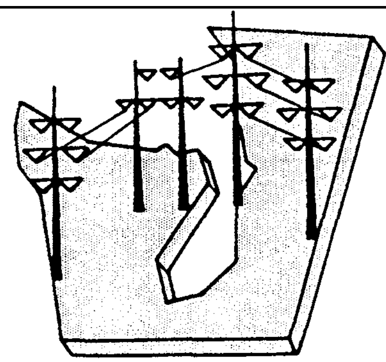
Puget Sound Area Electric Reliability Plan

Local Generation Evaluation Appendix B



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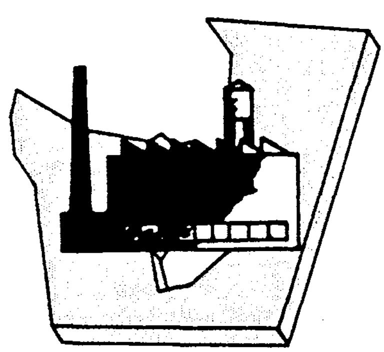
Conservation and Load Management



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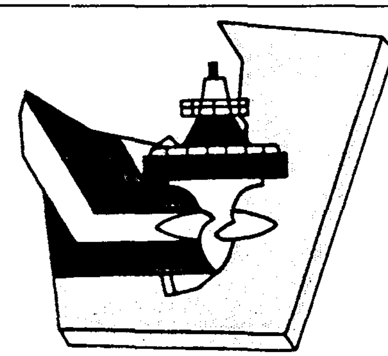

Local Generation

PUGET SOUND AREA ELECTRIC RELIABILITY PLAN
DRAFT EIS

APPENDIX B
LOCAL GENERATION MEASURES

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PUGET SOUND AREA ELECTRIC RELIABILITY PLAN
LOCAL GENERATION MEASURES

Introduction

The information and data contained in this Appendix was extracted from numerous sources. The principle sources used for technical data were Bonneville Power Administration's 1990 Resource Program along with its technical appendix, and Chapter 8 of the Draft 1991 Northwest Conservation and Electric Power Plan. All cost data is reported in 1988 dollars unless otherwise noted. This information was supplemented by other data developed by Puget Sound utilities who participated on the Local Generation Team.

The Local Generation Team, consisting of members from Puget Sound Power and Light, Seattle City Light, Snohomish County PUD, Tacoma City Light, and Bonneville, have met several times over the last two years to discuss the assumptions and develop generation measures for the Puget Sound area. This Appendix documents the detailed resource information that was available to the Local Generation Team and summarizes the findings of the team.

Summary

Identifying generating resources available to the Puget Sound area involved a five step process: (1) Listing all possible resources that might contribute power to the Puget Sound area, (2) Characterizing the technology/resource status, cost and operating characteristics of these resources, (3) Identifying exclusion criteria based on the needs of the overall Puget Sound Electric Reliability Plan study, (4) Applying these criteria to the list of resources, and (5) Summarizing of the costs and characteristics of the final list of resources.

Table 1, Summary of Resource Costs and Characteristics, lists all resources that were considered by the Local Generation Team. This table also shows the costs and quantities that should be considered available. Table 2, Generation Technologies Excluded From Further Consideration, shows the exclusion criteria that were applied to the list of resources and the results of this screening. For detailed discussion of the characteristics of each resource please refer to the resource discussions in the body of this appendix. Table 3, Peak Potential and Operating Characteristics of Available Resources, summarizes the key characteristics of those resources that are considered to be available from a planning perspective.

