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What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria

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Executive Summary

As load grows and old plants retire, the public will need new sources of electricity generation. State public utility commissioners will have obligations and opportunities to influence, and in some cases determine, the mix of generation technology and fuels for their states.

Understanding the nature and major characteristics of individual generation technologies is a first step in determining the appropriate mix of technologies. This report develops nine criteria key to that understanding; then applies those criteria to each of 14 technologies. The technologies and criteria are listed in the tables below.

A second step in determining the appropriate mix involves evaluating the "fit" of each technology in the context of an existing power system, consisting of generation facilities and customers with specific demand characteristics. The report examines the role that portfolio analysis can play in that evaluation. The report concludes by exploring what information decision-makers need to conduct their evaluations.

The appendices offer diagrams of each of the 14 technologies, along with tables detailing the current mix of generation in each state.

Types of generation technologies

Fossil-fueled
- Combined cycle gas turbines
- Combustion gas turbines
- Pulverized coal generation
- Fluidized bed combustion
- Integrated gasification combined cycle (IGCC)

Nuclear

Wind

Pumped-storage hydropower

Miscellaneous
- Photovoltaic power
- Concentrated solar power
- Biomass power
- Geothermal power
- Barrage and ocean current generation
- Fuel cells

Criteria for describing generation technologies

- Load-service function
- Time to construct
- Cost to construct
- Operational life
- Fuel costs
- Fuel dependability
- Plant dependability
- Maturity of the technology
- Externalities

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I. Introduction: Why care about generation mix?

State public utility commissions (PUCs) face decisions about the appropriate mix of generation technologies and fuels. These decisions will affect the public, the environment, the economy, and the owners of the technologies for thirty or more years. Cost is only one consideration. State regulators also must ensure reliability and service quality, all consistent with the state's environmental and economic development priorities.

Additional generation is only one part of the equation. Commissions should consider energy efficiency and demand-side management programs that lower the total level or alter the daily patterns of customer demand for electricity. But new sources of generation will be part of the solution to meeting future demand. This report focuses on generation.

Each technology has its proponents. Many of those proponents will assert that their technology serves the public interest. The commission's responsibility is to provide its judgment of what mix of technology best serves the public interest. This report provides some tools necessary to reaching that judgment, by comparing each technology across nine characteristics. **Part II** of the report describes those characteristics. **Part III** then discusses each of 14 technologies in terms of those characteristics. The technologies and criteria used to describe them are listed below.

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Understanding the major characteristics of individual generation technologies is a first step in evaluating generation. A second step involves evaluating each of the technologies in the context of a power system comprised of existing generation facilities and customers with specific demand characteristics. **Part IV** examines the role that portfolio analysis can play as a conceptual framework for state commissions to apply to information on individual generation technologies in order to make socially desirable decisions. **Part V** concludes the report by exploring what information decision-makers need to have when evaluating generation technologies.

The report now examines three reasons why the generation mix in their state should be important to state regulators: (1) the commission's regulatory obligations; (2) the presence of uncertainty in the regulatory process; and (3) federal statutory requirements.

A. Generation mix decisions arise in all states regardless of the status of retail competition

Concerns about generation mix fall within the core of state commissions' regulatory obligations. This proposition is true for all states, whether their market structure is the traditional regulated monopoly structure or one allowing for retail competition.

In states which have not authorized retail competition, there are monopoly providers of bundled retail electric service subject to rate-of-return and quality of service regulation.[1] Commissions in these states make multiple decisions that influence the mix of generation in the state:

1. Cost recovery proceedings require commissions to set the rates for power produced from current plants and set the terms and conditions for utility service.

2. Certification proceedings require commissions to evaluate a utility's resource adequacy in light of its obligation to serve the public.

3. Generation siting proceedings require commissions to examine the environmental and other locational effects of proposed plants, sometimes in the form of an environmental impact statement; transmission siting proceedings also influence the amount and type of generation since the lines are necessary to carry the power.[2]

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[1] Bundled electric service is the offering of combined generation supply, transmission, and distribution service by one company. A company offering bundled service may own its own generation, acquire its generation from third parties, or both.

[2] Siting and plant certification processes overlap in some states.

4. Some states set generation reserve margins deemed necessary to ensure that sufficient power is available to provide service and maintain the proper functioning of the transmission grid.

5. Traditionally regulated and, less often, retail competition states can also influence the generation mix though a state-wide or regional planning process. Integrated resource planning (IRP) processes are not used by commissions in all states; when used, they require utilities to evaluate different options for meeting and shaping projected future demand for electricity, with the goal of determining the best combination of demand-side and supply-side resources.

6. Renewable portfolio standards are laws that require retail electric suppliers to procure a given percentage of their power from renewable sources by a given target date. PUCs typically are responsible for implementing and enforcing these requirements. Appendix A lists the 23 states that currently have renewable portfolio standards in place.[3]

Commissions in states authorizing competition for retail sales of electricity have more circumscribed authority over power producers than in traditionally regulated states. Commission authority in restructured states typically centers on: (1) siting of new plants (where that authority existed previously); (2) overseeing statutory portfolio standards that apply to competitive retailers; (3) approving the procurement decisions of incumbent utilities acting as default service providers as mentioned above, and (4) overseeing public benefit programs for energy efficiency and renewable energy, in states where such programs exist.

Even in these retail competition states, there usually remains a legislated commitment to provide "default" or "standard" service to non-shopping customers. In these states, the majority of residential customers depend for this essential service on the default provider, which is usually the incumbent utility. These states still have an interest in attaining the proper mix of generation used for default service. And, provided these states' statutes continue to grant the commission jurisdiction over quality of service, rates, and infrastructure planning relating to default service, the state commissions still have responsibility to influence a utility's choice of generation.

B. Generation mix decisions address multiple uncertainties

A regulator's consideration of generation mix must take into account at least five sources of uncertainty:

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[3] For a detailed discussion of renewable portfolio standards, see Scott Hempling and Nancy Rader, *The Renewables Portfolio Standard: A Practical Guide*, National Association of Regulatory Utility Commissioners, February 2001. Document available at: www.naruc.affiniscape.com/associations/1773/files/rps.pdf.

1. **Market conditions:** Uncertainties exist in load growth (i.e., the change in the total amount of demand for electricity)), load shape,[4] and market prices for power.

2. **Fuel prices**: Fuel prices fluctuate according to the supply and demand of the marketplace. Natural gas is a recent example. The increase in construction of natural gas plants started in the early 1990s, during which decade the plants compromised approximately 90 percent of new electricity generating capacity. Additions to gas generating capacity slowed after 2000 in part as a result of the high and volatile natural gas prices from 2000 to the present. The U.S. Department of Energy (DOE) Energy Information Administration (EIA) forecasts that the share of planned additional generation using natural gas will fall from 73.1 percent in 2006 to 37.6 percent in 2010.[5]

3. **National policies:** Legal actions at the national level, in the form of legislation or regulatory orders, inject additional uncertainty. National renewable portfolio standards and regulation of carbon dioxide to curb global warming, for example, are two policies that would affect generation comparisons. In addition to possible action on greenhouse gas emissions

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[4] Load shape refers to the shape of the curve on a two-dimensional axis, in which the Y-axis displays demand, the X-axis displays the time of occurrence of that demand, and the values reflect the customer (or customer group's) load at each point in time. A city's load shape for a 24-hour period in August would show low levels from midnight until about 6am, with load then growing to a peak by late afternoon, then gradually falling into the evening. A manufacturing firm with constant demand throughout the day would have a load shape consisting of a horizontal line intersecting the Y-axis at that demand level.

[5] Untied States Department of Energy, Energy Information Administration (hereafter cited as EIA), *Electric Power Annual 2005,* DOE/EIA-0348(2005), November 2006, Table 2.4. Document available at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html.

As another indication of how changing natural gas prices alter forecasting and planning, EIA's predictions for the share of electricity generated in the U.S. from natural gas in 2020 fell from 31 percent to 21 percent in its forecasts released in 1999 and 2006. See EIA, *Annual Energy Outlook 2000*, DOE/EIA-0383, Table A8, December 1999, and EIA, *Annual Energy Outlook 2007 (Early Release)*, December 2006, Table A8. Natural gas represents 1,476 billion kilowatthours (kWh) out of a total 4,757 billion kWh of electricity generation projected for 2020 in *AEO 2000* compared to 1,060 billion kWh of natural gas-fired generation out of a total 5,037 billion kWh for the same year in *AEO 2007*.

by the 110th Congress, the Supreme Court is considering a case that addresses whether the federal government must regulate carbon dioxide under the Clean Air Act.

4. **Fuel supply:** Some fuels are more vulnerable than others to interruptions. The 1973 OPEC oil embargo is a prominent example. Other vulnerabilities include railroad lines essential to a utility's coal deliveries. natural gas pipeline ruptures, and a drought of wind or water affecting wind turbines or hydro-electric dams.

5. **Commission forecasting processes:** Forecasts are uncertain by definition. To increase accuracy, commissions and their regulated utilities revisit their forecasts periodically, within integrated resource planning or forecasting proceedings. Unforeseen events still occur, including technological change, construction delays, and cost overruns.

C. The Energy Policy Act of 2005 requires states to consider diversity in generation fuels and technologies

State commissions have a third reason to consider generation mix: Congress ordered them to do so. The Energy Policy Act of 2005 (EPAct 2005), in an amendment of the Public Utility Regulatory Policies Act of 1978 (PURPA), requires state commissions to consider whether it is appropriate to implement standards requiring each jurisdictional electric utility to: (1) develop a plan "to minimize its dependence on one fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies;" and (2) "develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation."[6]

EPAct 2005 leaves implementation of the fuel sources and fossil fuel generation efficiency standards to state commissions. The commissions will have to begin considering the standards for their jurisdictional utilities by August 8, 2007, making determinations by August 8, 2008.

Another influence on each state's generation mix is the 2005 amendments to Section 210 of PURPA. That section, enacted in 1978, required each utility to buy capacity and energy from "qualifying facilities" (defined to include cogenerators and small renewable power producers), at a price equal to the utility's "avoided cost" (the cost the utility would have incurred if it had procured the needed capacity and energy from other sources (or self-supplied)). The U.S. Supreme Court has described the 1989 Congress's two-fold intent: to reduce the demand for fossil fuels and to overcome

[6] PURPA Sec. 111(d)(12) and Sec. 111(d)(13), as added by Sec 1251(a) of EPAct 2005.

utilities' "reluctan[ce] to purchase power from, and to sell power to, the nontraditional facilities."[7]

Section 1253(a) of EPAct 2005 created multiple paths by which a utility may obtain from FERC an exemption from this purchase obligation. Common to these paths is a FERC finding that QFs who otherwise would seek to sell to the utility have access to buyers in competitive wholesale markets. Elimination of the mandatory purchase obligation in a market is likely to change the mix of generators selling into that market.

D. Structure of the remainder of this report

Part II of this report begins by describes nine criteria for evaluating different types of generation technologies. **Part III** describes the 14 generation technologies most likely to attract state interest; the descriptions apply Part II's nine criteria. **Part IV** introduces a conceptual framework, portfolio analysis, for commissions to apply to the information on individual generation technologies when determining the appropriate generation mix. **Part V** recommends steps for commissions to take in preparing for generation mix decisions.

The report includes three appendices: (1) a table listing states with renewable portfolio standards, including target years and target levels for generation from renewable resources; (2) diagrams illustrating the basic components of the 14 generation technologies; and (3) a state-by-state list of the current generation mix in each state, organized by the technologies and fuels used for the generation and listing the average age of the plants.

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[7] *FERC v. Mississippi*, 456 U.S. 742, 750 (1982); *American Paper Institute, Inc. v. American Elec. Power Serv. Corp.*, 461 U.S. 402, 405 (1983)

II. Nine criteria for comparison: What characteristics should regulators examine when evaluating generation technologies?

The following are the criteria that this report identifies as being useful for evaluating generation technologies:

- Load-service function
- Time to construct
- Cost to construct
- Operational life
- Fuel costs
- Fuel dependability
- Plant dependability
- Maturity of the technology
- Externalities

A. Load-service function

The attractiveness of a particular generation option depends on the role it will play in meeting load. Does the service territory need baseload, intermediate or peaking generation? What types of generators serve which of these functions? This subsection explains these concepts.

The demand for power – sometimes termed the "load" – varies every minute as residents and businesses make individual decisions to turn their appliances and machines on or off. Since utilities and customers cannot normally store electricity,[8] these load variations must be matched by generators, instantaneously and exactly, to keep power flowing and to keep the electric interconnected system (generation, transmission and distribution) stable. Along with the minute-by-minute variations are larger scale variations – intra-day (compare 2 pm with 2 am), intra-week (compare Monday with Sunday) and seasonal (compare August with April).

Load service function refers to the role that generators play in meeting these variations in load. Different types of generators vary in their cost of operation and time required to respond to load changes. Rather than run all plants at all times (an economically inefficient practice), in any particular hour the power system operator chooses that mix of generators that minimizes cost, subject to environmental constraints.[9]

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[8] Storage is possible in the context of pumped hydro plants. See Part III.D below.

[9] Given the dynamic nature of demand for electricity, regions of the country each maintain a margin of available generating capacity beyond the likely demand in order to provide the power necessary to maintain the stability of the power system. With the use of capacity margins, it is rarely necessary to use all available generation capacity for a given time of the day or year.

Key terms

Efficiency (or thermal efficiency): the extent to which a power plant is able to convert the energy content of fuel into electricity.

Heat rate: a measure of the thermal efficiency of a power plant.[10] The measure is expressed in British thermal units per net kilowatt-hour of electricity. The lower the plant's heat rate, the higher the plant's efficiency, because it requires fewer units of fuel input to produce a kwh of electricity.

Power supply planners normally classify generating units into one of three categories according to their operational role:

1. **Baseload plants** are run at all times, except during repairs or scheduled maintenance. These plants have low variable operating cost relative to other plants. Baseload plants are typically nuclear, coal-fired, or hydropower units. In combination, baseload plants provide the minimum level of power that is always required by customers. Because they run continuously, they provide the majority of the electric energy used. When demand rises above baseload levels, (e.g., a weekday afternoon), the operator brings other plants on line. The hours or days of "ramp up" time for typical baseload plants (i.e., the time it takes to "get them up and running" to deliver power) is longer than the time necessary for the other types of plants.

2. **Peaking plants** are dispatched to meet high demands, like air conditioning loads on weekday afternoons. Peaking plants range in operation from several hours a day to only a few hours a year. Failing to meet peak demand would lead to curtailment of customer service or, in the extreme, a system-wide blackout. Given that it is usually more expensive to build a highly efficient plant, peakers tend to be built with lower efficiency than base load plants since they are used for fewer hours. Peakers must be able to start up and deliver power on very short notice from the power system operator. Peaker plants are frequently simple cycle gas turbines burning natural gas, with diesel oil serving as a backup fuel, or compression ignition reciprocating engines burning diesel oil.

3. **Intermediate or "shoulder" plants** fall in between baseload and peaking plants in terms of their hours of usage and efficiency. The plants are used in combination with baseload plants to meet all but the highest demands for electricity; that is, they are not run all the time, but they come on line as load grows. Newly built intermediate plants are usually high-efficiency gas turbines. Sometimes operators do use natural gas- and

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[10] See Joel B. Klein, "The Use of Heat Rates in Production Cost Modeling; and Market Modeling," Staff Report, Electricity Analysis Office, California Energy Commission, April 17, 1998. Document is available at: http://www.energy.ca.gov/papers/98-04-07_heatrate.pdf.

coal-fired plants for intermediate load. Many intermediate plants are former baseload plants, no longer cost-effective for the baseload role.

Key terms

Capacity factor: The ratio of (a) the net amount of electricity a plant actually generates in a given time period to (b) the amount that the plant could have produced if it had operated continuously at full power operation during the same period.[11] Capacity factor is dependent on both the mechanical availability of the plant and the economic desirability to run the plant given the particular cost to run it.

Availability factor: The ratio of (a) the number of hours a generating unit is mechanically able to produce power in a given period to (b) the number of hours in the period.[12] A factor less than 100% indicates planned or unplanned outages for maintenance. A plant's availability factor will be higher than its capacity factor, because a plant is not used in every hour it is available.

Load factor: The ratio of the average load to peak load served by a plant or power system during a specified time interval. A higher load factor indicates higher use of the generating resources. This report does not use this factor as a variable for comparing technologies because it is specific to a particular plant and power system rather than being a general characteristic of a given technology. We include the term here to distinguish it from capacity and availability factors.[13]

A prospective owner of a plant will determine in advance of construction whether the plant is likely to serve as a baseload, intermediate, or peaking facility. This determination includes forecasts for a plant's average level of output and its annual production of electricity, which can be expressed as the plants load and capacity factors. Both of these factors affect the technical and economic choices that an owner makes when designing a plant.[14] The actual economic performance of a plant is dependent upon how often the power system operator calls upon the plant to send power onto the grid.

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[11] See EIA *Glossary*.

[12] See EIA, *Renewable Energy Annual Glossary*. Glossary is available at http://www.eia.doe.gov/cneaf/solar.renewables/page/rea_data/gl.html.

[13] Ibid.

[14] For example, an owner will likely design an intended peaking plant to be able start-up quickly but will not spend as much to engineer a highly fuel efficient since it will be operated infrequently compared to a base load plant.

Power system dispatchers (also known as "operators") manage the flow of electricity from generation plants over the transmission and distribution lines to the end customer. Depending on the region of the country, dispatchers work for a single utility, an independent system operator (ISO), or a regional transmission organization (RTO). It is the power system dispatcher's job to ensure that, within his physical area of responsibility, the amount of generation necessary to meet fluctuating load is available, either from generation located in that area or imported from outside the area. Dispatchers choose which generation units will supply power at a particular time. Dispatching is often conducted automatically using computers. The dispatcher's choice of plants is faces at least two limitations. One is the level of congestion in the transmission system at different locations; for example, the operator cannot dispatch a plant if the transmission system is congested at the location where that plant would inject its power. Imagine a police dispatcher needing to dispatch a police cruiser to an emergency. If the one cruiser is located at a congested intersection, the dispatcher will send the other. A second limitation is the plant's operating characteristics. A plant's variable operating cost (i.e., the cost of producing an additional watt of power) and its ramp-up time affect how often power system operators will dispatch it.[15]

Each hour, system operators choose plants based on the principles of economic dispatch. Economic dispatch refers to "operating a coordinated system so that the lowest-cost generators are used as much as possible to meet demand, with more expensive generators brought into production as loads increase (and conversely, more expensive generation eliminated from production as load falls)."[16] Of two comparable plants (e.g., with comparable heat rates and ramp-up times), one natural gas-fired and the other coal-fired, the coal plant with the lower variable cost (e.g., due to a lower cost of fuel), would be dispatched before the gas-fired plant during normal operation of a power system, all else equal. Among two plants using the same fuel, the one with the higher efficiency and, hence, lower variable operating cost, would be dispatched first. In addition, plants with engineering characteristics that increase their ramp-up time must be dispatched a few or many hours prior to the anticipated need.

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[15] Ramp-up time refers to the time it takes for a plant to become operational. Some plants can become operational within minutes or even seconds; others take several hours to move from cold status to operating status. As an analogy, compare a car waiting with its engine running to a car that has been sitting in the cold for a month.

[16] U.S. Department of Energy (hereafter cited as DOE), "The Value of Economic Dispatch: A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005," November 7, 2005, p. 9. Document is available at: http://www.oe.energy.gov/DocumentsandMedia/value.pdf.

B. Time to construct

Regulators must be aware of the lead time necessary to allow for the construction of new generation that will be necessary to meet future demand. In this document, "time to construct" is the estimated length of time necessary to construct the plant, excluding any pre-construction regulatory processes. The time to construct begins with the first day of construction and concludes with the first day the unit would be capable of generation if fuel was present.

Construction time also affects the capital requirement of a project because a long time horizon for construction raises the cost of financing the plant. The costs are higher because (a) the generation owner is paying interest on construction loans during the construction process, and (b) lenders tend to charge higher interest on loans associated with long construction periods due to the risk of delays and non-payments.

C. Cost to construct

Building and operating a power plant involves multiple categories of costs: fuel cost, operation and maintenance costs, overnight construction cost, and interest expense.[17] The two largest costs of a power plant are the overnight construction cost and the fuel cost. This report presents approximate values for both categories. The overnight construction cost and fuel cost are not project-specific, meaning that the reader can compare these costs across types of generation.

This report presents, for each technology, the overnight cost, consisting of all material and labor of the main contractor, plus the cost of associated sub-contractors, but excluding interest expenses.[18] We report the cost to construct in dollars per kilowatt

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[17] The following equations show the relationship between cost terms referenced in this report:

Capital cost	= overnight construction cost + interest expenses
Operating cost	= cost of fuel + fixed operation and maintenance + variable operation and maintenance
Variable cost	= variable operation and maintenance + cost of fuel
Total cost	= capital cost + operating cost
Levelized cost	= total cost per MWh, spread out equally over the life of the plant

[18] For estimates of O&M costs, see EIA, *Assumptions Used in the Annual Energy Outlook, 2006*, DOE/EIA-0554(2006), March 2006, Table 38, p. 73. Document is available at: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2006).pdf.

($/kW) of generation using constant 2006 dollars.[19] The term is known as "overnight cost" since it describes what the plant cost would be if it were built and paid for overnight, requiring no time-dependent expenses. The measure does not reflect the total construction cost of a plant since it excludes the interest expenses of financing a specific project. The longer the length of time needed for construction, the greater the difference between the true cost to construct and the overnight cost to construct.[20] To avoid any bias toward projects with long construction periods, a regulator must account for interest expense to arrive at the total construction cost. The figures cited in this report are representative numbers only. Given the dynamic nature of capital costs, regulators evaluating a given project should obtain data that is recent and specific to that project.

Interest rates will vary by the project and by the creditworthiness of the company proposing to build the plant. Another variable affecting fully capitalized cost to construct (i.e., overnight cost plus interest expenses) is each state's policy on the recovery of construction costs during the construction period. Some states prohibit recovery of construction costs until the plant commences operation. Other states allow recovery in the rate base of construction work in progress (CWIP). In the latter states, total construction costs for the owner will be lower since interest expenses will accumulate over a shorter period of time. The cost to consumers from a CWIP allowance depends upon whether the economic return that the consumers forego by paying for the plant before it is completed is greater than the benefit of paying lower interest costs for the plant in the rate base.

Construction costs for a project depend on many factors that vary over time or are specific to the project, including the prices of critical commodities (e.g., concrete and steel), waste disposal fees, and availability of transportation to the site. A second unit on an existing site will usually have lower costs than the first plant; a larger plant will tend to have a lower construction cost per kilowatt of capacity compared to a smaller plant due to economies of scale. State-specific environmental regulations can also require the use of more emissions control equipment, affecting the capacity and efficiency of the unit, and therefore its cost.

This report does not include costs for land, operation and maintenance (O&M), emission allowances, or transmission interconnection costs since their high variability by plant makes comparisons difficult at a generalized level across different types of generation technologies.

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[19] The authors converted nominal prices to 2006 dollars using the U.S. Department of Commerce, Bureau of Economic Analysis' GDPDEF index, the GDP implicit price deflator, available at http://research.stlouisfed.org/fred2/series/GDPDEF?&cid=18.

[20] See John M. Marshall and Peter Navarro, "Costs of Nuclear Plant Construction: theory and new evidence," *RAND Journal of Economics*, Vol. 22, No. 1, (Spring) 1991.

D. Operational life

Operational life is the amount of time that a plant is mechanically able to provide service, inclusive of any refurbishment or re-licensing. A plant typically requires more maintenance and experiences more forced outages as it ages, resulting in a lower availability factor. For each technology, the report presents the typical operational life of a plant. In addition, Appendix E presents the average age of generation units currently in service, grouped by state and type of technology, to provide a point of reference for considering the expected lifespan of plants.

Operational life is a physical concept (i.e., how long with the plant live?); it differs from book life, which is an accounting concept. (i.e., over what period of time should the owner recover its costs?).

E. Fuel costs

A generation technology that is not cost competitive at one point in time improves its competitiveness if the price for fuel used by that technology declines relative to other technologies using other fuels.[21]

This report first presents the cost of fuel in dollars per million British thermal units ($/MMBtu). This presentation facilitates comparison across fuel sources; e.g., does it cost more to get a unit of energy from coal or gas? The cost of purchasing fuel is only one variable in the calculation of a plant's total fuel cost. Total cost for a specific generation unit depends also on the unit's heat rate. The higher the heat rate, the more units of fuel is necessary to produce a given amount of energy; thus the higher the heat rate, the lower the plant's efficiency. For a particular generator, therefore, the total cost of fuel per kWh generated generation equals the product of the plant's heat rate and the price of the fuel.[22] To approximate each technology's fuel cost per kWh of output, this report uses heat rates that EIA has found typical of new units of a given type of technology.[23]

Generation technologies differ in the degree that fuel plays in its total operating cost. For example, approximately 75% of the production cost of electricity for a natural

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[21] Relative cost of fuel is only one factor that can affect the relative economic merit of technologies. Emission-control policies are an example of another factor.

[22] For a generation plant that uses fuel with a price of "x" dollars per million Btu and the plant burns the fuel with a heat rate of "y" Btu per kWh, the plant's price of fuel per kWh of electricity output would equal [$\$x$/MMBtu] · [($y$Btu($10^{-6}$))/kWh].

[23] EIA, *Assumptions Used in the Annual Energy Outlook, 2006*, Table 38.

gas combined-cycle plant is due to fuel cost, compared to 30% for a typical coal-fired plant.[24]

Key terms

British thermal unit (Btu): The amount of energy required to raise one pound of water by one degree Fahrenheit, if the water is at its highest density at about 39 degrees Fahrenheit.

Kilowatt-hour (kWh): The amount of energy produced when 1,000 watts of electrical power is expended for one hour. An average U.S. household uses about 11,000 kWh of electricity in a year.

Capacity: The maximum output that generating equipment can supply to the power system under ambient conditions, expressed in Megawatts (MW). The actual capacity of a given plant will usually be less than its installed capacity.

Installed capacity (or nameplate capacity): The maximum output of a generator under controlled conditions specified by the manufacturer, expressed in MW.[25]

F. Fuel dependability

A generator can operate only if the required fuel is available. The report describes fuel dependability for each generation type, highlighting strengths and vulnerabilities.

The presence of fuel transportation networks affects the suitability of a particular generation technology for a particular locale. Power plants sited near existing fuel supply networks are more economical, all else equal. Competition for a given fuel from other sectors of the economy can reduce the supply of that fuel available for generation. Natural gas, for example, also serves as a heating fuel and a feedstock for chemical manufacturing.

To avoid depending on a single fuel type, some plants (primarily natural gas units) have the capability to burn multiple fuels.[26] An ability to use multiple fuels is

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[24] George Booras and Neville Holt, "Pulverized Coal and IGCC Cost and Performance Estimates," presented at Gasification Technologies 2004 in Washington, D.C., October 3-6, 2004.

[25] Unless otherwise noted, these definitions are adapted from the EIA *Glossary*.

valuable where: (1) it is expensive to store one of the fuels (e.g., natural gas); (2) the delivery infrastructure lacks redundancy; or (3) capacity margins (i.e., the surplus of capacity over peak load, necessary to ensure continued operation if one or more generators or transmission lines go out of service or load grows beyond expectations) are low.

G. Plant dependability

The report uses a generation technology's availability factor as its measure of the dependability of the plant. Availability factor is the percentage of hours in a given period that a plant is physically available to produce power. The availability factor measures whether a plant is able to produce power, not whether it actually produces power. (The measure for actual production relative to total hours is the capacity factor; see section II.A for a full definition.) The availability factor is always higher than the capacity factor for a given plant. The more hours in a year that a plant is out of service (e.g., for scheduled or unscheduled maintenance), the lower is its availability factor.

Low dependability causes several costs. First, unplanned outages harm a plant owner's revenue stream. Second, shutdowns require utilities and other service providers with sales obligations to customers to pay penalties for contract breach, or purchase higher cost power in the spot market. Third, unplanned outages in one generator can strain other components of the interconnected system, if capacity margins are inadequate.

H. Maturity of the technology

Maturity of the technology refers to the degree to which a given technology is proven commercially. The criterion measures whether the generation type is:

(1) In development: One of the first examples of the technology, yet to be installed or installed in a very few locations for testing purposes, with insufficient long-term data to make reliable and detailed analysis possible.

(2) Newly operational: Few installations, with insufficient long-term data to make reliable and detailed analysis possible;

(3) Mature: Many installations, with sufficient data to make reliable and detailed analysis possible; or

(4) Fully mature: Many installations, some past or nearing operational life expectancy, with sufficient data to make reliable analysis possible; possibly no longer an efficient or appropriate technology.

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[26] Multi-fuel capability is a consideration primarily for natural gas-fired plants to enable the use of both natural gas and distillate fuel. Coal-fired plants are also sometimes designed to burn biomass at the same time (i.e., co-fire) or can be switched to operate fully on gas liquid fuels.

The measure of maturity is subjective. This report describes the generally accepted industry view on each generation type, based on the authors' examination of technical analyses. Maturity matters, because a proven technology offers less risk to investors and more certainty to regulators. As new technologies gain a market beachhead and begin commercial operation, engineers gather operational data useful in lowering cost and improving performance.

I. Externalities

An externality exists when costs (or benefits) associated with a commercial transaction are borne (or enjoyed) by a non-party to that transaction.[27] If a person plants flowers in his or her open yard, there is a positive externality benefiting neighbors and passersby, free of charge. If a new power plant built for (and paid for) by a specified customer group provides electric power to that group, but also improves reliability of the regional transmission grid, the region's non-paying residents receive a positive externality. And if these same non-paying customers also breathe in the pollutants from the plant, yet receive no compensation for their suffering, they incur a negative externality.[28] In each case, non-parties to the transaction receive benefits or incur costs. Other examples of negative externalities include the vistas lost due to wind farm installation in a scenic area, reduced public enjoyment of rivers that are dammed for a hydropower project, or the reduction in property values arising from proximity to a large plant causing traffic, pollution, or risk of explosion.

In each example, the total cost to society of a power plant is not captured in the dollar cost that is paid by the owner to build and operate the plant. Therefore, more power would be produced by the plant, or at a lower price, or with fewer pollution controls than what would be optimal if everyone's full costs and benefits were taken into account. Neither the economic marketplace, nor the courts, nor regulatory agencies are able to evaluate all societal costs of a given power plant. Regulatory statutes usually command regulators to use their best judgment of what serves the public interest when they evaluate the sources of power; these statutes differ in terms of what elements of the public interest must receive consideration. This report highlights the most prominent environmental, social, or security externalities for each type of generation technology.

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[27] See James M. Buchanan and William C. Stubblebine, "Externality," *Economica*, Vol. 29, November 1962, pp. 371-84; and Ronald M. Coase, "The Problem of Social Costs," *Journal of Law and Economics*, Vol. 3, October 1960, pp. 1-44.

[28] Emission taxes and trading plans (also known as "cap-and-trade"), such as the programs created under Title IV of the 1990 Clean Air Act or the U.S. Environmental Protection Agency's Clean Air Interstrate Rules (CAIR) and Clean Air Mercury Rules (CAMR) of 2005, are efforts to attach a monetary cost to emissions and assign that expense to the transacting parties so that the emissions are no longer fully external costs.

III. Fourteen generation technologies: What are their characteristics?

This section describes fourteen generation technologies in terms of the nine criteria for comparison described in the previous section. The report covers the first eight technologies in more detail because they are likely to constitute the bulk of new generation coming before commissions and more information is available about them. The fourteen generation technologies that the report covers are:

1. Combined cycle gas turbines
2. Combustion gas turbines
3. Pulverized coal generation
4. Fluidized bed combustion
5. Integrated gasification combined cycle (IGCC) generation
6. Nuclear generation
7. Wind generation
8. Pumped-storage hydropower
9. Photovoltaic
10. Concentrated solar power
11. Biomass power
12. Geothermal power
13. Barrage and ocean current generation
14. Fuel cells

Of the fourteen technologies, twelve of them rely on a generator that uses mechanical energy to move an electrically conductive material through a magnetic field. The movement through that field, under the laws of electromagnetism, translates the mechanical energy into electrical energy. Whether the source of mechanical motion is (a) blowing wind, (b) steam created by the burning of fossil fuels or a nuclear reaction, or (c) the rush of water across a dam, most generators operate by spinning the blades of a turbine to create motion within a magnetic field.

Certain other technologies rely on different processes, such as the effect of light energy falling on photovoltaic materials or the conversion of chemical potential energy to electricity in a fuel cell. The specific operation of alternative power plants will be described in more detail in the technology-specific sections below. Appendix D presents diagrams of each technology. Table 1, immediately below, presents a summary of the report's information about the generation technologies.

Table 1: Summary of generation technologies (continued on next page)

	Load service function	Time to construct	Cost to construct (Overnight cost: 2006$/kW)		Operating life	Fuel cost (2006 $/MWh)	Fuel depend-ability	Plant depend-ability (availability factor)	Maturity	Externality: CO2 emissions[2] (metric tons per MWh by 2010-2015) [Source: EPRI[1]]
			Source: EIA, others	Source: EPRI[1]						
Combined cycle	Baseload, Intermediate Peak	3-5 years	$565-$620	$500	25-30 years	$50.37	Medium	90%	Mature	.39
Combustion gas	Peak	Less than 1 year	$411-$431	Not available	25-30 years	$75.60	Medium	95%	Mature	Not available
Pulverized coal	Baseload	3-4 years	$1,235	$1,350 ($2,270 with CO2 capture)[3]	30-50 years	$14.02	High	72-90%	Mature	.80 for supercritical plant without C02 capture (.052 with capture)
Fluidized bed	Baseload	3-4 years	$1,327	$1,480	30 years	$15.08	High	90%	In development	.87
IGCC	Baseload	3-4 years	$1,431	$1,490 ($1,920 with CO2 capture)[3]	Not available	$13.17	High	88%	Newly operational	.86 without capture .156 with capture
Nuclear	Baseload	9 years	$1,849	$1,510-$1840	40-60 years	$4.89	Medium	90-97%	Mature	None
Wind	Intermediate	3 years	$1,157	$1,190	20 years	$0	Low	98%	Mature	None
Pumped-storage hydro	Peak	4-5 years	$2,379	Not available	50-60 years	Existent cost of electricity	High	90-95%	Mature	Not applicable

Table 1: Summary of generation technologies (continued from previous page)

	Load service function	Time to construct	Cost to construct (Overnight cost: 2006$/kW)		Operating life	Fuel cost (2006 $/MWh)	Fuel depend-ability	Plant depend-ability (availability factor)	Maturity	Externality: CO2 emissions[2] (metric tons per MWh by 2010-2015) [Source: EPRI[1]]
			Source: EIA, others	Source: EPRI[1]						
Photovoltaic	Intermediate Peak	2 years	$4,222	Not available	20-40 years	$0	Low	99%	Mature	None
Concentrated solar	Intermediate	3 years	$2,745	$3,410	30 years	$0	Low	Not available	Mature	None
Biomass	Baseload	4 years	$1,759	$2,160	Not available	$1.55-$49.19	High	90%	Mature	.10
Geothermal	Baseload	4 years	$2,227 binary	$2,270 binary; $1,400 flash	30 years	$0	High	92%	Mature	None
Barrage and Ocean current	Intermediate	Not available	Not available	Not available	Not available	$0	High	Not available	In development	None
Fuel cells	Baseload, Intermediate Peak	3 years	$4,015	$1,620 - $2,160 (by 2020)	Not available	Not available	Not available	Not available	In development	Not available

Notes on Table 1:

1. Comparison data on overnight cost to construct are courtesy of EPRI, from their 2006 presentation, "Generation Options Under a Carbon-Constrained Future." Costs are reported in 2006 dollars, but represent EPRI's outlook for 2010-2015. All fossil units assume 600 MW capacities. NGCC unit based on GE7F machine or equivalent. Binary geothermal unit includes reservoir development and associated cost of fuel supply; flash unit assumes re-injection of fluid in closed loop operation. Biomass CO_2 emissions assumes 90% of emissions are absorbed by biomass crop growth cycle.

2. See Appendix B for a discussion of CO_2 capture and storage and data on its effects on the cost to produce electricity.

3. EPRI's cost for CO_2 capture cost does not include the cost of CO_2 storage.

A. Fossil-fueled generation technologies

1. Combined cycle gas turbines

Overview: Since the early 1990s, gas-fired power plants have comprised over 90 percent of new generation capacity in the United States. Several reasons account for this happening, including new federal environmental regulations and the low price of natural gas that prevailed until 2000. Even with the continuation of high natural gas prices, EIA projections call for future construction of gas-fired facilities. Factors explaining the attractiveness of gas-fired plants include their low environmental effects relative to other fossil fuel plants, their modularity (i.e., the capability of gas-fired plants to alter their capacity over time at low cost in response to changed economic conditions), and low capital costs compared to most other generation technologies.[29] During 2005, the net generation of electricity from all gas-fired facilities approximated the generation from nuclear power plants.[30]

Gas-fired generating technologies include electric steam plants, combined cycle gas turbines (CCGTs), combustion gas turbine generators (CGTs), reciprocating engine generators, each covered in this report. CCGTs and CGTs are the gas-fired technologies under closest review in planning by electric utilities and non-utility generators. During the past fifteen years, CCGTs in particular have displaced old steam gas facilities with much lower energy efficiencies.

CCGTs use both gas and steam-turbine thermodynamic cycles to generate electricity. A CCGT uses the waste heat from the gas turbine to produce steam that, in turn, generates additional electricity by turning the blades within a steam turbine. Combining two cycles in the generation of electricity improves overall heating efficiency (i.e., the ratio of energy input to kW-hours of generated electricity) by as much as 50 percent over the heating efficiency of combustion gas turbines. The capacity of a new CCGT plant (employing two gas turbines and 1 steam turbine) is typically in the range of 500-600MW.[31] Section III.E of this report discusses integrated gasification combined-

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[29] See EIA, *Annual Energy Outlook 2006*, p. 85. In its long-term projections, the EIA projects 130 GW of new gas-fired capacity between 2005 and 2030, which represents about 85 percent of new coal-fired capacity for the same period.

[30] Ibid. Nuclear and gas-fired plants each produced about 19 percent of the total net electricity generation in 2005.

[31] For an overview of the CCGT technology, see Northwest Power Planning Council (hereafter cited as NPPC), "Natural Gas Combined-Cycle Gas Turbine Power Plants," internal paper, August 8, 2002. Report is available at: http://www.westgov.org/wieb/electric/Transmission%20Protocol/SSG-WI/pnw_5pp_02.pdf.

cycle (IGCC) power plants that fire the finished synthetic gas in a natural gas combined-cycle power plant

Load-service function: Most new gas-fired generating facilities built since the early 1990s are CCGTs. These facilities can provide baseload, intermediate or peak load services, or a combination of them. How much baseload electricity a CCGT provides depends largely on the price of natural gas, as the utilization of this technology depends upon its position in the dispatch order and, thus, its operating cost. Compared with other baseload technologies, CCGTs have high variable costs (mainly fuel costs) that cause their capacity factors to fluctuate more widely from period to period because of economic dispatch rules.

For new plants, some studies estimated the capacity factor for new CCGTs to average between 80-90 percent.[32] Over the past few years, CCGTs have operated at much lower levels – on the order of 30-40 percent – because of natural gas prices rising above the $6-$7 per thousand cubic feet (Mcf) range. An 80-90 percent capacity factor assumes a drop in natural gas prices from current levels (about $6 per Mcf at the time of this writing) that would allow a CCGT to operate mostly to serve baseload.

Time to construct: The typical construction time for a CCGT is approximately two years, as compared to the 3-5 year range for other baseload generating facilities like coal-fired and nuclear power.[33]

Cost to construct: The overnight construction costs of new CCGTs range from $565-$620 per kW.[34]

Operational life: The service life of CCGT is in the range of 25-30 years.[35]

Fuel costs: Fuel costs represent about 75 percent of the total cost (i.e., the sum of operating and capital costs) of CCGTs. In recent years with the high price of natural gas (gas prices this century are about three times their average level in the 1990s), CCGTs have operated less as other facilities with lower running costs, especially coal-fired plants, have replaced them in the dispatching order. Assuming that the price of natural

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[32] See California Energy Commission, *Comparative Cost of California Central Station Electricity Generation Technologies*, prepared for Docket 02-IEP-01, June 5, 2003, C-2; and Northwest Power and Conservation Council (hereafter cited as NPCC), *The Fifth Northwest Electric Power and Conservation Plan*, May 2005, p. I-29, report available at: http://www.nwcouncil.org/energy/powerplan/plan/Default.htm.

[33] Ibid.

[34] See EIA, *Assumptions to the Annual Energy Outlook, 2006,* Table 38, p. 73.

[35] Ibid.

gas equals $7 per Mcf and the heat rate for a CCGT is 7,196 Btu per kWh, the running cost of the CCGT (excluding other variable costs) would be about $0.05 per kWh, or $50.37 per Megawatt-hour (MWh).[36] This figure compares unfavorably with the running cost of other baseload plants. EPRI studies have shown that when gas prices exceed $6 per Mcf, new CCGTs lose their competitiveness with other technologies, particularly pulverized coal plants.[37] The volatility of gas prices has also made CCGTs less economically attractive. During the years 1997-2005, the average price of natural gas to power generators fluctuated between $2.40 per Mcf and $8.45 per Mcf, with pronounced volatility beginning this century.[38] To reduce the adverse consequences of gas-price volatility on cash flow and profits, some generators have locked in gas prices through contracting or hedging.

Fuel dependability: Fuel dependability has emerged as a problem for some CCGTs, notably for units located in pipeline-constrained areas such as New England and Florida. In New England, for example, most gas-fired generators find it uneconomical to have firm contracts with pipelines, making the generators vulnerable to the risk of unavailable pipeline capacity during extreme winter peak periods.

Dependability of the plant: CCGTs have high availability factors, with new facilities having a combined scheduled and forced outage rate of less than ten percent.[39] Their dependability has made them profitable when dispatched as baseload power in organized wholesale electricity markets.

Maturity of the technology: CCGTs represent a mature technology that has been in place for almost twenty years and that has experienced minimal operational problems in electricity-generation and other industrial applications. Heat rates for new CCGT facilities are likely to continue to improve in the future.

Externalities: CCGTs emit fewer air pollutants relative to other fossil-fuel facilities. CCGTs emit about half the CO_2 per MWh of a pulverized coal plant: 0.4 tons per MWh versus 0.8 tons per MWh.[40] If the federal government or individual states

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[36] See EIA, *Assumptions to the Annual Energy Outlook, 2006,* Table 38, p. 73.

[37] See Steve Specker, Electric Power Research Institute (hereafter cited as EPRI) "Generation Technologies in a Carbon-Constrained World," presented at RFF Policy Leadership Forum, Washington D.C., March 30, 2006. See also EPRI, "Generation Technologies for a Carbon-Constrained World," *EPRI Journal*, Summer 2006, pp. 22-39.

[38] See EIA, "Natural Gas Navigator," software program available at: tonto.eia.doe.gov/dnav/ng/hist/n3045us3a.htm.

[39] See NPPC, "Natural Gas Combined-Cycle Gas Turbine Power Plants."

[40] See Steve Specker, EPRI, "Generation Technologies in a Carbon-Constrained World"; and NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, p. I-34.

implement carbon-constraining regulations, the economic affect will be the highest on coal-facilities, with a lesser effect on CCGTs, and the least effect on renewable-energy and nuclear technologies.

CCGTs occupy about one-tenth the space of nuclear and a pulverized super-critical coal plants. This fact partially explains the low level of public opposition to CCGTs relative to other baseload technologies. Nevertheless, some local concerns have occurred, especially in the western states, over water consumption by a CCGT.[41] One source states that a 500 MW CCGT using the most common cooling method (i.e., recirculating wet-cooling) would use 2.1-2.6 million gallons of water per day.[42] While not a direct effect of a CCGT plant, the process of exploring, drilling, storing and transporting natural gas imposes land-use, ecological and aesthetic problems.

The siting and building of CCGTs have confronted little public opposition with the exception of some facilities contested for their consumption of water for plant condenser cooling. In the future, dry (or closed-cycle) cooling can help to reduce water consumption, although it has the potential to increase cost and reduce efficiency.

2. Combustion gas turbines

Overview: A combustion gas turbine, also known as a simple cycle gas turbine, is a rotary engine that compresses gas and air, combusts the mixture, and extracts energy by allowing the combusted gas to expand through rotating turbine blades. This technology finds use in transportation engines and heavy-duty industrial machines. Some CGTs are based on turbines designed for aircraft and are often referred to as "aero" or "aero-derivative" designs. The installed capacity of CGTs for electric generation ranges from less than one MW to approximately 200 MW, with smaller plants tending to provide localized distributed generation.[43]

Load-service function: CGTs operate mainly as peaking facilities. They can provide emergency and other ancillary services in addition to back-up power for wind and hydroelectric facilities. In the Pacific Northwest, for example, CGTs operate to back up the non-firm (i.e., not guaranteed for delivery) output of hydroelectric plants, especially during years with low rainfall and water levels.[44] CGTs are especially valuable in meeting peak demands for electricity because of their ability to provide

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[41] See NPPC, "Natural Gas Combined-Cycle Gas Turbine Power Plants."

[42] John S. Maulbetsch and Michael N. DiFillipino, "Cost and Value of Water Use at Combined-cycle Power Plants," April 2006, prepared for the California Energy Commission, CEC-500-2006-034, p. 7.

[43] Ibid.

[44] Ibid., pp. I-20 and I-21.

needed power within minutes. CGTs have a high ramp rate (i.e., the rate of change of plant output), so they are able to operate at full capacity in under an hour after a start-up notice, much more quickly than the hours or days needed for some coal and nuclear plants. Mainly serving peak demands, CGTs typically have a capacity factor in the range of 10-15 percent.

Time to construct: The construction period for CGTs varies from several weeks to as much as one year for larger facilities.

Cost to construct: In case of CGTs with an installed capacity of over 100 MW, estimates of overnight construction costs are in the $411-$431 per kW range.[45] Overnight costs per kW for smaller CGTs can rise to much higher levels as a consequence of economies of scale in construction.

Operational life: Service lives for CGTs range from 25 to 30 years depending in part on their load factors.

Fuel costs: Volatile natural gas prices impose a risk on CGTs generators and their customers. Compared to a CCGT, the levelized cost (i.e., the combined operating and capital costs per MWh, spread out equally over the life of the plant) of a 100-MW CGT plant operating at a ten percent capacity factor is approximately three times higher.[46] The higher cost for CGTs is largely the result of a higher heat rate and lower capacity utilization. The much higher levelized cost for CGTs does not detract from their potential economic value in meeting peak demand and in providing ancillary services. Higher gas prices also have a greater effect on the operating costs of CGTs compared with CCGTs because of their higher heat rates (approximately 40 percent higher, in the range of 9,500-10,000 Btu per kWh generated compared to a heat rate of 6,700-7,200 Btu per kWh for a CCGT). As an illustration, for every dollar increase in the price of natural gas, the cost of power from a CGT, assuming a heat rate of 10,842 Btu per kWh, would rise by $0.01 per kWh, or $10.80 per MWh; for a CCGT with a heat rate of 7,196 Btu per kWh, the cost of power would increase by a lesser $0.007 per kWh, or $7.19 per MWh.

Fuel dependability: As with CCGTs, dependability of natural gas supply delivery poses a challenge for CGTs because of potential localized pipeline bottlenecks, especially in New England and Florida.

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[45] See EIA, *Assumptions for the Annual Energy Outlook 2006*, p. 85.

[46] See California Energy Commission, *Comparative Cost of California Central Station Electricity Generation Technologies*, p.3

Dependability of the plant: CGTs are highly reliable, with availability factors of around 95 percent.[47] Similar to other gas-fired technologies, CGTs face the risk of the unavailability of delivered gas when needed, especially if the operator has non-firm pipeline capacity leading to potential shortfalls during "bottleneck" episodes.

Maturity of the technology: CGTs are a mature technology with a record of reliable performance over the last four decades.

Externalities: Due to their higher heat rates compared with CCGTs, CGTs emit more nitrogen oxide and carbon dioxide into the air per unit of electricity generated. For example, CGTs produce over 40 percent more CO_2 per kWh generated than CCGTs.[48] CGTs are smaller than the other power plants using fossil fuels, so their footprint on the local environment is less visible. Similar to CCGTs, natural gas drilling, storage, and transportation have a negative effect on land use, ecological conditions, and aesthetics. The footprint of a facility is more evident when it includes fuel oil storage and back-up capability for switching between gas and oil.

3. Pulverized coal generation

Overview: Currently, pulverized coal (PC) generation plants are the largest segment of the nation's generation fuel-mix, accounting for approximately 50% of the nation's energy. According to a report by the U.S. Department of Energy's National Energy Technology Laboratory (NETL), more than 50% of the planned new generation capacity plant additions through the year 2030 are likely to be coal-fired.[49]

In a PC generation facility the coal is *pulverized* (or ground) into a fine powder, mixed with air, and then blown – like a gas – into a boiler furnace. In the furnace, the PC-air mixture burns in a controlled manner somewhat similar to natural gas. However, the PC-air mixture is not as uniform as natural gas and, therefore, requires a more sophisticated combustion control process. The heat generated by the burning PC-air mixture is used to generate steam. The steam is used to drive the generator turbines which ultimately produce the electricity. The actual design of a PC generation plant varies according to the type and quality of coal, and the intended operating steam pressure and temperature.

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[47] See California Energy Commission, *Comparative Cost of California Central Station Electricity Generation Technologies*, p. D-1; and NPCC *The Fifth Northwest Electric Power and Conservation Plan*, Table 5-4.

[48] See NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, pp. I-27 and I-34.

[49] See DOE, National Energy Technology Laboratory (hereafter cited as NETL), *Tracking New Coal-Fired Power Plants – Coal's Resurgence in Electric Power Generation,* September 29, 2006.

Coal is typically divided into four major types with differing carbon and moisture contents. Generally, the coal with the highest carbon and lowest moisture contents has the highest heat value and is the cleanest to burn. In order of most to least carbon content, the four types (or ranks) of coal are anthracite, bituminous coal, subbituminous coal, and lignite.

Anthracite or "hard coal" generally has a carbon content between 86-95 percent, a heat value between 22 and 28 MMBtu per ton, and a moisture content of less than 15 percent. Anthracite is high in carbon, low in sulfur, very black and shiny.

Bituminous coal is the most abundant coal in the United States. It is softer than anthracite and has a carbon content between 45 – 86 percent, a heat value of between 21 and 30 MMBtu/ton, and a moisture content of 20 percent or less. It is often noted by having both shiny and matte portions.

Subbituminous coal is also called black lignite. It has a carbon content of 35-45 percent, a heat value between 17 and 18 MMBtu/ton, a moisture content of 20-30 percent, and it features a matte surface. Subbituminous coal is used for generating electricity and space heating.

Lignite or "brown coal" is, geologically speaking, the youngest type of coal. It has a carbon content of 25-35 percent, a heat value between 9 and 17 MMBtu/ton, and a moisture content up to 45 percent. Lignite is brown to black in color, has a matte surface, and tends to crumble (like soil).[50]

Plants designed to burn coal with higher moisture, sulfur, and/or ash contents require more internal boiler area for heat transfer than a PC plant designed to burn only low sulfur, low moisture, high-carbon coals.

The steam systems used in the current generation of PC plants are generally classified as subcritical (or conventional), supercritical, or ultra-supercritical.[51] The classification is based on the operating steam pressure and temperature. The exact specifications for the classification vary within the worldwide power generation industry. In the United States subcritical plants operate at a pressure of 2400 pounds per square

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[50] See EIA, *Glossary*.

[51] The critical point of water is the pressure and temperature points at which water ceases to be a liquid. Supercritical steam is a steam which is under pressure above its critical temperatures. Under supercritical conditions the water is technically neither a gas or a liquid, but a fluid with a unique combination of the properties of gas and liquid. A supercritical fluid can diffuse through solids and dissolve substances.

The term "advanced supercritical" is sometimes used instead of "ultra-supercritical."

inch (psi) and a maximum temperature of 1050°F. A supercritical unit would have similar temperatures but pressures of 3500 psi or more. Ultra-supercritical units are variably defined, but commonly would have operating pressures of 4500 psi and temperatures of 1100°F or higher.

As the temperature and pressure of the steam at the generator turbine inlet increases, so does the efficiency of the power steam cycle. As the efficiency of the steam cycle is increased, the amount of fuel necessary to produce the same amount of energy is reduced, thereby reducing plant emissions.

The decision to build either a subcritical or supercritical PC plant depends on several factors including, but not limited to, the cost of coal, environment requirements, capital costs of constructions, and intended load use. For example, high fuel costs and high environmental requirement costs can make the higher operating efficiency of a supercritical plant sufficient to offset (or surpass) the higher capital cost of construction.

Load-service function: PC-fired generation units are almost always operated for baseload capacity. Subcritical PC units can also be used for load-following or cycling service as the subcritical units can generally operate with better efficiency at reduced output levels than similarly sized supercritical units.

Currently operating PC plants have capacities ranging from 100 MW to 1300 MW. The average nameplate capacity of a PC generation unit installed in the United State in the in the past 20 years is just over 300 MW.[52]

Time to construct: EIA data, actual utility construction records, and utilities estimates show a range from 36-48 months for construction of a new PC power plant, assuming no construction delays.

Cost to construct: An average cost to construct is approximately $1235/kW. [53] EIA forecasts that the cost in 2010 will be $1,308/kW and by 2020 it will be $1,271/kW.[54] The advanced materials and systems necessary for a supercritical plant make the cost to construct generally higher than that of a similarly sized subcritical unit.

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[52] See EIA, "Existing Generating Units in the United States, 2004," *Form EIA-860 Database*. Database available at: http://www.eia.doe.gov/cneaf/electricity/page/capacity/existingunits2004.xls. Estimate is derived from EIA data; the estimate considers utility generators that use only coal for the fuel source.

[53] See EIA, *Electric Power Annual, 2005*. The average is calculated from a review data from EIA's *Annual Energy Outlook 2006* and a number of specific utility construction estimates.

[54] See EIA, *Assumptions to the Annual Energy Outlook 2006,* release, Table 48, p. 85.

Operational life: Allowing for upgrades and partial replacement, as of 2005 there were more than 500 currently operating coal-fired utility generation units that had been in operation for more than 30 years. As of 2005, there were 346 coal-fired units in service in the U.S. that had been in operation for over 50 years.[55]

Fuel costs: The sulfur content of coal affects its price since higher sulfur coal requires correspondingly higher costs for the purchase of state or federally-mandated allowances for the emission of sulfur dioxide (SO2). The proximity of the plant to the type of coal required is a key factor in the cost of fuel since transporting coal over long distances is expensive. The 2005 national average raw fuel cost for PC-fired generation was $1.54/MMBtu (in 2005 dollars), a 13.2% increase over 2004.[56] Assuming a heat exchange rate of 8,844 Btu/kWh, the cost of fuel per kWh of generation is $0.014, or $14.02/MWh (in 2006 dollars).[57]

Some portion of the increase in coal prices in 2005 was likely attributable to a extraordinary number of specific events that affected the 2005 coal production cycle.[58] The average 2001-2004 annual increase in coal prices was just over 3%. Prices declined annually between 1994 and 2000.

It is likely that coal prices will continue to increase. The demand for coal continues to increase as worldwide utilization increases. In the United States alone there are, at least, 50 new coal-fired generators planned additions in the next four years.[59]

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[55] Data are from EIA, "Annual Electric Generator Report, 2005," *Form EIA-860 Database*, released October 2006. Database available at: http://www.eia.doe.gov/cneaf/electricity/page/eia860.html. Data represents all operating, grid-connected plants using coal as their primary fuel source that were built in 1956 or earlier. See Appendix E for additional information on plant ages.

[56] See EIA, *Annual Energy Outlook 2006, Revised Report November 9, 2006,* Table 4.5 "Receipts, Average Cost, and Quality of Fossil Fuels for the Electric Power Industry, 1994 through 2005;" and EIA, "Coal Production in the United States – An Historical Overview, October 2006."

[57] See EIA, *Assumptions to the Annual Energy Outlook, 2006,* Table 38.

[58] Included in these events, among others, were three major hurricanes, other regional flooding, and low levels on some waterways that disrupted supply transportation routes.

[59] See DOE, NETL, *Tracking New Coal-Fired Power Plants – Coal's Resurgence in Electric Power Generation,* September 29, 2006.

Fuel dependability: The dependability of the coal supply appears favorable. According to EIA's *Annual Energy Outlook 2006*, coal production "remained near 1,100 million tons annually since 1996" and will increase steadily through 2030.[60] Mining production in the United States and worldwide continues to increase.[61]

Dependability of the plant: The average capacity factor for coal power plants in the United States in 2005 was 72 percent.[62] The availability factor for both subcritical and supercritical PC power plants is between 80-90%.[63] Supercritical plants generally have a higher availability factor than the subcritical plants.

Maturity of the technology: Coal-fired power plants use mature technology. As previously mentioned, 346 plants operating in 2005 were installed more than 50 years ago.[64] Even supercritical PC plant designs are highly proven technology with installations dating back to 1957.[65]

The ultra-supercritical plants are not yet common, but are growing in numbers. China recently launched that nation's first ultra-supercritical plant.[66] In August 2006, AEP announced a proposed 600 MW ultra-supercritical plant to be built near Texarkana, Arkansas.[67]

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[60] See EIA, *Annual Energy Outlook 2006 with Projections to 2030,* February 2006, p.98.

[61] Ibid.

[62] Howard Gruenspecht, Deputy Administrator Energy Information Administration, U.S. Department of Energy, statement before the U.S. Senate Committee on Energy and Natural Resources, U.S. Senate, May 25, 2006.

[63] Estimates derived from an examination of multiple utility reports of projections and/or actual availability factors. See Tennessee Valley Authority (hereafter TVA), *Power Facts*, document available at http://www.tva.com/power/powerfacts.htm; and Associated Electric Cooperative Inc., *2005 Annual Report,* p. 3.

[64] See EIA, "Existing Generating Units in the United States by State, Company and Plant 2004," *Annual Electric Generator Report, 2005: Form EIA-860 Database.* Data available at http://www.eia.doe.gov/cneaf/electricity/page/eia860.html

[65] Philo Unit 6 in Ohio operated from 1957 to 1975.

[66] Huaneng Yuhuan Power Plant in China's Zhejiang Province announced the launch of the first 1000MW unit of a multi-unit ultra-supercritical generation facility.

[67] See American Electric Power (AEP), press release, August 9, 2006, "SWEPCO announces Hempstead County as site for new base load generation power plant."

Externalities: The combustion of coal creates several byproducts damaging to the environment, including SO_2, nitrogen oxides (NO_x), carbon dioxide (CO_2), mercury and other trace metals, ash, and volatile organic compounds (VOC). These atmospheric emissions and other waste products are factors in the actual PC plant design and the associated type of coal used as fuel. In the United States, to meet federal Clean Air Act requirements many of the PC plants originally designed to burn higher sulfur coals have been converted to enable the burning of lower sulfur coals. These environmental retrofits have high capital costs, and they can also reduce the available capacity of the plants.[68] However, according to an August 2006 report from EPRI, recent improvements in post-combustion CO_2 capture technology can make a supercritical PC plant burning bituminous or sub-bituminous coal and using post-combustion CO_2 capture "competitive with IGCC using pre-combustion capture."[69] Historically, much of the environmental concern was directed at CO_2, NO_x, and SO_2. Increasing concerns about the harmful health and environmental effects of mercury and ash are present in the public debate over coal-fired power plants.

Water use is another potential negative environmental externality for PC plants. A supercritical PC plant uses an average of 1042 gallons of water per MWh of generation.[70] While much of the water is ultimately returned to the source, the temperature and purity of the wastewater are issues. Some of the wastewater being returned to the source may contain trace-levels of metals (including arsenic, copper, mercury, and selenium), ammonia, and other chemicals.[71] The wastewater may be at a higher temperature than the source water into which it is mixing. Wastewater pollutants and thermal effects can have an impact the quality of the source water and on the aquatic plant and animals of the source water. The construction of a new PC plant, whether subcritical or supercritical, is likely to face community opposition. A PC power plant, the transmission switching stations, power lines, associated facilities and other appurtenances and can occupy 500 acres or more. The perceptions of aesthetic and environmental impacts are typically the most significant topics of opposition. The

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[68] Systems such as flue gas desulphurization (FGD) and selective catalytic reduction (SCR) require power to operate and therefore draw power ("auxiliary power") from the generation unit. In combination the two systems may reduce available capacity by 4%.

[69] John Wheeldon, George Booras, and Neville Holt, *Post-Combustion CO_2 Capture from Pulverized Coal Plants*, Electric Power Research Institute, Palo Alto, California, August 2006.

