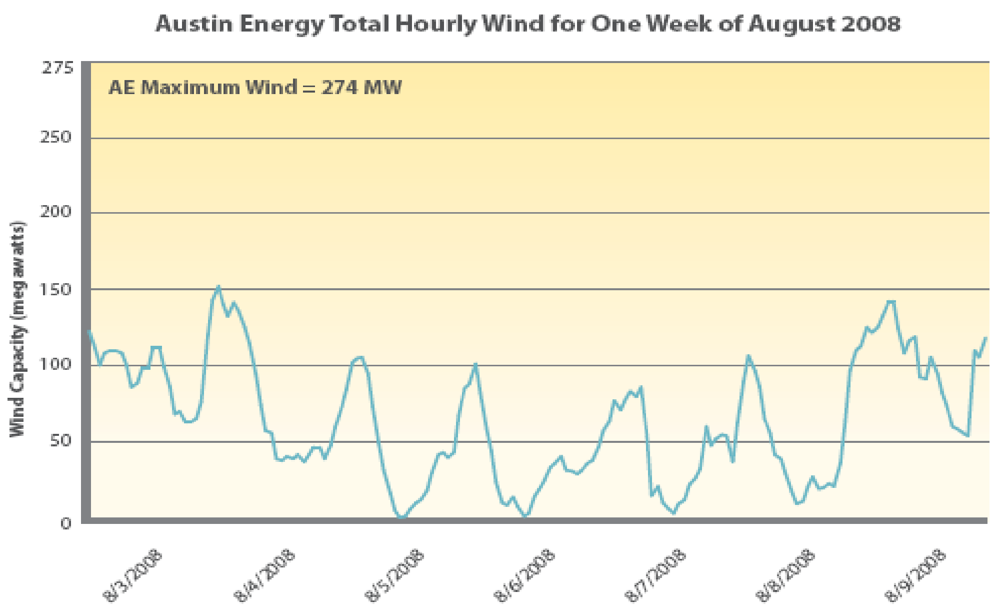
Figure 11.5
Picture of a Small-Scale Wind Turbine

Source: SkyStream Wind Power Generator. *Introducing SkyStream 3.7*. Online. Available: http://www.alpinesurvival.com/Skystream_3.7_Wind-Generator-Turbine.html. Accessed: November 6, 2008.

As wind fluctuates considerably, energy storage technologies could boost the value of wind power generation (see Figure 11.6). Options for possible storage include batteries (sodium-sulfur), compressed-air energy storage systems (CAES), and pumped-hydroelectric storage. These technologies are discussed elsewhere in this report. Storage can help alleviate wind fluctuations by converting electricity to stored energy during times of high wind and releasing the power when demand is greater and little or no wind is available. CAES systems compress air to store the less expensive electricity that is produced during off-peak times when wind is conveniently at its strongest, by forcing the air into an underground geological feature (such as an aquifer or salt dome). It takes about 1.5 to 2 years to create a salt-dome cavern by dissolving the salt.[36] When discharged, the compressed air can be combined with natural gas and combusted to go through a turbine to generate power.

Figure 11.6
Austin Energy's Wind Energy Profiles

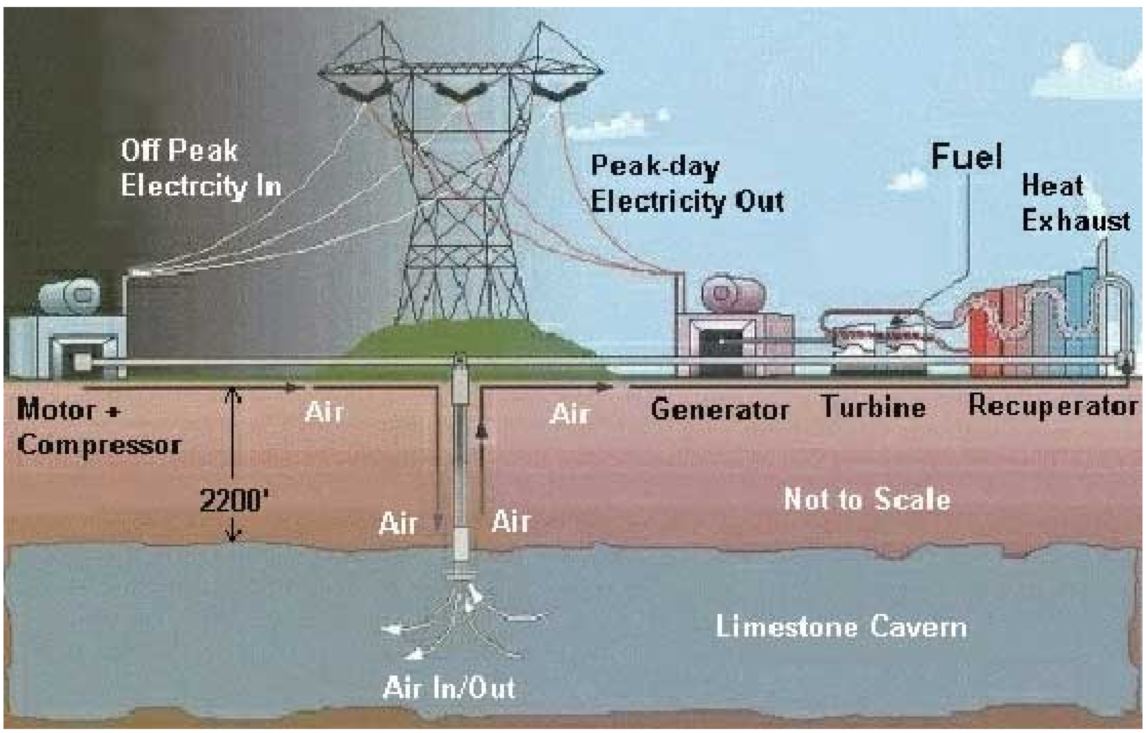




Source: Austin Energy, *Austin Energy Resource Guide* (October 2008), p. 29. Online. Available: http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf. Accessed: November 17, 2008.

A current operating example of a CAES system is located in McIntosh, Alabama (see Figure 11.7). Built in 1991 it took 30 months to construct with a price tag of $65 million, at about $591 per kilowatt (kW).[37] This plant can come online within 14 minutes.[38] One recent report found that for every 0.72 megawatt-hour (MWh) of electricity and 4.4 million British thermal unit of gas, the plant will provide 1 MWh of electricity.[39] The largest commercial CAES is planned for construction in Norton, Ohio. The plant will be rated at 2700 MW of power, and compress air to 1500 pounds per square inch; the air will be stored in a limestone mine about 2200 feet below the surface.[40]

Figure 11.7
Compressed-Air Energy Storage for Wind Supply



Source: State Energy Conversation Office, *Wind Energy Maps*. Online. Available: http://www.seco.cpa.state.tx.us/re_wind-reserve.htm. Accessed: October 12, 2008.

Storage facilities can either be located alongside wind farms or sited at the load. A benefit of locating backup storage next to a wind farm is the possibility that there will be fewer incidents where a transmission line will not be able to accept the load. A benefit of locating backup storage near the consumer is that the possibility of transmission delays due to grid congestion during peak hours is avoided. C AES systems are constrained to regions with applicable geological features. Pumped-hydroelectric storage may be limited to existing sites where dams, reservoirs, and flowing water are available. These locations may not correspond to available wind sites. Batteries provide a flexible option since they can be installed anywhere to operate in conjunction with small-scale wind power.[41] The ability to store electricity from wind power can help reduce peak loads and add value to wind technology.

Operating Examples

At the end of 2008, there were 120,800 MW of wind power generating capacity installed worldwide.[42] Texas has 7,115 MW of wind power generation capacity, with a further 1,651 MW proposed or under construction.[43] Horse Hollow Wind Energy Center, the world's largest wind farm (735.5 MW power generation capacity), is spread over nearly 47,000 acres in Taylor and Nolan County, Texas. In 2007, the average U.S. wind power price was about 4 cents per kilowatt-hour (kW/hr) in 2006 dollars.[44] The Peñascal Wind Power Project in Kenedy County, a coastal onshore farm, finished construction in March 2009 with 84 turbines capable of producing a maximum 202 MW of wind power.[45] The project is reported to have cost $440 million.[46] There are only 33 operating offshore wind projects in the world, generating a maximum 1471 MW of wind power.[47] WEST is beginning construction of the next offshore wind farm in the U.S. close to Galveston, Texas. The project is estimated to cost about $240 million with a maximum peak output of 150 MW (able to power about 45,000 homes).[48,49] WEST will mount conventional wind turbines on decommissioned oil platforms with a hydrologic lift to lower them in case of hurricanes. As of 2008, offshore wind projects are in the planning stages in five states, including Texas.[50] Cape Wind near Cape Cod, Massachusetts is awaiting a permit from the U.S. Minerals Management Service to construct such a facility if a final Environmental Impact Statement is supportive for construction of the wind farm.[51] Concerns of persons opposed to this include aesthetics, project safety, cost, and environmental impacts.

Economic Outlook

Costs for wind energy depend on wind speeds, wind availability, technology, and distance from load centers. The cost to construct a conventional wind turbine averaged about $2,106 per kW.[52] Construction costs are now relatively low compared to even most traditional power generation technologies such as coal or natural gas power plants. A shortage of skilled workers, manufacturing components and capacity, and lapses in the federal production tax credit (PTC) for wind energy have caused wind project costs to rise over the past few years. Wind farms have low variable costs as no fuel costs are involved. Fixed operating and maintenance (O&M) costs are high and so is the initial capital investment. Fixed O&M costs are about $30.92 per kW.[53] According to the U.S. Department of Energy (DOE), onshore wind power—currently available at 4 to 6 cents per kWh—may fall to 3 cents per kWh by 2012.[54] Likewise, the cost for offshore wind power could fall to 5 cents per kilowatt-hour (kWh) by 2012.[55]

Table 11.1 and Table 11.2 list costs by task for onshore and offshore wind facilities. Costs related to the variable nature of wind tend to vary based upon a particular utility's power generation mix and its ability to quickly ramp up traditional power generation technologies to account for the shortfalls of wind energy. In 2007, the Basin Creek

Power Plant, a Montana natural gas-fired plant, was built solely to compensate for the variability of a neighboring wind farm.[56] The generators from this plant were designed to be started and provide up to a full load of 51.8 MW in less than 10 minutes.[57] Basin Creek has assured customers that they will receive electricity at all times with no disruptions.

Table 11.1
Costs for an Onshore Wind Power Facility

Task	Costs (percent)
Turbines	49
Construction	22
Towers	10
Interest	4
Connection to grid	4
Land development	4
Fees	3
Design	2
Transportation	2

Source: John Geoghegan, "Inherit the Wind," *Wired*, vol.15, no. 2 (2002). Online. Available: http://www.wired.com/wired/archive/15.02/wind.html. Accessed: October 13, 2008.

Table 11.2
Costs for an Offshore Wind Power Facility

Task	Costs (percent)
Turbines	33
Support structure	24
Operation and maintenance costs	23
Grid connection	15
Decommissioning	3
Management	2

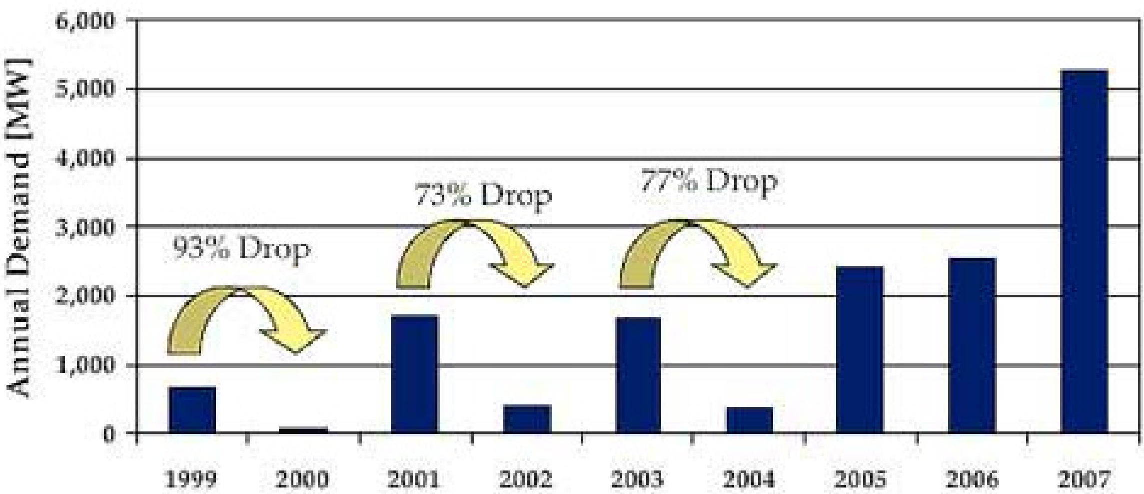
Source: United States Department of Energy, National Renewable Energy Laboratory, and National Wind Technology Center, *Offshore Wind Technology Overview* (October 2006), p. 7. Online. Available: http://www.nrel.gov/docs/gen/fy07/40462.pdf. Accessed: September 18, 2008.

Small wind systems can be competitive for homes and businesses located on at least an acre of land with winds of at least class two speeds and a monthly utility bill of at least $150.[58] In several areas of the country, small-scale wind power output that exceeds the home or business' current power requirements can be sold back to the home or business' electric utility.[59] This arrangement is referred to as "net metering." Small-scale wind energy systems can cost from $3,000 to $5,000 for each kW of power generating capacity, or about $40,000 for a 10 kW installed system.[60]

Although small-scale wind power costs are less per kilowatt than solar energy systems, the payback period is longer.[61] A well-sited small-scale wind turbine can pay for itself in 15 years with tax credit and rebates, covering about half of their service lifetimes.[62] A Production Tax Credit (PTC) for wind energy of about 2 cents per kWh[63] has recently been renewed through the end of 2009.[64] The same bill created an investment tax credit for small-scale wind turbines for eight years to power homes, farms, and small businesses.[65] The PTC has been renewed in the past and may be extended before the end of 2009.[66]

Figure 11.8 illustrates how the PTC expiration influences the volume of installed wind power generation capacity. The annual capacity of wind power installed dropped about 75 percent each instance following expirations of the PTC.[67]

Figure 11.8
How Production Tax Credit Affects Wind Energy Investment



Source: Craig Isakow, "U.S. Congress, Help us Help U.S. – Extend Tax Credits for Renewable Energy," *Constructive Ventures* (August 11, 2008). Online. Available: http://constructiveventures.wordpress.com/. Accessed: November 7, 2008.

Advances in wind technologies have continued to drive down costs and make wind competitive with traditional power generation technologies. The variable nature of wind along with high transmission costs presents a barrier to greater investment in wind energy. The Public Utility Commission of Texas (PUC) is investing nearly $5 billion in transmission lines to West Texas wind facilities to make wind energy even more available to urban areas of Texas, more economically attractive, and viable as a reliable energy source.[68] Offshore wind development in the Texas coastal waters is in close enough proximity to the state's current electrical grid to prevent similar transmission concerns from arising.

Environmental Impacts

Some environmental concerns that have been expressed about wind farms are the amount of land used for wind facilities, the noise associated with turbines, and deaths of birds and bats caused by the turbines and its blades. Aesthetic concerns have also been voiced. Wind power does not directly emit greenhouse gases including carbon dioxide (CO_2). A life cycle analysis of CO_2 emissions from wind turbines considers the impacts on the environment from building the facility, generating power, and ultimately decommissioning the facility. The Renewable Energy Policy Project (REPP) reported zero CO_2 emissions directly from wind power generation. The REPP was not able to estimate the emissions related to the building and decommissioning of a wind energy facility.[69] The REPP reported the total life cycle CO_2 equivalent emissions for wind power to be between 7 to 74 grams emitted per kWh of output, versus 738 to 931 grams emitted per kWh of output for a typical coal plant.[70,71] Wind power does not contribute to water pollution and does not produce solid waste while in service.

As most onshore wind facilities are located away from large population centers, noise produced by large wind turbines may or may not pose a barrier to wind farm construction. Noise and aesthetics are less of a concern for offshore wind energy, so larger turbines can be used and more power can be produced at those locations. Small-scale wind turbines utilized for distributed power generation may receive more opposition as they will more likely be placed near populated areas.

Wind farms can take up a large surface area. For example, the Horse Hollow Wind Energy Center, the world's largest wind farm at 735.5 MW of power generation capacity, is spread over nearly 47,000 acres in Taylor and Nolan Counties in Texas. Onshore wind farms are typically built in locations where land costs are low and far from populous load centers. WEST's offshore development will cover approximately 19 square miles about 10 miles off the coast of Galveston.[72] The offshore Nysted Wind Power Plant in Denmark took radar images of migrating birds in 2003 and concluded that birds have the ability to sense wind turbines even in poor visibility. The birds' response distance from the wind farm decreased from about 3,000 m in the day to just over 1,000 m at night.[73]

Some analysts argue that wind power turbines might not be as reliable and durable as manufacturers claim. In recent years thousands of turbine breakdowns and accidents have been reported.[74] The exact number of incidents is unknown because an industrial wind turbine owner does not have to file a report unless damage occurred to a person or property.[75] Fires can be caused by short circuits, overheated propellers, or lightning strikes.[76,77] A wind turbine caught fire and falling debris created small spot fires around the tower at Palm Springs, California in 2008 that cost about $750,000 in damages.[78] Lightning struck a wind turbine blade causing a fire near Dodge Center, Minnesota in

2007.[79] A tower collapsed during a routine inspection in Oregon in 2007, killing one worker and injuring another.[80] Although this collapse was due to human error, some towers have collapsed due to manufacturing defects and irregularities.[81] A wind tower buckled at a Vermont wind energy facility when it was struck by one of its own blades during high winds. Debris littered the ground several hundred feet from where the tower stood and its fluid reservoirs spilled 20 gallons of heavy oil onto the ground.[82]

Wind turbine manufacturers recommend a safety zone of at least 1,300 feet radius be established around a wind turbine so that children can be prohibited from being near the towers.[83] An informal study reported that approximately 60 percent of U.S. wind farm operators were behind with regards to maintenance.[84] A wind farm is not an attractive terrorist target, compared to other power sources such as a nuclear power plant.[85]

Future Outlook

It appears likely that wind power technologies will continue to advance and become less expensive per kWh in areas close to large cities and load centers that can benefit from even the variable nature of wind power. Some expected improvements include building taller towers, using larger blades to increase yields, reduce operating costs, and increase reliability, and designing turbines to operate at lower wind speeds to locate them closer to load centers.[86] One study assumes that the capacity factor will increase to 44 percent by 2010 (for high wind-speed classes) due to taller towers and more reliable equipment and technology.[87] If at least a 40 percent capacity factor is reached, wind power could become competitive economically with traditional power generation technologies even without a PTC.[88] The advancement of energy storage technologies could play a major role in the ability to tap into vast amounts of wind energy potential in West Texas.

The DOE has reported that some wind engineers believe a single offshore turbine could eventually have a power generation capacity10 MW of energy or more.[89] The DOE estimates that 900 gigawatts (GW) of wind energy capacity could be produced within 50 nautical miles of U.S. coasts, with much of that capacity near the major coastal load centers with high energy costs.[90] Firms searching to expand offshore wind farms use knowledge of offshore oil platforms to help expedite the process. The U.S. Department of Interior's Minerals Management Service regulates renewable energy and alternate uses of offshore public lands. One study identified the Louisiana-Texas coastline as an excellent location for offshore wind power in the U.S.[91] Not only is the average wind speed high in this area, but it also blows the strongest during the heat of the day when electricity demand and price is at its peak.[92] Many heavily populated areas and main load centers in the U.S. are near potential offshore wind sites.[93]

Options for Austin Energy

AE currently purchases its wind power from four Texas wind farms that are located in the Delaware Mountains, Upton County, Nolan County, and Floyd County.[94] Table 11.3 lists the power purchase agreements (PPAs) for wind power generating capacity that AE has entered into and the expiration years of those contracts. The Hackberry Wind Project near Abilene, which completed construction in January of 2009, has added an additional 165 MW of wind power generating capacity to AE's power generation mix (which includes 274 MW of wind power generation capacity).[95,96] As the PUC continues to builds new transmission lines, allowing more wind energy to reach Texas load centers, more wind farms will likely be constructed and expanded. AE can continue to enter into PPAs with new wind projects and renew older contracts. AE can look at offshore and coastal onshore wind farms as a source of renewable energy that complements onshore wind and AE's average daily electricity demand curve. AE could also promote small-scale wind turbines for local residential use by offering an incentive similar to what is offered through the solar rebate program.

Table 11.3
Austin Energy Wind Power Purchase Agreements

Year	Expiration Year	Generation Capacity (MW)	Project Name and Location (in Texas)
1995	2020	10	LCRA – Texas WPP; Delaware Mountains
2001	2011	76.7	Texas Wind/King Wind; Upton County
2005	2017	128	Sweetwater Phase III; Nolan County
2007	2027	60	RES/Whirlwind; Floyd County
2008	2023	165	RES/Hackberry; Abilene

Source: Austin Energy, *Austin Energy Resource Guide* (October 2008), p. 18. Online. Available: http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf. Accessed: November 17, 2008.

AE's proposed energy resource plan recommends an addition of 610 MW of wind power generating capacity during the years 2009 to 2020.[97] In 2008, wind composed 274 MW out of AE's 2,760 MW power generating portfolio; roughly 10 percent of the total. Considering the peak-hour capacity factor of AE's power generating equipment, in 2008 AE had a peak-hour power generating capacity of about 2,500 MW, which is near the peak of the demand AE experienced that year. Under AE's current strategy, wind generation would compose 846 MW out of AE's 3,932 MW resource portfolio in 2020, or 21.5 percent of total power generating capacity. Various studies that have considered utility-scale wind portfolio expansions to 20 percent of power generating capacities have shown the need for corresponding increases in reserve capacity or reduction in peak demand to ensure that power is available even when the wind does not blow.[98,99]

AE's proximity to the wind belt of West Texas and recent commitments by state and federal governments to expand electric transmission provide significant opportunities for AE to expand wind power generating capacity. A more ambitious plan to double AE's current plan for onshore wind power addition would lead to 1,456 MW of onshore wind power generating capacity by 2020. With all other capacity growing as currently specified by AE, wind would then compose 37 percent of total power generating capacity. Considering AE's 8.7 percent capacity factor for wind generation during peak demand, this wind power investment schedule gives AE a peak-hour capacity of 3109 MW in 2020. This figure is near the 2020 peak-demand forecast without conservation, but well within the predicted peak-demand forecast with conservation or accelerated demand-side management.[100]

Offshore wind sites are closer to the existing transmission grid, and may become the most feasible siting locations if public aesthetic consensus turns away from onshore wind turbines. Though at present there are no offshore wind turbines generating electricity in Texas, offshore wind energy receives broad support from Texas government officials. For example, Jerry Patterson, Commissioner of the GLO, stated "We're going to have offshore wind off the Texas coast."[101] Given projected growth of offshore wind, AE may wish to consider an investment schedule on the order of 50 MW every two years from 2012 to 2018, and 100 MW in 2020. Considering AE's peak-hour wind capacity factor, this would increase the peak demand power generating capacity forecasts to 3,136 MW in 2020. On an average day in 2020, considering AE's average annual wind capacity factor of 29 percent, AE would have a power generating capacity of 3,437 MW. Existing natural gas power generating capacity could continue to serve intermediate and peaking generation to back up increased wind capacity, but with reduced annual kWh requirement. If AE faced a worst-case scenario, with a complete drop in usable wind across the transmission grid, it would need to maintain 3,036 MW of power generating capacity, which in effect would require full use of planned 2020 fossil-fuel power generating capacity until sufficient wind speeds resumed.

An alternate response to the risk of variable wind failure is the development of capacity to store electrical energy produced by wind turbines. CAES may be difficult to develop in the Austin area given the porous karst landscape, but could be implemented near Texas onshore wind farms. Pumped hydraulic storage, conversely, seems locally well suited to the task, given the presence of the Colorado River and existing dams. Hydraulic storage technology is mature and has been employed at utility scale for more than a century. For a discussion of the pumped hydraulic storage efficiency and the capacity of dams in the Austin area, see the hydropower or energy storage chapter; for a discussion of CAES, see the energy storage chapter.

Along with these investments AE could offer incentives for small-scale wind turbines, especially with the advent of a "smart grid" system that allows for net metering, even though small-scale turbines do not always return the energy invested in their manufacture.

Conclusions and Recommendations

It is expected that there will be sufficient available and projected onshore and offshore power generating capacity to allow AE to purchase at least 1,456 MW of onshore wind power generation and 300 MW of offshore wind power generation by 2020. With AE's current estimates of peak and annual average capacity factor for wind generation, AE could more than double their planned wind portfolio additions through

2020 and maintain sufficient backup power to meet forecast peak demand in the event of a complete wind failure.

The development of pumped hydraulic or compressed air energy storage would allow AE to consider the option of reducing some of its current fossil-fuel power generating capacity so as to reduce CO_2 and other air emissions. If AE considers energy storage projects, developing pumped hydraulic or compressed-air storage capability early and in tandem with expansion of the wind portfolio would allow AE to build a knowledge base to deal with significant wind penetration into its resource portfolio by 2020.

Notes

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Chapter 12. Solar

Summary

While solar power has great promise for Austin Energy, several logistic and financial constraints currently limit the broad adoption of solar power. For example, solar energy is not currently cost-competitive. In addition, solar radiation is intermittent, which makes it a more unreliable and less dispatchable source of power. Nationwide adoption of solar power technologies is limited by a lack of sufficient transmission infrastructure, lack of affordable storage options, and economics. To facilitate electric transmission of solar energy, more high-voltage direct current transmission lines will likely be necessary. Furthermore, improvements to bottlenecked or old transmission infrastructures would help facilitate the use of solar technologies.[1]

While solar power must overcome certain constraints to be more broadly viable, solar energy's advantage over wind energy is that it can produce electricity during peak periods. Solar energy can also provide a distributed, off-grid generation resource, which would allow customers to sell energy back to their electric provider through net metering.

Background

Solar energy is a renewable and accessible resource that can be used to generate light, heat, and electricity. Several technologies that utilize the sun's energy for electricity and heat purposes have been developed and can be implemented at utility scale. The two primary technological types are 1) concentrated solar (CSP) technologies that use direct radiation and 2) photovoltaic (PV) systems that use diffused solar radiation.[2]

As a versatile resource that continues to increase in efficiency and monetary value, solar power will figure prominently in AE's future. While solar energy is not currently the most cost-effective form of utility scale power generation, further investment in cutting-edge solar technologies may allow for solar energy to compete with traditional technologies and fuel sources in the same way that wind energy has become competitive.

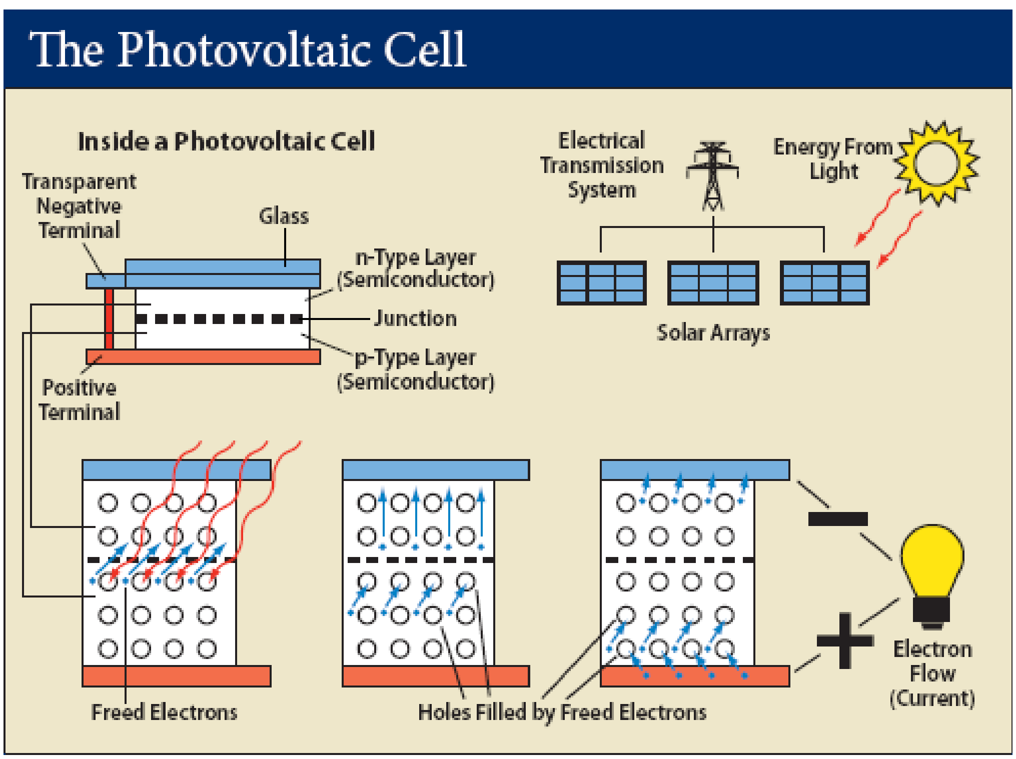
Solar Power Generation Technologies

Photovoltaic System Technologies

The term "photovoltaic" refers to a material or device that is capable of converting the energy contained in photons of light into an electric current. The history of photovoltaic (PV) systems begins in 1839 when French physicist Edmund Becquerel produced voltage when he illuminated a metal electrode in a weak electrolyte solution. Albert Einstein published a theoretical explanation of the photovoltaic effect in 1904.[3] By the 1940s and 1950s the first generation of single-crystal silicon PV systems were developed based on the Czochralski process, which consists of growing perfect crystals of silicon yielded. This technique continues to dominate the PV industry.[4] PVs were first used to convert light into electricity in the space industry for the Vanguard Satellite. Common applications of PV systems are pocket calculators, highway lights, emergency call boxes, rural water pumping, and small home systems.[5] From 2000 to 2007, U.S. PV system capacity increased from 139 to 874 MW. In 2006, of the 2,500 MW global solar PV market, only 3 percent corresponded to U.S. makers.[6]

PV cells are made mostly of silicon and consist of an n-type layer, p-type layer, and junction (see Figure 12.1). The n-type is electron rich, giving it a negative charge and the p-type is electron deficient, giving it a positive charge. The junction is located between the n-type and the p-type layers and restricts flow to one direction, from the p-type to n-type layers. Electrons that cross the electric field of the junction produce electricity. The energy used by electrons to cross the junction is supplied by photons from the sunlight.

Figure 12.1
Diagram of Photovoltaic Cell Technologies

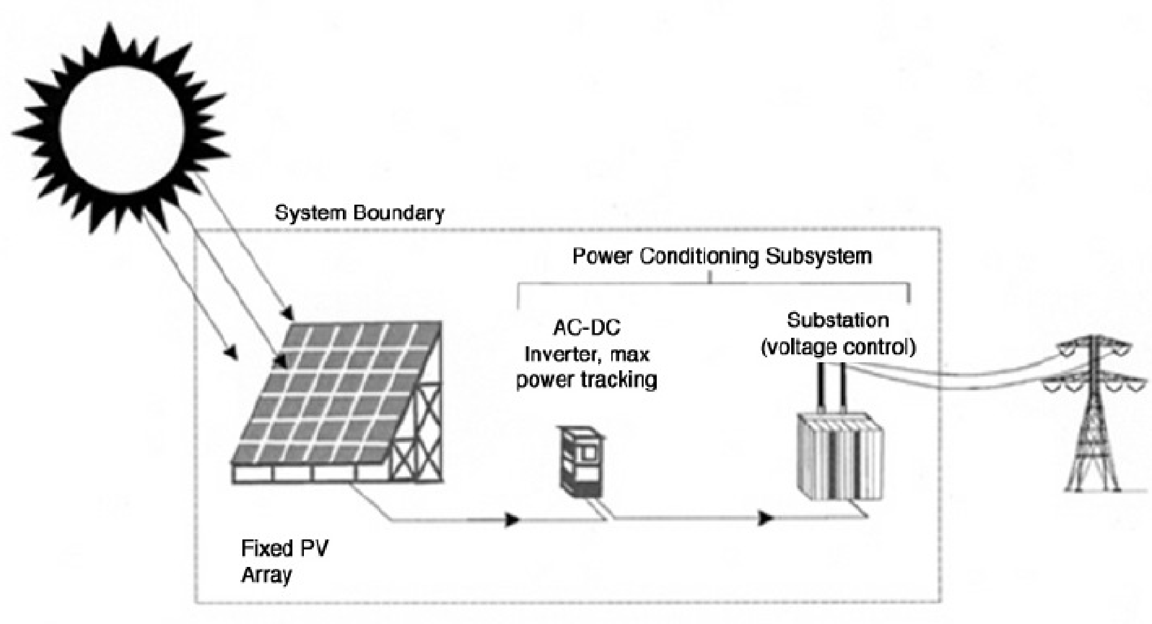


Source: Texas Comptroller of Public Accounts, *The Energy Report 2008* (May 2008), p. 140. Online. Available: http://www.window.state.tx.us/specialrpt/energy/. Accessed: October 13, 2008.

