Electric Resource Alternatives

This section is designed to provide a brief overview of technology alternatives for electric power generation. It encompasses mature technologies but emphasis is placed on new methods of power generation with near- and mid-term commercial viability.

All data has been gathered from public sources except where noted, and in these instances is non-sensitive PSE data. It should be noted that many data sources are the manufacturers themselves, who may provide optimistic availability, cost, and production figures.

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I. Demand-side Measures (DSM)

A. Energy Efficiency

Energy efficiency is defined as a technology that demonstrates the same performance for a given task as competing technologies, but requires less energy to accomplish the task.

Discretionary Measures

PSE refers to all energy efficiency improvements and upgrades to existing construction as “discretionary measures.” This may include bringing building components up to or beyond code levels, or the early replacement of existing technologies such as lighting or appliances. Similar measures exist for new construction, and are discussed below under Lost Opportunities.

Lost Opportunity

Lost opportunities refer to the moment when a customer is making a decision about acquiring new equipment. Once the purchasing decision is made, there will not be another opportunity to influence the decision towards an energy efficient technology. When new buildings are being built, the construction phase is the best time to install the most efficient measures. Also, when a customer needs to purchase new equipment, savings can be gained by purchasing high-efficiency models.

Lighting

Switching from highly inefficient incandescent lighting to fluorescent lighting can result in significant savings. Lighting measures for typical household applications are categorized by use: low (1 hr/day), medium (2.5 hr/day), and high (4 hr/day) represent frequency of use.

Heating, Ventilation, and Air-Conditioning (HVAC)

Measures associated with the HVAC system improve the overall heating and cooling loads on a building. They include both lost opportunity measures, such as a high efficiency DX cooling package, as well as discretionary measures such as programmable thermostats. Discretionary measures can impact all types of cooling or heating equipment.

Building Envelope

"Building envelope" measures improve the thermal performance of a building's walls, floor, ceiling or windows. The baseline technology and the energy efficiency upgrades are discussed below. Building envelope energy efficiency measures include insulation (ceiling/roof, wall, and floor) and windows.

Domestic Hot Water

In addition to a more efficient water heating system, any equipment measures that require less hot water are also included in the domestic hot water measures below.

Plug Load

ENERGY STAR® rated plug-in loads reduce the overall electric load of a household compared to standard equipment. This measure identifies the specific plug-in equipment. The following list includes both typical household entertainment equipment and home-office equipment. Office equipment such as computers, monitors, and printers can all be ENERGY STAR® classified, indicating lower energy use than conventional equipment. Savings is achieved, in part, because the machine is equipped with a standby mode.

B. Fuel Conversion

When customers switch from electricity to natural gas, particularly in the case of space and water heating, electrical savings are gained from the reduction in electrical energy use.

Fuel conversion measures, specifically water heaters, space heaters, zone heaters, ranges and dryers, fall under the Lost-Opportunity Equipment category, as described above.

C. Distributed Generation

Distributed generation refers to small-scale electricity generators located close to the source of the customer's load.

Non-renewable Distributed Generation

Combined Heat and Power. Combined heat and power (CHP) plants are a more energy-efficient use of non-renewable generation units. A CHP starts with a standard non-renewable generator, but improves the overall utility by capturing the waste heat produced by the generator. For example, a typical spark-ignition engine has an electrical efficiency of only about 35%. The “lost” energy is primarily waste heat. A CHP unit captures much of this waste heat and uses it for space heating or domestic hot water. Thus, there are cost savings for the water heating in addition to electricity generation. Three-engine generator technologies are considered for use with CHP: reciprocating engines, micro-turbines and fuel cells.

Renewable Distributed Generation

Renewable generation encompasses all generation that uses a renewable energy source for the fuel; in other words, a fossil fuel is not consumed. There are two main categories of renewable generation: biomass and clean energy.

Biomass. Sometimes referred to as “resource recovery,” biomass is used as the fuel to drive a generator. The source of the biomass can vary, but can be broadly categorized into “industrial biomass” or “anaerobic digesters.”

Clean Energy. Generation that is achieved without the consumption of a hydrocarbon fuel. The two main sources for clean energy are wind and solar photovoltaics (PV).

D. Demand Response

Demand-response (or demand-responsive) resources are comprised of flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility’s supply cost. Acquisition of demand-response resources may be based on either reliability considerations or economic/market objectives. Objectives of demand response may be met through a broad range of price-based (e.g., time-varying rates and interruptible tariffs) or incentive-based (e.g., direct load control, demand buy-back, and dispatchable stand-by generation) strategies. In this assessment, we considered five demand-response options: Direct Load Control, Critical Peak Pricing, Curtailable Rates, Demand Buyback and Distributed Standby Generation.

II. Solar Energy

Solar energy is the direct harnessing of the sun's energy and largely divides itself into the photovoltaic and thermal segments. Although the technology has been around for several decades, it is an emerging technology today in terms of cost and commercial maturity.

A. Photovoltaics

Description of Technology

Photovoltaic (PV) cells directly convert sunlight into electricity and represent the overwhelming majority of installations. PV currently comes in two major types, crystalline silicon and thin-films.

While the price of crystalline silicon PV has increased over the last couple of years due to competition for high-grade silicon with microchips, thin-film prices have fallen. Thin-film costs are approximately 50 cents per watt less than multi-crystalline. Thin-film panels are flexible, light-weight and non-glossy, resulting in their preferred use for building integrated photovoltaics.

Silicon panels remain more efficient than thin-films and thus have roughly half the footprint for the same power output. Thin-film panels have had a reputation for degrading performance over time, but now both technologies will come with manufacturer warranties guaranteeing their power curve for 20 to 25 years. Both types of PV panels generate DC power and require an inverter to switch to AC power, typically with 80% efficiency.

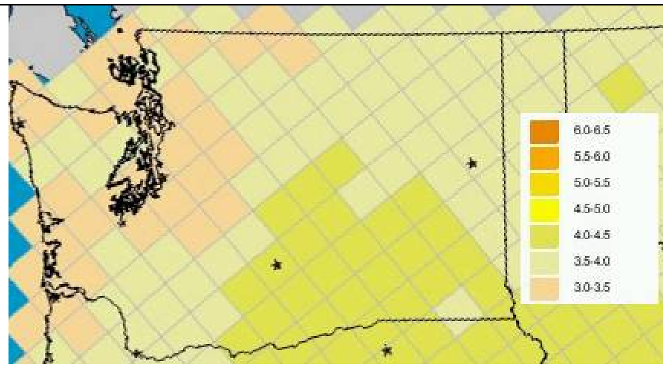
Opportunities in Puget Sound Region

In the Seattle area, average sunlight is around 3.6 kWh / m^2 / day (11% CF), contrasting with the eastern half of Washington where sunlight is significantly better at around 4.7 kWh / m2 / day (15% CF).[1]

[1] PV Watts, flat plate fixed at latitude for Seattle and Yakima and Frank Vignola, Univ. of Oregon

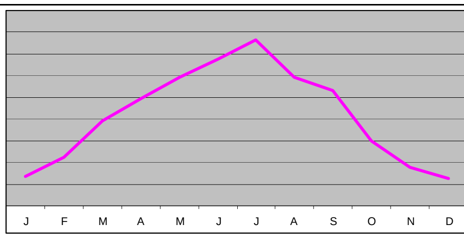
Figure D-1
Sunlight Averages for Washington State

Currently, solar projects are not eligible for Production Tax Credits, but are eligible for a 30% Investment Tax Credit provided that the solar assets are not "utility property." The 30% ITC reverts to a 10% ITC after 2008. Washington state recently passed legislation that provides a solar production incentive ranging from $150-$430/MWh but that is capped at $2,000 per project and a total of $25,000 / year.[2] Solar projects receive 5 year MACRS and are exempt from Washington sales tax.

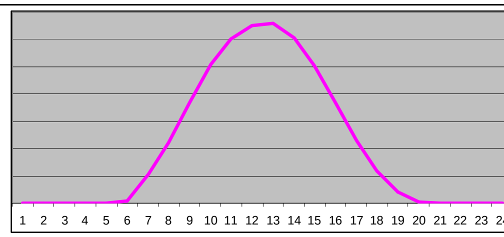


Source: National Renewable Energy Laboratories (NREL)

Figure D-2
Washington State Solar Irradiance



Annual Energy Shape (% by month)



Daily Energy Shape (% by Hour)

Notable Companies

Multi-crystalline Manufacturers: Sharp, Kyocera, BP, SCHOTT, REC, QCell

Thin-Film Manufacturers: Uni-Solar, First Solar, Nanosolar

Developers: Powerlight, SunEdison, URS, SolarWorld

Figure D-3
Solar Photovoltaic Key Metrics

Capital Cost w/o subsidies ($/kW)	Levelized Cost ($/MWh)	Typical Installation Size (kW)	Expected Life (years)
$7,000 – $9,000	$300 - 700	3 – 3,000	20 – 25

[2] DSIRE, http://www.dsireusa.org/

B. Thermal and Concentration Technologies

Technology Description

While solar thermal and concentrating technologies are less mature forms of solar generation, they may offer lower levelized costs in the long term. Generally, these technologies are best suited for commercial or utility scale installations. While there are several different types of solar thermal technology, they share a common characteristic of only being able to utilize direct sunlight, unlike photovoltaics, which can use both direct and diffuse sunlight. This reduces the solar energy they can harness in Washington state by about 30%. All such systems track the sun on at least one axis.

Figure D-4
Solar Thermal and Concentration Technologies

Solar Thermal Troughs - A parabolic mirrored trough concentrates energy onto a receiver pipe to heat oil and transports it to a turbine for power generation. The world's leading 300 MW SEGS facility in California uses solar troughs. Since the SEGS plants were built in the 1980s, no other plants were built until the last two years, when APS and Nevada Power both built a trough system. This technology has the potential to add thermal storage. There have been persistent problems with oil leaking from the receiver pipes at the SEGS facilities and with keeping the mirrors clean and properly focused. The two new systems hopefully resolve these problems.	
Dish-Engine Systems – Dish engine systems are comprised of a dish of mirrors that concentrate sunlight onto an engine or high-efficiency bank of photovoltaic cells. The largest system to date is a bank of six 25 kW dish-engines (total 150kW) at Sandia National Labs. San Diego Gas & Electric and Southern California Edison both signed 500 MW PPA agreements, but it is unclear if the facilities will ultimately be built.	
Concentrating Photovoltaics – Concentrating photovoltaics typically use a plastic lens to focus solar energy on a small PV cell and thus can greatly reduce the number of PV cells needed. The added heat has reduced the efficiency of the cells in some applications. The system pictured here is a 25 kW Amonix concentrating system built in 2006 in Nevada.	

Notable Companies

Manufacturers: Solargenix (formerly Duke Solar), Sterling Energy Systems (SES), Amonix, JX Crystals (local), Infinia (local)

Note that the following figures are still highly academic and based on studies of the technology, not actual commercial experience.

Figure D-5
Solar Trough Key Metrics

	Capital Cost ($/kW)	Levelized Cost ($/MWh)	Typical Installation Size (kW)	Expected Life (years)
Solar Trough[3]	$5,194	$315	25,000	20
Dish-Engine	Unavailable	Unavailable	Unavailable	Unavailable
Concentrating PV	Unavailable	Unavailable	Unavailable	Unavailable

[3] Morse Associates, Inc. for Medicine Hat, Alberta with 5.11 kWh of DNI (Yakima has about 4.0 kWh of DNI). The relationship of power production is less than linear with the solar energy, but as been treated as linear for simplicity.

III. Biomass

The term biomass generally applies to a fuel source (or feedstock) rather than a specific generation technology. Biomass fuels are combustible organic materials which can vary dramatically in form. Biomass fuel sources, as well as the generation technologies, are widely diverse. Biomass fuels include but are not limited to wood residues, spent pulping liquor, agricultural field residues, municipal solid waste, animal manure, and landfill and wastewater treatment plant gas. Biomass resources and power generation technologies are listed in the tables below.