[70] See NETL, *Power Plant Water Usage and Loss Study*, August 2005.

[71] NETL, Office of Fossil Energy, *Program Facts,* "Innovative Approaches and Technologies for Improved Power Plant Water Management", January 2004.

system of coal delivery (rail or barges) also raises noise concerns if the facility is within earshot of a residential area.

4. Fluidized bed combustion

Overview: Fluidized beds suspend solid fuels on upward blowing jets of air during the combustion process. This process results in a mix of gas and solids. This mix, which resembles a turbulent fluid, provides for efficient chemical reactions and heat transfer. Emissions of SO_x and NO_x are reduced by limiting combustion temperature to between 800-900° C and by injecting a sorbent material (e.g., crushed limestone or dolomite) into the combustion chamber.[72]

There are two types of fluidized bed combustion technology: atmospheric fluidized bed and pressurized fluidized bed. Atmospheric fluidized bed systems combust fuel under atmospheric pressure. In pressurized fluidized bed systems, the reactor vessel is pressurized to produce sufficient flue gas energy to drive a gas turbine in conjunction with a steam turbine in a combined cycle.

Fluidized bed combustion combines fuel flexibility and low emissions relative to pulverized coal plants. Almost any combustible material, from coal to municipal waste, can by burned. Fluidized bed combustion plants can meet SOx and NOx emission standards without the need for scrubbers or other external emission controls. Boiler manufacturers are currently offering fluidized bed boilers as a standard package.[73]

Load-service function: Fluidized bed combustion technology is suitable for baseload operation because it combines low cost fuels and high output. Babcock and Wilcox states that its second generation Ebensburg Plant had an average availability factor of 90% over a 13-year period, and that its third generation Southern Illinois University Plant averages 93% availability.[74] DOE's JEA Large Scale CFB Combustion

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[72] DOE, *Fluidized Bed Technology Overview*. Document available at: http://www.netl.doe.gov/technologies/coalpower/Combustion/FBC/fbc-overview.html.

[73] DOE, *Final Technical Report for the JEA Large-Scale CFB Combustion Demonstration Project*, June24, 2005. Report available at: http://www.netl.doe.gov/technologies/coalpower/cctc/resources/pdfs/jacks/Final_Technical_Report_Compendium.pdf

[74] M. Maryamchik and D.L. Wietzke, *B&W IR-CFB Operating Experience and New Development*, Babcock and Wilcox technical paper, presented to the 18th International Conference on Fluidized Bed Combustion May 22 - 25, 2005, Toronto, Ontario, Canada. Document available at: http://www.babcock.com/pgg/tt/pdf/BR-1765.pdf

Demonstration Project plant in Florida operated for 6,843 hours in 2003 and 5,450 hours in 2004.[75] The capacity range of installed units is from 80-460 MW.[76]

Time to construct: Construction times for fluidized bed combustion systems are similar to those of pulverized coal plants, ranging from 36-48 months.

Cost to construct: The approximate cost of an atmospheric fluidized bed combustor is $1,327/kW, or 5-10% more than a pulverized coal boiler without SO_2 scrubbers or selective catalytic NO_x reduction equipment.[77] With SO_2 scrubbers or selective catalytic NO_x reduction equipment installed, however, a pulverized coal boiler is 8-15% more expensive than a fluidized bed combustion boiler.[78] A cost estimate performed on Japan's 360-MWe pressurized fluidized bed combustion Karita Plant projected a capital cost of $1,536.[79]

Operational life: Fluidized bed combustion is a new technology and no firm estimates of operational life are available. The U.S. Environmental Protection Agency estimated a 30-year operational life for DOE's JEA Project in Florida.[80]

Fuel costs: A wide range of combustible materials can be used as fuel for a fluidized bed combustion boiler. The JEA demonstration plant in Florida has tested various coals, high sulfur petroleum coke, and coal-coke blends. The plant reported an

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[75] DOE, *Final Technical Report for the JEA Large-Scale CFB Combustion Demonstration Project*, June 24, 2005.

[76] The 460 MW unit is a Foster Wheeler supercritical boiler in Poland. Foster Wheeler has plans for units up to 600 MW. See Goidich *et al., Design Aspects of the Ultra-Supercritical CFB Boiler*, presented at the International Pittsburgh Coal Conference, Pittsburgh, PA, September 12-15, 2005.

[77] The cost to construct is calculated from a review of data from EIA's Annual Energy Outlook 2006, a number of specific utility construction estimates, and from Kavidass, S., *et al., Why Build a Circulating Fluidized Bed Boiler to Generate Steam and Electric Power*, Babcock & Wilcox Company, September 2000.

[78] Ibid.

[79] See NETL, *Project Fact Sheet: CCPI/Clean Coal Demonstrations: Tidd PFBC Demonstration*. The cost to construct the plant was $1,263/kW in 1997 U.S. dollars. Document available at: http://www.netl.doe.gov/technologies/coalpower/cctc/summaries/tidd/tidddemo.html.

[80] Record of Decision, JEA Circulating Fluidized Bed Combustor Project, Federal Register: December 7, 2000 (Vol.65, Num. 236). Document available at: http://www.epa.gov/fedrgstr/EPA-IMPACT/2000/December/Day-07/i31160.htm.

average heat rate of 9,516 Btu/kWh for 2003-2004. Using the same cost of coal reported in section III.C of this report (i.e., $1.54/MMBtu), the cost of fuel per kWh of generation at the JEA demonstration plant is $0.015, or $15.08/MWh (in 2006$).[81] For additional information on the costs of coal, please refer back to this report's examination of pulverized coal plants in section III.C. Fluidized bed combustion units can also use other fuels including biomass and sewage sludge.

Fuel dependability: Due to the range of fuels that fluidized bed combustion plants are able to use, the fuel supply is dependable.

Dependability of the plant: The large scale demonstration plant sponsored by DOE encountered boiler problems that led to forced outages, yet still had an availability of 75%.[82] As noted above, commercial manufacturers state availability factors of 90-93%.

Maturity of the technology: The technology is new and immature.

Externalities: The land requirements for fluidized bed combustion plants are the same as conventional coal fired plants. The combustion of coal creates several byproducts damaging to the environment, including SO_2, NO_x, CO_2, trace metals, ash, and some volatile organic compounds (VOC). Fluidized bed combustion plants can meet current SOx and NOx emission standards without any added emissions control devices. Researchers are currently investigating capturing CO_2 during the combustion process.[83] The DOE has begun selling bed ash and fly ash as industrial byproducts for fill material from the JEA Plant.[84]

5. Integrated gasification combined cycle (IGCC) generation

Overview: Integrated Gasification Combined Cycle (IGCC) generation is a combination of two technologies: coal gasification and combined cycle. Gasification

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[81] NETL, "JEA Large-Scale CFB Combustion Demonstration Project CCTDP." Document available at: http://www.netl.doe.gov/technologies/coalpower/cctc/cctdp/project_briefs/jacks/documents/jacks.pdf.

[82] DOE, *Final Technical Report for the JEA Large-Scale CFB Combustion Demonstration Project*, June 24, 2005.

[83] See Abandes *et al.*, "Fluidized Bed Combustion Systems Integrating CO_2 Capture with CaO," *Environmental Science and Technology,* Vol. 39, No. 8 (March 2005), pp. 2861-2866,.

[84] DOE, *Final Technical Report for the JEA Large-Scale CFB Combustion Demonstration Project*, June 24, 2005.

uses steam and oxygen to convert fuel into synthesis gas (syngas). Syngas is a mixture of carbon monoxide, carbon dioxide, and hydrogen created by the gasification process. IGCC plants can be powered by many carbon-based fuels, such as coal, petroleum coke, and biomass. The syngas contains two primary combustible components: hydrogen and carbon monoxide. The syngas is fired in a gas turbine. The hot exhaust gas from the turbine is routed to a heat recovery steam generator, where it produces steam to power a steam turbine. Electricity is produced by both cycles (the gas turbine and the steam turbine), thus the term combined cycle.

The syngas also contains carbon dioxide. Because carbon dioxide and other unwanted emission-forming constituents can be removed from the syngas and separated before combustion, IGCC plants could rival the low emissions of natural gas fired plants even when using coal as a fuel. If the gasifier is fed with oxygen rather than air, tle flue gas contains highly-concentrated CO_2 which can be captured at a lower cost than from conventional coal or gas-fired plants.[85]

Load-service function: IGCC plants are suitable for baseload operation because they combine low cost fuels and high output. The DOE-assisted demonstration plants have not achieved plant availabilities over 80%, although availability would be higher if a spare gasifier was employed. American Electric Power (AEP) predicts 85% availability for its IGCC plants.[86] The capacity of existing and planned units typically ranges from 250-630 MW. Tampa Electric's Polk County plant is 618 MW.[87] The Wabash River plant is 296 MW.[88] AEP plans to begin construction on a 600 MW unit in 2007.[89] Some companies considering IGCC plants are planning facilities that would provide from 540 to 1,100 MW of capacity.[90]

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[85] See Appendix B of this report for data from the Intergovernmental Panel on Climate Change (IPCC); see also the EPRI/CURC *Technology Roadmap*, available at http://www.coal.org/content/roadmap.htm.

[86] American Electric Power, presentation at "Wall Street Utility Group Meeting," September 21, 2006, New York City, available at: http://www.aep.com/investors/present/documents/AEPPresentationForWSUGMeeting9-21-2006.pdf.

[87] DOE, *Final Technical Report for the JEA Large-Scale CFB Combustion Demonstration Project*, June 24, 2005.

[88] Ibid.

[89] AEP, "Wall Street Utility Group Meeting," September 21, 2006, New York City.

[90] Robert Charles, *et al.*, *Study of Potential Mohave Alternative/Complementary Generation Resources Pursuant to CPUC Decision 04-12-016*, report prepared by

Time to construct: An IGCC plant requires 36 to 48 months to construct.[91] This time does not include planning and permitting.

Cost to construct: A 600 MW IGCC plant costs approximately $1,431/kW to construct.[92] Equipment to capture and sequester carbon dioxide would increase this cost to $1986/kW.[93] The gasification process facilitates carbon dioxide capture. Factoring in the possible future benefits of reduced carbon emissions lowers the net costs of IGCC.[94]

Operational life: IGCC is a new technology and no firm estimates of plant life are available.

Fuel costs: IGCC technology can use a range of fuels. The power plant portion of IGCC comprises the gas turbine combined cycle technology capable of operating on natural gas or distillate oil. The gasifier is also able to gasify most types of coal and other carbon based fuels such as biomass. IGCC technology is suitable for low grade fuel, though existing plants use bituminous coal or petroleum coke. Using the same cost of coal reported in section III.C of $1.54/MMBtu, and assuming a heat exchange rate of 9,713 Btu/kWh for IGCC with carbon capture, the cost of fuel per kWh of generation is about $0.015, or $15.39/MWh. Assuming a heat exchange rate of 8,309 Btu/kWh for IGCC without carbon capture, the cost of fuel per kWh of generation is about $0.013, or $13.17/MWh.[95] For additional information on the costs of coal, please refer back to this report's examination of pulverized coal plants in section III.C.

Fuel dependability: Due to the range of fuels that may be employed with IGCC, the fuel supply is dependable.

Dependability of the plant: Today IGCC plants have availability factors of 88% for single gasifier units. IGCC units with spare gasifiers have higher availability factors.

Sargent & Lundy and Synapse Energy Economics for Southern California Edison, February 2006, p. 212,.

[91] George Booras (EPRI) gives a construction time of about the same as a pulverized coal plant – 3 years. See George Booras, "Pulverized Coal and IGCC Plant Cost and Performance Estimates," presented at Gasification Technologies 2004, Washington, DC October 2004, p. 6. AEP estimates construction time to be 48 months.

[92] See EIA, *Assumptions to the Annual Energy Outlook, 2006,* Table 38, p. 73.

[93] Ibid.

[94] AEP White Paper, "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies," 2005.

[95] See, EIA, *Assumptions to the Annual Energy Outlook, 2006,* Table 38.

Suppliers (e.g., GE/Texaco, ConocoPhillips/E-Gas, and Shell) offer warranties and guarantees.

Maturity of the technology: Gasification technology has been in use since the 1920s, but IGCC electricity generation plants have a limited operating history.

Externalities: Particulate emissions into the air and discharge of solids into water are lower than other coal fired plants.[96] The sulfur in the fuel converts to hydrogen sulfide instead of sulfur dioxide. It is easier to capture hydrogen sulfide than sulfur dioxide; removal rates of 99% are common.[97] IGCC can also meet current emission standards for NOx without added control technology. Water usage is around 750 gallons/MWh for a 570 MW GE IGCC plant.[98] An IGCC plant requires at least 50 acres of land, not including buffer areas.[99] The land footprint AEP plans to use for a 629 MW plant is 390 acres. The footprint will vary depending on the land required for fuel unloading and storage and for ash disposal.

IGCC technology readily separates carbon dioxide from the syngas. The carbon dioxide can then be injected underground to keep it from entering the atmosphere. Emissions can be lowered to nearly zero by capturing and disposing of the carbon dioxide and using hydrogen as the power plant fuel. Such a plant is technically feasible now, but no hydrogen fueled combustion turbine is commercially available.[100] FutureGen is a partnership between DOE and private companies to develop a zero emissions IGCC plant with hydrogen fueled combustion.

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[96] Jay A. Ratafia-Brown, *et al.*, *An Environmental Assessment of IGCC Power Systems*, presented at the Nineteenth Annual Pittsburgh Coal Conference, 23-27 September 2002.

[97] George Booras, EPRI, *Pulverized Coal and IGCC Plant Cost and Performance Estimates*, presented at Gasification Technologies 2004, Washington, DC October 2004, p.6.

[98] Michael G. Klett, *et al.*, *Power Plant Water Usage and Loss Study*, prepared for NETL, August 2005. Document available at: http://www.netl.doe.gov/technologies/coalpower/gasification/pubs/pdf/WaterReport_IGCC_Final_August2005.pdf.

[99] Wisconsin Public Service Commission, *Integrated Gasification Combined Cycle Technology Draft Reports: Benefits, Costs, and Prospects for Future Use in Wisconsin*, June 2006.

[100] Robert Charles, *et al.*, *Study of Potential Mohave Alternative/Complementary Generation Resources Pursuant to CPUC Decision 04-12-016*, Sargent & Lundy and Synapse Energy Economics report prepared for Southern California Edison, February 2006, pp. 2-25.

The current public acceptability of IGCC is roughly the same as other coal-fired plants. Combining carbon dioxide capture and storage with IGCC could lead to greater public acceptability because of lower air emissions.

B. Nuclear generation

Overview: There are 104 commercial nuclear-fueled electricity generation units (nuclear power plants) operating in the United States.[101] Nuclear fuel generates approximately 20 percent of the nation's electricity. Worldwide, more than 400 nuclear power plants provide 16 percent of the global supply of electricity.[102] France has the highest percentage of nuclear power at approximately 79 percent.[103]

Most nuclear power plants have certain common features – the enriched uranium fuel, control rods, a cooling agent, and a moderator.[104] The rods regulate the fission of the uranium atoms. The heat produced by the fission in turn produces steam to operate the generating turbines. The coolant draws heat away from the reactor to prevent the reactor from overheating. The moderator slows the atomic process to increase the amount of energy released by the fissioning.

Nuclear power plants currently in operation around the world are of a number of different designs, including light water, heavy water, light water graphite, gas-cooled and fast-breeders reactors. Approximately 80 percent of the operating nuclear power plants are light water reactors.[105] Light water reactors are further classified as either pressurized water reactors (PWR) or boiling water reactors (BWR).

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[101] EIA, *Annual Energy Review, 2005*. "Table 9.2 Nuclear Power Plant Operations 1957 – 2005", July 2006, p. 275.

[102] World Nuclear Association, "World Nuclear Power Reactors 2005-06 and Uranium Requirements," November 27, 2006. Document available at: http://www.world-nuclear.org/info/reactors.htm. See also International Atomic Energy Agency, "Nuclear Power Reactors in the World", Reference Data Series No. 2, April 2006, table 10 "Reactors in Operation, December 31, 2005," pp. 21-42.

[103] World Nuclear Association, "Nuclear Share Figures, 1995-2005", May 2006. See www.world-nuclear.org/info/nshare.htm.

[104] The enriched fuel is approximately 4-5% uranium. Some nuclear power plants, such as the CANDU 6 design developed by Atomic Energy of Canada Limited, use natural unenriched fuel, which is about 0.7% U235.

[105] Light water is regular common water with the molecular formula H_2O. Heavy water molecules also occur naturally, but much less abundantly than light water molecules. Heavy water is still water -- it looks and tastes like regular water. The difference is that heavy water has a hydrogen atom with a mass twice that of the

"Generation III" is a common reference to the group of plant designs that have been constructed since the mid-1990's. Generation III (or "Generation III+") also includes those plants that are currently under construction or planned for construction in the next 10 or more years. Generation III does not refer to the nuclear-power plant designs still in the research and development phases. Industry observers project that these "Generation IV" designs are likely to be commercially available by 2030.[106]

Compared to Generation II designs (i.e. generally operational power plants built prior to 1990), Generation III plants have a greater emphasis on *passive safety*. A passive safety feature is one that is fully effective or that engages without operator action or electronic feedback. Passive safety features make use of the laws of physics and other highly predictable behaviors of materials, components, processes, and systems. One example would be the use of a liquid sodium pool instead of (or in conjunction with) a pressurized water-cooling system. In a PWR, the cooling system relies on water contained in a high-pressure system. The water would boil away quickly if the pressure system failed. If the reactor core were submerged in a large pool of liquid sodium, the natural heat absorption and boiling temperature properties of the liquid sodium would passively act to prevent overheating.

Load-service function: The capacity of nuclear power plants in the United States ranges from a low of 476MW to a high of 1314MW, with more than half of the units in the range of 1016 to 1314 MW.[107] Nuclear power facilities generally operate as baseload units.[108] Starting an off-line reactor requires at least 24 hours and often more

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hydrogen atom in regular water. The heavy hydrogen is commonly called deuterium. Heavy water is represented with either the molecular formula of ^2H_2O or D_2O. The significant increased mass of the D_2O gives heavy water different properties than H_2O. Heavy water boils at a higher temperature and has a lower critical temperature than light water.

[106] See: James A. Lake, Ralph G. Bennett and John F. Kotek. "Next-Generation Nuclear Power," *Scientific American*, January 2002. Also see: World Nuclear Association, *Generation IV Nuclear Reactors*, July 2006. Also see: Office of Advanced Nuclear Research, DOE Office of Nuclear Energy, Science and Technology: Idaho National Laboratory, *Generation IV Nuclear Energy Systems Ten-Year Program Plan, V. 1,* March 2005.

[107] EIA, *Annual Energy Review, Monthly Nuclear Generation by State and Reactor 2005,* released 2006. Data available at: http://www.eia.doe.gov/cneaf/nuclear/page/nuc_generation/usreactors2005.xls.

[108] Some nuclear power plants are used in a load-following mode rather than a straight baseload.

time.[109] This long start time means that a nuclear power plant is not a practical response to intermediate or peak demands.

Time to construct: Assuming a greenfield start (i.e., constructing on a location where no plant has existed before), it takes approximately four to six years of actual construction time to build a typical Generation III nuclear power plant. The mean period of time between the construction start date and the date of final connection to the grid for all operational nuclear power plants units in the United States is approximately 9 years. For nearly 25 percent of the currently operational units the period of time from construction start to operation was 12 or more years.[110]

Cost to construct: Construction has not started on a new nuclear power plant in the United States since 1972, so cost estimates for new plants must rely in some part on analysis of international construction data. The Energy Information Administration (EIA) has projected the overnight greenfield construction cost for a 1,000 MW nuclear unit at approximately $1.85 billion or $1,849/kW.[111] In August 2005, Tennessee Valley Authority (TVA) delivered a report to United States Department of Energy (DOE) estimating overnight construction cost at $1,708/kW (updated to 2006 dollars).[112]

Operational life: Most of the nuclear power plants currently in operation in the United States were originally licensed by the Nuclear Regulatory Commission (NRC) for a 40-year operational life. However, updates, engineering, and analysis improvements have lead to longer actual plant lives. The NRC has issued renewal licenses of up to 20 additional years to many plants in the United States.[113]

Fuel costs: Approximately two-thirds of the nuclear fuel cost is in the enrichment and fabrication process. In 2006, the approximate fuel cost was

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[109] Gerry Adamski, Ronaldo Jenkins, and Paul Gill, "Nuclear Plant Requirements during Power System Restoration", IEEE Transactions on Power Systems, Vol. 10, No.3, 1995, p.1486.

[110] The periods of time from construction start to grid connection are calculated using data from the International Atomic Energy Agency's list of "Reactors in Operation, 31 December 2005". See "Nuclear Power Reactors in the World", Reference Data Series No. 2, April 2006.

[111] EIA, *Assumptions to the Annual Energy Outlook, 2006,* Table 38.

[112] TVA, "New Nuclear Power Plant Licensing Demonstration Project ABWR Cost/Schedule/COL Project at TVA's Bellefonte Site", August 2005, pp. 4.2-3.

[113] U.S. Nuclear Regulatory Commission, *Status of License Renewal Applications and Industry Activities,* retrieved December 4, 2006 from http://www.nrc.gov/reactors/operating/licensing/renewal/applications.html.

$0.47/MMBtu, including the cost of spent fuel management and disposal.[114] Assuming a heat exchange rate of 10,400MMBtu/kWh, the cost of fuel per kWh of generation is $0.0049, or $4.89/MWh.[115]

Fuel costs of a nuclear power plant are a relatively small portion of the total cost of the electricity produced as compared to coal and natural gas.[116] Consequently, fluctuations in fuel costs have a smaller effect on the cost of electricity produced with nuclear fuel - relative to coal or natural gas. A 100 percent increase in the price of uranium might only increase the cost of electricity by about eight percent.[117] Another buffer from the effects of price volatility is the long fuel purchase interval that is common for nuclear plants. A typical light water reactor nuclear power plant refuels only every 18-24 months. This long interval could serve to give nuclear power plants sufficient time to avoid many of the fluctuations of spot market prices

Fuel dependability: Estimates of the remaining recoverable uranium resources vary widely, making it difficult to offer a reliable estimate of the dependability of the fuel supply. The World Nuclear Association asserts that the supply of uranium is sufficient to sustain the demand.[118] However, since most nuclear plants require enriched and specially

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[114] The inclusion of spent fuel management and disposal does not include any costs associated with delays in permanent storage or costs of any unplanned extensions of on-site interim storage. Fuel costs reporting and forecasts were examined from a number of different sources including: (1) EIA, *Annual Energy Outlook 2006 with Projections to 2030*, December 2005; (2) Uranium Information Centre, *The Economics of Nuclear Power, Briefing Paper 8*, Melbourne, Australia, November 2006; (3) Nuclear Energy Institute, Financial Center reports as of November 2006, available at: http://www.nei.org/index.asp?catnum=1&catid=4.

[115] See, EIA, *Assumptions to the Annual Energy Outlook, 2006,* Table 38.

[116] See Nuclear Energy Institute, *Fuel as a Percentage of Electric Power Industry Production Costs 2005.* Document available at: http://www.nei.org/documents/Fuel_as_Percent_Electric_Production_Costs.pdf.

[117] Assuming that enrichment and fabrication account for two-thirds of the cost of the reactor fuel, a 100 percent increase in the price of uranium would alone cause only a one-third increase in the price of the reactor fuel. Then assuming the cost of reactor fuel accounts for approximately 25 percent of a nuclear power plant's cost to produce electricity, the 100 percent increase in the price of uranium increase the cost of electricity by about eight percent.

[118] World Nuclear Association, *Position Statement: Can Uranium Supplies Sustain the Global Nuclear Renaissance?* September 2005. See http://www.world-nuclear.org.

fabricated fuel assemblies, assessing fuel supply requires an examination of both raw material supply and fuel production capacities.

An increase in reprocessing of spent fuel assemblies, new plant designs that reduce the need for enriched fuel, improved enrichment process, and use of other raw fuel materials could significantly extend the nuclear fuel supply. For example, if relative to other reactor types, the percentage of fast breeder reactors (which can self breed a portion of the fuel supply) where higher, the existing supply of raw uranium would be depleted more slowly.

Dependability of the plant: The average capacity factor for nuclear power plants in the United States is approximately 90 percent with some reactors achieving more than 97 percent.[119] The average availability factor for nuclear power plants in the United States is also approximately 90 percent.[120] These two factors appear to be approaching the practical threshold given that a nuclear power unit must typically refuel every 18-24 months.

Maturity of the technology: The Generation II and III nuclear power plants technology is proven in the United States and around the world. Approximately 75 percent of the U.S. nuclear power plants have been operating for 20 or more years, with more than 40 of these plants operating 30 years or more. The first Generation III plants built are now ten years old.[121] The cumulative hours of successful operation and the high operating capacity and availability averages further demonstrate the maturity of the technology.

Unique regulatory issues: There are a number of special regulatory issues involving the construction and operation of a nuclear power plant. The main issues can be placed in two categories – plant design and operations.

The Nuclear Regulatory Commission (NRC) has certified four advanced Generation III reactor designs. An entity building a plant using one of the certified designs may receive authorization to proceed directly to the site-specific certification processes. Site-specific certification includes the resolution of site safety, environmental protection, and emergency preparedness issues.

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[119] EIA, *Annual Energy Outlook 2006 with Projections to 2030*, December 2005.

[120] International Atomic Energy Agency, *Nuclear Power Plants Information, Energy Availability Factor 2003-2005.*

[121] EIA, *Electric Power Annual with data for 2005*, Table "Existing Generating Units in the United States, by State, Company and Plant, 2003," released October 4, 2006. See also Uranium Information Centre Ltd., "Nuclear Power in the World Today: Nuclear Issues Briefing Paper 7", Melbourne, Australia, September 2006.

A major regulatory concern involving the operation of a nuclear power plant is the current and future handling of spent fuel assemblies (nuclear waste). The long-term delays in the creation of a permanent nuclear waste storage facility have nearly exhausted the temporary storage facilities on the power plants sites.[122] Utilities have claimed – and in some cases, filed for recovery of – hundreds of millions of additional on-site storage costs caused by the federal government's delay in opening a permanent storage facility.[123] The financial risks associated with the continued uncertainty of nuclear waste storage impede future nuclear plant construction.

The Energy Policy Act of 2005 (EPAct) provides incentives for nuclear power. Among other incentives, EPAct provides a production tax credit of $0.018/kWh from the first 6,000MW of new plant operation and risk insurance coverage of regulatory delay costs for the first six new advance design plants.

Externalities: Operating nuclear power plants do not emit greenhouse gases. A normally operating nuclear power plant does produce low-level radioactive emissions, but these emissions are similar to or less than the radioactive emissions of a coal-fired power plant of the same capacity rating.[124]

Nuclear power plant commercial operations total more than 12,000 cumulative reactor-years. The worldwide operational record of commercial nuclear power plants includes two major core-melting accidents – 1979 Three Mile Island plant[125] and the

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[122] For a summary of the storage availability at U.S. nuclear power plants see; Nuclear Energy Institute, *Status of Used Nuclear Fuel Storage at U.S. Commercial Nuclear Plants*, October 2005. See also, Uranium Information Centre Ltd., "Nuclear Power in the World Today: Nuclear Issues Briefing Paper 7", Melbourne, Australia, September 2006.

[123] See, for example, the announced settlement agreement of Exelon Corp. and the U.S. Department of Justice, announced on August 10, 2004. See Mark Holt, "CRS Report for Congress: Civilian Nuclear Waste Disposal," (as updated September 19, 2006) RL33461, p. 4. Document is available at: http://ncseonline.org/NLE/CRSreports/06Sep/RL33461.pdf.

[124] For discussions of nuclear plant radioactive emissions see: (1) U.S. Nuclear Regulatory Commission, "Fact Sheet on Radiation Monitoring at Nuclear Power Plants and the "Tooth Fairy" Issue", January 2005; (2) U.S. Environmental Protection Agency, Office of Radiation and Indoor Air (6608J) "RadTown USA, Nuclear Power Plants", EPA 402-F-06-019, April 2006; (3) Gabbard, Alex. "Coal Combustion: Nuclear Resource or Danger?" *Oak Ridge National Laboratory Review*, Volume 26, Nos. 3 & 4, Summer/Fall 1993.

[125] According to the NRC, the partial meltdown of the Three Mile Island Unit 2 reactor core caused no deaths or injuries; most of the radiation was contained within the structure. Estimates of the average radiation doses to people in the surrounding area were

1986 Chernobyl plant[126] accidents. Historically, nuclear power plants have a better major accident record than other fossil fuel or hydro power plants.[127]

In addition to the operational safety concerns of a nuclear power plant, there has been heightened public concern since 2001 on potential terrorist acts against nuclear plants. The dangers include radioactive disasters caused by an intentional attack, infiltration, or sabotage of nuclear reactors, fuel and waste storage locations, and transportation facilities. According to the NRC, there is a general credible threat of a terrorist attack on nuclear power plants.[128] There are a number of conflicting estimates of the potential results of such intentional acts.[129]

C. Wind generation

Overview: Most wind facilities in the United States use blades that are aeronautically designed, with a shape similar to airplane propellers, to collect the wind's

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about 1 millirem. For comparison, a chest x-ray would be a does of approximately 6 millirems. For more information see U.S. Nuclear Regulatory Commission, "Fact Sheet on the Accident at Three Mile Island," March 2004.

[126] The Chernobyl accident did release a large amount of radioactive material into the environment and resulted in, at least 28 near-term deaths. Several million people received doses of radiation ranging from very small to more than 30 times the natural background level of annual radiation dose. Most analyses attribute the accident largely to plant design. For more information see; *Chernobyl's Legacy: Health, Environmental and Socio-Economic Impacts and Recommendations to the Governments of Belarus, the Russian Federation and Ukraine, Second Revised Edition.* The Chernobyl Forum: 2003-2005.

[127] Hirschberg, S., G. Spiekerman, and R. Dones. "Severe Accidents in the Energy Sector, Comprehensive Assessment of Energy Systems", *Paul Scherrer Institut*, Switzerland, 1998. In this study, the authors consider major power plant accidents resulting in death and injury between 1945 -1996. The authors also extrapolate the long-term injury and death effects for the Chernobyl accident to 70 years.

[128] United States Government Accountability Office, *Nuclear Power Plants, Report to the Chairman, Subcommittee on National Security, Emerging Threats, and International Relations, Committee on Government Reform, House of Representatives* (GAO – 06 – 388), March 2006, p.1.

[129] One of the larger studies examined the effects of a direct high-speed impact of a fully-fueled jet. This study concluded that jet impacts would not result in release of radioactive materials. See, Nuclear Energy Institute, "Deterring Terrorism: Aircraft Crash Impact Analyses Demonstrate Nuclear Power Plant's Structural Strength", December 2002.

kinetic energy and convert it to mechanical energy, which in turn produces electricity. The drive shaft connected to the blades turns an electric generator to produce electricity.

The capacity of a wind facility to produce electricity depends on the height of the wind machine, the area swept by the blades, the speed of the wind, among other factors.[130] Advances in wind technologies will continue to drive down the costs of wind power, making it more economical in areas with less desirable wind characteristics. Technological advancements since the 1980s have contributed toward reducing the unsubsidized cost of wind power from around 40 cents per kWh to the 4-6 cents per kWh range by 2005.[131] The additional intermittency and transmission costs that wind imposes on a power system have made wind energy less competitive with traditional sources of electricity.[132] These supplemental costs partially explain why wind energy currently provides only a small portion of the total electricity generated in the United States. Finally, the competitiveness of wind power relative to other fuel sources depends on the federal production tax credit, which currently stands at 1.9 cents per kWh. In the past when this credit had expired, investments in new wind capacity fell.

California, Iowa, Minnesota and Texas are the states with the most new wind capacity installed since 1998.[133] EIA projects the generation of wind power will increase at the average annual rate of 4.2 percent during the period 2005-2030. This corresponds to wind's share of total net electricity generation increasing to 1.1 percent by 2030, compared with 0.4 percent for 2005.[134]

Load-service function: Wind power is intermittent power, diminishing its capacity value during peak periods. System operators consider wind energy an "as-available" source of power, difficult to schedule more than a few hours in advance. This characteristic requires a power system operator to incur additional costs for ancillary services such as regulation service – the management of minute-to-minute load imbalances. The size of these regulation costs varies and is the subject of debate.[135]

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[130] For an overview of wind technology, see http://www.awea.org/faq/index.html and http://www.nrel.gov/wind/consumer_home_business.html.

[131] See Blair Swezey, "Renewable Energy in Today's Power Markets," NARUC Summer Meetings, July 2004.

[132] See Joe Darmstadter and Karen Palmer, "Renewable Sources of Electricity: Safe Bet or Tilting at Windmills," *Resources*, Issue 156 (Winter 2005), 24-27.

[133] See American Wind Energy Association, *Wind Energy Fast Facts*, 2006.

[134] EIA, *Annual Energy Outlook 2006*, p. 81.

[135] See, for example, J. Charles Smith, "Wind Energy Development in the U.S.," Presentation at the OC/PC Meeting, September 16, 2006; Michael Milligan *et al.*, "Wind Energy and Power System Operations: A Survey of Current Research and Regulatory

Wind's output variation also deviates from the power system's load variations; this reduced "load-following" capability further diminishes wind's value for load service, relative to other, more readily dispatchable sources.[136] This "intermittency" cost to a power system depends on, among other things, the system's generation mix. Lower costs would occur when the system has a higher mix of generation facilities with fast ramp rates, such as gas turbines and hydropower facilities; the reason is that these facilities can quickly compensate for any shortfalls in wind generation. Intermittency costs may grow as the mix of wind energy on a power system rises significantly above the current level.

Wind facilities are available in sizes up to 50 MW. Power system operators can choose the size that best fits their systems. The range of capacity factors across wind facilities vary widely, depending largely on wind conditions and the characteristics of the wind turbine. In 2004, according to the Electric Power Research Institute (EPRI) wind facilities had an average capacity factor of 30 percent.[137] This 30-percent capacity factor is low compared to other generation facilities that have large capital costs and low operating costs (e.g., pulverized coal-fired units). EIA projects higher capacity factors in the future. In its reference case, EIA projects a capacity factor of 44 percent for the best wind class by 2010, due to a combination of taller towers, more reliable equipment and advanced technologies.[138] Increasing the capacity factor improves the economic attractiveness of wind energy. EPRI estimated that increasing the capacity factor from 29 percent to 42 percent would reduce the unsubsidized cost of wind power from 7.5 cents per kWh to 5.5 cents per kWh; a relapse with the capacity factor achieving 20 percent would raise wind's cost to 10 cents per kWh.[139] According to EPRI studies of levelized costs of electricity, if wind energy could obtain a capacity factor of over 40 percent, its levelized cost of electricity would be comparable with other technologies, even absent a production tax credit.[140]

Actions," *The Electricity Journal* 15, Issue 2 (March 2002), pp. 56-67; Joseph F. DeCarolis and David W. Keith, "The Costs of Wind's Variability: Is There a Threshold?" *The Electricity Journal* 18, Issue 1 (January/February 2005), pp 69-77; and Ed DeMeo, "Integrating Wind Power into the Electric Power System," Presentation at the meeting on Unleashing the Potential: Wind Energy in Michigan, October 21, 2005.

[136] Load following refers to the response of a system operator to meet variations in electricity demand by scheduling and committing generating units for operation based on forecasted load changes over temporal cycles adjusted for random variations.

[137] See Steve Specker, "Generation Technologies in a Carbon-Constrained World."

[138] EIA, *Assumptions for the Annual Energy Outlook 2006*, March 2006, p. 135.

[139] Steve Specker, "Generation Technologies in a Carbon-Constrained World."

[140] Ibid.

Time to construct: In its long-term projections, EIA analyzes the economics of new wind facilities assuming a capacity of 50 MW.[141] EIA estimates that a 50-MW facility would have a three-year time period between the ordering of a facility and its completion. According to another source, the construction period for wind projects ranges from five to twelve months, depending on project size, weather conditions and terrain.[142]

Cost to construct: The EIA analysis of a 50 MW plant assumes construction costs of $1,157 per kW.[143] Because of economies of scale, the average cost of wind power decreases with the size of the facility.

Operational life: The service life of a wind facility is approximately twenty years; refurbishment of the turbine generators and other equipment can add as much as ten years to the service life.

Fuel costs and supply: Although wind facilities use no fuel sources, intermittency requires a system operator to deploy back-up facilities that burn fossil fuels. One potential benefit of wind energy is the displacement of power from fossil-fuel generation facilities that emit air pollutants and toxic wastes.

Dependability of the plant: Operational experience has shown that the availability factor of state-of-the-art wind turbines is around 98 percent. This statement considers only the mechanical aspects of a wind turbine. For example, a 98 percent availability factor means that a turbine is out of service for maintenance or repairs two percent of the time. If availability takes into account wind conditions, then a wind turbine could have a much lower availability factor, since the turbine may sit idle for an appreciable period even when it is ready to run if there is not sufficient wind to power it.

Wind availability and wind speed fluctuate and have limited predictability. Another measure of dependability that is helpful for understanding wind power is the effective load-carrying capability (ELCC). ELCC measures the amount of incremental load for which a new facility can handle without reducing overall power system reliability.[144] A higher ELCC means a higher capacity value for a new facility. Disagreements arise over

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[141] EIA, *Assumptions for the Annual Energy Outlook 2006*, p. 73.

[142] Global Energy Concepts, *Wind Project Lifecycle: Overview*, prepared for the New York State Energy Research and Development Authority, October 2005.

[143] EIA, *Assumptions for the Annual Energy Outlook 2006*, p. 73.

[144] See Ed Kahn, "Effective Load Carrying Capability of Wind Generation: Initial Results with Public Data," presentation at the California Energy Commission Renewables Committee Workshop, February 20, 2004.

the contribution of a wind facility in enhancing system reliability (i.e., in reducing loss of load probability (LOLP), which is the probability that demand exceeds supply within a given period of time).[145] Because of wind intermittency, the installed capacity of a wind facility contributes less to ELCC than the equivalent installed capacity of other generation technologies. ELCC estimates for wind facilities range fall within the range of 0-40 percent, whereas gas-fired and other fossil fuel generating facilities most frequently have an ELCC close to 80-90 percent.[146]

Maturity of the technology: Wind technologies are mature given their wide adoption throughout the world and more than a century of operating experience. Despite this long history, wind technologies will continue to undergo improvements making them more economical in the future. One change will facilitate interfacing wind facilities with the power grid. Another will improve turbine design by installing higher turbine towers and larger blades, both reducing operating costs and increasing reliability.[147] A major technological advancement will involve the design of wind turbines to operate economically at sites with low wind speeds and closer to load centers.[148] Overall, advancements in wind technologies, from the combination of research and development activities and increased market penetration (i.e., learning by doing), will produce improvements in both cost and operating performance.

Externalities: Wind power has more benign environmental effects compared with fossil-fuel generation technologies. Operation of wind facilities emits no air or water pollutants of any kind, and produces no toxic wastes or negative health impacts. On the other hand, one common problem with wind facilities is their noise, although new facilities have reduced this problem.

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[145] EIA defines reliability in terms of security and adequacy. Security is "the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements." Adequacy refers to "the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably unscheduled outages of system elements." Glossary available at: http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html.

[146] See Mark Bolinger and Ryan Wiser, *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans*, Lawrence Berkeley National Laboratory (LBNL-58450), August 2005; and California Energy Commission, *Comparative Cost of California Central Station Electricity Generation Technologies*, prepared for Docket 02-IEP-01, June 5, 2003, Appendix C and D.

[147] See NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, I-37; and American Wind Energy Association, *The Economics of Wind Energy*, February 2005.

[148] Dan Arvizu, "Fulfilling the Promise of Renewable Energy: A Look at the Future," Resources for the Future Forum, June 21, 2005.

Large wind facilities occupy more land area than fossil fuel facilities, but most of the land (between the towers) is available for other uses. Facilities are typically located in areas with high wind speeds, making wind energy more economical. Most facilities reside in remote areas with new transmission lines required to deliver the power to load centers. These new lines affect the economics of wind facilities, since average costs could increase with a low capacity factor. With current technology, wind energy output increases by the cube of the wind speed. Increasing the average wind speed just from 13 miles per hour to 15 miles per hour, for example, augment electricity output by over 50 percent.[149] Sites suitable for electric generation typically require sustained winds averaging, at the minimum, 14-15 miles per hour.[150]

In the future, if wind facilities locate near urban areas, they will provoke more opposition from local citizens than seen so far. Wind energy has met with mixed public acceptability up to now. Several wind projects have faced opposition because of their negative aesthetic effect and other siting concerns.[151] Especially in New England, local citizens and community groups have opposed the siting of new wind facilities.[152] The possibility for harm to birds and bats is another negative externality for large wind power units.

D. Pumped-storage hydropower

Overview: Electricity cannot be stored directly. Electricity must be produced at exactly the level to match demand at any particular moment. It is possible, however, to use electricity to store up potential energy to be released later and converted back to electricity. Pumped-storage hydropower is the most commonly used storage technology deployed on electric power systems.[153] This technology uses water from an upper

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[149] See American Wind Energy Association, *The Economics of Wind Energy.*

[150] See NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, pp. 5-24.

[151] Alan Nogee, "State Renewable Electricity Standards: Projections, Policy Details, and Experiences to Date," Presentation at the Harvard Electricity Policy group 39th Plenary Session, May 20, 2005.

[152] In one instance local-citizen groups and environmentalists opposed the building of the Cape Cod wind project in part because of the claimed impairment of coastal views. Rick Klein, "Kennedy Faces Fight on Cape Wind," *Boston Globe*, April 27, 2006.

[153] Compressing air in underground geological formations for release during peak demand is another approach to storing energy, but pumped-storage hydropower is currently the only commercially viable storage technology. For an overview of the pumped-storage technology, see:

reservoir through the blades of a turbine to generate electricity, typically during peak periods. The units pump the water into the upper reservoir from a lower reservoir during off-peak periods, such as nights and weekends. Although electricity itself is not stored, the potential energy is stored and can be released to be converted back to electricity without the use of fuel. Pumped storage serves as a load management tool by lowering the amount of power that other generation units must provide during the periods of highest demand (and highest cost) for electricity.

Today, pumped storage comprises less than two percent of the total generating capacity in the United States.[154] California has over 4,000 MW of pumped storage (which approximates 20 percent of total pump storage capacity in the U.S.), with two proposed projects expected to add as much as 900 MW of generating capacity before the end of this decade.[155] Pumped-storage net summer capacity throughout the United States has remained stable since 1990. Limitations on the expansion of pumped storage facilities stem from the availability of suitable sites where geological and ecological conditions allow for their construction and operation.

Load-service function: Pumped storage can respond quickly to sudden changes in electricity demand, making it especially valuable for meeting peak demand and the provision of ancillary services. On average, it takes between one and four minutes to activate a pumped storage facility from a cold start and less than thirty minutes to transfer the facility from pumping water to generating electricity. Pumped storage has become more economically attractive as wholesale electricity prices during peak periods increase relative to off-peak power and as wholesale prices become more volatile. Economically, storage plays an arbitrage function by exploiting short-term differentials in electricity prices.[156] Price differentials reflect the gap between the cost of electricity in pumping the water to the upper reservoir and the market price or the value of the electricity generated during peak periods. Pumped storage can help make wind energy more dispatchable. It can also absorb electricity generation from wind facilities during high-wind periods so as to minimize any system operational problems.

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http://www.duke-energy.com/about/energy/generating/pumped_storage, and http://www.electricitystorage.org/tech/technologies_technologies_pumpedhydro.htm.

[154] See http://www.eia.doe.gov/cneaf/electricity/epa/epat2p2.html.

[155] See California Energy Commission, *Integrated Energy Policy Report*, CEC-100-2005-007CMF, November 2005, pp. 146-147.

[156] See, for example, Frank Graves *et al.*, "Opportunities for Electricity Storage in Deregulating Markets," *The Electricity Journal* 12, Issue 8 (October 1999), pp. 46-56.

Functioning largely as a peaking facility, pumped storage plants have low capacity factors, in the range of 15-35 percent.[157] The sponsors for a proposed new pumped storage facility in California estimated a capacity factor of 36 percent. Although a pumped-storage facility uses no fuels at the time the stored water falls, the process of pumping the water into storage in the upper reservoir requires internal generation from existing power plants. New pumped-storage units have efficiency levels as high as 85 percent, meaning that this percentage of electricity used to pump water is "returned" in the form of generated power. The peculiarity of pumped storage is its negative net electricity generation (i.e., where more electricity is needed to pump water to an upper reservoir than the actual electricity later generated by the same pumped storage facility).

Time to construct: Limited data is available. The sponsors of a proposed new facility in California (the Lake Elsinore plant) estimate the construction time at four and a half years

Cost to construct: Pumped-storage facilities vary in size. In the United States, installed plant capacity ranges from 31 MW to over 2,880 MW, with the median plant close to 1000 MW. The Lake Elsinore plant has a capacity of 500 MW. The sponsors estimate the construction time at four and a half years, with a cost of $1.115 billion (in 2005 dollars) or $2,379 per kW (in 2006 dollars). When estimating the value of a pumped storage plant, regulators should consider its capital costs in comparison to peak power costs and its value as readily available reserve capacity for grid management. Pumped-storage facilities generally have higher construction costs and longer lead times than alternative peaking facilities such as steam combustion turbines, which have construction costs per kW that is typically less than 20 percent of the cost for the Lake Elsinore facility).

Operational life: Studies analyzing new pumped storage facilities assume a plant service life up to sixty years.[158] The sponsors of the Lake Elsinore requested an initial permit of fifty years for the plant.[159]

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[157] See Dale T. Bradshaw, "Pumped Hydroelectric Storage (PHS) and Compressed Air Energy Storage (CAES)," presentation at the IEEE PES Meeting on Energy Storage, July 19, 2000.

[158] See, for example, Paul Denholm and Gerald L. Kulcinski, "Life Cycle Energy Requirements and Greenhouse Gas Emissions from Large Scale Energy Storage Systems," *Energy Conversion and Management*, 45, Issues 13-14 (August 2004), pp. 2153-72.

[159] Information on the Lake Elsinore plant is contained in Federal Energy Regulatory Commission and U.S. Department of Agriculture, *Draft Environmental Impact Statement for Hydropower License: Lake Elsinore Advanced Pumped Storage Project, FERC Project No. 11858*, Docket No. P-11858-002, February 2006.

Fuel costs and fuel dependability: Pumped storage systems do not use fuel directly, but there is a cost for the electricity associated with pumping water to create the stored capacity. Since the plant typically pumps during periods of low electricity demand, the cost of the electricity needed for pumping will be low relative to other periods of demand. Similarly, the dependability of electricity for pumping is high because the pumping usually occurs when generating capacity is readily available.

Dependability of the plant: Pumped-storage facilities are reliable generating facilities, as long as the upper reservoir receives adequate water pumped from the lower reservoir. These facilities have availability factors of 90-95 percent and forced outage rates of less than 1.5 percent.[160] Historically a lack of water for pumping has not posed a serious problem for pumped storage facilities in the United States. The availability of electricity to pump water to the upper reservoir also poses no problem since pumping mostly occurs during off-peak periods when ample power is normally available.

Maturity of the technology: Pumped storage is a mature technology, featuring facilities that have decades of operating experience throughout the world with minimal operating problems.

Externalities: Local citizens have accepted the siting of pumped storage facilities with some reservations. Their concerns include the assurances of no adverse effects on the local wildlife habitat, recreational activities, and the water quality of local creeks and lakes. Improperly maintained and operated facilities have resulted in reservoir failure and flooding in past cases.

Pumped storage facilities occupy large tracts of land. The proposed Lake Elsinore facility referenced above would inhabit over 2,410 acres of land. In addition, the facility would require large amounts of water (namely, 5,500 acre-feet) for the initial filling of the upper reservoir. The Environmental Impact Statement (EIS) for the project expressed concern over the location of the upper reservoir in an area used for recreation and with a diverse ecosystem.

E. Miscellaneous generation technologies

In addition to the electric generation technologies discussed above, there are several others that are responsible for a small share of generating capacity. The technologies described below typically feature higher power costs compared to the technologies described above or their use is constrained by geography, as is the case with geothermal power and solar power. The technologies described below cannot be grouped together as "new" or "emerging" because some of them have been around for decades. On the other hand, most of the technologies are not fully mature because their engineered efficiency and cost profiles will likely improve with time and wider use. The report

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[160] Dale T. Bradshaw, "Pumped Hydroelectric Storage (PHS) and Compressed Air Energy Storage (CAES)."

offers less detailed coverage of the technologies below and omits entries for the criteria for comparison for which the authors identified no data.

1. Photovoltaic power

Overview: Photovoltaic (PV) systems consist of arrays of modules that absorb solar radiation and causes current to flow between oppositely charged layers of the module. The solar energy converts to electricity without moving parts. The PV material can be fixed in place or mounted on single or dual axis sun trackers that tilt toward the sun seasonally (north to south), daily (east to west), or both for maximum exposure to the sun. A complete PV system includes concentrator modules, support and tracking structures, a power-processing center, and land.[161]

Load-service function: High levels of sunlight to power PV systems tend to correspond to high levels of demand for electricity, so PV generation in the U.S. is used for providing peak power and intermediate daytime load.[162] One advantage of PV systems is that they can be built in arrays of almost any size; the large arrays currently in operation supply around 1 MW of power.[163] Most arrays are residential (about one kW) or commercial (one to several hundred kW) alternatives to retail electricity.[164]

Time to construct: Photovoltaic power plants require a construction time of 2 years.[165]

Cost to construct: The overnight cost for a photovoltaic electric generation plant is $4,222 /kW, according to the EIA.[166]

Operational life: PV generation systems typically last 20 to 40 years.[167]

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[161] See National Renewable Energy Laboratory. *Power Technologies Energy Data Book* (cited hereafter as, NREL-*PTED),* 3ed. NREL/TP-620-37930, April 2005; and NREL U.S. Climate change Technology Program, *Technology Options: For the Near and Long Term*, DOE/PI-0002, November 2003; and NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, pp. 5-22 and 5-23.

[162] See NREL-*PTED*, p 25.

[163] United Nations Environment Program, Division of Technology, Industry and Economics, "Energy Technology Fact Sheet: Photovoltaics," 2004. Document available at: http://www.unep.fr/energy/publications/pdfs/pv.pdf.

[164] Ibid.

[165] See EIA, *Assumptions for the Annual Energy Outlook 2006,* Table 38.

[166] Ibid.

Fuel costs: PV systems do not have fuel costs since they rely on solar radiation.

Dependability of fuel supply: The amount of sunlight available for PV arrays varies by time of day, latitude, cloud cover, and local shading. According to the National Renewable Energy Laboratory (NREL), however, nearly all locations in the U.S. have enough sunlight for PV electric generation to occur.[168] PV arrays tend to have higher capacity factors in sunny areas, making them the most economically attractive locations for new PV systems.

Dependability of the plant: PV systems have few moving parts, which minimizes their need for maintenance. Similar to wind, PV arrays have very high mechanical availability factors (approaching 99%), but much lower capacity factors (around 16%) partly because they provide power only intermittently following the availability of sunlight.[169]

Maturity of technology: Most PV arrays installed to date are made of crystalline silicone, a technology NREL considers relatively mature.[170] Photovoltaic arrays can also be made of utility scale thin-film and concentrator cells.[171] PV conversion efficiencies have improved 50% over the past ten years.[172] Current PV electric conversion efficiency for crystalline silicon, thin film, and concentrator systems is 14.1, 8.8, and 17.1 percent, respectively.[173]

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[167] See Tom Markvart, and Luis Castaner, eds. *Solar Cells: Materials, manufacture and operation,* Elsevier Science, Inc, New York, New York, 2005; Czanderna, A. W. and Jorgensen, G. J., *Accelerated life testing and service lifetime prediction for PV technologies in the twenty-first century,* NREL, Golden, Colorado, 1999; Realini, A., *et al.*, *Mean time before failure of photovoltaic modules (MTBF-PVm)*, Swiss Federal Office of Energy, Canobbio, Switzerland, 2002.

[168] NREL-*PTED*, p. 26. The amount of sunlight in Kansas, for example, varies only 25%.

[169] See Avery Lovins, *Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*, Snowmass, Colorado, Rocky Mountain Institute, 2002; and Itron, "CPUC Self-Generation Incentive Program Fourth Year Impact Report, submitted to Southern California Edison and the Self-Generation Incentive Program Working Group, April 2005, p. 1.4.

[170] NREL-*PTED,* p 28.

[171] Ibid.

[172] NREL-*PTED*, p. 26.

[173] NREL-*PTED*, p 35 and *Renewable Energy Technology Characterizations*, EPRI TR-109496, 1997.

Externalities: PV arrays avoid negative externalities like fuel wastes, air pollution, or greenhouse gasses. Small residential and commercial systems can be located inconspicuously (e.g., on rooftops or modeled to look like windows). Owners of large arrays can choose to locate them away from population centers, assuming the transmission service to do so.

2. Concentrated solar power

Overview: Concentrated solar power (CSP) systems produce electricity with sun-tracking mirrors that concentrate the sun's energy to heat a working fluid. The working fluid is used to create steam that produces electricity in conventional steam or gas turbines. CSP systems can also produce electricity on cloudy days by using stored heat energy or substituting fossil fuels to heat the working fluid.[174]

There are three types of CSP systems: parabolic trough, power tower, and dish engine. Parabolic trough CSP plants range in size from 10 to 100 MW; power tower CSP systems vary from 30 to 200 MW; and dish/engine systems from 2 to 25 kW.[175] According to NREL data, the capacity factor for parabolic trough, power tower, and dish/engine CSP plants are between 30 and 50 percent.

Load service function: CSP electric generation in the U.S. has been used primarily to supply bulk electricity for the grid in the southwest. These systems, however, were installed under power supply purchase rates that are no longer typical, according to the NREL. As it stands, CSP technology is too expensive to compete in domestic markets without subsidies.[176]

Time to construct: Solar thermal generation plants have a 3 year construction time.[177]

Cost to construct: The overnight cost of a solar thermal electric plant, a general category, is in the range of $2,745-$3,234/kW.[178]

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[174] NREL-*PTED*, p 19.

[175] See NREL-*PTED*, p23 and *Renewable Energy Project Information System* (REPiS), Version7, NREL, 2003; and *Renewable Energy Technology Characterizations*, EPRI TR-109496.

[176] NREL, *PTED*, p 26.

[177] EIA, *Assumptions for the Annual Energy Outlook 2006,* Table 38.

[178] Ibid.

Operational life: The operational life of a solar thermal electric generation plant is about 30 years.[179]

Fuel costs: CSP systems do not have fuel costs since they rely on solar radiation.

Maturity of technology: CSP generation is an immature technology.

Externalities: Like PV arrays, CSP systems avoid negative externalities like fuel wastes, air pollution, or greenhouse gasses.

3. Biomass power

Overview: Biopower refers to electric power generated from converted vegetation (i.e., biomass). The most common biomass resources today are waste wood and agricultural crop residues. Current research, however, is exploring the production of switch grass and other crops for the specific purpose of biomass conversion for electricity production.[180]

Biopower generation is a two step process. The first step is to convert biomass feed stock into what is known as biofuel. Feed stock can be converted into biofuel in one of three ways: homogenization, gasification, and anaerobic digestion. Homogenization is a process by which feedstock is made uniform for further processing or combustion. In the gasification process, biomass is converted into fuel gas that is used as a substitute for fossil fuel in combustion turbines. Anaerobic digestion converts agricultural and animal waste into biogas that can be used in standard or combined heat and power (CHP) applications. Anaerobic digestion also occurs in landfills as part of the decomposition process. Biogas can be converted into liquid fuels like methanol, ethanol, hydrogen, and bio-diesel as well.[181]

The second step is to convert biofuel into electricity. Most biopower today is produced in direct combustion gas turbines, but it can also be used in combined cycle turbines, diesel engines, or serve as a substitute in existing coal-fired burners.[182]

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[179] See California Energy Commission, *Comparative Cost of California Central Station Electricity Generation Technologies*, 2003. Table 1: Levelized Costs by Technology, p 3.

[180] See NREL-*PTED*, p3; NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, Table 5-2, "Generating resources and technologies with moderate potential," p. 5-9; and Alexander E. Farrell, *et al.*, "Ethanol Can Contribute to Energy and Environmental Goals," *Science*, Vol. 311, January 27, 2006.

[181] NREL-*PTED*, p3.

[182] Ibid.

Load service function: Biopower serves as baseload power supply. Direct combustion and gasification biopower generation plants have a capacity factor of about 80.0 percent.[183]

Time to construct: Biomass electric generation plants typically require four years for construction.[184]

Cost to construct: The overnight cost for a biomass electric plant is in the range of $1,759/kW.[185]

Fuel costs: The cost of fuel, or feed cost, for both direct combustion and gasification systems is $694.44/kW, and $202.78/kW for co-fired systems, according to NREL.[186] The cost of biofuel varies from about $0.174/MMBtu for landfill gas, to $2.78/MMBtu for agricultural field residue, to up to $5.52/MMBtu for logging residue.[187] Assuming a heat rate of 8,911 MMBtu/kWh, the cost of fuel per kWh of generation varies from $0.0016 ($1.55/MWh) to $0.49 ($49.19/MWh).[188]

Dependability of fuel supply: The supply of biomass is highly dependable, drawing on a waste products and agricultural crops.

Dependability of the plant: Direct combustion and gasification biopower generation plants have a capacity factor of about 80.0 percent.[189] And according to the NPCC, both wood residue and animal manure biogas electric generation plants have an availability factor of 90%. Landfill gas facilities have an availability factor of about 80%.[190]

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[183] Ibid., p. 9.

[184] EIA, *Assumptions for the Annual Energy Outlook 2006,* Table 38.

[185] Ibid.

[186] NREL-*PTED,* p. 9. The numbers for co-fired systems represent only the biofuel portion of capital, operating, and feed cost.

[187] See NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, Table 5-3, "Estimated biofuel supply and cost,"p. 5-10.

[188] See EIA, *Assumptions to the Annual Energy Outlook, 2006*. Table 38.

[189] See NREL-*PTED,* p. 9.

[190] See NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, Table 5-4, "Generating resource planning assumptions," p. 5-26.

Maturity of technology: Biopower is an immature technology.

4. Geothermal power

Overview: Geothermal energy plants tap underground reservoirs of hot water and steam that can be used for heat, electric generation, or both (i.e., CHP). Water pumped into hot dry rocks, found just below the earth's surface, can also be used to produce electricity.[191] There are three types of geothermal energy plants in use today, dry steam, flash steam, and binary-cycle. Dry steam plants use the earth's thermal energy to spin turbines directly. Flash steam plants pump hot high pressure water into low pressure tanks instantly creating steam which is then used to spin turbine blades to generate electricity. In binary-cycle plants, geothermal steam is used to heat a secondary fluid—one that has a much lower boiling point than water—causing it to vaporize. The vapor is then used to drive turbines. Cumulative geothermal installed capacity in the U.S. ranged from 2,020 to 2,252 MW in 2003.[192]

Load service function: Geothermal plants usually operate as baseload plants.[193] The capacity factors for flash steam and binary-cycle geothermal energy are approximately 93 percent; the capacity factor for hot dry rock systems is around 82 percent.[194]

Time to construct: Geothermal plants have a four year construction time.[195]

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[191] See Australian Department of the Environment and Heritage, Greenhouse Office, "Hot Dry Rock Geothermal Reservoir Development." Document available at: http://www.greenhouse.gov.au/renewable/recp/hotdryrock/two.html. Water is injected through a borehole, permeates the hot rock (which can reach 250 degrees C), and becomes superheated. The superheated water then returns to the surface where it is used to power conventional steam turbines.

[192] See NREL-*PTED*, p.1; EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003), 2004, Table 8.11a; International Geothermal Association at http://iga.igg.cnr.it/index.php; and NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, pp. 5-15 and 5-16.

[193] See NREL-*PTED*, p11; and NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, Table 5-2, "Generating resources and technologies with moderate potential," p. 5-2; and California Energy Commission, *Comparative Cost of California Central Station Electricity Generation Technologies*, June 6, 2003, Table 1, "Levelized Cost by Technology," 2003, p 3.

[194] NREL-*PTED*, p18.

[195] EIA, *Assumptions for the Annual Energy Outlook 2006*, Table 38, "Cost and Performance Characteristics of New Central Station Electricity Generating Technologies," p 73.

Cost to construct: The overnight cost of a geothermal generation plant is $2,227.10/kW.[196]

Operational life: The typical operational lifetime of a geothermal electric generation plant is 30 years.[197]

Fuel costs: Geothermal units do not have fuel costs since they rely on the heat of the earth.

Dependability of fuel supply: Sources of geothermal power are very dependable since they rely on heat generated by the earth.