PVs differ from most other electric generation sources, as they produce direct current (DC) power. Most transmission lines in the U.S. work with alternating current (AC) power, as is the power supplied from the outlets in America's homes. As a result, electricity generated from PV systems must pass through an inverter, which converts the direct current (DC) power to alternating current (AC) power. Two types of PV systems are used commercially: silicon-based and thin film. These technologies differ in terms of manufacturing materials, cost, and efficiency. Silicon cells can reach an efficiency of about 16 percent while thin film cells have a rated efficiency of approximately 10.6 percent.[7]

Most PV arrays are residential (averaging about one kW) or commercial (one to several hundred kWs). Larger PV power plants can provide several MW of energy. Large-scale plants take about two years to build and have relatively high capital costs.[8] Arrays installed at residential and commercial sites can be installed in a matter of weeks. Small PV systems include stand-alone, off-grid, and grid-connected systems. Stand-alone systems can be used as a residential energy source. Grid-connected systems supplement electric service from a utility. If the amount of energy generated by the grid-connected system exceeds the owner's load, the excess energy can be exported to the utility grid. But if the owner needs additional energy, the system can get it from the grid.[9] This can benefit consumers by having electricity charges in their bill for only the amount required from the grid. Figure 12.2 shows the operation of grid-connected power systems.

Figure 12.2
Photovoltaic Grid-Connected Power System



Source: The National Regulatory Research Institute, *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria,* p. 80. Online. Available: http://www.coalcandothat.com/pdf/35%20GenMixStateToolsAndCriteria.pdf. Accessed: October 25, 2008.

There are four representative technologies for PV systems: (1) wafers of mono- or polycrystalline silicone, (2) thin-film semi-conductors, (3) single-crystal silicon and multi-junction gallium-arsenide-alloy cells concentrators, and (4) grid-connected PV systems. Wafers of single-crystal or polycrystalline silicone can reach efficiencies of up to 25 percent and commercial modules' efficiencies vary from 12 to 17 percent. The current cost of silicon modules is about $2 per watt-peak (Wp), as this type currently dominates the market. Thin-film semiconductors reach efficiencies ranging from 12 to 19 percent with commercial modules efficiency ranging from 6 to 11 percent. A new generation of thin film PV modules is entering the large-scale manufacturing. High-efficiency, single-crystal silicon and multi-junction gallium-arsenide-alloy cells concentrators can reach efficiencies ranging from 27 to 39 percent with pre-commercial modules efficiency ranging from 15 to 24 percent. Prototypes of these concentrator PV systems are being tested in southwest areas of the country. Grid-connected PV systems are currently being sold for about $6 to $7 per Wp or $0.17 to $0.22 per kWh, even when including support structures, power conditioning, and land requirements.[10] NREL estimates that the efficiency of crystalline silicon modules is 15 percent and is expected to increase to 15 to 20 percent by 2020. The efficiency of concentrator systems in 2007 was estimated to be 22 percent and is expected to increase to 33 percent by 2025.[11]

A variety of materials are used to produce solar thin-film, including copper indium diselenide (CIS/CIGS) and cadmium telluride (CdTe). CIS/CIGS modules have achieved efficiencies of between 8 to 10 percent, while CdTe modules have achieved efficiencies of between 9 to 10 percent. However, according to the Prometheus Institute, the efficiency of CIS/CIGS modules is expected to yield higher efficiency than that of CdTe modules by 2010. Currently, Heliovolt, a local solar manufacturer, estimates that CdTe modules have a module production of 6 to 10 percent, with a potential (record cell) of 16 percent. CIGS modules produce at yields of 10 to 14 percent, with a potential (record cell) of 19.9 percent.[12]

According to the National Renewable Energy Laboratory (NREL), nearly all locations in the U.S. have enough sunlight to make PV electric generation possible.[13] Utility-scale PV systems serve intermediate and peak loads. High levels of sunlight to power PV systems correspond to high levels of demand for electricity. Therefore, distributed PV systems in the U.S. help utilities meet intermediate and peak load.[14] PV arrays have very high mechanical availability factors (about 99 percent) but low capacity factors (around 16 percent). This is because PV systems provide intermittent power according to sunlight availability.[15] According to the EIA, the heat rate for photovoltaic technologies is 10,022 Btu/kWh.[16] The operational life for PV systems ranges from 20 to 40 years.[17] Most PV systems currently installed are made of crystalline silicon. Crystalline silicon is considered to be relatively mature by NREL. PV conversion efficiencies have improved 50 percent over the past ten years.

Stand-alone PV systems also need to store energy gathered during the day to be used when sunlight is not available. While various energy storage technologies are available, batteries are the most common form of electric storage. Among battery technologies the lead-acid battery continues to be the most commonly used storage method for PV systems. Batteries also provide surges of current, as well as the natural property of controlling the output voltage of the array so that the electric loads that they serve receive acceptable levels of voltage.[18]

Concentrated Solar Power Technologies

Concentrating solar power (CSP) technologies collect and concentrate sunlight and transform it into thermal energy. The thermal energy then drives a heat engine and generates electricity. CSP systems include Stirling-engine systems, parabolic troughs, and power towers. This section compares the cost and performance characteristics of the three CSP technologies (see Table 12.1).

Table 12.1
Performance Characteristics of Concentrating Solar Technologies

Technology Characteristic	Dish/Stirling	Parabolic Trough	Power Tower
Intensity of radiation concentration (suns) [a]	3,000	1,000	100
Efficiency (percentage) [b]	21	14	16
Land requirement (acres per MW)	4	5	8
Reliability [c]	Disadvantaged	Advantaged	Advantaged
Water requirement	Advantaged	Disadvantaged	Disadvantaged
Size module [d]	Small (25 MW)	Not specified	Large (100MW)

Source: Adapted from Gilbert M. Masters, *Renewable and Efficient Electric Power Systems* (New Jersey: John Wiley and Sons, Inc., 2004), p. 191.

Notes: [a] 1 sun = no concentration capacity.

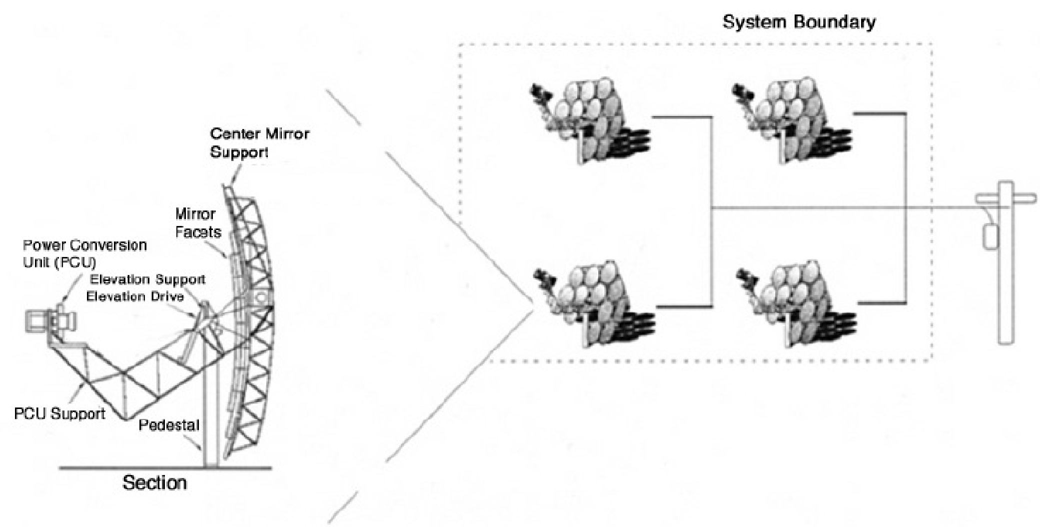
[b] Annual efficiency by percentage (from sunlight collection to power delivery).

[c] Reliability of the technology by the ability to store energy.

[d] Size module: the lower capacity, the less risks associated with financing the project.

Dish engine systems consist of parabolic collectors covered with curved mirrors that are programmed to face the sun. The surface collects and concentrates the solar energy onto a receiver at the dish's focal point that heats liquid hydrogen or helium. The receiver is connected to an engine and heated gas pressures pistons to make an electric motor spin to generate electricity (see Figure 12.3).[19] Other dish/engine systems use solar radiation to boil and condense an intermediate fluid, which is used to transfer heat from the solar receiver to an engine. The cold side of the engine is chilled with water-cooled and fan radiator systems. Since this technology involves a closed system, the requirement of water is low and the water can be recycled.[20] Currently, dish/engine systems have efficiencies ranging from 20 to 30 percent, the highest of any solar conversion technology.[21]

Figure 12.3
Diagram of Dish/Engine CSP Technology



Source: The National Regulatory Research Institute, *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria*, p. 8. Online. Available: http://www.coalcandothat.com/pdf/35%20GenMixStateToolsAndCriteria.pdf. Accessed: October 25, 2008.

Two dish/engine technology types have been successfully operated. Science Application International Corporation (SAIC) produces a dish and Stirling Thermal Motors (STM) builds the engine. Boeing and Stirling Energy Systems (SES) also have a similar product. Both technologies provide power of about 25 kW with conversion efficiencies from direct solar radiation to mechanical power generated of over 20 percent.[22] The SAIC/STM technology absorbs heat at 725 degrees Celsius and produces and generates power with an efficiency of 36 percent.[23] However, the technology loses power through the generation process and the overall efficiency drops to 21 percent.[24] Dish/engine systems often possess high efficiencies, can act as stand alone plants that do not need fuel lines or water and do not produce emissions. The timetable for project design to power generation can be on the order of a year.[25] Figure 12.4 shows a dish/engine system being tested at the Sandia National Laboratories in Albuquerque, New Mexico.

Parabolic-trough systems use curved u-shaped mirrors that can concentrate the sun's energy at 30 to 60 times its normal intensity by focusing energy onto a receiver pipe. The thermal energy heats a transfer fluid, which produces steam that moves a turbine to generate electricity. A collector field is formed by parallel rows of connected troughs. The rows are commonly oriented north to south, which allows the collectors to track the sunlight from east to west (see Figure 12.5).[26]

Figure 12.4
Example of Dish/Stirling Technology

Source: Sandia National Laboratories, *Sandia, SES wins Popular Mechanics Breakthrough Innovator Award*. Online. Available: http://www.sandia.gov/news/resources/releases/2007/trough.html. Accessed: February 15, 2009.

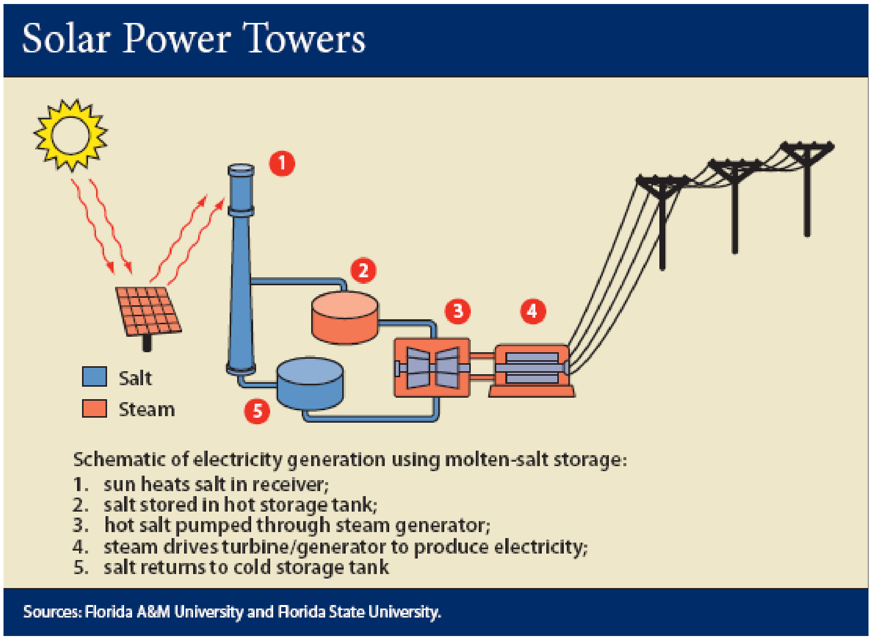
Power tower systems use large mirrors to concentrate the sun's energy at the top of a tower where a receiver is located. The energy heats a fluid a molten salt fluid that flows through the receiver. The salt's heat is used to generate electricity through a conventional steam generator. Molten salt retains heat efficiently, so it can be stored for days before being converted into electricity (see Figure 12.6).[27]

Figure 12.5
Example of Parabolic Trough Technology

Source: Sandia National Laboratories, *Sandia Invention to Make Parabolic Trough Solar Collector Systems More Energy Efficient*. Online. Available: http://www.sandia.gov/news/resources/releases/2007/trough.html. Accessed: February 15, 2009.

CSP systems serve as intermediate power sources and have primarily been used to supply bulk electricity Southwestern U.S.[28] According to the National Renewable Energy laboratory (NREL), the capacity factor for all CSP technologies (parabolic trough, dish/engine, and power tower) is between 30 and 50 percent.[29] According to the Energy Information Administration (EIA), the heat rate for solar thermal technologies is 10,022 Btu per kilowatt-hour (Btu/kWh).[30] The operating life for CSP systems is 30 years.[31]

Figure 12.6
Diagram of Solar Power Tower Technology



Source: Texas Comptroller of Public Accounts, *The Energy Report 2008* (May 2008), p. 144. Online. Available: http://www.window.state.tx.us/specialrpt/energy/. Accessed: September 29, 2008.

CSP technologies are still an immature technology. There are few installations and insufficient long-term data to make reliable and detailed analyses of their individual costs and performance factors.[32] Unless CSP processes are enhanced with fuels (or the plant operates in a combined cycle system that requires fuel), CSP systems do not use fuels.[33]

Access to the grid is necessary for CSP systems to thrive. Output from solar thermal power plants can be integrated onto existing grids since they do not require additional restructuring or grid stabilization measures.[34] Transmission costs are a factor for large solar facilities in West Texas, as the Electric Reliability Council of Texas (ERCOT) estimates that CSP plants built in West Texas may require similar transmission expenditures to what wind farms pay in the same area. The estimated cost of the approved CREZ transmission lines to West Texas to urban areas is about $1.5 million per mile, and the place of a CSP facility in the ERCOT interconnection queue could be far behind that of West Texas wind. In addition, some large land owners may object to utilities or private companies using their powers of eminent domain to acquire land and build transmission lines on or near their property.[35]

Storage Options for Concentrated Solar Power Facilities

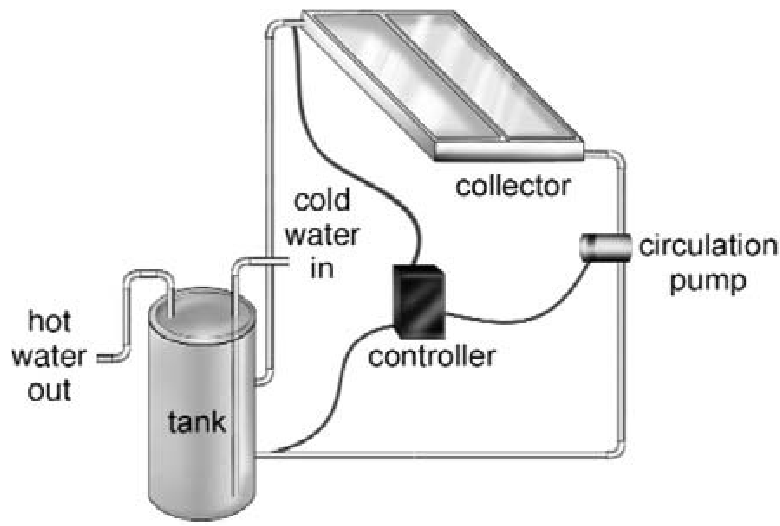
Solar thermal plants can increase their contribution to the grid if they are able to store energy from off-peak periods through heat transfer and molten salt storage. The molten salt heat transfer fluid already makes solar-generated electricity fully dispatchable during all hours of the day. For example, in Spain solar using molten salt technology has the same reliability status as power plants using fossil fuels.[36]

CSP facilities can also maximize their contribution to the grid is through concurrent siting with compressed air energy storage (CAES) systems. Using a CAES system concurrently with a CSP facility could have several distinct advantages. First, CAES systems have the lowest per kilowatt-hour cost of all viable energy storage technologies. Second, CAES facilities, could provide AE with a means to combat transmission congestion and spread the load of both its purchased wind power and for electricity produced by a concentrated solar facility, which would need to be build in West Texas due to its high direct normal insolation rates.[37] Third, a CAES facility would combat the innate volatility of solar and wind resources and allow AE to schedule renewable energy generation and transmission more easily. The Department of Energy estimates that energy storage could reduce balancing costs incurred by utilities who handle renewable-generated electricity by up to 2 to 3 percent.[38] In sum, using CAES in conjunction with solar power could remedy the expense and intermittency of solar power.

Solar Water Heating Technologies

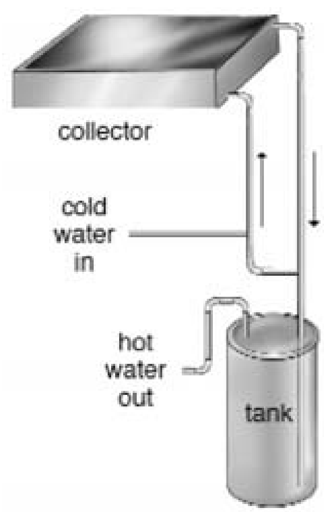
Most solar water heating systems are composed of a solar collector and a storage tank. The sun's energy is used to heat water or another heat-transfer fluid in the collector. The heated water is then stored for later use. Solar water heating systems can be either "active" or "passive," but active systems are more common. Active systems rely on pumps to circulate water. Figure 12.7 is a diagram of an active solar water heating system. Passive systems rely on gravity and the tendency for water to naturally circulate when heated.[39] Figure 12.8 shows the operation of passive solar water heating systems.

Figure 12.7
Active Solar Water Heating Technology



Source: Solar Energy Industry Association, *Solar Thermal Power Factsheet*. Online. Available: http://www.seia.org/galleries/pdf/Solar_Thermal_general_one_pager_Final.pdf. Accessed: November 3, 2008.

Figure 12.8
Passive Solar Water Heating Technology



Source: Solar Energy Industry Association, *Solar Thermal Power Factsheet*. Online. Available: http://www.seia.org/galleries/pdf/Solar_Thermal_general_one_pager_Final.pdf. Accessed: November 3, 2008.

Active solar water heaters include direct-circulation systems, which use pumps to circulate pressurized water directly through the collectors. Direct-circulation systems are appropriate for places that do not freeze for long periods. Indirect-circulation systems pump heat-transfer fluids through collectors. The two most common indirect-circulation systems are antifreeze and drainback systems. Passive solar water heaters include integral-collector storage systems, which consist of one or more storage tanks and are appropriate for places that rarely have freezing temperatures, and thermosyphon systems, which rely on the natural tendency of hot water to circulate. These systems are both economical and reliable.[40] There are four types of thermal collectors: swimming pool absorbers, flat plate collectors, vacuum tube collectors, and parabolic concentrating collectors. The dimension requirements for each type vary; for example, flat plate collectors require 1.25 to 1.5 m^2 per person, while vacuum tube collectors require 1 to 1.2 m^2 per person.[41]

Solar thermal energy systems have industrial or household applications such as hot water for a home or industry. The EIA differentiates low-, medium- or high-temperature solar thermal energy collectors. Low temperature collectors are primarily used in the U.S. to heat swimming pools and to heat (or cool) a home by offsetting of the amount of grid energy used for the same purpose. The process for either heating or cooling is essentially the same. Heat is stored during the day and released during the night. During the winter, the heat is stored during the day and provides heat during the night.

Medium temperature collectors are primarily used for cooking. More recent uses of medium temperature collectors can be seen in water treatment and desalination.

High temperature collectors are primarily used to convert heat energy to electricity. These are the CSP systems that use mirrors or lenses to concentrate the sun's power and make turbines spin to produce electricity. This technology is explained in more detail above.

Solar water heating is an effective method for utilizing renewable energies at a residence or larger building. It provides an alternative source of energy for heating water and can reduce building temperatures to offset the need for energy from the grid to cool it. The technology is well developed and the required materials are well understood. The worldwide market for this technology has been consistently growing. In Israel, for example, solar water heaters are displacing 6 percent of annual residential energy consumption.[42] In the U.S. solar water heating systems have experienced continuous growth.[43]

Solar thermal water heating systems can be constructed at small and large scales. Small scale uses includes decentralized water heating with small collector surfaces of 4 to 8 square meters (m^2), with a storage capacity from 300 to 500 liters.[44] Large scale includes central drinking water heating for hospitals, sports clubs, etc., with collector surfaces of over 100 m^2 with a storage capacity of about 10 m^3 and with buffer storage volume of 1 to 2 m^3.[45] Requirements for seasonal storage vary according to the scale in question. For example, the storage capacity requirement for large scale seasonal storage is at least 10 times more storage capacity per square meter of collector surface.[46]

Operating Examples

There are many operating examples of utility-scale solar projects in the western United States. Despite the presence of certain advantageous conditions for large-scale solar deployment in Texas, no large-scale solar projects currently exist.

Concentrated Solar Power Technologies

The five largest solar thermal plants are all located in Spain and the U.S.[47] One operating example of a parabolic trough is the Solar Electric Generation System (SEGS), located in the Mojave Desert in California. The SEGS I plant was built in 1985 with 13.4 megawatts (MW) of installed capacity. The SEGS IX completed in 1991 produces 80 MW.[48] Parabolic trough systems have been designed to work with conventional steam-cycle plants. However, this added interoperability increases the amount of required water.[49] Nevertheless, the SEGS plant has demonstrated that parabolic trough systems are reliable. The SEGS IX plant has an overall annual efficiency of 10 percent. The cost of electricity generated in 2001 at this facility was $0.12 per kWh, and it is projected to decrease to about $0.05 per kWh in the future.[50] The Solana Generating Station is currently under construction. This plant will have a capacity for 280 MW and is expected to cost $1 billion.[51]

Power tower systems have also been operating in the U.S. A large system built was Solar One near Barstow, California, which operated from 1982 to 1988.[52] The Department of Energy (DOE), Southern California Edison, the Los Angeles Department of Water and Power, and the California Energy Commission jointly designed Solar One.[53] In 1995 Solar One was converted into Solar Two by adding a second ring of 108 larger 95 m^2 (1,000 ft^2) heliostats around the existing Solar One facility, totaling 1,926 heliostats with a total area of 82,750 m^2 (891,000 ft^2). This gave Solar Two the capability of redirecting the equivalent of 600 suns and the ability to produce 10 MW of energy. Solar Two used molten salt, a combination of 60 percent sodium nitrate and 40 percent potassium nitrate, as an energy storage medium instead of oil as with Solar One.[54] This helped in energy storage during brief interruptions in sunlight due to clouds. The molten salt also allowed the energy to be stored in large tanks for future use. The second plant operated with molten salt rather than oil. Molten salt has proven to be successful. Its temperature of 565 degrees Celsius meets the needs of a steam turbine.[55] The thermal efficiency of Solar Two was greater than 97 percent; the plant was decommissioned in 1999.[56] Solar Two was designed to store energy for an additional three hours after sunset, and at reduced output, could deliver energy for much longer periods. [57] The Solar Tres plant is projected to start operations in late 2008 or early 2009 in Spain.

Nevada Solar One, the third-largest plant of its kind in the world and the largest CSP plant in the U.S., is a parabolic trough system that generates over 64 MW of electricity.[58] It is located in Boulder City, Nevada, and began operating in July 2007 at a cost of over $260 million to install. The plant was designed, manufactured and installed in a collaborative effort between ACCIONA Energy and DOE and all of its energy is purchased by the Nevada Power Company and Sierra Pacific Power Company. Nevada

Solar One uses parabolic troughs as thermal solar concentrators, heating tubes of liquid, which act as solar receivers. The solar receivers are specially coated tubes made of glass and steel, and about 19,300 of these four-meter long tubes are used in the newly built power plant. Nevada Solar One also uses a technology that collects extra heat by putting it into phase-changing molten salts. This energy can then be drawn upon at night.[59] Nevada Solar One plant's technological information is listed Table 12.2 along with other international operating examples. The DOE recently funded 15 solar projects to evaluate the cost-effectiveness of solar designs incorporating energy storage including one solar renewable thermal energy project with the goal of reducing the current CSP cost of $0.13 to $0.16 per kWh to $0.08 to $0.11 per KWh by 2015, and perhaps as little as $0.07 per kWh in the future.[60] Some of these studies seek to generate electricity when sunlight is not available by using stored thermal energy storage with a goal of six hours of storage by 2015.

Table 12.2
Characteristics of Concentrating Solar Power System Examples

Project	Nevada Solar One	Solar Tres
Type	Parabolic trough	Molten salt power tower
Backup	2 % natural gas	15% natural gas
Location	Nevada	Spain
Land requirement (acres)	400	351
Capacity (MW)	64	17
Storage (hours)	0.5	15
Construction period (months)	16	-
Annual production (million kWh)	130	110.5
Capacity Factor (percentage)	23	74
Commissioned	June 2007	Late 2008/ early 2009
Cost ($/kW)	4,156	17,060

Sources: Acciona, *ACCIONA's Nevada Solar One™ Demonstrating the Commercial Competitiveness of Solar Energy*. Online. Avalable: http://www.nevadasolarone.net/the-plant; Jose Martin, *Solar Tres – First Commercial Molten Salt Central Receiver Plant*, Presented at NREL CSP Technology Workshop (March 7, 2007); and Solar Paces, *1 MW Solar Thermal Power Plant in Arizona and 50 MW Plant in Nevada*. Online. Available: http://www.solarpaces.org/Tasks/Task1/Nevada_Solar_One.HTM

Texas hosts a concentration of different high-skill industry clusters relevant to CSP, such as high-tech manufacturing operations, information systems, logistics, and solar and utility generation and transmission. Due to the fact that it is contained entirely within the State of Texas, ERCOT can integrate new technologies into the grid without the approval of the Federal Energy Regulatory Commission (FERC). Through the Competitive Renewable Energy Zones (CREZ) proceeding, ERCOT and the Texas Public Utility Commission (PUC) were approved to build transmission lines that link wind energy from West Texas to the largest cities in the state. When completed, these lines should also be applicable for new CSP facilities. However, it is not known how far any new CSP projects might be behind new wind farms in the ERCOT interconnection queue.

Support from federal solar energy incentives is also a valuable resource in creating a growth sector of the economy for installing new CSP systems. Universities and other research institutions in Texas also facilitate the potential to install more CSP systems. CSP systems require ample space and a critical mass of hours of quality sunlight. Because of geographic and atmospheric characteristics, most of West Texas is well suited for installing CSPs. A study commissioned by AE concluded that construction of a 100 MW CSP materials manufacturing facility in the Austin area could create nearly 300 new jobs and add about $1 billion to the regional economy by 2020.[61]

Photovoltaic System Technologies

The largest operating utility-scale PV power plant in the U.S. is located at the Nellis Air Force Base in Nevada. The plant was completed in December 2007 and is a public-private ownership between the Air Force, Sunpower Corporation, Nevada Power Plant Company and MMA Renewable Ventures, a subsidiary of Municipal Mortgage and Equity.[62] The plant required an investment of $100 million, with capital costs of over $7,000 per kW. The plant has a contract to sell electricity back to the base for the next 20 years at $0.022/kWh (less than the $0.10/kWh it pays for electricity off the grid)[63] in part because these rates reflect the value of renewable energy certificates (RECs) from the Nellis Air Force Base solar array sold to Nevada Power to help meet their REC quota.[64] This system would otherwise be unable to provide power at such low prices. Technological information regarding the Nellis Plant is provided in Table 12.3, along with one other international operating example.

Table 12.3
Characteristics of Photovoltaic Systems Examples

Project	Nellis	Rote Jahne
Location	Nevada	Germany
Technology	PV	Thin film
Land Use (Acres)	140	33
Capacity (MW)	14.2	6
Construction Time (Months)	6	Not available
Annual Production (Million kWh)	30.1	5.7
Capacity Factor (Percentage)	24	10.8
Commissioned	12/2007	2007
Cost ($/kW)	7,042	4,667

Sources: Nellis Air Force Base, *Nellis Air Force Base Solar System Fact Sheet*. Online. Available: http://www.nellis.af.mil/shared/media/document/AFD-080117-043.pdf; Renewable Energy World, *Construction Complete on 6 MW Thin-Film PV Installation in Germany*. Online. Available: http://www.renewableenergyworld.com/rea/news/story?id=48027; and Project Finance, *Setting sun?* (February 1, 2008).

The U.S. already has three very large solar projects planned for the near future. PG&E started two power purchase agreements to purchase electricity from what will be the world's largest solar plants: a 9.5 square mile 550 MW thin film and a 3.5 square mile, 250 MW silicon PV plant.[65,66] The generators are expected to deliver electricity in 2010 and be complete by 2013.

PV systems are an attractive option for utilities that want to cut fuel costs and meet local environmental regulations.[67] Utility-scale PV systems are actually easier to construct than conventional fossil fuel or nuclear power plants since PV arrays are easier to install and connect. PV plants can be placed where they are most needed in the grid and modular PV plants can be expanded incrementally as demand increases. PV systems have few moving parts, which minimizes their need for maintenance. PV plants do not consume fuel and do not produce air or water pollution, silently generating electricity.

In Austin, the firm Heliovolt is working with thin film PV materials that offer several advantages. Thin film PV technologies can blend into existing structures by having an appearance of tinted glass on sides of buildings, slate, or roofs. Thin film PV technologies significantly reduce costs due to low material usage. This film PV is not affected by silicon supply and they have potential for improving cost throughout the chain.

Solar Water Heating Technologies

The largest operating solar water heating system in the U.S. is the one million gallon pool used for the 1996 Atlanta Olympic Games. It is a 10,000 square foot system and is estimated that the system saves about $12,000 per year in avoided energy costs.[68]

Economic Outlook

Overall, concentrated solar power technologies are more economical for utility-scale generation than PV technologies. However, the high capital and levelized costs of electricity associated with PV and CSP technologies cause many utilities, consumers and large AE customers to hesitate before initiating significant investments in solar power technologies for both grid and end uses.

Concentrated Solar Power Technologies

The levelized cost of electricity from CSP facilities is approximately 11 to 18 cents per kWh.[69] According to EIA, the overnight cost for concentrating solar systems was $2,745 per kWh. The Electric Power Research Institute's (EPRI) CSP estimate was $3,410 per kWh. The approximate construction time for a CSP plant is three years.[70] Due to the unique specifications required to build a CSP plant, CSP plant construction times can be longer than a conventional coal plant. The technology, design and scale of any CSP plant must be unique to the site specified for construction. Nevertheless, 17 CSP plants are currently under construction around the world. According to the EIA, the overnight cost for concentrated solar in 2006 was $3,744 per kW. The fixed operating and maintenance costs during the same period were $55.24 per kW.[71]

NREL reports that the cost of electricity of trough systems is between $0.12 to $0.14 per kWh. NREL also reports that the levelized cost of electricity of power tower systems is $0.06 per kWh (the same cost for trough systems) and $0.20 per kWh for dish systems. According to a study commissioned by the DOE, CSP systems can achieve lower costs (below $0.06 per kWh) at modest production volumes. Total overnight costs are $3,500 per kW for power tower systems and $3,422 per kW for parabolic trough systems. Cost information for dish systems is not available. Table 12.4 estimates costs for CSP systems. The DOE expects the cost of energy produced by parabolic trough CSP systems to decrease to about $0.085 per kWh by 2010.[72] NREL expects the overnight costs for power tower systems to be $2,500 per kW in 2018 and for trough systems $2,920 by 2012.