Table 1
Summary of Resource Costs and Characteristics

Technology	Status of Technology	Lead time (years)	Cost (Real 1988 Levelized mills/kWh)	Cost (Nominal Levelized mills/kWh)	Peak/Energy Availability in Puget Sound (MW/aMW)
Oil & Gas					
Steam	mature	3-5	a	a	
CombustionTurbines	mature	3-5	b	b	420+[c]
Coal					
Conventional	mature	10+	49	97	N/A
Advanced	mature	7	47	83	200/170
Nuclear Fission WNP-3	mature	8	34	67	1240/806
Nuclear Fusion	R&D	N/A	N/A	N/A	N/A
Geothermal	mature	3-5	42-74	64-113	N/A
Hydroelectric					
Conventional	mature	3-6	16-55	32-108	240/100
Other	mixed	3-6	N/A	N/A	N/A
Biomass Fired	mature	5-7	40-70	61-107	N/A
Municipal Solid Waste	mature	5-7	d	d	N/A
Cogeneration	mature	2-4	35-55	54-84	1100/950
Wind	mature	3-5	53-58	81-89	N/A
Solar	prototype	N/A	78-111	119-170	N/A
Ocean	prototype	N/A	N/A	N/A	N/A
Hydrogen	mature	5-7	158	242	N/A
Fuel Cells	mature	3-5	54	83	N/A
Storage Systems	mixed	3-10	e	e	N/A
Standby Generation	mature	1-2	e	e	N/A

[a] Cost for new small oil/gas fired boilers assumed to be the same as combustion turbines. CTs, however, are the technology of choice for utility application because their performance and flexibility continues to improve, whereas boiler technology is mature.

[b] Combustion turbine cost depends on how they are used. When displaced by non-firm hydro power, combined cycle CT's have a cost of 26-34 mills/kWh(real). If installed for capacity only, simple cycle CT's have a capital cost of 400-500 $/kW.

[c] The energy produced by a CT is relatively small for a peaking unit. A unit which is operated in conjunction with non-firm hydro energy effectively produces firm energy at its rating. For the Puget Sound area it is estimated that 350 MW of new CTs could be operated in a firming mode. Such units would operate at an estimated capacity factor of 15% and effectively create 350 MWa of firm energy.

[d] The cost of electricity is dependent on the tipping fee (the fee charged waste haulers). Cost tend to be set at existing avoided costs and then the tipping fee is adjusted accordingly.

[e] Levelized cost is not an appropriate measure for a these technologies. The capital cost, compared to alternatives, is a better measure.

Table 2
Generation Technologies Excluded From Further Consideration

Technology	Exclusion Criteria: Technology Not Mature	Not Commercially Available/ Resource Not Confirmed	Not Available During Winter	Not Cost Competitive (> 50 mills-real 1988 $)	Cannot be On Line by 2002
Coal-Conventional					X
Nuclear Fusion	X	X		X	X
Geothermal		X			
Wind		X	X	X	
Solar	X	X		X	
Ocean-Wave & Tidal	X	X	X	X	
Hydrogen	X	X		X	
Fuel Cells	X	X		X	
Storage Systems	X	X		X	

Table 3
Peak Potential and Operating Characteristics of Available Resources

Resource	Winter Peak Day Output (MW)	Energy (Percent of Annual)		
		Winter[b]	Shoulder[c]	Summer[d]
Cogeneration	1100	flat	flat	flat
Combustion Turbines	420+[a]	as reqd	as reqd	as reqd
Hydroelectric	240	as reqd	as reqd	as reqd
WNP-3	1240	40	40	20
Advanced Coal	200	flat	flat	flat

[a] The amount of CTs installed is not inherently limited. 420 MW of peaking CTs is assumed to be realistic for the Puget Sound area. The first 350 MW of CTs could be operated in a firming non firm mode with an expected capacity factor of approximately 15%. Additional increments of combustion turbines would be operated as peaking units with an capacity factor of approximately 5%.

[b] Winter includes November, December, January, and February.

[c] Shoulder includesSeptember, October, March and April.

[d] Summer includes May, June, July an August.

It is important to note that the estimates shown in Table 3 reflect potential estimates based on current information available. This assessment indicates what is prudent to assume regarding what resources are available for development in the time frames indicated. Actual resource development could vary from these estimates both in terms of costs and characteristics. This could result from incomplete data or utility specific needs that dictate different resources or unique applications.