Figure D-6
Biomass Fuel Resources

General Classification Biomass Type	**Brief Description**
Forest Products:	
- Forest Residue - Mill Residue - Pulping Chemical Recovery	- Logging slash and forest thinning - Wood chips, shavings, sander dust and other large bulk wood waste - Spent pulping liquor used in chemical pulping of wood
Agricultural Resources:	
- Crop Residues - Energy Crops - Animal Waste	- Residues obtained after each harvesting cycle of commodity crops - Crops grown specifically for use as feedstocks in energy generation processes, includes hybrid poplar, hybrid willow, and switchgrass - Combustible gas obtained by anaerobic decomposition of animal manure
Urban Resources:	
- Municipal Solid Waste - Landfill Gas / Wastewater Treatment	- Organic component of municipal solid waste - Combustible gas obtained by anaerobic decomposition of organic matter in landfills and wastewater treatment plants

Figure D-7
Biomass Conversion Technology Types[4]

Technology	Conversion Process Type	Major Biomass Feedstock	Energy or Fuel Produced
Direct Combustion	Thermochemical	wood agricultural waste municipal solid waste residential fuels	heat steam electricity
Gasification	Thermochemical	wood agricultural waste municipal solid waste	low or medium-Btu producer gas
Pyrolysis	Thermochemical	wood agricultural waste municipal solid waste	synthetic fuel oil (biocrude) charcoal
Anaerobic Digestion	Biochemical (anaerobic)	animal manure agricultural waste landfills wastewater	medium Btu gas (methane)
Ethanol Production	Biochemical (aerobic)	sugar or starch crops wood waste pulp sludge grass straw	ethanol
Biodiesel Production	Chemical	rapeseed soy beans waste vegetable oil animal fats	biodiesel
Methanol Production	Thermochemical	wood agricultural waste municipal solid waste	methanol

There is a wide array of technologies for converting biomass into power, fuel or heat. New and existing technology for using wood fuel effectively to produce power generation can be generally classified as direct combustion, co-firing, and gasification.

Direct combustion is the oldest and most proven technology. Most of today's biomass power plants are direct-fired systems, similar to most fossil fuel-fired power plants. The biomass fuel is burned in a boiler to produce high-pressure steam. This steam is then introduced into a steam turbine generator. While steam generation technology is very dependable and proven, its efficiency is limited. Biomass power boilers are typically in the

[4] http://egov.oregon.gov/ENERGY/RENEW/Biomass/BiomassHome.shtml

20 to 50 MW range. The small capacity plants tend to be lower in efficiency because of economic trade-offs. Typical plant efficiencies are in the low 20% range.

Co-firing involves substituting biomass for a portion of coal in an existing power plant furnace. It is the most economic near-term option for introducing new biomass power generation. Because much of the existing power plant equipment can be used without major modifications, co-firing is far less expensive than building a new biomass power plant. Compared to the coal it replaces, biomass reduces sulfur dioxide, nitrogen oxides, and other air emissions. After "tuning" the boiler for peak performance, there is little or no loss in efficiency from adding biomass. This allows the energy in biomass to be converted to electricity with the high efficiency (in the 33% to 37% range) of a modern coal-fired power plant.

Gasification is the process of heating wood in an oxygen-starved environment until volatile pyrolysis gases (carbon monoxide and hydrogen) are released from the wood. Depending on the final use of the typically low-energy wood gas, the gases can be mixed with air or pure oxygen for complete combustion and the heat that is produced can be transferred to a boiler for energy distribution. Otherwise, the gases can be cooled, filtered, and purified to remove tars and particulates and used as fuel for internal combustion engines, microturbines, and gas turbines. The use of pure biomass gas in a combustion turbine is in early research. Biomass IGCC and fluidized bed technologies have been experimented with, but they are not yet commercially viable.

Figure D-8
Biomass Power Technology Types[5]

Biomass Type	Technology	Size
Solid Fuels (agricultural, MSW, Forest residue, mill residue)	Direct fired / steam turbine or Direct co-fire with coal	5, 10, 25, 50, 100 (MW) 7.5, 15, 30 (MW)
Biogas/Manure	IC-engine	65, 130, 650 (kW)
Biogas/Landfill	IC-engine	1, 5 (MW)

As shown in Figure D-8 above, biomass generation can range from very small scale to utility scale power production. The diverse biomass fuel types and technology choices make biomass a complex resource to analyze for an electrical generation resource. There are many factors and determinates to consider before choosing biomass

[5] http://www.westgov.org/wga/initiatives/cdeac/Biomass-full.pdf

generation. Providing cost estimates for wood energy systems requires flexibility and a technical understanding that costs fluctuate widely depending on the site requirements and present site capabilities.

Like most combustion technologies, biomass generation's high energy cost is largely driven by the cost of the fuel itself. The technology also has a high capital cost, and is only half as efficient as a combined cycle gas turbine of similar size.

Biomass is a widely distributed resource. Fuel competition and transportation costs typically preclude the construction of power plants of greater than 50 MW capacities. Most future power plants fueled by dry biomass resources are likely to be in the range of 15 to 30 MW. The local market for available supply of wood may limit the benefits of burning wood fuel. Hauling wood biomass from outside a 50-mile radius is usually not economical. A rigorous life-cycle analysis is also necessary to fully understand the fuel supply chain. Initial costs of wood biomass generation facilities are typically 50% greater than that of a fossil fuel generation system due to the fuel handling and storage system requirements.

Biomass power is reliable baseload electric power. Biomass plants cannot easily perform load-following, and cannot be routinely dispatched due to the inherent limitations of a combustion/steam-cycle power plant. The necessity of a larger-sized boiler and the need for a waste-handling plant involve 1.5 to 4 times the investment cost of oil-fired package boilers.

The difficulties of fuel handling, boiler maintenance and ash disposal are labor and equipment intensive. Biomass plants require 10 to 20 times the staff per MW of a natural gas-fueled power plant, including the dedicated fuel infrastructure personnel.

Obvious benefits may be gained by burning wood residues to reduce a manufacturer's fuel oil and electricity bill. These benefits may be offset by high capital costs, low plant efficiency, and increased maintenance levels. Of course, the economics of wood waste energy generation becomes more attractive as traditional fuel prices increase.

There are 45 potential biomass sources in Washington state, according to a December 2005[6], report, "Biomass Inventory and Bioenergy Assessment: An Evaluation of Organic Material Resources for Bioenergy Production in Washington State." Categories included

[6] http://www.pacificbiomass.org/documents/WA_BioenergyInventoryAndAssessment_200512.pdf

field residues, animal manures, forestry residues, food packing/processing waste, and municipal wastes. The report states that Washington has an annual production of over 16.9 million tons of underutilized dry equivalent biomass, which is capable of producing, via assumed combustion and anaerobic digestion, approximately 1,769 MW of electrical power. Looking to just forestry resources (mostly mill residues and pulping recovery) the totals are approximately 945 MW. This study does not consider economic or commercial issues. Therefore, these results seem to be extremely aggressive and the report is based on the absolute potential, not viable or economic potential.

In June 2005, the Energy Trust of Oregon, Inc. received 25 proposals in response to a RFP seeking biomass electrical generation projects[7]. Eligible resources included landfill gas, wood waste from mills or forests, dairy manure, waste gas from sewage treatment, and other biomass sources. The 25 projects totaled 91 MW of gross nameplate capacity.

During PSE's 2004 and 2006 RFP cycles, three proposals for biomass cogeneration totaling 100 MW were received and evaluated. In the last several years, the region has seen the construction of only one biomass facility. Considering the impact of the Washington state RPS and the potential demand for diverse renewable resources, biomass may look more economically attractive as the demand grows.

Additional References:

- http://www.fpl.fs.fed.us/tmu/wood_for_energy/wood_for_energy.html
- http://www.nwcouncil.org/energy/powerplan/plan/Default.htm
- http://www1.eere.energy.gov/biomass/
- http://www.nrel.gov/biomass/
- http://www.eia.doe.gov/oiaf/analysispaper/biomass/
- http://www.calbiomass.org/

[7] http://www.energytrust.org/RR/bio/index.html

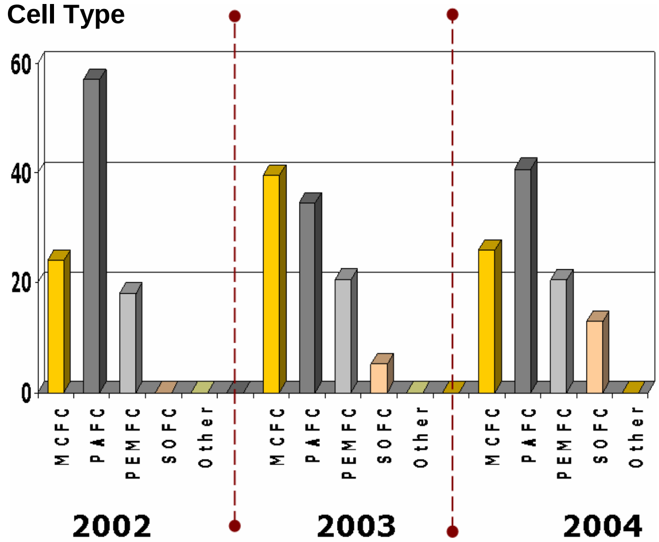
IV. Fuel Cells

Fuel cells have been touted for their potential as an alternative to the internal combustion engine, but are examined here predominantly for their application in stationary power generation. Despite its reputation with many types of renewable technologies, the United States remains a dominant fuel cell developer. The market for large fuel cell generation (>10 kW) is dominated by four types of cells: phosphoric acid, solid oxide, proton membrane exchange and molten carbonate. Prices remain uncompetitive at around $2500 per kW on the low end, although DOE has set a target of $400 per kW by 2010.[8]

A. Phosphoric Acid Fuel Cells (PAFC)

PAFC technology was the first to market and remains the most common. PAFC cells are limited to stationary applications as they are large, heavy, expensive, and slow to start. Their advantages in maturity and lifespan, however, have given PAFC the largest market share in stationary applications. PAFC fuel cells are predominantly manufactured by United Technologies and Fuji.

Figure D-9. New Large Installations by Fuel Cell Type



Source: Fuel Cell Today

B. Proton Exchange Membrane Fuel Cells

PEM fuel cells are generally thought to be the technology of choice for mobile applications, but have more limited roles in stationary situations. PEM fuel cells operate at much lower temperatures and have a long lifespan, but require an expensive platinum catalyst. PEM cells are very sensitive to fuel impurities and require pure hydrogen. Ballard Power Systems of Vancouver, B.C. is a world leader in PEMFC development, although many auto manufacturers also conduct their own PEM research.

[8] DOE http://www.fossil.energy.gov/programs/powersystems/fuelcells/

Ballard recently introduced a stand-alone 1 kW unit for sale in Japan that includes a natural gas reformer and co-generates hot water and power.

C. Molten Carbonate Fuel Cells

Molten carbonate fuel cells (MCFC) operate at much higher temperatures, but also much higher efficiencies than phosphoric acid fuel cells. The higher temperature of molten-carbonate fuel cells functions as an internal reformer and allows it to internally reform a variety of gasses, but also lengthens start-up and shut-down. Among the world's largest MCFCs is a 1 MW, two-year demo plant in Renton, WA at the South Wastewater Treatment Plant. In their 2004 Q4 report, the demo reported efficiencies of 43% to 44% on both natural gas (supplied by PSE) and digester gas from wastewater.[9] The Environmental Protection Agency provided approximately $12.5 million of the $22 million project cost.

D. Solid Oxide Fuel Cells

Solid oxide fuel cells (SOFC) operate at higher temperatures than MCFCs, and accept an even wider variety of fuels.[10] In addition, the high temperature precludes the need for noble metal catalysts, reducing costs.[11] SOFC technology is still in early stages of development but is expected to have an increasingly important role in stationary applications. Figure D-9 shows the number of new large scale fuel cell projects by technology type and the rise of SOFC starting in 2003. Cogeneration systems are particularly attractive with solid oxide cells, due to the high operating temperature. See Figure D-10, next page.

[9] King Country http://dnr.metrokc.gov/wtd/fuelcell/docs/0504_Report-2.pdf
[10] E-sources http://www.e-sources.com/fuelcell/fcexpln.html
[11] CEA, http://www.cea.fr/gb/publications/Clefs44/an-clefs44/clefs4453a.html

Figure D-10
Fuel Cell Operating Temperatures and Efficiencies

Fuel Cell Type	Development Stage	Projected Efficiency (w/ heat recover)	Operating Temp. (°C)	Lifespan (hrs)	Fuels
Phosphoric Acid	Commercial	35%	175-200	40,000 - 60,000	Hydrogen
Proton Exchange Membrane (PEMFC)	Demonstration	35-45%	60-100	40,000	Hydrogen
Molten Carbonate (MCFC)	Demonstration	50% (85%)	600-800	5,000-20,000	Hydrogen Methane Natural Gas
Solid Oxide (SOFC)	R&D	50-60% (80-85%)	600-1000	20,000	Hydrogen Methane Natural Gas

Sources: [12] [13] [14] [15] [16]

[12] DOE, http://www.eere.energy.gov/hydrogenandfuelcells/fuelcells/pdfs/fc_comparison_chart.pdf
[13] Avista Labs, http://www.avistalabs.com/fuelcells_spectr.asp
[14] Exergy, http://www.exergy.se/ftp/cng97fc.pdf
[15] Siemens http://www.siemenswestinghouse.com/en/fuelcells/technology/chp/index.cfm
[16] Dr. Karl Kordesch, http://www.electricauto.com/fc_compare.html

V. Water Based Generation

Water based generation can be broken into four distinct categories; river hydroelectricity, wave energy, tidal energy and ocean thermal conversion.

A. Hydroelectricity

Large scale impoundment and diversion hydroelectricity is the backbone of power generation in the Pacific Northwest. However, large-scale projects are now difficult to build because of their large capital costs, regulatory burdens and environmental concerns.