Table 12.4
Concentrating Solar Power Costs Overview

Technology/Metric	Cost
Cost of energy ($/kWh)	$0.12 and $0.12 to $0.14
Levelized Cost of Electricity ($/kWh):	
Power tower	$0.06
Trough systems	$0.06
Dish systems	$0.20
Total overnight costs ($/kW)	$2,745, $3,410, and $3,744
Power tower systems	$3,500
Trough systems	$3,422
Dish systems	Not Available
Variable O&M costs ($/kW)	$0.00
Fixed O&M costs ($/kW)	$55.24
Total O&M costs (source does not specify whether variable or fixed O&M costs ($/kW):	
Power tower	$0.01
Trough systems	$0.01
Dish/engine	Not available

Sources: Texas Comptroller of Public Accounts, *The Energy Report* (May 2008), Executive Summary. Online. Available: http://www.window.state.tx.us./specialrpt/energy/exec/solar.html. Accessed: October 13, 2008; The National Regulatory Research Institute, "*What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria"*(p. 19). Online. Available: http://www.narucpartnerships.org/Resources/NRRI-GenerationMix.pdf. Accessed: October 25, 2008; Energy Information Administration, "*Assumptions to the Annual Energy Outlook 2008*" (June 2008), p. 78. Online. Available: http://tonto.eia.doe.gov/FTPROOT/forecasting/0554(2008).pdf.; The National Renewable Energy Laboratory. Online. *Power Technologies Energy Data Book, Concentrating Solar Power.* Online. Available: http://www.nrel.gov/analysis/power_databook/docs/pdf/db_chapter02_csp.pdf. Accessed: October 28, 2008.p. 22.

Photovoltaic System Technologies

Capital costs for utility-scale PV systems are projected to decline as production expands, production methods improve, and economies of scale are reached. In 2006, the cost of electricity generated by PV systems was from $0.18 to $0.23 per kWh.[73] According to the DOE, the cost of PV power ranges from about $0.22 to $0.38 per kWh.[74] Total overnight construction costs for photovoltaic systems are $5,649, while fixed operating and maintenance costs are $11.37 per kW.[75] EIA also reported that the total overnight costs for a PV plant are $4,222/kw,[76] with no fuel costs for PV systems.[77] NREL reported in 2007 that the estimated cost of crystalline silicon modules is $2.50 per Wp. The estimated cost in 2007 for concentrator modules is $90 per m^2. The balance of system (BOS) estimated cost for crystalline silicon in 2007 is $0.60 per Wp. The BOS estimated cost for concentrators in the same year is $0.30 per Wp. The total installed system estimated cost for crystalline silicon in 2007 is $5.20 per Wp. The total installed system cost figures are not available for CSP systems. The estimated total operating and maintenance costs in 2007 for crystalline silicon PV systems is of $0.02 per kWh and for concentrator PV systems is $0.01 per kWh (see Table 12.5).[78]

Table 12.5
Photovoltaic System Costs Overview

Metric	Cost
Cost of energy ($/kWh)	0.18 – 0.23 and 0.22 – 0.38
Total overnight costs ($/kW) Total installed system ($/Wp)	$5,649 and $4,222 $5.20
Variable O&M costs ($/kW)	$0.00
Fixed O&M costs ($/kW) Total O&M costs ($/kWh): Crystalline silicon PV systems Concentrator PV systems	$11.37 $0.02 $0.02

Sources: Texas Comptroller of Public Accounts, *The Energy Report* (May 2008), Executive Summary. Online. Available: http://www.window.state.tx.us./specialrpt/energy/exec/solar.html. Accessed: October 13, 2008; Energy Information Administration, *Assumptions to the Annual Energy Outlook 2008* (June 2008). Online. Available: http://tonto.eia.doe.gov/FTPROOT/forecasting/0554(2008).pdf. Accessed: October 28, 2008. p. 78; The National Regulatory Research Institute, *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria* (p. 19). Online. Available: http://www.narucpartnerships.org/Resources/NRRI-GenerationMix.pdf. Accessed: October 25, 2008; The National Renewable Energy Laboratory, Online. *Power Technologies Energy Data Book*, *Photovoltaics* (p. 32). Online. Available: http://www.nrel.gov/analysis/power_databook/docs/pdf/db_chapter02_pv.pdf. Accessed: October 28, 2008.

The DOE expects that the cost of energy produced by PV systems will decrease to $0.11 per kWh by 2010 because of the usage of higher efficiency components and other improvements.[79] Analysts with Photon International expect that fully loaded PV system costs (from materials through installation) will be $0.10 per kWh by 2010.[80] NREL estimates that the cost of crystalline silicon modules is projected to be between $1 and $1.50 Wp by 2020. The estimated cost for concentrator modules is expected to decrease to $80 per m^2 in 2025. The BOS estimated cost for crystalline silicon is estimated to decrease to $0.40 per Wp in 2020 for concentrators to decrease to $0.15 per Wp by 2015. The total installed system estimated cost for crystalline silicon is expected to decrease to $2.30 from $2.80 per Wp by 2020. Total installed system cost figures are not available for concentrators. Total operating and maintenance estimated cost for crystalline silicon PV systems is expected to decrease to $0.005 per kWh by 2015 and for CSP systems is expected to decrease to the same amount by 2025.[81]

As 90 percent of PV systems' cost is incurred upfront, potential PV investors aggressively seek financial incentives. Indeed, the solar industry and particularly the PV systems industry has grown in direct response to federal, state, and local subsidies and tax policies. The industry has not been able to plan for long-term scenarios due to uncertain subsidies. This uncertainty has limited the development of the solar industry. For example, two government incentives known at the beginning of 2008 were to set to expire at the end of the year; the investment tax credit (ITC), which covers up to 30 percent of a new concentrating solar power plant and the production tax credit (PTC). Many efforts to renew the ITC were made but the approval was blocked eight times.[82] Finally, the production tax credit was renewed late in 2008. The new law, written into the financial rescue bill, extends the 30 percent credit for another eight years and eliminates any cap of benefits, which had been set at $2,000.[83]

AE has evaluated the worth of PV generation to their power system. The "value" is defined as the maximum price AE should be willing to pay. For a solar project to be cost-effective, its cost has to be equal to or less than the value. In 2008, for a fixed type PV system the average value was $0.164 per kWh, and the investment average value was $3,139 per kW. For a track type PV system the average value for energy was $0.158 per kWh, and the average investment value was $4,161 per kW.[84] These values are still below current generation and investment costs. The payback time of array field and rooftop systems is between 4 to 8 years (under 1700 kWh/m^2 irradiation) and is estimated to be between 1.2 to 2.4 years for future systems. If projected costs decrease as expected, AE's value could be matched in a few years, which should allow AE to make long term solar investment plans.

Solar Water Heating Technologies

According to NREL, in 2000, the capital cost of domestic hot water heater systems varied from $1,900 to $2,500 per system, and for pool heaters the capital cost varied from $3,300 to 4,000 per system. In the same year, the operating and maintenance cost of domestic hot-water heaters varied from $25 to 30 per system-year.[85]

Environmental Impacts

Life cycle analysis (LCA), an approach to quantify the pollution a system causes in its entire life cycle, starts with extraction of raw materials and ends when materials are recycled or disposed. PV systems do not produce any significant greenhouse gases during operation. However, the most powerful greenhouse gas in existence is used to manufacture solar PV components. In addition, decommissioned solar PV has highly toxic e-waste components that must be taken into account by anyone who purchases significant PV resources.

Overall, silicon PV systems generate GHG emissions of 100g CO_2e/kWh. The bulk of the CO_2 emissions come from sulfur hexafluoride (SF_6), which is used to clean the reactors used in silicon production. A greenhouse gas with 25,000 times the potency of CO_2 , SF_6 is considered by the Intergovernmental Panel on Climate Change (IPCC) to be the most powerful greenhouse gas in existence.[86] SF_6 can also react to create sulfur dioxide, which requires silicon PV manufacturing facilities to use scrubbers in order to comply with federal law.[87] Silicon PV manufacturing also involves heavy use of lead, sodium hydroxide and other corrosive substances such as hydrochloric acid, sulfuric acid and nitric acid. These chemicals require elaborate and expensive disposal systems and procedures that could add to the cost of the system.[88]

While thin-film manufacturing does not have the same CO_2e footprint as the manufacture of silicon PV, the process still produces hazardous byproducts. For example, CIS/CIGS thin-film manufacture has a byproduct of hydrogen selenide, a highly toxic substance. In addition, cadmium, which is used in cadmium telluride (CdTe) thin-film manufacture, is considered to be “extremely toxic” by the EPA.[89]

The disposal of PV systems and components could also present significant e-waste issues. Lead, in addition to the aforementioned chemicals involved in the manufacture of silicon PV and thin-film components, is highly toxic and could pose significant risks to the public if the e-waste is burned or left in landfills.[90]

Nevertheless, solar technologies do not emit any significant amount of greenhouse gases (GHG) or other air pollutants during the production of electricity.[91] According to the National Regulatory Research Institute, by 2010 to 2015, CSP systems will produce zero CO_2 emissions per MWh.[92] Solar technologies do not generate water pollution.[93] CSP systems may need water but this can be recycled. CSP systems do not produce solid waste, but the production of materials and equipment do produce small amounts of hazardous waste.[94] NREL estimates that CSP systems require about five to 10 acres per MW generation capacity.[95] According to the EPA, CSP plants do not damage the land, but may displace wildlife habitat,[96] requiring about 4 to 8 acres of land per MW of capacity installed. The dish/Stirling technology has the lowest land requirement, while power towers have the highest land requirement. According to the European Solar Thermal Industry Association, 1 MWh of installed solar thermal power capacity results in the saving of 600 kilograms of CO_2. The energy payback time of CSP systems is approximately five months, which is very low compared to their lifespan of 25 to 30 years.[97]

According to the National Regulatory Research Institute, by 2010 to 2015, photovoltaic systems produce zero CO_2 emissions per MWh.[98] According to the EPA, PV systems do not generate solid waste in creating electricity. However, their manufacture does generate small amounts of hazardous materials such as cadmium and arsenic which must be disposed of properly to avoid harm.[99] Most PV systems are installed on existing structures such as homes and commercial buildings and do not require additional land.[100]

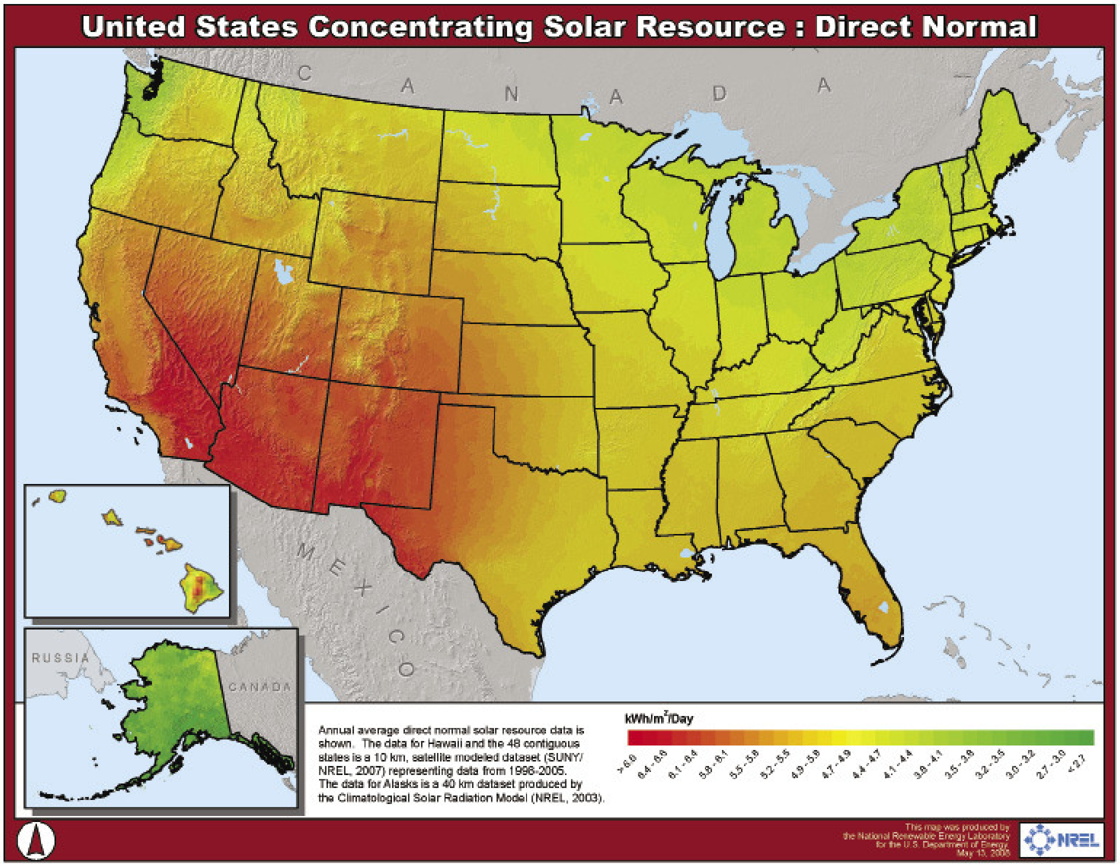
Solar water heating systems also do not produce emissions during operation. On the contrary, since on average water heating accounts for about 30 percent of a home's CO_2 emissions, solar water heaters can reduce total emissions by more than 20 percent.[101]

Future Outlook

While solar power promises zero fuel costs, renewable peaking power and the potential to revolutionize or augment our current central-station power generation model, solar power has several critical limitations that must be addressed by AE in this resource planning process.

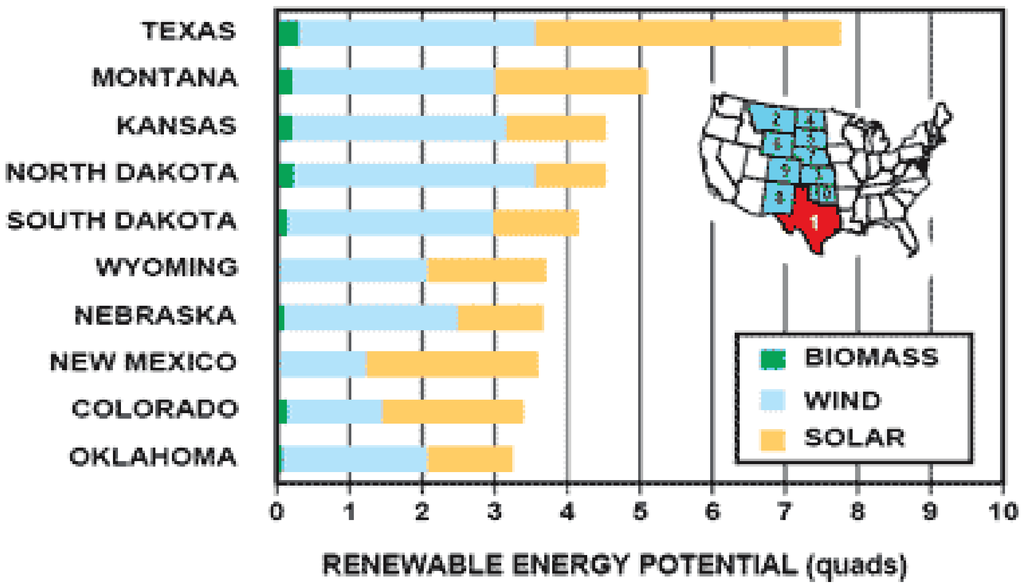
Figure 12.9 details the average direct normal insolation in Texas as well as the contiguous U.S., and as Figure 12.10 indicates, Texas' has the most significant solar potential in the nation. Texas receives 250 quads of power every year (one quad is one quadrillion British thermal units (Btus) and has the capacity to meet the annual needs of about three million people).[102] With insolation at 75 percent above east Texas, west Texas receives some of the highest levels of direct insolation on earth.[103] According to the State Energy Conservation Office (SECO), "the energy from sunshine falling on a single acre of land in West Texas is capable of producing the energy equivalent of 800 barrels of oil each year."[104] Figure 12.10 illustrates Texas' potential competitive position for utilizing solar energy in comparison with other states. It has been estimated that a solar power plant could produce 60 percent more power in West Texas than one of a similar size located in Austin. In other words, a solar generator in Austin producing the same amount of electricity would need to be 1.6 times as big as one in West Texas.[105]

Figure 12.9
Direct Solar Normal Insolation in Texas and the United States



Source: State Energy Conservation Office, *Chapter 3: Solar Energy*, *Renewable Energy Report.* Online. Available: http://www.seco.cpa.state.tx.us/publications/renewenergy/solarenergy.php. Accessed: April 8, 2009.

Figure 12.10
Renewable Energy Potential in Texas



Source: State Energy Conservation Office, *Renewable Energy in Texas.* Available: http://www.seco.cpa.state.tx.us/re.htm. Accessed: October 24, 2008.

Concentrated Solar Power Technologies

CSP systems have been researched and developed since the late 1970s. While the cost of producing electricity from CSP systems has dropped, it is still high compared to fuel-based energy. CSP systems offer several advantages over other power generation technologies: the materials (concrete, steel, glass) used at these plants can typically be recycled; the property needed is usually outside urban areas and it may have a low value, there are no social or ecological problems associated with its use, there are no hidden costs of environmental pollution, or other resulting economic effects. Lastly, CSP systems use construction materials that are available and affordable world-wide as CSP systems can be constructed and operated by local labor.[106]

Solar power tower technologies have a promising but uncertain future. For power towers to be cost effective, they have to be large, on the order of 100 MW installed capacity.[107] Furthermore, in order to facilitate electric transmission of solar energy, use of new CREZ transmission will be necessary.[108] Developing power tower technologies use air as the fluid rather than molten-salt. This solar-heated air could be used in a steam generator for a conventional Rankine-cycle power plant. It could be used to preheat air leaving the compressor during its way to the combustor of gas turbine in a combined-cycle hybrid plant.[109]

Photovoltaic System Technologies

The potential for PV systems is high because of the high potential for energy output. A utility-scale PV generating station of 140 km^2 sited at a high solar insolation location (like those in the southwest) could generate all of the electricity needed in the country (2.5×10^6 GWh/year), assuming a system efficiency of 10 percent and an area packing factor of 50 percent (to avoid self-shading).[110] After the recently approved government incentives and considering PV advantages, the PV industry could increase their growth and produce electric power at or less than AE's designated solar value.

PV producers recently faced a shortage of silicon, a basic input. This increased the price of electricity and put them at a disadvantage to compete in the renewable energy market. If PV systems lack batteries to store energy, they cannot provide electricity at certain times. Off-grid systems require batteries to provide electricity when sunlight is not available.[111] PV system developers face uncertain and inconsistent treatment, both at state and national levels.[112]

Heliovolt Corporation in Austin developed a cost-effective copper indium gallium selenide (CIGS) thin film PV process named *Field-Assisted Simultaneous Synthesis and Transfer (FASST®)*. This process is composed of two stages: precursor deposition and rapid thermal processing and separation. *FASST®* combines features of rapid thermal processing and anodic wafer bonding; and has the advantages of rapid processing, low thermal budget, confinement of volatile Selenium and high material utilization.[113] *FASST®* process allows developers to apply thin film PVs to construction materials such as roofing, steel, and flexible composites in 80 to 98 percent less time than conventional processes.[114] This would position the company to bring economical building products featuring integrated PV cells to the market.[115]

PV systems generate more jobs during their construction and manufacture per MW of installed capacity than fossil fuel generation facilities. However, PV systems require minimal maintenance compared to fossil fuel based plants, thus reducing the need to employ a large number of individuals for a given facility.

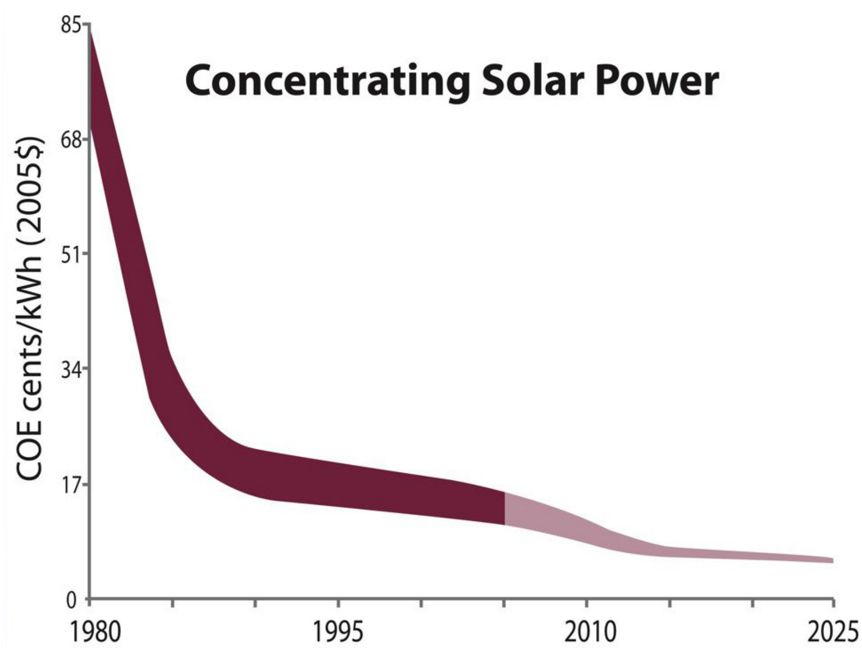
Solar Water Heating Technologies

Solar water heater systems save energy. According to NREL, in 2000, domestic water heaters saved 2,750 kWh/yr and pool heater systems saved 1,600 therms/yr.[116] Medium temperature collectors that can be used for water treatment may have potential to increase the use of water heating collectors and create profitable opportunities in the future. Solar thermal systems have the characteristic that they are modularly structured with collector units of about 2.5 to 10 m^2. These units can be used to replace conventional roofing material and meanwhile function as insulators for the roof.[117]

Options for Austin Energy

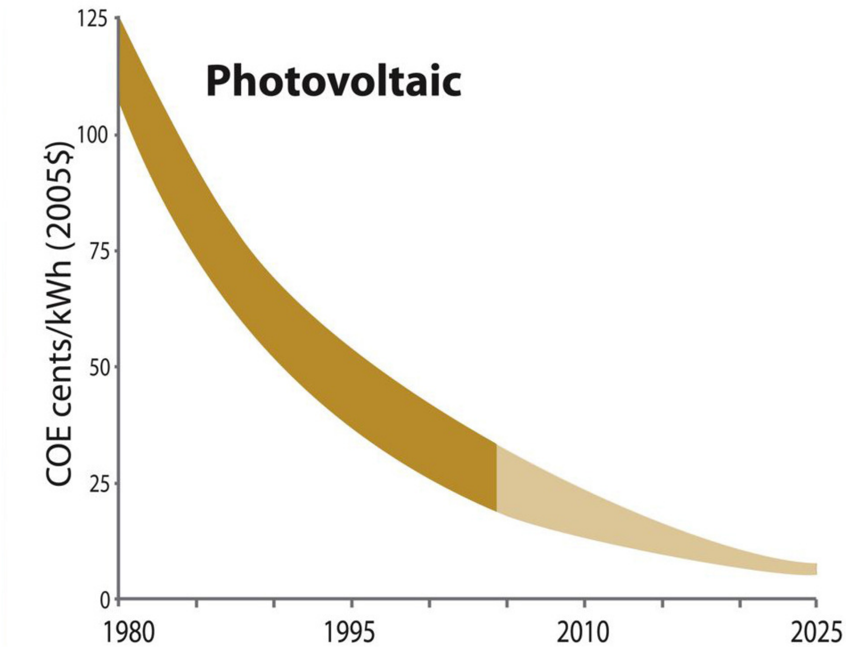
In the current utility business climate, the levelized cost of electricity from renewable resources such as CSP and solar PV is often too high for a large-scale investment. In addition, the current economic downturn has left consumers large and small with a reduced tolerance for rate increases. However, NREL estimates that the levelized cost of electricity from CSP and PV systems will drop significantly by 2015 and 2020, respectively.[118] Figures 12.11 and 12.12 illustrate the predicted decreases in the levelized costs of CSP and PV systems over the next 20 years. In addition, state and/or federal renewable portfolio standards and likely federal carbon regulation prior to 2020 will likely increase demand for utility-scale renewable projects such as CSP and large-scale PV. If AE is able to position itself to benefit from reduced levelized costs for solar power, it will likely be able to reap major financial windfalls from the sale of renewable energy credits under state and/or federal renewable standards. Additionally, massive investments in solar power and a gradual reduction in nonrenewable generation will allow AE to reap financial benefit from a cap and reduction system that will place an increasing price on carbon emissions. If AE can make aggressive investments in solar power, the utility's overall emissions would be more likely remain under the gradually decreasing federal cap and provide the City of Austin with a significant financial benefit through AE's annual general fund transfer.

Figure 12.11
Decreasing Levelized Cost of Electricity for CSP



Source: National Renewable Energy Technology, Energy Analysis Office, *Energy Cost Trends 2005*. Online. Available: http://www.nrel.gov/analysis/docs/cost_curves_2005.ppt. Accessed: February 15, 2009.

Figure 12.12
Projected Decreases in Levelized Cost of Electricity for PV



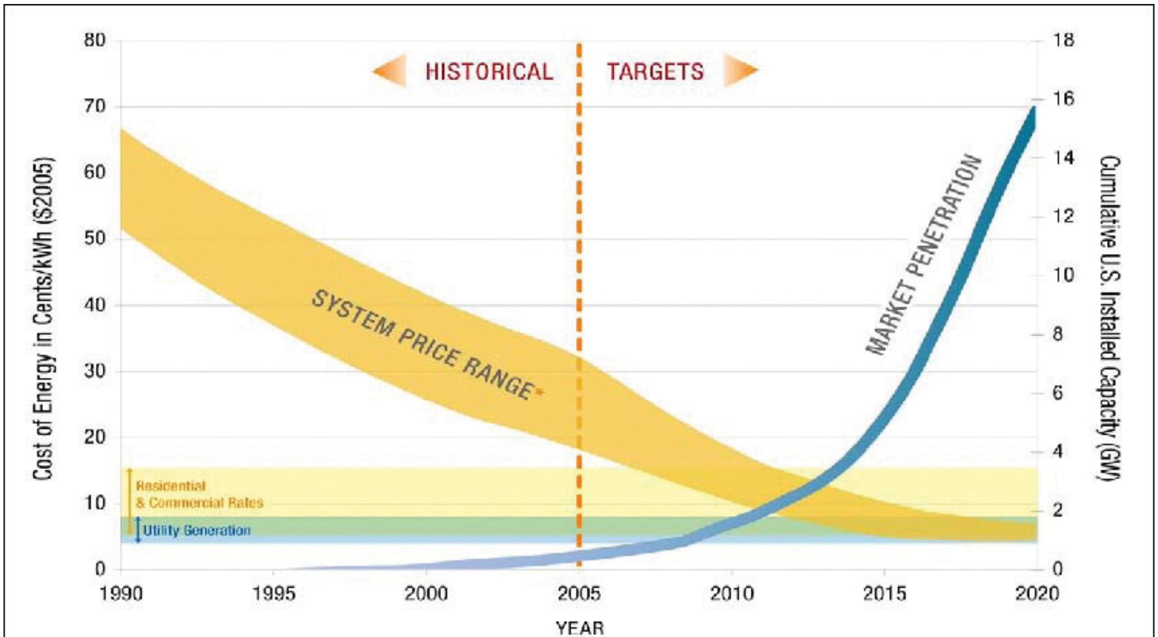
Source: National Renewable Energy Technology, Energy Analysis Office, *Energy Cost Trends 2005*. Online. Available: http://www.nrel.gov/analysis/docs/cost_curves_2005.ppt. Accessed: February 15, 2009.

Conclusions and Recommendations

Austin Energy could immediately begin planning and building two 300 MW CSP facilities in high-insolation areas of West Texas in 2015 and 2020 in order to take advantage of increased West Texas transmission access. The Austin Climate Protection Plan already includes a goal of 100 MW from solar energy by 2020. Austin is well situated to meet this goal by tapping into key local industries, including advanced manufacturing, semiconductor, information systems, logistics, construction and most importantly, utility generation and transmission. In addition, ERCOT can adopt new technologies into the grid without FERC approval. With ERCOT and the PUC developing new transmission lines to transfer wind energy from West Texas, these lines could also be used to transmit solar energy. Add something here about storage. Support from federal solar energy incentives is also a valuable resource in creating a growth sector of the economy for installing new solar power towers or other types of concentrated system.

Austin Energy has the opportunity to transition towards a distributed utility model and add 20-25 MW of rooftop solar per year. In order to do this, AE must expand its outreach to commercial large roof customers as well as to residential customers through a massive consumer education campaign. The City of Austin has wisely invested in the nation's first truly smart electrical grid and initiated the Pecan Street Project with the University of Texas at Austin, GridPoint, Sematech, the Environmental Defense Fund along with many others to map out a vision for a distributed utility, and it must take advantage of all of the talent engaged in the project to shape the utility's future. As Figure 12.13 indicates, PV market penetration is expected to skyrocket as PV systems reach economies of scale. To capture the potential benefit from distributed generation, AE must position itself as a distributed utility.

Figure 12.13
Projected Decreases in Levelized Cost of Electricity for PV and Projected Increases in PV Market Penetration



Market Sector	Current U.S. Market Price Range (¢/kWh)	Cost (¢/kWh) Benchmark 2005	Cost (¢/kWh) Target 2010	Cost (¢/kWh) Target 2015
Residential	5.8-16.7	23-32	13-18	8-10
Commercial	5.4-15.0	16-22	9-12	6-8
Utility	4.0-7.6	13-22	10-15	5-7

Source: United States Department of Energy Solar Energy Technologies Program, *Solar Energy Industry Forecast: Perspectives on U.S. Solar Market Trajectory.* Online. Available: http://www.earthday.net/files/doe.ppt. Accessed: February 15, 2009.

Austin Energy could finance a massive consumer education campaign using federal Qualified Energy Conservation Bonds. Until AE customers are fully aware of the generous incentives offered by AE for solar energy systems such as PVs and solar water heaters, the broad-scale paradigm-shifts needed for the success of energy efficiency programs, demand response and distributed generation will not come to pass. Fortunately, with the newly-passed American Recovery and Reinvestment Act, the Department of Energy and the Internal Revenue Service have recently received over $3 billion for largely interest-free loans to state and local governments to engage in "public energy efficiency campaigns."[119] With a share of these funds, AE could more actively advertise its outstanding solar incentive program, which would simultaneously encourage greater dependence upon distributed energy sources, eliminate the need for expensive new peaking natural gas facilities and support its efforts to reduce peak demand and the price of providing peak energy.

If Austin Energy is unable to create significant momentum behind distributed generation by 2020, it could invest in a 100+ MW PV farm and increase its solar rebate to achieve its solar goals. AE has already demonstrated considerable interest in PV systems through the solar rebate program that has increased AE's solar generation capacity to 2.9 MW. At $4.50 per watt, this is one of the lowest rates in the country. If distributed generation or an investment in CSP is not feasible given distance, cost and transmission constraints, AE must aggressively expand its investments in PV in order to meet its base resource case.

Austin Energy should be careful to future-proof its solar investments by carefully monitoring federal incentive practices and associated cost curves for each solar technology. The American Recovery and Reinvestment Act contains significant solar ITCs. AE should remain aware of which technologies are significantly favored by federal subsidies and act accordingly in order to stave off investments in obsolescent technology. While PV technologies are a highly versatile set of technologies with many uses and deployment capabilities, AE must be careful to choose the ones that have the best value over time.

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Chapter 13. Biomass

Summary

This chapter reports on various applications of biomass to generate power, including co-firing biomass with coal, combusting various forms of biomass, and converting landfill gas to energy. The chapter evaluates the current state and the future outlook for the technology, and the potential for feasible economic investments in the technology. The chapter concludes by determining that Austin Energy should consider making additional cost-effective investments in biomass technologies to meet targets for carbon neutrality.

Background

Biomass power refers to electric power that is generated from burning vegetation and other biodegradable wastes. Waste wood, landfill gas, and agricultural residues are the most common form of biomass resources used today, but research continues to explore options for producing specific crops to convert the biomass into electricity. Biomass has often been referred to as a renewable resource because unlike fossil fuels, it is still currently in the carbon cycle and does not necessarily affect the balance of carbon dioxide (CO_2) and other greenhouse gases (GHG) in the atmosphere. CO_2 that is released from the death and combustion of plant growth and matter can be replenished by planting new growth. Despite claims that biomass is a renewable resource and carbon-neutral, biomass for power generation can contribute to global warming as CO_2 is released into the atmosphere when biomass is used in the power production process.