The estimates contained in this appendix do not dictate what will be developed. These decisions will be made by individual utilities meeting their individual needs in the context of the Puget Sound Electric Reliability Plan.

A. Oil and Gas Combustion

Steam

Technical Description

Steam-generated electricity is one of the oldest, most reliable technologies used in the electric power industry. The basic system includes a feedwater pump, a boiler, a steam turbine, and a condenser--all connected together in a cycle. Steam power plants operate on the basis of a Rankine thermodynamic cycle, also called the steam cycle, with water as the working fluid. In this cycle, a feedwater pump pumps water from the condenser to high pressure and introduces the water into the boiler. The heat from fuel combustion in the boiler's burner is transferred to the boiler water. The boiler develops high temperature, high pressure steam, which is used to drive a turbine-generator. After the steam expands through the turbine, it condenses to liquid and is ready to begin the steam cycle once again.

In the condenser, there are both gas and liquid phases as the steam condenses from gas to liquid. The cooling temperature of the condenser determines the exhaust pressure of the turbine because the vapor pressure of steam is fixed for a given temperature. At condensing temperatures of water supplied at $55^{o}F$ to $80^{o}F$, condensers actually draw a vacuum on the turbine exhaust which is less than atmospheric pressure.

Boilers can use almost any combustion fuel, but gas, distillate oils and coal are the most common. (Coal-fired steam power plants are covered in another section of this appendix).

Efficiency in steam turbine plants can be increased by superheating the steam beyond the saturation temperature that corresponds to the boiler exit pressure. However superheating offers only a marginal increase in overall cycle efficiency. A more common means to enhance efficiency is the use of "reheat." In a reheat design, steam is allowed to expand partially through the turbine before it is reheated along a lower steam saturation limit and expanded once again through a lower pressure turbine.

Steam plants also employ a "regenerative" cycle to increase efficiency. In this design, steam is extracted from the turbine after partial expansion and then used to preheat water in the boiler. All these measures require additional equipment and complexity, which adds cost.

Operating Characteristics

Steam plants are the mainstay of many utilities' power generation supply. As long as the fuel supply is constant, these plants can operate continuously and make good baseload supply. Because of the large thermal inertia of getting boilers, condensers, and turbines operating to design temperatures and pressures, steam plants do not have good load following characteristics and therefore are not suitable for peaking capacity. Small oil fired units can, however, be called into service during periods when peaking problems are anticipated. Oil fired steam plants have heat rates that run from 10,000-12,000 Btu/kWh. Availability of existing older oil fired boilers is relatively low because of high maintenance requirements. Availability of a new facility would be expected to be comparable to larger boilers, 60-75%.

Costs

Costs for new small oil/gas fired boilers are assumed to be the same as simple cycle combustion turbines. CT's, however, are the technology of choice for utility application because their performance and flexibility continues to improve, whereas boiler technology is mature.

Environmental Characteristics

Air emissions from natural gas-fired power plants typically are less pronounced than emissions from plants fired with oil, coal, and municipal solid waste. There is appreciable emission of NO_x, SO_x(except natural gas-fired), CO_2 gases, some carbon monoxide and hydrocarbons but few particulates. NO_x, CO and hydrocarbons can be eliminated or dramatically reduced with better burning control. SO_x can be controlled with scrubbers and by selection of fuel sources.

Condensers require considerable cooling water supply. If cooling towers are used, there is some drift of humid air which can also bring fog and steam plumes. If direct cooling is used, the water source temperature is increased by several degrees as it passes over the condenser; this may be a source of thermal pollution to a river or stream and affect the aquatic environment.

As with all large facility construction, there is dust, noise, a potential for soil erosion, and disruption of local communities.

Supply Forecast

There are currently less than 150 MW of oil/gas fired boilers installed in the Northwest. All of these facilities are older plants and are seldom operated because of their inefficiency. Oil/gas fired boilers, dedicated to utility application, are not considered likely because of the availability of combustion turbines. Combustion turbines are more likely to be acquired because of their simplicity, high reliability, low capital cost, quick starting, and flexibility to be upgraded to highly efficient combined cycle operation.