Smaller scale hydroelectricity, on the other hand, has received attention due to its somewhat smaller implementation barriers. The Department of Energy defines “small” hydropower as generation capacity less than 30 MW, while “micro” hydropower refers to anything less than 100 kW.[17] In one example, Crown Hill Farm in Oregon successfully installed 25 kW of micro-hydro capacity. To do so, they invested $100,000 and dealt with 12 government bureaus over the course of 18 months.[18]

B. Tidal Energy

For the purpose of this brief, river in-stream energy and tidal energy are viewed as equivalent. The Electric Power Research Institute (EPRI) is seeking funding to identify potential river in-stream energy development locations along many major U.S. rivers. In addition, river in-stream energy conversion equipment will likely be quite similar to the tidal energy conversion devices currently under development.

The roots of tidal energy are closely related to the development of wind energy resources. Both technologies rely upon a multi-blade rotor to supply rotational energy to a generator. As with wind turbines, a speed increaser is required due to the physical limitations of the generator size and rotor diameters.

Most tidal energy development appears to be centered on the conventional “open” turbine that is very similar to the contemporary wind turbines: a “ducted” turbine where

[17] DOE, http://www.eere.doe.gov/RE/hydropower.html
[18] Oregen DOE http://egov.oregon.gov/ENERGY/CONS/BUS/docs/CrownHill.pdf

the turbine blades are enclosed within a venturi shape, or a hybrid Gorlov design with its characteristic spiral shaped turbine blades.

Figure D-11
Examples of Tidal Turbine Designs

When compared to wind turbines, tidal energy has two unique advantages: its predictable nature; and the possibility of using smaller rotor diameters for the same power output (owing to the mass flow density differences between air and water.) Tidal generation, however, is not expected to have a significantly greater capacity credit than wind since the load over time will not correlate with high load hours. Tidal currents are also bi-directional, which requires some of these turbine designs to pivot 180º to generate energy when the tidal current reverses its direction on the following tide cycle.

Because commercial scale tidal energy plants consist of multiple units, they could pose a significant risk to marine life. Each unit may incorporate one or more turbines and require its own anchoring and power transmission system, both of which could impact the local aquatic environment. Underwater construction challenges, local and federal permitting processes, and access to grid interconnection points also must be resolved at each tidal energy location before the tidal energy plant can proceed to commercial scale and become viable as a renewable energy resource.

Nationally, EPRI reports that 29 preliminary permits have been filed with the Federal Regulatory Energy Commission (FERC) for tidal energy projects. Of these, FERC has granted preliminary permits to only the Roosevelt Tidal Energy Project by Verdant Power, the San Francisco Bay Project by Golden Gate Energy, and the Tacoma Narrows Project by Tacoma Power.

The Roosevelt Tidal Energy Project near Roosevelt Island, New York, installed the first two of six generating units on December 11 and 12, 2006. One of these units will be used for testing, while the other appears to be performing near or above its expected capacity of 33 kW. Over 5,000 kWh of energy was generated by the second unit and provided to a local supermarket through December of 2006. The deployment of the remaining four units was expected within 90 days of the December 12th installation, following a review of the associated fish monitoring data to reveal the potential impacts to fish in the area.

In accordance with FERC's preliminary permit, Golden Gate Energy recently filed its second six-month progress report on the San Francisco Bay Project.[19] Citing examples of progress in understanding the scope and implementation of required studies, the report referred to a series of meetings with the San Francisco Bay Conservation and Development Commission and Pacific Gas and Electric Company. The report also stated that Oceana—Golden Gate Energy's parent company—has executed an agreement with the U.S. Naval Surface Warfare Center to install a demonstration project in the United States using Oceana's patent pending technology. The test project would be installed within the United States by late 2007 or 2008.

Likewise, Tacoma Power filed its first six-month progress report on July 31, 2006. The utility recently issued an RFP to initiate Phase II activities outlined in its preliminary permit. Among those activities, Tacoma Power must first determine whether to proceed with the installation of a pilot tidal energy unit in the Tacoma Narrows. If appropriate, the utility will then move forward with the necessary site engineering and consultation to address environmental concerns, and secure the necessary permits for the installation of the pilot unit during Phase III. If the pilot unit provides favorable results, Tacoma Power may proceed with its application for a formal FERC permit to install the commercial tidal energy plant. The utility estimates the plant will have an annual energy production of 120,000 MWh.

Currently, nine preliminary permits for various tidal energy locations throughout the Puget Sound area have been issued by FERC or are awaiting approval. Tacoma Power holds the initial preliminary permit granted by FERC for a location within Puget Sound near

[19] Recurring progress reports are a requirement to maintain preliminary permit status.

Point Evans in the Tacoma Narrows. FERC awarded the remaining preliminary permits for the balance of the desirable tidal energy locations throughout Puget Sound to Snohomish County Public Utility District. The locations within the Puget Sound are as follows:

Figure D-12
FERC Preliminary Permits for Tidal Energy Locations within Puget Sound

FERC ID#	Location	Developer	Estimated Annual Output[20]	Equivalent Wind Farm (30% CF)
12687	Deception Pass	Snohomish Co. PUD	20,700 MWh	7.9 MW
12688	Rich Passage	Snohomish Co. PUD	8,560 MWh	3.3 MW
12689	Spieden Channel	Snohomish Co. PUD	32,470 MWh	12.4 MW
12690	Admiralty Inlet	Snohomish Co. PUD	146,200 or 75,600 MWh[21]	55.6 MW
12691	Agate Passage	Snohomish Co. PUD	340 kW[22]	0.3 MW
12692	San Juan Channel	Snohomish Co. PUD	33,270 MWh	12.7 MW
12698	Guemes Channel	Snohomish Co. PUD	28,500 MWh	10.8 MW
12612	Tacoma Narrows	Tacoma Power	120,000 MWh	45.7 MW

A map of the various locations within Puget Sound appears on the next page.

[20] The estimated annual outputs are as reported in the preliminary permit applications submitted to FERC.
[21] The estimated annual output by Snohomish County PUD for the Admiralty Inlet location depends on the transect where the turbines are installed within Admiralty Inlet. The Point Wilson to Admiralty Head transect was estimated at 146,200 MWh and the Bush Point to Nodule Point transect was estimated at 75,600 MWh.
[22] Snohomish County PUD did not report an estimated annual output for the Agate Passage location.

Figure D-13

Puget Sound Tidal Energy Locations with FERC Preliminary Permits

A small, ducted tidal energy device was deployed at an ecological preserve located at the southeastern corner of Vancouver Island in British Columbia. The majority of the funding for this project was provided by EnCana™, a natural gas and oil provider with locations in both Canada and the United States. Pearson College provided the host site for the project, and both the government and parks departments of British Columbia provided the necessary permits. Although the exact size of the tidal power turbine is not clear to us, we do know the turbine was supplied by Clean Current Power Systems, and it charges the batteries used to power a lighthouse and associated buildings, as shown in the following illustration.

Figure D-14
Artist's Rendering of EnCana™ Tidal Project at Vancouver Island

The Electric Power Research Institute's (EPRI) estimated summary of the economics for a full installation at the Tacoma Narrows is provided in Figure D-15. It is important to note that no commercial installations exist and these estimates are highly theoretical.

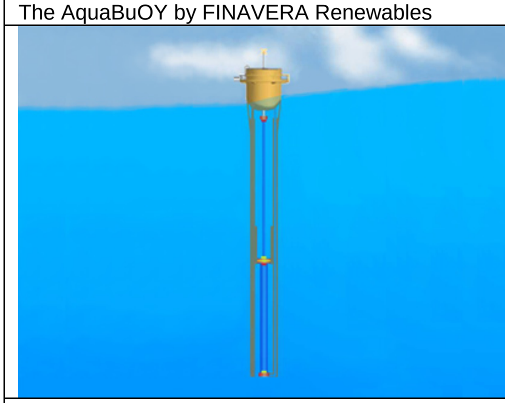
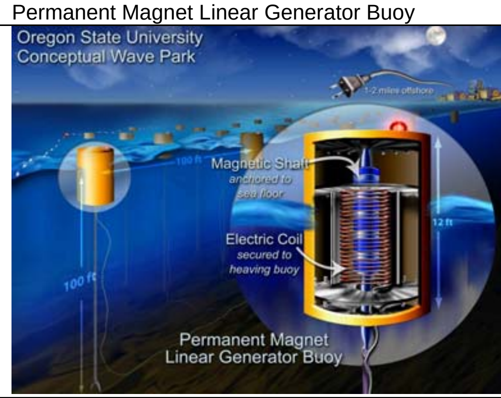
Figure D-15
Tacoma Narrows Tidal Plant Cost Estimates

Capital Cost ($/kW)	Levelized Cost ($/MWh)	Commercial Installation Size (kW)	Expected Life (years)	Typical Capacity Factor
$2,200 / kW	$90	16,000	20	30 %

C. Wave Energy

Wave energy devices appear to be at a much earlier stage of development than tidal devices, thus the range of developmental wave energy equipment is much more diverse. For space considerations, this technical brief focuses on four of these technologies. These include three devices that directly convert the rise and fall of a wave into electrical energy and an air driven power turbine that extracts energy from the airflow caused by oscillating columns of water.

Figure D-16
Examples of Wave Energy Conversion Devices

The AquaBuOY by FINAVERA Renewables	Oregon State University (OSU) Permanent Magnet Linear Generator Buoy
	
The Pelamis Wave Energy Converter by Ocean Power Delivery LTD.	The Land Installed Marine Power Energy Transmitter (LIMPET) by Wavegen®
	

The AquaBuOY, the Permanent Magnet Linear Generator Buoy and the Pelamis devices effectively use the vertical movement of the wave itself to generate electricity.

The AquaBuOY makes use of two hose pumps that alternately produce streams of water that impinge upon a small Pelton style wheel contained within the body of the buoy. The Pelton wheel is connected directly to a small generator where the rotation of the common shaft results in electrical power.

The Permanent Magnet Linear Generator Buoy also rides over the crest of the waves, but uses the vertical motion to move a magnet through the center of a small generator. The movement of the magnet through the copper windings in the core of the generator produces electrical energy each time the buoy rises or falls.

The Pelamis is the most sophisticated and commercially mature of wave energy equipment, as it uses the motion of the waves to pressurize a hydraulic system. Electrical energy is produced as the flow of oil through the hydraulic system rotates hydraulic motors attached to electrical generators. The key features of the Pelamis design are large cylindrical floats that attach directly to the hydraulic rams within a power module. Each power module is located between a pair of floats and the positions of the hydraulic rams within the power module allow the Pelamis device to convert both the vertical and horizontal movement of the floats into electrical energy.

The LIMPET relies upon wave action to initiate airflow through a turbine attached to an engineered structure located at either an on-shore or off-shore location with substantial wave activity. This structure consists of a series of inclined, open chambers with one end submerged in the sea. The wave action results in oscillating water columns inside the structure, that both expel air as the wave impinges upon the structure, then create a vacuum as the water columns drop during the subsequent trough before the next wave arrives. This, in turn, necessitates a bi-directional air driven power turbine to capture the energy of the air as it is both expelled and drawn back into the engineered structure.

Both the AquaBuOY and the Permanent Magnet Linear Generator Buoy have proposed applications within the Pacific Northwest, while the Pelamis and LIMPET devices are installed off of the north coast of Portugal and the Isle of Islay off the west coast of Scotland, respectively. Of these, the Pelamis site in Portugal has the highest reported installed capacity of 2.25 MW, followed by the 500 kW installed capacity of the LIMPET site on the Isle of Islay.

The maximum capacities for both the AquaBuOY and the Oregon State University (OSU) Permanent Magnet Linear Generator are reported to be the same, at 250 kW per buoy. However, the local conditions at each wave energy site heavily impact the expected capacities, as demonstrated by the four unit AquaBuOY pilot plant planned for Makah Bay. It has reported a per buoy capacity of 36 kW, for a total installed capacity of 144 kW. OSU will continue the development of its Permanent Magnet Linear Generator Buoy, and plans to contribute to the development of an open access wave energy park located along the west coast of Oregon. There, both OSU and other manufacturers of wave energy devices will be able to deploy their equipment, measure its power generation, and perform the field testing necessary to perfect their designs and improve efficiency.

Aside from the obvious design differences, it is also important to recognize another distinct difference between tidal energy and wave energy: Unlike tidal currents, which are influenced by the lunar cycle, wave energy is derived from the waves themselves. These waves result from wind acting upon the surface of the sea, local water depth, and sea bed conditions. The wind, being the most variable among these three factors, is also influenced by the combined effects of sunlight and barometric pressure. In this regard, wave energy power production is harder to schedule than tidal power, but will likely have a similar contribution to capacity.