Biomass is considered carbon-neutral because of its offset of the natural release of methane (CH_4), a much stronger GHG, into the atmosphere when organic waste is buried or spread. When biomass is used as an energy resource most of the CH_4 is converted into CO_2, offsetting the amount of CO_2 absorbed through photosynthesis. Some studies have shown that biomass power production can reduce GHG emissions, although the best way to measure net emissions from biomass burning remains a topic of contention. Biomass provides a lower carbon intensity form of energy than coal or oil.

Biomass Power Generation Technologies

Biomass must first be converted into a biofuel before it can be converted into electricity. Processes that convert biomass into biofuels include homogenization, gasification (in which a fuel gas is produced), and anaerobic digestion (in which biogas is produced). Biomass can be used as a fuel source for direct combustion gas turbines, combined cycle turbines, diesel engines, and many coal-fired burners.[1] Capacity factors, although lower than fossil-fueled baseload plants, tend to be high at about 80 percent. Biomass power generation plants average about four years to construct, with relatively high overnight construction costs.[2] Costs of fuel have a wide range based upon the type of biomass that is utilized at the power generation plant and its location relative to the plant. Biomass is also appealing because the supply can be dependable and use waste products that may not otherwise be used. Table 13.1 lists cost and performance characteristics of biomass as a power source.

Table 13.1
Cost and Performance Characteristics of Biomass

	Technology Type
Technology Characteristics	**Biomass Combustion**
Load service function	Baseload
Fuel dependability	High
Maturity	Mature
Time to construct (years)	4
Operational life (years)	Not available
Cost to construct (2006 $/kW)[1]	1,759
Cost to construct (2006 $/kW) (source: EPRI)	2,160
Fuel cost (2006 $/MWh)	1.55-49.19
Fixed operation and maintenance costs (2008 $/kW)	47.18[1]
Variable operation and maintenance costs (2008 $/kWh)	0.296[1]
Availability factor (%)	90
Capacity factor (%)	80
GHG emissions (metric tons of CO_2 equivalent per MWh)	0.10

Source: The National Regulatory Research Institute, *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria* (2007). Online. Available: http://www.coalcandothat.com/pdf/35%20GenMixStateToolsAndCriteria.pdf. Accessed: November 25, 2008.

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Co-Firing Biomass with Coal

Coal is plentiful and accessible, is reliable for baseload energy, and costs less than other fossil fuels for electricity generation. However, coal produces more GHGs per kilowatt-hour (kWh) than any other Austin Energy fuel source. AE could reduce its coal plant's CO_2 emissions by co-firing biomass with coal. One complication is that AE may not be able to acquire a reliable supply of wood waste biomass near the Fayette Power Project (FPP).

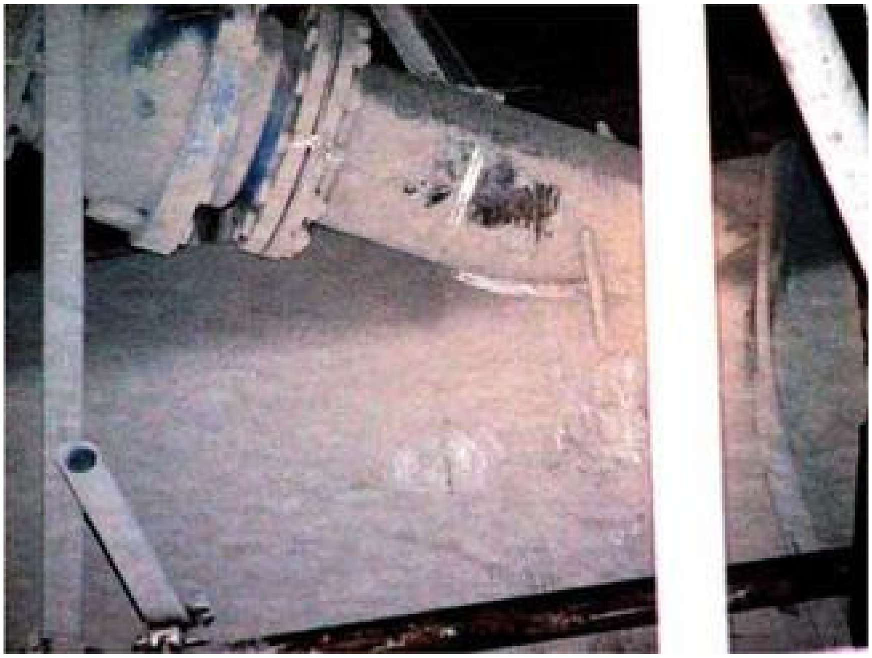
There are two approaches for introducing co-firing technology into a boiler. One approach is to blend biomass with coal as it is transported by conveyor belt to the boiler, an option that is low-cost because it involves minimal infrastructure improvements. However, blending only allows a 3 percent mix of biomass, which limits the potential

CO_2 reduction.[3] Figure 13.1 illustrates a blended feed co-firing system. Another approach is to build a separate feed system to the boiler only for biomass. This allows power plant operators to inject about 15 percent biomass mix into the boiler. Figure 13.2 illustrates an injection point in a separate feed system, while Figure 13.3 shows the tubes that comprise the separate feed system at another co-firing coal plant. The plant operator would bear the cost of retrofitting its boiler with the new feed system.[4] Some projects have experimented with co-firing coal and shredded rubber, often referred to as tire-derived fuel (TDF). Like biomass, TDF (or a mix of TDF and biomass) could be fed into the boiler via either of the two methods.

Figure 13.1
A Blended-Feed Co-Firing System

Source: Wright Tech Systems, Inc., *Biomass Fuel*. Online. Available: www.wrighttech.ca/Biomass%20Fuel.htm. Accessed: November 17, 2008.

Figure 13.2
An Injection Point for a Separate Feed System



Source: Power Engineering International. *Images.* Online. Available: http://images.pennnet.com/articles/pei/thm/th_biomass-drax.jpg. Accessed: November 17th, 2008.

Figure 13.3
A Co-Firing Biomass Feed System

Source: The Common Purpose Institute. *Images.* Online. Available: http://www.treepower.org/cofiring/fueltransport11.jpg. Accessed: November 17, 2008.

Although many different biomass fuel types exist, wood and sawdust have been used at the utility-scale for co-firing with coal. Further information about "energy crops" and other sources of biomass can be found at the website of the United States Department of Energy's (DOE) Energy Efficiency and Renewable Energy Division, as well as the Texas State Comptroller's Office.[5]

Coal is AE's largest baseload power source at 607 megawatts (MW).[6] Adding biomass (also a baseload source) to the fuel mix does not change its load service function, as the co-fired source also would operate at high capacity and availability factors. The capacity factor of a co-firing facility is 85 percent.[7] The availability factor is similar to that of a normal coal plant. The U.S. Energy Information Administration (EIA) estimates the heat rate of a typical scrubbed coal plant to be 9,200 British thermal units per kilowatt-hour (Btu/kWh). The EIA estimates the combusting biomass heat rate at about 8,911 Btu/kWh.[8] The combined heat rate of co-firing biomass with coal would depend on the percentage of biomass co-fired with coal. TDF has a heat rate that is equal to or higher than coal.[9] The average operational life of a coal plant is between 30 to 50 years and co-firing would not change the lifespan.[10] Co-firing biomass with coal is a mature technology that has been in use since the 1970s. Co-firing with substitute fuels such as TDF is a technology that is being tested by a West Virginia cement company and other power plants.[11] The Texas Commission on Environmental Quality reports that millions of unused scrap tires are spread throughout the Texas-Mexico border region.[12]

The effectiveness of co-firing is dependent upon securing a consistent supply of biomass, such as wood waste, and assuring a standard dryness of the waste. For example, a recent study found that the heat rate of various wood wastes ranges from 4,500 Btu per pound (Btu/lb) for wood wastes that are 50 percent dry and 8,500 Btu/lb for pelletized wood wastes that are 90 percent dry.[13] This range suggests the fuel benefits for drying wood prior to combustion, which leads to increased costs for preparation.

For FPP co-firing would represent a plant-specific change. The transmission and distribution of electricity generated by the plant would remain the same.

Biomass Combustion

Biomass, humankind's first fuel, has a future as well. Prior to the 19th century America was a predominantly agricultural nation that relied on wood power.[14] Burning wood has been a lasting form of energy production from carbon. Wood and charcoal are a preferred cooking fuel throughout many developing nations. As the U.S. advances into the 21st century, waste wood biomass is being reconsidered as an attractive renewable power source due to its smaller carbon footprint.

Wood waste biomass for electric power is burned in a way that is similar to the combustion of coal and gas. Waste wood is sent to a wood chipper that breaks the wood into small pieces that can be conveyed like pulverized coal into a boiler where they are burned. The heat from combustion boils water to create steam, which powers generators that create electric power for the grid.[15] Figure 13.4 shows a typical wood waste biomass combustion plant and Figure 13.5 illustrates the process of wood biomass combustion-based power. Table 13.1 shown previously details the costs and performance characteristics of biomass combustion.

Different biomass fuels exist, such as methane from decaying garbage, wood and crop wastes, and certain "energy crops" that can be grown for the express purpose of combusting them for power production. Figure 13.6 lists several of the different types of waste biomass available for power production. Figure 13.7 illustrates the wood biomass energy cycle. This section will focus exclusively on wood waste combustion for biomass power.[16]

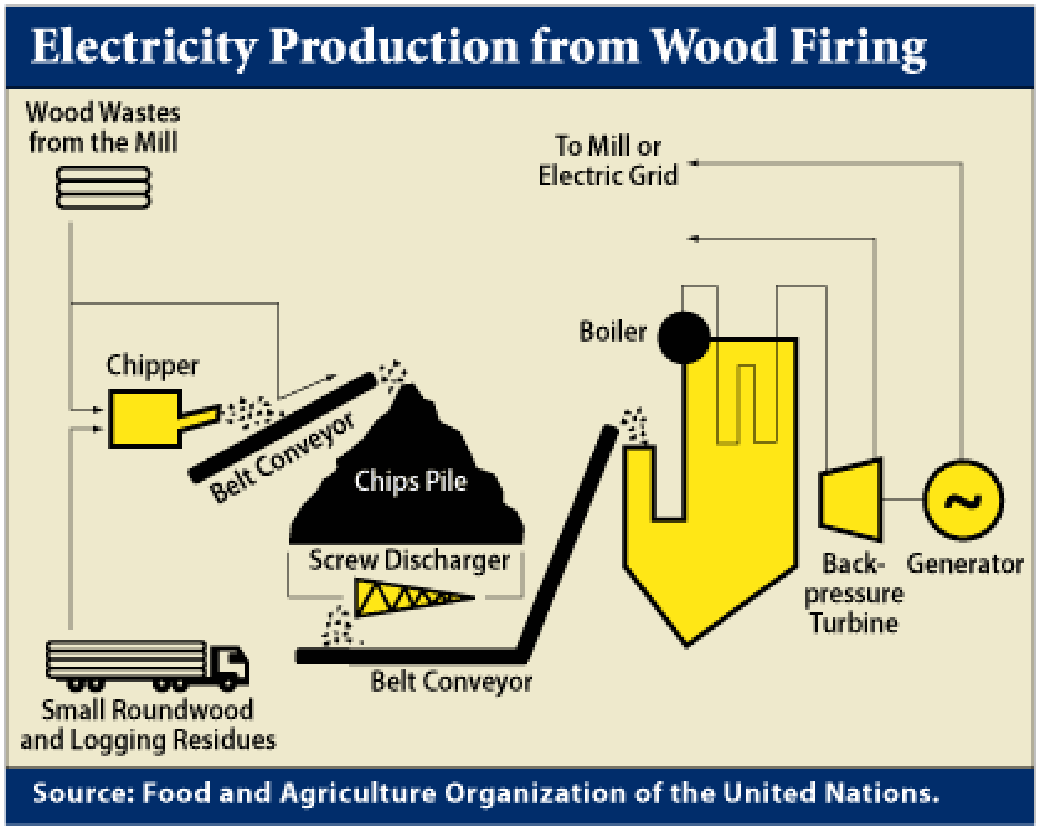
Wood waste biomass plants are intended to run for over 7,500 hours per year and can provide baseload power.[17] Burning biomass can occur 24 hours a day, unlike wind and solar, which are variable energy sources that cease to generate power when the wind stops or the sun sets. Wood waste biomass plants have high capacity and availability factors. For example, AE has contracted to purchase power from the new Nacogdoches

Power facility in Sacul, Texas, which is expected to operate 90 percent of the time.[18] Currently, the expected availability factor of the Nacogdoches plant is not known, but the average availability factor for wood waste biomass plants is approximately 90 percent.[19]

Figure 13.4
A Wood Waste Biomass Plant

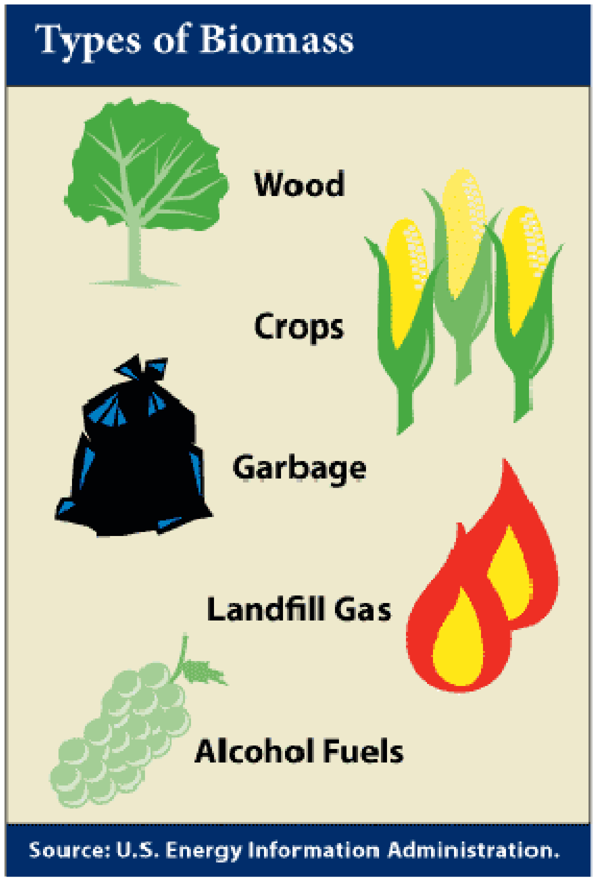
Source: M.I. Holzman and Associates. Online. Available: http://miholzman.com/resources/Shasta+wood+fired+power+plant.jpg. Accessed: November 17, 2008.

Figure 13.5
Diagram of a Wood Waste Biomass Plant



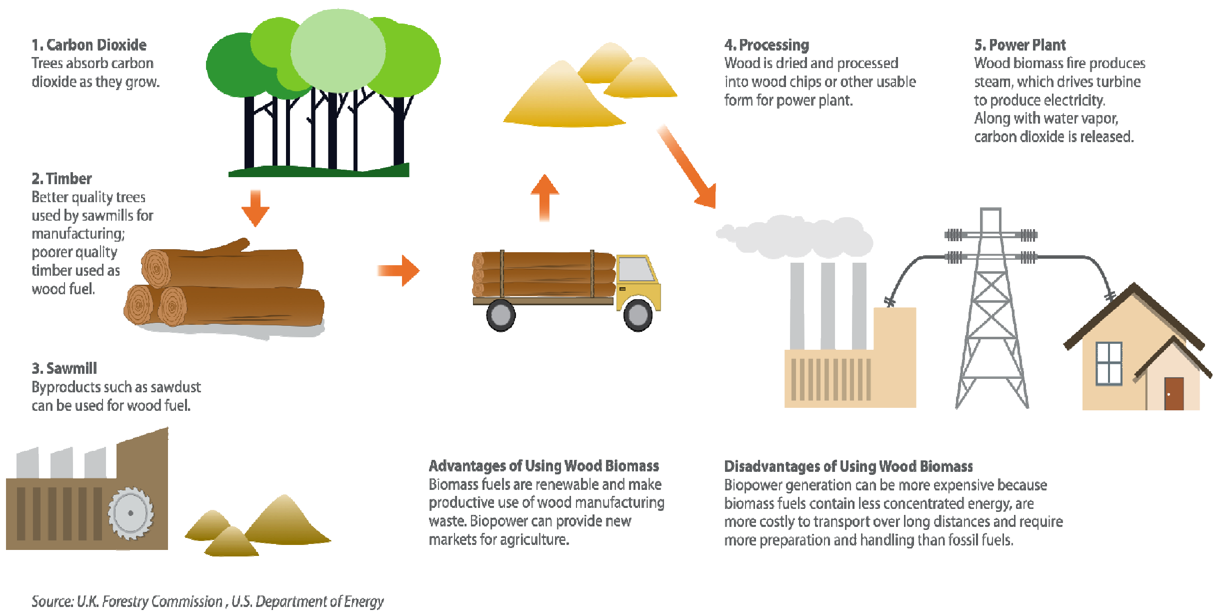
Source: Texas Comptroller of Public Accounts, *Energy Report – Wood* (May 2008). Online. Available: http://www.window.state.tx.us/specialrpt/energy/renewable/wood.php. Accessed: November 17, 2008.

Figure 13.6
Types of Biofuels



Source: Texas Comptroller of Public Accounts, *Energy Report – Biomass: Overview* (May 2008). Online. Available: http://www.window.state.tx.us/specialrpt/energy/renewable/biomass.php. Accessed: November 17, 2008.

Figure 13.7
Diagram of Wood Biomass Energy Cycle



Source: Austin Energy, *Austin Energy Resource Guide* (October 2008), p. 21. Online. Available: http://www.austinsmartenergy.com/. Accessed: November 17, 2008.

Wood waste biomass plants have a heat rate of 8,911 Btu/kWh, which is roughly equivalent to scrubbed coal.[20] The heat rate of biomass fuels is dependent upon the relative dryness of the fuel.

Wood waste power generation at a utility scale is a relatively new phenomenon. There is no readily available information concerning the operational lifetime of a biomass plant. However, there are many operating examples of wood waste biomass plants, ranging in size from 10 to 79.5 MW.[21] The Nacogdoches Power facility in East Texas will have a nameplate power generation capacity of 100 MW.[22]

Fuel availability is a major concern in the wood waste power industry. Texas has an estimated supply of over 20 million tons of biofuels, including urban wood waste, dedicated energy crops, forest and mill wastes, and agriculture residues.[23] For example, in 2005, 3.1 million tons of logging residues and 6.3 million dry tons of mill residues came out of East Texas.[24] These fuel sources have a wide range of moisture contents which affects their utility as a fuel source. Recently cut raw wood has a moisture content of 30 to 40 percent.[25] In order to maintain necessary heat rates, moist wood of this variety must be dried at additional cost.

Biomass power producers compete with Texas' $2.3 billion forest products industry, which provides jobs for 90,000 East Texans, and uses the same wood and mill wastes to heat and power mills.[26] It is difficult to estimate the supply of energy crops to fuel a local biomass plant, although several power plants use energy crops as fuel.[27]

AE cannot burn wood biomass near Austin because there is no reliable biomass supply in Central Texas. As a result, there are greater expenses and transmission losses over the distance between Sacul and the Austin area. While the Electric Reliability Council of Texas' (ERCOT) new nodal market may reduce the cost of transmitting 100 MW of power, transmission costs and losses are still likely to be higher than transmitting power from a local biomass plant. Another factor determining transmission costs under the new nodal market is concentrating new plants in the Nacogdoches area.[28]

Landfill Gas to Energy

One of the major successes of the American environmental movement in the second half of the 20th century was the creation and regulation of sanitary landfills in place of dumpsites. Most landfills have been covered with soil which eliminated some of the concerns regarding aesthetics and health risks. However, the natural decomposition in landfills produces methane, a powerful and flammable GHG. Methane can trap 21 times as much heat in the atmosphere per ton as compared to CO_2.[29]

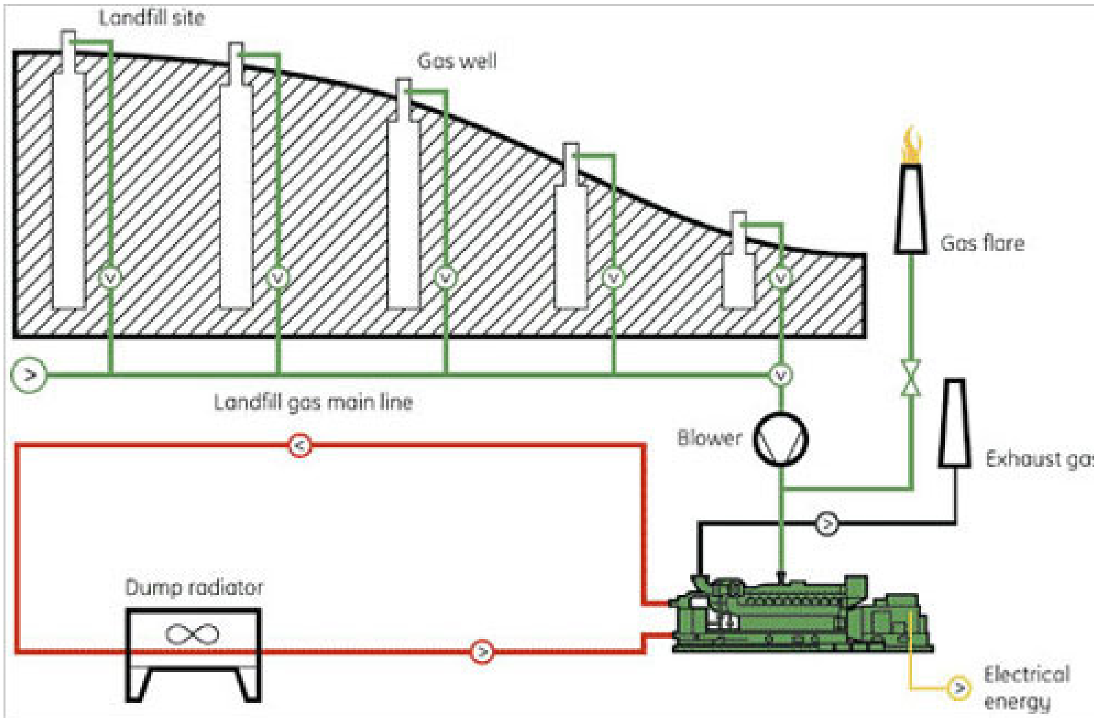
By the beginning of the 21st century, the landfill gas (LFG) energy industry had become a mature industry through regulations that require landfill operators to collect the LFG.[30] The 1990 Clean Air Act amendments put strict controls on landfill methane emissions. The federal government also encouraged the use of landfill methane gas for gas production and electric power. The Public Utility Regulatory Policies Act requires utilities to purchase power from smaller plants such as LFG energy projects.[31] The first federal production tax credits for LFG energy projects in 1980 encouraged more private investments.[32]

The landfill gas process begins when a landfill operator installs gas wells into an existing landfill to collect methane. Methane is burned to create steam to spin a turbine, generating electric power. Figure 13.8 shows the external housing of an LFG well. A collection system connects all the wells of a landfill to extract the gas through either a blower, flare system, or a vacuum power to a central point.[33] Figure 13.9 details a LFG power plant. The vast majority of electric power generating LFG facilities burn the landfill gas to power a reciprocating engine that in turn creates electric power.[34]

Figure 13.8
External Housing of a Landfill Gas Well

Source: United States Environmental Protection Agency, *Landfill Methane Outreach Program*. Online. Available: http://www.epa.gov/lmop/over-photos.htm. Accessed: November 25, 2008.

Figure 13.9
Diagram of a Landfill Gas Power Plant



Source: General Electric Power. *Images.* Online. Available: http://www.gepower.com/prod_serv/products/recip_engines/ en/images/landfill_en.jpg. Accessed: November 17, 2008.

Due to the consistent supply of methane generated by a landfill, LFG energy can be used for baseload power[35] and is treated as a baseload renewable energy source in many different green power programs across the country.[36] One million tons of municipal solid waste in one location can generate a continuous flow of up to 300 cubic feet of landfill gas per hour.[37] LFG plants have capacity factors up to 85 percent and an availability factor of 90 percent, so LFG plants can be counted on to produce energy for over 7,500 hours per year.[38,39,40] As a baseload power source, an LFG plant would not benefit from energy storage.

The life of a combustion engine powered by landfill gas is approximately ten years.[41] While the reciprocating engine is the most commonly used LFG power generation system, it converts carbon to energy at a low rate of efficiency.[42] EIA estimates that the heat rate for an LFG facility is relatively high at around 13,648 Btu/kWh.[43] This means that LFG heat rates are approximately 150 percent higher than a wood biomass facility.[44]

Operating Examples

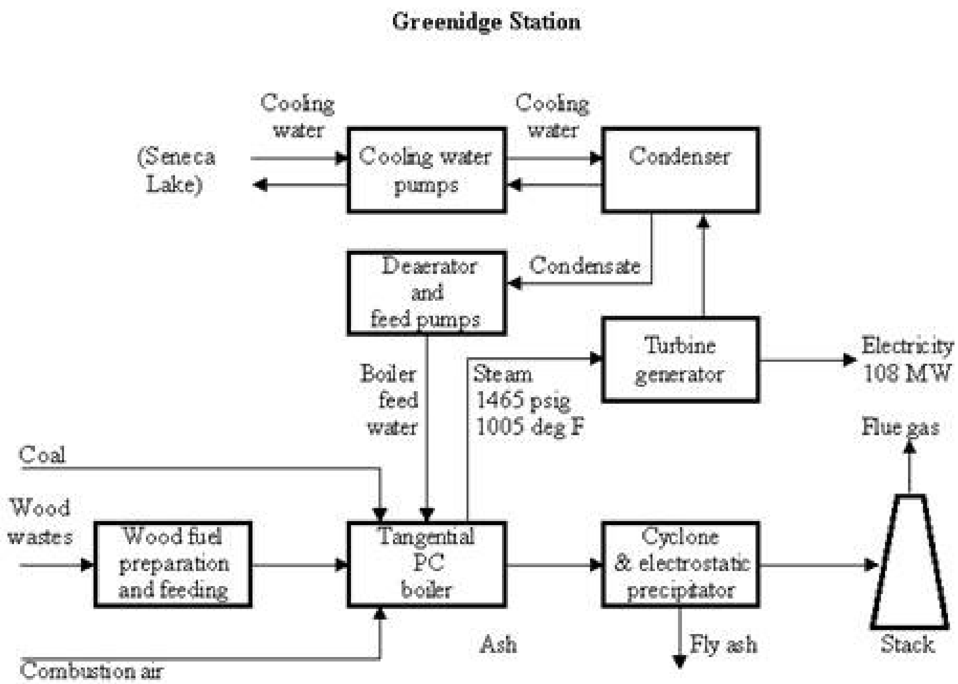
Co-Firing Biomass with Coal

The three different approaches to co-firing biomass with coal are (1) a stoker boiler system co-firing with pelletized biomass; (2) a tangentially fired boiler system using chipped wood; and (3) a cyclone boiler system co-firing sawdust and tire-derived fuels with coal. Wood biomass must be cut into quarter inch-sized cubes in order to be properly combusted by a pulverized coal boiler.[45]

The DOE's Savannah River facility has co-fired waste paper with coal in a stoker boiler since 2003. The 280 tons of waste paper the facility creates each year is placed into a machine that makes the cube-shaped biomass pellets.[46] These pellets can vary in size from as small as one-fourth cubic inch to one cubic inch.[47] The cubes are put on the same conveyor as the coal and subsequently fired in the plant's stoker boiler.[48] The facility estimates that co-firing saves 2,240 metric tons of coal and over $250,000 of total cost per year.[49] Savannah River plant's total co-firing retrofit costs were $850,000 while the yearly costs of co-firing are approximately $30,000 per year. The payback period for the retrofit was about four years.[50] After the system was installed, an emissions test revealed decreases in all pollutant levels, especially sulfur dioxide (SO_2).[51] The Savannah River facility models the potential costs and benefits of implementing a blended feed system at FPP.

In Dresden, New York, the Greenidge Station coal plant co-fires wood waste biomass in its boilers with a separate feed system. This facility uses a tangentially fired boiler system, similar to the boilers at FPP, with a biomass-maximizing separate feed system (see Figure 13.10). The plant has a biomass nameplate capacity of 11 MW.[52] To achieve the maximum capacity, the plant requires 58,500 tons of wet biomass per year.[53] The plant tested the retrofitted wood feed system over a period of three years before consistently co-firing the coal with wood.[54] In 1998, after two years of consistent use, the plant purchased a new hammermill and was able to increase the share of biomass in its boiler from 5 percent to 10 percent.[55] Total retrofitting costs incurred by the plant were roughly $300 to $500 per kW.[56] The wood waste supply was primarily from two furniture manufacturers and an experimental source of willow chips.[57] Emissions tests indicated a 0.2 to 0.6 ton per day reduction of nitrous oxides (NO_x) and SO_2 dropped from 798 parts per million (ppm) to 750 ppm. It is estimated that 6,000 metric tons of CO_2 is offset per MW of biomass used, which would reduce total CO_2 releases by 65,000 metric tons per year.[58]

Figure 13.10
Diagram of Co-Firing in a Tangentially Fired Boiler



Source: International Energy Agency, *Greenidge Generating Station #6, Dresden, New York*. Online. Available: http://www.ieabcc.nl/database/info/cofiring/118.html. Accessed: November 17, 2008.

In 2002, at the Willow Island Power Station in West Virginia, Allegheny Energy Supply (AES) burned 5,067 tons of TDF and 4,594 tons of sawdust biomass in place of coal. AES has not made public cost information or emissions test results. If successful, this project could indicate how a utility could increase its heat rate while reducing CO_2 and NO_x emissions.[59]

Biomass Combustion

An operating example of a partially wood waste-fired biomass plant is Grayling Generating Station in Grayling, Michigan. The 36 MW plant in North Central Michigan provides electricity using about 35 percent wood waste from local industries as fuel. The plant's output ranges from 15 MW to its nameplate capacity of 36 MW during the daily peak.[60] The majority of this electricity is used for local industry with some for residential use. The plant burns a mixture of 35 to 40 percent bark, 35 percent forest wood wastes, and 25 to 30 percent mill wastes.[61] The operators of the plant have been pleased with its performance of 70 to 80 percent capacity factor at peak and believe the station has largely fulfilled its mission as an effective waste management and power facility.[62]

No wood biomass power plants currently exist in Texas. However, AE has contracted to receive wood-fired biomass energy through a power purchase agreement with Nacogdoches Power beginning in 2012. The planned 100 MW biomass facility in Sacul will be among the largest currently in operation. The plant will generate steam to turn the electric turbines with a fluidized bed boiler.[63] In order to reduce its environmental impact, the boiler will use a baghouse to limit particulates, as well as a selective non-catalytic reduction system to control NO_x emissions.[64]

Landfill Gas to Energy

Landfill gas power plant technology is a mature technology that has been in use in Texas since 1986.[65] In 2006, Texas produced over 30.5 million tons of trash.[66] As long as trash is sent to landfills, LFG facilities can tap into an available fuel source.[67] Texas currently has 24 LFG projects in operation,[68] 22 of which produce 79 MW of electricity.[69] Texas has approximately 4,200 closed landfills, many of which can also be used for LFG power production or extraction.[70]

AE has a power purchase agreement with Energy Developments, Inc., the operator of the Tessman Road Power Plant. The facility is located on the grounds of BFI's Tessman Road Landfill outside San Antonio. The 8.1 MW LFG power plant provides approximately 17 percent of the power generated for AE's GreenChoice customers.[71,72] Figure 13.11 illustrates the Tessman Road Power Plant.

Figure 13.11
Landfill Gas-to-Energy Power Plant

Source: Energy Developments, Inc. *Energy Developments*. Online. Available: http://www.energy developments.com.au/mainpage.asp. Accessed: November 17, 2008.