Dependability of the plant: Flash steam geothermal electricity plants have an availability factor of 92%.[198]

Maturity of technology: Geothermal generation technology is very mature. The world's first geothermal CHP application was built in Idaho in 1892.[199]

5. Ocean current and barrage generation

Overview: There are several different technologies used to harness the power of the ocean. This section presents an overview of the two most prominent technologies, barrage-type and ocean current. A barrage-type generator is, essentially, a large underwater dam that traps water during high tide and releases it through conventional turbines to produce electricity during the ebb, much like land-based generation dams. Ocean current technology is further divided into two subcategories, depending on the orientation of the generator's driveshaft. In *vertical-axis turbines*, also known as Davis Hydro turbines, tidal currents flow through vertically mounted rotating hydrofoils connected to a rotating shaft. Ocean currents push through the hydrofoils, applying torque, and turn the drive shaft connected to a generator housed just above sea level.[200]

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[196] Ibid.

[197] See California Energy Commission, *Comparative cost of California Central Station Electricity Generation Technologies*," June 6, 2003, Table 1, "Levelized Costs by Technology," p 3.

[198] See NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, Table 5-4, "Generating resource planning assumptions," p. 5-26.

[199] See NREL-*PTED*, p 12.

[200] See Micahel Masser, *Tidal Energy: A Primer*, Blue Energy Canada, Inc., Vancouver, British Columbia, Canada, 2004. Horizontal-axis turbines are relatively new

Horizontal-axis electric generation works much like an underwater wind farm. Prevailing tidal currents turn large propeller-like hydrofoils that are coupled to submerged generators.[201] Electricity is transmitted to on-shore transformers and then to the grid.

Cost to construct: Ocean current technologies are too immature to provide firm cost data. Due to high construction and dredging costs (to remove accumulated silt), barrage-type generation dams are not economically competitive with other technologies.[202]

Fuel costs: There is no fuel cost associated with barrage-type or ocean current electric generation; the kinetic energy of the ocean is free.[203]

Dependability of fuel supply: Barrage and ocean current electric generation is very dependable because it relies on naturally occurring ocean currents.

Dependability of the plant: Information about the dependability of ocean current and barrage units is limited. The La Rance tidal barrage, located in the north of France, has been in use since the mid-1960. [204]

Maturity of technology: Barrage generators have been used in Europe since the mid-1960s and are still used around the world today.[205] Horizontal-axis ocean current technology was introduced during the 1970s, but it was not installed commercially until the mid-1990s and is still experimental today.[206]

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technology. The Canadian National Research Council and Blue Energy Canada, Inc. have successfully tested five turbine prototypes in the St Lawrence Seaway.

[201] Ibid.

[202] Ibid.

[203] Ibid.

[204] See University of Strathclyde in Glasgow, *Renewables in Scotland: Tidal Power Case Studies*. Document available at: http://www.esru.strath.ac.uk/EandE/Web_sites/01-02/RE_info/tidal1.htm.

[205] See Michael Maser, *Tidal Energy: A Primer*, and NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, pp. 5-21 to 5-24.

[206] See Michael Maser, *Tidal Energy: A Primer*, and http://www.itpower.co.uk/OceanEnergy.htm. The first horizontal-axis tidal wave turbine (15kW) was installed in Loch Linnhe, Scotland. As of 2003, two UK companies planned to demonstrate horizontal-axis turbines off the coast of Norway. Currently, there are

6. Fuel Cells

Overview: Fuel cells are similar to common batteries. Both have positive and negative ends, rely on chemical reaction, and produce electricity when the circuit is closed. In hydrogen fuel cells, hydrogen passes through an anode catalyst where it is split into an ion (positively charged H+) and an electron (negatively charged e-). The positive ions pass through a conductive medium (e.g., an electrolyte membrane) and then combine with oxygen flowing in through the cathode catalyst to form water as a byproduct. The separated hydrogen electrons (e-) flow along a circuit in the cathode, creating electrical current.[207]

Fuel cells are classified by the type of electrolyte used: AFC (alkaline fuel cells), PAFC (phosphoric acid fuel cells), PEMFC (proton exchange membrane fuel cells), and MCFC (molten carbonate fuel cells), and SOFC (solid oxide fuel cells). Electric output for PEMFCs and SOFCs ranges from 5 to 250 kW. PAFCs are capable of producing 200 kW, and MCFCs can produce anywhere from 250 kW to 2 MW of power. Electric efficiency for PEMFC, PACF, MCFC, and SOFCs are 32 to 40 percent, 30 to 40 percent, 35 to 45 percent, 40 to 50 percent, and 45 to 50 percent, respectively.[208]

Load service function: Fuel cells can be sized for grid-connected or customer-sited applications, but are generally too expensive to compete without subsidies.[209]

Time to construct: Lead time for fuel cell electric generation plants, according to the EIA, is 3 years.[210]

Cost to construct: The EIA estimates overnight cost for a 10 MW fuel cell generation plant to be about $4,015/kW.[211]

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seven other ocean tide generation projects and one river tide project launched by IT Power.

[207] NREL-*PTED*, p 73.

[208] See NREL-*PTED*, p75; and Anne Marie Borbely and Jan F. Kreider. *Distributed Generation: The Power Paradigm for the New Millennium*, CRC Press 2001; and Arthur D. Little, Distributed Generation Primer: Building the Factual Foundation (multi-client study), February 2000.

[209] NREL-*PTED*, p 73.

[210] See EIA, *Assumptions to the Annual Energy Outlook, 2006*, Table 38.

[211] Ibid.

Fuel supply reliability and costs: While hydrogen itself is a clean fuel, it is most commonly obtained from fossil fuels, predominantly natural gas. Emissions-free production of hydrogen is an objective of DOE's FutureGen project for a zero-emissions IGCC plant.

Maturity of technology: Fuel cells are an immature technology.

Externalities: The only byproducts of fuel cell electricity are water and heat, but currently production of hydrogen requires fossil fuels.[212]

[212] NREL-*PTED*, p 73.

IV. The interaction of old and new generation technologies in planning decisions: the role of portfolio analysis

A. Introduction

This section introduces a conceptual framework for state commissions and other decision-makers to apply the information on individual generation technologies for making socially desirable decisions. These decisions reflect the objectives underlying generation planning subject to economic, environmental, political and public acceptability, and other constraints. Comprehending the nature and major characteristics of individual generation technologies is a first step in planning. Parts II and III of this report provide information useful in achieving that comprehension. The second step involves evaluating each of these technologies in the context of a power system consisting of existing generation facilities and customers with specific demand characteristics. Carrying out the second step requires a framework that blends the information on new and existing generation technologies to derive a desirable planning outcome.

From the perspective of the decision-maker, a framework for integrating optimally new and existing generation technologies on a power system demands more than information about the characteristics of individual technologies. It also requires factors such as: (1) specification of the objectives underlying generation planning, (2) the weights imputed for each objective (e.g., the importance of achieving the lowest cost for electricity relative to improving environmental quality), and (3) the tradeoffs between conflicting objectives (e.g., the dollar cost in achieving a higher reliability level). The collection of information on individual generation technologies combined with the application of an analytical framework can help identify and quantify the consequences of alternative ways for trading off alternative objectives.

B. A paradigm for generation planning: the portfolio approach

1. Background on the portfolio approach

A framework well suited to conceptualize the optimal interaction of both old and new generation technologies on a power system is the portfolio approach (PA). PA, originally developed for financial assets, offers several perspectives on the economics of merging different physical assets such as generating facilities into a group of assets or a portfolio.[213] PA has the feature of making decision-makers cognizant of the tradeoffs between different objectives (i.e., objectives for which advancing one compromises another). As applied to both financial and physical assets, PA emphasizes the importance of managing risk to a tolerable level for decision-makers.

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[213] See, for example, Harry Markowitz, "Portfolio Theory," *The Journal of Finance* 7 (March 1952), pp. 77-91.

PA helps decision-makers achieve efficient outcomes by minimizing the opportunity cost of a particular decision. Put another way, PA assists a decisionmaker in attaining one objective (e.g., acceptable level of fuel price risk) with minimum impediment of other objectives (e.g., total fuel cost). Recognizing that no single generation technology can advance all societal objectives, PA attempts to balance various objectives ascribed to generation planning. In other words, no generation technology emerges as an elixir for addressing all societal objectives associated with generation planning. Exploiting one or more of them inevitably will involve tradeoffs and, thus, tough choices, in advancing societal objectives

The term "societal objectives" reflects the multi-objective nature of generation planning. These objectives encompass economic, environmental and other facets of generation planning. Even within the economic category, there are sub-dimensions (e.g., least-cost, risk minimization); the same holds for environmental effects (e.g., air pollutants, nuclear waste, aesthetics). In the 1990s, natural gas was the fuel of choice for the vast majority of new generating facilities because of its attractive economic and environmental attributes, which alleviated the need for decision-makers to trade off different objectives.

Any portfolio, whether of financial assets, generation assets, or any other assets, has a risk. In this context, "risk" means the possibility that the outcome will deviate negatively from the expected outcome. Portfolio theory says that the risk of a portfolio comprised of different components relates to: (1) the inherent risks of individual assets, (2) the share of individual assets in a portfolio, and (3) the covariances between the different assets (i.e., the interdependency of different assets where events affecting one asset also affect others).[214] This paradigm accounts for the dissimilar characteristics of generation technologies by amalgamating them into a grouping of facilities that satisfies multiple objectives most efficiently.

As an illustration, let us assume that one technology has lower generation costs than a second technology, but it has higher environmental costs. Under PA, the decision-maker would gather information on the generation costs-environmental costs combinations where minimal generation costs occur at different levels of environmental costs; or equivalently, where minimal environmental costs occur at different levels of generation costs. From these various efficient combinations, the decision-maker chooses the one best corresponding with his preference for low generation costs relative to low

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[214] Expressed mathematically: The expected return for a portfolio with i electricity generation technologies equals $E(R_p) = \Sigma\, w_i E(R_i)$, where $E(R_i)$ is the expected "return" from technology i and w_i is the weight of technology i held in portfolio p (e.g., the net electricity generation from i technology relative to total net generation). The risk of the portfolio is equal to its variance: $\sigma^2_p = \Sigma\Sigma w_i w_j \mathrm{cov}(i,j)$, where cov(i,j) is the covariance between two technologies i and j. Covariance measures the diversity of the portfolio, with a lower value reflecting greater diversity and lower overall portfolio risk, assuming other things held constant.

environmental costs. For example, in the hypothetical case where the decision-maker places no value on a clean environment, he would always choose the low generation-cost technology to supply 100 percent of the electricity. At the other extreme, indifferent to the magnitude of generation costs, the decision-maker would select only the low environment-cost technology. In the real-world case where the decision-maker imputes value to both lower generation costs and lower environmental costs, he would select both technologies proportionally to the value he places on low generation costs relative to low environmental costs.

2. The rationale for the portfolio approach

The rationale for the application of PA to generation planning stems from three major sources. The first is the uncertainty and risk facing decision-makers over all facets of generation planning.[215] For example, new generation technologies share one or more of the risks pertaining to: technology design, development and siting, construction costs, future legislation and regulations, operating performance, fuel price and supply, waste and other byproducts, and dispatching of generation facilities. With uncertainty quantifiable, PA can measure the risks associated with different groupings of generation technologies. It can also measure the effect on other objectives (e.g., minimum generation costs) when risk assumes different levels.

Although managing risk constitutes an important function for risk-averse firms and society, in almost all instances minimizing risk would impose a prohibitive cost. The tradeoff involved in reducing risk through the grouping of assets requires compromising other objectives (for example, least-cost generation for a utility system). Rather than minimizing risk, the objective of most corporate entities involves selecting the risk-versus-other-objectives combination most compatible with the mission and goals of the firm in addition to preventing future states of nature that would cause them undue stress. For this reason, the term managing risk is more appropriate than minimizing risk when describing regulatory or societal goals for generation planning.

Rationalizing the use of PA can also come from the multi-objective nature of generation planning. In the case of financial assets, PA assumes an objective other than merely maximizing expected return or minimizing risk. A portfolio of different assets usually means managing risk at a cost acceptable to the decision-maker subject to the degree and nature of her risk adversity (i.e., her preference for reducing risk relative to advancing other objectives). As an example, selecting a specific generation technology, or group of technologies, may stem from its lower risks relative to other technologies,

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[215] Uncertainty differs from risk. Uncertainty exists when the decisionmaker is unable to identify future events; or can identify them but is unable to assign them probabilities. Risk assumes the availability of this information. See Andrew Stirling, "Diversity and Ignorance in Electricity Supply Investment," *Energy Policy* 22 (1994), pp. 195-216. The author argues that diversity in an environment of ignorance or a high uncertainty over the future state of affairs (i.e., where quantification of the likelihood of future events is infeasible) has inherent benefits.

even if these other technologies have lower expected generation costs. As the number and variations of objectives increase, on many occasions a portfolio of generation assets with dissimilar characteristics would be socially desirable. If at one extreme the only objective is to minimize generation cost, the socially preferred portfolio would be both easier to identify and less diversified (i.e., having assets of a similar nature) than if several objectives come into play.

A third rationale for PA lies with the heterogeneity of different generation technologies. Heterogeneity can produce benefits when the inter-asset differences are complimentary. An example of complimentary assets is oil stocks paired with airline stocks. The price of oil stocks tends to move in the opposite direction of the price of airline stocks, because airline profits drop when their operating costs rise. Thus, a portfolio with only these two stocks would have much less risk than if the portfolio consists of only one of these stocks or if the portfolio includes stocks whose prices tend to move in the same direction.

3. The goal: complementarity, not diversity

Diversity exists in many systems – biological, social, financial and physical systems, among others. A diverse system contains dissimilar elements. In a diverse system, dissimilarity produces benefits if its heterogeneous elements complement each other. Complementary traits include those that compensate for the deficiencies and shortcomings of others.[216] The goal is not diversity for diversity's sake, but diversity which produces complementarity.

Fossil fuels and renewable energy complement each other. Fossil fuel generation has lower present cost, but renewable energy insulates against environmental compliance costs incurred by the fossil fuels. An example of a non-complementary relationship is two fuels (for example, natural gas and oil) whose prices move together. With these two fuels in the same portfolio, neither one protects against adverse events associated with the other.

Complementary generation technologies in a portfolio achieve robustness. Robustness reflects a system's ability to withstand adverse events, external or internal failures. Applied to generation planning, robustness reduces the risks to customers of adverse events like equipment failures, or price spikes or shortages in particular fuels. Robustness includes flexibility -- the electricity system's ability to respond quickly to unforeseen events. Flexibility can permeate the planning and operations processes of power systems. Robustness at reasonable cost is the goal of generation planning: to

[216] Congress has recognized the relevance of diversity. EPAct 2005, adding to the PURPA a new section 111(d)(12), requires each state to consider whether each electric utility under its jurisdiction "shall develop a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to customers is generated using a diverse range of fuels and technologies, including renewable technologies."

identify those groupings of technologies that best complement each other in attaining a balanced mix of predetermined objectives.

The concept of diversity relates to PA in different ways. PA recognizes the value of diversity in achieving the specified objectives. For example, if the objective is to avoid catastrophic outcomes, then diversity can act as insurance against such results. Diverse power systems or financial portfolios tend to be more adaptable to external changes. A network with a greater variety of generation facilities would more likely have a greater capacity to adapt to large or small internal or external changes. In other words, a more diverse network is better able to respond to contingencies by avoiding seriously adverse outcomes.

The various conditions rationalizing PA also applies to diversity. With multiple objectives, an optimal decision would more likely involve a diverse portfolio to mitigate unacceptable risk. As an example, selecting a specific generation technology, or group of technologies, may stem from its lower risks relative to other technologies, even if these other technologies have lower generation costs. As the number and variations of objectives increase, generally a more diversified portfolio of generation assets would be acceptable to decision-makers. Since no single generation technology by itself best advances all objectives, a diversified portfolio of generating plants becomes more tenable.

When uncertainty inevitably becomes part of the landscape, both PA and diversity takes on added importance. Uncertainty and risk increase the benefits from selecting a mix of generation assets with dissimilar characteristics. Finally, in recognizing benefits from a grouping of heterogeneous assets in a portfolio, PA explicitly places a value on diversity. PA suggests that an optimal outcome oftentimes involves the blending of assets with dissimilar and complementary characteristics. Overall, PA can assist decision-makers in examining the merits of a diverse portfolio in mitigating risks and advancing other societal objectives.

PA recognizes that while diversity can produce good results, it also can lead to adverse effects when not implemented carefully. By definition, optimal diversity maximizes net societal benefits, with departures from optimality resulting in a net cost. The cost of excessive diversity – or diversity for the sake of diversity -- can derive from the following sources: (1) lost scale economies resulting from the reduced operation of technologies (e.g., baseload plants) that require intensive use to exploit their full benefits on a power system; (2) transaction costs stemming from the acquisition and validity of information for generation technologies unfamiliar to the utility; and (3) additional capital and operating costs associated with configuring generating units to make them more flexible (for example, to handle alternative fuel sources or to interact complementarily with other generating plants). A co-author of this report previously concluded that fuel and technology diversity, considered alone, is not necessarily desirable. The desirability of diversity hinges on its ability to advance specified societal objectives, collectively, taking into account the various constraints and risks associated

with those objectives. He concluded that decision-makers should not bind themselves to a pre-specified diversity target.[217]

4. Implications of PA for generation planning

A generation portfolio aggregates the old and the new. A decision about new generation therefore must take into account existing generation. The decision-maker must ask not only "Do I like this proposed generation technology?" but also "Does adding this technology to my existing portfolio help achieve my multiple objectives?" Generation planning requires consideration of the interaction among possible new options with existing generation. Decision-makers should consider whether current procedures accommodate such analysis.[218]

In the typical generation approval proceeding, the proponent proffers a single generation option in detail. Less detail is available on how the proposed plant, and the rejected plants, would interact with existing generation. A selection process that focuses the decision-maker on a single option does not fit well with PA considerations. Evaluation of an option on a stand-alone basis ignores the benefits and costs of the option – and other options -- on the power system network. In sum, evaluation of different generating technologies requires evaluation of alternative resource portfolios.

The application of PA to generation planning explicitly accounts for the risk effects of different technologies on a power system. Although a particular technology can have high risk on a stand-alone basis, when combined with existing plants the risk can decrease and become societally desirable. PA also helps decision-makers to conceptualize the tradeoffs between different planning objectives. It goes further by quantifying the benefits and costs of advancing certain objectives at the expense of others. PA accounts for the tradeoffs between different planning objectives by identifying the most efficient way to advance one or more objectives. For example, in moderating risk to a specified level, PA can show the preferred approach in terms of minimizing the increase in generation costs.

Some critics of PA application to physical assets – for example, generation facilities -- argue that the underlying theory is more pertinent to financial assets partially because of they can more easily be bought and sold on the open market at incremental quantities. Critics also point to the complexities of applying PA to generation technologies because of the multiple objectives. (i.e., in addition to risk and generation costs, typically decision-makers judge technologies because of their environmental,

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[217] Ken Costello, *Making the Most of Alternative Generation Technologies: A Perspective on Fuel Diversity*, NRRI Briefing Paper (05-02), March 2005.

[218] For additional insights on the applicability of portfolio theory to generation planning, see Shimon Awerbuch, "Portfolio-Based Electricity Generation Planning: Policy Implications for Renewables and Energy Security," *Mitigation and Adaptation Strategies for Global Change* 11 (2006), pp. 693-710.

safety, and reliability effect, among others). Critics also contend that the immeasurable nature of probabilities for many future events diminishes the usefulness of PA or any tool that attempts to quantify the effects of those events. PA also requires a well-defined preference function for the different objectives of generation planning, in addition to covariance coefficients (i.e., measures of the interdependencies between different technologies in response to events), both of which are difficult to quantify.[219] Even the validity of these criticisms, however, does not prevent PA from offering decision-makers a useful conceptual framework to evaluate new generation technologies.

C. Applying portfolio analysis to generation: five steps

Determining an appropriate generation portfolio requires a five-step analysis. Each step involves the regulator's judgment:

1. *Identify the objectives of generation planning.* These objectives can include reasonable generation costs, a clean environment, high power-system reliability and moderate price risk; the specification of objectives affects the ranking and selection of new technologies.

2. Determine the relative weights of the individual objectives. For example, the regulator values low cost, and she values low environmental impact. By assigning weights to these desires, preferably through quantification (to allow for apples-to-apples comparisons), she can make the tradeoffs -- the opportunity costs - - explicit. This explicitness aids rational decisionmaking in the achievement of societal goals.

3. *Identify inherent characteristics of individual technologies.* For example, natural gas technologies have high price risk relative to other technologies while nuclear power has high construction cost and public-acceptability risks; information on individual technologies provides critical, but not sufficient, input into the generation planning process and the determination of socially optimal decisions.

4. *Recognize and consider "tradeoff" effects.* An example is the added generation cost associated with higher environmental quality or lower price risk. With no single technology advancing all societal objectives by itself, a balanced grouping of different technologies can best satisfy overall generation-planning goals; moving toward one or more technologies inevitably will involve tradeoffs and, thus, tough choices for decision-makers, in advancing societal objectives.

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[219] See Nigel Lucas *et al.*, "Diversity and Ignorance in Electricity Supply Investment: a Reply to Andrew Stirling," *Energy Policy* 23, no. 1 (1995), pp. 5-7; and Frank C. Graves, "Response to Synapse Report," unpublished paper, August 2006, available at: http://www.brattle.com/_documents/Publications/ArticleReport2408.pdf.

5. *Create efficient portfolios.* An efficient portfolio advances the desired objectives at minimum cost. The decisionmaker has multiple objectives. Some of these objectives are in opposition to each other (e.g., price level vs. price predictability). She seeks to minimize the tradeoffs among opposing objectives so that the achievement of one occurs at minimum cost to another. In regard to financial assets, PA derives an "efficient frontier" that maps out the set of portfolios with the maximum expected return for every given level of risk, or the minimum risk for every level of expected return; portfolios along the efficient frontier are preferable to all other portfolios; portfolios off the efficient frontier are ether infeasible or inefficient.

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

V. Conclusion

This report has discussed two steps necessary to ensuring an appropriate mix of generation: develop an understanding of different generation technologies and how those technologies can fit together in a portfolio. A regulator should also examine the possibility of using demand-side responses or providing additional investment in energy efficiency as a lower-cost alternative to additional generation capacity.

A state commission is responsible for advancing the public's need for affordable, available, and environmentally-acceptable sources of electricity. The regulator should determine what authorities his or her commission has over generation resource decisions and what new authorities the commission needs to fulfill its responsibilities. Regulators should also determine how to participate effectively in any regional and national planning processes.

A regulator should understand that a state commission's decision on future generation is shaped by the state and region's current mixture of generation. There are infrastructure costs and benefits from currently predominant technologies. Existing pipelines, railways, and transmission corridors all exert influence on the feasibility of alternative technologies. Currently predominant technologies also offer a familiarity to both regulators and utilities, but regulators should inform themselves about other alternatives.

In addition, commissions should recognize that the condition of a state or region's retail or wholesale market and the markets' ability to send clear signals to power producers also determines what technologies will be feasible. Ultimately, new plants are only built unless prices provide a return on investment to cover the cost of building and running the plant.

This report offers an approach for state commissioners to employ for evaluating different generation technologies. Technological considerations are only one factor among many in determining the proper mix of generation, however. In short, the judgment of decision-makers is critical when commissions make choices about generation choices. This judgment revolves around decision-makers' perceptions of the public policy objectives attached to electricity generation, their assessment of the possible risks and rewards offered by the technologies, and the decision-makers' comfort with those risks and rewards.

Appendix A

State renewable portfolio standards:

The percentage or amount of generation that must come from renewable sources by a given target year.

State	Year Enacted	Year Revised	Initial target	Final target
Arizona	2001	2006	0.2% by 2001	15% by 2025
California	2002	2005	13% by 2003	33% by 2020
Colorado	2004		3% by 2007	10% by 2015
Connecticut	1999	2003	4% by 2004	10% by 2010
Delaware	2005		1% by 2007	10% by 2019
District of Columbia	2005		4% by 2007	11% by 2022
Hawaii	2004		7% by 2003	20% by 2020
Illinois (voluntary)	2005		2% by 2007	8% by 2013
Iowa	1991		None	105 MW
Maine	1999		None	30% by 2000
Maryland	2004		3.5% by 2006	7.5% by 2019
Massachusetts	1997		1% new by 2003	4% new by 2009
Minnesota	1997		1,125 MW by 2010	1,250 MW by 2013
Montana	2005		5% by 2008	15% by 2015
Nevada	1997	2005	6% by 2005	20% by 2015
New Jersey	2001	2004	6.5% by 2008	20% by 2020
New Mexico	2002	2004	5% by 2006	10% by 2011
New York	2004		None	25% by 2013
Pennsylvania	2004		1.5% by 2007	18% by 2020
Rhode Island	2004		3% by 2007	16% by 2020
Texas	1999	2005	2,280 MW by 2007	5,880 MW by 2015
Vermont	2005		None	Load growth by 2012
Wisconsin	1999	2006	None	10% by 2015

Source: Barry R. Rabe, "Race to the Top: The Expanding Role of U.S. State Renewable Portfolio Standards," Pew Center on Global Climate Change, June 2006, p. 4.

Appendix B

Carbon dioxide capture and storage

Electricity generation results in multiple externalities. The technology-specific sections of Part III of this report describe the most salient externalities for each technology. This appendix addresses in more detail the emission of carbon dioxide (CO_2), which is produced by all of the fossil-fueled plants. The likelihood of future regulation of CO2 has reached a level warranting state commissions' attention. National, regional, or state-level policies to lower emissions of CO_2 will affect comparisons of generation technologies.[220]

CO_2 capture and storage (CCS) is one means of limiting the amount of CO_2 released into the atmosphere, namely by removing CO_2 from the flue gas of fossil fuel-based electricity generation plants. CCS consists of the separation of CO_2 from a plant's emissions, compression of the CO_2, transport to a storage location, and long-term sequestration from the atmosphere in subsurface geologic formations.[221]

The cost of a full CCS system for a new fossil fuel-based generation plant depends on a number of factors, including the characteristics of the power plant, the capture system, and the storage site; the amount of CO_2; and the transport distance. Capture (including compression) of CO_2 is the largest cost component.[222] There is little experience using CSS as an integrated system, so the data reported here about the cost of CSS are general estimates. Using data from multiple countries, the International Panel on Climate Change estimates that using CCS with a new plant increases the cost of producing electricity in comparison to a similar plant without a CCS system.[223] The costs are reported in Table 2 below.

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[220] The 110th Congress is considering legislation to limit greenhouse gas emissions. Currently there are greenhouse gas measures in place in the Northeast (the Regional Greenhouse Gas Initiative; see www.rggi.org) and California (The Global Warming Solutions Act of 2006).

[221] Intergovernmental Panel on Climate Change (IPCC), *Special Report on Carbon Dioxide Capture and Storage*, IPCC, Geneva, Switzerland, 2005. Report available at: http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final/IPCCSpecialReportonCarbondioxideCaptureandStorage.htm.

[222] Ibid., p. 9.

[223] Ibid., Table TS.10, p. 43. As the IPCC report indicates at footnote 5 (p. 27), "The cost of electricity production should not be confused with the price of electricity to customers." The production cost in the report excludes the capital cost of the generating unit. If the cost of CCS is applied to the total cost of electricity (capital plus operating cost) the percentage increase in cost from the use of CCS is lower than the figures reproduced in this appendix.

Table 2

Increase in cost of producing electricity with carbon capture and storage for selective technologies

Technology	Pulverized coal	Natural gas combined cycle	Integrated gasification combined cycle
Cost of producing electricity without CSS ($/kWh)	0.043 – 0.052	0.031 – 0.050	0.041 – 0.061
Increase in cost of producing electricity with CCS ($/kWh)	0.019 – 0.047	0.012 – 0.029	0.010 – 0.032
Percentage increase in cost of producing electricity with CCS	43 – 91%	37 – 85%	14 – 53%

Plant emissions can be lowered to nearly zero by employing CCS with hydrogen as the power plant fuel. Such a plant is technically feasible now, but no hydrogen-fueled combustion turbine is commercially available at present.[224] The FutureGen initiative is a partnership between DOE and private companies to develop a zero emissions IGCC plant with hydrogen fueled combustion.[225]

[224] Charles, R., *et al.*, *Study of Potential Mohave Alternative/Complementary Generation Resources Pursuant to CPUC Decision 04-12-016,* Sargent & Lundy and Synapse Energy Economics report prepared for Southern California Edison, pp. 2-25, 2006.

[225] See http://www.fossil.energy.gov/programs/powersystems/futuregen/.

Appendix C

List of acronyms

AFC	Alkaline fuel cell
Btu	British thermal unit
BWR	Boiling water reactors
CAES	Compressed air energy storage
CAIR	Clean Air Interstate Rules
CAMR	Clean Air Mercury Rules
CCGT	Combined cycle gas turbine
CGT	Combustion gas turbine
CCS	Carbon dioxide capture and storage
CHP	Combined heat and power
CO_2	Carbon dioxide
CSP	Concentrated solar power
CWIP	Construction work in progress
DOE	United States Department of Energy
EIA	Energy Information Administration, United States Department of Energy
EIS	Environmental impact statement
ELCC	Effective load-carrying capacity
EPAct	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulphurization
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated resource planning
ISO	Independent system operator
kW	Kilowatt
kWh	Kilowatt-hour
LOLP	Loss of load probability
Mcf	Million cubic feet
MCFC	Molten carbonate fuel cells

Appendix D

Generation technology diagrams

Figure 1: Combined cycle gas turbine
(Source: DOE, Office of Energy Efficiency and Renewable Energy)

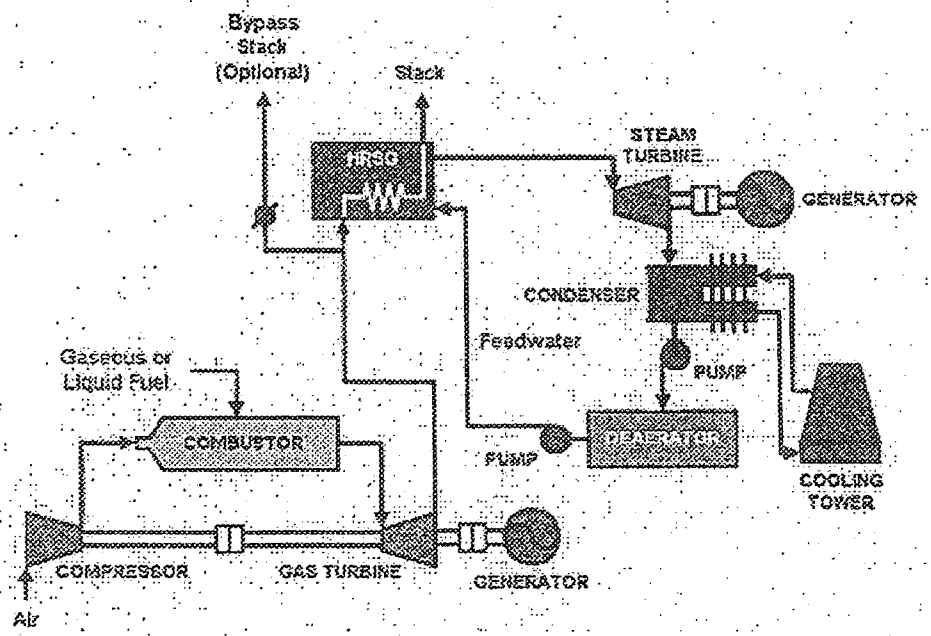


Figure 2: Combustion gas turbine
(Source: Tennessee Valley Authority)

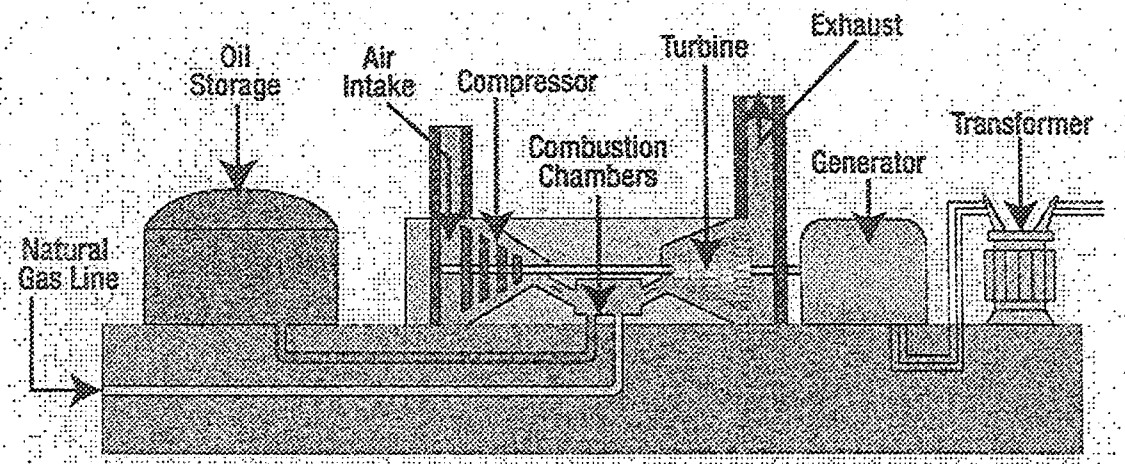


Figure 3: Pulverized coal generation
(Source: Tennessee Valley Authority)

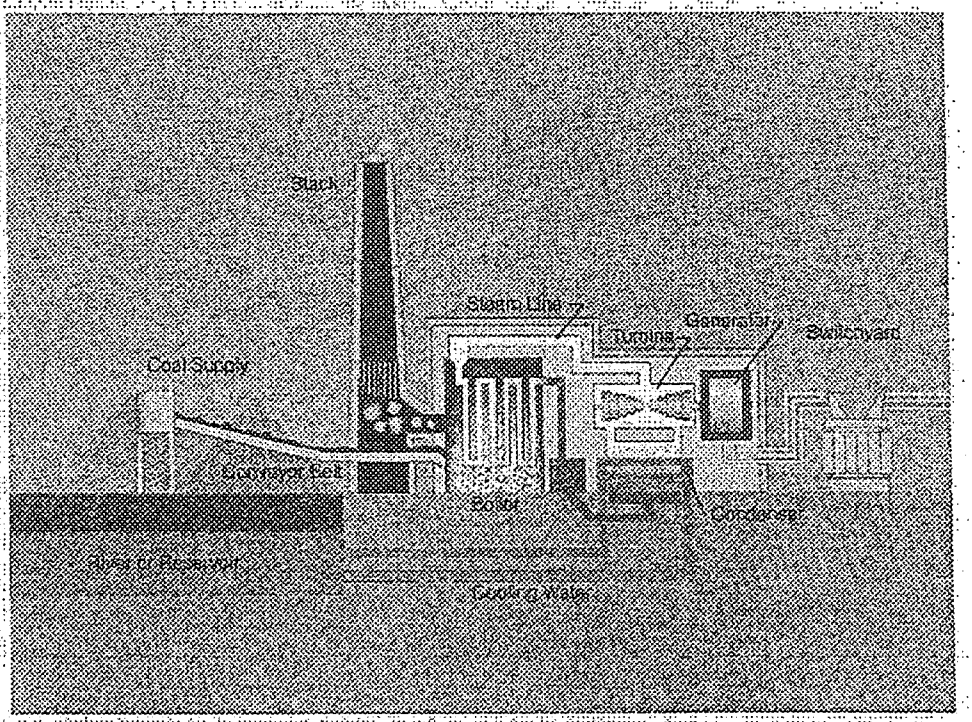


Figure 4: Fluidized bed combustion
(Source: DOE, National Energy Technology Laboratory)

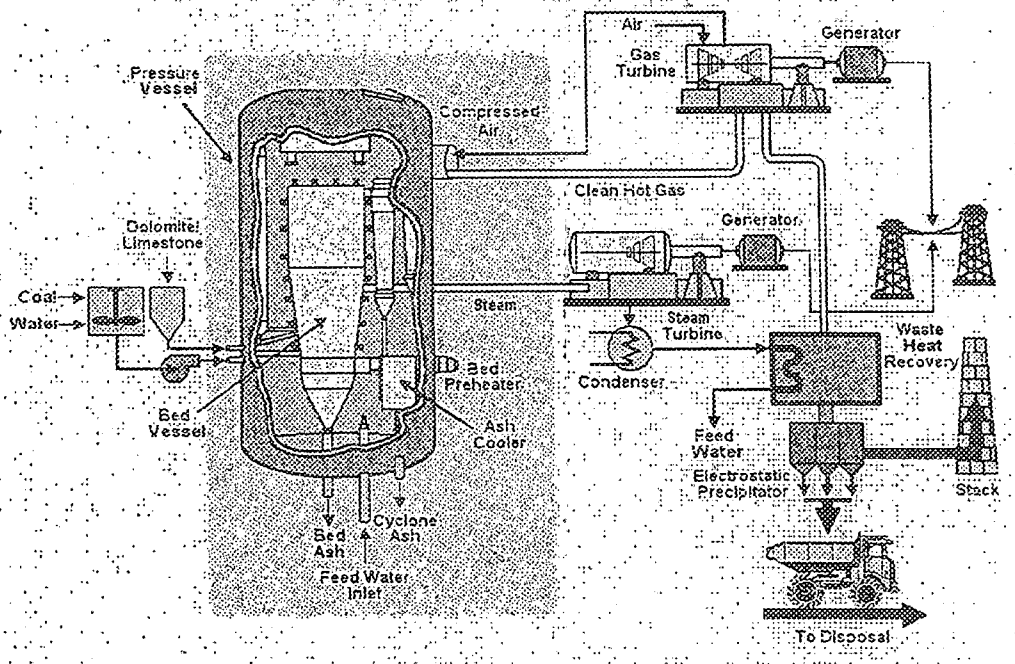


Figure 5: Integrated gasification combined cycle (IGCC) generation
(Source: DOE, National Energy Technology Laboratory)

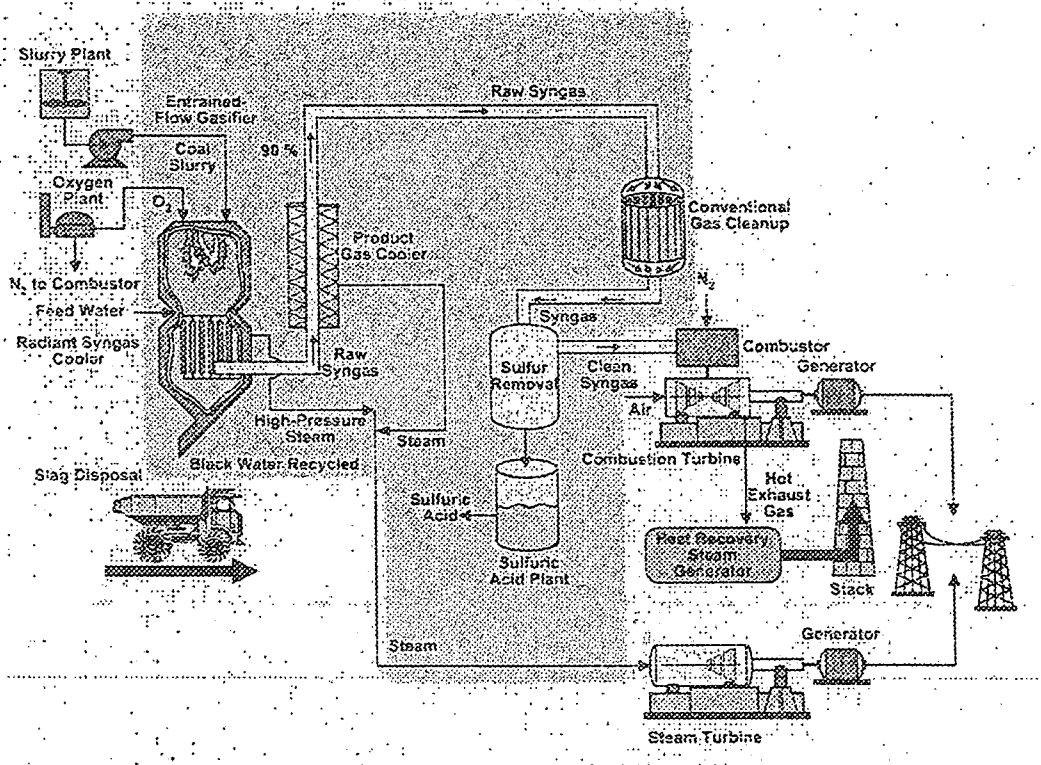


Figure 6: Pressurized water nuclear reactor
(Source: Tennessee Valley Authority)

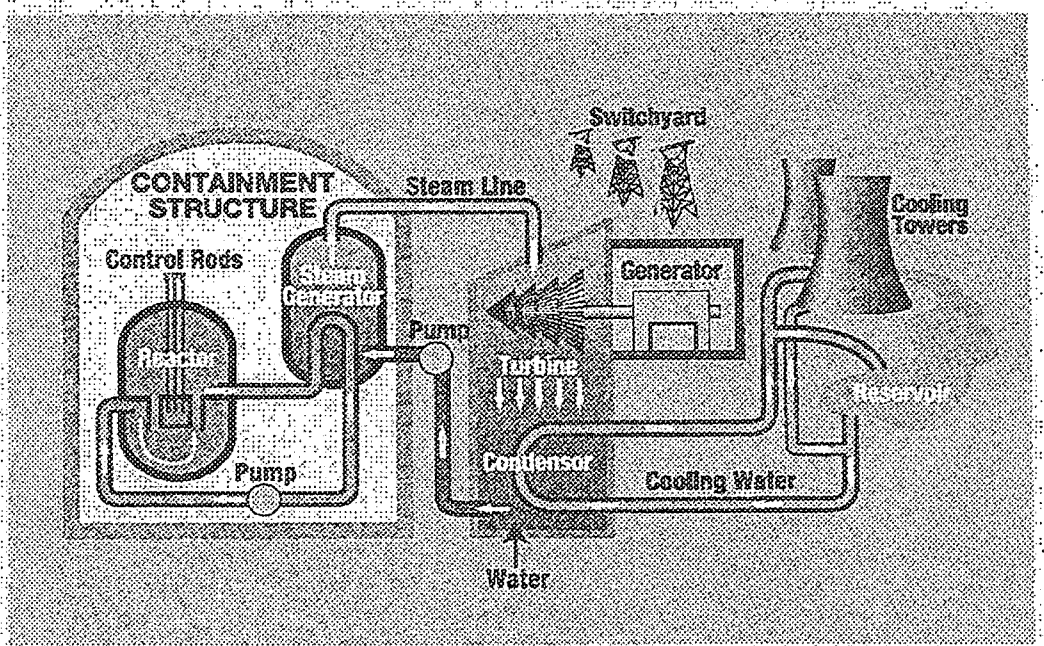


Figure 7: Wind turbine
(Source: DOE, National Renewable Energy Laboratory)

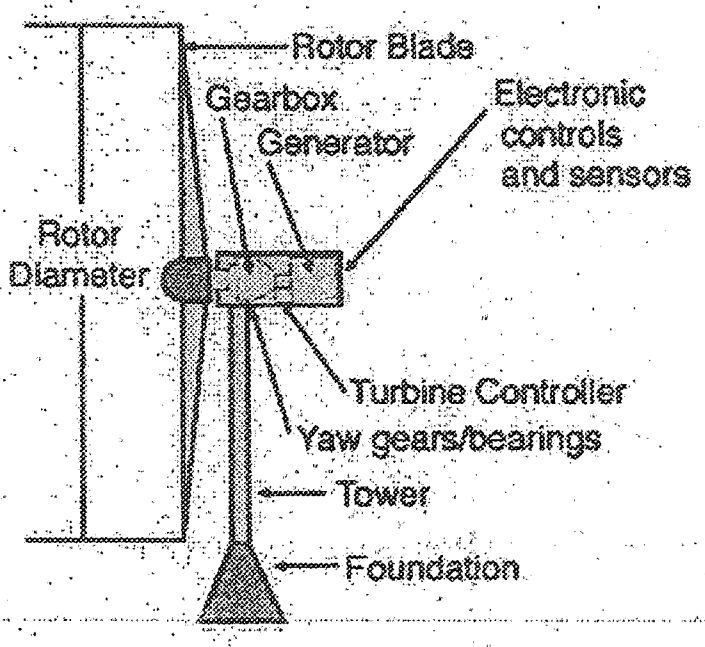


Figure 8: Pumped-storage hydropower
(Source: Tennessee Valley Authority)

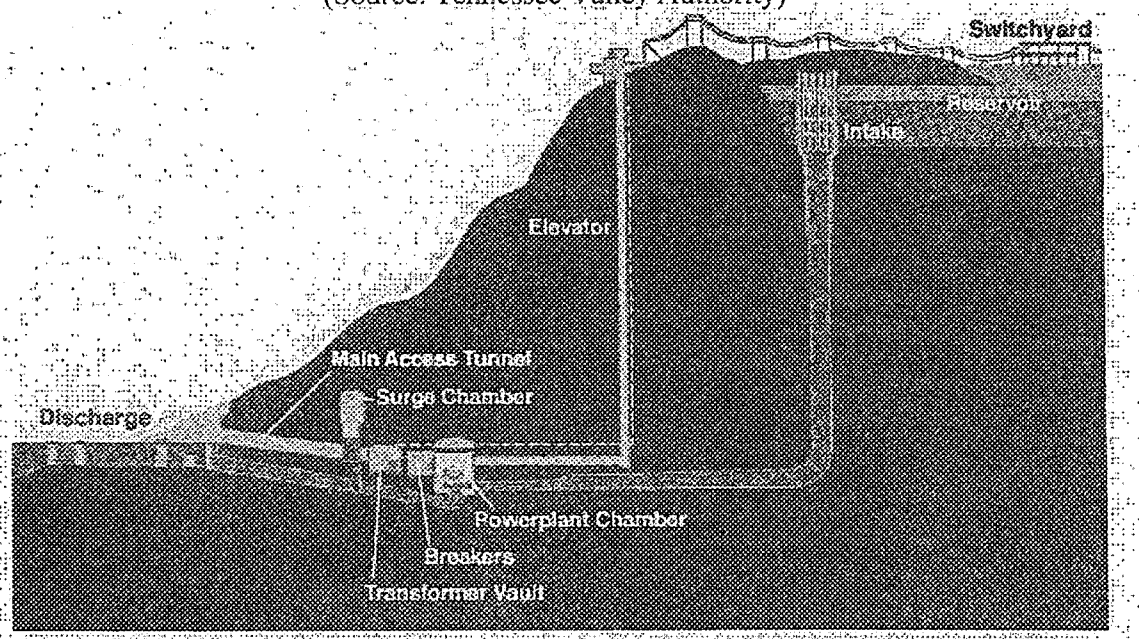


Figure 9: Photovoltaic power
(Source: DOE, National Renewable Energy Laboratory)

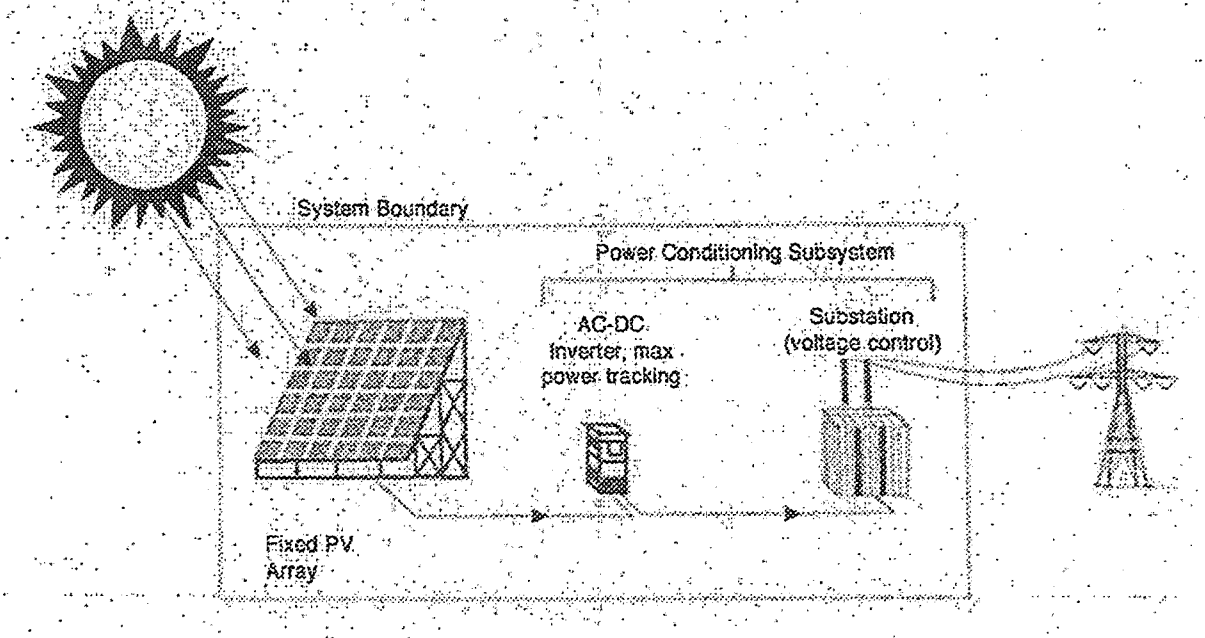


Figure 10: Concentrated solar power
(Source: DOE, National Renewable Energy Laboratory)

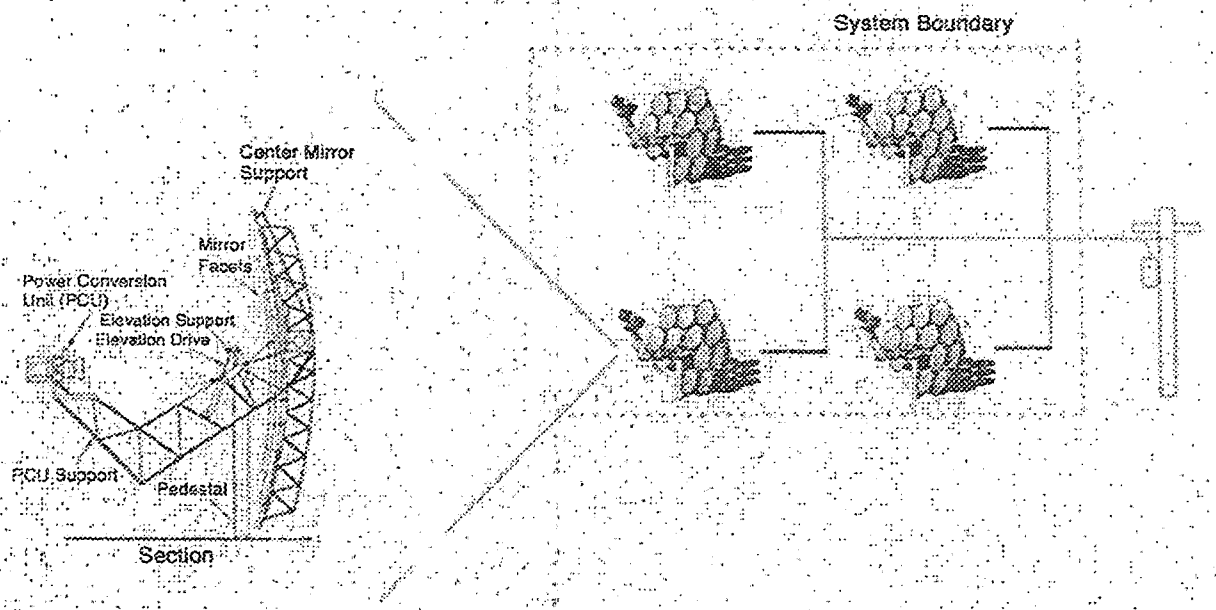


Figure 11: Biomass power
(Source: DOE, Office of Energy Efficiency and Renewable Energy)

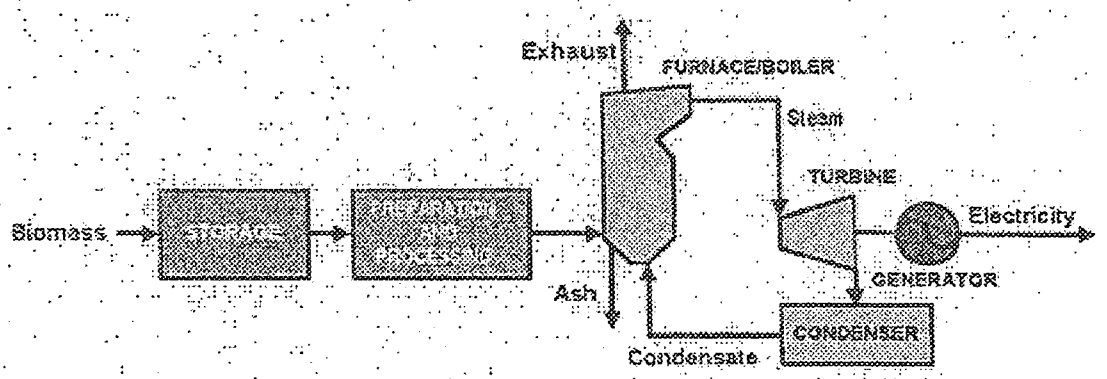


Figure 12: Geothermal power (binary-cycle)
(Source: DOE, Office of Energy Efficiency and Renewable Energy)

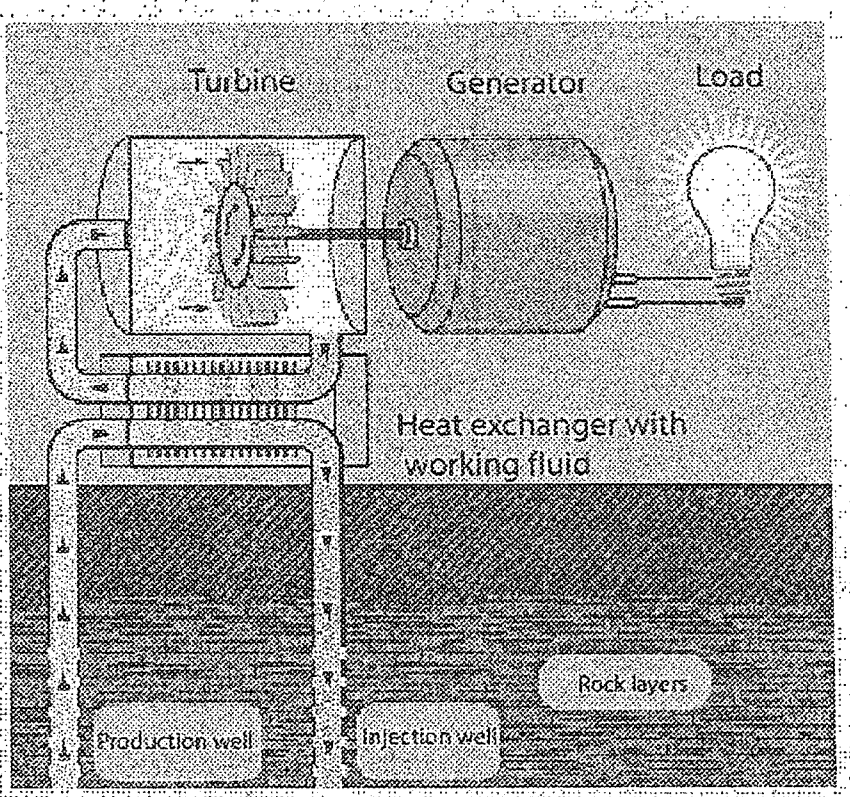


Figure 13: Tidal turbine
(Source: DOE, Energy Information Agency)

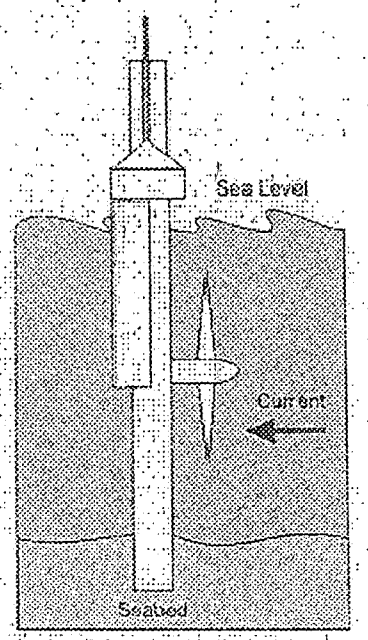
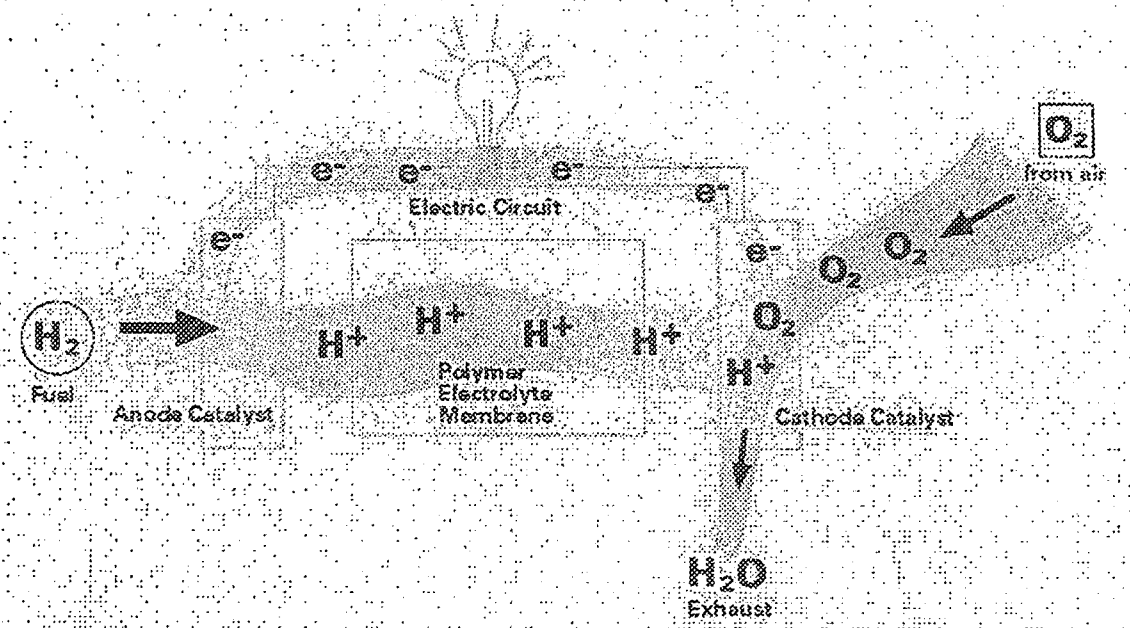


Figure 14: Fuel cell
(Source: DOE, National Renewable Energy Laboratory)