While wave energy technology is perceived to have less potential impact on marine life than its tidal energy counterpart, it still faces similar challenges. As with tidal energy plants, commercial scale wave energy plants will have multiple units, with sophisticated anchoring and power transmission systems. This means each plant will have its own potential impact to the local aquatic environment. Underwater construction challenges, the permitting processes with both local and federal agencies, and access to grid interconnection points must also be resolved at each potential wave energy location before the wave energy plant can proceed to commercial scale and become a viable renewable energy resource.

EPRI's estimated summary of the economics for a full commercial installation off the Oregon Coast using a Pelamis machine is provided in Figure D-17. It is important to note that no commercial installations exist, and these estimates are highly theoretical.

Figure D-17
Pelamis Wave Energy Plant Cost Estimates

Capital Cost ($/kW)	Levelized Cost ($/MWh)	Commercial Installation Size (kW)	Expected Life (years)	Typical Capacity Factor
$2611 / kW	$116/MWh	90,000	15	40 %

VI. Waste to Energy Technologies

Waste to energy technology refers to methods of generating heat and power from energy that would otherwise be lost. This includes the collection and use of landfill gas, the incineration of solid waste, and the capture of energy lost in industrial processes. All forms of waste to energy technology are considered green, albeit to varying degrees.

A. Landfill Gas (LFG)

The Environmental Protection Agency (EPA) requires the collection of landfill gas (LFG) at nearly all U.S. landfills. They can sell the LFG, or use it to generate electricity. Nearly three quarters of the 421 U.S. landfills choose to utilize the gas to generate electricity, including five facilities in Washington, generating 1097 MW and 15 MW, respectively. Roughly every million tons of municipal solid waste provides enough gas for 0.8 MW of generation. King County has nearly 33 million tons of unused waste in candidate landfills, enough for 26 MW of generation. [23]

LFG is comprised of approximately 50% methane, and 50% CO_2, with trace amounts of other gasses. Although combustion of this gas does result in a net increase of greenhouse gasses, it is considered a renewable energy and qualifies for some renewable portfolio standards. BMW recently joined a long list of multinational companies using LFG when it converted the gas turbines in its South Carolina factory to be LFG compatible. The turbines had previously been mothballed due to the cost of natural gas.[24]

[23] EPA LMOP Database, http://www.epa.gov/landfill/proj/xls/lmopdata.xls
[24] Wasteage, http://wasteage.com/mag/waste_gas/index.html

B. Incineration of Municipal Solid Waste (MSW)

Only 14.7% of U.S. municipal solid waste (i.e. common trash) is directly incinerated, from which about 2,500 MW are generated nationwide. The primary reason for incineration is the reduction (up to 90% by volume) of the waste to be landfilled.[25] Seattle area firm WRSI refers to its incineration technology as "Thermal Recycling," as the company does not landfill any of its residues. In nations with limited space, incineration is more common. For example, Singapore incinerates 90% of its municipal solid waste.[26]

Figure D-18. Emissions Control Improvements

	1992 % of Waste Total	1999 % of Waste Total
Cadmium	35.9%	0.8%
Mercury	17.5%	1.3%
Arsenic	1.2%	1.0%
Chrmomium	9.3%	0.2%
Nickel	1.8%	0.3%
Lead	5.5%	0.1%
Particulates	0.3%	<.1%
Nitrogen Oxides	0.2%	0.2%
Sulphur Dioxide	0.1%	<.1%
Dioxins and Furans [a]	57.3%	4%[b]

[a] I-TEG : International Toxic Equivalent. This is derived as the sum of the Toxic Equivalent Factor (TEF) of all the dioxins and furans present in a mixture. The TEF for each compound is its relative toxicity in relation to the most toxic dioxin 2,3,7,8 - tetrachlorodibenzo-p-dioxin (TCDD)

[b] 1998 Data

Source: UK emissions in detail 1999, National Atmospheric Emissions Inventory

Historically, the public has fairly intensely opposed incineration, predominantly because of environmental concerns. For example, efforts to build a Seattle-area incineration facility were halted in the late 1980s. Although we've seen significant improvements in emissions control technologies since then (see Figure D-18), public opposition remains strong. In fact, some environmental groups suggest that the need for a steady incinerator fuel supply may provide an impetus to limit or actually reverse recycling efforts.

C. Reverse Polymerization

Reverse Polymerization is a process by which microwaves bombard solid waste in a low-oxygen environment and generate hydro-carbons. The hydro-carbons can then be used to either generate electricity, or be refined for industrial uses. This process can be applied to plastics, but is most commonly discussed in relation to tire disposal. Tires have a higher heat-content than coal and generally have a negative fuel cost.[27]

[25] EPA, http://www.epa.gov/cleanenergy/muni.htm
[26] UN Environment Program, http://www.unep.or.jp/ietc/estdir/pub/msw/sp/sp5/sp5_1.asp
[27] EPA, http://www.epa.gov/epaoswer/non-hw/muncpl/tires/faq.htm

The key advantage of reverse polymerization over incineration is the ability to recover the tire's carbon black and steel. This allows for 100% recycling of the tire. In regards to the results, this is similar to tire pyrolysis, although pyrolysis is not currently commercially viable. Reverse polymerization is in early deployment, and is also not yet commercial. Environmental Waste International, a leading developer, lists its TR-3000 unit, which has a consumption of 3,000 tires per day, as having a net annual output of 5,610 MWh (about 700 kW capacity) of electricity, 3,770 tons of carbon black and 1,000 tons of scrap steel. Efficiencies are designed to increase with scale.

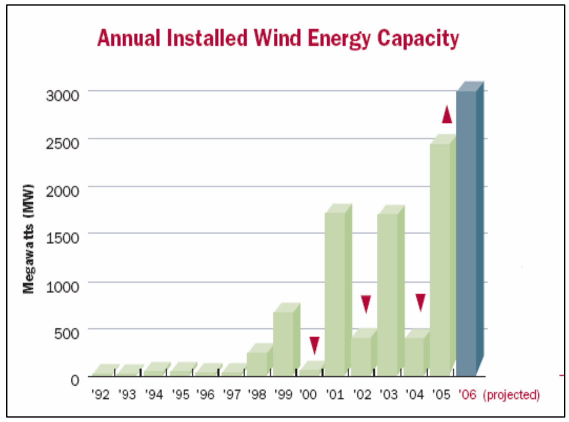
D. Waste Heat Recovery

Waste heat recovery projects typically harness exhaust heat to generate power. Recovery projects tend to be small in scope (less than 10 MW), as facilities with significant volumes of waste heat generally incorporated heat recovery into the original design. Specifics such as heat rates, availability and costs are highly project specific, depending on the volume and method of heat recovery. PSE has signed a letter of intent with ORMAT, an industry leader, for a 5 MW recovery system from the waste heat from turbines used for gas compression. ORMAT has identified roughly 600 turbines nationally as potential projects, for a total potential value of 932 MW. Similarly, ORMAT has identified 500 MW of waste energy available at cement factories.[28]

[28] Ormat, 2005, http://www.energy.wsu.edu/ftp-ep/pubs/events/geothermal/Buchanan_Targets.pdf

VII. Wind Energy

Figure D-19
Annual Installed Wind Capacity



Wind energy is the lowest cost alternative energy technology in the United States, and capacity is growing rapidly, as shown in Figure D-19. In 2006, the total installed wind energy capacity in the United States exceeded 11,000 MW, trailing only Spain and Germany in cumulative capacity, while being first in the world for capacity additions. Recent extension of the Production Tax Credit (PTC) to the end of 2008 should continue this trend. With the recent development and commercial operation of the Hopkins Ridge and Wild Horse wind farms, PSE has a strong familiarity with wind energy. This section addresses onshore wind technology as well as the potential for offshore wind farms.

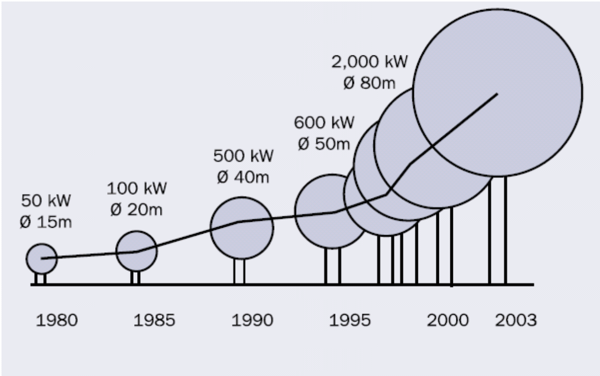
A. *Onshore Wind Power Trends*

The Danish Wind Industry notes three trends in grid connected turbines:

- The growth in size, height and capacity of turbines
- Increases in efficiency
- Decreased investment costs

Although the cost of turbines has risen in the last few years (a short-term spike driven by robust demand and limitations on manufacturing and supply logistics), all three of these trends have held true long term. This cost spike may extend because of Washington state's new Renewable Portfolio Standard (I-937), but is expected to return to its historical trend as manufacturing catches up to demand.

Figure D-20
Growth in Wind Turbine Capacity



Wind turbines, towers and blades are all growing in size, driven by relatively fixed O&M costs, a desire to reduce incremental construction cost, and the presence of stronger and more stable winds at higher rotor hub heights. Better designs, materials, and manufacturing are improving the efficiency and reliability of ever-increasing turbine sizes. At Hopkins Ridge, first-year project availability exceeded 98%.

The distribution of U.S. wind energy suggests that future projects will be located in the Midwest and West. Since 2000, 91% of wind generation has been installed west of the Mississippi River.[29] The extension of the federal PTC until 2008 suggests that 2007 and 2008 will again be "boom" years for wind power, with the American Wind Energy Association projecting over 3,000 MW of new installations.

B. Offshore Wind Generation

The world's first offshore wind project was built in Denmark in 1991, north of the island of Lolland. The 4.9 MW project has performed flawlessly. Now more than 20 offshore projects are in operation, with four more under construction and 18 in the planning stage. The world's largest offshore wind project, Horns Reef, was completed in 2003, with 80 Vestas 2.0 MW turbines totaling 160 MW of capacity.[30] Cape Wind (Figure D-21), a hotly debated project near Cape Cod in Nantucket Sound, could be the first U.S. offshore wind farm in operation by 2010[31]. However, two projects planned off of Long Island (Bluewater

[29] Henwood Energy Database, 2005
[30] Danish Wind Industry Association, 2003, http://www.windpower.org/en/pictures/offshore.htm
[31] Cape Wind, 2007, www.capewind.org

and LIPA Offshore) are close behind. NREL's goal is to lower costs to $50 per MWh by 2012, at which time they expect to utilize new 5 MW turbines installed in shallow water (less than 15 meters).

Figure D-21. Simulated view of Cape Wind turbines from 5.2 miles

Source: Cape Wind

Offshore wind farms benefit from stronger, more stable winds, but have higher capital and operating costs. Offshore turbines may also have higher capacities than their onshore cousins due to modified gearboxes with higher rotation rates and greater noise (prohibitive on shore). Currently, there is no land lease fee for building wind turbines in federal waters, where all turbines for the Cape Wind project are located. The U.S. Army Corps of Engineers, the final authority for permitting, issued a largely positive Draft Environmental Impact Study for Cape Wind in 2004.[32] It reported minimal impacts on marine and bird life, as well as minimal water and noise pollution. Cape Wind filed its Final Environmental Impact Report (FEIR) on February 15, 2007 with the Massachusetts Environmental Policy Act (MEPA) office.

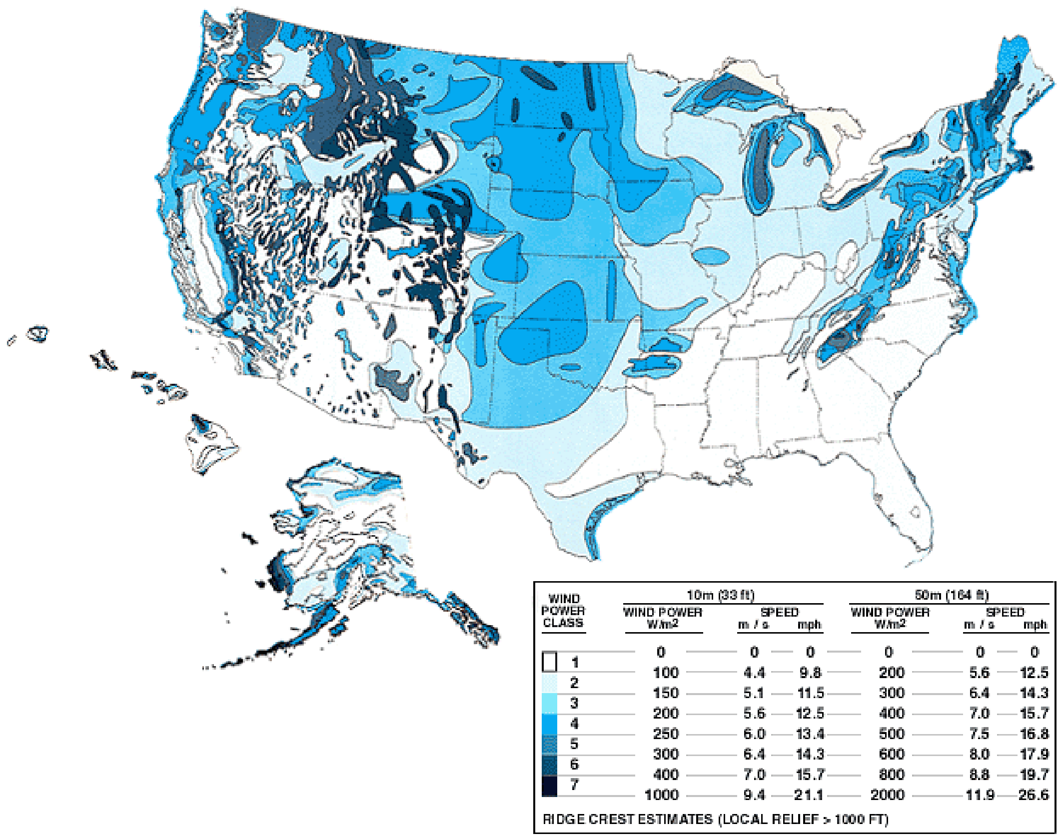
In general, offshore wind power is hoped to have less community resistance, although The Alliance to Protect Nantucket Sound, an energized opposition group comprised of prominent politicians, has formed in response to Cape Wind. Greenpeace and many other environmental groups have endorsed offshore wind energy, particularly Cape Wind.[33] It is unclear what kind of impact offshore farms will have on real estate values. Onshore studies in the United Kingdom have indicated that there is an initial negative impact to residential property values near wind farms, although this impact largely disappeared two years into operations.[34] European experience suggests that a decrease in property values may be offset, at least in part, by an increased tourism industry.