Economic Outlook

Co-Firing Biomass with Coal

The costs of co-firing biomass with coal vary with the co-firing system. For a utility to invest in retrofitting the fuel delivery system and boiler to co-fire with biomass, the cost savings per kWh and the environmental compliance cost savings of burning less coal must be great enough to pay for the retrofitting of an existing coal plant. Retrofit costs can vary from $100 to $400 per kWh. For example, retrofitting costs exceeded $3 million for a 100 MW pulverized coal boiler.[73] While variable costs depend largely upon the fuel used, the fixed costs for operating and maintaining a co-fired plant are approximately $7.63 per kWh.[74] Fuel costs can vary from as low as $1.55 per megawatt-hour (MWh) to $49.19 per MWh depending on the co-fired fuel used.[75] Overall, biomass co-firing can reduce kWh costs from $0.023 per kWh to approximately $0.021 per kWh.[76]

Biomass Combustion

The costs associated with a wood waste biomass plant are relatively competitive compared to other fuel sources. With federal production tax credits included, electricity from wood biomass can be produced at $0.05 to $0.07 per kWh.[77] The overnight cost of building a biomass plant ranges from $1,400 to $3,300 per kW.[78] The variable and fixed operations and maintenance costs are relatively stable at $6.53/kW and $62.70/kW, respectively.[79] Depending on the type of co-fired fuel used, fuel costs can vary from $1.55 to $49.19 per MWh.[80] It is difficult to estimate future costs, particularly of fuel sources. Costs reflect the local availability along with the cost and quality of biomass fuels, which may be related to AE's decision to purchase power at a set rate versus the option of incurring the risk of building its own wood biomass power plant.

Landfill Gas to Energy

While maintaining a landfill and complying with federal regulations can be expensive, the capital costs and costs per kWh associated with producing LFG power are modest. Building an LFG plant costs $1,897/kW, while LFG energy costs $0.03-$0.05/kWh to produce.[81,82] A typical LFG plant will take four years to build.[83] The high fixed O&M costs of $111.15/kW reflect a high cost of maintaining a safe landfill.[84] Fuel costs are low, with variable O&M costs of $0.01/kW.[85]

Environmental Impacts

Biomass Combustion and Co-Firing Biomass with Coal

Biomass power plants generate air pollution, water pollution, GHGs, and solid waste. While combusting wood, biomass is considered to be close to "carbon neutral" because although growing plants fix CO_2 even as the power plant releases it into the atmosphere, the process of burning wood still contributes to air pollution. The Northeast Regional Biomass Program estimates emissions of particulate matter (PM) to be relatively high, comparable to the PM emissions of coal.[86] Most PM emissions from biomass combustion are relatively large, and can be controlled using readily available technology.[87] With limited research on the size, distribution, and product components of biomass combustion, the human health and air quality impacts of the PM emissions are not well known.[88] A biomass plant can also have dust emissions. However, this is only a major problem if the wood wastes are too dry, which can be controlled by wetting the wood during the chipping and grinding process.[89] The U.S. Environmental Protection Agency (EPA) sets the allowable size of fine dust particulate generated from wood-fired plants.[90]

The environmental impacts of burning biomass with coal are not significantly different than those of simply burning coal, other than emitting less SO_x, NO_x, and CO_2. Coal-fired power plants typically emit significant amounts of CO_2, SO_x, NO_x, and mercury. Mercury often settles in bodies of water, while SO_2 is a major contributor to acid rain.[91] As most biomass sources have lower concentrations of mercury and sulfur, co-firing coal and biomass could reduce heavy metal and SO_x emissions.[92, 93]

The process of combusting coal creates bottom ash and fly ash, the latter of which can be sold to cement manufacturers for use in concrete. Co-firing biomass with coal reduces the total amount of ash. However, there is concern regarding the heavy metal content of wood waste ash, as measurable levels of the heavy metals cadmium, zinc, and lead have been found in laboratory tests of fly ash.[94]

The DOE estimates the life-cycle GHG emissions for a power plant co-firing biomass with coal to be 868 grams of CO_2 equivalent per kWh.[95] This calculation includes the carbon involved in the transportation of biomass, coal mining, coal transportation, and power plant construction and operation, as well as the carbon saved by not disposing methane-emitting biomass into a landfill.[96]

Wood waste biomass plants emit fewer GHGs than scrubbed coal plants. Combusting wood waste biomass also reduces NO_x levels compared to coal combustion because the biomass plant's furnace temperatures are lower. However, the amount of NO_x emissions depends on the biomass' nitrogen content and the efficiency of the boiler combustion technology.[97] Like coal-fired power plants, biomass plants can also use scrubbers or baghouses to limit their particulate, SO_x, and NO_x emissions. The NO_x emissions from wood combustion can be controlled by a selective non-catalytic reduction system[98] to separate the nitrogen and oxygen before it is released into the atmosphere.[99] For example, AE will purchase power from the Nacogdoches Power facility, which will have a state-of-the-art selective non-catalytic reduction system.[100] Selective non-catalytic reduction systems can also be used to control SO_x emissions.

Co-firing has distinct and significant near-term benefits to reduce GHG emissions in Central Texas. Pulverized coal emits eight times more CO_2 into the atmosphere than a comparable metric ton of biomass.[101] Therefore, mixing biomass could reduce AE's carbon footprint and may enable it to forego significant costs of purchasing carbon offsets in the future. The National Renewable Energy Laboratory (NREL) has found that existing coal plants have been able to reduce GHG emissions by 18 percent by co-firing coal with 15 percent biomass, when compared to using 100 percent coal.[102] NREL has also indicated that co-firing could reduce harmful NO_x emissions by 30 percent[103] and SO_x emissions on a one-to-one basis, because biomass has only trace sulfur content.[104] Another possible material for biomass combustion is shredded tires. Emission tests have indicated that using shredded tires at 10 and 20 percent co-firing rates can reduce SO_x emissions significantly; similar drops in NO_x and particulate emissions do not occur.[105]

Land use requirements for biomass or co-firing biomass include land used for: a) growing the biomass; b) storing biomass fuel; and c) biomass processing and handling. This space often can be found on location at the plant or, if necessary, can be purchased offsite at additional cost.[106] Any biomass storage, handling, and processing system will need to be designed to perform efficiently while fitting within the available space. There are no catastrophic concerns associated with either co-firing biomass or biomass combustion.

Preparing and storing wood can involve air and water pollution. The process of drying wood to increase its heat rate can release carcinogenic volatile organic compounds into the air,[107] although this process can be made safer by reducing the drying temperature.[108] If the wood is exposed to precipitation, the run-off is considered water pollution,[109] and such runoff is regulated under applicable state stormwater rules.[110] Taking forest residues from East Texas forest floors would contribute to some loss of forest soil moisture.[111]

It is beyond the scope of this report to evaluate life-cycle effluents of a biomass plant, including the GHG emissions from constructing the plant and its components, transporting wood from its source, emissions from wood storage, and the deduction of methane emissions for taking forest wastes out of the forest and for keeping municipal solid waste (MSW) out of landfills. Life cycle costs and emissions would depend on the choice of fuels, components, and industrial processes. Figure 13.7 shown previously illustrates the life-cycle of the wood biomass to energy process.

Landfill Gas to Energy

Methane is a GHG with 21 times the potency of CO_2.[112] While flaring landfill gas does release CO_2, it is considered "carbon neutral" due to the limiting of methane emissions. The stack emissions of a LFG power plant after combustion still contains up to 67 percent CO_2, as well as trace amounts of CO, SO_x, NO_x, and fine particulate matter.[113] From an overall life-cycle perspective, the transport of trash to landfills involves CO_2 and other GHG emissions.

Modern sanitary landfills are designed to control the subsurface migration of landfill liquids and gases which can cause ecological damage to surrounding land and waterways. As of 1993, all landfills were required by law to "line" new or expanded landfills to prevent subsurface fluids or gas migration.[114]

EPA regulations require landfills to limit the release of methane by either having a gas collection system or installing a LFG energy system.[115] Since LFG projects benefit from EPA-mandated gas collection systems, initiating an LFG project can help landfill owner-operators cover the cost of complying with federal regulations.[116] LFG systems use existing landfills that meet the EPA's recommended specifications. Requirements for LFG production include that the landfill site contain at least one million tons of decomposing waste, be at least 40 feet deep, and receive over 25 inches of annual rainfall.[117] Since LFG facilities burn a gaseous byproduct of landfill wastes, LFG facilities do not produce significant amounts of solid waste.[118]

Burning landfill gas for power generation can be a dangerous activity if not done properly. To reduce risks posed by the subsurface migration and surface emissions of LFG, landfill operators seek to contain the highly explosive methane. LFG power plants do not pose as much of a risk as LFG facilities that merely extract the gas for sale. LFG facilities that extract methane to sell must transport the gas in pipelines that can pass through populated areas. A LFG power plant, on the other hand, burns the gas on site, reducing the risk to people outside the landfill.[119]

One cleaner option for LFG power production could be to use fuel cells. A fuel cell used in LFG power production would extract hydrogen from the methane in LFG and combine it with oxygen in order to produce water, heat, and electric power. Connecticut Light and Power in Groton, Connecticut, currently operates an LFG facility using fuel cells.[120]

Future Outlook

Co-Firing Biomass with Coal

Co-firing coal with a 15 percent mix of biomass can greatly reduce the carbon footprint of large coal plants. Some studies indicate that biomass-coal mixes between 20 to 30 percent could be fired in tangentially fired boilers without significant efficiency losses.[121] FPP has the potential for such reductions.

Two significant risks are associated with co-firing coal and biomass. First, co-firing coal with biomass that have a high alkali and chlorine content can result in slagging,[122] or corrosion on the ash handling and heat transfer surfaces.[123] With the threat of corrosion on these crucial surfaces, plant operators must spend more money for screening process to separate high-alkali and chlorine biomass.[124] Second, the acquisition of a secure and inexpensive supply of biomass fuel can be a logistical challenge.[125] AE should examine what is feasible of acquiring such a supply.

One criticism of AE's recent deal with Nacogdoches Power was the limited information on costs, environmental impacts, and the future supply of the biomass. Several factors could affect the viability of co-firing biomass with coal. Federal carbon regulation through a tax or a cap-and-trade regime could affect the economic attractiveness of co-firing. Further rise in the high cost of transporting coal from the Powder River Basin could encourage AE to reduce the share of coal in its power generation portfolio.

The adoption of co-firing would likely be considered a strong and positive step toward the implementation of AE's goal of carbon neutrality by 2020 and the goal of 30 percent renewable power generation capacity under the Austin Climate Protection Plan.[126] Austinites' interest in the GreenChoice® program suggests that the utility has support for reducing its carbon footprint and increasing the amount of renewable energy that powers homes and businesses.

Biomass Combustion

The Texas State Comptroller of Public Accounts has estimated that 20 million tons of wood waste biomass are available in Texas each year, which could be burned to produce 4,600 MW of power.[127] Texas' Renewable Portfolio Standard currently calls for 500 MW of non-wind renewable energy capacity by 2015.[128]

While AE has been able to obtain a consistent supply of wood waste biomass power for the next 20 years, Nacogdoches Power may face cost increases making power production more difficult. While AE would not be obligated to pay for power that was not produced, it would still represent a loss of 100 MW of reliable, renewable power.[129]

Several unknown factors could affect AE's wood biomass portfolio. For example, a regime of carbon regulations may encourage AE to become more reliant upon biomass power and other renewable energy sources. It is difficult to assess the financial impact of ERCOT's new nodal market system upon transmitting electricity over 200 miles to Austin. Also, the volatility of natural gas prices could make greater reliance on biomass power a more feasible option for AE.

Some Austinites are concerned about the costs and sustainability of the recently approved PPA between AE and Nacogdoches Power. Many people argued that AE did not make it easy for citizens to evaluate the financial risks associated with purchasing power from the new plant: the cost of obtaining biomass, the effect of the agreement upon the fuel charge in each customer's monthly bill, and the sustainability of obtaining forest residues for the plant.

Landfill Gas to Energy

Texas has an additional 57 potential sites for LFG energy projects.[130] Research is constantly improving LFG energy technologies, such as bioreactors. In a bioreactor, landfill operators inject water into the landfill to speed up the process of decomposition allowing LFG facilities to burn more landfill gas and thereby generate more electricity.[131] While the City of Austin has closed its landfill, the Texas Commission on Environmental Quality (TCEQ) has identified four active landfills that are viable LFG sites (under the EPA Landfill Methane Outreach Program guidelines) under the purview of Austin's

Capital Area Planning Council. Optional LFG plant sites include Austin Community Landfill, Williamson County Landfill, BFI-operated Sunset Farms Landfill, or Texas Disposal Systems Landfill.[132]

There are some risks and uncertainties associated with expanding LFG power production. Methane is a flammable gas, so LFG plants employ maximum caution. Environmental authorities could place more stringent safety regulations on landfill gas collection systems, which could drive up plant O&M costs. If AE were to purchase more LFG energy from outside the service area, like the Tessman Road facility, construction of additional plants in the surrounding area could mean that AE may pay congestion charges based on the density of electricity in the area under ERCOT's new nodal market system. Carbon regulation, however, could encourage more widespread landfill methane development in an effort to generate clean power and sell carbon credits. In addition, higher natural gas prices could also spur a similar surge in LFG development. Greater investment due to carbon cap and trade might push relative costs down.

While LFG power is widely considered to be a renewable source of energy, some citizens living near landfills perceive them as being undesirable and dangerous and are therefore hostile to their presence. For example, citizens living near the Tessman Road landfill, AE's largest source of GreenChoice® power, have fought hard against BFI's plans to expand the landfill.[133] Therefore, if AE wishes to develop more LFG sources or enter into PPAs for LFG, it will need to consider the concerns of the local citizenry and have full environmental transparency.

Options for Austin Energy

Co-Firing Biomass with Coal

As FPP comprises 71 percent of AE's carbon emissions, co-firing up to 15 percent biomass could greatly reduce its carbon footprint.[134] Co-firing would also lead to reduced coal usage so less money would be spent in transporting coal from the Powder River Basin. As biomass has almost no sulfur, SO_x would be reduced at a near one to one rate.[135] NO_x would also be reduced, albeit less than SO_x. Any carbon regulation system is likely to encourage co-firing with biomass.

Co-firing coal with biomass, a less carbon-intensive fuel, can lead to reduced heat rates and reductions in produced electric power.[136] It is only economical when biomass costs less than coal, which cannot always be guaranteed with the broad range of potential biomass fuel prices. Co-firing biomass with coal produces an ash byproduct that may not meet current standards for use in concrete.[137] The inability to sell the coal ash could reduce the revenues of both AE and its partner in the FPP, the Lower Colorado River Authority, as additional expenses are required to remove alkali and chlorine from the biomass; otherwise, increased ash deposition could cause corrosion and damage affecting the efficiency of the plant.[138]

There are two general alternatives for using wood waste biomass to co-fire with coal: shredded rubber and fuel crops. Co-firing with shredded rubber would help if FPP is unable to acquire sufficient biomass supplies. Burning shredded rubber could be perceived as an environmental risk so transparency concerning the scientific tests would be important to the success of using shredded rubber. Another alternative is to use energy crops to co-fire with coal. While costs and benefits regarding energy crops vary depending on the crop in question, such energy crops could provide a practical alternative to forest wastes. Currently, the managers of the FPP are researching co-firing biomass with Alstom, a large boiler manufacturer.[139]

Biomass Combustion

Wood waste biomass power generation can be utilized as a baseload power source, and can also contribute to the city's efforts to become carbon neutral, as biomass plants emit CO_2 at one-eighth the rate of a scrubbed coal plant. For example, AE's contract to receive 100 MW of biomass power from Nacogdoches Power by 2012 should reduce the city's carbon footprint.[140] Like LFG, additional baseload renewable and carbon neutral power will allow AE to hedge against fluctuating natural gas prices.

A wood waste power plant can keep fuel transportation and life cycle costs low by being sited near a fuel source, which means that East Texas is the only significant source of readily available forest residues.[141] As East Texas forests are situated 200 miles from Austin, transmission costs from East Texas plants are higher than for power generated locally. AE has estimated that purchased power from the Nacogdoches Power facility in Sacul will cost AE $115 million per year. Uncertain nodal market transmission costs are not included in these calculations. Capital costs for a wood biomass plant are high as a large quantity of water is required.[142] Since wood requires more preparation prior to combustion there is likely to be added costs due to the wide variation of moisture in woods.[143] While generating renewable baseload power via wood waste biomass appears to be a viable method for reducing AE's carbon footprint, additional wood waste projects will face high and uncertain capital costs and fuel costs.

Landfill Gas to Energy

LFG is a promising source of green power but on a small scale. LFG power generation has the advantage of providing a secure source of baseload renewable power that can act as a hedge against volatile natural gas prices.[144] LFG supplies at least 17 percent of the power for AE's popular GreenChoice® plan. As the number of Austinites who are willing to pay a premium for more sustainable and carbon neutral electric power continues to increase, AE will be able to secure more LFG facilities and create a baseload renewable power supply. At $0.03 to $0.05/kWh, purchasing or generating more LFG energy can help offset the price increases of GreenChoice® wind power coming online in the near future.[145] Although the capital costs for outfitting a landfill with a gas collection system are substantial, it complies with the law. The capital costs can also be borne by a plant operator, such as Energy Developments, Inc., if the utility decides to purchase LFG power. AE could choose to extract LFG and refine it into pipeline-quality natural gas, which could be sold or used as a further hedge against unstable natural gas prices. A major disadvantage of LFG facilities is that they are by nature limited and cannot provide green power at the utility scale necessary to move AE towards carbon neutrality.

Distance away from the service territory is also an issue, as it leads to transmission losses that could either increase or decrease under a nodal market system. As it examines its options towards 2020, AE may consider all forms of biomass power, as some are more likely to cause larger and more desirable reductions in CO_2 and other GHGs.

Conclusions and Recommendations

AE has the potential for investment in co-firing biomass with coal. The maximum potential investment is about 91 MW (15 percent of AE's share of the FPP). Making this investment will require capital improvements to the FPP in order to allow it to accept 15 percent biomass. This investment would help AE reduce carbon emissions. However, this would likely add costs for fuel because of the lack of appropriate resources in the Central Texas area, meaning that biomass would have to be shipped from other locations. The need to get supplies from outside the local area may also constrain the availability of resources. AE could also offset a smaller amount of their carbon emissions by blending 3 percent biomass in the current FPP facility. This could be done without modifications to the existing facility. This option may be preferable due to reduced need to acquire biomass resources and uncertainties regarding future plans for FPP.

AE has the potential for investment in biomass combustion. It has already contracted with the Nacogdoches Power Plant for 100 MW of power capacity beginning in 2012. As new projects come online, further analysis will need to be done in order to determine whether the carbon offset achieved through purchase of biomass power is worth the added cost of transmitting the power through the grid. This will be dependent upon future carbon legislation as well as the projected nodal market, and thus is not possible to ascertain at this time.

AE has some potential for investment in landfill gas. The relative stability of supply of LFG makes it a good source of baseload power. Because landfills are already required to collect the LFG, the capital investment requirements are lower than for many other options. However, limited landfill availability and future low power generation capacity means that LFG will only play a small role in the eventual power generation mix of AE.

Notes

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Chapter 14. Geothermal

Summary

Geothermal power plants generate electricity by using the natural internal heat stored beneath the Earth's surface within rocks and fluids. Although geothermal sources have been used for some time in Texas for spas and home heating, there currently are no large-scale commercial geothermal power plants for electricity generation in Texas. However, based on studies of geothermal resources (see Figure 14.1), there are some areas of Texas that could be attractive for new utility-scale geothermal power generation.

Background

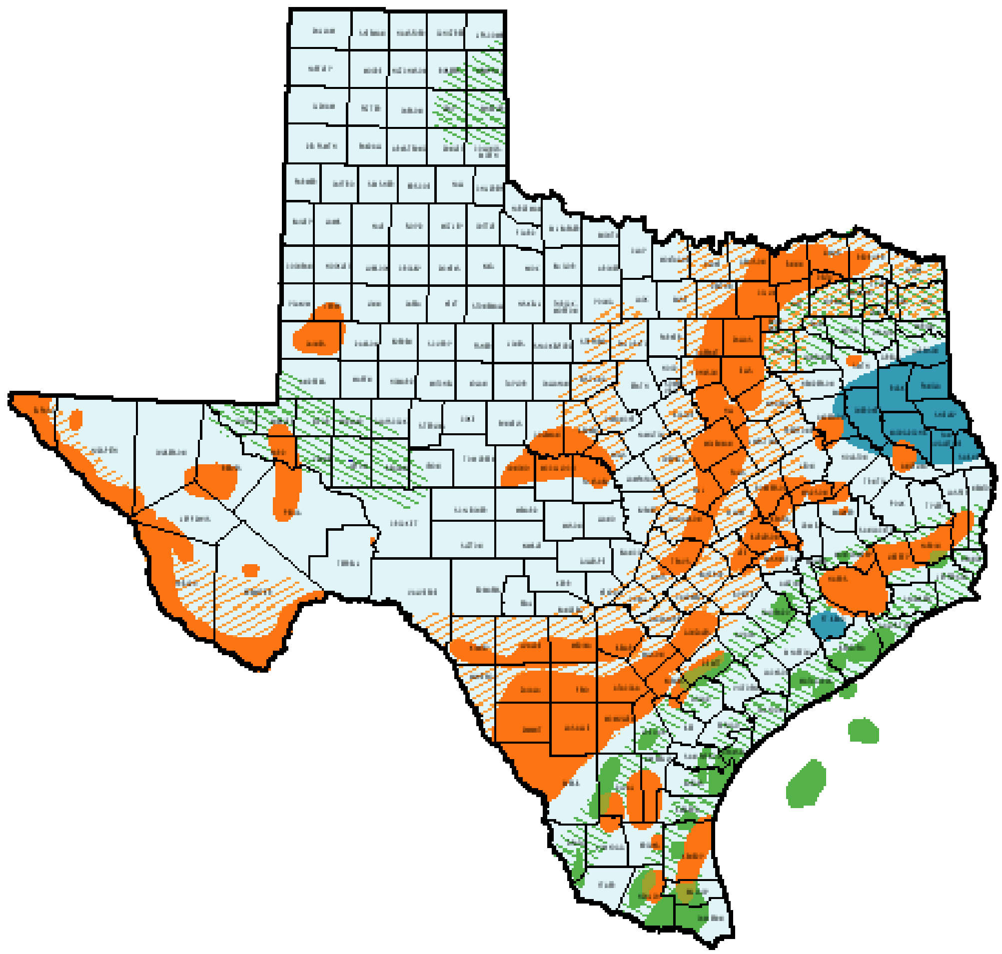
The three types of geothermal plants are dry steam, flash steam, and binary-cycle. Water pumped into hot-dry rocks found just below the surface has also been used to produce electricity, but this method is not yet a commercially-viable power generation technology.[1]

Dry steam plants use steam to directly turn conventional turbines, much like a conventional coal plant, but without the need to burn fossil fuels (see Figure 14.2).[2] Dry steam plants are the oldest form of geothermal electricity generation.[3] At flash steam plants, high-temperature fluid is injected into a low-pressure tank, causing the fluid to vaporize and turn a turbine (see Figure 14.3).[4] Secondary flash tanks can be constructed to vaporize or "flash" the remaining high-temperature liquid.[5] Flash steam plants require liquid temperatures of 360° Fahrenheit (182°celcius) or above.[6] 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 flash steam plants (see Figure 14.4).[7]

Geothermal energy can serve as a baseload source for electricity,[8] as the expected availability factor for geothermal electricity generation is 95 percent and its capacity factor ranges from 89 to 97 percent.[9] According to the National Regulatory Research Institute, the capacity factor for flash steam and binary-cycle power plants is 93 percent.[10] According to the Energy Information Administration, the heat rate for geothermal technologies is roughly 33,729 British thermal units per kilowatt-hour.[11]

Geothermal power generation is a mature technology. Although geothermal power plants have exhibited an average operational life of approximately 30 years,[12] such plants could last longer, as there are geothermal power plants that are still in operation after almost 100 years.[13] For example, the Laradello field in Italy has been functioning since 1913[14] and the Geyser field in California has been generating electricity since 1960.[15] Some plants, however, experience a decline in pressure and production over time. When this occurs operators often inject water to maintain pressure rates.[16]

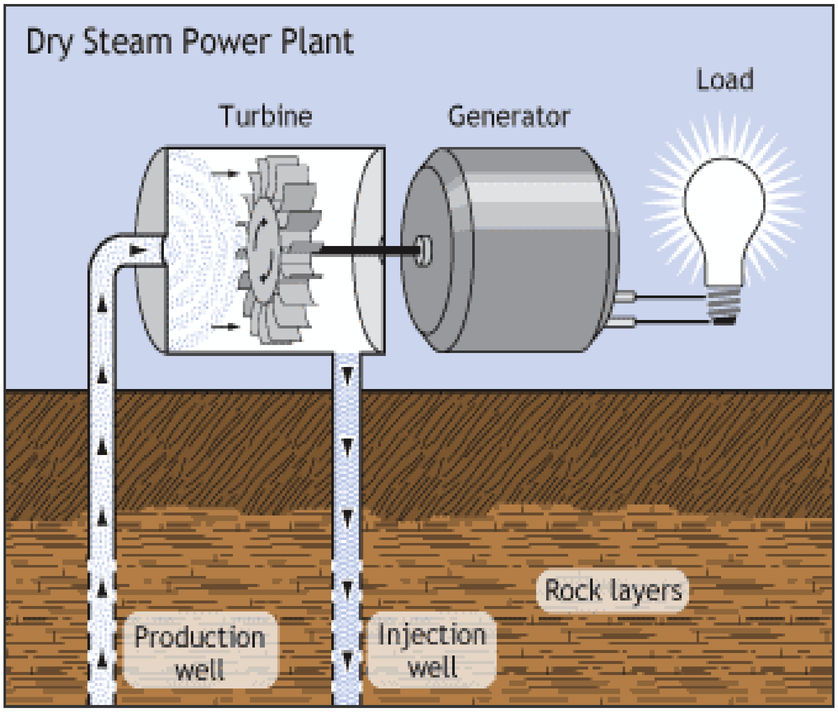
Figure 14.1
Map of Geothermal Resources in Texas



TEXAS GEOTHERMAL AREAS, CHARACTERISTICS, AND USES			
	HYDROTHERMAL	GEOPRESSURE	HOT DRY ROCK
AREAS	Known Potential	Known Potential	Known
CHARACTERISTICS	• 90-160F Water (500-5,000 ft. deep) • In some cases Water is Potable	• 300- 450F Brine (>13,000 ft. deep) • High Pressure • Dissolved Methane	• Gradient > 45°C/km • Little or No Water
USES	• Space Heating • Fish Farming • Desalinization • Resort Spas	• Heating • Enhanced Oil Recovery • Electricity	• Heating • Electricity

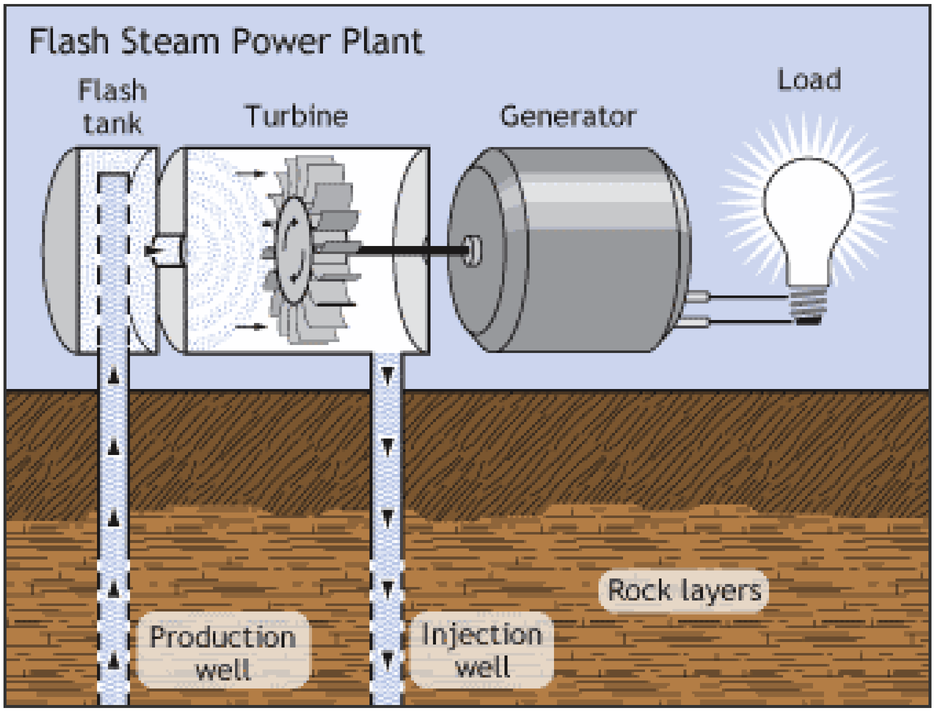
Source: Geothermal Energy Association. *Texas – Developing Power Plants*. Online. Available: http://www.geo-energy.org/information/developing/Texas/Texas.asp. Accessed: October 26, 2008.

Figure 14.2
Diagram of Dry Steam Power Plant Technology



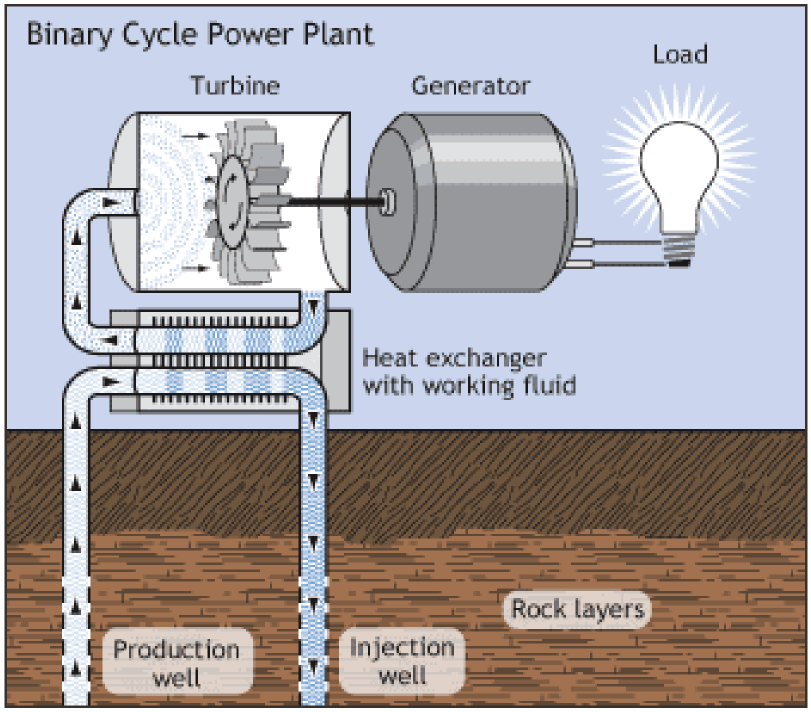
Source: United States Department of Energy, Energy Efficiency and Renewable Energy, *Geothermal Technologies Program: Hydrothermal Power Systems*. Online. Available: http://www1.eere.energy.gov/geothermal/powerplants.html#drysteam. Accessed: October 13, 2008.

Figure 14.3
Diagram of Flash Steam Power Plant Technology



Source: United States Department of Energy, Energy Efficiency and Renewable Energy, *Geothermal Technologies Program: Hydrothermal Power Systems*. Online. Available: http://www1.eere.energy.gov/geothermal/powerplants.html#drysteam. Accessed: October 13, 2008.