Appendix E: Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Alabama	Combined cycle	Natural gas	55	8,699.8	7,857.4	3	4	7
		Total	55	8,699.8	7,857.4	3	4	7
	Combustion (gas) turbine	Distillate fuel oil	1	21.2	16.0	36	36	36
		Natural gas	29	2,400.0	2,172.6	7	10	34
		Total	30	2,421.2	2,188.6	7	11	34
	Hydraulic turbine	Water	101	3,238.9	3,199.0	40	56	77
		Total	101	3,238.9	3,199.0	40	56	77
	Internal combustion engine	Distillate fuel oil	13	26.6	26.6	6	8	9
		Total	13	26.6	26.6	6	8	9
	Steam turbine	Biomass	5	192.4	181.5	24	27	28
		Coal	39	12,359.1	11,284.9	35	46	52
		Natural gas	2	49.0	38.0	21	30	39
		Nuclear material	4	4,118.4	3,943.0	27	29	30
		Other coal	1	269.2	255.0	40	40	40
		Other gas	3	28.8	19.8	9	48	48
		Total	54	17,016.9	15,722.1	28	41	51
	Total	Biomass	5	192.4	181.5	24	27	28
		Coal	39	12,359.1	11,284.9	35	46	52
		Distillate fuel oil	14	47.8	42.6	6	8	10
		Natural gas	86	11,148.8	10,068.0	4	6	11
		Nuclear material	4	4,118.4	3,943.0	27	29	30
		Other coal	1	269.2	255.0	40	40	40
		Other gas	3	28.8	19.8	9	48	48
		Water	101	3,238.9	3,199.0	40	56	77
		Total	**253**	**31,403.4**	**28,993.7**	**8**	**36**	**53**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Alaska	Combined cycle	Natural gas	6	388.7	329.4	27	28	30
		Total	6	388.7	329.4	27	28	30
	Combustion (gas) turbine	Distillate fuel oil	9	241.7	212.2	23	29	30
		Natural gas	22	490.2	460.1	22	30	38
		Total	31	731.9	672.3	22	29	35
	Hydraulic turbine	Water	37	324.2	326.6	22	33	52
		Total	37	324.2	326.6	22	33	52
	Internal combustion engine	Distillate fuel oil	156	229.6	220.1	8	18	26
		Natural gas	2	3.0	3.0	12	12	12
		Total	158	232.6	223.1	8	17	26
	Steam turbine	Coal	15	108.5	104.9	31	42	54
		Total	15	108.5	104.9	31	42	54
	Total	Coal	15	108.5	104.9	31	42	54
		Distillate fuel oil	165	471.3	432.3	9	18	27
		Natural gas	30	881.9	792.5	22	28	35
		Water	37	324.2	326.6	22	33	52
		Total	**247**	**1,785.9**	**1,656.3**	**12**	**22**	**35**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Arizona	Combined cycle	Natural gas	64	11,635.2	9,561.3	3	4	5
		Total	64	11,635.2	9,561.3	3	4	5
	Combustion (gas) turbine	Distillate fuel oil	4	127.1	108.0	28	30	33
		Natural gas	39	1,795.8	1,635.8	4	32	34
		Total	43	1,922.9	1,743.8	4	32	34
	Hydraulic turbine	Water	34	2,718.0	2,720.4	41	55	67
		Total	34	2,718.0	2,720.4	41	55	67
	Internal combustion engine	Distillate fuel oil	1	1.5	1.5	16	16	16
		Natural gas	1	1.6	1.6	6	6	6
		Other gas	5	5.0	4.0	5	5	5
		Total	7	8.1	7.1	5	5	6
	Photovoltaic	Solar	7	9.0	9.0	4	5	8
		Total	7	9.0	9.0	4	5	8
	Pumped storage hydraulic turbine	Water	6	194.1	216.0	13	13	34
		Total	6	194.1	216.0	13	13	34
	Steam turbine	Biomass	1	3.0	2.5	2	2	2
		Coal	16	5,861.3	5,430.0	26	28	32
		Natural gas	13	1,393.5	1,285.0	46	48	51
		Nuclear material	3	4,209.3	3,875.0	18	20	20
		Total	33	11,467.1	10,592.5	26	32	46
	Total	Biomass	1	3.0	2.5	2	2	2
		Coal	16	5,861.3	5,430.0	26	28	32
		Distillate fuel oil	5	128.6	109.5	28	28	32
		Natural gas	117	14,826.1	12,483.7	3	5	33
		Nuclear material	3	4,209.3	3,875.0	18	20	20
		Other gas	5	5.0	4.0	5	5	5
		Solar	7	9.0	9.0	4	5	8
		Water	40	2,912.1	2,936.4	35	54	66
		Total	**194**	**27,954.4**	**24,850.1**	**4**	**20**	**35**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Arkansas	Combined cycle	Natural gas	30	4,667.3	4,042.0	3	4	4
		Total	30	4,667.3	4,042.0	3	4	4
	Combustion (gas) turbine	Natural gas	10	265.9	252.6	16	26	36
		Total	10	265.9	252.6	16	26	36
	Hydraulic turbine	Water	45	1,300.3	1,379.8	18	41	53
		Total	45	1,300.3	1,379.8	18	41	53
	Internal combustion engine	Distillate fuel oil	7	13.3	13.4	30	43	51
		Natural gas	3	19.2	18.0	5	5	5
		Other gas	3	1.5	1.5	23	23	23
		Total	13	34.0	32.9	15	23	43
	Pumped storage hydraulic turbine	Water	1	28.0	28.0	34	34	34
		Total	1	28.0	28.0	34	34	34
	Steam turbine	Biomass	12	366.5	294.0	15	32	44
		Coal	5	3,958.0	3,793.0	23	25	26
		Natural gas	14	2,457.5	2,359.0	40	53	56
		Nuclear material	2	1,845.0	1,834.0	26	29	32
		Total	33	8,627.0	8,280.0	26	38	52
	Total	Biomass	12	366.5	294.0	15	32	44
		Coal	5	3,958.0	3,793.0	23	25	26
		Distillate fuel oil	7	13.3	13.4	30	43	51
		Natural gas	57	7,409.9	6,671.6	4	6	36
		Nuclear material	2	1,845.0	1,834.0	26	29	32
		Other gas	3	1.5	1.5	23	23	23
		Water	46	1,328.3	1,407.8	18	41	53
		Total	**132**	**14,922.5**	**14,015.3**	**6**	**31**	**44**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
California	Combined cycle	Natural gas	171	15,910.4	13,457.3	3	12	18
		Other gas	4	35.2	28.7	4	13	20
		Total	175	15,945.6	13,486.1	3	12	18
	Combustion (gas) turbine	Distillate fuel oil	14	651.7	536.7	26	29	30
		Natural gas	221	6,623.6	6,054.2	5	18	21
		Other gas	18	248.5	203.3	7	17	19
		Other petroleum	1	15.0	14.0	35	35	35
		Total	254	7,538.8	6,808.2	5	18	22
	Geothermal binary cycle turbine	Geothermal	22	99.5	91.4	13	15	16
		Total	22	99.5	91.4	13	15	16
	Hydraulic turbine	Water	430	9,978.2	10,079.7	22	45	82
		Total	430	9,978.2	10,079.7	22	45	82
	Internal combustion engine	Distillate fuel oil	10	24.0	24.0	37	37	41
		Natural gas	84	160.7	152.7	5	15	17
		Other gas	91	116.1	107.9	7	13	21
		Total	185	300.8	284.6	6	15	21
	Other	Waste heat	1	7.5	7.5	23	23	23
		Total	1	7.5	7.5	23	23	23
	Photovoltaic	Solar	2	2.0	2.0	20	21	22
		Total	2	2.0	2.0	20	21	22
	Pumped storage hydraulic turbine	Water	30	3,352.6	3,688.4	29	38	39
		Total	30	3,352.6	3,688.4	29	38	39
	Steam turbine	Biomass	34	660.7	589.2	16	17	21
		Coal	8	415.4	366.9	17	18	24
		Geothermal	125	2,632.8	1,903.4	18	19	20
		Natural gas	67	16,641.1	16,278.6	39	43	47
		Nuclear material	4	4,577.0	4,324.0	21	22	23
		Other gas	10	144.4	115.4	16	19	70
		Other petroleum	8	190.8	167.4	16	17	20
		Solar	9	400.4	399.8	18	19	20
		Waste	3	71.6	53.0	18	18	20
		Waste heat	1	19.3	19.3	17	17	17
		Total	269	25,753.5	24,217.0	17	20	33

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
California (continued)	Wind turbine	Wind	81	2,037.6	2,023.3	9	18	21
		Total	81	2,037.6	2,023.3	9	18	21
	Total	Biomass	34	660.7	589.2	16	17	21
		Coal	8	415.4	366.9	17	18	24
		Distillate fuel oil	24	675.7	560.7	28	31	37
		Geothermal	147	2,732.3	1,994.8	17	19	20
		Natural gas	543	39,335.8	35,942.8	5	17	21
		Nuclear material	4	4,577.0	4,324.0	21	22	23
		Other gas	123	544.2	455.3	7	15	21
		Other petroleum	9	205.8	181.4	16	17	23
		Solar	11	402.4	401.8	18	20	21
		Waste	3	71.6	53.0	18	18	20
		Waste heat	2	26.8	26.8	17	20	23
		Water	460	13,330.8	13,768.1	23	42	81
		Wind	81	2,037.6	2,023.3	9	18	21
		Total	**1,449**	**65,016.1**	**60,688.1**	**15**	**20**	**37**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Colorado	Combined cycle	Natural gas	30	2,750.1	2,311.0	7	12	16
		Total	30	2,750.1	2,311.0	7	12	16
	Combustion (gas) turbine	Distillate fuel oil	2	129.4	100.0	29	29	29
		Natural gas	34	2,344.0	1,788.3	4	5	7
		Other gas	2	7.0	5.0	6	6	6
		Total	38	2,480.4	1,893.3	4	6	7
	Hydraulic turbine	Water	49	634.1	646.1	21	52	75
		Total	49	634.1	646.1	21	52	75
	Internal combustion engine	Distillate fuel oil	43	68.8	64.9	13	42	58
		Natural gas	26	150.3	121.0	4	4	4
		Other gas	4	8.0	4.8	21	21	21
		Total	73	227.1	190.7	4	39	48
	Pumped storage hydraulic turbine	Water	5	508.5	562.5	25	39	39
		Total	5	508.5	562.5	25	39	39
	Steam turbine	Coal	31	5,304.4	4,923.7	27	38	47
		Natural gas	8	249.0	235.8	27	52	55
		Total	39	5,553.4	5,159.5	27	42	49
	Wind turbine	Wind	7	229.3	227.7	2	5	7
		Total	7	229.3	227.7	2	5	7
	Total	Coal	31	5,304.4	4,923.7	27	38	47
		Distillate fuel oil	45	198.2	164.9	29	42	57
		Natural gas	98	5,493.4	4,456.1	4	6	18
		Other gas	6	15.0	9.8	6	21	21
		Water	54	1,142.6	1,208.6	21	50	74
		Wind	7	229.3	227.7	2	5	7
		Total	**241**	**12,382.9**	**10,990.8**	**6**	**22**	**47**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Connecticut	Combined cycle	Natural gas	13	2,076.4	1,785.9	4	8	16
		Total	13	2,076.4	1,785.9	4	8	16
	Combustion (gas) turbine	Distillate fuel oil	5	104.9	96.8	2	2	34
		Natural gas	6	275.8	216.0	5	5	5
		Other gas	1	3.0	2.9	15	15	15
		Other petroleum	18	554.4	439.1	21	37	38
		Total	30	938.1	754.8	5	28	37
	Hydraulic turbine	Water	28	128.6	133.1	20	81	92
		Total	28	128.6	133.1	20	81	92
	Internal combustion engine	Distillate fuel oil	3	6.4	6.5	16	39	39
		Other gas	3	2.7	2.7	8	8	8
		Total	6	9.1	9.2	8	12	39
	Pumped storage hydraulic turbine	Water	2	7.0	4.0	77	78	78
		Total	2	7.0	4.0	77	78	78
	Steam turbine	Coal	2	613.9	555.3	17	28	38
		Nuclear material	2	2,162.9	2,037.1	20	26	31
		Other petroleum	11	2,414.2	2,366.4	35	45	49
		Waste	8	247.1	186.6	15	18	18
		Total	23	5,438.1	5,145.4	18	31	45
	Total	Coal	2	613.9	555.3	17	28	38
		Distillate fuel oil	8	111.3	103.3	2	25	39
		Natural gas	19	2,352.2	2,001.9	4	5	16
		Nuclear material	2	2,162.9	2,037.1	20	26	31
		Other gas	4	5.7	5.6	8	8	12
		Other petroleum	29	2,968.6	2,805.5	35	37	42
		Waste	8	247.1	186.6	15	18	18
		Water	30	135.6	137.1	20	80	92
		Total	**102**	**8,597.3**	**7,832.4**	**14**	**26**	**46**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Delaware	Combined cycle	Natural gas	8	1,193.0	1,087.5	5	9	16
		Total	8	1,193.0	1,087.5	5	9	16
	Combustion (gas) turbine	Distillate fuel oil	5	124.0	105.0	38	39	42
		Natural gas	4	190.1	192.4	5	5	10
		Other gas	2	184.0	172.0	6	6	6
		Total	11	498.1	469.4	5	15	39
	Internal combustion engine	Distillate fuel oil	5	7.0	6.8	44	48	52
		Total	5	7.0	6.8	44	48	52
	Steam turbine	Coal	10	1,082.2	1,083.0	36	48	67
		Other gas	4	140.0	135.0	35	48	50
		Other petroleum	4	597.2	581.0	32	39	44
		Total	18	1,819.4	1,799.0	33	45	50
	Total	Coal	10	1,082.2	1,083.0	36	48	67
		Distillate fuel oil	10	131.0	111.8	38	43	48
		Natural gas	12	1,383.1	1,279.9	5	5	15
		Other gas	6	324.0	307.0	6	35	50
		Other petroleum	4	597.2	581.0	32	39	44
		Total	**42**	**3,517.5**	**3,362.7**	**15**	**35**	**47**
District of Columbia	Combustion (gas) turbine	Distillate fuel oil	16	288.0	256.0	38	38	38
		Total	16	288.0	256.0	38	38	38
	Steam turbine	Distillate fuel oil	2	580.0	550.0	34	36	38
		Total	2	580.0	550.0	34	36	38
	Total	Distillate fuel oil	18	868.0	806.0	38	38	38
		Total	**18**	**868.0**	**806.0**	**38**	**38**	**38**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Florida	Combined cycle	Coal	2	326.3	255.0	10	10	10
		Natural gas	121	19,624.4	16,266.2	4	7	13
		Other gas	4	11.2	10.9	12	17	17
		Total	127	19,961.9	16,532.1	4	7	13
	Combustion (gas) turbine	Distillate fuel oil	58	3,733.6	3,118.3	31	32	33
		Natural gas	110	7,711.7	6,584.5	8	28	35
		Total	168	11,445.3	9,702.8	13	32	35
	Hydraulic turbine	Water	6	55.7	54.5	4	13	21
		Total	6	55.7	54.5	4	13	21
	Internal combustion engine	Distillate fuel oil	41	149.7	144.7	17	36	41
		Natural gas	26	88.6	80.6	25	34	39
		Other gas	11	11.7	11.2	3	9	20
		Total	78	250.0	236.5	17	33	38
	Steam turbine	Biomass	20	416.3	360.8	19	26	43
		Coal	28	11,055.8	10,148.0	20	25	38
		Natural gas	23	2,991.0	2,798.0	30	40	49
		Nuclear material	5	4,110.4	3,902.0	29	30	33
		Other	9	307.8	288.5	16	18	21
		Other petroleum	27	8,933.0	8,328.0	34	42	46
		Waste	13	499.8	422.6	15	19	21
		Waste heat	4	114.0	93.0	18	24	27
		Total	129	28,428.1	26,341.0	21	30	42
	Total	Biomass	20	416.3	360.8	19	26	43
		Coal	30	11,382.1	10,403.0	19	24	37
		Distillate fuel oil	99	3,883.3	3,263.0	28	32	36
		Natural gas	280	30,415.7	25,729.3	5	14	35
		Nuclear material	5	4,110.4	3,902.0	29	30	33
		Other	9	307.8	288.5	16	18	21
		Other gas	15	22.9	22.1	6	17	17
		Other petroleum	27	8,933.0	8,328.0	34	42	46
		Waste	13	499.8	422.6	15	19	21
		Waste heat	4	114.0	93.0	18	24	27
		Water	6	55.7	54.5	4	13	21
		Total	**508**	**60,141.0**	**52,866.8**	**11**	**25**	**35**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Georgia	Combined cycle	Natural gas	30	5,832.6	5,292.6	2	4	4
		Total	30	5,832.6	5,292.6	2	4	4
	Combustion (gas) turbine	Distillate fuel oil	28	2,216.4	1,871.0	6	34	34
		Natural gas	79	8,505.5	7,201.6	5	6	11
		Total	107	10,721.9	9,072.6	5	6	26
	Hydraulic turbine	Water	96	1,891.5	1,971.9	43	79	92
		Total	96	1,891.5	1,971.9	43	79	92
	Internal combustion engine	Distillate fuel oil	20	41.7	41.2	17	18	22
		Natural gas	1	3.0	3.0	26	26	26
		Other gas	3	2.4	2.4	13	13	13
		Total	24	47.1	46.6	15	18	22
	Pumped storage hydraulic turbine	Water	13	1,634.6	1,675.0	4	11	26
		Total	13	1,634.6	1,675.0	4	11	26
	Steam turbine	Biomass	14	313.4	298.7	17	26	49
		Coal	40	14,409.1	13,282.8	32	41	49
		Natural gas	1	126.0	115.0	34	34	34
		Nuclear material	4	4,041.8	4,060.0	18	23	29
		Other petroleum	4	233.7	205.7	18	33	51
		Waste	2	5.5	2.5	7	7	7
		Total	65	19,129.5	17,964.6	24	36	48
	Total	Biomass	14	313.4	298.7	17	26	49
		Coal	40	14,409.1	13,282.8	32	41	49
		Distillate fuel oil	48	2,258.1	1,912.2	17	22	34
		Natural gas	111	14,467.1	12,612.2	4	6	7
		Nuclear material	4	4,041.8	4,060.0	18	23	29
		Other gas	3	2.4	2.4	13	13	13
		Other petroleum	4	233.7	205.7	18	33	51
		Waste	2	5.5	2.5	7	7	7
		Water	109	3,526.1	3,646.9	29	56	86
		Total	**335**	**39,257.2**	**36,023.3**	**6**	**24**	**47**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Hawaii	Combined cycle	Distillate fuel oil	11	275.2	237.1	6	13	29
		Other petroleum	5	304.4	224.8	6	6	15
		Total	16	579.6	461.9	6	13	16
	Combustion (gas) turbine	Distillate fuel oil	6	157.8	150.8	17	29	33
		Other gas	3	9.0	9.0	16	16	16
		Other petroleum	2	59.1	47.5	4	14	24
		Total	11	225.9	207.3	16	17	33
	Hydraulic turbine	Water	13	24.9	23.8	24	81	85
		Total	13	24.9	23.8	24	81	85
	Internal combustion engine	Distillate fuel oil	63	207.4	200.3	10	19	33
		Total	63	207.4	200.3	10	19	33
	Steam turbine	Biomass	4	50.1	48.6	9	18	29
		Coal	1	203.0	180.0	14	14	14
		Geothermal	10	35.0	31.0	14	14	14
		Other petroleum	23	1,187.7	1,133.6	36	43	52
		Waste	1	63.7	60.0	17	17	17
		Total	39	1,539.5	1,453.2	14	34	47
	Wind turbine	Wind	3	11.4	11.4	19	21	21
		Total	3	11.4	11.4	19	21	21
	Total	Biomass	4	50.1	48.6	9	18	29
		Coal	1	203.0	180.0	14	14	14
		Distillate fuel oil	80	640.4	588.2	12	19	33
		Geothermal	10	35.0	31.0	14	14	14
		Other gas	3	9.0	9.0	16	16	16
		Other petroleum	30	1,551.2	1,405.9	24	40	49
		Waste	1	63.7	60.0	17	17	17
		Water	13	24.9	23.8	24	81	85
		Wind	3	11.4	11.4	19	21	21
		Total	**145**	**2,588.7**	**2,357.8**	**14**	**21**	**35**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Idaho	Combined cycle	Natural gas	4	322.3	268.8	5	8	10
		Total	4	322.3	268.8	5	8	10
	Combustion (gas) turbine	Natural gas	5	439.2	376.0	5	5	11
		Total	5	439.2	376.0	5	5	11
	Hydraulic turbine	Water	169	2,521.4	2,390.1	18	23	57
		Total	169	2,521.4	2,390.1	18	23	57
	Internal combustion engine	Distillate fuel oil	2	5.0	5.4	39	39	39
		Total	2	5.0	5.4	39	39	39
	Steam turbine	Biomass	6	126.2	77.7	23	25	29
		Coal	6	18.9	16.9	38	57	58
		Other	1	15.9	14.8	20	20	20
		Total	13	161.0	109.4	23	29	56
	Wind turbine	Wind	1	10.5	10.5	1	1	1
		Total	1	10.5	10.5	1	1	1
	Total	Biomass	6	126.2	77.7	23	25	29
		Coal	6	18.9	16.9	38	57	58
		Distillate fuel oil	2	5.0	5.4	39	39	39
		Natural gas	9	761.5	644.8	5	5	10
		Other	1	15.9	14.8	20	20	20
		Water	169	2,521.4	2,390.1	18	23	57
		Wind	1	10.5	10.5	1	1	1
		Total	**194**	**3,459.4**	**3,160.2**	**17**	**23**	**56**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Illinois	Combined cycle	Natural gas	23	3,479.2	2,964.0	4	5	8
		Other gas	4	25.0	19.0	9	9	9
		Total	27	3,504.2	2,983.0	4	5	9
	Combustion (gas) turbine	Distillate fuel oil	12	133.2	105.1	5	6	35
		Natural gas	175	13,116.1	10,505.6	4	5	7
		Other gas	17	82.8	76.2	7	10	17
		Other petroleum	12	400.8	305.0	38	38	38
		Total	216	13,732.9	10,991.9	4	6	15
	Hydraulic turbine	Water	19	28.5	24.1	15	77	81
		Total	19	28.5	24.1	15	77	81
	Internal combustion engine	Distillate fuel oil	117	217.5	206.4	6	26	47
		Natural gas	70	158.6	149.8	13	14	39
		Other gas	55	57.5	52.0	7	9	9
		Total	242	433.6	408.1	7	13	38
	Steam turbine	Coal	77	17,348.5	15,542.2	28	41	51
		Natural gas	12	217.2	183.7	50	57	58
		Nuclear material	11	11,882.0	11,388.0	19	22	34
		Other coal	3	99.0	120.0	43	43	43
		Other gas	2	17.7	17.7	19	20	20
		Other petroleum	6	439.7	424.0	56	57	59
		Total	111	30,004.1	27,675.6	24	41	52
	Wind turbine	Wind	2	103.4	103.4	1	2	3
		Total	2	103.4	103.4	1	2	3
	Total	Coal	77	17,348.5	15,542.2	28	41	51
		Distillate fuel oil	129	350.7	311.5	6	24	42
		Natural gas	280	16,971.1	13,803.1	4	6	18
		Nuclear material	11	11,882.0	11,388.0	19	22	34
		Other coal	3	99.0	120.0	43	43	43
		Other gas	78	183.0	164.9	7	9	10
		Other petroleum	18	840.5	729.0	38	38	56
		Water	19	28.5	24.1	15	77	81
		Wind	2	103.4	103.4	1	2	3
		Total	**617**	**47,806.7**	**42,186.1**	**6**	**13**	**38**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Indiana	Combined cycle	Coal	2	304.5	274.0	11	32	53
		Natural gas	19	2,829.9	2,479.6	2	3	4
		Total	21	3,134.4	2,753.6	2	4	9
	Combustion (gas) turbine	Distillate fuel oil	11	252.4	242.0	33	37	38
		Natural gas	53	3,931.5	3,228.7	5	6	14
		Total	64	4,183.9	3,470.7	5	6	33
	Hydraulic turbine	Water	21	92.1	59.5	17	39	83
		Total	21	92.1	59.5	17	39	83
	Internal combustion engine	Distillate fuel oil	28	56.0	53.6	14	34	39
		Other gas	12	9.6	9.6	7	12	12
		Total	40	65.6	63.2	12	14	37
	Other	Other gas	1	15.0	10.0	25	25	25
		Total	1	15.0	10.0	25	25	25
	Steam turbine	Coal	72	20,746.8	19,006.0	33	43	51
		Distillate fuel oil	5	202.0	188.0	57	59	62
		Other gas	9	489.2	377.4	36	37	47
		Waste	1	6.5	5.0	18	18	18
		Waste heat	1	94.6	88.0	8	8	8
		Total	88	21,539.1	19,664.4	33	44	51
	Total	Coal	74	21,051.3	19,280.0	32	43	51
		Distillate fuel oil	44	510.4	483.6	21	35	39
		Natural gas	72	6,761.4	5,708.3	4	6	12
		Other gas	22	513.8	397.0	9	12	37
		Waste	1	6.5	5.0	18	18	18
		Waste heat	1	94.6	88.0	8	8	8
		Water	21	92.1	59.5	17	39	83
		Total	**235**	**29,030.1**	**26,021.4**	**7**	**30**	**44**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Iowa	Combined cycle	Natural gas	11	1,245.4	1,128.9	2	3	49
		Total	11	1,245.4	1,128.9	2	3	49
	Combustion (gas) turbine	Distillate fuel oil	14	472.0	405.4	6	16	28
		Natural gas	39	1,371.0	1,144.8	12	28	37
		Other petroleum	1	23.8	17.0	36	36	36
		Total	54	1,866.8	1,567.2	12	22	36
	Hydraulic turbine	Water	23	131.3	131.4	75	93	93
		Total	23	131.3	131.4	75	93	93
	Internal combustion engine	Distillate fuel oil	265	451.7	438.9	6	16	48
		Natural gas	28	64.3	60.1	28	37	45
		Other gas	10	8.0	8.0	8	8	8
		Total	303	524.0	507.0	6	19	47
	Steam turbine	Coal	61	6,378.1	6,029.2	25	39	49
		Natural gas	1	18.7	17.2	59	59	59
		Nuclear material	1	597.1	580.6	31	31	31
		Total	63	6,993.9	6,627.0	25	39	50
	Wind turbine	Wind	8	816.7	816.7	3	5	7
		Total	8	816.7	816.7	3	5	7
	Total	Coal	61	6,378.1	6,029.2	25	39	49
		Distillate fuel oil	279	923.7	844.3	6	16	47
		Natural gas	79	2,699.4	2,351.0	12	32	39
		Nuclear material	1	597.1	580.6	31	31	31
		Other gas	10	8.0	8.0	8	8	8
		Other petroleum	1	23.8	17.0	36	36	36
		Water	23	131.3	131.4	75	93	93
		Wind	8	816.7	816.7	3	5	7
		Total	**462**	**11,578.1**	**10,778.2**	**6**	**30**	**48**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Kansas	Combustion (gas) turbine	Distillate fuel oil	4	288.6	230.1	30	31	32
		Natural gas	37	1,965.1	1,565.0	6	24	33
		Total	41	2,253.7	1,795.1	6	27	33
	Hydraulic turbine	Water	6	2.2	2.2	81	84	84
		Total	6	2.2	2.2	81	84	84
	Internal combustion engine	Distillate fuel oil	184	345.5	318.0	12	35	46
		Natural gas	112	284.7	267.3	24	39	49
		Total	296	630.2	585.3	18	36	48
	Steam turbine	Coal	16	5,472.3	5,249.8	27	35	48
		Natural gas	27	1,705.0	1,663.0	41	47	55
		Nuclear material	1	1,235.7	1,166.0	21	21	21
		Total	44	8,413.0	8,078.8	35	45	52
	Wind turbine	Wind	4	263.4	263.4	3	6	7
		Total	4	263.4	263.4	3	6	7
	Total	Coal	16	5,472.3	5,249.8	27	35	48
		Distillate fuel oil	188	634.1	548.1	13	35	46
		Natural gas	176	3,954.8	3,495.3	23	38	48
		Nuclear material	1	1,235.7	1,166.0	21	21	21
		Water	6	2.2	2.2	81	84	84
		Wind	4	263.4	263.4	3	6	7
		Total	**391**	**11,562.5**	**10,724.8**	**20**	**36**	**47**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Kentucky	Combustion (gas) turbine	Distillate fuel oil	1	98.8	65.0	30	30	30
		Natural gas	47	5,890.3	4,657.0	4	5	11
		Total	48	5,989.1	4,722.0	4	5	11
	Hydraulic turbine	Water	30	777.4	817.1	54	62	78
		Total	30	777.4	817.1	54	62	78
	Internal combustion engine	Distillate fuel oil	9	13.9	13.9	52	57	58
		Other gas	12	9.6	9.6	3	3	3
		Total	21	23.5	23.5	3	3	54
	Steam turbine	Biomass	2	5.0	3.3	4	8	11
		Coal	56	16,509.5	14,337.1	32	39	50
		Distillate fuel oil	2	62.4	58.0	58	59	59
		Total	60	16,576.9	14,398.4	31	39	51
	Total	Biomass	2	5.0	3.3	4	8	11
		Coal	56	16,509.5	14,337.1	32	39	50
		Distillate fuel oil	12	175.1	136.9	42	58	59
		Natural gas	47	5,890.3	4,657.0	4	5	11
		Other gas	12	9.6	9.6	3	3	3
		Water	30	777.4	817.1	54	62	78
		Total	**159**	**23,366.9**	**19,961.0**	**5**	**36**	**52**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Louisiana	Combined cycle	Natural gas	62	8,924.5	7,699.3	4	5	28
		Total	62	8,924.5	7,699.3	4	5	28
	Combustion (gas) turbine	Natural gas	38	2,065.0	1,696.4	5	6	9
		Total	38	2,065.0	1,696.4	5	6	9
	Hydraulic turbine	Water	8	192.0	192.0	16	16	16
		Total	8	192.0	192.0	16	16	16
	Internal combustion engine	Distillate fuel oil	3	18.5	15.0	37	37	41
		Natural gas	10	17.8	15.6	44	49	55
		Total	13	36.3	30.6	41	44	53
	Other	Natural gas	1	4.5	3.1	2	2	2
		Total	1	4.5	3.1	2	2	2
	Steam turbine	Biomass	1	12.1	10.9	22	22	22
		Coal	6	3,764.3	3,453.0	23	24	24
		Natural gas	68	11,107.8	10,127.9	34	39	46
		Nuclear material	2	2,235.7	2,124.0	20	21	21
		Other	2	22.0	20.5	38	38	38
		Other gas	3	75.0	63.9	37	64	64
		Other petroleum	2	227.2	213.0	47	47	47
		Purchased steam	1	7.2	7.2	1	1	1
		Total	85	17,451.3	16,020.3	31	38	46
	Total	Biomass	1	12.1	10.9	22	22	22
		Coal	6	3,764.3	3,453.0	23	24	24
		Distillate fuel oil	3	18.5	15.0	37	37	41
		Natural gas	179	22,119.6	19,542.3	5	28	41
		Nuclear material	2	2,235.7	2,124.0	20	21	21
		Other	2	22.0	20.5	38	38	38
		Other gas	3	75.0	63.9	37	64	64
		Other petroleum	2	227.2	213.0	47	47	47
		Purchased steam	1	7.2	7.2	1	1	1
		Water	8	192.0	192.0	16	16	16
		Total	**207**	**28,673.6**	**25,641.7**	**6**	**24**	**40**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Maine	Combined cycle	Natural gas	8	1,377.0	1,250.0	5	6	6
		Total	8	1,377.0	1,250.0	5	6	6
	Combustion (gas) turbine	Distillate fuel oil	2	35.0	29.4	36	36	36
		Natural gas	5	359.8	314.8	5	6	7
		Total	7	394.8	344.2	5	7	36
	Hydraulic turbine	Water	251	677.0	678.0	22	66	86
		Total	251	677.0	678.0	22	66	86
	Internal combustion engine	Distillate fuel oil	20	36.0	32.7	45	47	57
		Total	20	36.0	32.7	45	47	57
	Steam turbine	Biomass	26	657.8	618.6	17	21	36
		Coal	1	102.6	85.0	16	16	16
		Natural gas	1	72.0	72.0	18	18	18
		Other petroleum	11	966.1	940.4	36	48	50
		Waste	4	65.6	53.4	16	19	19
		Total	43	1,864.1	1,769.4	18	24	41
	Total	Biomass	26	657.8	618.6	17	21	36
		Coal	1	102.6	85.0	16	16	16
		Distillate fuel oil	22	71.0	62.1	45	46	57
		Natural gas	14	1,808.8	1,636.8	5	6	6
		Other petroleum	11	966.1	940.4	36	48	50
		Waste	4	65.6	53.4	16	19	19
		Water	251	677.0	678.0	22	66	86
		Total	**329**	**4,348.9**	**4,074.3**	**20**	**52**	**86**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Maryland	Combined cycle	Natural gas	3	288.8	230.0	10	10	10
		Total	3	288.8	230.0	10	10	10
	Combustion (gas) turbine	Distillate fuel oil	30	1,514.0	1,305.0	16	34	36
		Natural gas	15	1,364.1	1,175.2	3	37	37
		Other petroleum	1	135.0	127.0	36	36	36
		Total	46	3,013.1	2,607.2	15	35	37
	Hydraulic turbine	Water	13	494.4	566.0	42	78	78
		Total	13	494.4	566.0	42	78	78
	Internal combustion engine	Distillate fuel oil	25	60.9	57.4	11	33	38
		Other gas	4	4.0	3.9	3	3	3
		Other petroleum	4	25.0	25.0	17	23	28
		Total	33	89.9	86.3	11	18	38
	Steam turbine	Biomass	2	3.8	1.9	19	19	19
		Coal	14	3,919.3	3,654.0	40	44	47
		Natural gas	4	89.7	95.5	26	49	53
		Nuclear material	2	1,828.7	1,735.0	29	30	31
		Other coal	2	1,252.0	1,244.0	35	36	36
		Other gas	4	120.0	152.3	57	57	57
		Other petroleum	5	2,027.5	1,908.0	31	34	34
		Waste	3	132.3	115.3	5	11	22
		Total	36	9,373.3	8,906.0	24	41	48
	Total	Biomass	2	3.8	1.9	19	19	19
		Coal	14	3,919.3	3,654.0	40	44	47
		Distillate fuel oil	55	1,574.9	1,362.4	15	34	38
		Natural gas	22	1,742.6	1,500.7	10	37	37
		Nuclear material	2	1,828.7	1,735.0	29	30	31
		Other coal	2	1,252.0	1,244.0	35	36	36
		Other gas	8	124.0	156.2	3	30	57
		Other petroleum	10	2,187.5	2,060.0	25	30	34
		Waste	3	132.3	115.3	5	11	22
		Water	13	494.4	566.0	42	78	78
		Total	**131**	**13,259.5**	**12,395.5**	**15**	**36**	**42**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Massachusetts	Combined cycle	Distillate fuel oil	5	383.0	325.6	25	25	25
		Natural gas	40	6,058.5	4,819.2	4	13	16
		Other petroleum	1	95.0	87.0	31	31	31
		Total	46	6,536.5	5,231.8	4	13	18
	Combustion (gas) turbine	Distillate fuel oil	17	503.7	392.5	24	36	37
		Natural gas	8	252.2	184.9	4	8	25
		Other gas	1	5.3	4.4	6	6	6
		Other petroleum	4	126.0	107.2	31	35	37
		Total	30	887.2	689.0	11	34	36
	Hydraulic turbine	Water	71	257.7	247.4	25	78	89
		Total	71	257.7	247.4	25	78	89
	Internal combustion engine	Distillate fuel oil	35	105.3	95.5	19	28	37
		Natural gas	21	29.6	29.1	5	12	22
		Other gas	25	26.1	24.2	6	9	9
		Total	81	161.0	148.8	9	13	28
	Other	Other petroleum	1	21.1	16.6	37	37	37
		Total	1	21.1	16.6	37	37	37
	Pumped storage hydraulic turbine	Water	6	1,540.0	1,642.9	32	33	33
		Total	6	1,540.0	1,642.9	32	33	33
	Steam turbine	Biomass	1	18.0	17.0	14	14	14
		Coal	11	1,701.5	1,672.6	43	48	54
		Natural gas	7	1,004.7	943.1	26	37	59
		Nuclear material	1	670.0	684.7	34	34	34
		Other gas	1	17.5	9.0	8	8	8
		Other petroleum	15	2,333.3	2,178.4	34	38	51
		Waste	7	295.5	232.3	17	18	21
		Total	43	6,040.5	5,737.1	21	38	50
	Total	Biomass	1	18.0	17.0	14	14	14
		Coal	11	1,701.5	1,672.6	43	48	54
		Distillate fuel oil	57	992.0	813.6	21	30	37
		Natural gas	76	7,345.0	5,976.3	5	13	23
		Nuclear material	1	670.0	684.7	34	34	34
		Other gas	27	48.9	37.6	6	9	9
		Other petroleum	21	2,575.4	2,389.2	34	37	49
		Waste	7	295.5	232.3	17	18	21
		Water	77	1,797.7	1,890.3	32	76	88
		Total	278	15,444.0	13,713.5	13	25	47

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Michigan	Combined cycle	Natural gas	46	5,190.6	4,749.0	4	11	16
		Other gas	5	30.3	23.8	10	10	10
		Total	51	5,220.9	4,772.8	4	10	16
	Combustion (gas) turbine	Distillate fuel oil	21	399.1	320.8	32	35	40
		Natural gas	70	3,755.7	3,262.5	5	7	37
		Total	91	4,154.8	3,583.3	6	32	38
	Hydraulic turbine	Water	208	360.6	229.8	43	77	89
		Total	208	360.6	229.8	43	77	89
	Internal combustion engine	Distillate fuel oil	135	273.2	269.3	13	36	46
		Natural gas	26	85.8	85.8	30	36	46
		Other gas	61	51.0	49.2	9	12	14
		Other petroleum	2	8.2	6.6	54	59	64
		Total	224	418.2	410.9	12	29	39
	Pumped storage hydraulic turbine	Water	6	1,978.8	1,872.0	33	33	33
		Total	6	1,978.8	1,872.0	33	33	33
	Steam turbine	Biomass	8	200.6	181.8	14	18	19
		Coal	78	12,792.6	11,889.9	33	44	51
		Natural gas	13	2,361.8	2,116.8	37	50	56
		Nuclear material	4	4,314.1	3,982.0	23	30	33
		Other petroleum	1	815.4	785.0	27	27	27
		Waste	2	86.4	79.3	17	18	18
		Total	106	20,570.9	19,034.8	28	40	51
	Wind turbine	Wind	1	1.8	0.7	5	5	5
		Total	1	1.8	0.7	5	5	5
	Total	Biomass	8	200.6	181.8	14	18	19
		Coal	78	12,792.6	11,889.9	33	44	51
		Distillate fuel oil	156	672.3	590.1	20	36	40
		Natural gas	155	11,393.9	10,214.1	5	17	37
		Nuclear material	4	4,314.1	3,982.0	23	30	33
		Other gas	66	81.3	73.0	9	12	14
		Other petroleum	3	823.6	791.6	27	54	64
		Waste	2	86.4	79.3	17	18	18
		Water	214	2,339.4	2,101.8	43	75	88
		Wind	1	1.8	0.7	5	5	5
		Total	**687**	**32,706.0**	**29,904.3**	**14**	**37**	**54**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Minnesota	Combined cycle	Natural gas	10	869.7	773.0	9	11	35
		Other gas	3	16.6	13.6	10	10	10
		Total	13	886.3	786.6	9	10	12
	Combustion (gas) turbine	Distillate fuel oil	22	517.2	411.0	14	28	32
		Natural gas	36	2,161.2	1,992.2	5	30	36
		Total	58	2,678.4	2,403.2	5	28	34
	Hydraulic turbine	Water	67	173.4	163.4	56	81	87
		Total	67	173.4	163.4	56	81	87
	Internal combustion engine	Distillate fuel oil	167	310.9	301.2	4	13	47
		Natural gas	32	93.1	87.0	24	34	45
		Other gas	6	8.9	8.3	12	12	12
		Total	205	412.9	396.5	5	26	46
	Steam turbine	Biomass	8	200.1	136.4	12	28	46
		Coal	37	5,623.1	5,392.6	35	44	49
		Natural gas	22	279.6	283.0	47	54	59
		Nuclear material	3	1,737.1	1,617.0	32	32	35
		Waste	10	95.4	81.3	19	55	57
		Total	80	7,935.3	7,510.3	34	47	55
	Wind turbine	Wind	69	685.9	685.2	3	3	5
		Total	69	685.9	685.2	3	3	5
	Total	Biomass	8	200.1	136.4	12	28	46
		Coal	37	5,623.1	5,392.6	35	44	49
		Distillate fuel oil	189	828.1	712.2	4	21	45
		Natural gas	100	3,403.6	3,135.2	9	35	46
		Nuclear material	3	1,737.1	1,617.0	32	32	35
		Other gas	9	25.5	21.9	10	12	12
		Waste	10	95.4	81.3	19	55	57
		Water	67	173.4	163.4	56	81	87
		Wind	69	685.9	685.2	3	3	5
		Total	**492**	**12,772.2**	**11,945.2**	**5**	**31**	**51**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Mississippi	Combined cycle	Natural gas	39	5,713.1	5,160.1	3	5	5
		Total	39	5,713.1	5,160.1	3	5	5
	Combustion (gas) turbine	Distillate fuel oil	2	30.0	25.0	34	36	38
		Natural gas	59	4,144.6	3,624.2	4	4	7
		Total	61	4,174.6	3,649.2	4	5	7
	Internal combustion engine	Distillate fuel oil	10	18.0	9.0	5	7	8
		Natural gas	3	3.9	9.3	5	5	5
		Total	13	21.9	18.3	5	5	8
	Steam turbine	Biomass	6	172.6	190.6	19	24	38
		Coal	9	2,696.3	2,562.9	28	29	38
		Natural gas	28	3,418.3	3,242.6	38	52	55
		Nuclear material	1	1,372.5	1,266.0	21	21	21
		Total	44	7,659.7	7,262.1	29	39	53
	Total	Biomass	6	172.6	190.6	19	24	38
		Coal	9	2,696.3	2,562.9	28	29	38
		Distillate fuel oil	12	48.0	34.0	5	8	8
		Natural gas	129	13,279.9	12,036.2	4	5	35
		Nuclear material	1	1,372.5	1,266.0	21	21	21
		Total	**157**	**17,569.3**	**16,089.7**	**4**	**6**	**35**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Missouri	Combined cycle	Natural gas	14	2,152.9	1,867.0	5	6	7
		Total	14	2,152.9	1,867.0	5	6	7
	Combustion (gas) turbine	Distillate fuel oil	24	1,038.9	961.0	29	31	34
		Natural gas	61	4,114.2	3,450.4	4	6	27
		Total	85	5,153.1	4,411.4	5	20	31
	Hydraulic turbine	Water	20	499.2	552.2	47	75	75
		Total	20	499.2	552.2	47	75	75
	Internal combustion engine	Distillate fuel oil	172	291.4	273.1	8	21	40
		Natural gas	39	146.6	138.7	27	35	43
		Total	211	438.0	411.8	10	25	41
	Pumped storage hydraulic turbine	Water	9	600.4	657.0	24	24	27
		Total	9	600.4	657.0	24	24	27
	Steam turbine	Coal	55	11,803.9	11,266.3	34	41	49
		Natural gas	6	117.7	111.9	36	46	56
		Nuclear material	1	1,235.8	1,190.0	22	22	22
		Total	62	13,157.4	12,568.2	34	42	49
	Total	Coal	55	11,803.9	11,266.3	34	41	49
		Distillate fuel oil	196	1,330.3	1,234.1	10	25	39
		Natural gas	120	6,531.4	5,568.0	5	15	34
		Nuclear material	1	1,235.8	1,190.0	22	22	22
		Water	29	1,099.6	1,209.2	27	47	75
		Total	**401**	**22,001.0**	**20,467.6**	**9**	**29**	**42**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Montana	Combustion (gas) turbine	Natural gas	3	107.0	100.2	3	27	34
		Total	3	107.0	100.2	3	27	34
	Hydraulic turbine	Water	76	2,434.5	2,554.8	48	81	91
		Total	76	2,434.5	2,554.8	48	81	91
	Internal combustion engine	Distillate fuel oil	1	1.8	2.0	1	1	1
		Total	1	1.8	2.0	1	1	1
	Steam turbine	Biomass	2	10.8	10.8	16	31	46
		Coal	6	2,494.8	2,304.3	22	31	38
		Other coal	1	41.5	35.0	16	16	16
		Other petroleum	1	65.0	55.0	11	11	11
		Total	10	2,612.1	2,405.1	16	26	38
	Wind turbine	Wind	1	135.0	135.0	1	1	1
		Total	1	135.0	135.0	1	1	1
	Total	Biomass	2	10.8	10.8	16	31	46
		Coal	6	2,494.8	2,304.3	22	31	38
		Distillate fuel oil	1	1.8	2.0	1	1	1
		Natural gas	3	107.0	100.2	3	27	34
		Other coal	1	41.5	35.0	16	16	16
		Other petroleum	1	65.0	55.0	11	11	11
		Water	76	2,434.5	2,554.8	48	81	91
		Wind	1	135.0	135.0	1	1	1
		Total	**91**	**5,290.4**	**5,197.1**	**40**	**68**	**91**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Nebraska	Combined cycle	Natural gas	7	468.3	406.9	1	2	3
		Total	7	468.3	406.9	1	2	3
	Combustion (gas) turbine	Distillate fuel oil	9	577.6	530.3	10	33	33
		Natural gas	12	964.9	784.0	3	7	34
		Total	21	1,542.5	1,314.3	5	31	33
	Hydraulic turbine	Water	18	310.3	258.7	54	65	70
		Total	18	310.3	258.7	54	65	70
	Internal combustion engine	Distillate fuel oil	85	105.1	97.8	19	46	54
		Natural gas	74	159.6	144.9	35	43	51
		Other gas	10	7.7	7.6	4	12	19
		Total	169	272.4	250.3	30	42	53
	Steam turbine	Coal	15	3,203.7	3,195.8	27	41	47
		Natural gas	6	245.8	222.5	39	46	49
		Nuclear material	2	1,303.0	1,238.3	32	33	33
		Total	23	4,752.5	4,656.6	29	41	48
	Wind turbine	Wind	6	72.5	72.5	4	8	8
		Total	6	72.5	72.5	4	8	8
	Total	Coal	15	3,203.7	3,195.8	27	41	47
		Distillate fuel oil	94	682.7	628.1	19	40	54
		Natural gas	99	1,838.6	1,558.3	32	39	50
		Nuclear material	2	1,303.0	1,238.3	32	33	33
		Other gas	10	7.7	7.6	4	12	19
		Water	18	310.3	258.7	54	65	70
		Wind	6	72.5	72.5	4	8	8
		Total	**244**	**7,418.5**	**6,959.3**	**24**	**40**	**51**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Nevada	Combined cycle	Natural gas	39	3,943.0	3,188.4	3	12	14
		Total	39	3,943.0	3,188.4	3	12	14
	Combustion (gas) turbine	Distillate fuel oil	2	25.0	20.0	44	45	45
		Natural gas	15	1,024.8	860.0	5	12	15
		Total	17	1,049.8	880.0	5	12	32
	Geothermal binary cycle turbine	Geothermal	27	77.2	39.5	17	17	20
		Total	27	77.2	39.5	17	17	20
	Hydraulic turbine	Water	16	1,047.0	1,047.2	69	70	95
		Total	16	1,047.0	1,047.2	69	70	95
	Internal combustion engine	Distillate fuel oil	12	25.4	24.6	39	43	46
		Total	12	25.4	24.6	39	43	46
	Steam turbine	Coal	6	1,133.2	1,077.0	23	28	38
		Geothermal	27	203.9	145.8	14	16	19
		Natural gas	9	724.8	731.0	38	42	45
		Total	42	2,061.9	1,953.8	16	19	32
	Total	Coal	6	1,133.2	1,077.0	23	28	38
		Distillate fuel oil	14	50.4	44.6	39	45	46
		Geothermal	54	281.1	185.3	16	17	19
		Natural gas	63	5,692.6	4,779.4	5	12	24
		Water	16	1,047.0	1,047.2	69	70	95
		Total	153	8,204.3	7,133.5	14	17	37

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
New Hampshire	Combined cycle	Natural gas	6	1,505.5	1,322.0	3	4	4
		Total	6	1,505.5	1,322.0	3	4	4
	Combustion (gas) turbine	Distillate fuel oil	1	18.0	14.1	37	37	37
		Natural gas	3	17.2	14.9	5	5	5
		Other gas	2	6.0	5.8	9	9	9
		Other petroleum	4	77.0	68.1	37	38	38
		Total	10	118.2	102.9	5	23	37
	Hydraulic turbine	Water	92	444.2	506.0	21	38	82
		Total	92	444.2	506.0	21	38	82
	Internal combustion engine	Distillate fuel oil	4	3.8	3.8	9	17	34
		Other gas	8	7.6	7.1	12	14	16
		Total	12	11.4	10.9	11	14	18
	Steam turbine	Biomass	8	103.3	88.4	18	19	20
		Coal	5	609.2	575.1	46	49	51
		Natural gas	1	6.5	6.5	59	59	59
		Nuclear material	1	1,242.0	1,220.1	16	16	16
		Other petroleum	3	441.5	422.7	2	32	80
		Waste	2	18.5	18.5	17	18	19
		Total	20	2,421.0	2,331.3	18	20	49
	Total	Biomass	8	103.3	88.4	18	19	20
		Coal	5	609.2	575.1	46	49	51
		Distillate fuel oil	5	21.8	17.9	12	21	37
		Natural gas	10	1,529.2	1,343.4	3	4	5
		Nuclear material	1	1,242.0	1,220.1	16	16	16
		Other gas	10	13.6	12.9	10	14	14
		Other petroleum	7	518.5	490.8	32	37	38
		Waste	2	18.5	18.5	17	18	19
		Water	92	444.2	506.0	21	38	82
		Total	**140**	**4,500.3**	**4,273.1**	**18**	**24**	**76**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
New Jersey	Combined cycle	Natural gas	55	5,347.3	4,482.1	12	15	17
		Other gas	3	22.5	18.8	5	5	45
		Total	58	5,369.8	4,500.9	12	15	17
	Combustion (gas) turbine	Distillate fuel oil	4	186.0	185.0	34	34	34
		Natural gas	86	3,865.8	3,456.4	12	34	35
		Other gas	1	10.3	7.4	8	8	8
		Other petroleum	23	888.4	881.0	34	35	37
		Total	114	4,950.5	4,529.8	17	34	35
	Hydraulic turbine	Water	3	10.8	0.9	21	21	21
		Total	3	10.8	0.9	21	21	21
	Internal combustion engine	Distillate fuel oil	4	8.0	8.0	45	45	45
		Natural gas	6	16.4	10.5	9	18	23
		Other gas	17	14.5	14.1	8	9	16
		Total	27	38.9	32.6	9	16	21
	Pumped storage hydraulic turbine	Water	3	453.0	400.0	41	41	41
		Total	3	453.0	400.0	41	41	41
	Steam turbine	Coal	9	2,237.2	2,076.6	36	42	45
		Natural gas	7	969.6	843.6	42	55	58
		Nuclear material	4	4,150.7	3,984.0	23	27	33
		Other	1	11.2	11.2	39	39	39
		Other gas	1	9.9	9.5	9	9	9
		Other petroleum	5	568.2	613.0	46	49	49
		Waste	7	177.3	149.5	15	16	16
		Total	34	8,124.1	7,687.4	16	38	48
	Total	Coal	9	2,237.2	2,076.6	36	42	45
		Distillate fuel oil	8	194.0	193.0	34	40	45
		Natural gas	154	10,199.1	8,792.7	12	17	35
		Nuclear material	4	4,150.7	3,984.0	23	27	33
		Other	1	11.2	11.2	39	39	39
		Other gas	22	57.2	49.8	8	9	16
		Other petroleum	28	1,456.6	1,494.0	34	36	38
		Waste	7	177.3	149.5	15	16	16
		Water	6	463.8	400.9	21	31	41
		Total	**239**	**18,947.1**	**17,151.7**	**13**	**21**	**35**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
New Mexico	Combined cycle	Natural gas	8	322.6	281.4	3	9	49
		Total	8	322.6	281.4	3	9	49
	Combustion (gas) turbine	Distillate fuel oil	1	20.0	20.0	33	33	33
		Natural gas	15	858.6	745.2	3	8	25
		Total	16	878.6	765.2	4	8	27
	Hydraulic turbine	Water	6	58.1	60.1	17	66	66
		Total	6	58.1	60.1	17	66	66
	Internal combustion engine	Distillate fuel oil	6	16.1	15.0	31	40	47
		Natural gas	12	41.4	39.7	34	35	39
		Other gas	4	6.6	6.4	4	12	19
		Total	22	64.1	61.1	29	35	39
	Steam turbine	Coal	11	4,382.1	3,956.9	27	36	43
		Natural gas	13	828.4	797.0	44	47	49
		Total	24	5,210.5	4,753.9	35	43	48
	Wind turbine	Wind	4	404.0	404.0	1	2	3
		Total	4	404.0	404.0	1	2	3
	Total	Coal	11	4,382.1	3,956.9	27	36	43
		Distillate fuel oil	7	36.1	35.0	31	38	47
		Natural gas	48	2,051.0	1,863.3	7	34	45
		Other gas	4	6.6	6.4	4	12	19
		Water	6	58.1	60.1	17	66	66
		Wind	4	404.0	404.0	1	2	3
		Total	**80**	**6,937.9**	**6,325.7**	**9**	**34**	**44**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
New York	Combined cycle	Distillate fuel oil	1	56.0	48.6	12	12	12
		Natural gas	88	7,170.0	5,987.4	11	12	14
		Total	89	7,226.0	6,036.0	11	12	14
	Combustion (gas) turbine	Distillate fuel oil	45	1,608.2	1,450.1	32	35	35
		Natural gas	111	3,563.2	2,967.1	12	35	36
		Other petroleum	15	412.1	323.1	35	36	37
		Total	171	5,583.5	4,740.2	31	35	36
	Hydraulic turbine	Water	364	4,609.6	4,168.1	21	57	82
		Total	364	4,609.6	4,168.1	21	57	82
	Internal combustion engine	Distillate fuel oil	21	43.7	39.6	35	41	44
		Natural gas	13	12.3	11.1	12	15	16
		Other gas	54	44.3	42.6	5	10	15
		Total	88	100.3	93.3	8	15	18
	Pumped storage hydraulic turbine	Water	16	1,240.0	1,296.8	39	44	44
		Total	16	1,240.0	1,296.8	39	44	44
	Steam turbine	Biomass	2	40.8	37.0	13	14	14
		Coal	40	4,120.6	4,067.8	39	50	56
		Natural gas	21	6,886.7	6,653.1	37	43	50
		Nuclear material	6	5,611.2	5,150.2	30	35	37
		Other petroleum	14	5,648.0	5,324.0	32	40	51
		Waste	11	314.8	249.4	15	19	22
		Total	94	22,622.1	21,481.5	30	41	52
	Wind turbine	Wind	4	185.1	185.1	3	6	6
		Total	4	185.1	185.1	3	6	6
	Total	Biomass	2	40.8	37.0	13	14	14
		Coal	40	4,120.6	4,067.8	39	50	56
		Distillate fuel oil	67	1,707.9	1,538.3	32	35	39
		Natural gas	233	17,632.2	15,618.6	12	15	35
		Nuclear material	6	5,611.2	5,150.2	30	35	37
		Other gas	54	44.3	42.6	5	10	15
		Other petroleum	29	6,060.1	5,647.1	34	36	39
		Waste	11	314.8	249.4	15	19	22
		Water	380	5,849.6	5,464.9	22	53	82
		Wind	4	185.1	185.1	3	6	6
		Total	**826**	**41,566.6**	**38,000.9**	**16**	**35**	**53**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
North Carolina	Combined cycle	Distillate fuel oil	6	102.0	84.0	37	37	82
		Natural gas	13	1,019.6	862.0	16	18	28
		Total	19	1,121.6	946.0	16	28	37
	Combustion (gas) turbine	Distillate fuel oil	20	528.1	410.5	35	35	37
		Natural gas	53	6,507.4	5,135.2	6	11	14
		Other gas	2	9.8	7.6	7	9	10
		Total	75	7,045.3	5,553.3	6	11	35
	Hydraulic turbine	Water	99	1,824.7	1,942.4	44	76	83
		Total	99	1,824.7	1,942.4	44	76	83
	Internal combustion engine	Distillate fuel oil	13	25.2	25.2	12	15	15
		Other gas	3	2.9	2.9	4	7	7
		Total	16	28.1	28.1	7	15	15
	Pumped storage hydraulic turbine	Water	1	95.0	94.9	50	50	50
		Total	1	95.0	94.9	50	50	50
	Steam turbine	Biomass	4	208.1	193.4	18	24	29
		Coal	58	13,188.5	13,102.5	33	47	54
		Nuclear material	5	5,181.5	4,938.0	22	25	29
		Other	1	39.9	37.1	22	22	22
		Waste	2	10.5	3.6	4	10	15
		Total	70	18,628.5	18,274.6	23	41	53
	Total	Biomass	4	208.1	193.4	18	24	29
		Coal	58	13,188.5	13,102.5	33	47	54
		Distillate fuel oil	39	655.3	519.7	15	35	37
		Natural gas	66	7,527.0	5,997.2	6	11	27
		Nuclear material	5	5,181.5	4,938.0	22	25	29
		Other	1	39.9	37.1	22	22	22
		Other gas	5	12.7	10.5	7	7	7
		Waste	2	10.5	3.6	4	10	15
		Water	100	1,919.7	2,037.3	44	74	83
		Total	**280**	**28,743.2**	**26,839.3**	**16**	**37**	**57**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
North Dakota	Combustion (gas) turbine	Distillate fuel oil	2	48.2	46.5	28	29	30
		Natural gas	2	10.0	9.6	53	53	53
		Total	4	58.2	56.1	29	42	53
	Hydraulic turbine	Water	5	614.0	432.0	46	50	50
		Total	5	614.0	432.0	46	50	50
	Internal combustion engine	Distillate fuel oil	23	28.9	28.8	50	57	60
		Total	23	28.9	28.8	50	57	60
	Steam turbine	Coal	12	4,225.0	4,105.9	26	30	40
		Total	12	4,225.0	4,105.9	26	30	40
	Wind turbine	Wind	4	95.6	95.6	2	3	3
		Total	4	95.6	95.6	2	3	3
	Total	Coal	12	4,225.0	4,105.9	26	30	40
		Distillate fuel oil	25	77.1	75.3	30	57	60
		Natural gas	2	10.0	9.6	53	53	53
		Water	5	614.0	432.0	46	50	50
		Wind	4	95.6	95.6	2	3	3
		Total	**48**	**5,021.7**	**4,718.4**	**27**	**48**	**57**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Ohio	Combined cycle	Natural gas	13	2,843.8	2,694.0	3	3	3
		Total	13	2,843.8	2,694.0	3	3	3
	Combustion (gas) turbine	Distillate fuel oil	25	767.1	635.2	33	34	37
		Natural gas	76	6,116.7	5,302.8	5	6	14
		Total	101	6,883.8	5,938.0	5	8	35
	Hydraulic turbine	Water	15	128.4	100.5	12	18	24
		Total	15	128.4	100.5	12	18	24
	Internal combustion engine	Distillate fuel oil	50	122.4	117.9	6	34	38
		Natural gas	2	5.1	5.1	10	27	43
		Other gas	2	3.8	3.6	7	7	7
		Total	54	131.3	126.6	6	34	38
	Steam turbine	Biomass	4	10.9	8.7	13	17	28
		Coal	98	23,370.8	21,901.9	34	45	52
		Natural gas	2	35.0	35.0	46	49	52
		Nuclear material	2	2,236.8	2,108.0	19	24	29
		Other gas	1	32.0	30.0	8	8	8
		Other petroleum	1	140.6	136.0	51	51	51
		Total	108	25,826.1	24,219.6	33	44	52
	Total	Biomass	4	10.9	8.7	13	17	28
		Coal	98	23,370.8	21,901.9	34	45	52
		Distillate fuel oil	75	889.5	753.1	16	34	38
		Natural gas	93	9,000.6	8,036.9	4	6	14
		Nuclear material	2	2,236.8	2,108.0	19	24	29
		Other gas	3	35.8	33.6	7	7	8
		Other petroleum	1	140.6	136.0	51	51	51
		Water	15	128.4	100.5	12	18	24
		Total	**291**	**35,813.4**	**33,078.7**	**6**	**33**	**39**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Oklahoma	Combined cycle	Natural gas	44	6,881.4	6,118.3	3	4	14
		Total	44	6,881.4	6,118.3	3	4	14
	Combustion (gas) turbine	Natural gas	23	935.0	813.4	5	16	35
		Total	23	935.0	813.4	5	16	35
	Hydraulic turbine	Water	31	757.5	780.2	36	42	53
		Total	31	757.5	780.2	36	42	53
	Internal combustion engine	Distillate fuel oil	24	62.3	56.5	28	43	55
		Natural gas	5	18.8	12.6	52	54	57
		Total	29	81.1	69.1	34	50	57
	Pumped storage hydraulic turbine	Water	6	288.0	260.0	35	37	38
		Total	6	288.0	260.0	35	37	38
	Steam turbine	Coal	12	5,606.0	5,284.1	22	26	27
		Natural gas	35	6,031.7	5,603.1	35	47	53
		Waste	1	16.8	15.6	17	17	17
		Total	48	11,654.5	10,902.8	27	38	50
	Wind turbine	Wind	6	474.3	474.3	1	2	3
		Total	6	474.3	474.3	1	2	3
	Total	Coal	12	5,606.0	5,284.1	22	26	27
		Distillate fuel oil	24	62.3	56.5	28	43	55
		Natural gas	107	13,866.9	12,547.4	4	29	43
		Waste	1	16.8	15.6	17	17	17
		Water	37	1,045.5	1,040.2	35	42	53
		Wind	6	474.3	474.3	1	2	3
		Total	**187**	**21,071.8**	**19,418.1**	**5**	**33**	**47**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Oregon	Combined cycle	Natural gas	23	3,047.6	2,547.4	5	10	32
		Total	23	3,047.6	2,547.4	5	10	32
	Combustion (gas) turbine	Natural gas	8	261.0	217.0	4	4	5
		Total	8	261.0	217.0	4	4	5
	Hydraulic turbine	Water	190	8,236.5	8,331.0	36	48	54
		Total	190	8,236.5	8,331.0	36	48	54
	Internal combustion engine	Other gas	7	5.6	5.5	11	13	14
		Total	7	5.6	5.5	11	13	14
	Steam turbine	Biomass	21	253.8	181.2	26	30	51
		Coal	1	601.0	585.0	26	26	26
		Natural gas	2	4.0	3.9	46	51	56
		Waste	1	13.1	11.5	20	20	20
		Total	25	871.9	781.6	26	30	51
	Wind turbine	Wind	7	298.5	298.0	3	4	5
		Total	7	298.5	298.0	3	4	5
	Total	Biomass	21	253.8	181.2	26	30	51
		Coal	1	601.0	585.0	26	26	26
		Natural gas	33	3,312.6	2,768.3	4	6	29
		Other gas	7	5.6	5.5	11	13	14
		Waste	1	13.1	11.5	20	20	20
		Water	190	8,236.5	8,331.0	36	48	54
		Wind	7	298.5	298.0	3	4	5
		Total	**260**	**12,721.1**	**12,160.4**	**24**	**43**	**53**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Pennsylvania	Combined cycle	Natural gas	57	9,061.5	7,728.7	3	4	9
		Total	57	9,061.5	7,728.7	3	4	9
	Combustion (gas) turbine	Distillate fuel oil	71	2,032.6	1,547.9	34	36	39
		Natural gas	31	1,801.3	1,597.9	5	5	19
		Other gas	8	27.4	23.8	5	8	13
		Total	110	3,861.3	3,169.6	10	35	37
	Hydraulic turbine	Water	49	757.4	730.0	19	73	82
		Total	49	757.4	730.0	19	73	82
	Internal combustion engine	Distillate fuel oil	26	76.1	74.3	36	38	39
		Natural gas	11	54.8	53.7	3	18	18
		Other gas	11	19.3	18.0	8	19	19
		Total	48	150.2	146.0	18	30	39
	Pumped storage hydraulic turbine	Water	11	1,269.0	1,505.0	36	39	39
		Total	11	1,269.0	1,505.0	36	39	39
	Steam turbine	Biomass	4	123.6	108.2	13	16	18
		Coal	53	18,318.0	16,714.8	36	45	52
		Distillate fuel oil	2	91.9	97.0	33	45	57
		Natural gas	1	3.0	3.0	19	19	19
		Nuclear material	9	9,859.8	9,195.0	20	23	32
		Other coal	19	2,170.9	1,926.5	14	16	20
		Other gas	3	83.2	80.0	10	10	18
		Other petroleum	6	2,903.4	2,797.0	30	32	48
		Waste	4	211.9	184.6	14	15	16
		Total	101	33,765.7	31,106.1	18	34	48
	Wind turbine	Wind	5	131.9	131.9	3	5	5
		Total	5	131.9	131.9	3	5	5
	Total	Biomass	4	123.6	108.2	13	16	18
		Coal	53	18,318.0	16,714.8	36	45	52
		Distillate fuel oil	99	2,200.6	1,719.2	35	37	39
		Natural gas	100	10,920.6	9,383.3	3	5	17
		Nuclear material	9	9,859.8	9,195.0	20	23	32
		Other coal	19	2,170.9	1,926.5	14	16	20
		Other gas	22	129.9	121.8	8	10	19
		Other petroleum	6	2,903.4	2,797.0	30	32	48
		Waste	4	211.9	184.6	14	15	16
		Water	60	2,026.4	2,235.0	20	39	80
		Wind	5	131.9	131.9	3	5	5
		Total	**381**	**48,997.0**	**44,517.3**	**14**	**32**	**39**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Rhode Island	Combined cycle	Natural gas	16	1,820.7	1,550.6	6	13	16
		Total	16	1,820.7	1,550.6	6	13	16
	Hydraulic turbine	Water	4	1.6	1.5	22	22	22
		Total	4	1.6	1.5	22	22	22
	Internal combustion engine	Other gas	15	26.1	23.7	1	16	16
		Total	15	26.1	23.7	1	16	16
	Steam turbine	Other petroleum	1	3.2	3.0	24	24	24
		Total	1	3.2	3.0	24	24	24
	Total	Natural gas	16	1,820.7	1,550.6	6	13	16
		Other gas	15	26.1	23.7	1	16	16
		Other petroleum	1	3.2	3.0	24	24	24
		Water	4	1.6	1.5	22	22	22
		Total	**36**	**1,851.6**	**1,578.8**	**5**	**16**	**16**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
South Carolina	Combined cycle	Natural gas	16	2,504.7	2,060.0	2	4	7
		Total	16	2,504.7	2,060.0	2	4	7
	Combustion (gas) turbine	Distillate fuel oil	16	708.3	563.0	32	32	34
		Natural gas	57	3,734.7	3,053.0	5	32	35
		Total	73	4,443.0	3,616.0	7	32	35
	Hydraulic turbine	Water	111	1,213.3	1,211.3	53	80	92
		Total	111	1,213.3	1,211.3	53	80	92
	Internal combustion engine	Distillate fuel oil	12	38.1	37.1	3	3	19
		Natural gas	3	3.3	3.3	19	19	19
		Other gas	6	8.8	9.0	1	2	5
		Total	21	50.2	49.4	3	3	19
	Pumped storage hydraulic turbine	Water	16	2,188.4	2,616.0	22	28	30
		Total	16	2,188.4	2,616.0	22	28	30
	Steam turbine	Biomass	2	109.6	100.0	15	19	22
		Coal	29	5,628.1	5,289.0	31	40	54
		Nuclear material	7	6,799.4	6,472.0	21	32	33
		Other coal	4	810.9	754.0	29	48	50
		Other petroleum	2	100.0	92.0	52	52	52
		Waste	1	13.0	9.5	17	17	17
		Total	45	13,461.0	12,716.5	25	36	51
	Total	Biomass	2	109.6	100.0	15	19	22
		Coal	29	5,628.1	5,289.0	31	40	54
		Distillate fuel oil	28	746.4	600.1	6	32	33
		Natural gas	76	6,242.7	5,116.3	4	17	35
		Nuclear material	7	6,799.4	6,472.0	21	32	33
		Other coal	4	810.9	754.0	29	48	50
		Other gas	6	8.8	9.0	1	2	5
		Other petroleum	2	100.0	92.0	52	52	52
		Waste	1	13.0	9.5	17	17	17
		Water	127	3,401.7	3,827.3	33	76	90
		Total	**282**	**23,860.6**	**22,269.3**	**17**	**35**	**66**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
South Dakota	Combustion (gas) turbine	Distillate fuel oil	5	255.4	185.4	28	28	28
		Natural gas	10	602.9	540.6	12	21	29
		Total	15	858.3	726.0	12	28	28
	Hydraulic turbine	Water	23	1,598.1	1,500.0	41	44	51
		Total	23	1,598.1	1,500.0	41	44	51
	Internal combustion engine	Distillate fuel oil	23	42.0	38.5	4	36	41
		Natural gas	5	12.6	12.6	32	44	44
		Total	28	54.6	51.1	10	37	44
	Steam turbine	Coal	2	481.0	482.1	31	38	45
		Total	2	481.0	482.1	31	38	45
	Wind turbine	Wind	3	43.1	43.1	3	5	5
		Total	3	43.1	43.1	3	5	5
	Total	Coal	2	481.0	482.1	31	38	45
		Distillate fuel oil	28	297.4	223.9	10	32	41
		Natural gas	15	615.5	553.2	12	29	44
		Water	23	1,598.1	1,500.0	41	44	51
		Wind	3	43.1	43.1	3	5	5
		Total	**71**	**3,035.1**	**2,802.3**	**28**	**41**	**44**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Tennessee	Combustion (gas) turbine	Natural gas	68	4,763.6	4,025.7	6	31	34
		Total	68	4,763.6	4,025.7	6	31	34
	Hydraulic turbine	Water	84	2,418.0	2,608.2	49	57	66
		Total	84	2,418.0	2,608.2	49	57	66
	Internal combustion engine	Biomass	1	2.0	1.8	1	1	1
		Distillate fuel oil	32	64.0	57.6	5	5	6
		Other gas	4	3.2	3.2	14	14	14
		Total	37	69.2	62.6	5	5	6
	Pumped storage hydraulic turbine	Water	4	1,530.0	1,597.1	27	27	28
		Total	4	1,530.0	1,597.1	27	27	28
	Steam turbine	Biomass	3	3.4	3.0	20	26	34
		Coal	33	9,780.4	8,394.0	47	51	52
		Nuclear material	3	3,710.9	3,398.0	10	24	25
		Total	39	13,494.7	11,795.0	47	49	52
	Wind turbine	Wind	4	28.8	29.1	4	6	6
		Total	4	28.8	29.1	4	6	6
	Total	Biomass	4	5.4	4.8	11	23	30
		Coal	33	9,780.4	8,394.0	47	51	52
		Distillate fuel oil	32	64.0	57.6	5	5	6
		Natural gas	68	4,763.6	4,025.7	6	31	34
		Nuclear material	3	3,710.9	3,398.0	10	24	25
		Other gas	4	3.2	3.2	14	14	14
		Water	88	3,948.0	4,205.4	49	57	65
		Wind	4	28.8	29.1	4	6	6
		Total	**236**	**22,304.3**	**20,117.8**	**6**	**35**	**53**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Texas	Combined cycle	Natural gas	255	35,903.3	31,114.8	4	6	19
		Other gas	1	104.4	104.0	10	10	10
		Total	256	36,007.7	31,218.8	4	6	19
	Combustion (gas) turbine	Natural gas	133	7,486.1	6,391.3	9	17	29
		Other gas	4	16.6	14.2	5	12	18
		Total	137	7,502.7	6,405.5	9	17	29
	Hydraulic turbine	Water	43	646.6	645.9	41	61	74
		Total	43	646.6	645.9	41	61	74
	Internal combustion engine	Distillate fuel oil	14	20.8	18.3	5	5	9
		Natural gas	4	16.2	12.6	18	19	19
		Other gas	27	31.8	35.0	3	3	3
		Total	45	68.8	65.9	3	3	5
	Other	Other	1	13.0	13.0	42	42	42
		Other petroleum	1	12.0	12.0	23	23	23
		Total	2	25.0	25.0	23	33	42
	Steam turbine	Biomass	1	5.0	5.0	23	23	23
		Coal	40	21,237.9	20,188.0	24	27	29
		Natural gas	134	27,863.1	26,839.3	34	40	48
		Nuclear material	4	5,138.6	4,860.0	15	17	18
		Other	2	7.5	6.7	36	36	36
		Other gas	6	132.2	119.9	21	22	23
		Other petroleum	1	184.0	140.0	20	20	20
		Purchased steam	4	195.0	154.0	19	27	27
		Waste heat	4	90.9	86.5	8	11	15
		Total	196	54,854.2	52,399.4	20	36	46
	Wind turbine	Wind	20	1,846.2	1,846.2	3	5	6
		Total	20	1,846.2	1,846.2	3	5	6