[32] Army Corp of Engineers, 2004, http://www.nae.usace.army.mil/projects/ma/ccwf/deis.htm
[33] Cape Wind, 2005, http://www.capewind.org/article47.htm
[34] Royal Institute of Surveyors, UK, 2003, http://www.rics.org/NR/rdonlyres/66225A93-840F-49F2-8820-0EBCCC29E8A4/0/Windfarmsfinalreport.pdf

An alternative with potentially fewer citizen objections is deep water wind farms. The European Commission is funding a pilot project in which two 5.0 MW REPower wind turbines were installed in the Scottish region of the North Sea at the Talisman Beatrice project in 2006.[35]

As indicated in Figure D-23 the coast of Washington state has strong winds, which may make it a potential site for offshore wind power projects. However, it remains to be determined whether such technology will become commercially viable and acceptable to the community.

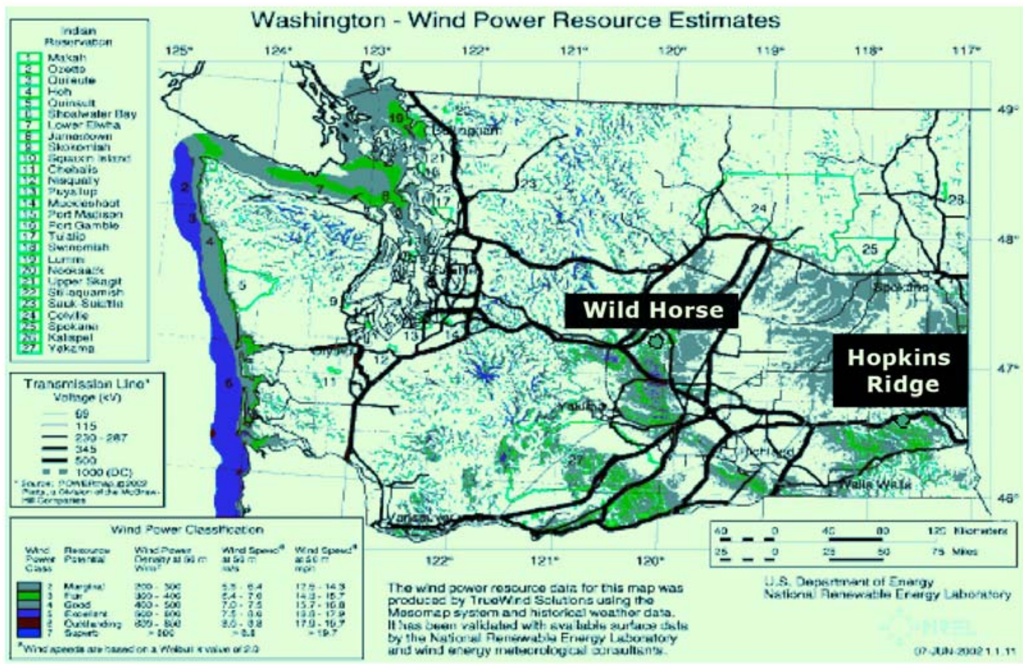
Figure D-22. Available US Wind Energy



Source: NREL

[35] Royal Institute of Technology in Stockholm, http://www.kth.se/forskning/pocket/project.asp?id=22466

Figure D-23
Available Washington State Wind Energy



Source: NREL

VIII. Geothermal

Despite over 100 years of history, the worldwide geothermal generation capacity is only around 8,000 MW, of which the United States has the largest national share at 2,700 MW.[36] Some countries such as Iceland (170 MW) and the Philippines (1909 MW) generate large portions of their power from geothermal sources[37], but the technology is inherently limited by geology. Development of geothermal power in the United States is concentrated in California, with the remaining capacity in Nevada, Hawaii and Utah.

Geothermal power captures heat from inside the earth using one of four methods:

- Dry Steam Plants utilize hydrothermal steam from the earth directly in turbines. This was the first type of geothermal power generation technology, but is limited by the number of sites that offer very hot (greater than 235°C) hydrothermal fluids that are predominantly steam.[38]
- Flash Steam Plants operate similarly to dry steam plants but use low pressure tanks to vaporize hydrothermal liquids into steam. Like dry steam plants, this technology is best suited to high temperature geothermal sources (greater than 182°C).[39]
- Binary Cycle Power Plants can use lower temperature (107°C to 182°C) hydrothermal fluids to transfer energy through a heat exchanger to a fluid with a lower boiling point. This system is completely closed-loop, without even steam emissions. The majority of new geothermal installations are likely to be binary cycle systems due to emissions and the greater number of potential sites.[40]
- While the United States is not currently exploring hot dry rock technology, Japan, England, France, Germany and Belgium are looking into it.[41] It involves the drilling of deep wells into hot dry or nearly dry rock formations and injecting water to develop the hydrothermal working fluid. The heated water is then extracted and used for generation.

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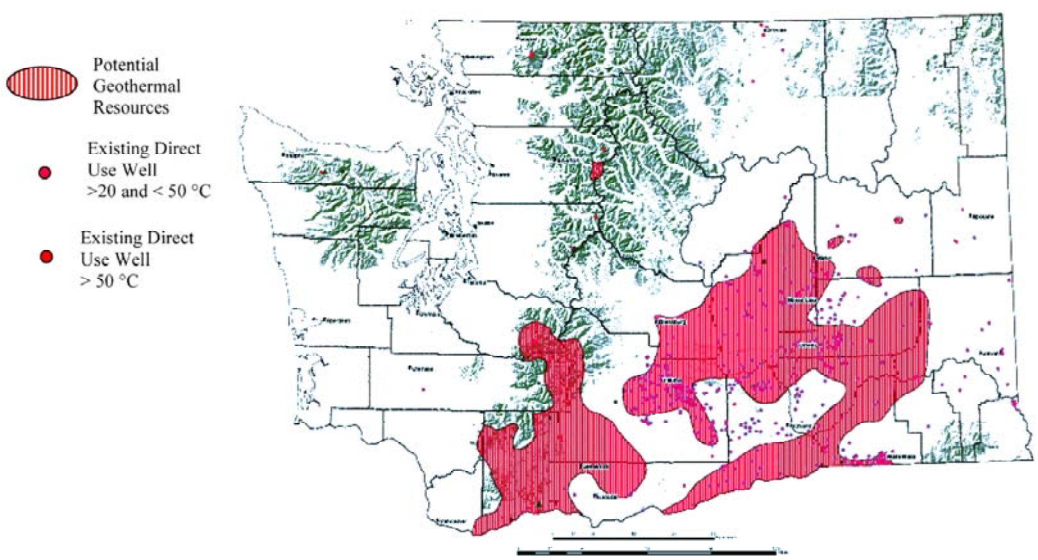
[36] EERE, http://www.eere.energy.gov/consumerinfo/factsheets/geothermal.html
[37] IGA 2000, http://iga.igg.cnr.it/geoworld/geoworld.php?sub=elgen
[38] Renewable Energy Policy Project http://www.crest.org/geothermal/geothermal_brief_power_technologyandgeneration.html
[39] EERE, http://www.eere.energy.gov/consumerinfo/factsheets/geothermal.html
[40] Ibid
[41] Geothermal Education Office, 2000, http://geothermal.marin.org/pwrheat.html

Geothermal depletion is a concern that leads many to question whether geothermal power is truly a renewable resource. Continued aggressive use of a geothermal well can lead to temperature and pressure reductions. The Geysers complex of geothermal installations in northern California decreased in output from over 1,800 MW in the late 1980s to around 1,000 MW in 2001. Economic modeling of 20 to 30 years of production is standard.[42] In addition, although SO_x and CO_2 emissions are very low, they are both present in both dry and flash steam plants as part of the geothermal fluid.

One of the primary challenges with geothermal power generation is handling the corrosive and scaling elements present in geothermal fluids. Research is ongoing with heat exchanger linings and acid resistant cements. In addition, there are efforts to extract commercial products such as zinc or high purity silica from geothermal fluids to offset costs.[43]

Figure D-24
Geothermal Potential in Washington



Source: DOE EERE, 2003

[42] Geothermal.org, 2002, http://www.geothermal.org/articles/California.pdf
[43] Lawrence Livermoore National Labs, 2004, http://www.geothermal.org/DOE_presentations/BRUTON_L.PPT

Dr. Gordon Bloomquist of Washington State University, a specialist in geothermal energy, believes there is between 200 and 300 MW of geothermal potential in Washington state, notably around Mt. Baker, Mt. Adams and the Yakima Nation. He also notes that test wells in Oregon and British Columbia have identified geothermal fluids in excess of 500°C, and says there is no reason to believe that Washington state lacks geothermal resources.

IX. Coal

There are three principal technologies available for utilizing coal, and other solid fuels, in the production of electricity. Two of these technologies, pulverized fuel boilers and fluidized bed boilers, combust fuel to produce heat. The heat boils water to produce steam, which in turn drives a steam turbine-generator to produce electricity. When fueled with coal, these are referred to as “conventional coal” technologies. The third technology, gasification, converts any carbon-containing material into a synthesis gas (syngas) composed primarily of carbon monoxide and hydrogen. This syngas can be used to fuel the generation of electricity or steam.

A. Pulverized Coal

With pulverized coal (PC) technology, the coal is ground into a fine powder that is mixed with air and blown into the boiler furnace to be burned. The resulting heat is then used to produce steam. Fuel efficiency can be improved by increasing the temperature and pressure of the steam generated in the boiler. Current designs utilize steam pressures of 2500 psi and greater.

Supercritical boilers produce steam in excess of 3200 psi. Such boilers were introduced in the United States in the 1970s, but were plagued by metallurgical problems due to high operating temperatures and pressures. More recently, supercritical PC units (SCPC) have been operated successfully in Europe and Japan and have begun to re-emerge in North America. To further improve efficiency, ultra-supercritical PC units (UCPC), operating at even higher pressures, are now available.

Most coal boilers operating in the United States today use PC technology. PC boilers are also used to burn petroleum coke and other solid fuels. Boiler designs are available in a range of sizes from units producing less than 100 MW to those exceeding 1000 MW, powered by a single PC boiler. In addition to increasing boiler efficiency, vendors and equipment suppliers have improved combustion and post-combustion pollution control equipment to meet increasingly stringent emission reduction requirements.

B. Fluidized Bed

Fluidized bed (FB) technologies mix coal and an inert bed material, such as sand, in a combustor or boiler. The mixture of particles is suspended by an upward flow of air and burns producing heat to generate steam. Increasing air flow affects the fluid-like flow of the particles, resulting in a fixed, bubbling or circulating bed. Limestone may be added to the bed material to help capture sulfurous gases that are released as the coal is burned. High heat transfer in the boiler occurs with lower combustion temperatures, resulting in lower levels of NOx formation than in PC boilers. Post-combustion technologies may also be used to further lower air emissions.

FB boilers burn a wide variety of solid fuels in addition to coal and petroleum coke. The Jacksonville Electric Authority Demonstration Project is the largest single FB boiler built to date. It produces approximately 250 MW net.

The pressurized fluidized bed combustion (PFBC) boiler utilizes fluidized bed technology at elevated operating pressures to produce heat for steam production and hot pressurized exhaust gases that may be used to drive a combustion turbine. In the early 1990s, Ohio Edison built a demonstration PFBC plant to power a 55 MW steam turbine[44] and a 15 MW combustion turbine. Although the PFBC offers the promise of higher energy production efficiency, there has been no further commercial development of PFBC technology in the United States.