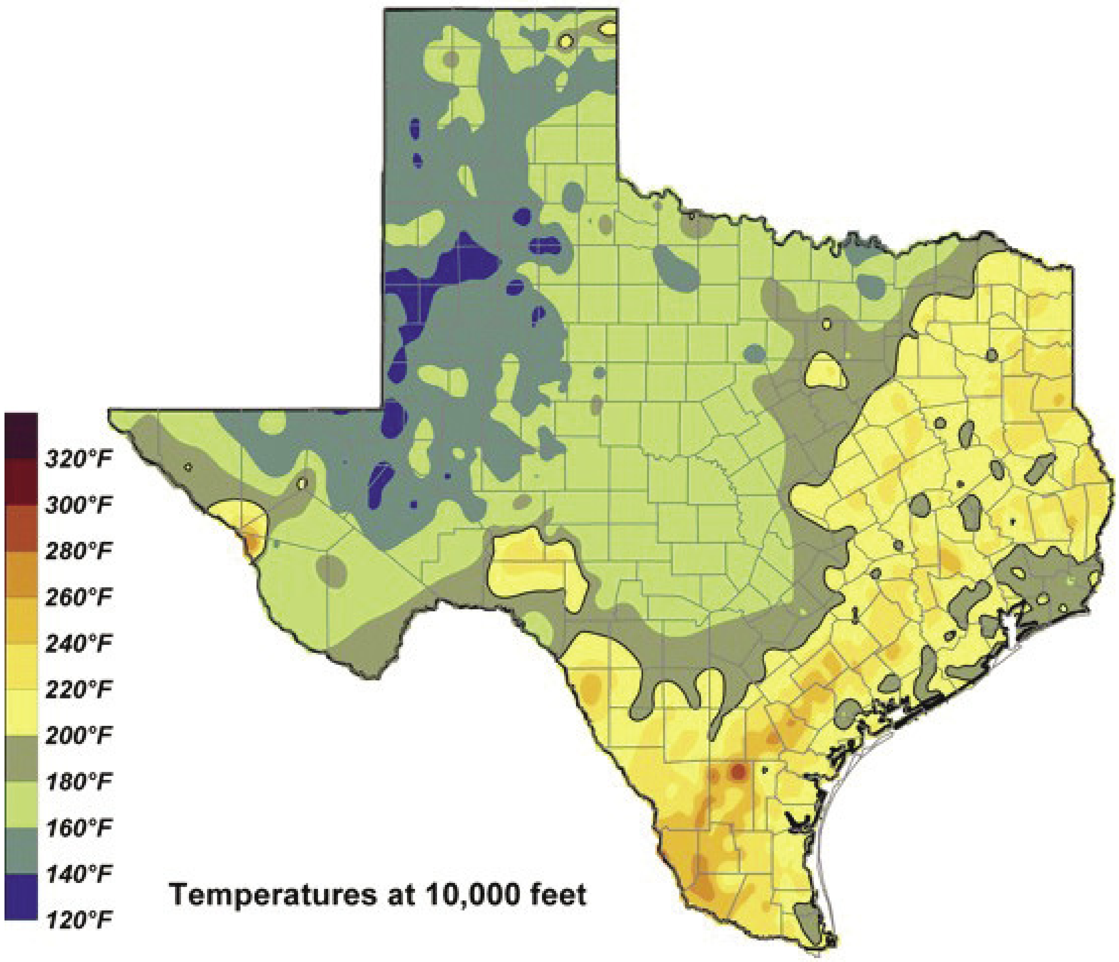
Figure 14.4
Diagram of Binary-Cycle Power Plant Technology



Source: United States Department of Energy, Energy Efficiency and Renewable Energy, *Geothermal Technologies Program: Hydrothermal Power Systems*. Online. Available: http://www1.eere.energy.gov/geothermal/powerplants.html#drysteam. Accessed: October 13, 2008.

One of the broadest applications of geothermal resources available to individual homeowners and commercial developers in Texas is through Geothermal Heating, Ventilation and Air Conditioning (HVAC). Geothermal HVAC systems utilize localized geothermal gradients for the heating and cooling of buildings. A geothermal HVAC system has three primary components: 1) the local geological environment, 2) the thermal transfer exchange system, and 3) and the mechanical system or heat pump and the ventilation ducts inside the building. Previously known primarily as a heating system in cold climates, geothermal HVAC systems can work in most parts of Texas if properly designed. The temperature of the subsurface at 10 to 50 feet remains relatively constant year round. A geothermal pump uses an internal fluid loop to exchange excess heat or cold inside the structure with the subsurface environment. For example, the ground temperature in Texas ranges from 12°C in the Panhandle to as high as 25°C in South Texas (see Figure 14.5).[17]

Figure 14.5
Map of Uncorrected Temperatures of Formations at 10,000 Feet Depth



Source: Texas State Energy Conservation Office, *Renewable Energy Resource Assessment, Chapter Seven: Geothermal Energy* (2008). Online. Available: http://www.seco.cpa.state.tx.us/publications/renewenergy/geothermalenergy.php. Accessed: February 10, 2009

Operating Examples

The power plants at Steamboat Springs near Reno, Nevada, demonstrate successful geothermal electricity generation (see Figure 14.6).[18] Combined use of flash steam and binary-cycle plants generates up to 45 megawatts (MW) of energy capacity.[19,20] The first plant, a flash steam plant, came online in 1988 and produces 14.4 MW of energy capacity.[21] The most recent addition is a binary-cycle plant, which was added in 2005.[22] This plant was constructed in less than one year and added 20 MW to Steamboat Springs' overall power generating capacity, bringing its total capacity to 45 MW. Since all of the geothermal fluid used in power generation is re-injected at this Steamboat Springs site, the plant effectively releases no water or chemicals outside the enclosed system.[23] Cost data regarding the plants at Steamboat Springs are not available to the public.

Figure 14.6
Aerial View of Geothermal Plant

Source: Montara Energy Ventures, *Renewable Energy Journal.* Online. Available: http://montaraventures.com/blog/2007/10/08/steamboat-springs-geothermal-plant/. Accessed: October 28, 2008.

Economic Outlook

According to the United States Department of Energy, a geothermal plant built today is capable of delivering energy at an estimated cost of 5 cents per kilowatt-hour (kWh).[24] Other cost estimates range between 5.5 and 7.5 cents per kWh[25] to between 5.5 and 10 cents per kWh.[26] There are no fuel costs associated with geothermal power. Fixed operation and maintenance costs range from 1-3 cents per kWh.[27] The average cost of construction for all geothermal technologies nationally is $2,500 per installed kW.[28] According to the National Regulatory Research Institute, the total overnight costs for flash steam plants average $1,400 per kW installed and the total overnight costs for binary-cycle plants range from $2,227 to $2,270 per kW installed.[29] While overnight costs to construct a geothermal plant are high per kilowatt, these costs are offset by low to no fuel costs.[30]

Geothermal power plants have not yet been built in Texas. Therefore, potential cost estimates for plants in Texas are based on current technology, drilling expenses, and the cost of existing western U.S. geothermal power plants. Assuming the use of a binary fluid turbine for the power plant and basic transmission line hook-up, the estimated cost to build a power plant is $1.5 million for a 250 kW system and $5 million for a 1 MW system.[31] A geothermal power plant typically requires six to nine months to build once construction begins. However, when the time needed for exploration, discovery, permitting, and other hurdles is factored in, the entire geothermal development process can last anywhere from three to seven or more years.[32]

Unlike some conventional technologies, such as natural gas and coal, cost projections for geothermal energy are not as volatile due to the lack of fuel costs associated with this resource. Costs for geothermal energy generation are expected to remain stable or decrease as improved technology increases efficiency. The DOE and the geothermal industry continue to test designs to lower the cost of geothermal energy production to between 3 cents and 5 cents per kWh.[33]

There are few major economic or financial risks associated with geothermal power generation. The largest economic risk, exploration, occurs at the outset of the project development. The risks associated with exploration have been lowered in recent years due to the rich data regarding potential sites gathered in Texas by both government entities and the oil and gas industry.

Fluid temperatures are critical to determine if a geothermal resource can produce electricity economically. Until 2006 there was no technology or energy pricing that would generate development interest of fluids less than 250°F (121°C) for geothermal power production.[34] Then in 2006, a project in Chena Hot Springs, Alaska, produced electricity economically with 165°F (74°C) water and opened renewed interest in many previously ignored geothermal resources, such as the sedimentary basins in the Gulf Coast and West Texas.[35]

Environmental Impacts

Geothermal power plants have fewer and less significant environmental impacts than fossil-fueled or nuclear power plants.[36] Little solid waste is produced at geothermal power plants.[37] While geothermal fluids can contain a number of dissolved gases [including nitrogen, carbon dioxide (CO_2), and hydrogen sulphide], most gases are usually re-injected underground and not released into the environment.[38] Pursuant to federal regulation, any potential hydrogen sulphide emissions from geothermal power plants must be captured and re-injected underground.[39] In general, the level of emissions of these gases does not pose an environmental threat to the atmosphere.[40] Dry steam and flash steam power plants do emit low levels of CO_2, while binary-cycle power plants emit essentially no greenhouse gases at all. Table 14.1 compares geothermal emissions with emissions from other conventional power generation technologies.[41] For example, dry steam and flash steam plants emit 27.2 and 40.3 kilograms (kg) of CO_2 per megawatt-hour (MWh), respectively, while coal-fired power plants emit 994 kg of CO_2 per MWh.[42]

Table 14.1
Fossil-Fueled and Geothermal Power Plant Emissions

	Emissions of Gas (kg/MWh)			
Plant Type	**Carbon Dioxide**	**Sulfur Dioxide**	**Nitrogen Oxides**	**Particulates**
Coal	994	4.71	1.995	1.012
Oil	758	5.44	1.814	Not applicable
Natural gas	550	0.0998	1.343	0.0635
Flash steam	27.2	0.1558	0	0
Dry steam	40.3	0.000098	0.000458	Negligible
Binary-cycle	0	0	0	Negligible

Source: Department of Energy Geothermal Technologies Program, *Environmental Impacts, Attributes, and Feasibility Criteria,* p. 6. Online. Available: http://www1.eere.energy.gov/geothermal/pdfs/egs_chapter_8.pdf. Accessed: November 2, 2008.

The release of geothermal fluids on the surface can affect both surface waters as well as groundwater.[43] The common practice to re-inject the fluids back into the well from which they came reduces this environmental impact,[44] maintains geothermal pressure, and allows for longer operational life of a plant.[45] Good management practices can prevent groundwater contamination from occurring during the well-drilling process.[46]

Geothermal technologies use small amounts of land and have a low visual impact. Table 14.2 compares land use for various power generation technologies.[47] However, as many viable geothermal sources are located in remote areas, the construction of transmission lines can result in a negative impact on land use in order to transmit geothermal power to electrical customers.[48]

Table 14.2
Land Use Requirements of Various Power Generation Technologies

Technology	Land Use	
	m^2/MW	m^2/GWh
110 MW flash (excluding wells)	1,260	160
20 MW binary cycle (excluding wells)	1,415	170
56 MW flash (including wells, piles, etc.)	7,460	900
2,258 MW coal (including strip mining)	40,000	5,700
670 MW nuclear (plant site only)	10,000	1,200
47 MW solar thermal (CA)	28,000	3,200
10 MW solar PV (Southwestern U.S.)	66,000	7,500

Source: Department of Energy Energy Geothermal Technologies Program, *Environmental Impacts, Attributes, and Feasibility Criteria,* p. 8. Online. Available: http://www1.eere.energy.gov/geothermal/pdfs/egs_chapter_8.pdf. Accessed: November 2, 2008.

A life-cycle analysis of geothermal power generation technologies would include an analysis of the energy used to construct the power plant and pipelines, as well as an analysis of any direct emissions. According to the Renewable Energy Policy Project, the life-cycle emissions (grams/kWh) of CO_2 equivalent are 47.97 for flash steam geothermal plants, compared to 7.74 for wind farms, 60-150 for solar PV, 39 for nuclear plants, and 1,050 for coal plants.[49]

Future Outlook

Geothermal power is accessible and price competitive if the geothermal plant is close to locations where hot water or steam can be tapped, as the geography of an area dictates feasibility and cost. Lower below-surface temperatures lead to higher construction costs.[50] A common comment in the literature is that geothermal power plants are economically viable when fluid temperatures are 212 degrees Fahrenheit or above and are located no deeper than four kilometers.[51]

There are currently no commercial geothermal plants in operation or construction in Texas because the use of geothermal energy for electricity purposes has not yet been found economically attractive in this state. The State Energy Conservation Office and the Southern Methodist University's Geothermal Laboratory estimate that Texas could develop between 2,000 and 10,000 MW of geothermal power generation capacity in the next ten years by taking advantage of oil and gas drilling sites, thereby reducing the cost of exploration.[52] The U.S. Department of Energy's geopressured-geothermal demonstration in 1989-90 of a one MW power plant at Pleasant Bayou along the Texas Gulf Coast established that the production of electricity from geothermal resources in Texas is possible.[53]

In February 2007, Texas Land Commissioner Jerry Patterson awarded a land lease on the Texas coast for geothermal energy production to Ormat Technologies, Inc., a Nevada-based company.[54] As Patterson noted at the time: "There's no way to tell what the potential [for geothermal energy] is until private industry invests its capital to find out."[55] According to the Geothermal Energy Association, Texas has an advantage with respect to geothermal energy as a result of the detailed information available from historical and current oil and gas drillings in the state, including data regarding heat resources and deep water availability.[56] Energy potential from these oil and gas sites is estimated from 400 MW to over 2,000 MW of power generation capacity.[57] Figure 14.1 shown previously details Texas' geothermal potential,[58] such as the Trans-Pecos region, the Delaware Val Verde Basins, the Panhandle Anadarko Basin, and East Texas, with the green areas indicating known potential for heating and electricity and the lined areas represent regions with a strong potential for geothermal power production. The blue areas show known potential for heating and electricity from hot dry rock technologies. The orange areas represent sites of known potential for use in space heating, fish farming, desalinization, or recreational uses.

Geothermal power generation can operate as a distributed source of electricity production. Over 600,000 oil and gas wells have been drilled in Texas and are scattered over much of the state, although there are distinct high density regions.[59] The advent of smaller (50 kilowatt (kW) to 250 kW) binary power plants provides an opportunity to use many of these wells together for an economically viable distributed system of geothermal power generation.

Because much of the state's geothermal energy potential is located in West Texas, transmission costs and energy losses could diminish any cost advantages of geothermal energy for use as power production in Central Texas. However, transmission lines currently under construction to tap into the vast West Texas wind potential potentially could be used to deliver geothermal energy from West Texas to Central Texas.

Options for Austin Energy

Due to the fact that potential geothermal energy sources in Texas are located outside of Central Texas, any future geothermal power plants constructed in Texas may require the construction of new transmission lines. While there is a potential for large-scale geothermal power generation in Texas, the high transmission cost may make geothermal energy less cost effective than other renewable energy sources. However, given that $5 billion is being invested by the Public Utility Commission of Texas in transmission lines from West Texas, there may be an opportunity for use of geothermal power by Austin Energy from West Texas, depending upon the costs associated with such a facility.

Conclusions and Recommendations

Austin Energy should investigate the possibility of investment in geothermal plants in the most productive areas of the state. AE has indicated a preference for cleaner forms of baseload power generation capacity through its recent purchase of 100 MW of biomass power generation capacity. Geothermal power would help AE meet its carbon neutrality goal. The three primary sources are the conventional hydrothermal and the “dry” geothermal systems (EGS) of West Texas, the geopressured formations along the Gulf Coast, and EGS from East to South Texas. In order to share the risks, AE could seek private partnerships for the development of commercial electrical production from geothermal resources in West Texas, utilizing the future development of a more advanced state transmission grid. Based upon the status of geothermal technology and the expected availability of transmission capacity, it would not be unreasonable for AE to consider investing in a cost-competitive source of geothermal power generation capacity (up to 100 MW) before 2020.

AE should explore the use of distributed geothermal utilizing the oil and gas wells in close proximity to its area of service. Small (50 kW to 250 KW) binary power plants can be used next to geothermal productive oil and gas wells in a distributed system of power generation.

AE could develop a rebate program to encourage its customers to install geothermal HVAC systems to reduce peak summer AC electrical demand in its service area. Similar rebates are currently available from some public utilities across the U.S., ranging from $200-$500 per nominal ton for successfully commissioned geothermal systems with a caps ranging from $500-$1500 per customer meter.[60]

Notes

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Chapter 15. Ocean Energy

Summary

This chapter examines the potential for electricity generation by ocean currents, waves or tides to contribute as a renewable energy source to Austin Energy's (AE) resource portfolio by prior to 2020. Wind, wave, and tidal power generation technologies can convert energy from the ocean into electricity. A tidal barrage can exploit flows between low and high tides. Underwater turbines can draw energy from ocean currents. Electricity can also be harnessed from the movement of waves. While ocean energy is used in a variety of sites around the world, no investments to develop power generation from the Gulf of Mexico adjacent to Texas have been proposed. It is unlikely that AE will be able to purchase electricity from ocean energy to add to its resource portfolio prior to 2020.

Background

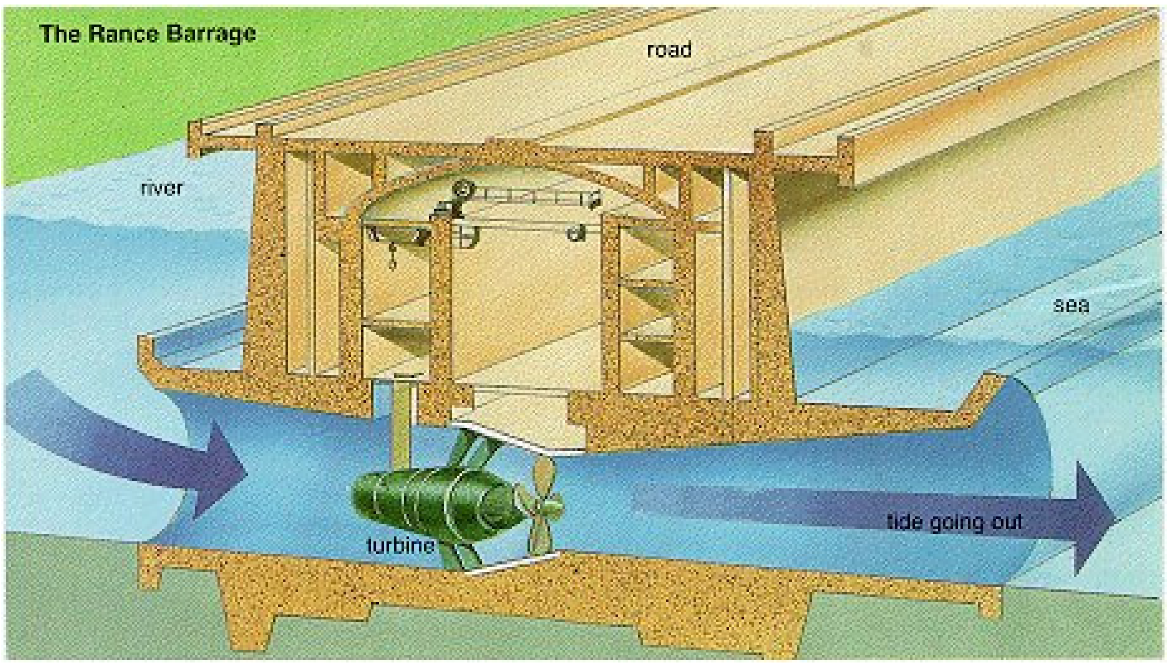
Ocean energy can be converted into electricity generation utilizing the natural forces of ocean tides, currents, or waves. A barrage generator is an underwater dam, similar to a land-based hydroelectric generator, which captures water during high tide and releases it through conventional turbines to produce electricity during low tide. Barrage power requires a difference of approximately 16 feet between high and low tides, which occurs along the northeast and northwest coasts of the United States.[1] Barrage generators such as the La Rance tidal barrage in France (see Figure 15.1) have operated since the 1960s.[2]

An underwater turbine can operate much like an underwater wind farm, using water currents instead of wind. Figure 15.2 illustrates an artist rendition of the New York City underwater turbine project. Strong currents turn large propeller-like hydrofoils attached to a submerged generator near the bottom of the seafloor to create electricity that is then sent back to land by a cable that rests at the bottom of the ocean. Ocean currents create a high energy yield because they are approximately 1000 times denser than air.[3] Minimum requirements for underwater turbines include a depth of 9 meters, an average velocity of 2 meters per second, and a site requirement of 5 to 10 acres.[4]

Wave power generation uses the natural flow of water to move hinges of a hydraulic ram that sways back and forth through the waves to generate electricity.[5] Figure 15.3 illustrates an artist rendition of the Pelamis Wave Energy Project off the coast of Portugal, the first commercial wave power station in the world. Locations between 30 and 60 degrees latitude both north and south of the equator are ideal for wave power generation because of the high winds in these locations.[6] The Gulf of Mexico lies between 18 degrees and 29 degrees latitude north.[7] Wave energy uses 3 to 4 times less surface area than an offshore wind farm generating the same amount of power.[8]

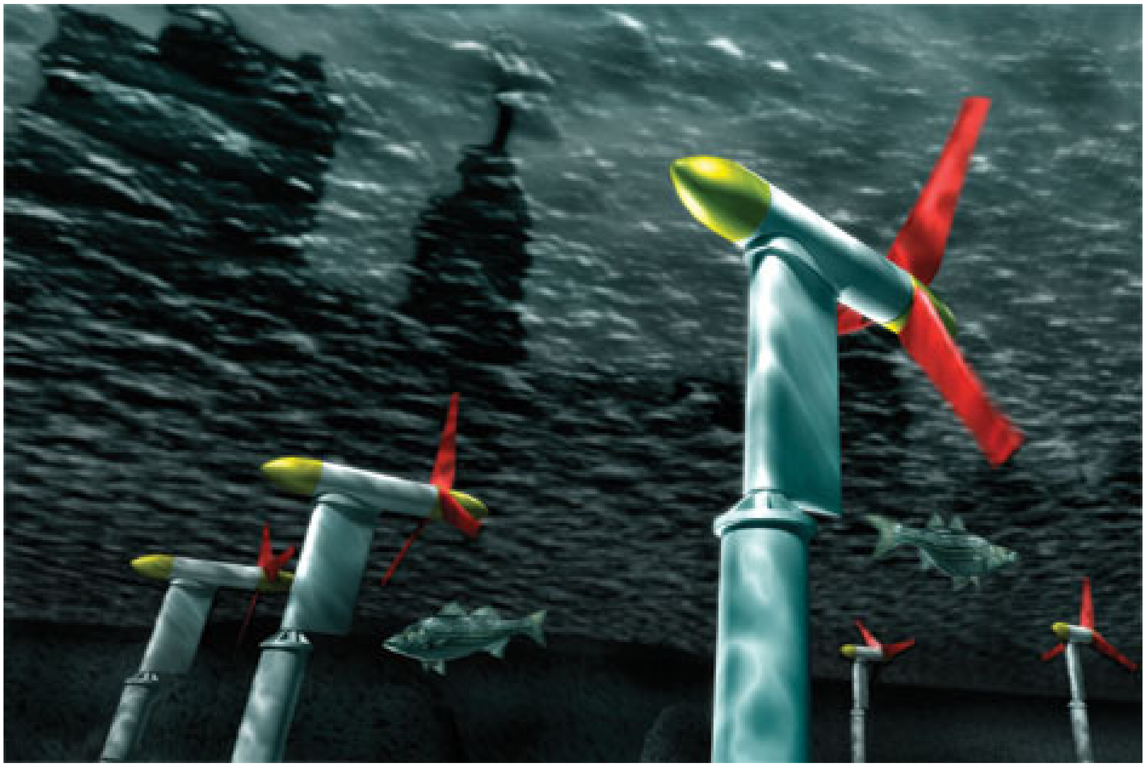
All three ocean energy technologies produce variable and intermittent power. The amount of electricity output varies with fluctuations in currents, tides, and waves.[9] Ocean power generation is most often used as an intermediate power source.[10] Wave energy can create more electricity from one square meter than solar photovoltaic systems or wind turbines.[11] Wave technology can generate 30-70 kilowatts (kW) of power per meter width while PV systems, on average, only generate 0.1 kW of energy per square meter and wind turbines only generate 1 kW of energy per square meter.[12] Tidal power, unlike wind and solar, is a more predictable source of power generation.[13]

Figure 15.1
Diagram of La Rance Tidal Barrage



Source: About Electronics, *How Tidal Energy Works?* Online. Available: http://born4electronics1.blogspot.com/2008/01/how-tidal-energy-works.html. Accessed: October 12, 2008.

Figure 15.2
Artist Rendition of New York City Underwater Turbine Project



Source: Erik Sofge, "Underwater Wind Turbines Tap River Energy," *Popular Mechanics* (April 2007). Online. Available: http://www.popularmechanics.com/science/earth/4213223.html. Accessed: November 10, 2008.

Figure 15.3
Artist Rendition of Pelamis Wave Energy Project

Source: International Conference on Ocean Energy, *Call for Abstracts*. Online. Available: http://www.icoe2008.com/en/call-for-papers.html. Accessed: October 13, 2008.

Operating Examples

Table 15.1 lists some of the current operational ocean energy projects worldwide. No ocean energy project currently operates in the U.S.[14] While tidal barrages, underwater turbines, and wave power generators currently operate to produce electricity, a recent study classifies ocean power technology as experimental.[15] The best example of a successful ocean energy project is the La Rance, France, tidal barrage.[16] The La Rance facility has been operating since 1967 with a total power generating capacity of 240 megawatts (MW), generating nearly 841 million kilowatt-hours (kWhr) of electricity per year.[17] The La Rance plant was constructed over seven years at a total construction cost of approximately $512 million.[18,19] The La Rance Tidal Barrage has a capacity factor of 40 percent.[20]

Table 15.1
Operational Ocean Energy Projects Worldwide

Country	Project	Annual Energy Production (GWh)
France	La Rance	544
Canada	Annapolis Royal	40
China	Jiangxia	10
Russia	Kislaya Guba	1

Source: David Kerr, "Marine Energy: Getting Power from Tides and Waves," Proceedings of the Institution of Civil Engineers, vol. 158, no. 2 (2005), p. 33. Online. Available: http://www.atypon-link.com/doi/pdf/10.1680/cien.2005.158.6.32?cookieSet=1. Accessed: November 10, 2008.

New York City began to install the Roosevelt Island Tidal Energy (RITE) underwater turbine project in the East River in December 2006.[21] Upon completion its 300 turbines will provide electricity to up to 10,000 households.[22] It took three trials before a turbine was successful at this site, after the first two were damaged due to strong currents.[23] The complete system of turbines is projected to generate up to 10 MW of energy.[24] The total cost of this facility is estimated at $20 million and is expected to take eight years to complete.[25,26] The RITE underwater turbine project in New York City's East River is expected to exhibit a capacity factor of 77 percent.[27]

The first commercial wave power station in the world is the Pelamis Wave Energy Project, located three miles off the coast of Portugal. The facility has three units that can produce a total of 2.25 MW of electricity at a construction cost of $12.55 million.[28] Each 750 kW unit is 140 meters (m) long and 3.5 m in diameter.[29,30] Sited in waters with depths of about 50-70 m and located 2-20 kilometers (km) from shore, they are marked on ocean charts and delineated by navigational buoys to avoid collisions with boats.[31] The Pelamis wave power project has demonstrated a capacity factor of about 25 to 40 percent.[32] Although barrage generators and underwater turbines were first installed a few decades ago, development has been slow due to the high cost of building in the ocean and the impacts on the local environment.[33] Information on the expected lifetime of ocean energy technologies should develop as the technology matures. The projected operational life of a tidal barrage can be indefinite, although turbines may need to be replaced every 30 years.[34] The Pelamis wave power systems currently have a service life in excess of 15 years.[35] Upon completion of its operational life, it can be completely removed from the water leaving no traces of the system behind.[36]

Ocean energy depends on tidal flows and currents which vary by location.[37] Once an ideal setting is identified, an energy source tends to be dependable.[38] For example, the La Rance tidal barrage and the Pelamis Wave Energy Project provide sustained and predictable power with a higher availability factor than wind.[39,40]

As with wind, tidal energy could benefit from energy storage since the power is generated only when conditions are favorable. A tidal barrage must first be filled from high tide in order to release water when the ocean is at low tide. Underwater turbines work only at sites that have a consistent current. Wave power can decrease as a result of a lack of wind to create the waves.

Economic Outlook

Operations and maintenance costs are high for all ocean energy producing technologies due to the harsh environment of the ocean.[41] Each built ocean energy project has had a unique cost associated with it. It would be difficult to estimate capital cost for any ocean energy project in the U.S. Although ocean engineering has high construction and dredging costs to remove accumulated silt, such cost could be offset by the fact that there is no fuel cost associated with ocean energy, particularly if it could provide a dependable source of energy. For example, the La Rance tidal barrage has been able to sell power at 0.02 euro per kWh, approximately $0.026/kWh.[42] The RITE Project expects to sell electricity at $0.07/kWh.[43]

The operating costs of ocean power technologies are not well established due to the lack of demonstration and commercial projects. The Electrical Power Research Institute (EPRI), which manages several pilot projects along the California and Oregon coasts, estimates commercial wave farm energy cost to be in the range of 9 cents to 14 cents per kWh. EPRI expects wave power cost at good sites to be below the cost of wind farms with similar power generation capacity.[44]

Table 15.2 lists performance characteristics of ocean power technologies. One recent study estimates that electricity from wave power technology could cost between 5 cents and 10 cents.[45] Another study suggests that the cost of ocean power production should decrease significantly as the volume of production increases.[46] There are no federal or state tax breaks for ocean energy projects.[47] Since 2007, the Marine Renewable Energy Research and Development Act has provided $200 million to promote ocean energy research and projects.[48]

Table 15.2
Ocean Power Costs and Performance Characteristics

Performance Measure	La Rance Tidal Barrage (France)	RITE Underwater Turbine (New York)	Pelamis Wave Power (Portugal)
Construction	7 years[2]	8 years[3]	4 years[4]
Construction Cost	$512 million[1]	$20 million[4]	$12.55 million[7]
Total Capacity	240 MW[2]	10 MW[5]	2.25 MW[7]
Capacity Factor	40% [2]	77% [5]	25-40% [8]
Cost of Electricity Production	0.026 $/kWh[1]	.07 $/kWh[4]	Not given

Sources: [1] Adapted from Renewable Energy UK, *La Rance Tidal Power Plant*. Online. Available: http://www.reuk.co.uk/La-Rance-Tidal-Power-Plant.htm. Accessed: November 10, 2008.

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Environmental Impacts

Ocean energy technologies produce renewable sources of power that do not directly emit greenhouse gases or other air pollutants into the atmosphere. Ocean power does not directly emit any solid waste while in service nor does it directly cause water pollution. However, the operation of machinery potentially could potentially affect local ecosystems.

Despite years of ocean energy research, it is hard to assess long term environmental risks of large scale current, wave or tidal power plants. Ocean technologies have created some environmental concerns, including concerns regarding silt build-up, influence on fish populations or other ocean ecosystems impacts. Large scale ocean power plants will likely affect the environment and ecology during and after construction.[49] For example, a barrage is a dam that separates two sides that once moved freely and independently. One report stated that the construction of a tidal barrage can result in a loss of up to 75 percent of the existing inter-tidal habitat.[50]

A life-cycle analysis of ocean energy technologies considers the impacts on the environment from building a facility, generating power, and ultimately decommissioning the facility. A United Kingdom study reported the lifetime carbon dioxide (CO_2) emissions from tidal electricity generated by the Severn Barrage to be 2 kilograms (kg) of CO_2 equivalent emitted per megawatt-hour of electricity generated, reflecting the energy used during initial construction.[51] Life-cycle emissions for an underwater turbine and wave power technology have yet to be published.

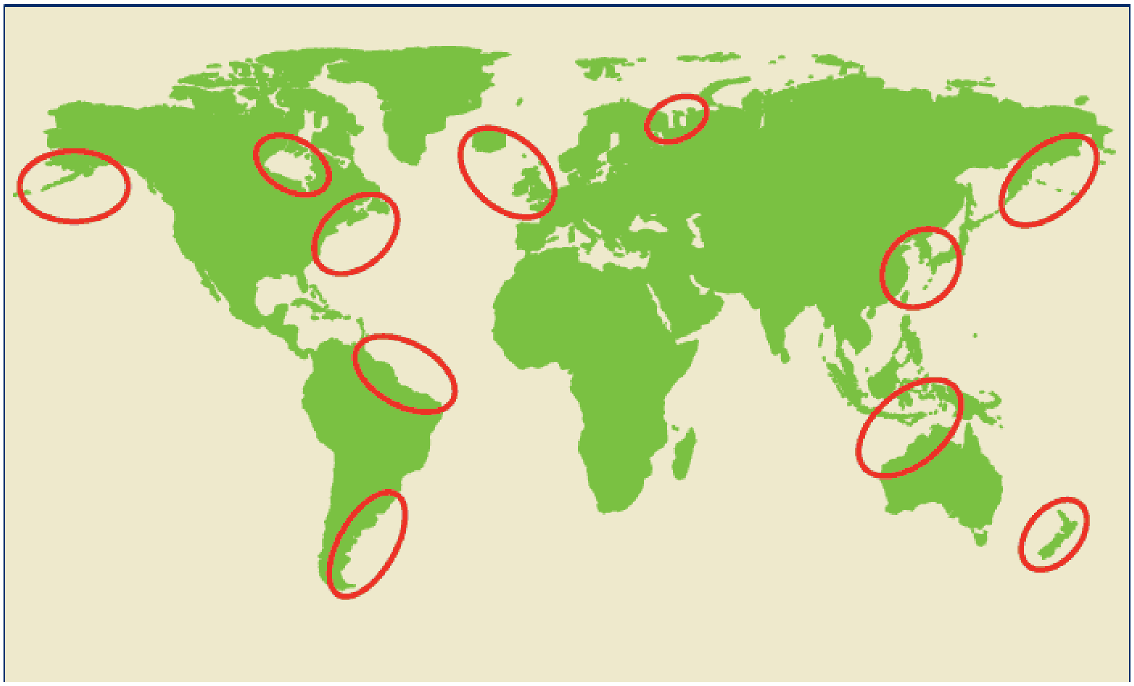
Ocean energy technology could affect boating and shipping industries. Because a tidal barrage acts as a dam, boats will be cut off from sites to where they once had access.[52] Underwater turbines must be placed far enough below the surface so that boats and divers will not hit them. Wave power systems can also affect boats as they float to the surface. New York City has spent $2 million studying the impact that underwater turbines have on its local environment; apparently fish and birds can avoid the blades of the RITE Project.[53] Regulations are in place for New York City to monitor this continuously.[54] There are also concerns about the aesthetic impact of building an ocean power facility within coastal view.