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Texas (continued)	Total	Biomass	1	5.0	5.0	23	23	23
		Coal	40	21,237.9	20,188.0	24	27	29
		Distillate fuel oil	14	20.8	18.3	5	5	9
		Natural gas	526	71,268.7	64,358.0	6	19	35
		Nuclear material	4	5,138.6	4,860.0	15	17	18
		Other	3	20.5	19.7	36	36	42
		Other gas	38	285.0	273.1	3	3	10
		Other petroleum	2	196.0	152.0	20	22	23
		Purchased steam	4	195.0	154.0	19	27	27
		Waste heat	4	90.9	86.5	8	11	15
		Water	43	646.6	645.9	41	61	74
		Wind	20	1,846.2	1,846.2	3	5	6
		Total	**699**	**100,951.2**	**92,606.7**	**5**	**19**	**35**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Utah	Combined cycle	Natural gas	4	432.4	402.4	1	2	2
		Total	4	432.4	402.4	1	2	2
	Combustion (gas) turbine	Natural gas	18	658.0	578.6	4	4	4
		Total	18	658.0	578.6	4	4	4
	Hydraulic turbine	Water	48	254.9	248.0	20	48	81
		Total	48	254.9	248.0	20	48	81
	Internal combustion engine	Distillate fuel oil	9	25.9	24.5	7	7	7
		Natural gas	28	70.3	63.4	5	16	20
		Total	37	96.2	87.9	5	11	19
	Steam turbine	Coal	14	4,978.8	4,800.0	23	31	52
		Geothermal	1	26.0	23.0	22	22	22
		Natural gas	3	251.6	235.0	51	54	55
		Other coal	1	58.1	51.0	13	13	13
		Waste	1	1.6	1.4	20	20	20
		Waste heat	1	31.8	31.6	11	11	11
		Total	21	5,347.9	5,142.0	20	29	52
	Total	Coal	14	4,978.8	4,800.0	23	31	52
		Distillate fuel oil	9	25.9	24.5	7	7	7
		Geothermal	1	26.0	23.0	22	22	22
		Natural gas	53	1,412.3	1,279.4	4	5	18
		Other coal	1	58.1	51.0	13	13	13
		Waste	1	1.6	1.4	20	20	20
		Waste heat	1	31.8	31.6	11	11	11
		Water	48	254.9	248.0	20	48	81
		Total	**128**	**6,789.4**	**6,458.8**	**7**	**20**	**48**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Vermont	Combustion (gas) turbine	Distillate fuel oil	6	79.1	53.9	14	38	44
		Other petroleum	1	41.8	35.0	34	34	34
		Total	7	120.9	88.9	14	35	44
	Hydraulic turbine	Water	103	286.3	296.7	22	78	89
		Total	103	286.3	296.7	22	78	89
	Internal combustion engine	Distillate fuel oil	13	16.0	15.3	52	56	59
		Total	13	16.0	15.3	52	56	59
	Steam turbine	Biomass	3	85.0	75.7	14	22	24
		Nuclear material	1	563.4	506.0	34	34	34
		Total	4	648.4	581.7	18	23	29
	Wind turbine	Wind	1	6.0	5.2	9	9	9
		Total	1	6.0	5.2	9	9	9
	Total	Biomass	3	85.0	75.7	14	22	24
		Distillate fuel oil	19	95.1	69.2	42	52	58
		Nuclear material	1	563.4	506.0	34	34	34
		Other petroleum	1	41.8	35.0	34	34	34
		Water	103	286.3	296.7	22	78	89
		Wind	1	6.0	5.2	9	9	9
		Total	**128**	**1,077.6**	**987.8**	**23**	**59**	**87**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Virginia	Combined cycle	Natural gas	28	3,787.1	3,319.0	6	13	15
		Total	28	3,787.1	3,319.0	6	13	15
	Combustion (gas) turbine	Distillate fuel oil	35	930.3	668.1	9	35	37
		Natural gas	34	3,828.6	3,195.3	4	5	14
		Total	69	4,764.9	3,863.4	5	14	35
	Hydraulic turbine	Water	50	711.5	645.7	52	67	91
		Total	50	711.5	645.7	52	67	91
	Internal combustion engine	Distillate fuel oil	51	99.1	96.5	9	14	19
		Other gas	16	13.4	12.8	12	13	14
		Other petroleum	2	6.0	6.0	13	15	17
		Total	69	118.5	115.3	10	14	16
	Pumped storage hydraulic turbine	Water	9	2,347.9	2,917.0	21	21	26
		Total	9	2,347.9	2,917.0	21	21	26
	Steam turbine	Biomass	14	370.6	330.6	21	33	50
		Coal	38	3,643.7	3,357.9	18	47	53
		Natural gas	4	361.6	313.7	17	34	48
		Nuclear material	4	3,654.4	3,432.0	27	31	34
		Other coal	8	2,455.1	2,326.0	24	44	51
		Other petroleum	2	1,764.0	1,604.0	31	32	32
		Waste	5	184.0	125.5	16	19	19
		Total	75	12,433.4	11,489.7	18	36	50
	Total	Biomass	14	370.6	330.6	21	33	50
		Coal	38	3,643.7	3,357.9	18	47	53
		Distillate fuel oil	86	1,035.4	764.6	9	16	36
		Natural gas	66	7,977.3	6,828.0	4	9	16
		Nuclear material	4	3,654.4	3,432.0	27	31	34
		Other coal	8	2,455.1	2,326.0	24	44	51
		Other gas	16	13.4	12.8	12	13	14
		Other petroleum	4	1,770.0	1,610.0	15	24	32
		Waste	5	184.0	125.5	16	19	19
		Water	59	3,059.4	3,562.7	40	53	91
		Total	**300**	**24,163.3**	**22,350.1**	**12**	**18**	**43**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Washington	Combined cycle	Natural gas	26	2,588.7	2,180.1	4	11	13
		Total	26	2,588.7	2,180.1	4	11	13
	Combustion (gas) turbine	Natural gas	15	869.6	726.2	4	5	25
		Total	15	869.6	726.2	4	5	25
	Hydraulic turbine	Water	279	20,586.6	21,077.2	28	46	63
		Total	279	20,586.6	21,077.2	28	46	63
	Internal combustion engine	Distillate fuel oil	21	34.7	38.5	5	5	5
		Natural gas	6	24.6	24.6	4	4	4
		Other gas	8	14.4	14.4	7	7	23
		Total	35	73.7	77.5	5	5	6
	Other	Other gas	3	2.7	2.3	7	7	7
		Total	3	2.7	2.3	7	7	7
	Pumped storage hydraulic turbine	Water	6	314.0	314.0	23	23	33
		Total	6	314.0	314.0	23	23	33
	Steam turbine	Biomass	19	270.6	257.1	23	49	58
		Coal	2	1,459.8	1,405.0	33	34	34
		Natural gas	1	5.0	1.0	37	37	37
		Nuclear material	1	1,200.0	1,131.0	22	22	22
		Waste	1	26.0	22.7	15	15	15
		Total	24	2,961.4	2,816.8	23	44	58
	Wind turbine	Wind	3	393.9	393.3	1	4	5
		Total	3	393.9	393.3	1	4	5
	Total	Biomass	19	270.6	257.1	23	49	58
		Coal	2	1,459.8	1,405.0	33	34	34
		Distillate fuel oil	21	34.7	38.5	5	5	5
		Natural gas	48	3,487.9	2,931.9	4	5	13
		Nuclear material	1	1,200.0	1,131.0	22	22	22
		Other gas	11	17.1	16.7	7	7	23
		Waste	1	26.0	22.7	15	15	15
		Water	285	20,900.6	21,391.2	28	46	63
		Wind	3	393.9	393.3	1	4	5
		Total	**391**	**27,790.6**	**27,587.3**	**20**	**38**	**55**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
West Virginia	Combustion (gas) turbine	Natural gas	17	1,464.5	1,288.5	5	5	5
		Other petroleum	1	18.5	12.0	39	39	39
		Total	18	1,483.0	1,300.5	5	5	5
	Hydraulic turbine	Water	19	314.3	254.3	18	70	71
		Total	19	314.3	254.3	18	70	71
	Steam turbine	Coal	35	13,458.5	12,954.0	35	48	55
		Natural gas	1	13.5	2.0	24	24	24
		Other coal	6	1,907.0	1,773.0	14	24	40
		Total	42	15,379.0	14,729.0	33	44	54
	Wind turbine	Wind	1	66.0	66.0	4	4	4
		Total	1	66.0	66.0	4	4	4
	Total	Coal	35	13,458.5	12,954.0	35	48	55
		Natural gas	18	1,478.0	1,290.5	5	5	5
		Other coal	6	1,907.0	1,773.0	14	24	40
		Other petroleum	1	18.5	12.0	39	39	39
		Water	19	314.3	254.3	18	70	71
		Wind	1	66.0	66.0	4	4	4
		Total	**80**	**17,242.3**	**16,349.8**	**6**	**37**	**56**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Wisconsin	Combined cycle	Natural gas	15	2,214.7	2,026.6	1	1	4
		Total	15	2,214.7	2,026.6	1	1	4
	Combustion (gas) turbine	Distillate fuel oil	11	558.0	557.3	28	28	33
		Natural gas	51	3,880.3	3,563.4	6	13	35
		Other gas	5	15.3	14.6	21	21	21
		Total	67	4,453.6	4,135.4	7	21	33
	Hydraulic turbine	Water	227	491.9	474.7	64	82	90
		Total	227	491.9	474.7	64	82	90
	Internal combustion engine	Distillate fuel oil	83	188.3	177.4	7	24	43
		Natural gas	6	24.2	23.2	5	21	36
		Other gas	40	34.7	33.3	4	5	6
		Total	129	247.2	233.9	5	10	36
	Steam turbine	Biomass	12	155.5	153.4	35	55	56
		Coal	55	6,979.2	7,016.0	37	46	55
		Natural gas	5	205.0	210.1	52	52	58
		Nuclear material	3	1,607.7	1,582.0	32	34	36
		Other petroleum	3	38.9	35.4	42	44	76
		Total	78	8,986.3	8,996.8	37	47	55
	Wind turbine	Wind	6	52.6	45.2	7	7	7
		Total	6	52.6	45.2	7	7	7
	Total	Biomass	12	155.5	153.4	35	55	56
		Coal	55	6,979.2	7,016.0	37	46	55
		Distillate fuel oil	94	746.3	734.7	8	28	42
		Natural gas	77	6,324.2	5,823.3	5	12	35
		Nuclear material	3	1,607.7	1,582.0	32	34	36
		Other gas	45	50.0	47.9	4	6	9
		Other petroleum	3	38.9	35.4	42	44	76
		Water	227	491.9	474.7	64	82	90
		Wind	6	52.6	45.2	7	7	7
		Total	**522**	**16,446.3**	**15,912.5**	**16**	**45**	**80**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Wyoming	Combustion (gas) turbine	Natural gas	13	152.5	116.6	4	4	5
		Other gas	3	108.0	91.8	1	1	1
		Total	16	260.5	208.4	4	4	5
	Hydraulic turbine	Water	25	297.3	301.3	46	54	67
		Total	25	297.3	301.3	46	54	67
	Steam turbine	Coal	23	6,167.8	5,846.9	27	34	43
		Other	1	11.5	11.5	20	20	20
		Total	24	6,179.3	5,858.4	26	33	43
	Wind turbine	Wind	16	287.4	287.4	6	7	7
		Total	16	287.4	287.4	6	7	7
	Total	Coal	23	6,167.8	5,846.9	27	34	43
		Natural gas	13	152.5	116.6	4	4	5
		Other	1	11.5	11.5	20	20	20
		Other gas	3	108.0	91.8	1	1	1
		Water	25	297.3	301.3	46	54	67
		Wind	16	287.4	287.4	6	7	7
		Total	**81**	**7,024.5**	**6,655.5**	**6**	**25**	**47**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
United States	Combined cycle	Coal	4	630.8	529.0	10	11	32
		Distillate fuel oil	23	816.2	695.3	13	25	37
		Natural gas	1,520	202,092.0	173,651.4	3	6	15
		Other gas	24	245.2	218.8	8	10	14
		Other petroleum	6	399.4	311.8	6	11	17
		Total	1,577	204,183.6	175,406.3	3	6	16
	Combustion (gas) turbine	Distillate fuel oil	561	21,426.6	17,950.4	30	34	36
		Natural gas	2,056	129,006.3	109,218.7	5	11	32
		Other gas	69	733.0	638.0	6	10	17
		Other petroleum	83	2,751.9	2,376.0	34	36	38
		Total	2,769	153,917.8	130,183.1	5	17	35
	Geothermal binary cycle turbine	Geothermal	49	176.7	130.9	14	17	17
		Total	49	176.7	130.9	14	17	17
	Hydraulic turbine	Water	3,725	76,555.0	76,764.8	27	56	82
		Total	3,725	76,555.0	76,764.8	27	56	82
	Internal combustion engine	Biomass	1	2.0	1.8	1	1	1
		Distillate fuel oil	2,061	4,027.5	3,836.5	7	27	43
		Natural gas	659	1,770.4	1,639.8	13	28	43
		Other gas	537	566.8	538.4	6	9	14
		Other petroleum	8	39.2	37.6	17	23	41
		Total	3,266	6,405.9	6,054.1	7	19	40
	Other	Natural gas	1	4.5	3.1	2	2	2
		Other	1	13.0	13.0	42	42	42
		Other gas	4	17.7	12.3	7	7	10
		Other petroleum	2	33.1	28.6	23	30	37
		Waste heat	1	7.5	7.5	23	23	23
		Total	9	75.8	64.5	7	23	25

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
United States (continued)	Photovoltaic	Solar	9	11.0	11.0	5	7	18
		Total	9	11.0	11.0	5	7	18
	Pumped storage hydraulic turbine	Water	150	19,569.3	21,346.6	26	33	39
		Total	150	19,569.3	21,346.6	26	33	39
	Steam turbine	Biomass	249	5,149.6	4,565.8	17	23	41
		Coal	1,291	321,553.7	299,990.3	29	41	51
		Distillate fuel oil	11	936.3	893.0	38	57	59
		Geothermal	163	2,897.7	2,103.3	17	19	20
		Natural gas	562	88,734.9	84,465.9	36	45	51
		Nuclear material	103	104,432.9	98,923.0	20	28	32
		Other	17	415.8	390.3	18	21	36
		Other coal	45	9,063.7	8,484.5	14	20	43
		Other gas	47	1,289.9	1,129.9	17	24	53
		Other petroleum	156	32,222.6	30,453.0	32	42	49
		Purchased steam	5	202.2	161.2	10	27	27
		Solar	9	400.4	399.8	18	19	20
		Waste	90	2,556.9	2,083.0	15	18	20
		Waste heat	11	350.6	318.4	9	14	22
		Total	2,759	570,207.2	534,361.4	23	37	49
	Wind turbine	Wind	267	8,680.9	8,654.1	3	5	9
		Total	267	8,680.9	8,654.1	3	5	9

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
United States (continued)	Total	Biomass	250	5,151.6	4,567.6	17	23	41
		Coal	1,295	322,184.5	300,519.3	29	41	51
		Distillate fuel oil	2,656	27,206.6	23,375.2	9	32	40
		Geothermal	212	3,074.4	2,234.2	16	18	20
		Natural gas	4,798	421,608.1	368,978.8	5	14	34
		Nuclear material	103	104,432.9	98,923.0	20	28	32
		Other	18	428.8	403.3	18	21	36
		Other coal	45	9,063.7	8,484.5	14	20	43
		Other gas	681	2,852.6	2,537.5	6	9	16
		Other petroleum	255	35,446.2	33,207.0	32	37	45
		Purchased steam	5	202.2	161.2	10	27	27
		Solar	18	411.4	410.8	7	18	20
		Waste	90	2,556.9	2,083.0	15	18	20
		Waste heat	12	358.1	325.9	10	16	23
		Water	3,875	96,124.3	98,111.4	27	54	82
		Wind	267	8,680.9	8,654.1	3	5	9
		Total	**14,580**	**1,039,783.2**	**952,976.8**	**11**	**29**	**47**

Source Data: Department of Energy, Energy Information Agency, Form EIA-860, 2005.
Data available at: http://www.eia.doe.gov/cneaf/electricity/page/eia860.html

Notes on fuel categories:
"Other coal" includes waste coal, coal-based synfuel, anthracite culm, bituminous gob, fine coal, and lignite waste.
"Other gas" includes blast furnace gas, butane, propane, landfill, other biomass, and gases recovered from other processes.
"Other petroleum" includes jet fuel, kerosene, residual fuel oil, waste oil, liquid propane and butane, and re-refined oil.
"Other" includes batteries, chemicals, hydrogen, tar coal and miscellaneous technologies.

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Sec 9.2 Ref 24

Rardin et al 200

Factors that Affect the Design and Implementation of Clean Coal Technologies in Indiana

Interim Report
June 6, 2005

Purdue Energy Research Modeling Groups
Purdue University
West Lafayette, Indiana

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Prepared for:
Center for Coal Technology Research

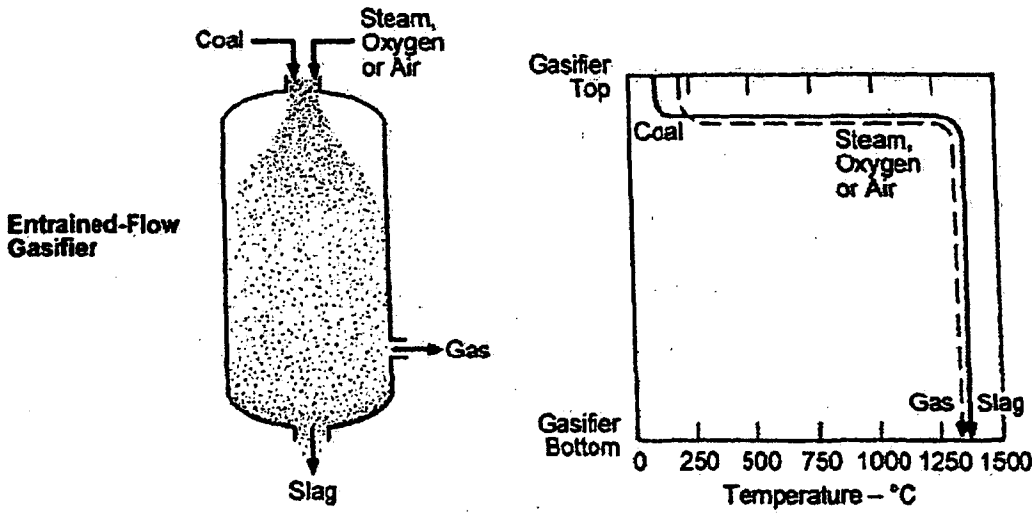

Figure 1.01g. Entrained flow gasifier and temperature profiles. Taken from [5]

1.02 IGCC Maturity and Prior Experience

The first IGCC power plant in the world was tested in Germany in the 1970s [6]. The first IGCC power plant in the U.S. was in operation in Southern California in the 1980s [6]. Today, there are at least five IGCC plants in operation or testing with power as sole output or co-product in the U.S. (see [7] and [8]), of which five, the Wabash River Repowering Project is the first modern IGCC plant that has been in commercial operation intermittently since late 1995.

There are many IGCC power plants around the world [7]. More are under planning, pre-development or construction. In addition, IGCC has been considered for chemicals co-production, including ammonia based fertilizers, clean diesel fuels, and many others [7].

People have mixed opinions on IGCC. Some think that IGCC power plant technology is relatively mature, while some others think it immature. Enough experience has been gained with the chemical processes of gasification, coal properties and their impact on IGCC design, efficiency, economics, etc. However, system reliability is still relatively lower than conventional coal-based power plants (pulverized coal (PC) plants) and the major reliability problem is from gasification section. There are problems with the integration between gasification and power production as well. For example, if there is a problem with gas cleaning, uncleaned gas can cause various damages to the gas turbine. There are several areas that can make the technology more mature: gasifiers' ability to withstand high temperature, high pressure, and high sulfur coals; hot gas cleaning with high reliability; extending the life of gas cleaning filters, etc.

Even though not mature, IGCC is the cleanest technology so far and it has been considered the most favorable technology for CO_2 capture. However, there has been no actual demonstration in the area in the U.S., except some ongoing research programs.

One such program is the EPRI "Destination 2004" to research and demonstrate IGCC designs and CO_2 capture efficiency [9], with a target completion around 2012. DOE has been sponsoring CO_2 sequestration research since the mid-90s (see [7], [8] and DOE website at http://www.doe/gov/), and has expressed an interest in the use of the Tampa IGCC power plant for demonstrating CO_2 sequestration.

Supercritical (SC) and ultra supercritical (USC) PC plants may also be ready for CO_2 capture. Some claimed that the USC PC is already a CO_2-ready technology [10]. However, the technology is again not demonstrated.

Table 1.02 illustrates the time when the IGCC power plants were first in operation. Some plants such as the Tampa IGCC and the Wabash River IGCC have been in commercial operation for about 10 years, while others are still under various tests. Note the modified Wabash River IGCC plant, a copy of the project with some minor modifications was moved to the South and produce power for a refinery plant since 2000.

The USC-PC technology has a long history (almost 50 year). According to the Babcock & Wilcox company, it designed the world first USC-PC in 1957 for the American Electric Power in Ohio [11]. No doubt that the SC-PC technology has a longer history even though we do not know which one was the first SC-PC plant in the world. Both the SC and USC PC technologies are mature in many aspects because of their extensive application and history. However, they are still under research and development for meeting new emission standards, of which CO_2 control is a focus point.

In short, SC-PC and USC-PC have a longer history than IGCC and are more mature than IGCC. However, IGCC also has a relative long history of commercial operation since the mid-90s, and the IGCC history can even be traced back to the 1970s when the then West Germany constructed the first IGCC power plant in the world. Neither of the technologies is considered "mature" in CO_2 sequestration is considered because none of them have been commercially tested for CO_2 sequestration.

Table 1.02. Timeline of Some IGCC and PC Power Plants.

Technology	Location or name	Operation year	Capacity (net)	Comments
Entrained flow	1. Wabash, IN 2. Wabash-I, LA 3. Tampa, FL 4. Mesaba, MN 5. So. Ill. Clean Energy Center, IL	Dec. 1995 Mid-2000 Oct. 1996 2010 target n/a	262 MW 395.8 MW 250 MW 531 MW 615 MW	In operation In operation In operation Under design Under design
Fluidized bed	Pinon Pine, NV	1998	99 MW	Test operation
Fixed bed	EKPC, KY	n/a	540 MW	Test operation
Supercritical SC - PC	n/a	n/a	n/a	Much earlier than 1957
USC-PC	Philo, AEP, OH	1957	125 MW	First in world, Babcock design

Dec 9.2 Ref 27

Santee Cooper.

One Riverwood Drive
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(843) 761-8000
P.O. Box 2946101
Moncks Corner, SC 29461-6101

November 17, 2006

Mr. Mitchell Perkins
Director
South Carolina Energy Office
1201 Main Street, Suite 1010
Columbia, South Carolina 29201

Re: Annual Update to Integrated Resource Plan (2004) from the South Carolina Public Service Authority

Dear Mr. Perkins:

Enclosed is the annual update (dated November 2006) to Santee Cooper's Integrated Resource Plan (IRP). This update provides a status of DMS Programs and the Generation Resource Plan as required by the South Carolina Code, Section 58-37-40.

If you have any questions, please call me at (843) 761-4123.

Sincerely,

Sylleste H. Davis

Sylleste H. Davis
Manager, Wholesale Markets

SCE 10

2004 INTEGRATED RESOURCE PLAN
ANNUAL UPDATE

South Carolina Public Service Authority

Originally submitted: December 2005

Updated: November 2006

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2004 Integrated Resource Plan Annual Update

As required by South Carolina Code, Section 58-37-40, this report provides an annual update to the South Carolina Public Service Authority ("Santee Cooper") 2004 Integrated Resource Plan submitted December 8, 2005.

I. Update to: Load Forecast

Load Forecast LF0501 was completed and published in October 2005, and provides an update to the 2004 Load Forecast.

Projected Energy & Summer/Winter Peak Demands

	Summer Peak (MW)	Winter Peak (MW)	Energy Sales (GWH)
2005	5,189	5,252	27,672
2006	5,305	5,393	28,258
2007	5,421	5,534	28,848
2008	5,538	5,676	29,448
2009	5,659	5,821	30,069
2010	5,772	5,960	30,646
2011	5,886	6,098	31,235
2012	6,003	6,240	31,833
2013	6,122	6,385	32,441
2014	6,243	6,532	33,059
2015	6,364	6,679	33,678
2016	6,486	6,827	34,301
2017	6,610	6,977	34,934
2018	6,736	7,129	35,577
2019	6,864	7,284	36,229

*Source is 2005 Load Forecast

Historical Sales and System Peak Loads

Year	Sales (GWH)	System Peak Load [1] (MW)
2005	25,064	5,371
2004	24,451	5,088
2003	24,060	5,373
2002	24,121	4,795
2001	22,400	4,803
2000	22,139	3,876
1999	20,286	3,729
1998	19,466	3,523
1997	18,437	3,336
1996	17,548	3,441
1995	16,022	3,102

(1) Excludes firm off-system sales to other utilities

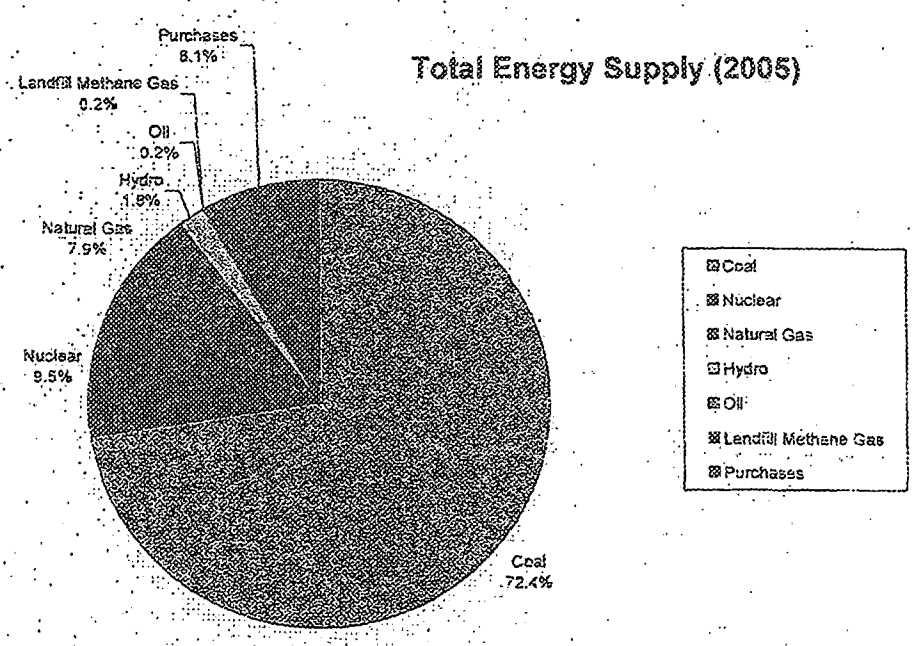
II. Update to: Existing Capacity

The Authority's generating facilities consist of the following facilities:

Generating Facilities	Location	Initial Date in Service	Winter Peak Capability (MW)	Summer Peak Capability (MW)	Energy Source
Jefferies Hydroelectric Generating Station	Moncks Corner	1942	128	128	Hydro
Wilson Dam Generating Station	Lake Marion	1950	2	2	Hydro
Jefferies Generating Station	Moncks Corner				
Nos. 1 and 2		1954	92	92	Oil
Nos. 3 and 4		1970	306	306	Coal
Grainger Generating Station Nos. 1 and 2	Conway	1966	170	170	Coal
Combustion Turbines Nos. 1 and 2	Myrtle Beach	1962	22	20	Oil/Gas
Combustion Turbines Nos. 3 and 4	Myrtle Beach	1972	50	40	Oil
Combustion Turbine No. 5	Myrtle Beach	1976	35	30	Oil
Combustion Turbine No. 1	Hilton Head Island	1973	25	20	Oil
Combustion Turbine No. 2	Hilton Head Island	1974	25	20	Oil
Combustion Turbine No. 3	Hilton Head Island	1979	70	57	Oil
Winyah Generating Station	Georgetown				
No. 1		1975	295	295	Coal
No. 2		1977	295	295	Coal
No. 3		1980	295	295	Coal
No. 4		1981	270	270	Coal
Summer Nuclear Station(1)	Jenkinsville	1983	318(2)	318(2)	Nuclear
Cross Generating Station	Cross				
Unit 1		1995	620	620	Coal
Unit 2		1983	540	540	Coal
Horry Landfill Gas Station	Conway	2001	3	3	LMG(3)
Lee County Landfill Gas Station	Bishopville	2005	5	5	LMG
Richland County Landfill Gas Station	Elgin	2006	5	5	LMG
Rainey Generating Station	Starr				
Unit 1		2002	508	447	Gas
Unit 2A		2002	168	146	Gas
Unit 2B		2002	168	146	Gas
Unit 3		2004	85	74	Gas
Unit 4		2004	85	74	Gas
Unit 5		2004	85	74	Gas
Diesel Generating Units		2003(4)	17	17	Oil
Total Capability			4,687	4,509	

(1) Virgil C. Summer Nuclear Station ("Summer Nuclear Station").
(2) Represents the Authority's one-third ownership interest.
(3) Landfill Methane Gas ("LMG")
(4) Year Purchased by the Authority.

In 2005, Santee Cooper met its energy requirements using the following resources:



III. Update to: Projections of Load, Capacity, and Reserves

Santee Cooper continues to operate using planning reserve targets of 10% and 13% for the winter and summer months, respectively. The load forecast, as well as reserve margin and capacity information, is contained in the table that follows:

Seasonal Projections of Load, Capacity, and Reserves

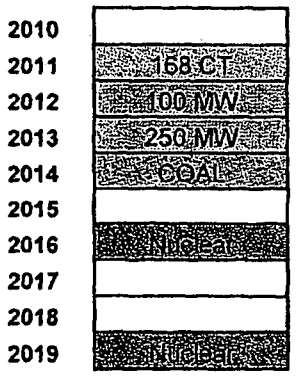
W=Winter, S=Summer	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S
	05/06	2006	06/07	2007	07/08	2008	08/09	2009	09/10	2010	10/11	2011	11/12	2012	12/13	2013	13/14	2014	14/15	2015
Forecast Requirements																				
1 Santee Cooper System Peak	5,394	5,307	5,534	5,423	5,675	5,538	5,822	5,659	5,960	5,773	6,100	5,887	6,241	6,003	6,385	6,123	6,532	6,244	6,679	6,366
2 Interruptible Load	(298)	(299)	(298)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)
3 Firm Sales	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
4 Total Reserved Load	5,122	5,034	5,262	5,150	5,402	5,265	5,549	5,386	5,687	5,500	5,827	5,614	5,968	5,730	6,112	5,850	6,259	5,971	6,406	6,093
5 Load Not Requiring Reserve	(619)	(619)	(619)	(619)	(619)	(619)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)
6 Total Load Requiring Reserve	4,503	4,415	4,643	4,531	4,783	4,646	5,138	4,975	5,276	5,089	5,416	5,203	5,557	5,319	5,701	5,439	5,848	5,560	5,995	5,682
Cumulative System Capacity																				
7 Available Generating Capacity	4,722	4,544	4,722	4,544	4,722	4,544	4,722	4,544	4,722	4,544	4,722	4,544	4,722	4,544	4,722	4,544	4,722	4,544	4,722	4,544
8 Catawba Entitlement	208	208	208	208	208	208														
9 Projected Resource Additions	0	10	592	592	600	607	1,196	1,196	1,202	1,204	1,204	1,204	1,804	1,804	1,804	1,804	1,804	1,804	1,804	1,804
10 Available Generating Capacity	4,930	4,762	5,522	5,344	5,530	5,359	5,918	5,740	5,924	5,748	5,926	5,748	6,526	6,348	6,526	6,348	6,526	6,348	6,526	6,348
Cumulative Purchase Contracts																				
11 Long Term	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411
12 Mid Term Contract	175	175																		
13 Proj Short Term Contract	60	265				105				5	35	135							70	75
14 Cumulative Production Capacity	5,576	5,613	5,933	5,755	5,941	5,875	6,329	6,151	6,335	6,164	6,372	6,294	6,937	6,759	6,937	6,759	6,937	6,759	7,007	6,834
Reserves																				
15 Generating Reserves	454	579	671	605	539	610	780	765	648	664	545	680	969	1,029	825	909	678	788	601	741
16 % Reserve Margin	10%	13%	14%	13%	11%	13%	15%	15%	12%	13%	10%	13%	17%	19%	14%	17%	12%	14%	10%	13%

*based on 2005 Load Forecast

IV. Update to: Generation Expansion Plan

As noted in the 2004 Integrated Resource Plan, a 600 MW coal-fired unit (Cross 3) is scheduled for commercial operation in January 2007, with another 600 MW coal-fired unit (Cross 4) scheduled for January 2009. The construction of these units is well underway and projected COD dates are expected to be met.

In 2005, the Generation Resource Plan was updated and recommended the following, in addition to the Cross 3 and 4 units, for the 2010-2019 time period:



- (1) 168 MW simple cycle combustion turbine to be operational in 2011,
- Purchased power amounts of 100 MW and 250 MW for 2012 and 2013 respectively,
- (1) 600 MW class supercritical pulverized coal unit to be built and operational no later than January 2014, and,
- A 45% ownership share of two (2) 1100 MW class Westinghouse Nuclear units located at the V.C. Summer Nuclear site to be built and operational no later than January 2016 and January 2019, respectively.

In March 2006, the Santee Cooper Board of Directors (i) approved the 2005/2006 Generation Plan, (ii) authorized management to take actions necessary or appropriate to construct and install a 600 MW coal unit to begin operations as soon as possible but not later than January 2014, and (iii) authorized management to take actions necessary or appropriate to obtain a construction and operating permit for ownership shares of (2) 1100 MW nuclear units. In May 2006, the Board authorized management to take actions necessary to accelerate the construction schedule for the 2014 coal unit to as early as January 2012. Shortfalls in capacity and reserves requirements will be met using purchases as necessary.

V. Update to: Demand Side Management (DSM) Activities

1. Good Cents New and Improved Home Program

The Good Cents Program was developed to provide residential customers an incentive to build new homes to higher levels of energy efficiency and improve existing homes by upgrading heating and air conditioning equipment and the thermal envelope to high energy efficiency standards. All homes are evaluated to determine if they meet the standards set for the program. Inspections are completed during construction for new homes and at the completion of construction for new and improved homes.

Program participation in 2005 resulted in an estimated demand savings of 15,470 kW and estimated energy savings of 22,101,000 kWh. Total expenditures for the Good Cents Program incurred through Santee Cooper in 2005 were $202,559.21. (Demand savings are based on summer peak demand reduction of 1.05 kW).

2. H_2O Advantage Water Heating Program

H_2O Advantage is a storage water heating program designed to shift the demand related to water heating off-peak. This is accomplished with the installation of an electronic timer or radio controlled switch on an 80 gallon water heater. This program began in 1990 and was offered for the last time in 2000. The contract spans 10 years so this program will no longer be impacting the system after 2010.

Program participation in 2005 resulted in an estimated demand savings of 853 kW. Total expenditures for the H_2O Advantage Program incurred through Santee Cooper in 2005 for existing participants were $167,294.85.

3. Commercial Good Cents

Commercial Good Cents is offered to commercial customers building new facilities that improve the efficiency in the building thermal envelope, heating and cooling equipment, and lighting. Commercial customers that meet program standards are given an up-front rebate to encourage participation in the program.

Program participation in 2005 resulted in an estimated demand savings of 119 kW and estimated energy savings of 182,884 kWh. Total expenditures for the Commercial Good Cents Program incurred through Santee Cooper in 2005 were $24,620.

4. Thermal Storage Cooling Program

The Thermal Storage Cooling Program shifts energy used by commercial customers for air conditioning from peak to off-peak hours by utilizing thermal energy stored in a medium such as ice or water. Rebates are offered to customers who install this type of equipment. There is currently one active participant in this program.

As part of Santee Cooper's demand control program, currently there are approximately 500 MW of load taking service under interruptible and economy power schedules. This load is excluded from the peak demand calculations for generation planning and reserves resource planning.

VI. Update to: Environmental

1. Green Power

Santee Cooper entered the arena of Green Power in 2001, being the first electric utility in South Carolina to offer electricity generated from renewable resources. In March 2006, the Richland County Generating Station was dedicated as Santee Cooper's third "Green Power" generating facility. A similar Green Power station at the Anderson Regional Landfill is currently under construction. Approval was given in September 2006 for the development of a new environmental program to offer to everyone in South Carolina, for the first time, the ability to purchase local renewable energy through a Green Tag program. This program allows all citizens and businesses in the state to do something positive to improve their environment, no matter their electric provider.

2. Renewables

In 2005, Santee Cooper announced a five-year, statewide and multi-tiered plan that would add solar projects at state universities and in various South Carolina regions, potential wind demonstration projects, and the continuation of landfills across South Carolina to the mix of renewables. In October 2006, Santee Cooper and Coastal Carolina University officially dedicated South Carolina's first solar Green Power site, a historic solar pavilion demonstration project that delivers on Santee Cooper's commitment to reinvest Green Power funds into future renewable energy projects in the state. Santee Cooper has also partnered with Clemson University to implement solar energy technology there.

3. Other

Santee Cooper's coal-fired power plants at Cross and Winyah generate a synthetic gypsum byproduct as a result of using scrubbing technology to reduce sulfur dioxide emissions. American Gypsum is currently constructing a new wallboard plant adjacent to Santee Cooper's Winyah Generating Station. By utilizing Santee Cooper's synthetic gypsum and excess steam in its gypsum wallboard production, the partners are converting waste that would otherwise be landfilled into a valuable building product.

Santee Cooper 2005

Santee Cooper.

One Riverwood Drive
Moncks Corner, SC 29461-2901
(843) 761-8000
P.O. Box 2946101
Moncks Corner, SC 29461-6101

December 8, 2005

Mr. Mitchell Perkins
Director
South Carolina Energy Office
1201 Main Street, Suite 1010
Columbia, South Carolina 29201

Re: Integrated Resource Plan (2004) from the South Carolina Public Service Authority

Dear Mr. Perkins:

Enclosed is the 2004 Integrated Resource Plan (IRP) from the South Carolina Public Service Authority ("Santee Cooper") as required by SC Code Section 58-37-10, -30 and -40. The plan contains the demand and energy forecast for a fifteen-year period, as well as a program for meeting the requirements shown in the forecast. A description of demand-side management programs is also included.

If you have any questions, please call me at (843) 761-4123.

Sincerely,

Sylleste H. Davis
Manager, Wholesale Markets

Santee Cooper

South Carolina Public Service Authority

Integrated Resource Plan 2004

Introduction

The South Carolina Public Service Authority ("Santee Cooper") is a body corporate and politic of the State of South Carolina. Santee Cooper operates an integrated electric utility system, including facilities for generation, transmission, and distribution of electric power and energy at retail and wholesale levels.

The source of power for more than 1.8 million South Carolinians, Santee Cooper provides direct service to almost 138,000 residential and commercial customers in Berkeley, Georgetown and Horry counties. Santee Cooper is the primary source of power distributed by the state's 20 electric cooperatives to over 625,000 customers located in all of the state's 46 counties. Santee Cooper also supplies power to 31 large industrial facilities, the cities of Bamberg and Georgetown, and the Charleston Air Force Base. Santee Cooper is the nation's fourth largest publicly owned electric utility of its type based on generation and megawatt-hour sales to ultimate customers.

On a regular basis, Santee Cooper analyzes the existing and future energy needs of its customers in order to ensure it has a plan that will serve its customers in an economical and reliable manner. The process of developing a comprehensive plan to effectively serve the needs of the diverse customer classes involves several various steps. In deciding what future resources are necessary to meet the customers' needs, it is necessary to first forecast the long-term load for each group. The load forecast is then compared to Santee Cooper's existing capacity and planned reserve margins to determine how much generation is needed in the future. A generation plan is developed, and the adequacy of the transmission and distribution system is evaluated. Additionally, options to manage the customer's demand needs are evaluated.

This Integrated Resource Plan ("IRP") contains the demand and energy forecast for a fifteen-year period, as well as a program for meeting the requirements shown in the forecast. This report also includes a description of demand-side management programs as required by SC Code Section 58-37-10, -30 and – 40.

Process

1) Data Collection

The load forecast database is updated each year to include the most recent historical data, including: electric system data (number of customers, kWh sales, and revenues by customer class), economic data, and weather data.

2) Economic Outlook

An economic outlook is prepared each year to address recent trends in economic activity and to develop growth trends for key economic and demographic factors, including: population, employment, personal income, retail sales, and inflation. Economic outlooks are prepared for three areas: the Santee Cooper service area (Horry and Georgetown counties), the Central Electric Cooperative ("Central") service area (primarily the state of South Carolina excluding counties in the northwest area), and the Saluda River Electric Cooperative ("Saluda") service area (northwest counties of the state). Historical values are based on data provided by the U.S. Census Bureau, the Department of Labor, and the Bureau of Economic Analysis. Projected values are based on information obtained from Woods & Poole Economics, Economy.com, the University of South Carolina (Division of Research, Moore School of Business), and the Center for Economic Forecasting at Charleston Southern University.

3) Forecasting Development

The Santee Cooper load forecast represents a territorial load covering portions throughout the state of South Carolina and is comprised of three independent electric systems: Santee Cooper, Central, and Saluda. Forecasts are prepared for each entity and aggregated to produce the Santee Cooper territorial load forecast.

4) Santee Cooper Requirements

Santee Cooper requirements include energy sales, peak demand, and associated distribution losses for the residential, commercial, municipal, and industrial customer classifications. Econometric models are used to project the number of customers and average energy use per customer for both the residential and commercial classifications.

energy use per customer for both the residential and commercial classifications. The models quantify the impacts of population, employment, personal income, retail sales, and weather conditions relative to customer growth and energy sales. Energy sales are computed as the product of number of customers and average energy use per customer.

Projections of peak demand are developed at the total Saluda River level for the summer and winter seasons and based on equations that incorporate total energy requirements and the development of an econometric model to project long-term peak demand.

7) Total Territorial Requirements

Total territorial requirements include the combined energy and peak demand requirements for Santee Cooper, Central, and Saluda. The peak demand projections represent the highest simultaneous 60-minute load for the three combined entities.

Future uncertainties are addressed in the forecasting process through model simulations. Simulation software is used to analyze peak demand and to develop a peak demand probability distribution. Historical weather data is used to develop a probability distribution of temperatures at the time of the territorial peak. The temperature distribution serves as input for the peak demand simulation. Results of the simulation analysis provide peak demand estimates for given temperatures and the probabilities that peak demand will rise or fall to specific levels around the base case forecast. The simulation process addresses both peak demand and energy requirements.

Below is a table with the 2004 Load Forecast for energy and demand, and a table with historical energy and demand.

II. Existing Capacity

The following table lists Santee Cooper's existing generating facilities:

Generating Facility	Units	Location	Summer Capacity	Winter Capacity	Fuel	Began Commercial Operation
Jefferies Hydroelectric	1, 2, 3, 4, 6	Moncks Corner	128	128	Hydro	1942
Wilson Dam		Lake Marion	2	2	Hydro	1950
Jefferies	1 and 2	Moncks Corner	92	92	Oil	1954
	3 and 4		306	306	Coal	1970
Grainger	1 and 2	Conway	170	170	Coal	1966
Myrtle Beach Combustion Turbines	1 and 2	Myrtle Beach	20	22	Oil/Gas	1962
	3 and 4		40	50	Oil	1972
	5		30	35	Oil	1976
Hilton Head Combustion Turbines	1	Hilton Head Island	20	25	Oil	1973
	2		20	25	Oil	1974
	3		57	70	Oil	1979
Winyah Station	1	Georgetown	295	295	Coal	1975
	2		295	295	Coal	1977
	3		295	295	Coal	1980
	4		270	270	Coal	1981
V.C. Summer Nuclear Station*		Jenkinsville	318	318	Nuclear	1983
Cross Station	1	Cross	620	620	Coal	1995
	2		540	540	Coal	1983
Horry County Landfill Gas Station		Conway	3	3	Landfill methane gas	2001
Lee County Landfill Gas Station		Bishopville	5	5	Landfill methane gas	2005
Rainey Station	Combined Cycle	Starr	447	508	Gas	2002
	CT 2A		146	168	Gas	2002
	CT 2B		146	168	Gas	2002
	CT 3		74	85	Gas	2004
	CT 4		74	85	Gas	2004
	CT 5		74	85	Gas	2004
Diesel Units		Various	17	17	Oil	Purchased in 2003
Total Capacity			**4,504**	**4,682**		

* Santee Cooper's one-third ownership share. The operating license was extended to August 6, 2042 on April 23, 2004.

III. Projections of Load, Capacity, and Reserves

In order to ensure Santee Cooper has sufficient generation capacity to cover uncertainties in serving the needs of our customers, it operates using planning reserve targets of 10% and 13% for the winter and summer months, respectively. Uncertainties in meeting customers' load requirements can arise from unit outages, adverse weather conditions, unexpected demand, or an unplanned loss in the transmission system. The planning reserves of 10% for the winter and 13% for the summer have been deemed to be sufficient to mitigate the risks that the various uncertainties pose.

Deciding the optimal reserve margin level requires Santee Cooper to use the most recent long term load forecast. In planning for the future reserve needs, the load forecast's firm load requirements, less any requirements that are served by reserved resources such as SEPA, are used. The load forecast is based on normal weather temperatures in order to determine a base line forecast. The load forecast, as well as reserve margin and capacity information, is contained in the table that follows:

IV. Generation Expansion Plan

Santee Cooper's overall power supply objective is to continue to satisfy the electric power and energy needs of its customers with economical and reliable service. Santee Cooper reviews, from time to time, its power resources and requirements and considers the possible addition of new power resources, which may include nuclear, natural gas, oil and coal fired units, as well as long-term power purchase agreements. Current and future Demand Side Management programs are evaluated on an individual, case-by-case basis.

The 2001 Generation Resource Plan ("2001 Plan") assessed the need for additional generating resources to meet future customer demands and developed a least-cost plan to provide the resources for Santee Cooper to meet these demands. The 2001 Plan evaluated potential purchased power options against Santee Cooper's self-build generation options.

For the planning period of 2001 through 2008, the 2001 Plan recommended the following:

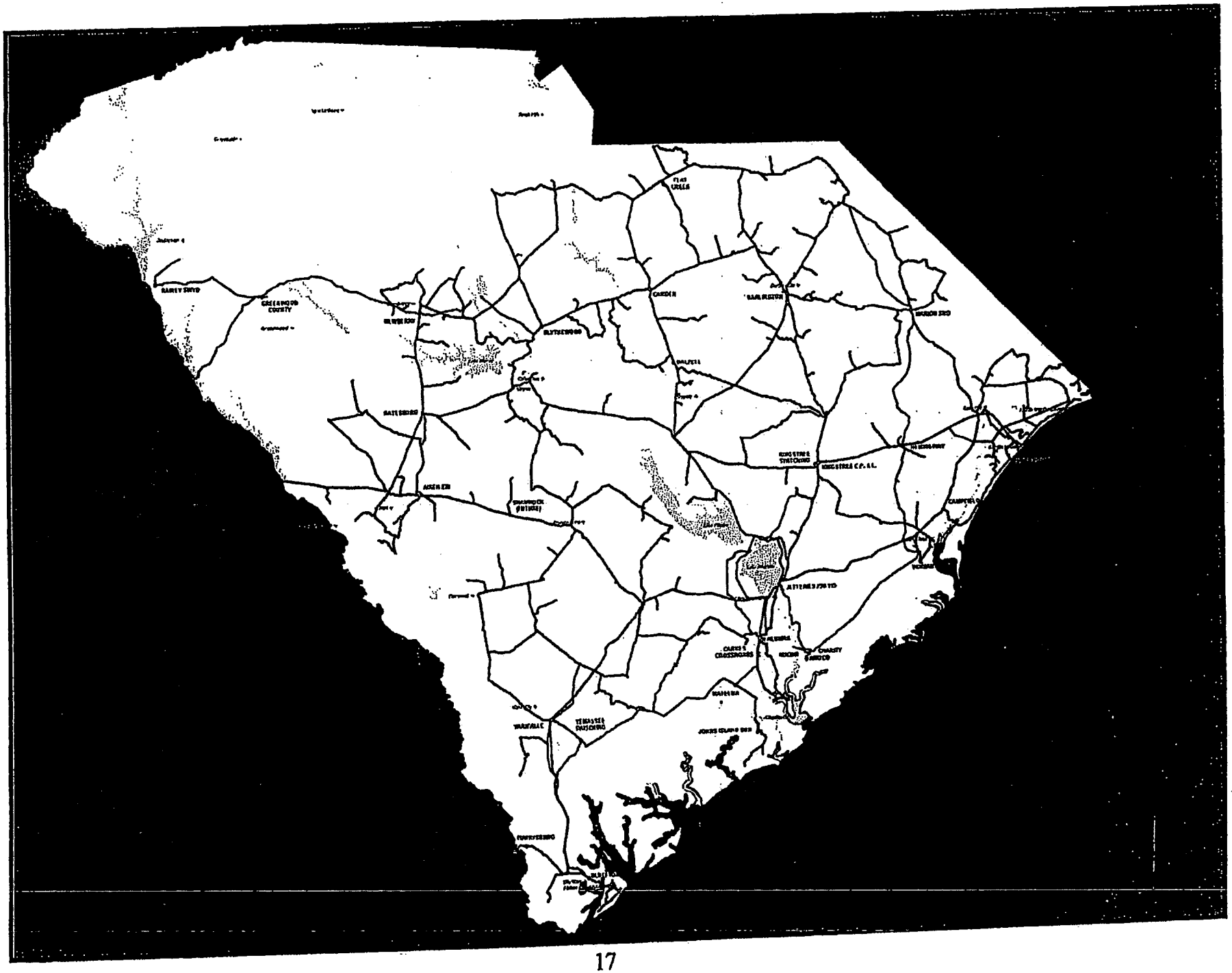
- Short-term firm power purchases,
- Completion of the construction of the Rainey Station Units as planned, including one (1) 500 MW-class combined cycle unit and two (2) simple cycle combustion turbine units,
- Installation of (2) additional simple cycle turbines by January 2004, and
- Construction of a new 600 MW coal-fueled unit at the Cross Generating Station.