C. Gasification

Coal and other solid or waste fuels have been gasified to create liquid or gaseous fuels for more than 100 years. In the 1800s crude coal gasification provided gas for lighting streets and homes. During World War II, Germany gasified coal to produce fuel for airplanes and tanks. South Africa has gasified its indigenous coal supply to create liquid and gas fuels since the 1950s, and these plants continue to operate today.

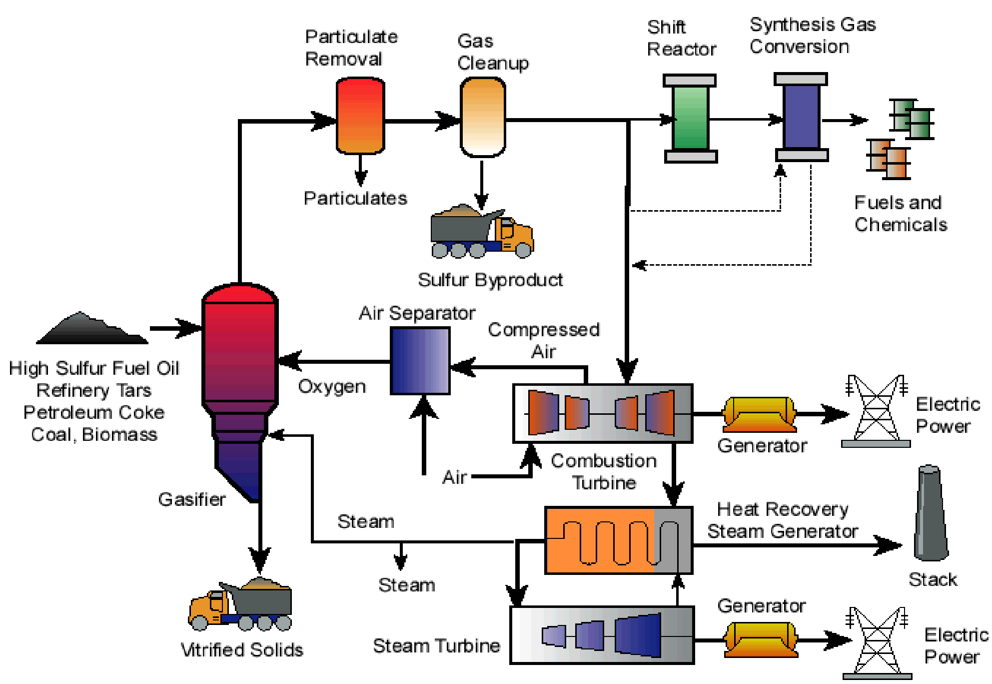
Coal gasification uses a partial oxidation process to produce a low to medium Btu (100-450 Btu per SCF) syngas, which can be fired in a boiler to produce steam to drive a steam turbine generator or may be substituted for natural gas in combustion turbines. In the partial oxidation reaction, there is insufficient oxygen present to convert all of the carbon in the fuel to carbon dioxide. When available oxygen is reduced, less heat is released from the coal and gaseous products appear. These products include hydrogen, carbon monoxide and methane (CH_4), all of which contain potential chemical energy.

[44] The US DOE funded 35% of the cost of this project

Integrated Gasification Combined Cycle (IGCC)

The integrated gasification combined cycle process teams a gasifier with combined cycle equipment. While the extent of integration may vary, depending upon the gasification and combustion turbine equipment selected, IGCC generally refers to a model in which syngas from the gasifier fuels a combustion turbine to produce electricity, while the combustion turbine compressor compresses air for use in the production of oxygen for the gasifier. Additionally, heat from the gasifier is coupled with exhaust from the combustion turbine to generate steam, which is used to drive a steam turbine-generator to produce additional electricity. This use of combustion turbine exhaust heat to generate steam that powers a steam turbine generator is a configuration known as combined cycle. This design has been widely used with natural gas and distillate fuels since the 1980s.

Figure D-25
The Coal Gasification Process



Source: Gasification Technologies Council (w ww.gasification.org)

The combination of coal gasification and combustion turbine technologies was first successfully demonstrated in the United States for electric power production on a commercial scale at the 100 MW Cool Water Demonstration Project in Daggett, California. This plant was operated successfully by Texaco, Bechtel, General Electric, and EPRI from 1984 to 1989 and was then decommissioned. A number of additional demonstration projects were developed in the 1980s and 1990s.

Commercial Availability

To date, the application of gasification for electric power production using IGCC has been limited to demonstration projects. While there are a number of vendors and technologies, their experience with different ranks of coal varies. The table below identifies the experience of major technology vendors with different types of U.S. coal.

Figure D-26
Gasification Technology Experience

	Fuel Type					
Technology Vendor	Lignite	Sub-Bituminous	Bituminous-Illinois Basin	Bituminous-Appalachian	Anthracite & Other Bituminous	Petroleum Coke
Allied Syngas - BGL	D	T	D	D		T
ConocoPhillips E-Gas	T	MM	MM	T		MM
General Electric (Texaco)	T	T	D	MM	MM	MM
KBR Transport Reactor	T	T	T			
Sasol-Lurgi	MM	MM	D	D	MM	
Shell	T	T	T	T	MM	MM
Siemens (Sustec)	D	T			D	

Key:
T = Tested
D = Demonstrated at 500 TPD or more
MM = Operated over 1 Millions Tons

Source: Lukes Consulting

To encourage commercialization of IGCC, major technology licensors have formed "alliances" with engineering and construction firms to provide design and construction on a turnkey basis, with guarantees for construction duration and cost. These alliances would also provide guarantees for initial operating performance, if employed under operating service agreements. To obtain such guarantees, a buyer must select a design fuel type and proceed with a Front End Engineering Design (FEED) study to develop the design envelope. Each alliance requires a specific FEED study before negotiating the contract and guarantees. Each FEED study is reported to cost more than $10 million.

There are currently two operating, commercial-size, coal-based IGCC power plants in the United States. The 262 MWe[45] Wabash River IGCC repowering project in Indiana commenced operation in October 1995[46]. Tampa Electric's 250 MWe Polk Power Station IGCC project in Florida commenced operation in September 1996[47]. Additionally, there are two operating, commercial-sized IGCC power plants in Europe and one coal gasification project in the United States which provides feedstock for Eastman Chemicals in Kingsport, Tennesee.

The increase in cost and price volatility of natural gas has generated renewed interest in IGCC for electric power production. American Electric Power Company, Duke Energy (formerly Cinergy), Excelsior Energy and Energy Northwest have announced feasibility studies for commercial-scale IGCC facilities. NRG Energy recently proposed an IGCC facility in response to a New York Power Authority RFP. PSE has also received proposals from independent power developers for IGCC facilities.

D. Estimated Cost of Current Coal Technologies[48]

There is currently debate within the electric power industry regarding the costs and reliability of IGCC technology versus "conventional coal combustion" technologies. The

[45] MWe is the abbreviation for megawatt electric. In this case MWe is used to indicate that the gasified coal is used to fuel a gas turbine, thus producing electric power.
[46] The Wabash River IGCC project uses the E-Gas gasification technology, which was acquired by ConocoPhillips in 2003.
[47] The Polk Power Station uses the Texaco gasification technology, which was acquired by GE Energy in 2004.
[48] This discussion is based on costs related to permitting, planning, design, construction and commissioning of the "power island" which begins at the point of receipt of the coal fuel at the plant site and ends with the generator step-up transformers before connection of the plant to a substation and the high voltage transmission system. The cost of interest during construction, or AFUDC, is not included.

installed cost of a power island using a pulverized coal (PC) boiler ranges between $2,400 per KW to $2,800 per KW in current dollars. Circulating fluidized bed (CFB) plants are in the same range; however, larger plants (over 250 MW) must be built in modules due to the size limits of available CFB boilers. IGCC plants are estimated to cost 15% to 20% more to construct than PC units of equal size.

Further, the gasification train of IGCC projects is less reliable than the power generation equipment of PC and atmospheric FB boilers. Without a spare gasifier, the equivalent availability of an IGCC unit is projected to be 85% while new PC units commonly attain over 90% equivalent availability. The reliability of the electricity-producing combined cycle plant can be increased to over 90% if the facility is designed to use both syngas and natural gas.

IGCC vendors are under pressure to reduce both the cost and down-time of their products. It is expected that IGCC unit costs will become similar to PC unit costs as more plants are built. IGCC plants will also be modular, in units of 250 MW to 300 MW, to take advantage of existing combustion turbine technology. The reliability of modular CFB or IGCC plants will likely be higher than that of a single boiler, single turbine PC unit.

The cost of a new coal plant is highly affected by siting factors: availability of electric transmission interconnection, availability of water and rail, and other infrastructure. Such costs may eliminate the cost differences between technologies. The cost of development, permitting and preliminary design can range from $20 million to $50 million without assurance that the plant can be built.

E. Environmental Climate

Major electric generating plants are subject to federal and state permitting laws and regulations covering air and water emissions, water use, waste management and pollution prevention. Additionally, state and local land use and zoning laws may govern site selection, and may also affect other plant siting issues, economic impacts or operating requirements. In the Pacific Northwest, the states of Washington, Oregon and Montana have created special regulation to manage the process of permitting major electric generating plants.

The Federal Clean Air Act applies to any electric generating facility and covers six Criteria Pollutants and more than 180 Hazardous Air Pollutants (HAPs). Of the HAPs, it is usually only Mercury and Nickel[49] that affect plant permitting and require specific control devices as part of the plant design, though many others must be analyzed during the permitting process. The EPA enforces the Clean Air Act and has set National Ambient Air Quality Standards (NAAQS) for six Criteria Pollutants: Sulfur Oxides, Nitrogen Dioxide, Particulate Matter, Ozone, Carbon Monoxide and Lead.

The federal Clean Air Mercury Rule (CAMR) requires that existing and new coal plants reduce at least 30% of their mercury emissions by 2010, and at least 70% by 2018. This rule is designed to permanently cap and reduce mercury emissions from coal-fired power plants. To date, 16 states have enacted or are in the process of enacting more restrictive mercury controls. Washington state's Department of Ecology is currently drafting such a rule.

Additionally, while the federal government has not addressed the issue of greenhouse gases (GHGs), states and local governments have been taking action. 2006 has seen a surge in political activity regarding GHG emission limits. As a result, a patchwork of local GHG policies and regulations has been developed, creating significant challenges for utility planning.

Carbon dioxide (CO_2) emissions from power generators are not currently regulated at the state or federal level; however, Washington and many other states currently require actual or economic mitigation of CO_2 emissions from new plants. PSE believes limits on CO_2 emissions will be imposed in the future and must be considered in the evaluation of future resources. See the Regulatory and Policy Activity chapter of the Environmental Concerns appendix for more information about possible future legislation.

New power plants (and major modifications to existing power plants) must employ Best Available Control Technology (BACT) and meet the New Source Performance Standards (NSPS) established by the EPA before receiving a permit to begin construction. What constitutes BACT is a function of the equipment and fuel to be utilized and the local and regional air quality. BACT is determined on a case-by-case basis, taking into account energy, environmental and economic impacts, and costs. Competition among equipment vendors, combined with pressure from plant owners and regulators have caused the BACT process to result in significant reductions in permitted emission levels. At present, the rate of change in BACT for gasification is far more rapid than for PC and FB units. Current EPA regulations and policy do not require that IGCC be included when

[49] Mercury and Nickel are subject to recent EPA rule-making to set emission limits.

performing BACT analyses for new PC and FB units; however, the permitting processes in many states do require such comparison. In February 2006, EPA revised its regulations to clarify that combustion turbines and combined cycle plants that receive 75% or more of their heat input from synthetic coal gas are subject to the same rules as utility steam boilers (40 CFR 60, Subpart Da) rather than the rules (Subpart KKKK) covering combustion turbines.

For more information about local and federal environmental regulations and related environmental issues, see Chapter 2, Planning Environment, and the Environmental Concerns Appendix, where PSE's Greenhouse Gas Policy can be found.

F. Emission Control Technologies

A significant difference between PC, FB and IGCC technologies is how, where in the process cycle, and how effectively Criteria Pollutants and HAPs are controlled. Conventional coal plants built recently include specialized, highly efficient pollution control equipment to reduce the emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx) and particulates. Some older plants have also added such pollution control devices and the federal Clean Air Interstate Rule is expected to significantly increase the number of existing plants with retrofitted pollution control equipment by 2010.

IGCC vendors claim greater capture rates for sulfur dioxide, nitrogen oxides and particulates because pollutant removal is performed prior to the introduction of the syngas fuel into the combustion turbine. In PC and FB boilers, these pollutants are captured during or after coal combustion. Vendors of conventional boilers have responded to these claims by continuing to offer equipment designs with lower emission rates. Nonetheless, some states are requiring the inclusion of gasification in the evaluation of BACT as part of the New Source Review process required for air permit application.