Future Outlook

One analyst estimates that ocean power has the ability to generate somewhere between 140 and 750 terawatt-hours or almost 5 percent of the world's 2004 electricity consumption.[55] Tidal energy may also have potential to be tapped into, but it depends upon whether costs can become competitive.[56] As many major U.S. cities are located near the coast there would not be a need to build long distance transmission lines from ocean energy sites, as the power plants would have easy access to the grid through an underwater cable. Figure 15.4 identifies areas appropriate for traditional tidal power. Figure 15.5 illustrates an approximate global distribution of wave power levels. States with ideal ocean power sites include Hawaii, Maine, and Oregon.[57] Both figures show that the Texas coast is not ideally located for either technology compared to other parts of the world.[58] Until ocean energy becomes routine, a utility provider in Texas has little incentive to try to use its coastal waters for power generation.

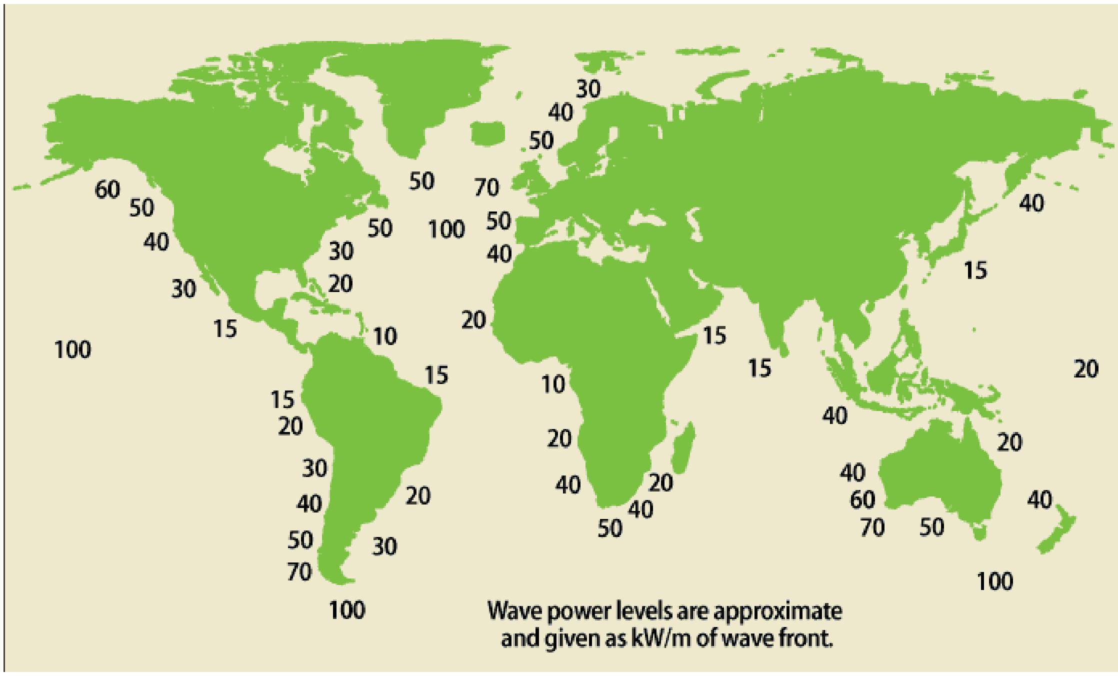
Through its offshore oil and gas industry, Texas has much experience with producing durable equipment that can survive in the harsh ocean environment. However, one of the barriers for a Texas ocean energy market is that the Gulf of Mexico is both shallow and has a semi-enclosed shape.[59] It is not an ideal site for ocean power generation as almost 40 percent of the Gulf is shallower than 20 m.[60] Texas does not have sites like La Rance in France, East River in New York, or Pelamis in Portugal. The strongest Gulf of Mexico current is the Loop Current (see Figure 15.6) that goes around the Yucatan Peninsula, which is inconsistent and never goes very far west towards Texas.[61, 62] The most likely places for the Loop Current to provide energy are near the Yucatan Strait (the entrance) or the Florida Strait (the exit).[63]

Figure 15.4
Global Areas Appropriate for Traditional Tidal Power



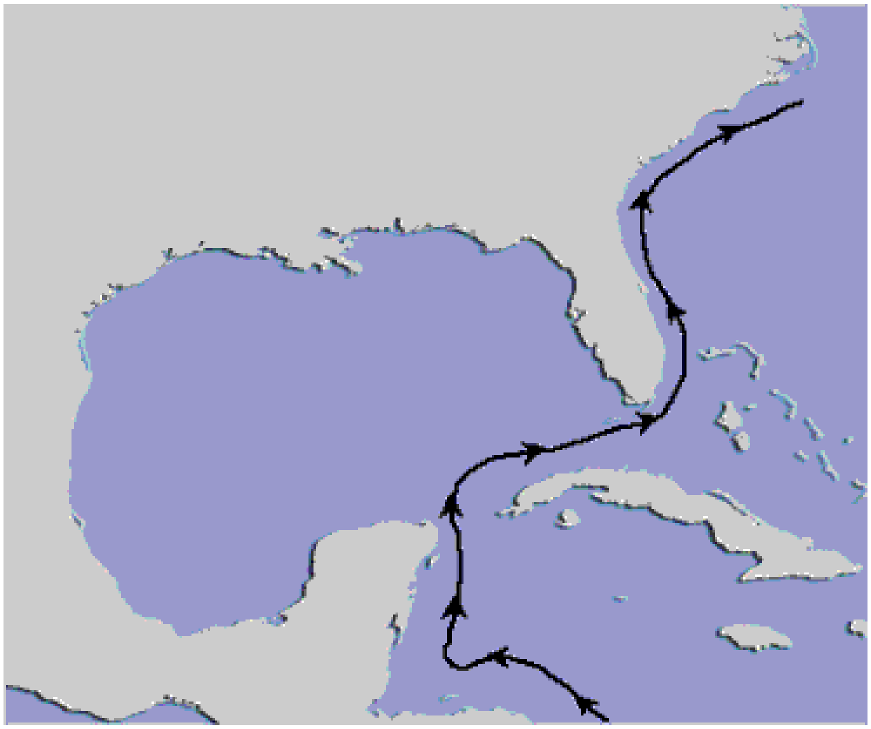
Source: Texas Comptroller of Public Accounts, *The Energy Report, Chapter Twenty: Ocean Power: 2006*. Online. Available: http://www.window.state.tx.us/specialrpt/energy/renewable/ocean.php. Accessed: November 10, 2008.

Figure 15.5
Global Distribution of Wave Power Levels



Source: Texas Comptroller of Public Accounts, *The Energy Report, Chapter Twenty: Ocean Power: 2006*. Online. Available: http://www.window.state.tx.us/specialrpt/energy/renewable/ocean.php. Accessed: November 10, 2008.

Figure 15.6
Location of the Loop Current



Source: Gyre Formation in the Gulf of Mexico. Online. Available: http://oceanexplorer.noaa.gov/explorations/islands01/background/wind/media/gyre_370.html. Accessed: October 13, 2008.

Mean tidal ranges in Texas vary from a minimum of 0.5 feet at Port O'Connor, Matagorda Bay to a maximum of 2.8 feet at Sabine Bank Lighthouse.[64] Median predicted tidal range for Texas coastal locations is estimated to be 1.3 feet. Texas' tidal ranges are small in comparison to Passamquoddy Bay, Maine, which has a mean tidal range of 18 feet. Because tidal power generation varies as the square of the tidal range, the available tidal power at Passamquoddy is 190 times greater than that of the average Texas location. Underscoring the challenge of tidal energy development in Texas, the Passamquoddy Bay project was abandoned due to its marginal economic feasibility.[65]

Options for Austin Energy

Ocean energy tidal barrages, underwater turbines, and wave energy are not likely to become new power generation sources for AE by 2020. Texas does not have the conditions that are necessary to make ocean-based renewable energy economically viable. High construction and maintenance costs create a further disadvantage. Tidal and wave energy levels around the Texas Gulf Coast are too low to utilize existing technologies in an economically viable renewable energy program. Areas of the world with much greater ocean energy potential would first have to develop commercially viable generation technology before Texas should considers developing its lower potential ocean energy resources.

Conclusions and Recommendations

Based upon an analysis of ocean energy options available to Austin Energy, it is unlikely that ocean energy technology can play any role in AE's power generation mix by 2020. There is no reason why AE should invest in ocean energy at this time or plan for ocean energy to be included as a viable renewable energy resource to meet AE's goal of carbon neutrality by 2020. AE should continue to monitor the development of ocean energy technology globally to determine when the technology has developed sufficiently to be economically viable for the lower ocean energy levels of the Texas Gulf Coast region.

Notes

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Chapter 16. Hydrogen and Fuel Cells

Summary

This chapter will discuss the limited viability of hydrogen fuel cells as producers and carriers of electricity at three different scales: the substation and utility scale, its distributed application to provide cooling and heating for certain land-uses and as portable and stationary fuel cells for the transportation and supply-chain industries. Some future applications of hydrogen fuel cells include powering vehicles, producing and carrying electricity, and providing cooling and heating for residential, commercial, and industrial land uses.[1]

Background

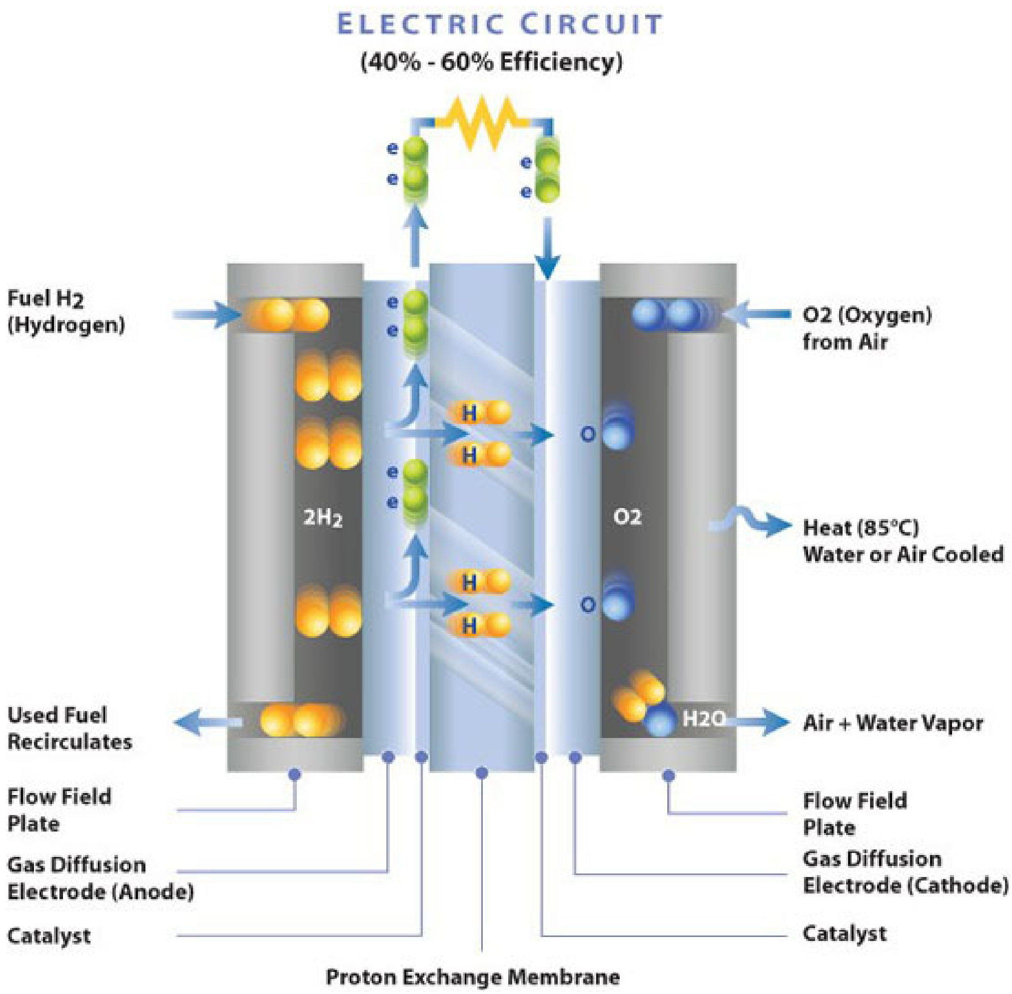
Many analysts believe that hydrogen fuel cells have a place in the future energy landscape as a highly efficient power generation technology.[2] One asset of fuel cells is that they can generate electricity with very little effect on the air, water, or other natural resources. Hydrogen can be produced from water using electrolysis or high heat. It can also be derived from plants or through chemical reformation. There are over 5000 stationary fuel cells in the world.

The structure of a fuel cell is very basic: it requires a fuel and an oxidant, which react to create electricity (see Figure 16.1). While the hydrogen fuel cell is a recent invention, fuel cells have existed since the 19th century. Prior to hydrogen, fuel cells utilized hydrocarbons and alcohols as fuel. Other oxidants have included air, chlorine, and chlorine dioxide. Table 16.1 lists the performance characteristics and costs associated with fuel cells.

There are many types of fuel cell technologies in varying states of production. Fuel cells can either be portable (e.g., in cellular phones) or stationary (e.g., a fuel cell at a hospital used for both electricity production and cooling and heating power off-grid during peak hours). This report describes hydrogen-oxygen proton exchange membrane fuel cells, reversible fuel cells, phosphoric acid, and natural methanol fuel cells.

Three hurdles must be overcome before hydrogen fuel cells can be widely adopted. First, hydrogen fuel cells are not commonly used for transportation, utility scale energy service, or for cooling and heating of buildings because they are not yet efficient enough to be cost-effective electricity carriers. Second, costs of fuel cell systems are still high. Furthermore, the public's lack of knowledge about fuel cell technology, the costs associated with electrolysis and isolating hydrogen, temperature management of fuel cells, durability, the service life of fuel cells, and safety concerns about fuel cell devices constrain its potential future role in energy production, transmission, and distribution.

Figure 16.1
Diagram of a Fuel Cell



Source: Ballard Power, *How Fuel Cells Work*. Online. Available: http://www.ballard.com/About_Ballard/Resources/How_Fuel_Cells_Work.htm. Accessed: October 13, 2008.

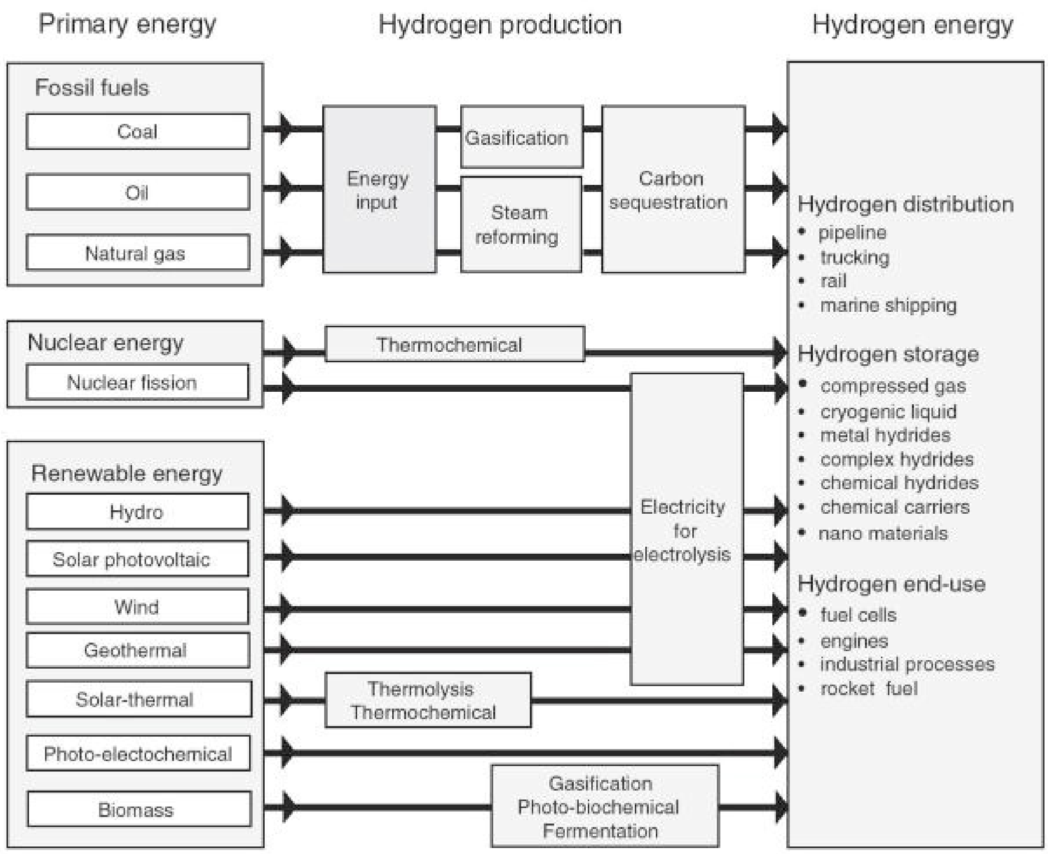
Table 16.1
Fuel Cell Cost and Performance Characteristics

Technology	Construction Time (years)	Size (MW)	Total Overnight Cost (2006 $/kw)	Variable O&M (2006 $/kw)	Fixed O&M (2006 $/kw)	Heat Rate in 2007 (Btu/kWhr)
Fuel Cells	3	10	5,374	46.62	5.5	7,930

Source: Energy Information Administration, *Assumptions to the Annual Energy Outlook 2008* (June 2008). Online. Available: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf.

This chapter will discuss the limited viability of hydrogen fuel cells as producers and carriers of electricity at three different scales: the substation and utility scale, its distributed application to provide cooling and heating for certain land-uses and as portable and stationary fuel cells for the transportation and supply-chain industries. Some future applications of hydrogen fuel cells include powering vehicles, producing and carrying electricity, and providing cooling and heating for residential, commercial, and industrial land uses.[3] Figure 16.2 depicts numerous ways of obtaining hydrogen energy from the full spectrum of sources and their possible applications. At the utility scale, hydrogen is an energy carrier than can be used to smooth out the variable characteristics of renewable energy sources.[4]

Figure 16.2
The Hydrogen Economy Concept



Source: D.A.J. Rand and R.M. Dell, *Hydrogen Energy: Challenges and Prospects* (Cambridge: Royal Society of Chemistry, 2008).

The Hydrogen Economy

The hydrogen economy is a proposed method of generating, transmitting, and distributing electricity for use in transportation such as cars, boats, airplanes, and the infrastructure that links transportation corridors. Hydrogen fuel could also be used in buildings, construction industry, manufacturing and their supply chains. Hydrogen could also be applicable to portable electronics and appliances used at homes, in conjunction with plug-in fuel cell vehicles that are power producers to the grid via the solar panels on one's roof.

Some believe that hydrogen can become a ubiquitous energy carrier and replace conventional energy sources such as coal, natural gas, and nuclear energy. In the concept of a hydrogen economy, fuel cells would move this excess energy to storage when energy production from renewable energy sources is at the capacity ceiling, thereby removing a key inefficiency associated with the intermittent nature of wind and solar energy technologies.

However, the hydrogen economy could only occur if a critical mass of excess renewable energy technologies can enable electrolysis. If this occurs, fuel cells have the potential to operate without emitting greenhouse gases. This breakthrough could be duplicated and deployed only if the renewable energy can provide enough heat to generate the electrolysis process at a cost-efficient level.

Operating Examples

Numerous major technology and energy companies are competing for the hydrogen market. Primary investors include fuel cell developers such as Ballard Power, Stuart Energy, Plug Power, and United Technologies Company (UTC) Power; leaders in transportation and automotive hydrogen use, including Siemens, Honda, Daimler-Chrysler, and General Motors; stationary and power plant development of all sizes including FuelCell Energy, Ballard Power, Rolls Royce, as well as significant military programs that have been tested since the 1990s.[5]

In 2001, Austin Energy collaborated with the city-owned Rebekah Baines Johnson Health Center to install a 200 kilowatt UTC Power Model PC25™C phosphoric acid fuel cell, the first fuel cell in Texas to feed electric power into the utility grid.[6] The system provided energy for the city health clinic, and the by-product of heat produced by the fuel cell was used in a combined heat and power application. This site was selected for the project based on a request for proposal to receive a $200,000 federal grant provided by the Climate Change Program administered by the United States Department of Defense (DOD) for the project. Special siting conditions made it a unique opportunity for AE and DOD to work through many challenges and issues associated with fuel cells. The fuel cell consisted of two modules, the power module and the cooling module. The power module converted natural gas fuel into alternating-current electric power. The separate cooling module rejected excess heat generated by the power module.[7]

United Technologies Corporation and Fuel Cell Energy (FCE), two leading stationary fuel cell generator manufacturers, have collaborated with AE and the University of Texas' Center for Electromechanics. In June 2008, UTC's Power Division was selected to provide stationary emergency power generation through fuel cells for the new World Trade Center (WTC) in Manhattan.[8] The stationary power generators at the new WTC site are projected to supply 4.8 megawatts (MW) of power to the Freedom Tower complex, an energy output roughly equivalent to that provided by the Mueller Energy Center in Austin when it is operating at full power.[9] Additionally, UTC Power completed a deal in March 2008 to provide a new Whole Foods Market in Connecticut with a combined cooling, heating, and power system using a quiet, highly energy-efficient fuel cell that will reduce its carbon footprint.[10] FCE has fielded commercial variations of its line of stationary generators, from a 300 kW model (the DFC 300) to a 2.4 MW plant suitable for hospitals, data centers, universities, large commercial complexes, and utility grid support applications for electricity quality and reliability.[11]

The University of Texas at Austin is currently testing a fuel cell bus.[12] According to Dr. Don Hebner, Director for the Center of Electromechanics, the fuel cell bus project is advancing other hydrogen-based options, such as retrofitting internal combustion engines to burn hydrogen.[13] The hydrogen refueling station in Austin was intended to open and begin servicing hydrogen vehicles in fall 2008.[14] Existing refueling stations in the U.S. obtain hydrogen from a natural gas two-step steam reformation process on-site.

Another indication of the ongoing commitment to fuel cell development in Texas is an educational initiative underwritten by the State Energy Conservation Office. Texas State Technical College (TSTC) in Waco has a program to train students in installation, operation, and maintenance of fuel cell technologies in transportation and stationary systems. TSTC Department Chair Sid Bolfing oversees experiments to successfully operate fuel cells, such as the PC 25, a common and standard large-scale model.[15] The fuel cell program at TSTC is designed as a partner program with other educational initiatives around Texas, such as the wind energy program at West Texas State University.[16]

Economic Outlook

The U.S. government has committed $181 million for direct hydrogen programs and $310 million for associated programs. However, the cost of fuel cells using electrolysis would have to drop to approximately $50 per kW from current rates to make it sufficiently competitive to support commercialization.[17]

Installation, operation, and maintenance and replacement costs are higher and the expected operational lives of fuel cells are too short relative to other technologies that provide similar services. In addition to reducing the overall costs of fuel cells, finding accurate cost estimates is a very challenging aspect of expanding overall fuel cell deployment. Private fuel cell technology companies often keep the actual costs of their systems as proprietary and confidential information.

Future Outlook

Texas has the second most available hydrogen within the U.S. and the most mature hydrogen distribution system in the U.S. This infrastructure could position Texas to exploit hydrogen as an energy carrier if and when applications become cost effective.

U.S. government forecasts predict widespread hydrogen adoption in the fuel cell vehicle sector by 2050. Most future scenarios call for substantial application of hydrogen technologies only in the long term (past 2020). However, the same scenarios predict that even a high level of integration of hydrogen fuel cells into the grid is dependent on numerous technological breakthroughs and price reductions associated with the deployment of hydrogen technologies and fuel cells.[18] For example, if current carbon-intensive methods for hydrogen fuel production cannot be replaced with renewable, algae or biomass-based methods, the hydrogen economy will be impossible to achieve.

Another key roadblock to widespread hydrogen fuel cell deployment is the energy loss in transferring electricity by way of hydrogen electrolysis process time and again from one carrier to another across a distributed utility grid/network that has been adjusted to be a uniform size, and modality.

Conclusions and Recommendations

Austin Energy should prioritize other renewable sources of energy above hydrogen. Based on cost and performance factors, hydrogen does not appear to be an attractive fuel source for AE prior to 2020. In addition to these factors, a) improvements to the efficiency of fuel cells; b) their safety (i.e., transportation of hydrogen in a volatile state); c) security (susceptibility to terrorist sabotage); d) development of infrastructure, and e) public and governmental resistance also will likely obstruct hydrogen’s development. Until measurable progress is made in all of these areas, the likelihood that hydrogen can contribute significantly to the development of a sustainable AE remains in question.

While hydrogen may not be a viable energy source for 2020, Austin Energy should monitor its development as a renewable source and grid. When hydrogen can be generated in a renewable manner on a sufficient scale, the lack of greenhouse gases produced by hydrogen fuel cell stacks could be an attractive option as a carbon-free power source.

Notes

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Chapter 17. Energy Storage

Summary

Austin Energy has reported that the 100 most expensive megawatts (MW) of annual peak energy are only used during 43 peak hours during the late summer.[1] If a energy storage system could provide the same 100 MW of peak power, AE could save millions of dollars every year.[2] If AE did not have to build that 100 MW of peak load generation capacity, the utility could save billions of dollars in capital costs.

Background

Energy storage involves saving energy generated during a period of low cost that can be used at a later time when the cost of electricity is higher due to increased demand. Storage technologies can improve electric quality and reliability, provide lower cost electricity to customers on the electrical grid, and reduce greenhouse gas (GHG) emissions. Advancements in grid energy storage technologies would allow Austin Energy to implement more effective load management strategies such as load shifting and peak clipping, which could reduce reliance upon intermediate plants and peaking plants to meet peak demand. Temporary storage solutions would enhance the dispatchability of variable renewable technologies such as solar and wind energy. Utility scale storage could enable distributed generation and facilitate greater market penetration of plug-in hybrid vehicles with temporary battery storage units. Table 17.1 lists the potential uses of energy storage.

Utility-scale grid energy storage allows energy producers to send excess electricity over the electric grid to temporary energy storage sites that become energy producers when electricity demand is greater. The Electricity Storage Association estimates that there are 90 Gigawatts (GW) of storage systems currently operating worldwide.[3] One recent report evaluated the financial opportunities in energy storage investment and found investment opportunities to be promising.[4]

A utility can use storage to ensure that electricity comes from an uninterruptible source, grid support and bulk storage management. One way to distinguish storage technologies is by scale. The three primary storage types are utility-scale bulk storage, medium-scale and small-scale. S mall-scale storage is also referred to as distributed energy storage (DES). Utility-scale storage systems (from 10 megawatts (MW) to 500 MW) such as pumped hydro-storage and CAES act as bulk power management. Medium-sized storage systems (from 100 kilowatts (kW) to 10 MW) provide grid support for load-shifting activities. Small-scale storage systems (from 1 kW to 100 kW) provide uninterruptible electricity source to improve power quality and load shifting. These options include batteries, flywheels, and electrochemical capacitors ("super" or "ultra" capacitors).

Table 17.1
Purposes and Capabilities of Energy Storage Technologies

Storage use	Result
Reliability and power quality	Storage allows loads to operate through outages.
Load leveling	Storage is charged during light-load periods, using low-cost energy from baseload plants, and discharged during high-load times, when the energy value is higher. Benefits include improved load factor, deferred generation expansion, reduced purchase at peak times and generation by peaking units.
System stability	Power and frequency oscillations can be dampened by rapidly varying the real and reactive output of storage.
Support of renewable energy systems	Storage can reduce fluctuations in wind and photovoltaic (PV) output, and allow sale of renewable energy at high-value times.
Bulk energy management	Bulk power transfers can be delayed by storing the energy until it is needed or its value increases.
Spinning reserve	Because of its inability to rapidly change the output, storage with power electronic interfaces can act as spinning reserve. Reduces the need for conventional spinning reserve units.
Black start capability	Stored energy can be used to start an isolated generating unit.
Environmental benefits	Reduced fuel use leads to reduced CO_2 equivalent emissions.
Reactive power control, power factor correction, and voltage control	Power electronic interfaces provide the ability to rapidly vary reactive as well as active power.
Deferral of new transmission capacity	Properly located storage units can be charged during off-peak times, reducing peak loading of transmission lines and effectively increasing transmission capacity.
Deferral of new generating capacity	Fewer peaking units are needed when storage reduces peak demand.
Support of distributed generation	Storage allows distributed generation (DG), such as microturbines and fuel cells, to be operated at constant output at its highest efficiency, reducing fuel use and emissions, discharging DES during peak demand times also reduces the needed capacity of DG.
Load following	Storage with power electronic interfaces can follow load changes very rapidly, reducing the need for generating units to follow load.
Increased efficiency and reduced maintenance of generating units	Load following by storage units allows prime movers to be operated at more constant and efficient set points, increasing their efficiency, maintenance intervals, and useful life.
Increased availability of generating units	During peak periods, charged energy storage added to available generation increases total system capacity.

Sources*:* P. Poonpun and Ward T. Jewell, "Analysis of the Cost per Kilowatt Hour to Store Electricity," *IEEE Transactions on Energy Conversion*, vol. 23, no. 2 (June 2008), p. 1; and Dan Rastler, "New Demand for Energy Storage," *Electric Perspective* (Edison Electric Institute, September/October 2008), p. 40. Online. Available: http://www.eei.org/magazine/EEI%20Electric%20Perspectives%20Article%20Listing/2008-09-01-EnergyStorage.pdf. Accessed: April 12, 2009.

Each energy storage technology possesses strengths and weaknesses. Table 17.2 lists the costs for each storage technology. Some factors that affect energy storage costs include initial capital cost, replacement and maintenance costs, safety standards, and system siting.

Table 17.2
Costs and Performance Characteristics of Energy Storage Technologies

Technology	Dollars per kilowatt ($/kW)	Dollars per kilowatt-hour ($/kWh)	Storage hours	Total capital cost ($/kw operating)	Example
Compressed air energy storage (CAES) large, below ground (100-300 MW)	590-730	20-102	10	600-750	McIntosh, Alabama CAES project (110 MW)
CAES small, above ground (10-20 MW)	700-800	200-250	4	1,000-1,800	Currently being test run
Pumped hydro (1,000 MW)	1,500-2,000	100-200	10	2,500-4000	Common
Lead acid battery (10 MW)	420-660	330-480	4	1,740-2,580	Common
Sodium sulfur (NaS) battery (10 MW)	450-550	350-400	4	1,850-2,150	NGK in Japan, MPower in UK, NYPA 1 MB on Long Island, NY
Flow battery (10 MW), e.g., Vanadium Redox, Zinc bromine	425-1,300	280-450	4	1,545-3,100	VRB Inc developing storage for Irish wind farms, AEP project W. Va
Flywheel (10 MW)	3,360-3,920	1,340-1,570	0.25	3,695-4,313	Pentadyne project for defense contractors – 500 unit purchase
Superconducting magnetic storage	200-250	650,000-860,000	0.003 (1 second)	350-489	Still in lab, not currently field tested
Supercapacitators	250-350	20,000-30,000	0.03 (10 seconds)	300-450	Still in lab, not currently field tested

Source: Dan Rastler, "New Demand for Energy Storage," *Electric Perspective* (Edison Electric Institute, September/October 2008), p. 40. Online. Available: http://www.eei.org/magazine/EEI%20Electric%20 Perspectives%20Article%20Listing/2008-09-01-EnergyStorage.pdf. Accessed: April 12, 2009.