As recommended by the 2001 Plan, a 508 MW combined-cycle unit began operation in January 2002. One 168 MW simple cycle unit began commercial operation in March 2002 and a second 168 MW simple cycle unit began operation in May 2002. In January, 2004, additional simple cycle turbines began operation at the Rainey Station, for a total of over 1000 MWs at that site. The construction of a third coal-fueled unit at the Cross Generating Station was approved and is planned for commercial operation January 1, 2007.

V. Transmission System Adequacy

Santee Cooper's transmission and distribution lines, as well as substations, deliver from the generating stations the reliable, low-cost power expected by customers. Santee Cooper operates an integrated transmission system which includes lines owned and leased by Santee Cooper as well as those owned by Central. The transmission system includes approximately 4,400 miles of transmission lines (see map below). Santee Cooper operates 82 transmission substations and switching stations serving 75 distribution substations and 335 Central Cooperative delivery points. Communications sites at 97 locations are in place to support the monitoring and controlling of integrated power system operations. Santee Cooper plans the transmission system to operate during normal and single contingency conditions and to maintain system voltages that are consistent with good utility practice.

Santee Cooper's transmission system is interconnected with other major electric utilities in the region. It is directly interconnected with SCE&G at eight locations; with Progress Energy Carolinas ("Progress Energy") at five locations; with Southern Company Services, Inc. ("Southern Company") at one location; and with Duke Power, a subsidiary of Duke Energy Corporation ("Duke"), at two locations. Santee Cooper is also interconnected with SCE&G, Duke, Southern Company and SEPA through a five-way interconnection at SEPA's J. Strom Thurmond Hydroelectric Project, and with Southern Company and SEPA through a three-way interconnection at SEPA's R. B. Russell Hydroelectric Project. Through these interconnections, Santee Cooper's transmission system is integrated into the regional transmission system serving the southeastern areas of the United States and the Eastern Interconnection. Santee Cooper has separate interchange agreements with each of the companies with which it is interconnected which provide for mutual exchanges of power. Santee Cooper is currently developing two additional ties with Progress Energy.


BARLEY SWYD
GREENWOOD COUNTY
BLUFFTON
BATESBURG
AIKEN CR
CAYCE
SAN FLUTTER
BRAZON ZRD
KING STREET SWITCHING
KING STREET C.P. A.L.
ATTEMES JOHNSTO
CHARLES CROSSINGS
COUNTY
WAMMAW
WALLACE
TENNESSEE SWITCHING
JOHNS ISLAND BRD

Program participation in 2004 resulted in an estimated demand savings of 177 kW and estimated energy savings of 284,858 kWh. Total expenditures for the Commercial Good Cents Program incurred through Santee Cooper in 2004 were $52,758.

4. Thermal Storage Cooling Program

The Thermal Storage Cooling Program shifts energy used by commercial customers for air conditioning from peak to off-peak hours by utilizing thermal energy stored in a medium such as ice or water. Rebates are offered to customers who install this type of equipment. There is currently only one active participant in this program.

Interruptible / Economy Power Pricing Rates

Santee Cooper has developed and offers time-of-use, non-firm, and off-peak rates to its direct-served commercial and industrial customers to encourage them to reduce their peak demand.

An "economy power" rate is available to industrial customers, which is based on an hourly incremental energy rate. This is a real time pricing rate; the price for energy changes each hour. Customers must schedule their usage each hour. Service under this Rider is curtailable in emergency situations by Santee Cooper. Pricing alternatives are available under this rate where the energy price is fixed during certain hours.

There are also supplemental curtailable and interruptible rates available to industrial customers which allow for curtailment under certain circumstances.

Rec 9.2 Ref 30

195757 ~~195755~~

K. Chad Burgess
Senior Counsel
chad.burgess@scana.com

SCANA
POWER FOR LIVING

DPUC
SA
5-1-07
7:30

April 30, 2007

VIA HAND DELIVERY
The Honorable Charles Terreni
Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, South Carolina 29210

RE: Least-Cost Planning Procedures for Electric Utilities
Docket No. 87-~~223-E~~ 2006-103-E

Dear Mr. Terreni:

In accordance with S.C. Code Ann. §58-37-40 (1976, as amended) and Order No. 98-502 enclosed you will find ten (10) copies of the 2007 Integrated Resource Plan of South Carolina Electric & Gas Company ("SCE&G"). This filing also serves to satisfy the annual reporting requirements of the Utility Facility Siting and Environmental Protection Act, S.C. Code §58-33-430. Please acknowledge your receipt of this document by file-stamping the extra copy that is enclosed and returning it to us via our courier.

By copy of this letter we are also serving the South Carolina Office of Regulatory Staff with a copy of SCE&G's 2007 Integrated Resource Plan and attach a certificate of service to that effect.

If you should have any questions or need additional information, please do not hesitate to contact me.

Very truly yours,

K. Chad Burgess

KCB/kms
Enclosures

cc: Shannon Bowyer Hudson, Esquire
Dan F. Arnett
John W. Flitter

BEFORE THE

PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 87-223-E

Least-Cost Planning Procedures for Electric Utilities	)	
	)	**CERTIFICATE**
	)	**OF SERVICE**
	)	

This is the certify that I have caused to be served this day one (1) copy of the **2007 Integrated Resource Plan of South Carolina Electric & Gas Company** via hand delivery to the person named below at the addresses set forth:

Shannon Bowyer Hudson, Esquire
Office of Regulatory Staff
1441 Main Street, Suite 300
Columbia, South Carolina 29201

Dan F. Arnett
Office of Regulatory Staff
1441 Main Street, Suite 300
Columbia, South Carolina 29201

John W. Flitter
Office of Regulatory Staff
1441 Main Street, Suite 300
Columbia, South Carolina 29201

Karen Scruggs

Karen M. Scruggs

Columbia, South Carolina

This 30th day of April 2007

2007

Integrated

Resource

Plan

SCE&G®
A SCANA COMPANY

Introduction

This document presents South Carolina Electric & Gas Company's (SCE&G) Integrated Resource Plan (IRP) for meeting the energy needs of its customers over the next fifteen years, 2007 through 2021. The Company's objective is to provide reliable and economically priced energy to its customers.

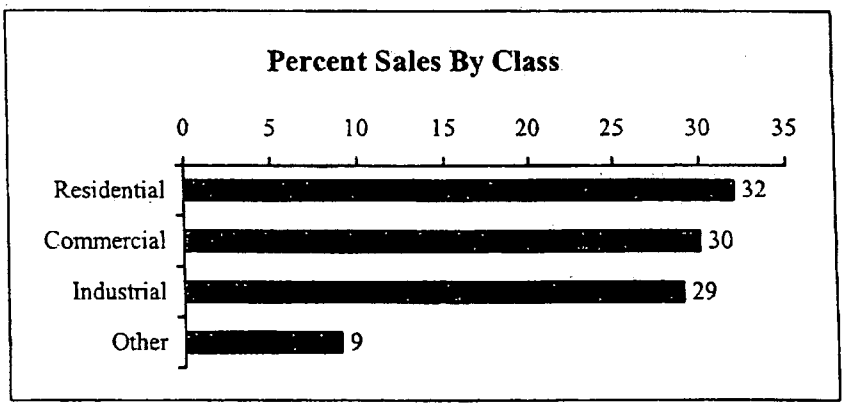
The Load Forecast

Total territorial energy sales on the SCE&G system are expected to grow at an average rate of 2.0% per year over the next 15 years. The summer peak demand and winter peak demand will increase at 2.0% per year over this forecast horizon. The table below contains the projected loads.

	Summer Peak (MW)	Winter Peak (MW)	Energy Sales (GWH)
2007	4,823	4,322	23,741
2008	4,919	4,405	24,277
2009	5,012	4,483	24,790
2010	5,060	4,523	24,994
2011	5,167	4,619	25,482
2012	5,269	4,712	25,956
2013	5,375	4,810	26,457
2014	5,493	5,918	27,006
2015	5,615	5,032	27,588
2016	5,732	5,144	28,157
2017	5,854	5,257	28,734
2018	5,976	5,373	29,323
2019	6,098	5,491	29,927
2020	6,228	5,615	30,559
2021	6,355	5,738	31,187

The energy sales forecast for SCE&G is made for over 30 individual categories. The categories are subgroups of our seven classes of customers. The three primary customer classes, residential, commercial, and industrial, comprise about 91% of our sales. The following bar chart shows the relative contribution to territorial sales of each class in 2006. The "other" classes are street lighting, other public authorities, municipalities and cooperatives. A detailed description of the short-range forecasting process and statistical models is contained in Appendix

A of this report. Short-range is defined as the next two years. Appendix B contains similar information for the long-range methodology. Sales projections to each group are based on statistical and econometric models derived from historical relationships.



The forecast of summer peak demand is developed using a load factor methodology. Load factors for each class of customer are associated with the corresponding forecasted energy to project a contribution to summer peak. The winter peak demand is projected through its correlation with annual energy sales and winter degree-day departures from normal. By industry convention, the winter period is assumed to follow the summer period.

Demand-Side Management at SCE&G

The Demand-Side Management Programs at SCE&G can be divided into three major categories: Customer Information Programs, Energy Conservation Programs and Load Management Programs.

CUSTOMER INFORMATION PROGRAMS

SCE&G's customer information programs fall under two headings: the annual energy campaigns and the web-based information initiative. Following is a brief description of each.

1. The 2006 Energy Campaigns: In 2006 SCE&G continued to proactively educate its customers and create awareness of issues related to energy and conservation management.

- Weatherline – energy saving tips promoted on the Weatherline.
- Bill Inserts – bill insert issued to targeted customers promoting the Low-Income Home Energy Assistance Program (LIHEAP).

- Brochures/Printed Materials – energy saving tips available on various printed materials in business offices.
- News Releases – distributed to print and broadcast media throughout SCE&G's service territory.
- Featured News Guests – SCE&G energy experts conducted several interviews with the media regarding energy conservation and useful tips.
- Web site – energy saving tips and other conservation information placed on the company's Web site. The address for the Web site was promoted in most of the communication channels mentioned above.
- Weatherization Project – SCE&G partners targeted low-income homes in Beaufort and Sumter for weatherization. SCE&G employees volunteer their time to assist the effort.
- Speakers Bureau – Representatives from SCE&G talked to local organizations about energy conservation. Also used were company-produced videos that highlight energy conservation.
- Energy Awareness Month – company used the month as an opportunity to send information to the media discussing energy costs and savings tips.

2. WEB-Based Information and Services Programs: SCE&G has available a Web-based tool which allows customers to access current and historical consumption data and compare their energy usage month-to-month and year-to-year, noting trends, temperature impact and spikes in their consumption. Feedback on this tool has been positive and over 166,000 customers have registered to access this tool as well as other account related information. The SCE&G Web site supports all communication efforts to promote energy savings tips. The "Manage Energy Use" section of the SCE&G Web site, which features an interactive bill estimator tool, video instruction on weatherization and other useful content, is currently averaging almost 12,000 visits per year. For business customers, online information includes: power quality technical assistance, conversion assistance, new construction information, expert energy assistance and more.

ENERGY CONSERVATION PROGRAMS

There are three energy conservation programs: the Value Visit Program, the Conservation Rate and our use of seasonal rate structures. A description of each follows:

1. Value Visit Program: The Value Visit Program is designed to assist residential electric customers that are considering an investment in upgrading their home's energy efficiency. We visit the customer's home and guide them in their purchase of energy related equipment and materials such as heating and cooling systems, duct insulation, attic insulation, storm windows, etc. Our representative explains the benefits of upgrading different areas of the home and what affect upgrading these areas will have on energy bills and comfort levels as well as informing the customer on the many rebates we offer for upgrading certain areas of the home (see attached rebate schedule). We also offer financing for qualified customers which makes upgrading to a higher energy efficiency level even easier. The Value Visit Program is often used in conjunction with our Rate 6 Program to achieve the maximum benefit for customers wanting to reduce their energy usage, make their homes more comfortable and to increase their home's overall value. There is a $25 charge for the program, but this charge is reimbursed if the customer implements any suggested upgrade within 90 days of the visit. Information on this program is available on our website and by brochure.

   0 to R30 attic insulation - $6.00 per 100 sq. ft.
   R11 to R30 attic insulation - $3.00 per 100 sq. ft.
   Storm windows - $30.00 per house
   Duct insulation - $60.00 per house
   Wall Insulation - $80.00 per house

2. Rate 6 Energy Saver / Energy Conservation Program: The Rate 6 Energy Saver / Energy Conservation Program rewards homeowners and home builders who upgrade their existing homes or build their new homes to a high level of energy efficiency with a reduced electric rate. This reduced rate, combined with a significant reduction in energy usage, provide for considerable savings for our customers. Participation in the program is very easy as the requirements are prescriptive and do not require a large monetary investment which is beneficial to all of our customers and trade allies. Homes built to this standard also have improved comfort levels and increased re-sale value over homes

built to the minimum building code standards which are also a significant benefit to our customers. Information on this program is available on our website and by brochure.

3. Seasonal Rates: Many of our rates are designed with components that vary by season. Energy provided in the peak usage season is charged a premium to encourage conservation and efficient use.

LOAD MANAGEMENT PROGRAMS

SCE&G's load management programs have as their primary goal the reduction of the need for additional generating capacity. There are four load management programs: Standby Generator Program, Interruptible Load Program, Real Time Pricing Rate and the Time of Use Rates. A description of each follows:

1. Standby Generator Program: The Standby Generator I Program for retail customers was introduced in 1990 to serve as a load management tool. General guidelines authorize SCE&G to initiate a standby generator run request when reserve margins are stressed due to a temporary reduction in system generating capability, or high customer demand. The Standby Generator II Program for retail customers was developed in 2000, authorizing standby generator runs for revenue producing opportunities during times of high market prices. Through consumption avoidance, generator customers release capacity back to SCE&G where it is then used to satisfy system demand. Qualifying customers (able to defer a minimum of 200 kW) receive financial credits determined initially by recording the customer's demand during a load test. Future demand credits are based on what the customer actually delivers when SCE&G requests them to run their generator(s). This program allows customers to reduce their monthly operating costs, as well as earn a return on their generating equipment investment. There is also a wholesale standby generator program that is similar to the retail programs.
2. Interruptible Load Program: SCE&G has over 200 megawatts of interruptible customer load under contract. Participating customers receive a discount on their demand charges for shedding load when SCEG is short of capacity.
3. Real Time Pricing (RTP) Rate: A number of customers receive power under our real time pricing rate. During peak usage periods throughout the year when capacity is low in

the market, the RTP rate sends a high price signal to participating customers which encourages conservation and load shifting. Of course during low usage periods, prices are lower.

4. Time of Use Rates: Our time of use rates contain higher charges during the peak usage periods of the day to encourage conservation and load shifting during these periods. All our customers have the option of a time of use rate.

Load Impact of Load Management Programs

The Company relies on the standby generator program and the interruptible service program to help maintain the reliability of its electrical system. There are currently 206 megawatts of capacity made available to the system through these programs. This is expected to increase to 250 megawatts by 2009. The table below shows the peak demand on the system with and without these programs. The firm peak demand is the load level that results when the DSM is used to lower the system peak demand.

	System Peak (MW)	DSM Impact (MW)	Firm Peak (MW)
2007	5029	206	4823
2008	5148	228	4920
2009	5262	250	5012
2010	5310	250	5060
2011	5418	250	5168
2012	5520	250	5270
2013	5625	250	5375
2014	5743	250	5493
2015	5865	250	5615
2016	5982	250	5732
2017	6105	250	5855
2018	6226	250	5976
2019	6349	250	6099
2020	6478	250	6228
2021	6605	250	6355

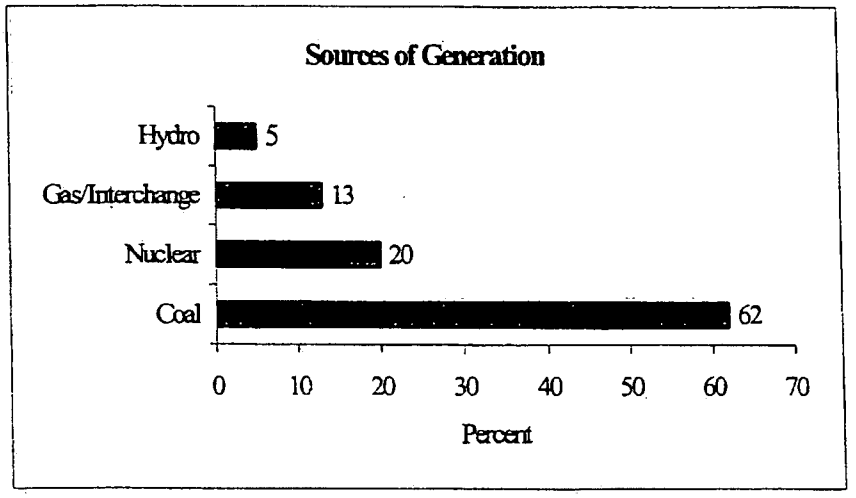
Existing Supply Capacity

The following table shows the generating capacity that is available to SCE&G.

Existing Capacity	In-Service Date	Summer (MW)
Coal-Fired Steam:		
Urquhart – Beech Island, SC	1953	94
McMeekin – Near Irmo, SC	1958	250
Canadys - Canadys, SC	1962	397
Wateree – Eastover, SC	1970	700
*Williams – Goose Creek, SC	1973	615
Cope - Cope, SC	1996	420
Cogen South – Charleston, SC	1999	90
Total Coal-Fired Steam Capacity		2,566
Nuclear:		
V. C. Summer - Parr, SC	1984	644
I. C. Turbines:		
Burton, SC	1961	27
Faber Place – Charleston, SC	1961	8
Hardeeville, SC	1968	12
Urquhart – Beech Island, SC	1969	40
Coit – Columbia, SC	1969	32
Parr, SC	1970	69
Williams – Goose Creek, SC	1972	40
Hagood – Charleston, SC	1991	86
Urquhart No. 4 – Beech Island, SC	1999	51
Urquhart Combined Cycle – Beech Island, SC	2002	472
Jasper Combined Cycle – Jasper, SC	2004	880
Total I. C. Turbines Capacity		1717
Hydro:		
Neal Shoals – Carlisle, SC	1905	5
Parr Shoals – Parr, SC	1914	15
Stevens Creek - Near Martinez, GA	1914	12
*Columbia Canal - Columbia, SC	1927	9
Saluda - Near Irmo, SC	1930	206
Fairfield Pumped Storage - Parr, SC	1978	576
Total Hydro Capacity		823
Other: Long-Term Purchases		25
SEPA		33
Grand Total:		5,808

* Williams Station is owned by GENCO, a wholly owned subsidiary of SCANA and Columbia Canal is owned by the City of Columbia. All of this capacity is operated by SCE&G to meet its load obligations.

The bar chart below shows the projected 2007 relative energy generation by fuel source. SCE&G generates the majority of its energy from coal and nuclear fuel.



Supply Reserve Margin and Operating Reserves

The Company provides for the reliability of its electric service by maintaining an adequate reserve margin of supply capacity. The appropriate level of reserve capacity for SCE&G is in the range of 12 to 18 percent of its firm peak demand. This range of reserves will allow SCE&G to have adequate daily operating reserves and to have reserves to cover two primary sources of risk: supply risk and demand risk. Mitigation of these two types of risk is discussed below.

The level of daily operating reserves required by the SCE&G system is dictated by operating agreements with other VACAR companies. VACAR has set the region's reserve needs at 150% of the largest unit in the region. While it varies by a megawatt or two each year, SCE&G's prorata share of this capacity is always around 200 megawatts.

Supply reserves are needed to balance the "supply risk" that some SCE&G generation capacity may be forced out on any particular day because of mechanical failures, wet coal problems, environmental limitations or other force majeure/unforeseen events. The amount of capacity forced-out or down-rated will vary from day to day. SCE&G's reserve margin range is designed to cover most of these days as well as the outage of any one of our generating units except the two largest: Summer Station and Williams Station.

Another component of reserve margin is the demand reserve. This is needed to cover "demand risk" related to unexpected increases in customer load above our peak demand forecast. This can be the result of a hotter than normal summer or forecast error.

By maintaining a reserve margin in the 12 to 18 percent range, the Company addresses the uncertainties related to load and to the availability of generation on its system. It also allows the Company to meet its VACAR obligation. SCE&G will monitor its reserve margin policy in light of the changing power markets and its system needs and will make changes to the policy as warranted.

The Need for Base Load Capacity

As our customers' need for energy continues to grow, so does the need for generating capacity to serve those customers. In particular SCE&G projects the need for additional baseload capacity around the year 2016. Currently about 56% of the Company's generation fleet is baseload. When the last coal plant, Cope Station, came online in 1996, the percentage of baseload capacity was about 74%. The choice among baseload, intermediate and peaking capacity is an economic one and depends on how much energy the new capacity will need to generate. Baseload capacity typically dispatches at a capacity factor in excess of 70%.

Nuclear Capacity and Fuel Diversity

SCE&G and Santee Cooper are currently planning to jointly build an AP1000 Westinghouse nuclear unit at the VC Summer site. The Westinghouse unit is preferred because of the size of the unit, about 1100 MWs, and because of the progress that Westinghouse has made in its engineering and design. The Westinghouse design was approved by the Nuclear Regulatory Commission (NRC) on September 13, 2004. The AP1000 design uses passive safety systems to enhance the safety of the unit and to satisfy the NRC safety criteria. In addition to the environmental benefits associated with the nuclear option, it also offers an opportunity to diversify our capacity. SCE&G's current capacity is about 43% coal fired, 30% gas fired, and 11% nuclear. Adding more nuclear capacity can provide a better balance among fuel types. While SCE&G is currently pursuing the nuclear option and believes it to be in the best interest of its rate payers, the Company does have several years before it is financially committed.

Role of Purchased Power

SCE&G constantly monitors the markets for electric energy and capacity and at times is an active purchaser and seller in those markets. Where it appears that market resources may be able to meet supply needs for its system appropriately, SCE&G polls the market, in some cases informally, and in other cases through the issuance of formal RFPs. In cases where the market resources can be an appropriate part of SCE&G's supply mix, SCE&G includes those resources in its comparative analysis of alternative supply options.

On December 8, 2006 SCE&G issued an RFP to purchase capacity and has received responses. An evaluation of those responses against other options available to the Company is currently underway.

Non-Traditional Generation Sources

SCE&G considers non-traditional sources of generation in its planning. In fact it depends on 90 MWs of co-generation capacity in its Cogen South facility. This facility co-fires with coal the biomass waste from a paper manufacturing plant. Also, SCE&G is increasing its attention on renewable sources of generation while at the same time policy makers are considering new energy efficiency standards and renewable portfolio standards. Some proposed bills in congress have defined renewable as: geothermal, hydro, wind, solar and biomass. Unfortunately there are no sites for geothermal generation available in South Carolina. SCE&G generates about 5% of its energy from hydro power. The Company has invested in its existing hydro sites and increased hydro output as a result and will continue to pursue other such economic opportunities but no sites have been identified for a new hydro facility. Both wind and solar have been considered but because of the high capital costs and the limited energy production caused by low wind speeds and insufficient solar radiation, these generation sources are not economical within the SCE&G service territory. SCE&G has also evaluated potential biomass applications in recent years, but none have proven economically feasible and operationally practical yet, but we continue to examine proposals and opportunities as they are identified.

Projected Loads and Resources

The table on the following page shows SCE&G's projected loads and resources for the next 15 years. The resource plan shows the need for additional capacity and identifies, at least,

on a preliminary basis whether the need is for peaking/intermediate capacity or baseload capacity.

The resource plan shows the need for the addition of almost 500 MWs of peaking/intermediate capacity in the 2009 - 2015 timeframe. Some or all of this capacity may be supplied as purchased power. The plan also calls for baseload capacity in 2016 and 2019. As discussed previously one or both of these units may be nuclear powered. The Company has a number of years before it needs to make these decisions.

The Company believes that its supply plan, summarized in the following table, will be as benign to the environment as possible because of the Company's continuing efforts to utilize state-of-the-art emission reduction technology in compliance with state and federal laws and regulations. The supply plan will also help SCE&G keep its cost of energy service at a minimum since the generating units being added are competitive with other units being added in the market.

SCE&G Forecast of Summer Loads and Resources - 2007 IRP

	YEAR	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Load Forecast																
1	Gross Territorial Peak	5029	5148	5262	5310	5418	5520	5625	5743	5865	5982	6105	6226	6349	6478	6605
2	Less: DSM	206	228	250	250	250	250	250	250	250	250	250	250	250	250	250
3	Net Territorial Peak	4823	4920	5012	5060	5168	5270	5375	5493	5615	5732	5855	5976	6099	6228	6355
4	Firm Contract Sales	350	250	250	250	250	250									
5	Total Firm Obligation	5173	5170	5262	5310	5418	5520	5375	5493	5615	5732	5855	5976	6099	6228	6355
System Capacity																
6	Existing	5808	5808	5808	5808	5997	5997	5997	5997	5997	5997	6597	6597	6597	7197	7197
	Additions															
7	Peaking/Intermediate				200											
8	Baseload										600			600		
9	Other				-11											
10	Total System Capacity	5808	5808	5808	5997	5997	5997	5997	5997	5997	6597	6597	6597	7197	7197	7197
11	Firm Annual Purchase			90		70	190	25	160	290			100			
12	Total Production Capability	5808	5808	5898	5997	6067	6187	6022	6157	6287	6597	6597	6697	7197	7197	7197
Reserves With DSM																
13	Margin	635	638	636	687	649	667	647	664	672	865	742	721	1098	969	842
14	% Reserve Margin	12.3%	12.3%	12.1%	12.9%	12.0%	12.1%	12.0%	12.1%	12.0%	15.1%	12.7%	12.1%	18.0%	15.6%	13.2%
15	% Capacity Margin	10.9%	11.0%	10.8%	11.5%	10.7%	10.8%	10.7%	10.8%	10.7%	13.1%	11.2%	10.8%	15.3%	13.5%	11.7%
Reserves Without DSM																
16	Margin	429	410	386	437	399	417	397	414	422	615	492	471	848	719	592
17	% Reserve Margin	8.0%	7.6%	7.0%	7.9%	7.0%	7.2%	7.1%	7.2%	7.2%	10.3%	8.1%	7.6%	13.4%	11.1%	9.0%
18	% Capacity Margin	7.4%	7.1%	6.5%	7.3%	6.6%	6.7%	6.6%	6.7%	6.7%	9.3%	7.5%	7.0%	11.8%	10.0%	8.2%

Transmission Planning

SCE&G's transmission planning practices develop and coordinate a program that provides for timely modifications to the SCE&G transmission system to ensure a reliable and economical delivery of power. This program includes the determination of the current capability of the electrical network and a ten-year schedule of future additions and modifications to the network. These additions and modifications are required to support customer growth, provide emergency assistance and maintain economic opportunities for our customers while meeting SCE&G and industry performance standards.

SCE&G has an ongoing process to determine the performance level of the SCE&G transmission system. Numerous internal studies are undertaken that address the service needs of our customers. These needs include: 1) distributed load growth in existing residential, commercial, industrial, and wholesale customers, 2) new residential, commercial, industrial, and wholesale customers and 3) transmission only customers.

SCE&G has developed and adheres to a set of internal Long Range Planning Criteria which can be summarized as follows:

> *The requirements of the SCE&G "LONG RANGE PLANNING CRITERIA" will be satisfied if the system is designed so that during any of the following contingencies, only short-time overloads, low voltages and local loss of load will occur and that after appropriate switching and re-dispatching, all non-radial load can be served with reasonable voltages and that lines and transformers are operating within acceptable limits.*
>
> a. *Loss of any bus and associated facilities operating at a voltage level of 115kV or above*
> b. *Loss of any line operating at a voltage level of 115kV or above*
> c. *Loss of entire generating capability in any one plant*
> d. *Loss of all circuits on a common structure*
> e. *Loss of any transmission transformer*
> f. *Loss of any generating unit simultaneous with the loss of a single transmission line*
>
> *Outages more severe are considered acceptable if they will not cause equipment damage or result in uncontrolled cascading outside the local area.*

Furthermore, SCE&G is an active member of the SERC Reliability Corporation, which has adopted the North American Electric Reliability Corporation (NERC) Reliability Standards as approved by the NERC Board of Trustees. SCE&G tests and designs its transmission system to

be compliant with the requirements as set forth in these standards. A copy of the NERC Reliability Standards is available at the NERC homepage http://www.nerc.com/.

As a member of the Virginia-Carolinas (VACAR) Reliability Group, SCE&G participates in joint studies with other utilities to determine the reliability of the integrated systems throughout Virginia, North Carolina and South Carolina. As a member of the SERC Reliability Corporation, SCE&G participates with other utilities in the SERC Regional Planning Process, including the SERC Regional Studies Executive Committee, the SERC Long-Term Power Flow Study Group, the SERC Near-Term Power Flow Study Group, the SERC Dynamics Study Group, the SERC Short Circuit Database Working Group and the SERC Inter-regional studies efforts.

SCE&G also participates in the SERC power flow database development efforts and the NERC Multi-area Modeling Working Group (MMWG) annual model development process. These processes develop computer models of the transmission grid across the VACAR area, SERC area, and other portions of NERC (Eastern Interconnection). All participants' models are merged together to produce current and future models of the integrated electrical network. Using these models, SCE&G evaluates its' current and future transmission system for compliance with the SCE&G Long Range Planning Criteria and the NERC Reliability Standards.

The SCE&G transmission system is interconnected with Progress Energy – Carolinas, Duke Power, South Carolina Public Service Authority (Santee Cooper), Georgia Power Company, Savannah Electric Power Company, and the Southeastern Electric Power Administration (SEPA) systems.

The following is a list of regional and sub-regional studies conducted over the past year:

1. VACAR 2007 Summer Study
2. VASTE 2006 Summer Reliability Study
3. VASTE 2006/2007 Winter Reliability Study
4. VSTE 2011 Summer Future Year Study
5. VEM 2006 Summer Reliability Study
6. VEM 2006/2007 Winter Reliability Study
7. 2006 January-March OASIS Study
8. 2006 April-June OASIS Study
9. 2006 July-September OASIS Study
10. 2006 October-December OASIS Study
11. SCEG-Santee-Southern 2011 Joint Study
12. VACAR Stability Study of Projected 2012 Summer Peak Conditions
13. Evaluation of the Under-Frequency Load Shedding (UFLS) Program of the SERC Region

These activities, as discussed above, provide for a reliable and cost effective transmission system for SCE&G customers.

Appendix A

Short Range Methodology

This section presents the development of the short-range electric sales forecasts for the Company. Two years of monthly forecasts for electric customers, average usage, and total usage were developed according to company class and rate structures, with industrial customers further classified into SIC (Standard Industrial Classification) codes. Residential customers were classified by housing type (single family, multi-family, and mobile homes) and by whether or not they use electric space heating. For each forecasting group, the number of customers and either total usage or average usage was estimated for each month of the forecast period.

The short-range methodologies used to develop these models were determined primarily by available data, both historical and forecast. Monthly sales data by class and rate are generally available historically. Monthly heating and cooling degree data for Columbia and Charleston are also available historically, and may be forecast using averages based on NOAA normals[1]. Industrial production indices are also available by SIC on a quarterly basis, and can be transformed to a monthly series. Therefore, sales, weather, industrial production indices, and time dependent variables were used in the short range forecast. In general, the forecast groups fall into two classifications, weather sensitive and non-weather sensitive. For the weather sensitive classes, regression analysis was the methodology used, while for the non-weather sensitive classes regression analysis or time series models based on the autoregressive integrated moving average (ARIMA) approach of Box-Jenkins were used.

The short range forecast developed from these methodologies was also adjusted for marketing programs, new industrial loads, terminated contracts, or economic factors as discussed in Section 3.

Regression Models

Regression analysis is a method of developing an equation which relates one variable, such as usage, to one or more other variables which help explain fluctuations and trends in the first. This method is mathematically constructed so that the resulting combination of explanatory variables produces the smallest squared error between the historic actual values and those estimated by the regression. The output of the regression analysis provides an equation for the variable being explained. Several statistics which indicate the success of the regression analysis fit are shown for each model. Several of these indicators are R^2, Root Mean Squared Error, Durbin-Watson Statistic, F-Statistic, and the T-Statistics of the Coefficient. PROC REG of SAS[2] was used to estimate all regression models. PROC AUTOREG of SAS was used if significant autocorrelation, as indicated by the Durbin-Watson statistic, was present in the model.

Two variables were used extensively in developing weather sensitive average use models: heating degree days (HDD) and cooling degree days (CDD). The values for HDD and CDD are the average of the values for Charleston and Columbia. The base for HDD was 60° and for CDD was 75°. In order to account for cycle billing, the degree day values for each day were weighted by the number of billing cycles which included that day for the current month's billing. The daily weighted degree day values were summed to obtain monthly degree day values. Billing sales for a calendar month may actually reflect consumption that occurred in the previous month based on weather conditions in that period and also consumption occurring in the current month. Therefore, this method should more accurately reflect the impact of weather variations on the consumption data.

The development of average use models began with plots of the HDD and CDD data versus average use by month. This process led to the grouping of months with similar average use patterns. Summer and winter groups were chosen, with the summer models including the

months of May to October, and the winter models including the months of November through April. For each of the groups, an average use model was developed. Total usage models were developed with a similar methodology for the municipal and cooperative customers. For these customers, HDD and CDD were weighted based on Cycle 20 distributions. This is the last reading date for bills in any given month, and is generally used for larger customers.

The plots also revealed significant changes in average use over time. Three types of variables were used to measure the effect of time on average use:

1. Number of months since a base period;
2. Dummy variable indicating before or after a specific point in time; and,
3. Dummy variable for a specific month or months.

Some models revealed a decreasing trend in average use, which is consistent with conservation efforts and improvements in energy efficiency. However, other models showed an increasing average use over time. This could be the result of larger houses, increasing appliance saturations, lower real electricity prices, and/or higher real incomes.

ARIMA Models

Autoregressive integrated moving average (ARIMA) procedures were used in developing the short range forecasts. For various class/rate groups, they were used to develop customer estimates, average use estimates, or total use estimates.

ARIMA procedures were developed for the analysis of time series data, i.e., sets of observations generated sequentially in time. This Box-Jenkins approach is based on the assumption that the behavior of a time series is due to one or more identifiable influences. This method recognizes three effects that a particular observation may have on subsequent values in the series:

1. A decaying effect leads to the inclusion of autoregressive (AR) terms;

2. A long-term or permanent effect leads to integrated (I) terms; and,

3. A temporary or limited effect leads to moving average (MA) terms.

Seasonal effects may also be explained by adding additional terms of each type (AR, I, or MA).

The ARIMA procedure models the behavior of a variable that forms an equally spaced time series with no missing values. The mathematical model is written:

$$Z_t = u + Y_i\ (B)\ X_{i,t} + q\ (B)/\ f\ (B)\ a_t$$

This model expresses the data as a combination of past values of the random shocks and past values of the other series, where:

t	indexes time
B	is the backshift operator, that is $B\ (X_t) = X_{t-1}$
Z_t	is the original data or a difference of the original data
f(B)	is the autoregressive operator, $f(B) = 1 - f_1\ B - \ldots - f_1\ B^p$
u	is the constant term
q(B)	is the moving average operator, $q\ (B) = 1 - q_1\ B - \ldots - q_q\ B^q$
a_t	is the independent disturbance, also called the random error
$X_{i,t}$	is the ith input time series
$y_i(B)$	is the transfer function weights for the ith input series (modeled as a ratio of polynomials)
$y_i(B)$	is equal to $w_i\ (B)/\ d_i\ (B)$, where $w_i\ (B)$ and $d_i\ (B)$ are polynomials in B.

The Box-Jenkins approach is most noted for its three-step iterative process of identification, estimation, and diagnostic checking to determine the order of a time series. The autocorrelation and partial autocorrelation functions are used to identify a tentative model for univariate time series. This tentative model is estimated. After the tentative model has been

fitted to the data, various checks are performed to see if the model is appropriate. These checks involve analysis of the residual series created by the estimation process and often lead to refinements in the tentative model. The iterative process is repeated until a satisfactory model is found.

Many computer packages perform this iterative analysis. PROC ARIMA of (SAS/ETS)[3] was used in developing the ARIMA models contained herein.

The attractiveness of ARIMA models comes from data requirements. ARIMA models utilize data about past energy use or customers to forecast future energy use or customers. Past history on energy use and customers serves as a proxy for all the measures of factors underlying energy use and customers when other variables were not available. Univariate ARIMA models were used to forecast average use or total usage when weather-related variables did not significantly affect energy use or alternative independent explanatory variables were not available.

Footnotes

1. The 15-year average daily weather "normals" were based on data from 1989 to 2003 published by the National Oceanic and Atmospheric Association.

2. SAS Institute, Inc., SAS/STAT™ Guide for Personal Computers, Version 6 Edition. Cary, NC: SAS Institute, Inc., 1987.

3. SAS Institute, Inc., SAS/ETS User's Guide, Version 6, First Edition. Cary, NC: SAS Institute, Inc., 1988.

Electric Sales Assumptions

For short-term forecasting, 31 forecasting groups were defined using the Company's customer class and rate structures. Industrial (Class 30) Rate 23 was further divided using SIC codes. In addition, nineteen large industrial customers were individually projected. The residential class was disaggregated into those customers with electric space heating and those without electric space heating and by housing type (single family, multi-family, and mobile homes). Each municipal and cooperative account represents a forecasting group and were also individually forecast. Discussions were held with Industrial Marketing and Economic Development representatives within the company regarding prospects for industrial expansions or new customers, and adjustments made to customer, rate, or account projections where appropriate. Table 1 contains the definition for each group and Table 2 identifies the methodology used and the values forecasted by forecasting groups.

The forecast for Company Use is based on historic trends and adjusted for Summer nuclear plant outages. Unaccounted for energy is usually about 4.5% of total territorial sales. The monthly allocations for unaccounted for were based on a regression model using normal total degree-days for the calendar month and total degree-days weighted by cycle billing. Adding company use and unaccounted for to monthly territorial sales produces electric generation requirements.

TABLE 1
Short-Term Forecasting Groups, 2004 – 2005

Class Number	Class Name	Rate/SIC Designation	Comment
		Single Family	Rates 1, 2, 5, 6, 8, 18, 25, 26, 62, 64
10	Residential Non-Space Heating	Multi Family	Rates 67, 68, 69
910	Residential Space Heating	Mobile Homes	Rates 1, 2, 5, 7, 8
20	Commercial Non-Space Heating	Rate 9	Small General Service
		Rate 12	Churches
		Rate 20, 21	Medium General Service
		Rate 22	Schools
		Rate 24	Large General Service
		Other	Rates 10, 11, 14, 16, 17, 18, 24, 25, 26, 29, 60, 62, 64, 67, 68, 69
920	Commercial Space Heating	Rate 9	Small General Service
30	Industrial Non-Space Heating	Rate 9	Small General Service
		Rate 20, 21	Medium General Service
		Rate 23, SIC 22	Textile Mill Products
		Rate 23, SIC 24	Lumber, Wood Products, Furniture and Fixtures (SIC Codes 24 and 25)
		Rate 23, SIC 26	Paper and Allied Products
		Rate 23, SIC 28	Chemical and Allied Products
		Rate 23, SIC 30	Rubber and Miscellaneous Products
		Rate 23, SIC 32	Stone, Clay, Glass, and Concrete
		Rate 23, SIC 33	Primary Metal Industries; Fabricated Metal Products; Machinery; Electric and Electronic Machinery, Equipment and Supplies; and Transportation Equipment (SIC Codes 33-37)
		Rate 23, SIC 91	Executive, Legislative and General Government (except Finance)
		Rate 23, SIC 99	Other or Unknown SIC Code*
		Rate 27, 60	Large General Service
		Other	Rates 25 and 26
930	Industrial Space Heating	Rate 9	Small General Service
60	Street Lighting	Rates 3, 9, 13, 17, 25, 26, 29, and 69	
70	Other Public Authority	Rate 3 and 29	
		Rates 65 and 66	
92	Municipal	Rate 60, 61	Four Individual Accounts
97	Cooperative	Rate 60, 61	Three Individual Accounts

Includes small industrial customers from all SIC classifications that were not previously forecasted individually. Industrial Rate 23 also includes Rate 24. Commercial Rate 24 also includes Rate 23.

TABLE 2

Summary of Methodologies Used To Produce
2004 and 2005 Short Range Forecast

Value Forecasted	Methodology	Forecasting Groups
Average Use	Regression	Class 10, All Groups Class 910, All Groups Class 20, Rates 9, 12, 20, 22, 24, 99 Class 920, Rate 9 Class 70, Rate 3
Total Usage	ARIMA/ Regression	Class 30, Rates 9, 20, 99, and 23, for SIC = 91 and 99 Class 930, Rate 9 Class 60 Class 70, Rates 65, 66
	Regression	Class 92, All Accounts Class 97, All Accounts
Customers	ARIMA	Class 10, All Groups Class 910, All Groups Class 20, All Rates Class 920, Rate 9 Class 30, All Rates Except 60, 99, and 23 for SIC = 22, 24, 26, 28, 30, 32, 33, and 91 Class 930, Rate 9 Class 60 Class 70, Rate 3

Appendix B

Long Range Sales Forecast

Electric Sales Forecast

This section presents the development of the long-range electric sales forecast for the Company. The long-range electric sales forecast was developed for seven classes of service: residential, commercial, industrial, street lighting, other public authorities, municipal and cooperatives. These classes were disaggregated into appropriate subgroups where data was available and there were notable differences in the data patterns. The residential, commercial, and industrial classes are considered the major classes of service and account for over 90% of total territorial sales. A customer forecast was developed for each major class of service. For the residential class, forecasts were also produced for those customers with electric space heating and for those without electric space heating. They were further disaggregated into housing types of single family, multi-family and mobile homes. In addition, two residential classes and residential street lighting were evaluated separately. These subgroups were chosen based on available data and differences in the average usage levels and/or data patterns. The industrial class was disaggregated into two digit SIC code classification for the large general service customers, while smaller industrial customers were grouped into an "other" category. These subgroups were chosen to account for the differences in the industrial mix in the service territory. With the exception of the residential group, the forecast for sales was estimated based on total usage in that class of service. The number of residential customers and average usage per customer were estimated separately and total sales were calculated as a product of the two.

The forecast for each class of service was developed utilizing an econometric approach. The structure of the econometric model was based upon the relationship between the variable to be forecasted and the economic environment, weather, conservation, and/or price.

Forecast Methodology

Development of the models for long-term forecasting was econometric in approach and used the technique of regression analysis. Regression analysis is a method of developing an equation, which relates one variable, such as sales or customers, to one or more other variables that are statistically correlated with the first, such as weather, personal income or population growth. Generally, the goal is to find the combination of explanatory variables producing the smallest error between the historic actual values and those estimated by the regression. The output of the regression analysis provides an equation for the variable being explained. In the equation, the variable being explained equals the sum of the explanatory variables each multiplied by an estimated coefficient. Various statistics, which indicate the success of the regression analysis fit, were used to evaluate each model. The indicators were R^2, mean squared Error of the Regression, Durbin-Watson Statistic and the T-Statistics of the Coefficient. PROC STEPWISE, PROC REG, and PROC AUTOREG of SAS were used to estimate all regression models. PROC STEPWISE was used for preliminary model specification and elimination of insignificant variables. PROC REG was used for the final model specifications. Model development also included residual analysis for incorporating dummy variables and an analysis of how well the models fit the historical data, plus checks for any statistical problems such as autocorrelation or multicollinearity. PROC AUTOREG was used if autocorrelation was present as indicated by the Durbin-Watson statistic. Prior to developing the long-range models, certain design decisions were made:

- The multiplicative or double log model form was chosen. This form allows forecasting based on growth rates, since elasticities with respect to each explanatory variable are given directly by their respective regression coefficients. Elasticity explains the responsiveness of changes in one variable (e.g. sales) to changes in any other variable (e.g. price). Thus, the elasticity coefficient can be applied to the forecasted growth rate of the explanatory variable

to obtain a forecasted growth rate for a dependent variable. These forecasted growth rates were then applied to the last year of the short range forecast to obtain the forecast level for customers or sales for the long range forecast. This is a constant elasticity model, therefore, it is important to evaluate the reasonableness of the model coefficients.

- One way to incorporate conservation effects on electricity is through real prices, or time trend variables. Models selected for the major classes would include these variables, if they were statistically significant.
- The remaining variables to be included in the models for the major classes would come from four categories:
  1. Demographic variables - Population.
  2. Measures of economic well-being or activity: real personal income, real per capita income, employment variables, and industrial production indices.
  3. Weather variables - average summer/winter temperature or heating and cooling degree-days.
  4. Variables identified through residual analysis or knowledge of political changes, major economics events, etc. (e.g., foreign oil price increases in 1979 and recession versus non-recession years).

Standard statistical procedures (all possible regressions, stepwise regression) were used to obtain preliminary specifications for the models. Model parameters were then estimated using historical data and competitive models were evaluated on the basis of:

- Residual analysis and traditional "goodness of fit" measures to determine how well these models fit the historical data and whether there were any statistical problems such as autocorrelation or multicollinearity.
- An examination of the model results for the most recently completed full year.

- An analysis of the reasonableness of the long-term trend generated by the models. The major criteria here was the presence of any obvious problems, such as the forecasts exceeding all rational expectations based on historical trends and current industry expectations.
- An analysis of the reasonableness of the elasticity coefficient for each explanatory variable. Over the years a host of studies have been conducted on various elasticities relating to electricity sales. Therefore, one check was to see if the estimated coefficients from Company models were in-line with others. As a result of the evaluative procedure, final models were obtained for each class.
- The drivers for the long-range electric forecast included the following variables.

Service Area Population
Service Area Real Per Capita Income
Service Area Real Personal Income
State Industrial Production Indices
Real Price of Electricity
Average Summer Temperature
Average Winter Temperature
Heating Degree Days
Cooling Degree Days

The service area data included Richland, Lexington, Berkeley, Dorchester, Charleston, Aiken and Beaufort counties, which account for the vast majority of total territorial electric sales. Service area historic data and projections were used for all classes with the exception of the industrial class. Industrial productions indices were only available on a statewide basis, so forecasting relationships were developed using that data. Since industry patterns are generally

based on regional and national economic patterns, this linking of Company industrial sales to a larger geographic index was appropriate.

Economic Assumptions

In order to generate the electric sales forecast, forecasts must be available for the independent variables. The forecasts for the economic and demographic variables were obtained from Global Insight, Inc., (formerly DRI-WEFA) and the forecasts for the price and weather variables were based on historical data. The trend projection developed by Global Insight is characterized by slow, steady growth, representing the mean of all possible paths that the economy could follow if subject to no major disruptions, such as substantial oil price shocks, untoward swings in policy, or excessively rapid increases in demand.

Average summer temperature or CDD (Average of June, July, and August temperature) and average winter temperature or HDD (Average of December (previous year), January and February temperature) were assumed to be equal to the normal values used in the short range forecast.

Peak Demand Forecast

This section describes the procedures used to create the long-range summer and winter peak demand forecasts. It also describes the methodology used to forecast monthly peak demands. Development of summer peak demands will be discussed initially, followed by the construction of winter peaks.

Summer Peak Demand

The forecast of summer peak demands was developed with a load factor methodology. This methodology may be characterized as a building-block approach because class, rate, and some individual customer peaks are separately determined and then summed to derive the territorial peak.

Briefly, the following steps were used to develop the summer peak demand projections. Load factors for selected classes and rates were first calculated from historical data and then used to estimate peak demands from the projected energy consumption among these categories. Next, planning peaks were determined for a number of large industrial customers. The demands of these customers were forecasted individually. Summing these class, rate, and individual customer demands provided the forecast of summer territorial peak demand. Next, the incremental reductions in demand resulting from the Company's standby generator and interruptible programs were subtracted from the peak demand forecast. This calculation gave the firm summer territorial peak demand, which was used for planning purposes.

Load Factor Development

As mentioned above, load factors are required to calculate KW demands from KWH energy. This can be seen from the following equation, which shows the relationship between annual load factors, energy, and demand:

$$\textit{Load Factor} = \textit{Energy}/(\textit{Demand} \times 8760)$$

The load factor is thus seen to be a ratio of total energy consumption relative to what it might have been if the customer had maintained demand at its peak level throughout the year. The value of a load factor will usually range between 0 and 1, with lower values indicating more variation in a customer's consumption patterns, as typified by residential users with relatively large space-conditioning loads. Conversely, higher values result from more level demand patterns throughout the year, such as those seen in the industrial sector.

Rearrangement of the above equation makes it possible to calculate peak demand, given energy and a corresponding load factor. This form of the equation is used to project peak demand herein. The question then becomes one of determining an appropriate load factor to apply to projected energy sales.

The load factors used for the peak demand forecast were not based on one-hour coincident peaks. Instead, it was determined that use of a 4-hour average class peak was more appropriate for forecasting purposes. This was true for two primary reasons. First, analysis of territorial peaks showed that all of the summer peaks had occurred between the hours of 2 and 6 PM. However, the distribution of these peaks between those four hours was fairly evenly spread. It was thus concluded that while the annual peak would occur during the 4-hour band, it would not be possible to say with a high degree of confidence during which hour it would happen.

Second, the coincident peak demand of the residential and commercial classes depended on the hour of the peak's occurrence. This was due to the former tending to increase over the 4-hour band, while the latter declined. Thus, load factors based on peaks occurring at, say, 2 PM, would be quite different from those developed for a 5 PM peak. It should also be noted that the class contribution to peak is quite stable for groups other than residential and commercial. This means that the 4-hour average class demand, for say, municipals, was within 2% of the 1-hour coincident

peak. Consequently, since the hourly probability of occurrence was roughly equal for peak demand, it was decided that a 4-hour average demand was most appropriate for forecasting purposes.

The effect of system line losses were embedded into the class load factors so they could be applied directly to customer level sales and produce generation level demands. This was a convenient way of incorporating line losses into the peak demand projections.

Energy Projections

For those categories whose peak demand was to be projected from KWH sales, the next requirement was a forecast of applicable sales on an annual basis. These projections were utilized in the peak demand forecast construction. In addition, street light sales were excluded from forecast sales levels when required, since there is no contribution to peak demand from this type of sale.

Combining load factors and energy sales resulted in a preliminary, or unadjusted peak demand forecast by class and/or rate. The large industrial customers whose peak demands were developed separately were also added to this forecast.

Derivation of the planning peak required that the impact of demand reduction programs be subtracted from the unadjusted peak demand forecast. This is true because the capacity expansion plan is sized to meet the firm peak demand, which includes the reductions attributable to such programs.

Winter Peak Demand

To project winter peaks actual winter peak demands were correlated with two primary explanatory variables, total territorial energy and weather during the day of the winter peak's occurrence. Several other dummy variables were also included in the model to account for recessions, two extreme winters, and the higher than average growth experienced on the system over the past decade.

The logic behind the choice of these variables as determinants of winter peak demand is straightforward. Over time, growth in total territorial load economic growth and activity in SCE&G's service area, and as such may be used as a proxy variable for those economic factors, which cause winter peak demand to change. It should be noted that the winter peak for any given year occurs by definition after the summer peak for that year. The winter period for each year is December of that year, along with January and February of the following year. For example, the winter peak in 1968 of 962 MW occurred on December 11, 1968, while the winter peak for 1969 of 1,126 MW took place on January 8, 1970. In addition to economic factors, weather also causes winter peak demand to fluctuate, so the impact of this variable was measured by the average of heating degree days (HDD) experienced on the winter peak day in Columbia and Charleston. The presence of a weather variable reduces the bias, which would exist in the other explanatory variables' coefficients if weather were excluded from the regression model, given that the weather variable should be included. When the actual forecast of winter peak demand was calculated, the normal value of heating degree-days over the sample period was used. Finally, although the ratio of winter to summer peak demands fluctuated over the sample period, it did show an increase over time. A primary cause for this increasing ratio was growth in the number of electric space heating customers. Due to the introduction and rapid acceptance of heat pumps over the past three decades, space-heating residential customers increased from less than 5,000 in 1965 to almost 217,000 in 2004, a 10.2% annual growth rate. However, this growth slowed dramatically in the 1990's, so the expectation is that the ratio of summer to winter peaks will change slowly in the future.

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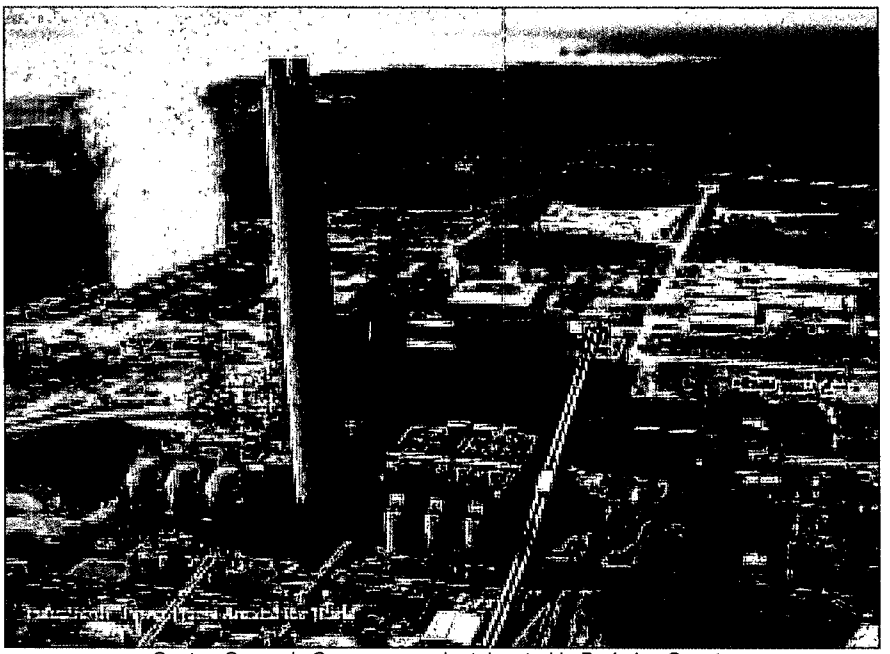
The Status of Utility Demand-Side Management in South Carolina, 2004



Santee Cooper's Cross power plant, located in Berkeley County

A Report by the
South Carolina Energy Office
Division of Insurance and Grants Services
State Budget and Control Board

SOUTH CAROLINA Energy Office

The Status of Utility Demand-Side Management in South Carolina, 2004

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EXECUTIVE SUMMARY

Introduction

The South Carolina Energy Office conducted a survey of electric and natural gas utilities to acquire a better understanding of the current status of power demand and usage in South Carolina as of 2004. Unlike previous editions of *The Demand-Side Management Report* (DSM Report), this edition is not an attempt to quantify the savings from demand-side management programs, or to provide an in-depth analysis of the various demand-side management activities undertaken by some of the utilities. In earlier DSM Reports, utilities were fairly active in providing DSM programs to their customers. However, over the past few years, DSM activities have been steadily declining, and in many cases have been eliminated altogether.

The Status of Utility Demand-Side Management Activities in South Carolina, 2004 (DSM Report) provides quantitative power usage information submitted by retail distributors of electricity and natural gas in South Carolina, including investor-owned utilities, the state-owned Santee Cooper, electric cooperatives, and municipalities. It includes actual and projected data, as well as a compendium of the various demand-side management programs implemented by some of the utilities. Additional information from various sources is also included to provide a more comprehensive understanding of the role the electric industry plays in South Carolina.

Objective of Report

The legislation requiring this report was passed in 1992 by the South Carolina General Assembly, and was published annually up to 2000. At that time, the overall purpose of the report was to measure demand-side activities for lowering electric and gas needs in South Carolina, and to present that information to the people of the state, its elected officials and the utilities themselves, with the hope of encouraging further implementation of demand-side management practices. Since then, the state of deregulation of the electric utility industry in the U.S., as well as policy evaluation in South Carolina, has thrust a climate of ambiguity over all of the decision-making processes in areas such as load or demand-side management. Demand-side management (DSM) involves modifying energy use to maximize energy efficiency. In contrast to "supply-side" strategies, which increase energy supplies (by building new power plants, for example), DSM strives to get the most out of existing energy resources, whether electric or gas. DSM involves utility consumers changing their energy use habits and using energy-efficient appliances, equipment, and buildings.

The objective of this 2004 report is to provide a truncated quantitative overview of the basic peak system demand, total annual system usage, total miles of distribution line, number of customers, and power generation supplied from qualified producers (QP). In addition, this report includes the DSM activities of those utilities that willingly provided such information. These programs consist of the planning, implementing, and monitoring activities of electric utilities that are designed to encourage consumers to modify their level and pattern of electricity usage. From 1995 to 2000, the writing and publication of this report was time intensive, and basically revealed very little new information.

This edition contains supplementary electric data covering topics such as class of ownership, number of ultimate consumers, revenue, sales, and average rate per kilowatthour, and other relevant statistical data.

Findings:

Data submittals were received from 37 of the 46 electric utilities operating in South Carolina, and 11 of the 18 natural gas suppliers operating in the state. The general findings of the survey indicate that the future of electric demand-side programs in South Carolina appears bleak, due in part to the low cost of electricity as compared with the other states. Although interest in deregulation in the state has mostly faded, there has been no corresponding renewal of interest in demand-side management programs.

Electricity

- Only 7 electric utilities reported having active DSM programs: all three investor-owned utilities, the state-owned Santee Cooper, and three electric cooperatives.
- Annual peak demand reached 15,069 MW in 2004.
- Over 76,703 MWh of electricity were used in 2004, as indicated by data from the reporting utilities.
- The average annual electric bill for South Carolina residential electric customers from all utilities in 2002 was $1,126.54, in comparison to $920.83 for the national average.
- South Carolina ranks third in electricity consumption per capita in the U.S., and has the fifth highest residential monthly electric bill with an average of $94.95.
- South Carolina residential customers rank fourth in the nation in per capita amount of money spent on electricity.

Qualified Facilities

Qualified facilities include industrial cogenerators and independent power producers using renewable fuel sources. They currently have the capacity to provide about 372 MW of power, which helps contribute to the ability to meet system peak demand.

Natural Gas

For purposes of the 2004 report, the survey requested annual deca-therm (DT) peak system demand, total annual system deca-therm sales, total miles of distribution line, and total numbers of customers. Ten natural gas utilities submitted their data for the survey. According to survey data, during 2004, the annual peak system demand was 3.88 million DT, the total annual system use was 93.5 million DT, there were over 20,000 miles of distribution line, and 539,480 natural gas customers.

The Status of Utility Demand-Side Management Activities for 2004

Introduction

What is Demand Side Management? Demand-side management or "DSM" is the process of managing the consumption of energy, generally to optimize available and planned generation resources.

How does it work? The goal of demand-side management is to smooth out the daily peaks and valleys in electric or gas energy demand to make the most efficient use of energy resources and to defer the need to develop new power plants. This may entail shifting energy use to off-peak hours, reducing energy requirements overall, or even increasing demand for energy during off-peak hours. All DSM strategies have the goal of maximizing efficiency to avoid or postpone the construction of new generating plants.

This report provides quantified electricity and natural gas data, which was submitted by retail distributors in South Carolina, including investor-owned utilities, the state-owned Santee Cooper, electric cooperatives, and municipalities. The report includes actual data from calendar years 2000 through 2004, and projected data from 2005 through 2009. Unlike previous editions, the main focus of this report is not on the detailed cost avoidance and usage savings due to DSM activities, but to present the requested utility data in its most basic form.

Background

The South Carolina Energy Conservation and Efficiency Act of 1992 requires all utilities to report annually on demand-side activities. This is the tenth report on demand-side management that includes data submitted by the suppliers of electricity and natural gas in South Carolina.

In the past, the primary objective of most DSM programs was to provide cost-effective energy and capacity resources to help defer the need for new sources of power, including generating facilities, power purchases, and transmission and distribution capacity additions. However, due to changes occurring within the industry, electric utilities are also using DSM to enhance customer service. DSM refers only to energy and load-shape modifying activities undertaken in response to utility-administered programs. It does not refer to energy and load-shape changes arising from the normal operation of the marketplace or from government-mandated energy-efficiency standards.

Since interest in demand-side management programs has waned both in South Carolina and the nation over the past few years, this report is designed to make available pertinent electric and natural gas statistics to South Carolina utilities for comparative and industry-specific evaluations.

Findings

I. Electricity

Annual Peak System Demand

The survey requested the utilities to provide the total amount of retail energy demand in MW during the highest annual peak demand during the calendar year. Figure 1 indicates that SCE&G and Duke Power accounted for the largest peak demand with 28.8 percent and 27.6 percent, respectively. The actual and projected growth in annual peak system demand is presented in Figure 2, and shows an overall increase in actual peak demand of 5.1 percent from 2000 to 2004, and a projected increase of 12.7 percent from 2004 to 2009.