The following discussion focuses on the typical pollutants and HAPs that must be considered in converting coal to electricity. Because of the wide variety of proprietary gasification system designs, the process flow and equipment described may vary somewhat in configuration; however, all use the same basic steps.

Particulate Matter

Particulate matter refers to inorganic impurities in the coal in the form of fine ash.

Figure D-27
Particulate Matter Controls

PC and FB units	Particulate matter is captured using an electro-static precipitator (ESP) or a fabric filter (FF), also called a bag-house, to clean flue gases after they exit the boilers. ESPs were the first control devices applied to existing PC boilers. ESPs or FFs are used in the construction of all new PC and FB designs. Current performance requirements for ESPs and FFs are 0.02 lbs per MMBtu of heat input (about 0.2 lbs per MWh) or less in flue gases released to the atmosphere.
IGCC	Particulates are separated by gravity from the raw syngas in the gasifier. They exit the gasifier as slag or other similar solids. Additional removal of fine particulates takes place in candle filters in the raw syngas clean-up equipment between the gasifier and the combustion turbine. Current performance requirements are less than 0.01 Lbs per MMBtu or 0.1 Lbs. per MWh.

Sulfur Dioxide (SO_2)

All coal contains sulfur. It ranges from less than 1% by weight in some western U.S. coals to more than 6% in some mid-western coals. Petroleum coke, the waste product from the refining process, contains most of the sulfur from the original crude oil supply, which may be 4% by weight or more.

Figure D-28
Sulfur Dioxide Controls

PC units	Scrubbers are employed downstream of the boiler to mix an alkaline material, such as lime, with boiler exhaust gases to capture sulfur compounds. Some older scrubber designs also capture particulate matter (fly ash), eliminating the need for a separate ESP or FF. Scrubber designs fall into two broad categories: dry and wet. Dry scrubbers: Flue gas heat evaporates water media used to supply the alkaline material, leaving a dry alkali-sulfur compound. Particulate control equipment, normally placed after the scrubber, captures this dry product. Wet scrubbers: Particulate control occurs ahead of the scrubber. In such case, the alkali-sulfur product is a slurry with a chemical composition similar to natural gypsum. If transportation cost can be minimized, the scrubber product can be dried and sold for wall board manufacture.
FB units	Most FB units use an alkaline material as part of the bed. Before leaving the boiler, the alkali captures the sulfurous gas released during combustion and is then captured by the particulate control equipment, normally an FF. A polishing scrubber, similar to the main scrubbers on a PC unit, can be added to further reduce the amount of sulfur that leaves the stack in flue gases.
IGCC	The raw syngas that leaves the gasifier contains carbonyl sulfide (COS), which is converted to hydrogen sulfide (H2S) through electrolysis. Acid gas clean-up equipment then removes the H2S. Between the gasifier and the sulfur removal, the syngas is cooled in heat exchangers that use recovered heat to generate additional steam for the steam turbine. A sulfur recovery system may be added after the acid gas clean-up to recover sulfur as a salable by-product, either as elemental sulfur or as sulfuric acid.

Current SO_2 performance requirements for both PC and FB units require removal of more than 99% of the sulfur in the coal, yielding an emission level of 0.1 lbs per MMBtu (about 1 lbs per MWh) or less in the flue gases released into the atmosphere.

Current SO_2 performance requirements for gasification systems require removal of 99.5% of the sulfur in the coal, yielding an emission level as low as 0.03 lbs per MMBtu (less than 0.3 lbs per MWh) or less in the flue gases released into the atmosphere. In order to effectively capture mercury, the SO_2 emission level must be below 0.01 lbs per MMBtu before reaching the mercury absorber equipment. This requires use of a proprietary acid gas clean-up process, such as Selexol.

Nitrogen Oxides

Figure D-29
Nitrogen Oxide Controls

PC units	Nitrogen oxides (NOx) can be reduced in the PC boiler during combustion of the coal using Low NOx Burners, which reduce combustion temperatures, thereby affecting the amount of NOx produced. Over-fire air is used with Low NOx Burners to further cool the fireball in the furnace and reduce NOx production. Ammonia (NH3) can be injected into the PC boiler flue gas as it leaves the boiler to reduce NOx. A catalyst can be employed to aid in the chemical reaction between NH3 and NOx, that results in formation of water (H2O) and elemental nitrogen (N2). When a catalyst is used, this is called Selective Catalytic Reduction (SCR). Without a catalyst, it is known as Selective Non-Catalytic Reduction (SNCR).
FB units	In FB boilers, NOx is reduced in the combustor by keeping the combustion temperatures lower and may be further reduced by the addition of SCR or SNCR technology in the flue gas stream after the boiler.
IGCC	There is no NOx produced in the oxygen blown gasification process. The only NOx production occurs during the syngas combustion in the combustion turbine. NOx emission levels below 0.03 Lbs per MMBtu can be obtained with normal combustion practices using water and N2 (from the air separation plant) injection into the combustors of the combustion turbine with the syngas. Even lower levels, down to 0.01 Lbs per MMBtu or lower may be obtained by addition of SCR equipment to the combustion turbine exhaust. This requires extremely low levels of SO2 in the syngas stream to the combustion turbine.

Current NOx performance requirements for both PC and FB units is an emission level of 0.07 Lbs per MMBtu (about 0.7 Lbs per MWh) or less in the flue gases released to the atmosphere.

IGCC projects currently being permitted are being asked to review whether use of SCR equipment is BACT.

Mercury

As previously discussed, the federal Clean Air Mercury Rule (CAMR) will require that all coal-burning power plants reduce their mercury emissions beginning in 2010. Much research and demonstration of sorbent injection and other techniques to remove mercury from PC and FB unit flue gasses has taken place in the past five years, but no technology has been confirmed to provide long-term mercury removal for all types of coal and all boiler designs.

The Tennessee Eastman coal gasification facility has demonstrated success in removing mercury to non-detectable levels using sorbent beds during its syngas clean-up processes. The plant has been in operation generating chemical feedstocks since 1984. This sorbent bed technology should facilitate mercury removal at levels high enough to meet the requirements of CAMR.

Carbon Dioxide

Although carbon dioxide (CO_2) is not currently regulated as an air pollutant, there is keen interest in developing technologies to economically remove it from flue gases. Washington is one of several states that requires mitigation of carbon dioxide emissions from new power plants. The technology for carbon dioxide capture in the gas clean-up portion of the IGCC is clearly more developed than is post-combustion capture of carbon dioxide from either a PC or FB boiler. However, effective methods of permanent sequestration, other than injection for enhanced oil recovery in specific locations, is not commercially developed and readily accessible. A July 2006 study for the Environmental Protection Agency found that adding carbon capture technology to various IGCC designs increased the cost of electricity by 25% to 40%. The estimated increase in the cost of energy from a supercritical PC unit was as much as 65%. Not only does carbon capture involve the capital and operating costs of additional equipment, it also increases parasitic plant energy use significantly. This study and others available in the public literature caution that IGCC design and cost information is more sensitive to both the specifics of the site and the type of coal to be used than a PC unit. The limited development of carbon dioxide sequestration technologies and sites, however, limits the current ability of both IGCC and conventional coal technologies to “solve” the GHG problem.

Carbon capture

Very limited demonstration of amine-based CO2 capture systems have been demonstrated on flue gas slipstreams of PC and FB systems. Research is also underway to produce more cost-effective systems using ammonia-based or other processes, but no systems are currently available for full-scale CO2 removal from PC or FB units. Further, preliminary estimates indicate that such systems could increase the cost of electricity by 60% or more.

The use of “oxy-fuel” combustion practices, which uses an air separation plant to deliver O_2, rather than air, for the combustion process is being developed for PC units. This could be used in new designs or retro-fit to existing PC units. Using oxy-fuel techniques yields a flue gas stream of nearly pure CO_2, eliminating the need to separate the CO_2 from the other gases, primarily nitrogen, in the flue gas stream. There has been no demonstration of this technology except in pilot projects and no good estimates of cost.

Separation of CO_2 in the gasification process has been demonstrated using the water shift reaction to convert carbon monoxide (CO) and water into CO_2 and elemental hydrogen (H_2) as the fuel gas. However, combustion turbines that can utilize H_2 are being developed but are not currently available -- research is on-going by several combustion turbine producers.

Carbon Sequestration

Terrestrial carbon sequestration utilizes natural methods for returning carbon to the soil and plants at the surface level. Soil contains CO_2, which is sequestered by the plants. But overgrazing reduces the plants’ ability to perform their function. Improved pasture management can increase the amount of CO_2 in the soil. Crops also sequester carbon in the soil, but the tilling process releases it back into the atmosphere. Agriculture practices that reduce tilling have been shown to increase the level of carbon in the soil. Afforestation is the growing of trees that will capture carbon and hold it until the wood decomposes or is combusted. Hence, long term management of afforestation projects is necessary to insure that the carbon stays sequestered. Overall, while agriculture is responsible for a small portion of America’s contribution to climate change, it can still be part of the solution.

Geologic sequestration involves pumping CO_2 deep into the ground, where it reacts with the rocks to form an inert compound. There are numerous opportunities for carbon capture and sequestration (CCS). For example, for 30 years oil companies have practiced “enhanced oil recovery” whereby they pump CO_2 from the refining process into the wells to improve the recovery of oil. In the Northwest, testing is currently underway with wells drilled deep into the saline aquifer where the pressure is also very high. The pumped CO_2, in an aqueous state, reacts with the mafic rock (basalt) to form the inert calcite. The economic cost of the geologic sequestration has not been determined at this time; however, significant infrastructure investments are necessary in order to accomplish CCS on a large scale.

PSE participates in the Big Sky Carbon Sequestration Partnership based in Bozeman, MT, which is investigating numerous sequestration technologies for effectiveness and cost[50].

Water Use

Because IGCC units utilize both gas turbines and steam turbines for electricity production, consumptive water use is typically about one-third less than that of similarly-sized PC or FB units. IGCC units use smaller steam turbines, requiring less condenser cooling water.

Solid Wastes

PC, FB and IGCC units all produce solid waste products that can be marketed or disposed of as solid waste. The types of products produced vary by technology and design. The ability to market these products is largely a function of plant location and bulk material transportation costs.

[50] Big Sky Carbon Partnership, Montana State University, Bozeman, MT; http://www.bigskyco2.org/

X. Natural Gas

A. Combined-cycle Combustion Turbines

A combined-cycle combustion turbine (CCCT) power plant consists of one or more gas turbine generators (GTG) equipped with heat recovery steam generators (HRSG) to capture heat from the gas turbine exhaust. Steam produced in the HRSG powers a steam turbine generator (STG) to produce additional electric power. Use of the otherwise wasted heat in the turbine exhaust gas results in high thermal efficiency compared to other combustion based technologies. CCCT plants currently entering service can convert about 50% of the chemical energy of natural gas into electricity.

A single-train CCCT plant consists of one GTG, HRSG, and STG (or 1x1 configuration). Using “F-class” combustion turbines - the most common technology in use for large CCCT plants - this configuration can produce about 270 MW of capacity. Plants can also be configured using two or even three GTGs and a HRSG feeding a single, proportionally larger STG. Larger plant sizes result in economies of scale for construction and operation, and designs using multiple GTGs provide improved part-load efficiency. A 2x1 configuration using F-class technology will produce about 540 MW of capacity. Other plant components include a switchyard for electrical interconnection, cooling towers for cooling the STG condenser, a water treatment facility and control and maintenance facilities.

Additional peaking capacity can be obtained by use of various power augmentation features, including inlet air chilling and duct firing (direct combustion of natural gas in the HRSG). For example, an additional 20 MW to 50 MW can be gained from a single-train plant by use of duct firing. Though the incremental thermal efficiency of duct firing is lower than that of the base CCCT plant, the incremental cost is low and the additional electrical output can be valuable during peak load periods.

GTGs can operate on either gaseous or liquid fuels. Pipeline natural gas is the fuel of choice because of historically low and relatively stable prices, deliverability and low air emissions. Distillate fuel oil can be used as a backup fuel.

Because of high thermal efficiency, low initial cost, high reliability, relatively low gas prices and low air emissions, CCCTs have been the new resource of choice for bulk power generation for well over a decade. Other attractive features include significant operational flexibility, the availability of relatively inexpensive power augmentation for peak period operation and relatively low carbon dioxide production.

Proximity to natural gas mainlines and high voltage transmission is the key factor affecting the siting of new CCCT plants. Secondary factors include water availability, ambient air quality and elevation.

Carbon dioxide, a greenhouse gas, is an unavoidable product of combustion of any power generation technology using fossil fuel. The carbon dioxide production of a CCCT plant on a unit output basis is much lower than that of other fossil fuel technologies.