Note: Cost figures include power conditioning system and equipment necessary to provide power. Does not include replacement costs, site permitting, interest during construction, or substation costs.

Advanced grid-level energy storage is likely to be a necessary component of creating a baseload supply of wind and solar energy. In Texas, wind often peaks between midnight and 6 AM when demand is lowest in the summer. There is also seasonal variation in operating capacity. As a result, the variable nature of solar and wind power limits AE's ability to provide energy from these clean energy resources. Texas winds blow strongest in sparsely populated western Texas, which is far from major electric transmission lines. While wind turbines produce more energy during off-peak hours, the cost of the same off-peak electricity is lower compared to peak demand hours. This abundance of wind at a low demand period has caused significant grid congestion in western Texas, where the bulk of wind farms are located. Advanced storage technologies deployed by AE could divert excess electricity produced during periods of low demand and low cost to be used during the day when demand and costs are high.

Types of Energy Storage Technologies

This chapter discusses five types of energy storage: compressed air storage (CAES), flywheels, thermal storage, flow batteries, and other types of batteries, and how they may be employed by AE to reduce carbon emissions by 2020. Table 17.3 lists storage technologies and their potential capabilities.

Table 17.3
Characteristics of Energy Storage Options

Storage technology	Application	System power rating	Storage hours	Dollars per kilowatt-hr
Pumped hydro	Bulk-power management	100 - 500 MW	10	100 – 200
Compressed air (below ground)	Bulk-power management	100 - 500 MW	10	550 - 750
Superconducting magnetic	Grid support (load-shifting) up to bulk-power management	5 - 50 MW	1 second	650,000 – 860,000
Flow batteries (vanadium redox, zinc bromine)	Grid support (load-shifting)	100 kW - 6 MW	4	280 – 450
Sodium sulfide battery	Grid support (load-shifting)	100 kw - 5 MW	4	350 – 400
Lithium-ion battery	Ensuring power quality up to grid support	1 kW - 2 MW	4	N/A
Lead-acid battery	Ensuring power quality up to grid support	1 kW - 5 MW	4	330 – 480
Flywheel	Ensuring power quality up to grid support	1 kW - 10 MW	5 - 15 minutes	1,340 – 1,570
Supercapacitor	Ensuring power quality up to grid support	1 kW - 100 kW	10 seconds	20,000 – 30,000

Source: Dan Rastler, "New Demand for Energy Storage," *Electric Perspective* (Edison Electric Institute, September/October 2008), p. 40. Online. Available: http://www.eei.org/magazine/EEI%20Electric%20Perspectives%20Article%20Listing/2008-09-01-EnergyStorage.pdf. Accessed: April 12, 2009.

Pumped hydropower storage is the most advanced and widely used form of energy storage. However, this technology may have limited opportunities for AE due to location constraints and high costs. Other energy storage technologies could be used to save energy.

Compressed air can be stored in geological features or old mines to later be heated by natural gas to generate electricity. Electricity generated during off-peak hours (possibly from renewable sources) could use this method for load shifting purposes.

Thermal energy storage is a method that could temporarily store energy collected by solar towers. Molten salt can be used as a heat source. Ice can be made from water, stored until the next day, and then used to cool either the air in a large building during peak demand or the intake air of a gas turbine generator.

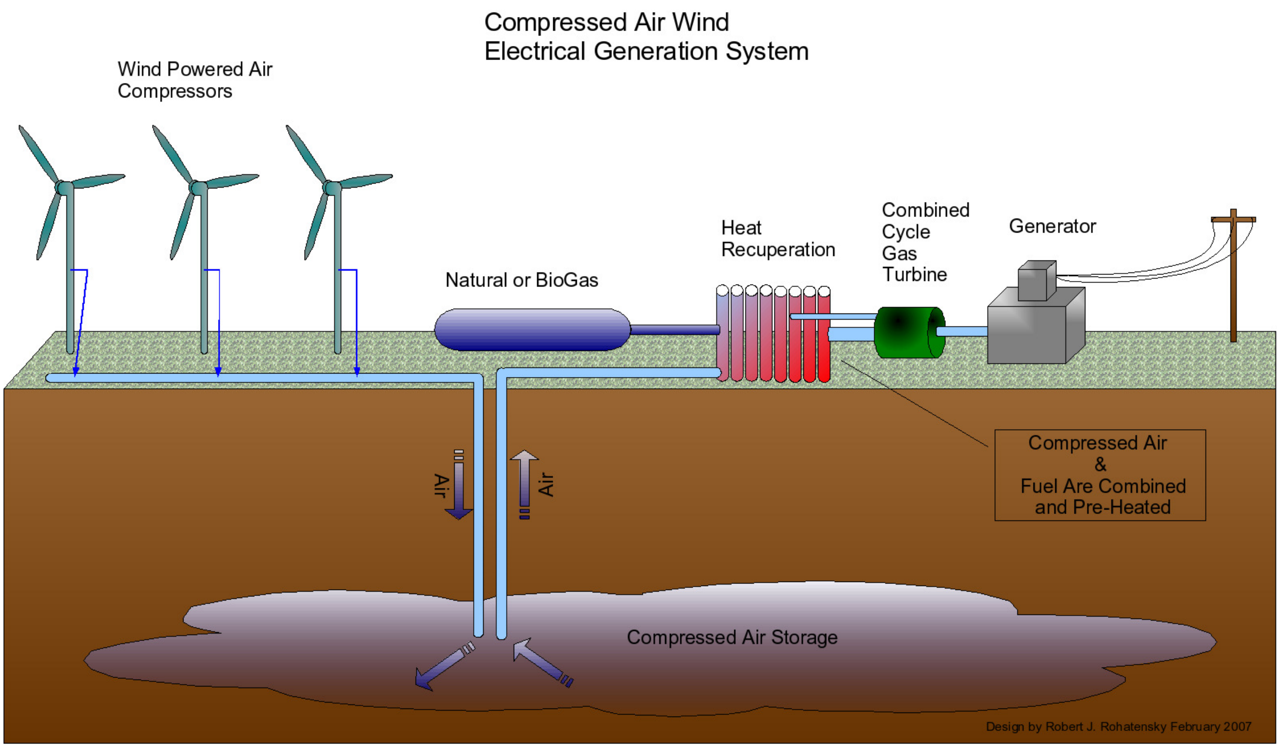
Superconducting magnetic energy storage systems can save energy in a magnetic field created by the flow of direct current in a superconducting coil. This technology is limited to short durations, but could shift loads. Its use has been limited due to high costs. Flywheel energy storage can temporarily store energy through mechanical inertia, but its application has also been limited to small-scale purposes.

Hydrogen could be used as a temporary energy storage method in the operation of fuel cells. Hydrogen must first be extracted by other energy sources in order to be used. If renewable technologies are used to create water, hydrogen could be used as a source clean energy, a concept termed the “hydrogen economy.” Substantial losses are involved in the hydrogen production process. Hydrogen storage efficiencies range from 50 to 60 percent, a loss that is greater than pumped storage systems and batteries.

Compressed Air Energy Storage

CAES systems use off-peak electricity to compress air within storage vessels and then burn natural gas to heat the air to generate electric power during peak periods as it is removed from storage (see Figure 17.1). CAES can refer to either air stored in a vessel or a hybrid power plant operated by natural gas. CAES systems use a little under half the natural gas of an ordinary gas turbine to produce a watt per hour of electricity. In a CAES system, air is produced from a generation source such as wind turbines, which is then compressed and stored in an underground reservoir. Potential storage sites include mined salt caverns, abandoned oil and gas fields, and abandoned hard-rock mine. Technical improvements to CAES systems allow site operators to store the compressed air above ground. Stored energy from CAES plants can be available immediately and can be used alleviate peak demand costs. Construction time for a utility-scale, below-ground CAES system is estimated at three or four years. Compressed air power plant costs reflect specific site conditions such as providing a large enough storage space and the ability of the container to efficiently hold the compressed air.

Figure 17.1
Diagram of Compressed Air Energy Storage Facility



Source: The Energy Tower, *A New System for Open, Location Independent, Reliable, Clean and Renewable Energy*. Online. Available: http://www.energytower.org/images/cawegs.png. Accessed: February 15, 2009.

There are three types of CAES storage systems: adiabatic heat storage, diabatic heat storage, and isothermal constant heat exchange systems. In smaller scale projects (and slower cycles of the device) isothermal systems achieve greater storage efficiencies. In isothermal systems, there is a constant temperature operation for both the compression and expansion portions of the process.[5] This constant heat exchange to the environment makes it particularly suitable for combined heat and power systems not feasible at a utility scale because they do not store the rapid large power surges required for peak power replacement. Diabatic storage is the only form of CAES available on the market. It requires a natural gas fired burner to re-heat compressed air upon removal from storage, prior to expansion in a turbine to power a generator. This plant requires 0.69 kilowatt-hour (kWh) of electricity per 1.17 kWh of natural gas use for each 1 kWh of electrical output.[6] Adiabatic storage is the process of withdrawing heat generated during compression and storing it. Adiabatic storage can achieve operational efficiencies between 65 and 75 percent for large or rapidly cycled devices. Heat is able to be stored in solids such as molten salt. No utility-scale projects have been developed using adiabatic storage.

CAES has three competitive advantages: cost, volume, and start-up speed. CAES provides significant energy storage for any amount of time at relatively low cost. CAES can generate power rapidly, known as black-start capability. The two so-called “first generation” CAES facilities are black-start capable. The first CAES plant was constructed in 1978 in Huntorf, Germany, and provides over 200 megawatts of storage capacity. A second CAES plant was constructed in McIntosh, Alabama, in 1991 and can store 110 MW.

Two projects are currently in the development stage, and will mark the advent of second generation CAES technology. At a CAES project in Iowa, testing and analysis of the ability to store air underground is being conducted at potential site locations. The next development phase involves an analysis of the siting tests. Once the results from the studies are completed, the project will move into the design phase, with construction to follow. The Iowa Stored Energy Park is expected to be providing electricity storage to utilities by 2011.[7] On August 26, 2008, the utility Public Service Enterprise Group (PSEG), Global LLC, and McIntosh plant engineer Dr. Michael Nakhamkin announced the formation of Energy Storage and Power LLC in New Jersey, a venture “to exclusively market, license, support the development and supervise project execution of the second generation of CAES technology.”[8] The joint venture’s first proposal is contingent on PSEG being awarded a contract to build a 350+ MW wind farm. The CAES plant would then be constructed nearby. If a storage plant were to be built in New Jersey, it would most likely use aboveground tanks or abandoned gas pipelines.[9] According to a press release, a consortium is investing $20 million in this project.[10]

After 16 years of operation, CAES has separated itself as the most affordable utility-scale energy storage technology.[11] The Edison Electric Institute (EEI) projects a large (100-300 MW), below ground CAES project to cost in the range of $590-730 per kilowatt. The July 2008 edition of the Department of Energy/Electric Power Research Institute (EPRI) estimates that “second-generation” CAES plant costs will range from $400/kW to $500/kW.[12,13] These figures do not necessarily include cost estimates for power conditioning systems and equipment necessary to provide power, replacement costs, site permitting, interest during construction, or substation costs among general construction, material, maintenance, and operation costs.

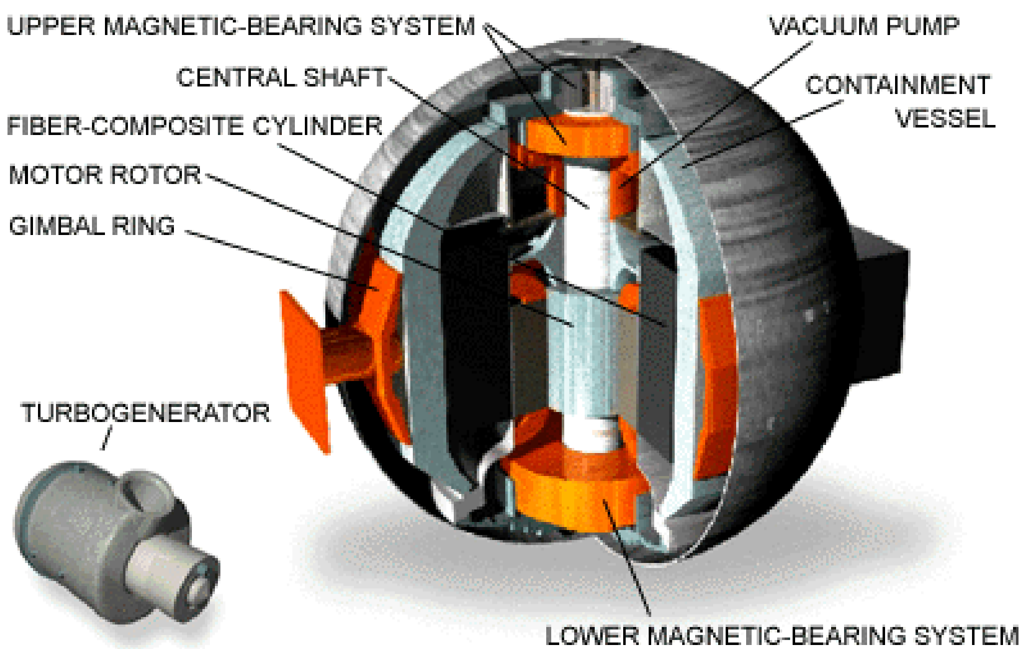
While utility-scale storage systems have the potential to enable broader use of renewable energy sources, CAES systems are not carbon-neutral. Natural gas is typically used to drive a CAES system’s compressor. Emissions run in the range of one-third to half the CO_2 emissions of a regular natural gas unit. Another environmental issue associated with CAES systems is efficiency. Excess heat is removed from the air in a chemical reaction and is dissipated into the atmosphere as waste.[14] The University of Texas at Austin (in conjunction with AE) is evaluating the capabilities of solar PV technologies to heat the compressed air, thereby removing natural gas from this equation.[15]

Flywheels

Flywheels are cylinders that store kinetic energy (see Figure 17.2). Flywheels spin at very high speeds, delivering reliable power for energy redistribution and power stability.

As the flywheel spins faster, it stores more energy. Energy can be removed from the flywheel simply by slowing down the cycle. Flywheels can either store energy by latching onto an electric motor that speeds up the flywheel to store energy or by utilizing a generator that produces electricity from the energy that is stored in the flywheel. Modern flywheels use rotors with a very high strength-to-density ratio and rotate in a vacuum chamber to minimize energy losses. Friction can be reduced through the use of superconducting electromagnetic bearings that reduce energy losses. Flywheel systems offer stability, simplicity of operation, and relatively substantial storage capacity.[16]

Figure 17.2
Diagram of a Flywheel



Source: University of Prince Edward Island, Physics Department, *Flywheels: A look to the future*. Online. Available: http://www.upei.ca/~physics/p261/projects/flywheel2/flywheel2.htm. Accessed: February 15, 2009.

Flywheel technology is still immature, but research is ongoing. Beacon Power is currently testing flywheels for frequency regulation applications at the transmission level in New York and California. Beacon has scaled up its flywheel technology from storing 15 kW, at a discharge rating of 6 kWh, up to systems that can store 100 kW, at a 25 kWh discharge rating. Beacon Power is working with an end-of-2008 goal of building a 20 MW “Smart Energy Matrix” frequency regulation plant.[17] A recent EPRI meeting regarding storage generated a great deal of interest in flywheel technology.[18] In both New York and California flywheel tests, systems were capable of storing 1 MW at a discharge rate of 250 kWh with an overnight cost in the range of $0.75-$2 million.[19] Annual operation and maintenance cost have been estimated at $20,000 to $30,000 per year, with a service life ranging from 15 to 25 years.[20]

Flywheels can supplement other power sources to enhance quality and reliability. This technology's current storage capacity lies roughly between 10 kW to 1 MW. Flywheels do not require fossil fuels or electricity off the grid.

However, flywheel systems have yet to substantially penetrate the energy storage market. One common use of the flywheel is in Hybrid Electric Vehicles (HEVs).[21] In a HEV, a flywheel works in conjunction with a small gas-powered or electric-powered engine. Flywheel-based vehicles are still in the early research and development phase. Rosen Motors recently tested a prototype for regular road use that can recharge in less than two minutes.[22]

One risk with flywheel systems is that when the flywheel speeds up, it reduces the local tensile strength and catastrophic failure may occur. Improved construction methods have served to reduce this problem. However, while greater improvements remain possible, maintenance are a significant barrier to broad market introduction.[23] Another downside to flywheels comes from their relatively poor energy density and large standby losses. Material costs in the construction of flywheels continue to be a great challenge to mass introduction of this technology into the market.

Ice-Based Thermal Storage

Thermal storage technologies can come in one of two forms: ice-based or molten-salt based. These systems have achieved wide market penetration and should continue to play a role in AE's 2020 plans.

Ice-based thermal storage systems are distributed sources of both chilled water and cold air that are designed to ensure electricity quality, reliability between service from substations, grid energy efficiency, and demand response. District cooling systems, large-scale tank-based chilled water storage systems can provide cool air during peak periods while making ice during off-peak periods for facilities such as a hospital, technology parks, manufacturing plants, commercial retailers, multi-unit residences and other energy consumers of varying sizes and customer classes.

AE operates several district cooling systems, most notably in downtown Austin, the Domain mixed-use area in Northwest Austin, and the Mueller Energy Center. In downtown Austin, AE operates a 33,000 ton cooling system that comprises the largest ice thermal storage system in Texas.[24] At the Domain, AE operates the first ice storage facility in the nation that uses waste heat to feed an absorption chiller. The Mueller Energy Center is a comprehensive combined heat and power facility that provides electric power, waste heat, and chilled air and water to the Dell Children's Hospital at Austin's Mueller Development.[25]

In addition to its district cooling assets, AE also operates a large tank-based chilled water storage facility at Austin-Bergstrom International Airport. Between the hours of 2 p.m. to 9 p.m., the airport's terminal is cooled by ice produced during off-peak hours, nearly eliminating the peak electricity demand of one of AE's largest consumers. Figure 17.3 illustrates the large water tank the system uses to store chilled water.

Figure 17.3
Photograph of Chilled Water Storage Tank at Austin-Bergstrom International Airport

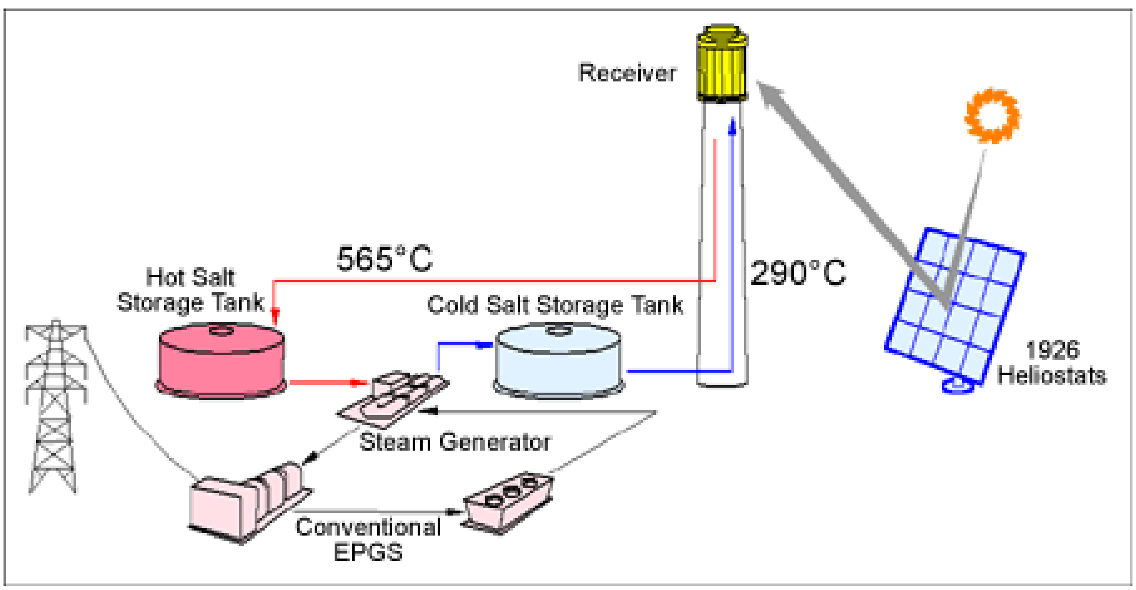
Source: Class presentation by Fred Yebra, Austin Energy, at the Lyndon B. Johnson School of Public Affairs, Austin, Texas, October 14, 2008.

Thermal Storage for Solar Power

Thermal energy storage reduces the variability of solar power. The two main storage types are tank-based systems and molten salt storage systems. Each system type takes advantage of heat transfer fluids to store heat and drive a steam turbine hours after the energy is produced.

Tank-based systems come in three types: two-tank direct, two-tank indirect, and one-tank thermocline systems. A two-tank direct system was first used in 1985 at the SEGS I facility in Southern California, one of the first concentrated solar power facilities. The system used mineral oil to shift power production from the afternoon to meet the winter peak period from 5 to 10 p.m.[26] Later versions of the direct systems used a more complex oxide heat transfer fluid or molten salt. Figure 17.4 illustrates how a power tower system can use a two-tank system. The two-tank indirect system is a more recent invention that reheats the cold heat transfer fluid. The system is considered to be indirect because it uses a different fluid to drive a steam turbine than was used in the parabolic trough field. This technology will be used as part of new solar installations in Spain.[27] A one-tank thermocline system blends both hot and cold molten salts in the same storage tank. The advantage of a thermocline system is that much of the molten salt fluid can be replaced with a low-cost filler material.[28]

Figure 17.4
Diagram of a Salt Storage System



Source: Green Terra Firma, *Solar Thermal For Electricity*. Online. Available: http://greenterrafirma.com/solar-thermal-for-electricity.html. Accessed: February 16, 2009.

Flow Batteries

Flow batteries are capable of storing and releasing energy through a reversible electro-chemical reaction between two salt solutions (electrolytes). Different designs exist for sodium sulfide (NaS), vanadium redox (VRB) and zinc bromide batteries. Flow batteries are generally two electrolyte systems where the electrolytes are pumped through a cell.

The attractiveness of flow batteries is that this system provides relatively long electrical storage capacity. The only limitation on storage capacity time is the size of the electrolyte storage reservoirs.[29] Flow batteries cost estimates exhibit large ranges due to local variables. Cost estimates range from $425 to $1,300/kW, $280 to $450/kWh. Capital costs are estimated at roughly $1,545 to $3,100/kW.[30]

Flow batteries differ from conventional batteries because the anode and cathode (solids in a conventional battery) are liquids that are pumped across a stack of plates that resembles a fuel cell stack. Incremental costs of additional hours of energy storage in a flow-cell battery are much lower than for conventional batteries, which create highly favorable economies of scale. Advanced batteries can be optimized for either high quality energy or power delivery, and can respond within milliseconds. These systems can also achieve black start (ramp-up from full shutdown to full operation within a few minutes).

VRB and NaS batteries are the two most common types of flow batteries. The energy in each battery is stored in vanadium or sodium sulfide in an electrolyte (as a liquid), which is pumped from separate storage tanks across an ion exchange membrane, creating a current. The electrochemical reaction can be reversed by allowing the system to repeatedly discharge and recharge.[31] These batteries are particularly beneficial for large-scale wind energy systems due to their ability to absorb power surges, inject energy during lull periods, and turn unscheduled energy (low value) into power (high value).

Flow battery technologies provide very high power and very high capacity batteries for load-leveling applications on the national electricity grid system. American Electric Power (AEP) has installed the first ever Transmission & Distribution Deferral System on the United States grid. This NaS flow battery can store 1.2 MW, at a power rate of 7.2 MWh. This system located in Charleston, West Virginia, has been operational since June 2006. According to AEP, the system has saved over $50,000 during the system's first 10 months of operation by effectively purchasing on-peak power from the off-peak rates. The system also improved the feeder's load factor from 75 to 80 percent on average and provided an average energy value of $5,000 per month. [32]

The first flow battery project in the U.S. was undertaken by a consortium led by the New York Power Authority for a municipal bus system in Long Island. The project can supply 1 MW of electricity for up to seven hours. The system recharges itself at night when the cost of electricity is greatly reduced. The natural gas compressor station that operates off the flow battery is also used to fuel up to 220 municipal buses. Ireland is investing heavily in a widespread application of Vanadium Redox Battery (VRB) technology. The battery systems there initially provided over 200 kW in 2005. The project now supplies multiple batteries totaling storage capacity of over 2 MW, with 12 MWh of storage capacity. The 2 MW threshold was achieved in fall 2007.[33] The Japanese NaS battery developer NGK has produced a 30 MW battery to be installed at a wind turbine facility in Japan. This battery type is cost-effective in Japan where the cost of natural gas is significantly higher than in the U.S. [34]

Other Types of Batteries

At a fundamental level, a battery is a group of two or more secondary cells that undergo an electrochemical reaction that releases energy through a process that is readily reversible. As a result, rechargeable electrochemical cells are a type of accumulator. Batteries come in many forms and use many different types of chemicals and are the most common devices used for storing electrical energy.[35] Advanced battery technology has made technological advances with sodium-sulfide and Lithium-ion.[36] Lithium-ion batteries have great market potential in white appliances and hi-tech appliances. At the utility scale, lithium-ion batteries provide power quality and allow for load shifting.[37] Although test projects have reached 5 to 6 MW, higher system power ratings will likely be achieved in the next few years. The Edison Electric Institute (EEI) believes that various flow batteries can provide long-term storage in the 4-10 hour range, with a capacity to store 5 to 10 MW with minimal siting complications.[38]

Several different international partnerships and multinational corporations have worked together to expand the utility-scale battery market. Two Japanese corporations, Tokyo Electric Power Company (TEPCO) and NGK Insulators Ltd, have jointly developed NaS batteries. Since the late 1990s, this joint venture has field-tested and demonstrated the capability of storing 26 MW of electricity at a discharge rate of 48 MWh. The installations at TEPCO substations are currently operating successfully. Project results show NaS batteries have low operations and maintenance costs, and a relatively longer cycle life. This technology is expensive and was brought to market in Japan, where electricity costs are substantially higher, on average, than the U.S. By 2003, worldwide installation had reached over 55 projects, an indication that this technology is penetrating the market.[39]

The European Photovoltaic Industry Association (EPIA) and the European Storage Battery Manufacturers (EUROBAT) have announced a plan to enhance battery storage in both on-grid and off-grid PV systems.[40] For example, MPower Solutions, a United Kingdom battery manufacturer, supplies over 500,000 batteries every month for everything from utility-scale storage to industrial site storage and low-cost consumer product battery service.[41] In 2005, the New York Power Authority (NYPA) and Consolidated Edison, along with the DOE, installed a NaS battery that can store 1.2 MW and a discharge rating of 7.2 MWh. This system is being used to improve power quality and ensure affordable electricity supply at times of peak demand. The system also provides backup power at a Long Island Bus Company refueling station.[42] The firm AEP purchased a NaS battery for a substation in Charleston, West Virginia. The project has expanded from 1.2 to 7.2 MWh. The battery was bought from and installed by the TEPCO/NGK joint venture.[43] The AEP battery in West Virginia was designed to defer upgrades to substations for six to seven years, allowing significant reduction in capital expense.[44,45]

Cost estimates for sodium-sulfide batteries run in the range of $450-$550/kW and $350-$400/kWh. Capital costs are estimated between $1,850-$2,150.[46]

Niche Storage Technologies

Superconducting systems store energy in a magnetic field created by the flow of direct current in a superconducting coil that has been cryogenically cooled to a temperature below its superconducting critical temperature. This technology is a suitable system for power conditioning the electrical supply. A typical superconducting system includes a superconducting coil, power conditioning system, and cryogenically cooled refrigerator. Once the superconducting coil is charged, the current will not decay and the magnetic energy can be stored indefinitely.[47] The stored energy can then be released back to the network by discharging the coil. The power conditioning system uses an inverter/rectifier to transform alternating current power to direct current or vice versa. The inverter/rectifier accounts for about 2 to 3 percent energy loss in each direction. Superconducting loses the least amount of electricity in the energy storage process compared to other methods of storing energy. Superconducting systems are highly efficient with a round-trip efficiency greater than 95 percent.[48] Due to the energy requirements of refrigeration and the high cost of superconducting wire, SMES is currently being used for short duration energy storage for improving power quality. If SMES were to be used for utilities it would be a system that charged from baseload power at night to help meet peak loads during the day.[49] Due to high capital and operating costs, superconducting electromagnetic energy storage systems and supercapacitors do not appear to be viable options for utility scale energy storage by 2020.

Options for Austin Energy

AE can extract additional value from its solar and wind investments through storage. By siting utility-scale storage near its West Texas investments in renewable electricity, AE could alleviate transmission congestion, transmission scheduling and the innate variability of renewable generation sources while reducing the price and levelized cost of electricity from the sun and the wind.

West Texas, which is the origin of AE's current purchased wind power and the optimal area for a concentrated solar power facility investment, has many of the geological features necessary for building a utility-scale CAES facility: salt caverns, aquifers and depleted oil and gas fields.[50] AE could take advantage of all three of these formations in order to find a unique and optimized location for a CAES facility.

In 2005, the State Energy Conservation Office (SECO) commissioned an in-depth study of the impact of a large-scale CAES facility in the Texas Panhandle.[51] The study analyzed two scenarios, the use of a CAES facility to optimize and manage the dispatch of 440 MW of wind versus a CAES facility that would manage the 440 MW along with an additional 500 MW of wind.[52] Overall, the SECO study found that an investment in a 270 MW CAES facility with 940 MW of wind would be cost competitive with new non-renewable generation.[53]

The report concluded that a large-scale CAES facility could shift load to better match load shapes. The report also concluded that storage could also mitigate variability losses and inefficiencies from hour-by-hour ramping of wind resources, which could allow utilities to "baseload" a certain fraction of their nameplate wind capacity.[54] However, the report concluded that CAES was not able to mitigate transmission congestion if additional wind were added into the grid. In other words a utility would benefit most from the reduction of transmission congestion in the absence of large nearby additions of wind capacity.[55]

CSP facilities can also maximize their contribution to the grid is through concurrent siting with CAES systems. Using a CAES system concurrently with a CSP facility could have several distinct advantages. First, CAES systems have the lowest per kWh cost of all viable energy storage technology. Second, CAES facilities, could provide AE with a means to combat transmission congestion and spread the load of both its purchased wind power and for electricity produced by a concentrated solar facility, which would need to be build in West Texas due to its high direct normal insolation rates.[56] Third, a CAES facility would combat the innate variability of solar and wind resources and allow AE to schedule renewable energy generation and transmission more easily. The Department of Energy estimates that energy storage could reduce balancing costs incurred by utilities who handle renewably-generated electricity by up to 2 to 3 percent.[57] In sum, using CAES in conjunction with solar power could remedy the expense and intermittency of solar power.

Conclusions and Recommendations

Austin Energy should consider the potential of CAES resources as a key energy investment through 2020. AE should consider underground as well as above ground systems. This type of technology is specific to central Texas, where there are a substantial number of salt domes, hard mineral mines and oil deposits. AE has already identified CAES as a viable technology for immediate implementation. Since CAES uses less than half the natural gas of regular plants and there are underground caverns in suitable locations, such a facility could lower overall carbon emissions while maintaining its cost-competitiveness with new power generation technologies.[58] AE is currently developing a test site for a CAES project. This pilot project could be the basis of a proposal to the Austin City Council to build a large underground CAES system (in the range of 200 MW of energy storage capacity) and/or an above-ground storage facility capable of 10 to 20 MW.

Austin Energy should consider the value of thermal energy storage systems. To do so, AE must increase community use of district cooling systems and the use of tank-based chilled water storage systems among all customer classes. If AE is able to take advantage of these distributed storage systems, it can improve energy efficiency and peak demand response. While many other storage technologies are either too expensive to be viable on a large scale by 2020, AE already deploys these these storage systems and should take maximum advantage of them. AE must also ensure that any large-scale CSP investments include thermal energy storage. This could allow AE to provide "baseload" solar by spreading solar energy across both on- and off-peak periods and reduce its levelized cost.

Austin Energy should consider enhancing new and existing partnerships for other storage technologies including batteries, flow batteries, flywheels, and superconductors for development by 2020 and beyond. Thermal energy storage, flywheels and battery technologies could greatly help reduce peak demand to create cost savings and reduce AE's carbon footprint. There is currently a large industry cluster in Central Texas made up of energy storage corporations as well as complementary service and supply-chain businesses.

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