Figure 1. Distribution Sources of Supply to Meet Annual Peak Demand of 15,069 MW in 2004

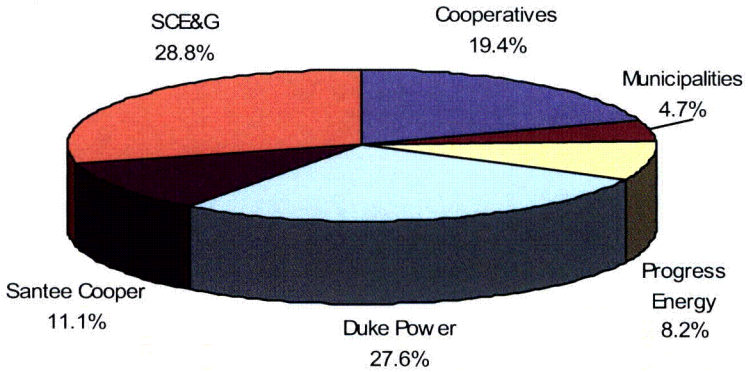
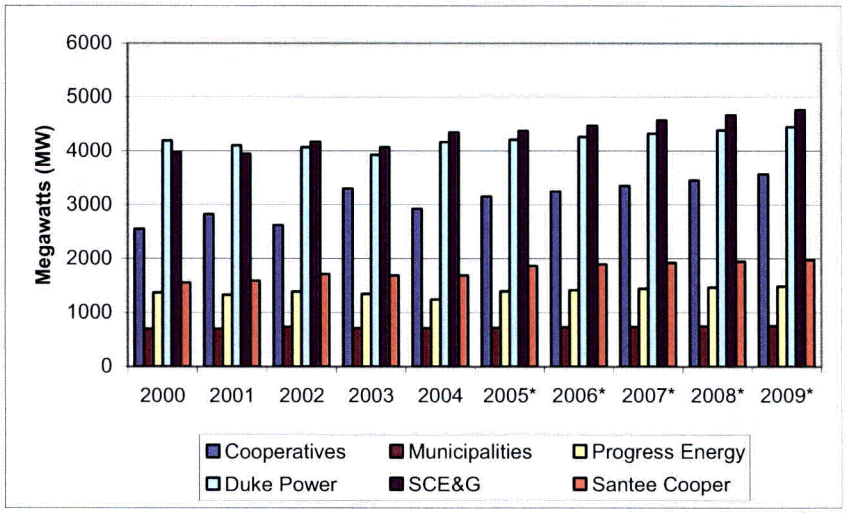


Figure 2. Growth in Annual Peak System Demand



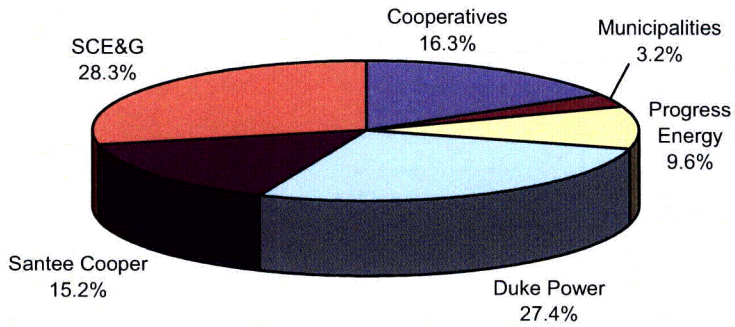
*Projected.

Total Annual System Consumption

Another goal of demand-side activities is to increase efficiency by reducing the overall amount of energy used over time (as opposed to the peak demand amount used at a given instant). This energy is measured in megawatt hours (MWh) and is based on annual consumption. Whereas, the lowering of peak demand decreases the need for additional power plants, reducing the amount of energy consumed conserves fuel resources and reduces harmful emissions into the atmosphere.

Figure 3 illustrates the total amount of annual generation in MWh that was used by retail customers during 2004. Of the utilities that submitted data, over 76,700 MWh of electricity were used in 2004. Two investor-owned utilities, SCE&G (28.3%) and Duke Power (27.4%), account for the largest amounts of total electricity consumption in South Carolina for this category.

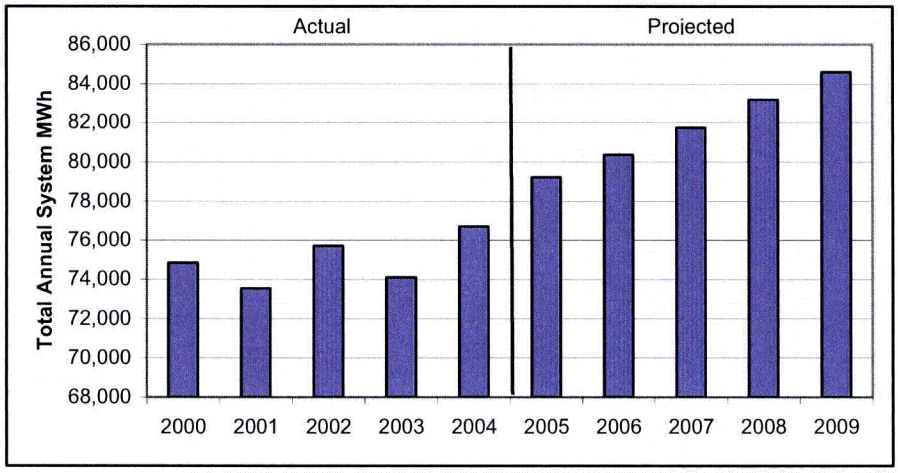
Figure 3. Total Annual System Electricity Consumption (MWh), 2004



*Lockhart Power Company did not report data for annual system MWh.

According to data submitted by utilities, the growth of total annual system generation for retail consumption is projected to increase 13 percent from 2004 to 2009, as shown in Figure 4.

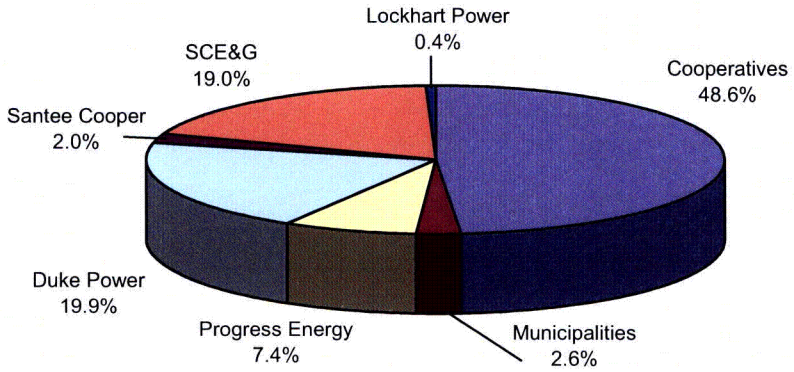
Figure 4. Growth of Annual System Generation for Retail Consumption



Miles of Distribution Line

In 2004, there were 118,360 total miles of power distribution line as indicated by data from reporting utilities. Interestingly enough, Figure 5 shows that the electric cooperatives comprise nearly half of all distribution line in the state. Projected growth indicates only a slight increase in the miles of distribution line over the next few years.

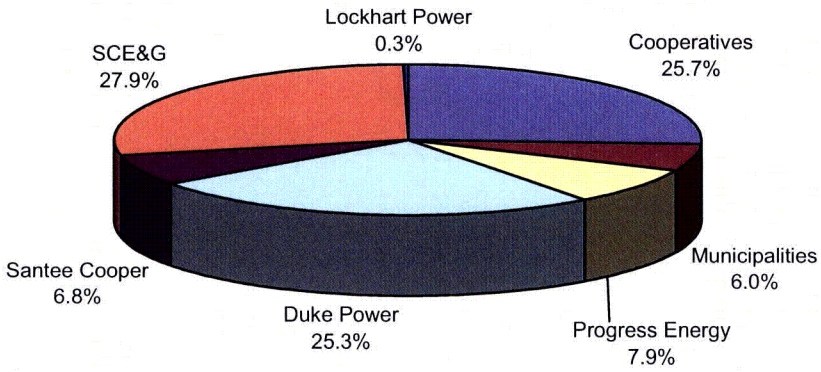
Figure 5. Total Miles of Power Distribution Line, 2004



Number of Customers

Historically, SCE&G has had the largest electric power customer base in South Carolina, accounting for 27.9 percent of the total numbers of customers in 2004. Submitted data projects a sustained annual customer growth rate of about 2 percent for all utilities through 2009.

Figure 6. Number of Retail Electric Utility Customers, 2004



Qualified Facilities

The federal Public Utilities Regulatory Policies Act of 1978 (PURPA) allows end users who need to generate power for their facilities to make any excess power available to the electric utilities supplying those users. PURPA also allows private companies to generate and to supply electricity to public utilities if that power is generated using renewable energy resources. A Qualified Facility (QF), as defined by PURPA, includes industrial cogeneration facilities and independent power producers using renewable fuel sources, including wood wastes, incinerated municipal solid waste and small-scale hydro-electricity. Qualified facilities reduce the need for new power plants just as load management does, by reducing the demand on utilities' systems at peak times.

Table 1. Listing of Electricity Qualified Facilities, 2004

Utility	Plant Owner	Location	Fuel Type	Capacity (MW)	Purchase/ Displace
Progress Energy	DuPont Chemical	Camden	Coal	68	Displace
Progress Energy	Foster Wheeler	Charleston	Refuse	0.5	Purchase
Progress Energy	LA-Z-Boy Chair	Florence	Wood	29	Displace
Progress Energy	SONOCO	Hartsville	Coal	27	Displace
Progress Energy	Stone Container	Florence	Wood Chips	8.7	Purchase
			TOTAL=	**133.2**	
Duke Power	Aquenergy	Piedmont	Hydro	1.5	Purchase
Duke Power	Aquenergy	Cateechee	Hydro	3.5	Purchase
Duke Power	Aquenergy	Cateechee	Hydro	2.4	Purchase
Duke Power	Aquenergy	Ware Shoals	Hydro	1.05	Purchase
Duke Power	BMW	Greer	Gas	0.45	Displace
Duke Power	Bob Jones University	Greenville	Diesel	5	Displace
Duke Power	Cherokee County	Gaffney	Gas	6.3	Purchase
Duke Power	Converse Energy	Clifton	Hydro	0.24	Purchase
Duke Power	Daniel Nelson Evans	Spartanburg	Hydro	0.8	Purchase
Duke Power	Northbrook Carolina Hydro	Ware Shoals	Hydro	1.25	Purchase
Duke Power	Northbrook Carolina Hydro	Belton	Hydro	4.5	Purchase
Duke Power	Northbrook Carolina Hydro	Greenville	Hydro	2.2	Purchase
Duke Power	Pacolet River Power	Clifton	Hydro	3.3	Purchase
Duke Power	Pelzer Hydro Co.	Pelzer	Hydro	5	Purchase
Duke Power	Pelzer Hydro Co.	Williamston	Hydro	100	Purchase
			TOTAL=	**137.5**	
SCE&G	Dept. of Defense	Parris Island	Coal	97.5	Displace
SCE&G	International Paper	Eastover	Wood Chips	3	Purpose/Displace
			TOTAL=	**100.5**	
Lockhart Power Co.		Pacolet	Hydro	0.8	Purchase
City of Seneca	Coneross Power Co.	Seneca	Hydro	0.8	Purchase
TOTAL FOR 24 STATIONS				**372.8**	

Source: South Carolina Office of Regulatory Staff.

Electricity from qualified facilities is classified into two categories: 1) purchase, meaning the utilities purchase the power generated; and 2) displace, meaning that the power is used by the facility itself, which would otherwise be using power from the utility's grid. Displacement from qualified facilities, in other words, is analogous to demand-side activities presented by some utilities in this report, in that it contributes to reducing overall system peak. Purchase is a direct, non-utility addition to total system peak capacity. As shown in Table 1, qualified facilities in South Carolina had the capacity to provide 142.8 MW of purchase power and 230 MW of displacement power, for a total of 372.8 MW of power in 2004.

The survey sent out by the Energy Office requested the total generation kWh (converted to MWh) supplied from qualified producers or avoided due to their operation. From the submitted data, Progress Energy comprised 57.9 percent of such generation in 2004, followed by Duke Power with 39.4 percent, and SCE&G, with 2.6 percent. Although submitted data on projected generation was incomplete, there was a 12 percent decrease from 2000 to 2004.

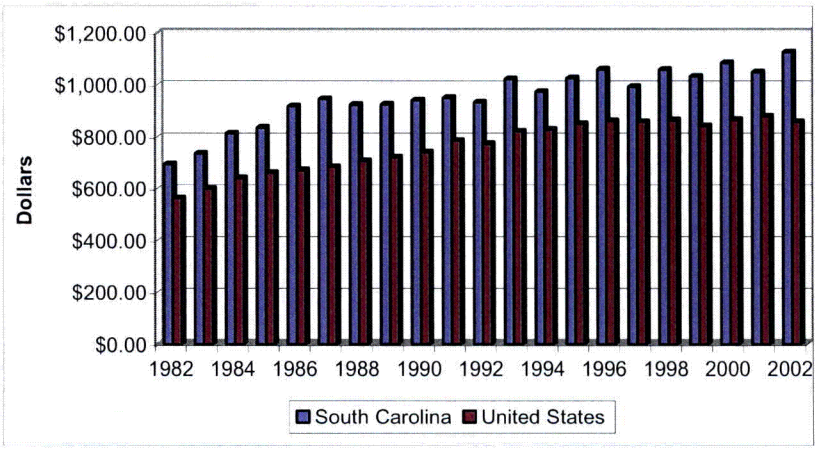
Supplementary Electricity Data

This section includes electric data research findings extrapolated from the *South Carolina Energy Statistical Profile*, published by the Energy Office, which helps provide a better overall picture of the status of the electric industry in South Carolina.

Consumption, Cost, and Expenditures

The average annual residential electric bill for South Carolina investor-owned utilities in 2002 was $1,126.36, an increase of 62.3 percent or $432.19 from 1982, as compared with $857.12 on the national level, an increase of 52.4 percent or $294.58 (Figure 7). The average annual electric bill for South Carolina residential electric customers from all utilities (municipal, cooperatives, investor-owned) in 2002 was $1,126.54, and $920.83 for the national average. In addition, from 1982 to 2002 the kWh per customer increased by 23.5 percent in South Carolina as compared with 17.6 percent on the national level.

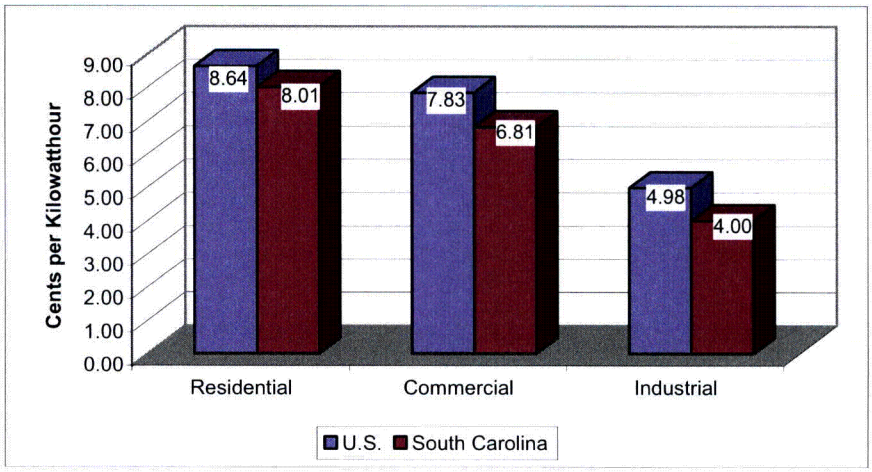
Figure 7. South Carolina and U.S. Annual Average Residential Electric Bill for Investor-owned Electric Utilities, 1982-2002



Source: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry.

South Carolina ranks third in electricity consumption per capita in the U.S., and has the fifth highest residential monthly electric bill with an average of $94.95. Although the average residential rate per kWh in South Carolina is better than the average rates for 25 other states, South Carolina residential customers rank fourth in the nation in the per household amount of money spent on electricity. This greater cost of electricity is the result of high consumption levels, not high rates. Moreover, not only does South Carolina have a lower average rate per kilowatthour in the residential sector than the national average, but also in the commercial and industrial sectors as indicated in Figure 8.

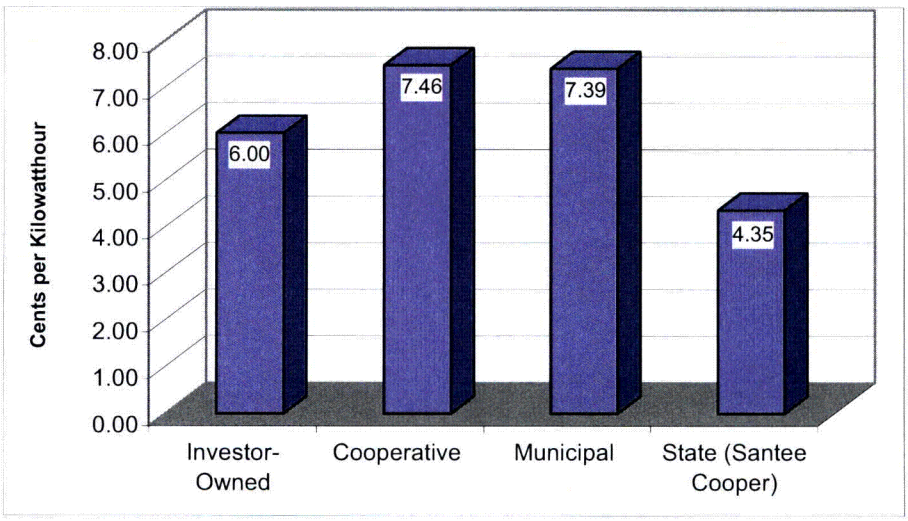
Figure 8. U.S. and South Carolina Comparison of Electric Utility Average Rate per kWh by Sector, 2003



Source: Energy Information Administration, *Electric Sales and Revenue Database File.*

As shown in Figure 9, the average electric rate per kilowatthour for investor-owned utilities in 2003 was 6 cents, 7.46 cents for cooperatives, 7.39 cents for municipal utilities, and 4.35 cents for the state-owned Santee Cooper.

Figure 9. South Carolina Average Electric Rate per kWh by Class of Ownership, 2003



Source: Energy Information Administration, *Electricity Database File.*

Table 2 provides a profile of residential statistical information for all the power utilities in South Carolina.

Table 2

Class of Ownership, Number of Ultimate Consumers, Revenue, Sales, and Average Rate per Kilowatthour for the Residential Sector by South Carolina Electric Utilities, 2003

Electric Utility	Class of Ownership	Number of Consumers	Revenue (Thousand dollars)	Sales (Thousand kWh)	Average Rate per kWh (Cents)
Abbeville, City of	Municipal	3,101	$3,019	31,672	9.53
Aiken Electric Coop Inc	Cooperative	37,854	$48,307	540,508	8.94
Bamberg Board of Public Works	Municipal	1,465	$1,220	19,375	6.30
Bennettsville, City of	Municipal	4,225	$4,256	54,750	7.77
Berkeley Electric Coop Inc	Cooperative	72,930	$86,357	1,068,796	8.08
Black River Electric Coop, Inc	Cooperative	24,680	$31,617	421,209	7.51
Blue Ridge Electric Coop Inc	Cooperative	54,877	$62,531	670,373	9.33
Broad River Electric Coop, Inc	Cooperative	17,861	$21,030	233,952	8.99
Camden, City of	Municipal	9,411	$7,411	96,950	7.64
CP&L/Progress Energy	Investor-owned	136,620	$166,912	2,061,811	8.10
Clinton Combined Utility Sys	Municipal	3,635	$3,459	34,992	9.89
Coastal Electric Coop, Inc	Cooperative	9,936	$13,269	141,831	9.36
Due West, City of	Municipal	316	$412	3,296	12.50
Duke Energy Corporation	Investor-owned	413,450	$395,926	5,693,569	6.95
Easley Combined Utility System	Municipal	10,873	$12,308	135,717	9.07
Edisto Electric Coop, Inc	Cooperative	14,774	$20,559	230,723	8.91
Fairfield Electric Coop, Inc	Cooperative	19,942	$24,621	307,278	8.01
Gaffney, City of	Municipal	6,056	$5,640	66,175	8.52
Georgetown, City of	Municipal	3,780	$3,679	49,860	7.38
Greenwood Commissioners PW	Municipal	10,967	$6,274	108,315	5.79
Greer Commission of Public Wks	Municipal	10,733	$10,973	121,108	9.06
Haywood Electric Member Coop*	Cooperative	11	$4	35	11.43
Horry Electric Coop Inc	Cooperative	42,398	$54,790	644,266	8.50
Laurens, City of	Cooperative	4,381	$4,074	567,296	8.56
Laurens Electric Coop, Inc	Municipal	43,004	$48,586	41,189	9.89
Little River Electric Coop Inc	Cooperative	11,327	$12,937	143,264	9.03
Lockhart Power Co	Investor-owned	5,169	$5,370	66,567	8.07
Lynches River Elec Coop, Inc	Cooperative	18,936	$20,535	242,597	8.46
Marlboro Electric Coop, Inc	Cooperative	5,348	$7,742	87,323	8.87
McCormick, Town of	Municipal	878	$949	11,529	8.23
Mid-Carolina Electric Coop Inc	Cooperative	38,900	$50,735	619,101	8.19
Newberry, City of	Cooperative	3,937	$3,883	150,215	7.40
Newberry Electric Coop, Inc	Municipal	11,121	$11,109	46,673	8.32
Orangeburg, City of	Municipal	20,151	$17,484	285,000	6.13
Palmetto Electric Coop Inc	Cooperative	48,227	$55,171	798,424	6.91
Pee Dee Electric Coop, Inc	Cooperative	27,486	$37,525	440,786	8.51
Prosperity, Town of	Municipal	561	$505	6,646	7.60
Rock Hill, City of	Municipal	23,222	$24,168	275,698	8.77
Santee Electric Coop, Inc	State	39,983	$51,084	617,862	6.98
Seneca, City of	Cooperative	4,788	$4,381	54,817	8.27
South Carolina Electric & Gas	Municipal	481,380	$604,104	6,998,139	7.99
Santee Cooper	Investor-owned	112,213	$102,213	1,464,246	8.63
Tri-County Electric Coop, Inc	Cooperative	16,758	$22,188	30,500	9.20
Union, City of	Municipal	6,006	$6,857	241,073	9.86
Westminster, City of	Municipal	1,404	$1,345	69,570	11.03
Winnsboro, Town of	Municipal	3,396	$2,683	12,192	8.80
York Electric Coop Inc	Cooperative	29,451	$36,980	414,371	8.92
Total	**47l**	**1,867,922**	**$2,117,182**	**26,421,639**	**8.01**

*A North Carolina-based electric cooperative.
Source: Energy Information Administration, *Electricity Database File*.

Table 3 presents a statistical breakdown of electric utilities that provide power to the commercial sector in South Carolina.

Table 3

Class of Ownership, Number of Ultimate Consumers, Revenue, Sales, and Average Rate per Kilowatthour for the Commercial Sector by South Carolina Electric Utilities, 2003

Electric Utility	Class of Ownership	Number of Consumers	Revenue (Thousand Dollars)	Sales (Thousand kWh)	Average Rate per kWh (Cents)
Abbeville, City of	Municipal	495	$2,428	27,835	8.72
Aiken Electric Coop Inc	Cooperative	2,508	$8,233	114,986	7.16
Bamberg Board of Public Works	Municipal	363	$1,277	21,004	6.08
Bennettsville, City of	Municipal	530	$3,136	40,335	7.77
Berkeley Electric Coop Inc	Cooperative	7,721	$13,431	166,685	8.06
Black River Electric Coop, Inc	Cooperative	3,369	$7,199	90,040	8.00
Blue Ridge Electric Coop Inc	Cooperative	3,754	$10,662	127,170	8.38
Broad River Electric Coop, Inc	Cooperative	617	$2,079	23,906	8.70
Camden, City of	Municipal	1,442	$5,286	66,895	7.90
CP&L/Progress Energy	Investor-owned	31,395	$127,101	1,784,958	7.12
Clinton Combined Utility Sys	Municipal	605	$3,749	41,131	9.11
Coastal Electric Coop, Inc	Cooperative	848	$1,773	19,017	9.32
Due West, City of	Municipal	31	$390	8,644	4.51
Duke Energy Corporation	Investor-owned	80,153	$309,908	5,172,087	5.99
Easley Combined Utility System	Municipal	1,608	$10,528	121,867	8.64
Edisto Electric Coop, Inc	Cooperative	4,041	$3,716	40,092	9.27
Fairfield Electric Coop, Inc	Cooperative	1,002	$4,943	66,188	7.47
Gaffney, City of	Municipal	1,175	$8,510	92,171	9.23
Georgetown, City of	Municipal	1,164	$7,108	85,328	8.33
Greenwood Commissioners-PW	Municipal	2,278	$3,391	51,976	6.52
Greer Commission of Public Wks	Municipal	3,607	$9,150	116,294	7.87
Haywood Electric Member Corp*	Cooperative	3	$5	56	8.93
Horry Electric Coop Inc	Cooperative	6,296	$11,465	138,700	8.27
Laurens Electric Coop, Inc	Cooperative	3,335	$10,634	114,812	9.26
Laurens, City of	Municipal	836	$3,863	51,615	7.48
Little River Electric Coop Inc	Cooperative	1,906	$3,299	36,479	9.04
Lockhart Power Co	Investor-owned	1,132	$1,709	19,399	8.81
Lynches River Elec Coop, Inc	Cooperative	873	$3,269	38,979	8.39
Marlboro Electric Coop, Inc	Cooperative	1,150	$1,971	24,165	8.16
McCormick, Town of	Municipal	194	$722	7,747	9.32
Mid-Carolina Electric Coop Inc	Cooperative	4,311	$15,187	198,533	7.65
Newberry Electric Coop, Inc	Cooperative	541	$748	9,928	7.53
Newberry, City of	Municipal	829	$4,963	61,311	8.09
Orangeburg, City of	Municipal	3,263	$6,750	104,000	6.49
Palmetto Electric Coop Inc	Cooperative	9,137	$30,368	446,276	6.80
Pee Dee Electric Coop, Inc	Cooperative	1,674	$5,013	60,538	8.28
Prosperity, Town of	Municipal	117	$220	2,745	8.01
Rock Hill, City of	Municipal	3,049	$30,353	397,521	7.64
Santee Cooper	State	2,451	$7,407	105,643	6.17
Santee Electric Coop, Inc	Cooperative	1,031	$5,239	65,448	7.01
Seneca, City of	Municipal	82,588	$496,643	7,122,007	8.00
South Carolina Electric & Gas	Investor-owned	25,610	$111,040	1,799,970	6.97
Tri-County Electric Coop, Inc	Cooperative	629	$1,214	17,700	7.90
Union, City of	Municipal	658	$3,543	44,834	9.21
Westminster, City of	Municipal	1,051	$5,399	58,599	9.27
Winnsboro, Town of	Municipal	240	$1,477	15,933	6.86
York Electric Coop Inc	Cooperative	2,918	$9,627	114,582	8.40
Total	**47**	**304,528**	**$1,316,126**	**19,336,129**	**6.81**

*A North Carolina-based electric cooperative.
Source: Energy Information Administration, *Electricity Database File*.

Table 4 provides statistical information on the 33 utilities in South Carolina that provide power in the industrial sector in South Carolina.

Table 4

Class of Ownership, Number of Ultimate Consumers, Revenue, Sales, and Average Rate per Kilowatthour for the Industrial Sector by South Carolina Electric Utilities, 2003

Electric Utility	Class of Ownership	Number of Consumers	Revenue (Thousand Dollars)	Sales (Thousand kWh)	Average Rate per kWh (Cents)
Aiken Electric Coop Inc	Cooperative	26	$7,040	163,469	4.31
Bamberg Board of Public Works	Municipal	5	$369	7,944	4.65
Berkeley Electric Coop Inc	Cooperative	250	$9,637	176,851	5.45
Black River Electric Coop, Inc	Cooperative	18	$6,411	127,806	5.02
Blue Ridge Electric Coop Inc	Cooperative	20	$2,790	57,601	4.84
Broad River Electric Coop, Inc	Cooperative	3	$1,156	16,682	6.93
CP&L/Progress Energy	Investor-owned	781	$155,723	3,222,888	4.83
Clinton Combined Utility Sys	Municipal	6	$2,261	34,610	6.53
Due West, City of	Municipal	1	$10	103	9.71
Duke Energy Corporation	Investor-owned	1,866	$371,185	9,872,667	3.76
Edisto Electric Coop, Inc	Cooperative	15	$1,147	19,011	6.03
Fairfield Electric Coop, Inc	Cooperative	11	$6,595	164,408	4.01
Gaffney, City of	Municipal	27	$1,566	33,905	4.62
Greenwood Commissioners-PW	Municipal	176	$5,668	121,902	4.65
Horry Electric Coop Inc	Cooperative	6	$1,815	27,361	6.63
Laurens Electric Coop, Inc	Cooperative	29	$8,803	156,366	5.63
Lockhart Power Co	Investor-owned	11	$5,091	113,488	4.49
Lynches River Elec Coop, Inc	Cooperative	11	$3,672	69,041	5.32
Marlboro Electric Coop, Inc	Cooperative	6	$20,993	616,608	3.40
Mid-Carolina Electric Coop Inc	Cooperative	5	$1,078	23,036	4.68
Newberry Electric Coop, Inc	Cooperative	80	$5,294	94,542	5.60
Newberry, City of	Municipal	14	$3,947	64,915	6.08
Orangeburg, City of	Municipal	344	$22,347	450,000	4.97
Palmetto Electric Coop Inc	Cooperative	8	$2,677	55,613	4.81
Pee Dee Electric Coop, Inc	Cooperative	21	$15,570	369,414	4.21
Santee Cooper	State	32	$275,286	7,978,576	3.45
Santee Electric Coop, Inc	Cooperative	14	$24,038	583,553	4.12
Seneca, City of	Municipal	3	$1,556	32,530	4.78
South Carolina Electric & Gas	Investor-owned	1,073	$281,056	6,547,908	4.29
Tri-County Electric Coop, Inc	Cooperative	85	$78	654	11.93
Union, City of	Municipal	14	$709	8,318	8.52
Winnsboro, Town of	Municipal	37	$2,272	34,000	6.68
York Electric Coop Inc	Cooperative	26	$3,262	50,560	6.45
Total	**33**	**5,024**	**$1,251,102**	**31,296,330**	**4.00**

Source: Energy Information Administration, *Electricity Database File*.

Demand-Side Management Activities, 2004

This section provides the demand-side management activities of the utilities which submitted such reports to the South Carolina Energy Office. Included are program activities from three electric cooperatives, three investor-owned utilities, and the state-owned power utility, Santee Cooper.

Cooperatives

Pee Dee Electric Cooperative

Pee Dee Electric Cooperative does not generate any of the electricity it sells to its member-owners. However, it does implement two programs geared toward reducing the generation required from its wholesale power provider. The first of these is a load control procedure. During possible peak conditions, PDEC personnel lower substation bus voltages through SCADA-controlled regulators. This can shave roughly two percent off of the total demand required by its system. The second method is a strict power factor penalty applied to any industrial member-owner (> 50 kW) whose power factor falls below 90 percent lagging. This penalty has encouraged the majority of such member-owners to purchase capacitor systems to correct power factors above 90 percent. Both of these procedures decrease the total amount of kVA that must be generated by Santee Cooper to meet PDEC's needs.

Broad River Electric Cooperative

Broad River Electric Cooperative does not have a DSM program to control loads on their system. Offers a "Time-Of-Use Rate" that discourages power usage during peak hours. There are approximately 200 meters (1.0%) on the TOU rate. Long range plan does not include any DSM activities.

Laurens Electric Cooperative

Conservation and Energy Efficiency: Laurens Electric's conservation and energy efficiency strategy is two-fold. First, Laurens Electric educates customers on energy efficiency and conservation through its web site, *Living in South Carolina* magazine, bill stuffers, brochures, and press releases to the local media. Second, Laurens Electric motivates customers to make improvements to existing homes and build energy efficient houses by offering a residential energy conservation rate.

Load Management: Laurens Electric offers load management to both small and large commercial and industrial customers. Small commercial and industrial customers are offered a Time-Of-Use energy rate, which provides cost savings for reducing energy consumption during on-peak hours. In addition to the Time-Of-Use rate, Laurens Electric's large commercial and industrial customers are provided a load management program that communicates to them when conditions are likely that our wholesale supplier could experience its monthly energy peak. In doing so, our customers have the opportunity to significantly drive down their energy costs by reducing their peak demand during this time.

Renewable Energy: In 2004, for the first time, Laurens Electric began selling blocks of green power to its residential customer-base. The green power for the program comes from methane gas that is generated at landfills across South Carolina. To date, Laurens Electric has sold approximately 269 blocks of green power.

Municipalities

There are no reported DSM activities by municipal utilities.

Investor-Owned Utilities

Duke Power Company

Program Descriptions For Each Demand-Side Activity

Residential Load Control – Air Conditioning (RIDER LC)

This program is designed to provide a source of interruptible capacity to Duke at any time it encounters capacity problems during the cooling months of the year. Participants receive billing credits during the billing months of July through October for allowing Duke to interrupt electric service to their central air conditioning systems when capacity problems arise.

Residential Load Control – Water Heating (RIDER LC)

This program is designed to provide a source of interruptible capacity to Duke at any time it encounters capacity problems during the year. Participants receive billing credits each month of the year for allowing Duke to interrupt electric service to their water heaters when capacity problems arise. This program was closed to new installations on January 1, 1993 in North Carolina, and on February 17, 1993 in South Carolina.

Standby Generator Control (RIDER SG)

This program is designed to provide a source of interruptible capacity to Duke at any time it encounters capacity problems during the year. Participants in the program contractually agree to transfer electrical loads from the Duke source to their standby generators when so requested by Duke. The generators in this program do not operate in parallel with Duke's system and, therefore, cannot "backfeed" (or export power) into the Duke system. Participating customers receive payments for capacity and/or energy based on the amount of capacity and/or energy transferred.

Interruptible Power Service (RIDER IS)

This program is designed to provide a source of interruptible capacity to Duke at any time it encounters capacity problems during the year. Participants in the program contractually agree to reduce their electrical loads to specified levels when so requested by Duke. Failure to do so results in a penalty for the increment of demand which exceeds a specified level. The program has not been available to new participants since 1992.

Residential Service Water Heating - Controlled/Submetered

This program shifts a participating customer's water heating usage to off peak periods as determined by Duke. The program is currently available in accordance with rate Schedule WC. The customer is billed at a lower rate for all water heating energy consumption in exchange for allowing Duke to control the water heater.

High Efficiency Heat Pump and Central Air Conditioning Payment Program

This program encourages the installation of high efficiency (11 SEER or greater) heat pumps and central air conditioners in the residential and commercial markets. Qualifying units must meet specified size (Btu/hour) requirements. The central air conditioning portion of the program was closed effective October 1995 in South Carolina and December 1995 in North Carolina. The High Efficiency Heat Pump Program was rolled into the New and Existing Residential Housing Programs. The New Residential Housing Program is no longer available. Payments were removed from the Existing Residential Housing Program effective August 1998. Prior to 1994, the results were tracked separately for heat pumps and air conditioners.

High Efficiency Chillers Incentive Program

This program promotes the use of high efficiency central chiller equipment that reduces space conditioning electrical demand and energy consumption for cooling. The incentive paid is on a sliding scale depending on size and efficiency of equipment. This program was closed to new applications in July 1995 in South Carolina, and October 1995 in North Carolina.

Manufactured Housing Payment Program

Incentives are provided to manufactured home retailers to promote increased insulation levels and high efficiency heat pumps. Manufactured housing retailers are the first line contact with this market's potential home buyer. In order to qualify for the incentive, the new manufactured homes must meet the thermal requirements of rate Schedule RE-2. This program was rolled into the New Residential Housing Program, which is no longer available.

Residential HVAC Tune-Up Program

The purpose of this program is to assist the owners of single-family residential structures in improving the efficiency of their heating and cooling air distribution systems to reduce energy consumption and lower operating costs. A blower door analysis is performed by a qualified HVAC technician on each home to quantify the amount of duct leakage at a reference pressure. Repairs are made to the ductwork using a permanent sealant, such as mastic. These repairs benefit the customer by improving comfort and by increasing system efficiency which lowers energy usage. This program was rolled into the Existing Residential Housing Program. Payments were removed from the program effective August 1998.

High Efficiency Agricultural Ventilation Payment Program

This program promotes and encourages the installation of high efficiency fan systems in livestock growing, or greenhouse applications through incentive payments to agricultural

customers. Only new fan systems in either new or retrofit applications are eligible for incentives under this program. This program was closed on December 31, 1994.

Duct Sealing Payment Program

This existing residential program offers builders incentives to ensure that HVAC systems in new residential construction have minimal leaks in ductwork. The option includes requirements for thermal conditioning and a high-efficiency heat pump with a SEER of 11 or more. This program was rolled into the New Residential Housing Program, which is no longer available.

Residential Insulation Loan

Loans are offered to existing all-electric residential customers to offset the cost of increasing the insulation levels in their homes to the thermal requirements listed in rate Schedules RS-3 or 4, RE-2, or Maximum Value Home insulation standards. This program was rolled into the Existing Residential Housing Program.

Existing Residential Housing Program

This residential program represents Duke's activities in the existing residential market to encourage increased energy efficiency in existing residential structures, and to encourage the use of efficient electric end-uses. This program consists of the following options:

1) High Efficiency Heat Pump Program (discontinued as of August 1998)
2) Residential HVAC Tune-up Program (discontinued as of August 1998)
3) Residential Energy Products Loan Program

South Carolina Electric & Gas

The Demand-Side Management Programs at SCE&G can be divided into three major categories: Customer Information Programs, Energy Conservation Programs and Load Management Programs.

Customer Information Programs

SCE&G's customer information programs fall under two headings: the annual energy campaigns and the web-based information initiative. Following is a brief description of each.

- The 2004 Energy Campaigns: In 2004 as in the past, SCE&G continued to proactively educate its customers and create awareness of issues related to energy and conservation management. Below is a list of the key elements of this campaign.
    - The summer and winter campaign consisted of several different strategies in communicating to our customers. Following are the strategies implemented:
        - Radio and Newspaper – two-week radio and newspaper campaigns were conducted in early July and October in all the major service areas. The spots featured energy savings tips, online energy management tools, and energy savings clinics.
        - Weatherline – energy saving tips on the Weatherline promoted.
        - "Energy Wise" newsletter – energy saving tips featured in the SCE&G "Energy Wise" newsletter distributed to customers in July via their bills.

- Bill Inserts – a bill insert issued to targeted customers promoting the Low-Income Home Energy Assistance Program (LIHEAP).
- Brochures/Printed Materials – energy saving tips available on various printed materials in business offices.
- On-hold Messaging – key energy messages developed for SCE&G call centers for customers placed on hold.
- News Releases – distributed to print and broadcast media throughout SCE&G's service territory.
- Featured News Guests – SCE&G energy experts conducted several interviews with the media regarding energy conservation and useful tips.
- Project Cool Breeze – SCE&G was a sponsor of this program in Charleston that provided fans and/or air conditioners to lower income persons in the Lowcountry.
- Web site – energy saving tips and other conservation information placed on the company's Web site. The address for the Web site was promoted in most of the communication channels mentioned above.
- Weatherization Project – SCE&G partners targeted low-income homes in Beaufort and Sumter for weatherization. SCE&G employees volunteer their time to assist the effort.
- Speakers Bureau – Representatives from SCE&G talk to local organizations about energy conservation. Also use company-produced video that highlights energy conservation.
- Energy Awareness Month – company used the month as an opportunity to send information to the media discussing energy costs and savings tips.
- Lowe's Partnership – SCE&G partnered with Lowe's to conduct energy saving seminars at Lowe's stores throughout SCE&G's service territory in October, Energy Awareness Month.

- WEB-Based Information and Services Programs: SCE&G now has available a Web-based tool which allows customers to access current and historical consumption data and compare their energy usage month-to-month and year-to-year, noting trends and spikes in their consumption. Feedback on this tool has been positive and nearly 100,000 customers have registered to access this tool as well as other account related information. The SCE&G Web site supports all communication efforts to promote energy savings tips and provides video instruction on weatherization as well as other useful content. For our business customers, online information includes: retrofit and conversion assistance, standby generator program, new construction information, expert energy assistance and more.

Energy Conservation Programs

There are three energy conservation programs: the Value Visit Program, the Conservation Rate and our use of seasonal rate structures. A description of each follows:

- Value Visit Program: The Value Visit Program is designed to assist residential electric customers that are considering an investment in upgrading their home's energy

efficiency. We visit the customer's home and guide them in their purchase of energy related equipment and materials such as heating and cooling systems, duct insulation, attic insulation, storm windows, etc. Our representative explains the benefits of upgrading different areas of the home and what affect upgrading these areas will have on energy bills and comfort levels as well as informing the customer on the many rebates we offer for upgrading certain areas of the home (see attached rebate schedule). We also offer financing for qualified customers which makes upgrading to a higher energy efficiency level even easier. The Value Visit Program is often used in conjunction with our Rate 6 Program to achieve the maximum benefit for customers wanting to reduce their energy usage, make their homes more comfortable and to increase their home's overall value. There is a $25 charge for the program, but this charge is reimbursed if the customer implements any suggested upgrade within 90 days of the visit. Information on this program is available on our website or by brochure.

- 0 to R30 attic insulation - $6.00 per 100 sq.ft.
- R11 to R30 attic insulation - $3.00 per 100 sq.ft.
- Storm windows - $30.00 per house
- Duct insulation - $60.00 per house
- Wall Insulation - $80.00 per house

- Rate 6 Energy Saver/Energy Conservation Program: The Rate 6 Energy Saver / Energy Conservation Program rewards homeowners and home builders who upgrade their existing homes or build their new homes to a high level of energy efficiency with a reduced electric rate. This reduced rate, combined with a significant reduction in energy usage, provides for considerable savings for our customers. Participation in the program is very easy as the requirements are prescriptive and do not require a large monetary investment which is beneficial to all of our customers and trade allies. Homes built to this standard also have improved comfort levels and increased re-sale value over homes built to the minimum building code standards which is also a significant benefit to our customers. Information on this program is available on our website and by brochure.
- Seasonal Rates: Many of our rates are designed with components that vary by season. Energy provided in the peak usage season is charged a premium to encourage conservation and efficient use.

Load Management Programs

SCE&G's load management programs have as their primary goal the reduction of the need for additional generating capacity. There are four load management programs: Standby generator program; Interruptible load program; Real Time Pricing Rate; and the Time of Use Rates. A description of each follows.

- Standby Generator Program: The Standby Generator I Program was introduced in 1990 to serve as a load management tool. General guidelines authorize SCE&G to initiate a standby generator run request when reserve margins are stressed due to a temporary reduction in system generating capability, or high customer demand. The Standby Generator II Program was developed in 2000, authorizing standby generator

runs for revenue producing opportunities during times of high market prices. Through consumption avoidance, generator customers release capacity back to SCE&G where it is then used to satisfy system demand. Qualifying customers (able to defer a minimum of 200 kW) receive financial credits determined initially by recording the customer's demand during a load test. Future demand credits are based on what the customer actually delivers when SCE&G requests them to run their generator(s). This program allows customers to reduce their monthly operating costs, as well as earn a return on their generating equipment investment.

- Interruptible Load Program: SCE&G has over 200 megawatts of interruptible customer load under contract. Participating customers receive a discount on their demand charges for shedding load when SCE&G is short of capacity.
- Real Time Pricing (RTP) Rate: A number of customers receive power under our real time pricing rate. During peak usage periods throughout the year when capacity is low in the market, the RTP rate sends a high price signal to participating customers which encourages conservation and load shifting. Of course during low usage periods, prices are lower.
- Time of Use Rates: Our time of use rates contain higher charges during the peak usage periods of the day to encourage conservation and load shifting during these periods.

Progress Energy

Progress Energy Carolinas, Inc.
Annual Report of Demand Side Management Activities

Progress Energy Carolinas, Inc. (PEC) has a number of conservation and energy efficiency, load management, cogeneration, and renewable energy programs in effect. These include the following programs:

Residential:

PEC's Residential programs are structured under a full-service energy efficiency umbrella to provide end-use customers with comfort, convenience, and peace of mind. These include:

Education and Awareness

Education and awareness are used to promote energy efficiency to customers. This encompasses the retrofit and new home markets for all types of residential structures (single family, multi-family, and manufactured housing). PEC proactively educates the end-use customers, assists them with questions and provides additional information, as needed, concerning energy efficiency.

Home Energy Check

Home Energy Check is an energy analysis tool (audit) first implemented in 2001 to assist residential consumers to better understand their energy usage and make personalized recommendations for energy improvements. The tool consists of an on-

line and mail-in version, depending on the customer's requirements. The on-line version links to a Lawrence Berkeley National Laboratory audit developed for the U.S. Department of Energy (DOE): http://homeenergysaver.lbl.gov/. In January 2005, PEC implemented a new improved Home Energy Check on its web site: www.progress-energy.com

Energy Efficient Home

PEC introduced in the early 1980's the Energy Efficient Home program. This program provides residential customers with a 5 percent discount of the energy and demand portions of their electricity bills when their homes meet certain thermal efficiency standards that are significantly above the existing building codes and standards. Through September 2004, almost 300,000 dwellings qualify for the discount.

Currently, PEC utilizes the ENERGY STAR standard for new applications for the energy conservation discount. ENERGY STAR is the national symbol for energy efficiency. It is a partnership between the DOE, the U.S. Environmental Protection Agency (EPA), local utilities, product manufacturers, and retailers. Homes built with this label are at least 30% more efficient than the national Model Energy Code, have greater value, lower operating costs, increased durability, comfort, and safety. Features of an Energy Star Home include:

- Improved insulation
- Advanced windows
- Tightly-sealed ducts
- High-efficiency heating and cooling
- Reduced air infiltration

Homes that pass an ENERGY STAR test receive a certificate as well as a 5 percent discount on energy and demand portions of their electric bills. Builders receive training in building energy efficient homes, and a means of differentiating their product on the market place.

Energy Efficiency Financing Program

The *Energy Efficiency Financing Program* offers low-interest loans so that customers can purchase heating and cooling systems, storm windows and doors, insulation and other cost-effective home improvements. Progress Energy sponsors the program which is administered by Volt VIEWtech in California, and dealer screening is performed by Smart Consumer Services of Asheville, North Carolina.

Large Load Curtailment:

Progress Energy Carolinas utilizes three tariffs whereby industrial and commercial customers receive discounts for PEC's ability to curtail system load during times of high energy costs

and/or capacity constrained periods. Currently, there are 317 MW of curtailable load under these tariffs on PEC's system.

Voltage Control:

This procedure involves reducing distribution voltage by up to 5 percent during periods of capacity constraints and can reduce peak load requirements about 57 MW. Typically, this level of reduction does not adversely impact customer equipment or operations.

Renewables:

Progress Energy Carolinas is involved in several renewable energy activities.

Biodiesel Fuel

PEC supports the North Carolina Triangle J Council of Government's biodiesel initiative by fueling some of Progress Energy's trucks at two biodiesel fueling stations in Wake County, N.C. – one in Garner and one in Cary.
Biodiesel is a fuel that can be used in any diesel vehicle with no modifications. It is produced from organic feed stocks such as soybeans, cooking oil and animal fats.

Cogeneration:

Progress Energy Carolinas purchases electricity from 30 cogenerators or small power producers. Twenty-three (23) of these utilize renewable resources to produce all or a part of the energy sold to PEC. These renewable resources include solar, biomass, hydro, wood, and refuse.

In addition, PEC is also aware of 17 customers with customer-owned generation with a generation capacity of 361 MW, which serves a portion of their electrical load.

State-Owned Utility

Santee Cooper (South Carolina Public Service Authority)

Demand Side Management Activities

Good Cents New and Improved Home Program
The Good Cents Program provides residential customers an incentive to build new homes to higher levels of energy efficiency and improve existing homes by upgrading heating and air conditioning equipment and the thermal envelope to high energy efficiency standards. All homes are evaluated to determine if they meet the standards set for the program. Inspections are completed during construction for new homes and at the completion of construction for new and improved homes. Participants are eligible for an incentive rate.

H_2O Advantage Water Heating Program

H_2O Advantage is a storage water heating program designed to shift the demand related to water heating off-peak. This is accomplished with the installation of an electronic timer or radio controlled switch on an 80-gallon water heater. This program began in 1990 and was offered for the last time in 2000. The contract spans ten years so this program will no longer be impacting the system after 2010.

Commercial Good Cents

Commercial Good Cents is offered to commercial customers building new facilities that improve the efficiency in the building thermal envelope, heating and cooling equipment, and lighting. Commercial customers that meet program standards are given an up-front rebate to encourage participation in the program.

Thermal Storage Cooling Program

The Thermal Storage Cooling Program shifts energy used by commercial customers for air conditioning from peak to off-peak hours by utilizing thermal energy stored in a medium such as ice or water. Rebates are offered to customers who install this type of equipment.

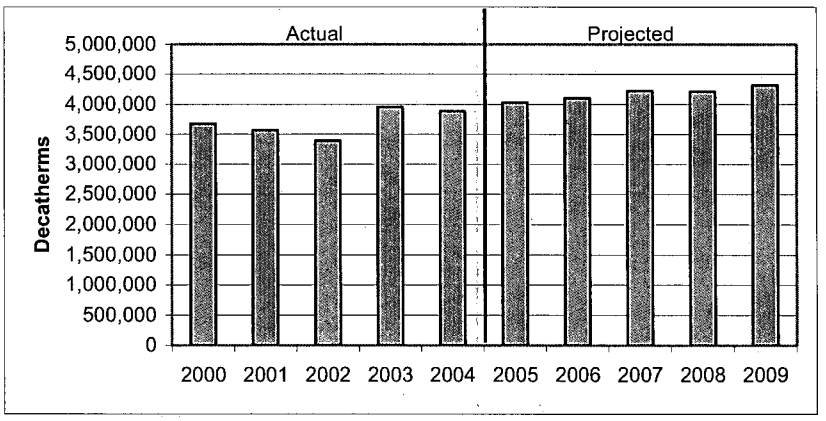
II. Natural Gas

As discussed in the electricity section, the basic purpose of demand-side activities is to change energy-use decisions of customers in ways that are beneficial to both the customers and the utility itself. Whereas electric utilities must meet their load instantaneously, natural gas suppliers have the ability to store gas and use interruptible contracts to maintain reliability. There are two categories of demand-side activities for natural gas: conservation and load management programs.

Annual Peak System Demand

Of the ten natural gas utilities submitting data, Clinton-Newberry Natural Gas Authority had the highest annual peak system demand with 1,493,906 decatherms in 2004. Figure 10 illustrates that from 2000 to 2004, peak demand increased by 5.8 percent, and an increase of 11.2 percent is projected from 2004 to 2009.

Figure 10. Annual Peak System Demand (Decatherms)



Total Annual System Data and Customers

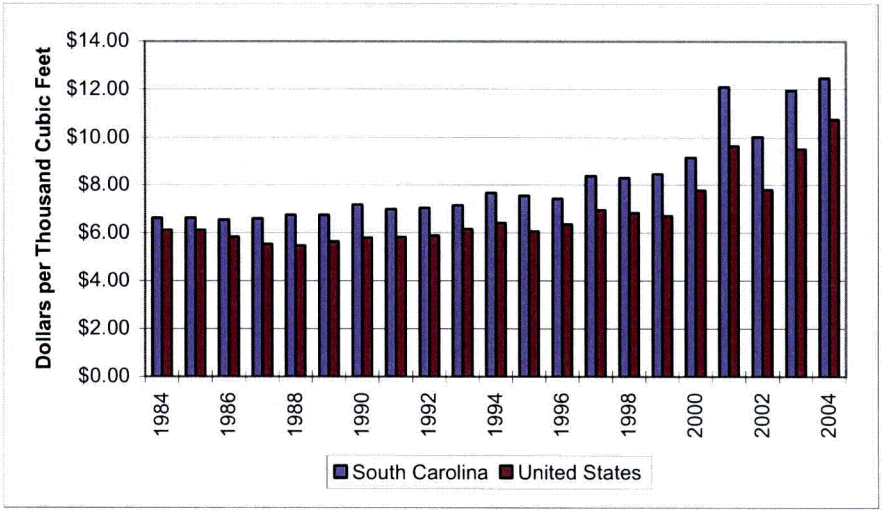
From 2000 to 2004, the total annual system consumption of natural gas in decatherms, decreased by 4.2 percent, but is projected to increase by 13.6 percent through 2009. In 2004, SCE&G accounted for 46.3 percent of the total natural gas sold to customers as indicated by the reporting entities, followed by Piedmont Natural Gas Company with 28.1 percent.

According to data submitted for the survey, the total number of natural gas customers for all classes (residential, commercial, and industrial), rose by 10.8 percent from 2000 to 2004, and projected numbers show an increase of 11 percent through 2009. In 2004, SCE&G comprised 53.2 percent of all natural gas customers, with Piedmont Natural Gas Company accounting for 23.1 percent.

Supplemental Natural Gas Findings

Since only 26 percent of South Carolina households use natural gas for heating, the price has been historically higher than the national average. South Carolina natural gas prices rose by $5.84 per thousand cubic feet from 1984 to 2004 in the residential sector, as compared with $4.62 for the U.S. average. The average annual cost per residential natural gas customers in South Carolina is $622.19.

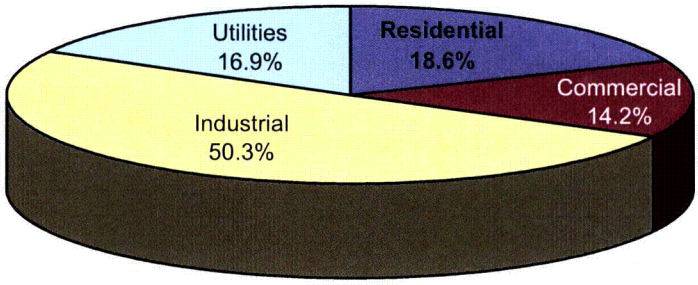
Figure 11. Average Price Comparison of Natural Gas Delivered to South Carolina and U.S. Residential Customers, 1984-2004



Source: Energy Information Administration, *Natural Gas Price* database.

Figure 12 shows the natural gas distribution by end-use sector, and clearly specifies that the industrial sector is the largest consumer of this fuel source. When broken down for average consumption per consumer in thousand cubic feet, the industrial sector leads with 50,068, followed by the commercial sector with 400, and the residential sector with 56.

Figure 12. Distribution Proportion of Natural Gas to End-Use Customers, 2004



Source: Energy Information Administration, *Natural Gas Monthly*.

Appendix A. 2004 Demand-Side Management Survey Participants

Electric Utilities

Abbeville, City of
Aiken Electric Cooperative
Berkeley Electric Cooperative
Black River Electric Cooperative
Broad River Electric Cooperative
Camden, City of
Clinton, City of
Coastal Electric Cooperative
Duke Power Company
Easley Combined Utility System
Edisto Electric Cooperative
Fairfield Electric Cooperative
Gaffney Board of Public Works
Greer Commission of Public Works
Horry Electric Cooperative
Laurens Commission of Public Works
Laurens Electric Cooperative
Lockhart Power Company
Lynches River Electric Cooperative
Marlboro Electric Cooperative
McCormick Commission of Public Works
Mid-Carolina Electric Cooperative
Newberry Electric Cooperative
Newberry, City of
Orangeburg Department of Public Utilities
Palmetto Electric Cooperative
Pee Dee Electric Cooperative
Progress Energy (formerly CP&L)
Prosperity, Town of
Rock Hill, City of
Santee Cooper (South Carolina Public Service Authority)
Santee Electric Cooperative
South Carolina Electric & Gas Company
Tri-County Electric Cooperative
Union, City of
Westminster Comm. of Public Works
Winnsboro, Town of

Natural Gas Utilities

Blacksburg, Town of
Chester County Natural Gas Authority
Clinton-Newberry Natural Gas Authority
Fort Hill Natural Gas Authority
Greer Commission of Public Works
Laurens Commission of Public Works
Orangeburg Department of Public Utilities
Piedmont Natural Gas Company
South Carolina Electric & Gas Company
Winnsboro, Town of
York County Natural Gas Authority

Appendix B. Merchant Power Plants

This is a list of merchant power plants that have applied for a Certificate of Operation from the South Carolina Public Service Commission.

Merchant Facility	Application Filing Date	Projected Investment (millions)	Capacity (MW)/ type/fuel (Combined or Simple Cycle)	Docket and Order No./ Date Approved	Location of Facility
Broad River Energy (Calpine)	6-7-99 & 5-19-00	$205 (Approx.)	500/SC 320/SC 820 total Natural Gas	1999-253-E; 1999-671 9-22-99; 2000-754 3-26-01	Gaffney
Columbia Energy (Calpine)	9-22-00	$250	500/CC Natural Gas	2000-487-E; 2001-108 2-6-01	At Carolina Eastman, 10 miles south of Columbia
Greenville Generating (Entergy)	11-13-00	$380	900/SC Natural Gas	2000-558-E; 2001-194 3-28-01	Fork Shoals
GenPower Anderson	3-1-01	$300	640/CC Natural Gas	2001-78-E; 2001-576 8-3-01	Town of Gluck near Anderson
Greenville County Power (Cogentrix)	9-24-01	$450	810/CC Natural Gas	2001-411-E; 2002-120 04-01-02 **(DENIED)**	Fork Shoals
Cherokee Falls Development Company (FPL Energy)	12-21-01	$130	332/SC Natural Gas	2001-504-E; 2002-306 3/26/02	Gaffney
Palmetto Energy Center (Calpine)	12-21-01	$500+	970/CC/SC Natural Gas	2001-507-E; 2003-113 3/5/03 **(WITHDRAWN)**	Fort Mill

Source: South Carolina Office of Regulatory Staff.