B. Peaking Power Plants[51]

Peaking power plants, also known as peaker plants, are power plants that generally run only when there is a high demand, known as peak demand, for electricity. In contrast, base load power plants operate continuously, stopping only for maintenance or unexpected outages. Intermediate plants operate between these extremes, curtailing their output in periods of low demand, such as during the night. Base load and intermediate plants are used preferentially to meet electrical demand because the lower efficiencies of peaker plants make them more expensive to operate.

The time that a peaker plant operates may be many hours a day or as little as a few hours per year. It depends on the loading condition of the region's electrical grid. It is expensive to build an efficient power plant, so if a peaker plant is only going to be run for a short and variable time, it does not make economic sense to make it as efficient as a base load power plant. In addition, the equipment and fuels used in base load plants are

[51] References for peaking power plant information
http://www.simplecyclepowerplants.com/
http://en.wikipedia.org/wiki/Gas_turbine
http://www.energysolutionscenter.org/DistGen/Tutorial/TutorialFrameSet.htm
http://www.gepower.com/prod_serv/products/tech_docs/en/downloads/ger4222a.pdf
http://www.energysolutionscenter.org/DistGen/Tutorial/TutorialFrameSet.htm
http://en.wikipedia.org/wiki/Reciprocating_engine
http://www.energy.ca.gov/distgen/equipment/reciprocating_engines/reciprocating_engines.html
http://www.cat.com/cda/layout?m=37508&x=7
http://www.eere.energy.gov/de/gas_fired/
http://www.wartsila.com/,en,solutions,applicationdetail,application,F00F72F1-9579-47E6-B6BD-60A0E42943A4,B0B76B09-FEAF-497D-9D59-BA2EC30AFB1E,,.htm

often unsuitable for use in peaker plants because the fluctuating conditions would severely strain the equipment. For these reasons, nuclear, geothermal, waste-to-energy, coal and biomass plants are rarely, if ever, operated as peaker plants.

Peaker plants are generally gas turbines that burn natural gas. A few burn distillate fuel, but it is usually more expensive than natural gas, so its use is limited. However, many peaker plants are able to use distillate fuel as a backup. The thermodynamic efficiency of gas turbine peaker power plants ranges from 20% to 40%, with about 30% to 35% being average for a new plant. The most efficient gas turbine plants are generally used for load cycling, cogeneration projects, or are intended to be operated for longer periods than usual. Reciprocating engines are sometimes used for smaller peaker plants.

C. Simple Cycle Combustion Turbines (SCCT)

Simple cycle combustion turbines in the power industry require smaller capital investment than coal, nuclear or even combined cycle natural gas plants and can be designed to generate small or large amounts of power. Also, the actual construction process can take as little as several weeks to a few months, compared to years for base load power plants. Their other main advantage is the ability to be turned on and off within minutes, supplying power during peak demand. Since they are less efficient than combined cycle plants, they are usually used as peaking power plants, which operate anywhere from several hours per day to a couple dozen hours per year, depending on the electricity demand and the generating capacity of the region. In areas with a shortage of base load and load following power plant capacity, a gas turbine power plant may regularly operate during most hours of the day and even into the evening. A typical large simple cycle combustion turbine may produce 75 MW to 180 MW of power and have 35% to 40% thermal efficiency. The most efficient turbines have reached 46% efficiency.

The modern power combustion turbine is a high-technology package that is comprised of a compressor, combustor, power turbine, and generator. In a combustion turbine, a large volume of air is compressed to high pressure in a multistage compressor. Fuel is then added to the high-pressure air and combusted. The combustion gases from the combustion chambers power an axial turbine that drives the compressor and the generator. In this way, the combustion gases in a combustion turbine power the turbine directly, rather than requiring heat transfer to a water/steam cycle to power a steam turbine, as in the steam plant. The latest combustion turbine designs use a turbine inlet temperature of 1,500°C (2,730°F) and compression ratios as high as 30:1 (for aeroderivatives) giving thermal efficiencies of 35% or more for a simple-cycle combustion turbine.

D. Reciprocating Engine Systems

Reciprocating engines are piston-driven electrical power generation systems ranging from a few kilowatts to over 15 MW. Reciprocating engine technology has improved dramatically over the past three decades because of economic and environmental pressures for power density improvements (more output per unit of engine displacement), increased fuel efficiency, and reduced emissions.

The reciprocating, or piston-driven, engine is a widespread and well-known technology. Also called internal combustion engines, reciprocating engines require fuel, air, compression, and a combustion source to function. Depending on the ignition source, they generally fall into two categories: (1) spark-ignited engines, typically fueled by gasoline or natural gas, and (2) compression-ignited engines, typically fueled by diesel oil fuel.

Almost all engines used for power generation are four-stroke and operate in four cycles (or stokes). The four-stroke, spark-ignited reciprocating engine has intake, compression, power, and exhaust cycles. In the intake phase, as the piston moves down in its cylinder, the intake valve opens, and the upper portion of the cylinder fills with fuel and air. When the piston returns upward in the compression cycle, the spark plug emits a spark to ignite the fuel-air mixture. This controlled reaction, or "burn," forces the piston down, thereby turning the crank shaft and producing power. In the exhaust phase, the piston moves back up to its original position, and the spent mixture is expelled through the open exhaust valve.

The compression-ignition engine operates in the same manner, except the introduction of diesel fuel at an exact instant ignites in an area of highly compressed air-fuel mixture at the top of the piston. In diesel units, the air and fuel are introduced separately with fuel injected after the air is compressed by the piston in the engine. As the piston nears the top of its movement, a spark is produced that ignites the mixture (in most diesel engines, the mixture is ignited by the compression alone).

Dual fuel engines use a small amount of diesel pilot fuel in lieu of a spark to initiate combustion of the primarily natural gas fuel. The pressure of the hot, combusted gases drives the piston down the cylinder. Energy in the moving piston is translated to rotational energy by a crankshaft. As the piston reaches the bottom of its stroke, the exhaust valve opens and the exhaust is expelled from the cylinder by the rising piston.

Commercially available reciprocating engines for power generation range from 0.5 kW to 16.5 MW. Reciprocating engines can be used in a variety of applications because of their small size, low unit cost, and useful thermal output. They offer moderate capital cost, easy start-up, proven reliability, good load-following characteristics, and heat recovery potential. Possible applications for reciprocating engines include continuous or prime power generation, peak shaving, backup power, premium power, remote power, standby power, and mechanical drive use. When properly treated, the engines can run on fuel generated by waste treatment (methane) and other biofuels.

XI. Nuclear

A nuclear power plant (NPP) is a thermal power station in which the heat source is one or more nuclear reactors. Nuclear power is the controlled use of the nuclear fission reaction to release energy for work including propulsion, heat, and the generation of electricity. Nuclear energy is produced when a fissile material, such as uranium-235 (U^{235}), is concentrated such that nuclear fission takes place in a controlled chain reaction and creates heat—which is used to boil water, produce steam, and drive a steam turbine to generate electricity[52].

Nuclear fuel production for light water reactors begins with concentrating the U^{235} fraction of natural uranium to the desired enrichment. The enriched uranium is reacted with oxygen to produce uranium oxide. This is fabricated into pellets, which are then stacked and sealed into zirconium tubes to form a fuel rod. Fuel rods are assembled into fuel assemblies - bundles of rods arranged to accommodate neutron absorbing control rods and to facilitate removal of the heat produced by the fission process. Nuclear fuel is a highly concentrated and readily transportable form of energy, freeing nuclear power plants from fuel-related geographic constraints[53].

Operating nuclear units in the United States are based on light water reactor technology developed in the 1950s. Future nuclear plants are expected to use advanced designs employing passively operated safety systems and factory-assembled standardized modular components. These features are expected to result in improved safety, reduced cost and greater reliability. Though preliminary engineering is complete, construction and operation of a demonstration project is required before the technology can be considered commercial. Electricity industry interest in participating in one or more commercial-scale demonstrations of advanced technology is increasing. But even if demonstration plant development moves ahead in the next several years, lead times are such that advanced technology is unlikely to be fully commercial until about 2015. This suggests the earliest operation of fully commercial advanced plants would be around 2020. Also needed for public acceptance of new nuclear development is a fully operational spent nuclear fuel disposal system. Though spent fuel disposal technology is available and the Yucca Mountain site is under development, the timing of commercial operation remains uncertain.

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[52] http://en.wikipedia.org/wiki/Nuclear_power
[53] Northwest Power Planning Council

Nuclear plants could be attractive under conditions of sustained high natural gas prices and aggressive greenhouse gas control. Other factors favoring nuclear generation would be failure to develop economic means of reducing or sequestering the CO2 production of coal based generation, and difficulty expanding transmission to access new wind or coal resources.

Nuclear energy uses an abundant, widely distributed fuel, and mitigates the greenhouse effect if used to replace fossil-fuel-derived electricity. Lately, there has been renewed interest in nuclear energy from national governments due to economic and environmental concerns. Other reasons for interest include increased oil prices, new passively safe designs of plants, and the low emission rate of greenhouse gas.

Nuclear power plants are base load stations, which work best when the power output is constant (although boiling water reactors can come down to half power at night). Their units range in power from about 40 MW to over 1200 MW. New units under construction in 2005 are typically in the range 600 MW to 1200 MW. As of 2006, new nuclear power plants are under construction in several Asian countries, as well as in Argentina, Russia, Finland, Bulgaria, Ukraine, and Romania.

Nuclear power is highly controversial, enough so that the building of new commercial nuclear power plants in the United States has ceased - at least temporarily. Under recent legislation intended to jump-start development, Congress is offering more than $8 billion in subsidies and loan guarantees for the first few new plants that get built. Constellation Energy Inc. has publicly identified two sites for development. A consortium of utilities called NuStart Energy Development LLC is in the application and development process for two new plants. Also, Dominion Resources Inc. and Southern Company are each considering new plants.[54]

Almost all the advantages and disadvantages of commercial nuclear power are disputed in some degree by the advocates for and against nuclear power. The use of nuclear power is controversial because of the problem of storing radioactive waste for indefinite periods, the potential for possibly severe radioactive contamination by accident or sabotage, and the possibility that its use in some countries could lead to the proliferation of nuclear weapons. Proponents believe that these risks are small and can be further reduced by the technology in the new reactors. Disposal of spent fuel and other nuclear waste is claimed by some as an advantage of nuclear power, claiming that the waste is

[54] "Power Producers Rush to Secure Nuclear Sites: First to Develop Plans Could Tap $8 Billion In Federal Subsidies" WSJ 1/29/2007

small in quantity compared to that generated by competing technologies, and the cost of disposal small compared to the value of the power produced. Others list it as a disadvantage, claiming that the environment cannot be adequately protected from the risk of future leakages from long-term storage.

The cost benefits of nuclear power are also in dispute. It is generally agreed that the capital costs of nuclear power are high and the cost of the necessary fuel is low compared to other fuel sources. Proponents claim that nuclear power has low running costs, and opponents claim that the numerous safety systems required significantly increase running costs.

New Plant Costs[55]

There has been little hard evidence of recent U.S. nuclear developments from which reasonable cost estimates can be made. However, the table below contains current information from the Northwest Power and Conservation Council that can shed some light on international nuclear developments. Please note that these figures reflect "overnight" costs as opposed to "all-in" costs, meaning that they assume the plant could be acquired overnight and thus, no interest or related development cost risks are assessed for the seven to ten year development period.

Figure D-30
Nuclear Plant Capital Costs

Plant Name	Location	COD	"Overnight" Cost (in 2002 dollars)
Genkai 3	Japan	1994	$2818/kW
Genkai 4	Japan	1997	$2218/kW
Onagawa	Japan	2002	$2409/kW
KK6	Japan	1996	$2020/kW
KK7	Japan	1997	$1790/kW
Yonggwang 5&6	Korea	2004/5	$1800/kW
Olkiluoto 3	Finland	2010-2011	$2500-3000/kW

As Figure D-30 illustrates, the average "overnight" cost of the seven recently-built units is $2,130 per kW in 2002 dollars. These figures do not reflect the impact of escalation to 2007 dollars. Further, they do not reflect the impact of nuclear fuel cost increases, which have risen significantly since 2002.

[55] The information provided in this section has been adapted from a Northwest Power and Conservation Council presentation titled "Costs and Prospects for New Nuclear Reactors", which was developed and presented by Jim Harding in February 2007.

XII. PPAs and PBAs

A purchased power agreement (PPA) is a bilateral wholesale or retail power contract, wherein power is sold at either a fixed or variable price and delivered to an agreed-upon point. PPAs may be long term (up to or greater than 15 years) or short term (less than two years) in nature, and can be shaped to provide peak power.

PSE also uses the term “power bridging agreements” (PBAs) to designate PPAs that bridge the period until long-lead resources or transmission can be developed. Over our 20-year planning horizon, PSE’s load-resource balance demonstrates an immediate and continually growing need for new resources. Certain desirable resources may not be immediately available or may require new transmission before becoming viable. PBAs allow us the option to bridge our need before such longer-lead resources are online. PBAs also allow us to directly test delaying a resource.