Appendix C. Electricity Overall System Totals by Category

	Actual					Projected				
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Total Cooperatives										
Annual Peak System Demand (MW)	2,553.43	2,826.53	2,620.95	3,290.34	2,927.44	3,148.42	3,243.06	3,346.70	3,450.40	3,562.22
Total Annual System MWh	10,889.39	11,129.15	11,681.16	11,884.48	12,532.81	12,901.44	13,296.87	13,701.38	14,123.31	14,554.64
Total Miles of Distribution Line	53,776.9	54,607.6	55,993.0	56,685.2	57,509.4	58,438.0	59,370.0	60,309.0	61,368.0	62,320.0
Total Number of Customers	493,492.0	502,957.0	514,388.0	531,937.0	538,935.0	550,462.0	562,198.0	573,599.0	585,800.0	597,576.0
Total Generation from Qualified Producers (MWh)	0.00	0.00	0.00	0.00	0.00	2.24	2.56	2.86	3.14	3.41
Total Municipalities										
Annual Peak System Demand (MW)	701.66	699.69	733.13	709.29	712.49	717.60	731.24	737.73	745.11	751.84
Total Annual System MWh	3,281.02	3,214.47	3,232.57	2,399.63	2,447.91	3,373.90	3,392.16	3,420.00	3,447.20	3,475.90
Total Miles of Distribution Line	2,864.0	2,956.0	3,001.0	3,036.0	3,085.0	3,111.3	3,121.5	3,165.5	3,206.5	3,243.5
Total Number of Customers (all classes)	119,363.0	121,161.0	123,453.0	124,414.0	125,726.0	126,769.0	128,068.0	130,225.0	132,385.0	134,315.0
Total Generation from Qualified Producers (MWh)	262.56	304.10	371.10	343.00	281.80	282.96	298.15	303.15	303.15	303.15
Progress Energy										
Annual Peak System Demand (MW)	1,368.00	1,327.00	1,383.00	1,343.00	1,237.00	1,390.00	1,410.00	1,440.00	1,460.00	1,480.00
Total Annual System MWh	7,147.60	6,987.29	7,073.07	7,074.09	7,337.38	7,444.00	7,558.00	7,671.00	7,780.00	7,879.00
Total Miles of Distribution Line	8,587.0	8,654.0	8,692.0	8,728.0	8,769.0	8,900.0	9,000.0	9,200.0	9,300.0	9,400.0
Total Number of Customers (all classes)	160,923.0	162,419.0	163,746.0	164,764.0	165,872.0	167,000.0	169,000.0	170,000.0	172,000.0	173,000.0
Total Generation from Qualified Producers (MWh)	628,489.0	623,603.0	639,497.0	637,308.0	646,419.0	692,042.3	703,933.8	370,161.2	287,896.2	277,742.2
Duke Power Company										
Annual Peak System Demand (MW)	4,194.00	4,101.00	4,068.00	3,921.00	4,166.00	4,211.00	4,262.00	4,323.00	4,388.00	4,453.00
Total Annual System MWh	22,482.23	21,396.04	21,346.27	20,613.30	21,041.11	21,095.38	21,160.62	21,424.92	21,748.30	22,070.79
Total Miles of Distribution Line	22,528.0	22,748.0	23,050.0	23,324.0	23,597.0	N/A	N/A	N/A	N/A	N/A
Total Number of Customers (all classes)	492,507.0	510,639.0	503,020.0	498,876.0	530,407.0	539,744.0	549,344.0	559,483.0	569,817.0	580,414.0
Total Generation from Qualified Producers (MWh)	619,027.20	560,509.79	653,519.59	207,848.11	440,592.30	298,700.30	673,829.30	673,829.30	673,829.30	673,829.30
Lockhart Power Company										
Annual Peak System Demand (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Annual System MWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Miles of Distribution Line	505.0	510.0	515.0	520.0	525.0	530.0	535.0	540.0	545.0	550.0
Total Number of Customers (all classes)	6,154.0	6,196.0	6,250.0	6,316.0	6,360.0	6,408.0	6,456.0	6,504.0	6,553.0	6,602.0
Total Generation from Qualified Producers (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Electricity

Overall System Totals by Category

	Actual					Projected				
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Santee Cooper										
Annual Peak System Demand (MW)	1,551.00	1,583.00	1,712.00	1,680.00	1,680.00	1,863.00	1,892.00	1,920.00	1,947.00	1,973.00
Total Annual System MWh	11,003.94	10,986.16	11,570.54	11,515.71	11,633.38	12,420.95	12,531.79	12,641.69	12,746.99	12,851.30
Total Miles of Distribution Line	2,127.0	2,173.0	2,222.0	2,258.0	2,351.0	2,412.0	2,473.0	2,535.0	2,596.0	2,657.0
Total Number of Customers (all classes)	128,548.0	130,930.0	134,332.0	136,484.0	142,405.0	144,653.0	148,475.0	152,232.0	155,937.0	159,616.0
Total Generation from Qualified Producers (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SC Electric & Gas Company										
Annual Peak System Demand (MW)	3,968.00	3,939.00	4,171.00	4,069.00	4,347.00	4,379.00	4,474.00	4,571.00	4,670.00	4,767.00
Total Annual System MWh	20,049.00	19,834.00	20,827.00	20,612.00	21,711.00	21,994.00	22,415.00	22,876.00	23,329.00	23,785.00
Total Miles of Distribution Line	20,342.0	20,614.0	21,529.0	21,964.0	22,524.0	N/A	N/A	N/A	N/A	N/A
Total Number of Customers (all classes)	523,555.0	537,263.0	560,227.0	570,419.0	584,654.0	594,864.0	607,563.0	618,657.0	629,854.0	640,839.0
Total Generation from Qualified Producers (MWh)	22,716.00	19,370.00	20,964.00	26,627.00	29,574.00	N/A	N/A	N/A	N/A	N/A
TOTALS										
Annual Peak System Demand (MW)	14,336.09	14,476.22	14,688.08	15,012.63	15,069.93	15,709.02	16,012.30	16,338.43	16,660.51	16,987.06
Total Annual System MWh	74,853.18	73,547.10	75,730.61	74,099.22	76,703.58	79,229.67	80,354.43	81,734.98	83,174.80	84,616.63
Total Miles of Distribution Line	110,729.9	112,262.6	115,002.0	116,515.2	118,360.4	73,391.3	74,499.5	75,749.5	77,015.5	78,170.5
Total Number of Customers (all classes)	1,924,542	1,971,565	2,005,416	2,033,210	2,094,359	2,129,900	2,171,104	2,210,700	2,252,346	2,292,362
Total Generation from Qualified Producers (MWh)	1,270,494.8	1,203,786.9	1,314,351.7	872,126.1	1,116,867.1	991,027.8	1,378,063.8	1,044,296.5	962,031.8	951,878.1

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Shibaki 2003

Geothermal Energy for Electric Power

A REPP Issue Brief

December 2003

By Masashi Shibaki
Fredric Beck, Executive Editor

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Geothermal Energy for Electric Power

A REPP Issue Brief

By Masashi Shibaki
With Fredric Beck, Executive Editor*

December 2003

FORWARD

This paper provides a general background on utility-scale geothermal power and seeks to teach the readers a basic understanding of geothermal power, as well as build a solid foundation for further understanding of the technical, economic, and policy dimensions of geothermal power worldwide. Economic data and current U.S. geothermal policy help illustrate the concepts of this paper. Readers may refer to the extensive references to reports and Web links to well-established geothermal energy sources, at the end of this brief to learn the latest developments in geothermal power's role in clean energy generation.

INTRODUCTION

Geothermal[1] energy is energy derived from the heat of the earth's core. It is clean, abundant, and reliable. If properly developed, it can offer a renewable and sustainable energy source. There are three primary applications of geothermal energy: electricity generation, direct use of heat, and ground-source heat pumps. Direct use includes applications such as heating buildings or greenhouses and drying foods, whereas ground source heat pumps are used to heat and cool buildings using surface soils as a heat reservoir. This paper covers the use of geothermal resources for production of utility-scale electricity and provides an overview of the history, technologies, economics, environmental impacts, and policies related to geothermal power.

GEOTHERMAL RESOURCES

Understanding geothermal energy begins with an understanding of the source of this energy—the earth's internal heat. The Earth's temperature increases with depth, with the temperature at the center reaching more than 4200 °C (7600 °F). A portion of this heat is a relic of the planet's formation about 4.5 billion years ago, and a portion is generated by the continuing decay of radioactive isotopes. Heat naturally moves from hotter to cooler regions, so Earth's heat flows from its interior toward the surface.[2]

Because the geologic processes known as *plate tectonics*, the Earth's crust has been broken into 12 huge plates that move apart or push together at a rate of millimeters per

* The authors would like to thank Karl Gawell and Diana Bates of the Geothermal Energy Association for circulating this paper for peer review and for providing valuable comments, and Kelly Ross and Leona Kanaskie of REPP for technical editing of the document.

year. Where two plates collide, one plate can thrust below the other, producing extraordinary phenomena such as ocean trenches or strong earthquakes. At great depth, just above the down going plate, temperatures become high enough to melt rock, forming magma.[3] Because magma is less dense than surrounding rocks, it moves up toward the earth's crust and carries heat from below. Sometimes magma rises to the surface through thin or fractured crust as lava.

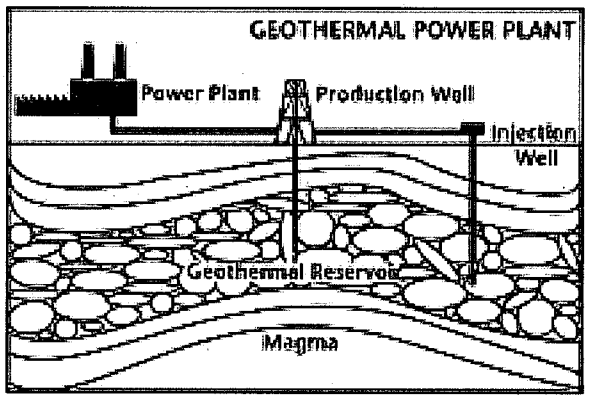


Figure 1. Schematic of geothermal power plant production and injection wells.

Source: U.S. Department of Energy
http://www.eia.doe.gov/kids/renewable/geothermal.html

However, most magma remains below earth's crust and heats the surrounding rocks and subterranean water. Some of this water comes all the way up to the surface through faults and cracks in the earth as *hot springs* or *geysers*. When this rising hot water and steam is trapped in permeable rocks under a layer of impermeable rocks, it is called a *geothermal reservoir*. These reservoirs are sources of geothermal energy that can potentially be tapped for electricity generation or direct use. Figure 1 is a schematic of a typical geothermal power plant showing the location of magma and a geothermal reservoir.[4] Here, the production well withdraws heated geothermal fluid, and the injection well returns cooled fluids to the reservoir.

Resource Identification

Geological, hydrogeological, geophysical, and geochemical techniques are used to identify and quantify geothermal resources. *Geological and hydrogeological studies* involve mapping any hot springs or other surface thermal features and the identification of favorable geological structures. These studies are used to recommend where production wells can be drilled with the highest probability of tapping into the geothermal resource. *Geophysical surveys* are implemented to figure the shape, size, depth and other important characteristics of the deep geological structures by using the following parameters: temperature (thermal survey), electrical conductivity (electrical and electromagnetic methods), propagation velocity of elastic waves (seismic survey), density (gravity survey), and magnetic susceptibility (magnetic survey).[5] *Geochemical surveys* (including isotope geochemistry) are a useful means of determining whether the geothermal system is water or vapor-dominated, of estimating the minimum temperature expected at depth, of estimating the homogeneity of the water supply and, of determining the source of recharge water.

Geothermal exploration addresses at least nine objectives:[6]

1. Identification of geothermal phenomena
2. Ascertaining that a useful geothermal production field exists
3. Estimation of the size of the resource
4. Classification of the geothermal field
5. Location of productive zones

6. Determination of the heat content of the fluids that will be discharged by the wells in the geothermal field
7. Compilation of a body of data against which the results of future monitoring can be viewed
8. Assessment of the pre-exploitation values of environmentally sensitive parameters
9. Determination of any characteristics that might cause problems during field development

Drilling

Once potential geothermal resources have been identified, exploratory drilling is carried out to further quantify the resource. Because of the high temperature and corrosive nature of geothermal fluids, as well as the hard and abrasive nature of reservoir rocks found in geothermal environments, geothermal drilling is much more difficult and expensive than conventional petroleum drilling. Each geothermal well costs $1–4 million to drill, and a geothermal field may consist of 10–100 wells. Drilling can account for 30–50% of a geothermal project's total cost.[7] Typically, geothermal wells are drilled to depths ranging from 200 to 1,500 meters depth for low- and medium-temperature systems, and from 700 to 3,000 meters depth for high-temperature systems. Wells can be drilled vertically or at an angle. Wells are drilled in a series of stages, with each stage being of smaller diameter than the previous stage, and each being secured by steel casings, which are cemented in place before drilling the subsequent stage. The final production sections of the well use an uncemented perforated liner, allowing the geothermal fluid to pass into the pipe. The objectives of this phase are to prove the existence of an exploitable resource and to delineate the extent and the characteristics of the resource. An exploratory drilling program may include shallow temperature-gradient wells, "slim-hole" exploration wells, and production-sized exploration/production wells. Temperature-gradient wells are often drilled from 2–200 meters in depth with diameters of 50–150 mm. Slim-hole exploration wells are usually drilled from 200 to 3000 meters in depth with bottom-hole diameters of 100 to 220 mm. The size and objective of the development will determine the number and type of wells to be included in exploratory drilling programs.[8]

HISTORY

People have used geothermal resources in many ways, including healing and physical therapy, cooking, space heating, and other applications. One of the first known human uses of geothermal resources was more than 10,000 years ago with the settlement of Paleo-Indians at hot springs.[9] Geothermal resources have since been developed for many applications such as production of electricity and geothermal heat pumps. Prince Piero Ginori Conti invented the first geothermal power plant in 1904, at the Larderello dry steam field in Italy.[10] The first geothermal power plants in the United States were operated in 1960 at The Geysers in Sonoma County, California. Table 1 (below) shows the timeline of the recent history of geothermal energy in the United States.

Table 1. Important Events in the History of Geothermal Energy in the United States[11]

Year	Event
1960	The first large scale geothermal plant was opened and operated at The Geysers in California, with a capacity of 11MW.
1970	The Geothermal Resources Council is formed to encourage the development of geothermal resources worldwide. The Geothermal Steam Act is enacted, providing the Secretary of the Interior with the authority to lease public lands and other federal lands for geothermal exploration and development in an environmentally sound manner. Re-injection of geothermal fluids of spent geothermal fluids back into the production zone began as a means to dispose of wastewater and maintain reservoir life.
1972	The Geothermal Energy Association is formed. The association comprises U.S. companies that develop geothermal resources worldwide for electrical power generation and direct-heat uses. Deep-well drilling technology improvements led to deeper reservoir drilling and access to more resources.
1974	The U.S. government enacts the Geothermal Energy Research, Development and Demonstration (RD&D) Act, instituting the Geothermal Loan Guaranty Program, which provides investment security to public and private sectors using and developing technologies to exploit geothermal resources.
1975	The Energy Research and Development Administration (ERDA) is formed, with the goal of focusing the federal government's energy research. The Division of Geothermal Energy takes over the RD&D program begun in 1974.
1977	The U.S. Department of Energy (DOE) is formed. Hot dry rock geothermal power demonstrated with financial assistance from DOE. Scientists develop the first hot dry rock reservoir at Fenton Hill, New Mexico.
1978	The Public Utility Regulatory Policies Act (PURPA) is enacted. PURPA mandated the purchase of electricity from qualifying facilities (QFs: small power producers using renewable energy sources and cogenerators) meeting certain technical standards regarding energy source and efficiency. PURPA also exempted QFs from both State and Federal regulation under the Federal Power Act and the Public Utility Holding Company Act.
1981	With support from DOE, Ormat successfully demonstrates binary technology in the Imperial Valley of California. The project established the technical feasibility of larger-scale commercial binary power plants. The project is so successful that Ormat repays the loan within a year.
1982	Economic electrical generation begins at California's Salton Sea geothermal field using crystallizer–clarifier technology. The technology resulted from a government/industry effort to manage the high-salinity brines at the site. Geothermal (hydrothermal) electric generating capacity, primarily utility-owned, reached a new high level of 1,000 MW
1989	The world's first hybrid (organic Rankine/gas engine) geopressure-geothermal power plant begins operation at Pleasant Bayou, Louisiana, using both the heat and the methane of a geopressured resource.
1994	DOE creates two industry/government collaborative efforts to promote the use of geothermal energy to reduce greenhouse gas emissions. One effort is directed toward the accelerated development of geothermal resources for electric power generation; the other is aimed toward the accelerated use of geothermal heat pumps.
1995	A DOE low-temperature resource assessment of 10 western states identified nearly 9,000 thermal wells and springs and 271 communities co-located with a geothermal resource greater than 50°C. Worldwide geothermal capacity reaches 6,000 MW
2000	DOE initiates its GeoPowering the West program to encourage development of geothermal resources in the western United States. An initial group of 21 partnerships with industry is funded to develop new technologies.

GEOTHERMAL POWER TECHNOLOGY

Utility-scale geothermal power production employs three main technologies. These are known as dry steam, flash steam and binary cycle systems. The technology employed depends on the temperature and pressure of the geothermal reservoir. Unlike solar, wind, and hydro-based renewable power, geothermal power plant operation is independent of fluctuations in daily and seasonal weather.

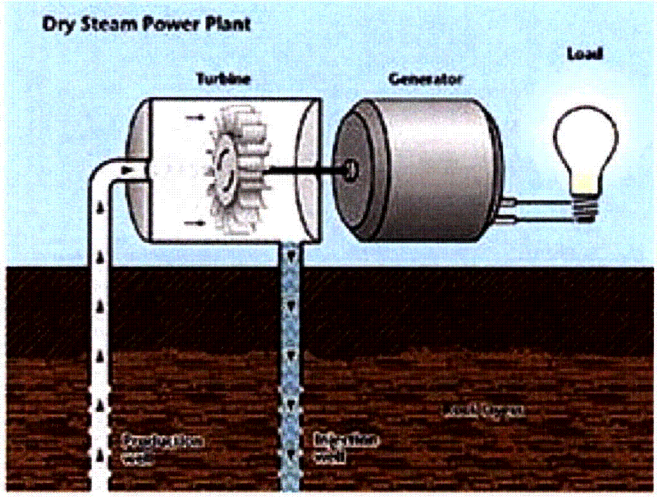


Figure 2. Dry Steam Power Plant Schematic
Source: National Renewable Energy Laboratory (NREL)

Dry steam

Dry steam power plants use very hot (>455 °F, or >235 °C) steam and little water from the geothermal reservoir.[12] The steam goes directly through a pipe to a turbine to spin a generator that produces electricity. This type of geothermal power plant is the oldest, first being used at Lardarello, Italy, in 1904.[13] Figure 2 is a schematic of a typical dry steam power plant.[14]

Flash steam

Flash steam power plants use hot water (>360 °F, or >182 °C) from the geothermal reservoir.[15] When the water is pumped to the generator, it is released from the pressure of the deep reservoir. The sudden drop in pressure causes some of the water to vaporize to steam, which spins a turbine to generate electricity. Both dry steam and flash steam power plants emit small amounts of carbon dioxide, nitric oxide, and sulfur, but generally 50 times less than traditional fossil-fuel power plants.[16] Hot water not flashed into steam is returned to the geothermal reservoir through injection wells. Figure 3 is a schematic of a typical

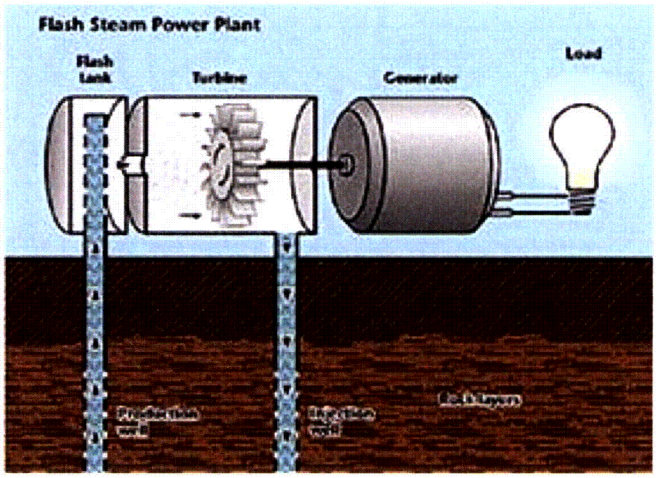


Figure 3. Flash Steam Power Plant Schematic
Source: National Renewable Energy Laboratory (NREL)

flash steam power plant.[17]

Binary-cycle

Binary-cycle power plants use moderate-temperature water (225 °F–360 °F, or 107 °C–182 °C) from the geothermal reservoir. In binary systems, hot geothermal fluids are passed through one side of a heat exchanger to heat a working fluid in a separate adjacent pipe. The working fluid, usually an organic compound with a low boiling point such as Iso-butane or Iso-pentane, is vaporized and passed through a turbine to generate electricity. An ammonia-water working fluid is also used in what is known as the Kalina Cycle. Makers claim that the Kalina Cycle system boosts geothermal plant efficiency by 20–40 percent and reduces plant construction costs by 20–30 percent, thereby lowering the cost of geothermal power generation.

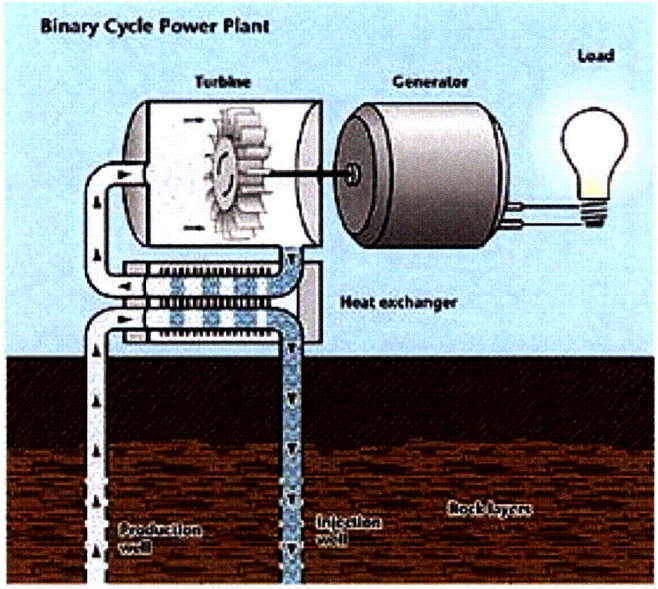


Figure 4. Binary Cycle Power Plant Schematic
Source: National Renewable Energy Laboratory (NREL)

The advantages of binary cycle systems are that the working fluid boils at a lower temperature than water does, so electricity can be generated from reservoirs with lower temperature, and the binary cycle system is self-contained and therefore, produces virtually no emissions. For these reasons, some geothermal experts believe binary cycle systems could be the dominant geothermal power plants of the future. Figure 4 is a schematic of a typical binary cycle power plant.[18]

GEOTHERMAL POWER GENERATION

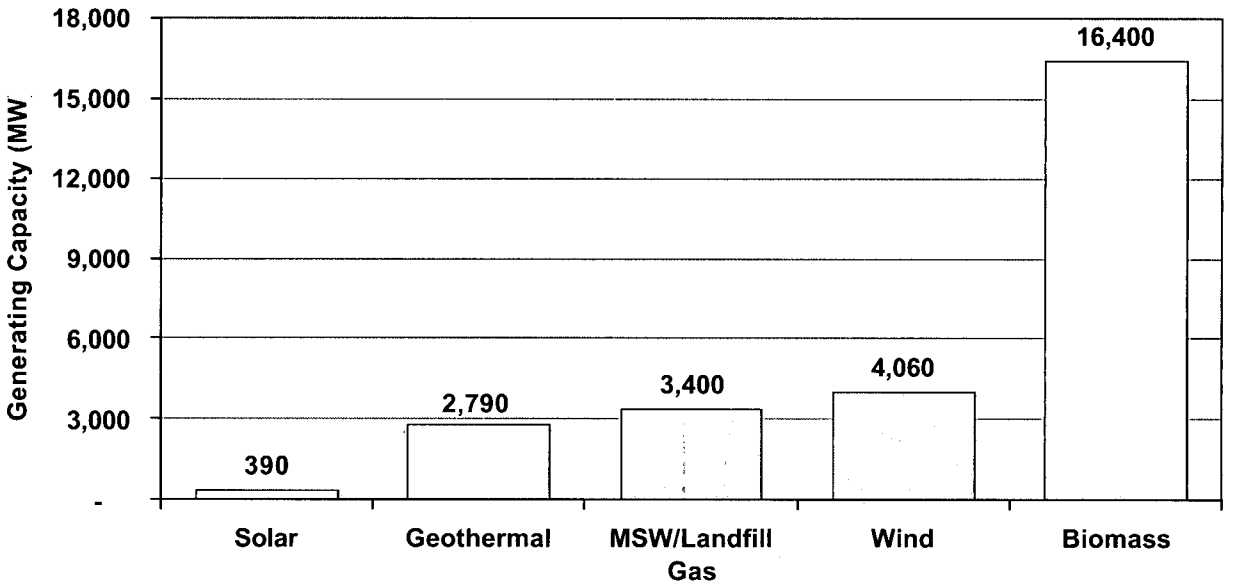
As of 2000, approximately 8,000 megawatts (MW) of geothermal electrical generating capacity was present in more than 20 countries, led by the United States, Philippines, Italy, Mexico, and Indonesia (see Table 2 below). This represents 0.25% of worldwide installed electrical generation capacity. In the United States, geothermal power capacity was 2,228 MW, or approximately 10% of non-hydro renewable generating capacity in 2001 (see Figure 5 below).[19] This capacity would meet the electricity needs of approximately 1.7 million U.S. households.[20]

Current geothermal use is only a fraction of the total potential of geothermal energy. U.S. geothermal resources alone are estimated at 70,000,000 quads[21], equivalent to 750,000-years of total primary energy supply (TPES) for the entire nation at current rates of consumption. The geothermal energy potential in the uppermost 6 miles of the Earth's crust amounts to 50,000 times the energy of all known oil and gas resources in the world.[22] Not all of these resources are technologically or economically accessible, but

tapping into even a fraction of this potential could provide significant renewable resources for years to come. The Geothermal Energy Association reports the potential for developing an additional 23,000 MW of generating capacity in the United States using conventional geothermal energy technology. [23]

Table 2. Installed Geothermal Generating Capacities Worldwide [24]

Country	1995 (MWe)	2000 (MWe)	Country	1995 (MWe)	2000 (MWe)
United States	2,817	2,228	Kenya	45	45
Philippines	1,227	1,909	Guatemala	33	33
Italy	632	785	China	29	29
Mexico	753	755	Russia	11	23
Indonesia	310	590	Turkey	20	20
Japan	414	547	Portugal	5	16
New Zealand	286	437	Ethiopia	0	8
Iceland	50	170	France	4	4
El Salvador	105	161	Thailand	0.3	0.3
Costa Rica	55	142	Australia	0.2	0.2
Nicaragua	70	70	Argentina	0.7	0
Total (MW)				6,833	7,974



Source: EIA Renewable Energy Annual 2001. Biomass excludes agriculture byproducts/crops, sludge waste, tires, and other biomass solids, liquids and gases.

Figure 5. U.S. Non-Hydro Renewable Power Generating Capacity, 2001

Capacity Factor

The percentage of time a power plant runs is the plants *capacity factor*. Geothermal power plants typically produce electricity about 90% of the time, though can be run up to 98% of the time if the contract price of power is high enough to justify increased operational and maintenance costs. In comparison, coal-fired power plants are typically run 65–75% of the time, while nuclear plants in the United States have run at very high capacity factors (95–98%) in recent years due to lucrative market and regulatory conditions.

ECONOMICS

The commercial viability of geothermal power production is influenced by capital costs for land, drilling, and physical plant; operating and maintenance costs; the amount of power generated and sold from the plant; and the market value of that power. However, because geothermal power plants incur high capital costs at the beginning of the project, they are typically at an economic disadvantage to conventional fossil fueled power plants. Fossil fuel plants have lower up-front capital costs, but incur fuel costs for the life of the plant. This section discusses capital cost, operating and maintenance cost, average cost of power production over the life of the plant (known as the levelized cost of power production), as well as the economic impacts of geothermal power such as labor creation, tax base contributions, and balance-of-trade impacts.

Capital Cost

Capital costs are the fixed costs for power plant construction. Geothermal capital costs include the cost of land, drilling of exploratory and steam field wells, and physical plant, including buildings and power-generating turbines. Geothermal plants are relatively capital-intensive, with low variable costs and no fuel costs. The capital cost for geothermal power plants ranges from $1150 to $3000 per installed KW, depending on the resource temperature, chemistry, and technology employed. These costs may decrease over time with additional technology development. Plant lifetimes are typically 30–45 years. Financing is often structured such that the project pays back its capital costs in the first 15 years. Costs then fall by 50–70%, to cover just operations and maintenance for the remaining 15–30 years that the facility operates.[25] Table 3 shows the capital costs for geothermal plants, and Table 4 shows conventional baseload power direct capital costs for comparison.

Operating and Maintenance Cost

Geothermal power plant operating and maintenance costs range from $0.015 to $0.045 per KWh, depending on how often the plant runs. Geothermal plants typically run 90% of the time. They can be run up to 97–98% of the time, but this increases maintenance costs. High run times are found when contractual agreements pay high prices for power. Higher-priced electricity justifies running the plant at high-capacity factors because the resulting higher maintenance costs are recovered. Table 5 provides geothermal operating and maintenance cost by plant size. Large plants tend to have lower O&M costs due to economies of scale. As shown by Table 6, geothermal operating costs of 0.4–1.4 ¢/kWh are within the range of O&M costs of conventional power plants.

Table 3 Geothermal Power Direct Capital Costs (US$1999 /KW installed capacity)[26]

Plant Size	Cost	High-Quality Resource	Medium-Quality Resource
Small plants (<5MW)	Exploration	$400–800	$400–1000
	Steam field	$100–200	$300–600
	Power plant	$1100–1300	$1100–1400
	Total	$1600–2300	$1800–3000
Medium plants (5–30MW)	Exploration	$250–400	$250–600
	Steam field	$200–500	$400–700
	Power plant	$850–1200	$950–1200
	Total	$1300–2100	$1600–2500
Large plants (>30MW)	Exploration	$100–200	$100–400
	Steam field	$300–450	$400–700
	Power plant	$750–1100	$850–1100
	Total	$1150–1750	$1350–2200

Table 4. Conventional Baseload Power Direct Capital Costs

Resource	Capital Cost ($US1999/kW)
Geothermal	$1150–$3000
Hydropower[27]	$735–$4778
Coal[28]	$1070–$1410
Nuclear[29]	$1500–$4000

Table 5. Geothermal Operating and Maintenance Costs by Plant Size (U.S. cents/kWh)[30]

Cost Component	Small plants (<5MW)	Medium plants (5–30MW)	Large plants (>30MW)
Steam field	0.35–0.7	0.25–0.35	0.15–0.25
Power plants	0.45–0.7	0.35–0.45	0.25–0.45
Total	0.8–1.4	0.6–0.8	0.4–0.7

Table 6. Operating and Maintenance Cost Comparison by Baseload Power Source (U.S. cents/kWh)

Resource	O&M Cost (cents/kWh)
Geothermal	0.4 – 1.4
Hydropower[31]	0.7
Coal[32]	0.46
Nuclear[33]	1.9

Levelized Cost

The levelized cost of power production is the average cost of power production over the life of a power plant, taking into account all capital expenses and operating and maintenance costs, as well as fuel costs for power plants that rely on external fuel sources. Major factors affecting geothermal power cost are the depth and temperature of the resource, well productivity, environmental compliance, project infrastructure and economic factors such as the scale of development, and project financing costs.

Real levelized costs for geothermal electricity generation are $0.045-$0.07 per KWh, which is competitive with some fossil fuel facilities, without the pollution.[34] The lowest cost of geothermal electricity is approximately $0.015 per KWh. At the Geysers, power is sold at $0.03 to $0.035 per KWh. Some geothermal power plants can charge more per KWh during some time periods, because of incentives related to reliability of generation and power provided during peak demand. The cost of generating power from geothermal resources has decreased about 25% over the past two decades.[35]

The goal of the geothermal industry and the U.S. Department of Energy is to achieve a geothermal energy life-cycle cost of electricity of $0.03 per KWh. It is anticipated that costs in this range will result in about 10,000 MW of new capacity installed by U.S. firms within the next decade. Table 7 presents the levelized cost comparison of power by source. It shows that in some cases, geothermal energy can compete directly with conventional baseload power sources.

Table 7. Levelized Cost Comparison of Baseload Power by Source

Resource	Levelized Cost[36] (US cents/kWh)
Geothermal	1.5–7.0
Hydropower	0.5–2.4
Coal	2.0–5.0
Nuclear	1.5–3.0

Job Creation

In 1996, the U.S. geothermal energy industry as a whole provided approximately 12,300 direct jobs in the United States, and an additional 27,700 indirect jobs in the United States. The electric generation part of the industry employed about 10,000 people to install and operate geothermal power plants in the United States and abroad, including power plant construction and related activities such as exploration and drilling; indirect employment was about 20,000.[37] Table 8 provides estimates of job creation from renewable energy development based on existing and planned projects in California and the market outlook of project developers and equipment manufacturers. Natural gas is included in the table because the bulk of new nonrenewable generation is expected to rely upon natural gas. The table indicates that geothermal and landfill methane energy generation yields significantly more jobs per MW of installed capacity than do natural gas plants.

Table 8. Employment Rates by Energy Technology[38, 39]

Power Source	Construction Employment (jobs/MW)	O&M Employment (jobs/MW)	Total Employment for 500 MW Capacity (person-years)	Factor Increase over Natural Gas
Wind	2.6	0.3	5,635	2.3
Geothermal	4.0	1.7	27,050	11.0
Solar PV	7.1	0.1	5,370	2.2
Solar thermal	5.7	0.2	6,155	2.5
Landfill Methane/ Digester Gas	3.7	2.3	36,055	14.7
Natural Gas	1.0	0.1	2,460	1.0

Economic Impacts

One of the most important economic aspects of geothermal energy is that it is generated with indigenous resources, reducing a nation's dependence on imported energy, thereby reducing trade deficits. Reducing trade deficits keeps wealth at home and promotes healthier economies. Nearly half of the U.S. annual trade deficit would be erased if imported oil were displaced with domestic energy resources.

Geothermal energy production in the United States is a $1.5-billion-dollar-per-year industry.[40] Nevada's geothermal plants produce about 210 MW of electricity, saving energy imports equivalent to 800,000 tons of coal or 3 million barrels of oil each year. In addition, state governments receive tax revenue. In 1993, Nevada's geothermal power plants paid $800,000 in county taxes and $1.7 million in property taxes. The U.S. Bureau of Land Management collects nearly $20 million each year in rent and royalties from geothermal plants producing power on federal lands in Nevada—half of these revenues are returned to the state.[41]

Economic Impacts in Developing Countries

Nearly half of the developing countries have rich geothermal resources, which could prove to be an important source of power and revenue.[42] Geothermal projects can reduce the economic pressure of developing country fuel imports and can offer local infrastructure development and employment. For example, the Philippines have exploited local geothermal resources to reduce dependence on imported oil, with installed geothermal capacity and power generation second in the world after the United States. In the late 1970s, the Philippine government instituted a comprehensive energy plan, under which hydropower, geothermal energy, coal, and other indigenous resources were developed and substituted for fuel oil, reducing their petroleum dependence from 95% in the early 1970s to 50% by the mid-1980s.[43]

Developing countries will likely require increasing amounts of power in the coming years. Through technology transfer programs, some industrialized countries are helping developing countries make use of their local sustainable and reliable geothermal energy resources.

ENVIRONMENTAL IMPACTS

Geothermal power plants do have some environmental impacts. However, these impacts should be balanced against geothermal energy's advantages over conventional power sources when conducting assessments of power plant project environmental impacts. The primary impacts of geothermal plant construction and energy production are gaseous emissions, land use, noise, and potential ground subsidence.

Gaseous Emissions

Geothermal fluids contain dissolved gases, mainly carbon dioxide (CO_2) and hydrogen sulfide (H_2S), small amounts of ammonia, hydrogen, nitrogen, methane and radon, and minor quantities of volatile species of boron, arsenic, and mercury. Geothermal power provides significant environmental advantage over fossil fuel power sources in terms of air emissions because geothermal energy production releases no nitrogen oxides (NO_x), no sulfur dioxide (SO_2), and much less carbon CO_2 than fossil-fueled power. The reduction in nitrogen and sulfur emissions reduces local and regional impacts of acid rain, and reduction in carbon-dioxide emissions reduce contributions to potential global climate change. Geothermal power plant CO_2 emissions can vary from plant to plant depending on both the characteristics of the reservoir fluid and the type of power generation plant. Binary plants have no CO_2 emissions, while dry steam and flash steam plants have CO2 emissions on the order of 0.2 lb/kWh, less than one tenth of the CO_2 emissions of coal-fired generation (see Table 9). According to the Geothermal Energy Association, improved and increased injection to sustain geothermal reservoirs has helped reduce CO2 emissions from geothermal power plants.

Table 9. Comparison of CO_2 Emissions by Power Source[44]

Power Source	CO_2 Emissions (lb/kWh)
Geothermal	0.20
Natural Gas	1.321
Petroleum	1.969
Coal	2.095

Hydrogen sulfide emissions do not contribute to acid rain or global climate change but does create a sulfur smell that some people find objectionable. The range of H_2S emissions from geothermal plants is 0.03–6.4 g/kWh.[45] Hydrogen sulfide emissions can vary significantly from field to field, depending on the amount of hydrogen sulfide contained in the geothermal fluid and the type of plant used to exploit the reservoir. The removal of H_2S from geothermal steam is mandatory in the United States. The most common process is the Stretford process, which produces pure sulfur and is capable of reducing H_2S emissions by more than 90%.[46] More recently developed techniques include burning the hydrogen sulfide to produce sulfur dioxide, which can be dissolved, converted to sulfuric acid and sold to provide income.

Landscape Impacts and Land Use

Geothermal power plants require relatively little land. Geothermal installations don't require damming of rivers or harvesting of forests, and there are no mineshafts, tunnels, open pits, waste heaps or oil spills. An entire geothermal field uses only1–8 acres per MW versus 5–10 acres per MW for nuclear plants and 19 acres per MW for coal plants.[47]

Table 10 compares acreage requirements by technology. Geothermal power plants are clean because they neither burn fossil fuels nor produce nuclear waste. Geothermal plants can be sited in farmland and forests and can share land with cattle and local wildlife. For example, the Hell's Gate National Park in Kenya was established around an existing 45-MWe geothermal power station, Olkaria I. Land uses in the park include livestock grazing, growing of foodstuffs and flowers, and conservation of wildlife and birds within the Park. After extensive environmental impact analysis, a second geothermal plant, Olkaria II, was approved for installation in the park in 1994, and an additional power station is under consideration.[48]

Table 10. Comparison of Land Requirement for Baseload Power Generation

Power Source	Land Requirement (Acre/MW)
Geothermal	1–8
Nuclear	5–10
Coal	19

Geothermal plants are also benign with respect to water pollution. Production and injection wells are lined with steel casing and cement to isolate fluids from the environment. Spent thermal waters are injected back into the reservoirs from which the fluids were derived. This practice neatly solves the water-disposal problem while helping to bolster reservoir pressure and prolong the resource's productive existence.[49]

Noise

Noise occurs during exploration drilling and construction phases. Table 11 (next page) shows noise levels from these operations can range from 45 to 120 decibels (dBa). For comparison, noise levels in quiet suburban residences are on the order of 50 dBa, noise levels in noisy urban environments are typically 80–90 dBa, and the threshold of pain is 120 dBa at 2,000–4,000 Hz.[50] Site workers can be protected by wearing ear mufflers. With best practices, noise levels can be kept to below 65 dBa, and construction noise should be practically indistinguishable from other background noises at distances of one kilometer.

Ground Subsidence

In the early stages of a geothermal development, geothermal fluids are withdrawn from a reservoir at a rate greater than the natural inflow into the reservoir. This net outflow causes rock formations at the site to compact, particularly in the case of clays and

sediments, leading to ground subsidence at the surface. Key factors causing subsidence include:

- A pressure drop in the reservoir as a result of fluid withdrawal
- The presence of a highly compressible geological rock formation above or in the upper part of a shallow reservoir
- The presence of high-permeability paths between the reservoir and the formation, and between the reservoir and the ground surface

If all of these conditions are present, ground subsidence is likely to occur. In general, subsidence is greater in liquid-dominated fields because of the geological characteristics typically associated with each type of field. Ground subsidence can affect the stability of pipelines, drains, and well casings. It can also cause the formation of ponds and cracks in the ground and, if the site is close to a populated area, it can lead to instability of buildings.

The largest recorded subsidence in a geothermal field was at Wairakei in New Zealand. Here the ground subsided as much as 13 meters. Monitoring has shown that a maximum subsidence rate of 45 cm/year occurred in a small region, outside the production area, with subsidence of at least 2 cm/year occurring all over the production field.[51] Effects of the subsidence in the Wairakei region included:

- The creation of a pond about 1 km in length and 6 m in depth in what was originally a fast-flowing stream;
- Cracking of both a nearby highway and the main waste water drain on the site;
- Compressive buckling and tensile fracturing of steam pipelines;
- Fissures in surroundings fields.

Although Wairakei presents an extreme example, little is currently known about how to prevent or mitigate subsidence effects. The only action is to try to maintain pressure in the reservoir.[52] Fluid re-injection can help to reduce pressure drop and hence subsidence, but its effectiveness depends on where the fluid is re-injected and the permeability conditions in the field. Typically, re-injection is done at some distance from the production well to avoid the cooler rejected waste fluid from lowering the temperature of the production fluid and may not help prevent subsidence.[53]

Table 11. Geothermal Exploration and Construction Noise Levels by Operation[54]

Operation	Noise Level (dBa)
Air drilling	85–120
Mud drilling	80
Discharging wells after drilling (to remove drilling debris)	Up to 120
Well testing	70–110
Diesel engines (to operate compressors and provide electricity)	45– 55
Heavy machinery, e.g. for earth moving during construction	Up to 90

POLICY

Renewable energy can reduce dependence on fossil fuels, reduce harmful pollution from energy production and consumption, and reduce emissions of greenhouse gases. However, most renewables have very different cost structures from conventional energy generating technologies, with high up-front costs and low operating costs. This is true for geothermal energy, which has high exploration and drilling costs in aditional to capital plant expenses. With additional technology development, these costs can be lowered, and geothermal energy can become more cost-competitive with other energy sources.

To spur geothermal technology and market development, the United States has developed policies at the federal and state government level offering a variety of tax incentives for the manufacture, installation, and use of renewables. This section discusses U.S. federal and state policies to promote geothermal energy, as well as policies in other nations with significant geothermal resources.

U.S. Federal Policies

With the oil embargoes and energy crisis of the 1970s, as well as growing environmental awareness, concerns about the United States continued dependence on conventional fossil fuels, as well as energy-related health and environmental hazards were raised. Policies to promote renewable energy and energy efficiency were developed to help decrease the Nation's dependence on fossil fuels and increase domestic energy conservation and efficiency. This section focuses on the some approaches by the U.S. government to encourage the development of geothermal energy, including R&D funding, tax credits, and regulatory policy.

Federal Research and Development (R&D)

Federal energy R&D funding is important for maintaining technological progress in energy development since private industry cannot afford to fully fund, on its own, the continued research required. Energy R&D progress reduces cost, as well as increases energy yields from existing resources. Federal energy R&D includes nuclear, fossil fuel, renewable, energy conservation, and other energy technologies. Many geothermal energy R&D projects are undertaken in conjunction with industry partners and universities to ensure rapid deployment of the new technology into the marketplace.

During the mid-1990s, ongoing deregulation of the electric and natural gas utility industry in the United States, along with lower energy prices, resulted in a significant downturn in the private sector's support for energy R&D. President Clinton, reacting to the trends, asked his Committee of Advisors on Science and Technology (PCAST) to perform an assessment of the U.S. energy R&D effort.[55] As a result of PCAST's energy R&D assessment, a recommendation was made to set aside $51 million for geothermal energy R&D. This proposal included recommendations to expand advanced drilling R&D through the National Advanced Drilling and Excavation Technologies Institute, increase R&D on reservoir testing and modeling, and increase geothermal productivity. However, appropriations for FY'01 only amounted to $26.6 million, less than half of PCAST's recommended funding. As demonstrated in Figure 6, appropriations for

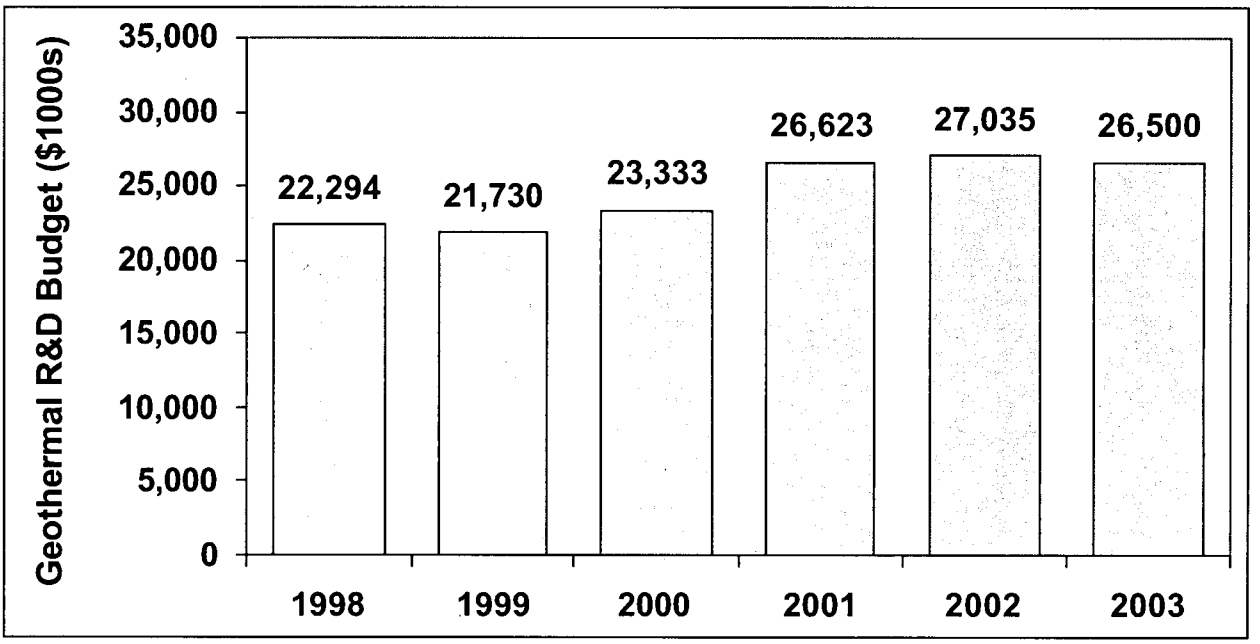


Figure 6. U.S. Geothermal Energy R&D Budget, 1998 – 2003
Source: Department of Energy Office of Budget

geothermal R&D have remained relatively flat from 1998 to 2003, at approximately half of the PCAST recommended level. [56] Increased federal geothermal R&D appropriations would help geothermal energy is to expand to its fullest potential.

Public Utility Regulatory Policies Act (PURPA)
The Public Utility Regulatory Policies Act (PURPA) is one of five statutes of the National Energy Conservation Policy Act of 1978, which sought to decrease the Nation's dependence on foreign oil. The intent of PURPA is to encourage the development of independent, non-utility, fuel-efficient cogeneration plants and small renewable energy power projects by requiring utilities to buy power from such plants at the utility's avoided cost. An avoided cost is that amount that a utility would otherwise have to spend to generate or procure power. As state above, PURPA requires utilities to buy power from two types of independent power producers: (1) small power producers using renewable energy sources; and (2) co-generators. Under PURPA, independent power producers are designated as qualifying facilities (QFs). A QF seeking a small power producer status must produce energy with at least 75 percent of the total energy input provided by renewable energy. A QF seeking co-generator status under PURPA must produce electricity and another form of energy sequentially while using the same fuel source. One of the benefits of PURPA is that it allows a period of fixed payments for both energy and capacity via long-term contracts which then makes a favorable environment for renewables, including geothermal, to obtain financing.

Tax credits
Tax credits are used as a tool to encourage certain behaviors or influence decisions. The U.S. government has been using tax credits to influence energy production decisions for decades. The first energy tax incentives arrived on the scene in 1978 with the passage of

the Energy Tax Act of 1978. Tax incentives have been created, terminated, and reactivated in the United States over the past 20 years. In 1978, the Energy Tax Act extended a 10% business energy tax credit for investments in solar, wind, geothermal, and ocean thermal technologies. In 1986, the Tax Reform Act repealed the 10% business energy tax credit. In 1992, the 10% business energy tax credit returned as a permanent tax credit under the Energy Policy Act, but the credit could only be applied to investments in solar and geothermal equipment.

Other factors influence the ebb and flow of tax credits, such as politics, economics, and energy supply. Variability in the political support of tax incentives creates uncertainly in long-term renewable markets, therefore, making it difficult for developers to maximize the opportunities for development of renewables. However, without tax credits, the penetration of renewable energy, such as geothermal, into the energy production sector would be more difficult. Including geothermal energy under the federal Production Tax Credit (PTC) could provide a significant boost to the geothermal sector.

U.S. State Policies

State governments, in addition to the federal government, have initiated programs and policies to drive the diversification of the nation's energy portfolio by incorporating renewable energy into the energy supply. Identified below are some policy measures that are influencing energy policy decisions at the state level.

Public Benefit Funds

Public Benefit Funds (PBF) are generated from a few sources such as a customer charge on utility bills and new user access fees to fund various public programs. These programs include low-income energy assistance, energy efficiency, consumer energy education, and renewable energy technology development and demonstration. California was the first state to create a PBF. In 1996, California placed a charge on all electricity bills from 1998 through 2001 that would provide $540 million for "new and emerging" renewable energy technologies. As of 2002, at least 24 states have a Public Benefit Fund program in place. See REPP's map of state PBF policies for specific details of these policies at http://www.repp.org/sbf_map.html.

Renewable Portfolio Standards

Renewable Portfolio Standards (RPS) mandate a state to generate a percentage of its electricity from renewable sources or meet a specific renewable capacity requirement. Each state has a choice of how to fulfill this mandate using a combination of renewable energy sources, including wind, solar, biomass, geothermal, or other renewable sources. As of 2002, 12 states have adopted an RPS as part of their restructuring processes. California, for example, has an aggressive renewable portfolio standard requiring utilities to purchase 20% of their electricity from renewable sources by 2017. In 1999, Texas initiated a capacity-based standard to ensure that 2,000 megawatts (MW) of new generating capacity from renewable energy technologies be installed by 2009. Geothermal energy will most likely help fulfill RPS requirements in western states where geothermal energy is more prevalent. See REPP's map of state RPS policies for specific details of these policies at http://www.repp.org/rps_map.html.

Policies in Other Nations

The Philippines, the world's second largest user of geothermal energy for power generation, provides an example of several incentives to attract geothermal development. They are as follows:

- Recovery of operating expenses not exceeding 90% of the gross value in any year with carry forward of unrecovered cost
- Service fee of up to 40% of net proceeds
- Exemption from all taxes except income tax
- Income tax obligation paid out of government's share
- Exemption from payment of tariff duties and compensating tax on the importation of machinery, equipment, share parts and all materials for geothermal operation
- Depreciation of capital equipment over a 10-year period
- Easy repatriation of capital equipment investment and remittance of earnings
- Entry of alien technical and specialized personnel (including members of immediate families

According to the Philippine Department of Energy, an additional eight geothermal power plants will come on line from 2003 to 2010. Expected capacity additions during this time total 621 MWe.[57]

FUTURE DEVELOPMENTS

Renewable energy technology is continuously evolving with the goal of reducing risk and lowering cost. The goal of the geothermal industry and the U.S. Department of Energy is to achieve a geothermal energy life-cycle cost of electricity of $0.03 per KWh.[58] To achieve the goal of lowering cost and risk, other types of nontraditional resources and experimental systems are being explored. Among these are hot dry rock resources, improved heat exchangers, and improved condenser efficiency.

Hot Dry Rock

Hot dry rock geothermal technology offers enormous potential for electricity production. These resources are much deeper than hydrothermal resources. Hot dry rock energy comes from relatively water-free hot rock found at a depth of about 4,000 meters or more beneath the Earth's surface. One way to extract the energy is by circulating water through man-made fractures in the hot rock. Heat can then be extracted from the water at the surface for power generation, and the cooled water can then be recycled through the fractures to pick up more heat, creating a closed-looped system. Hot Dry Rock resources have yet to be commercially developed. One reason for this is that well costs increase exponentially with depth, and since Hot Dry Rock resources are much deeper than hydrothermal resources, they are much more expensive to develop. Figure 7 shows the projected capital cost for hot dry rock compared to traditional geothermal power technology from 1996 to 2030. The figure shows that the capital cost of hot dry rock will decrease by almost half in 30 years, but it will still be twice as expensive as other

traditional geothermal technologies. If the technology can evolve to make hot dry rock resources commercially viable, hot dry rock resources are sufficiently large enough to supply a significant fraction of U.S. electric power needs for centuries.

Heat Exchanger Liners

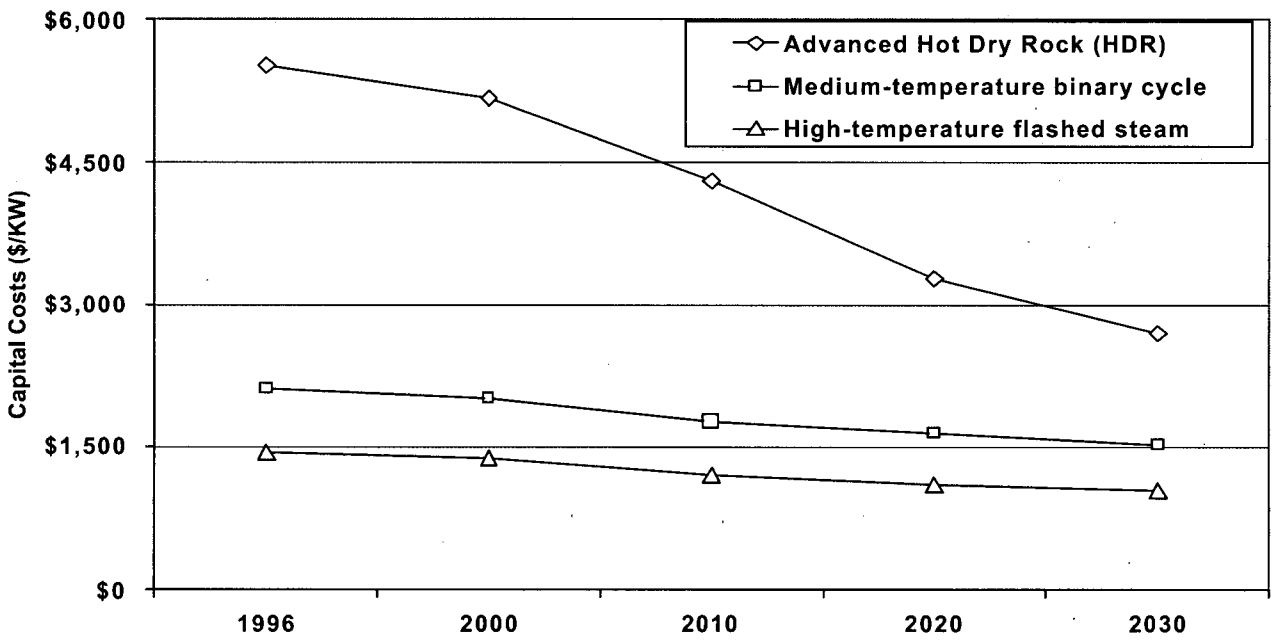
The highly corrosive nature of geothermal plants poses a challenge to heat exchangers by reducing their thermal conductivity. Research is currently being conducted to replace the use of expensive heat exchanger materials, such as stainless steel and titanium, with new, less expensive polymer-base coated carbon steel. The polymer-base-coated carbon steel is proving to be as resistive to corrosion as the conventional, expensive materials. [59]

Air-Cooled Condensers

Currently, the National Renewable Energy Laboratory (NREL) is investigating ways to improve the efficiency of air-cooled condensers that are commonly used in binary-cycle geothermal plants. Air-cooled condensers use large airflow rates to lower the temperature of the gas once it has passed through the system to produce condensation. The fluid is then collected and returned to the cycle to be vaporized. This cycle is

Figure 7

Projected Capital Costs for Hot Dry Rock compared to traditional Geothermal Power Technology, 1996-2030

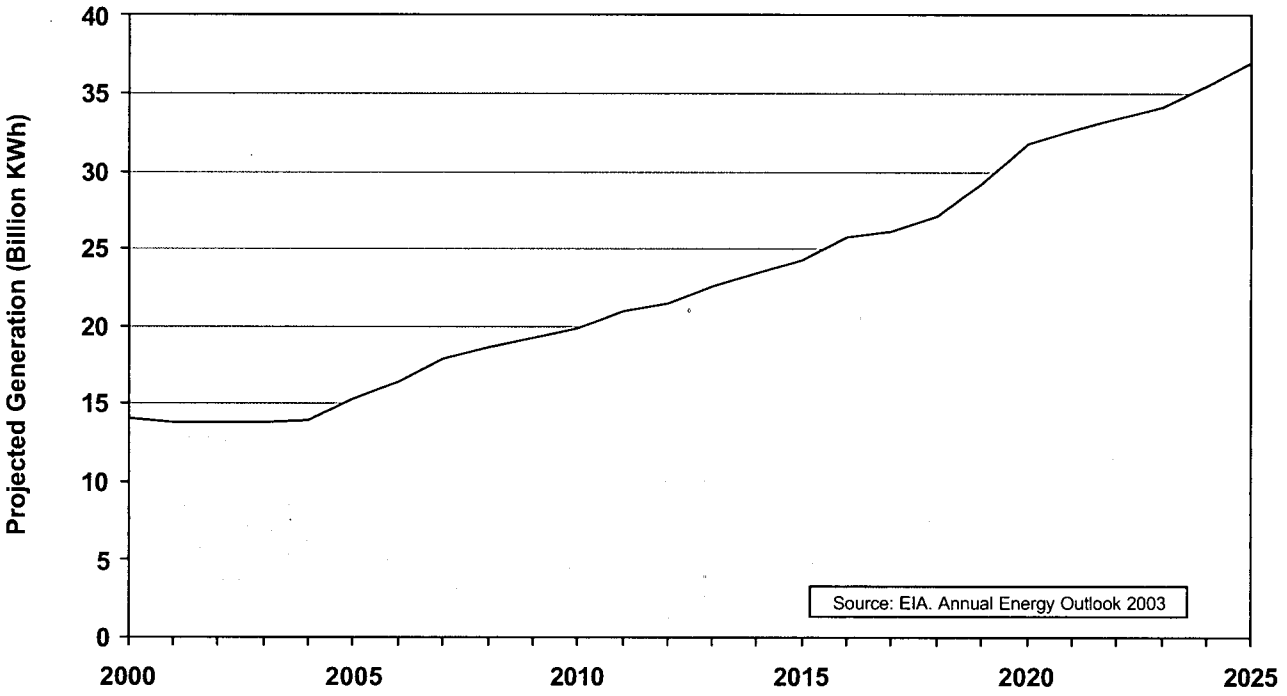


Source: U.S. Department of Energy, 1997.

important in binary-cycle geothermal plants because of the lack of make-up water. To increase the heat exchange efficiency, NREL is currently testing the use of perforated fins in the condensers, with all of the air flowing through the perforations, to increase the heat exchange and therefore, condensation. Initial tests have indicated a 30–40% increase in heat transfer. Such an increase in heat transfer technology could increase the efficiency of future binary-cycle geothermal plants.

As technological improvements continue to be discovered and more geothermal plants are brought online, geothermal generating capacity in the United States will continue to increase. Figure 8 shows projected geothermal power generation under these scenarios and projected generation from Annual Energy Outlook 2002. [60] Installed capacity is likely to increase via new installation, as well as technological improvement leading to increased yield. The U.S. DOE projects that U.S. geothermal generation will increase by over 160% from 2000 to 2025, from 14.1 to 36.9 billion kilowatt-hours per year.

Figure 8. DOE Annual Energy Outlook
Projected Geothermal Generation 2000-2025 (Billion KWh)



CLOSING

Our intention has been to provide the reader with a balanced overview of the utility-scale geothermal power industry. We believe clean, reliable power can be developed from renewable resources, with geothermal power making an important contribution. Examples from the U.S. geothermal sector have been used to illustrate the costs, benefits, policies, and trends in geothermal energy today. What follows is a list or further resources available on the world-wide web to allow the reader to gain a deeper understanding of the potential of geothermal power and the issues surrounding its development. We urge the reader to seek further understanding of these issues, and the means to their resolution, in order to support the progress of geothermal energy in providing clean, reliable, and economic power.

SOURCES OF FURTHER INFORMATION

U.S. Government Programs

U.S. Department of Energy
http://www.eere.energy.gov/geothermal/

National Renewable Energy Laboratory: Geothermal Technologies Program
http://www.nrel.gov/geothermal/geoelectricity.html

International Programs

Philippines Department of Energy
http://www.doe.gov.ph/

The World Bank Group
http://www.worldbank.org/html/fpd/energy/geothermal/

Industry Associations

Geothermal Energy Association
http://www.geo-energy.org

Geothermal Resources Council
http://www.geothermal.org

International Geothermal Association
http://iga.igg.cnr.it

Non-Profit Organizations

Marin County Geothermal Education Office
http://www.geothermal.marin.org/

Renewable Northwest Project
http://www.rnp.org/RenewTech/tech_geo.html

Technical Information

University of Utah Energy & Geoscience Institute
http://egi-geothermal.org/

Idaho National Engineering and Environmental Laboratory
http://geothermal.id.doe.gov/

Oregon Institute of Technology
http://geoheat.oit.edu

Geothermal Resource Assessment

Geothermal Energy Research State Maps
http://geothermal.id.doe.gov/maps-software.shtml

United States Geothermal Potential
http://www.eere.energy.gov/geopoweringthewest/geomap.html

Opportunities for Near-Term Geothermal Development on Public Lands in the Western United States (CD-ROM)
http://www.nrel.gov/docs/fy03osti/33105.pdf

US Geothermal Projects and Resource Areas
http://geoheat.oit.edu/dusys.htm

Additional Resources

http://www.geo-energy.org/Links.htm
http://iga.igg.cnr.it/links.php

ENDNOTES

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Table 13: Average Operating Expense for Major U.S. Investor-Owned Electric Utilities 1995 through 1999, 1999 data
[33] Energy Information Administration/ Electric Power Annual 1999 Volume II
Table 13: Average Operating Expense for Major U.S. Investor-Owned Electric Utilities 1995 through 1999, 1999 data
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Natural gas data from CALPIRG Charitable Trust (June 2002) Job Growth from Renewable Energy Development in California. http://www.calpirg.org/reports/renewableswork.pdf Accessed Oct 16,2002
Calculation of total lifetime employment assumes a 30-year power plant lifetime for each technology.
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