Combustion Turbines

Technical Description

Combustion turbines (or CT's, also called gas turbines) are the same technology used in jet engines. In the basic CT design, air enters a compressor which packs large amounts of air into a combustor at high pressure. In the combustor fuel is added to the air and burned, releasing heat energy and producing a high temperature, high pressure exhaust gas. This gas is expanded through a turbine, which powers the compressor and generator.

Natural gas or distillate oils are the primary fuels used in combustion turbines. Gasified fuels, such as the syngas derived from coal, are also potential fuel candidates. (Gasified coal is covered under "Coal" in another section of this appendix). Compared to steam turbine generation, the heat rate (Btu/kWh) for simple cycle gas turbines is about the same. Combustion turbine technology, however, is still improving and more efficient machines are expected to be developed.

The inefficiency of a combustion turbine can been seen in the high temperatures of the gases discharged from the turbine. There is significant available energy in the exhaust gases, which can be directed to a heat recovery process. One way to take advantage of this available energy is to use steam injection (which also has the benefit of reducing NO_x emissions). In a steam-injected turbine, hot exhaust gases are recirculated to heat pressurized water into superheated steam. The steam is then injected into the combustor of the turbine and mixes with compressed inlet air. The additional inlet steam helps drive the turbine.

CT efficiencies can also be improved by using multi-stage compressors with inter-cooling between stages and by operation at higher turbine inlet temperatures. Currently, turbines operate at temperatures around 2000^oF, but improvement in heat tolerant materials can increase this limit to more than 2300^oF.

The high thermal energy in the turbine exhaust makes CT's ideal in cogeneration applications where high grade process heat is used in addition to electricity. Another way to take advantage of the energy in the exhaust gases is to use the combustion turbine as the "topping cycle" in a combined cycle plant. (Cogeneration is covered under a separate section in this appendix.)

A combined cycle power plant combines a combustion turbine with a steam cycle plant to generate power more efficiently. Electricity is first generated from the combustion turbine. The exhaust gases from the CT then become the heat source for raising water to steam in a steam cycle system. The combustion turbine cycle is referred to as the "topping cycle" and the steam turbine cycle is the "bottoming" cycle.

Combined cycle plants are designed to maximize the thermal efficiency of a power plant by using the available energy in the combustion turbine's high temperature exhaust gases. The key to the combined cycle is the heat recovery steam generator system, which takes the place of the steam cycle boiler. Typical steam conditions in a heat recovery steam generator are 900-1000°F and 1000-1500 psi. Instead of rejecting heat to the environment at gas turbine temperatures of more than 1000°F, the combined cycle eliminates heat at the steam cycle condenser temperature, which is the temperature of available cooling water--around 50-70°F.

Combustion turbine technology is proven and widely used. CT's are simple, reliable, and easy to site. They can be installed with a minimum of site renovation and preparation because they are so compact and do not require additional equipment such as cooling towers or elaborate fuel processing subsystems.

Operating Characteristics

Simple cycle gas turbines can be fired up quickly and therefore are excellent peaking systems. Part load efficiencies, however, are lower than efficiencies when operating at design loads. For this reason, and because of high fuel cost, CT's tend to be used at a constant rate for a limited time period. Availability factors run from 80-90%. Simple cycle CT's have heat rates in the 11,000-12,000 Btu/kWh range. When operated in a peaking mode, capacity factors are relatively low, on the order of 5%.

Because of their excellent heat rates (7500-8000 Btu/kWh), combined cycle plants are candidates for both baseload and firming applications. If CT's are operated to "firm up" or supplement non-firm hydropower, capacity factors can range from 15 to 40%.

Combined cycles can be designed and operated to phase in the CT first, with the steam cycle portion added later. Commercial combined cycle technology is available and likely to be put into service as fuel costs increase.

Costs

Combustion turbine installed capital costs range from $330/kW to $700/kW. The capacities for these CT's range from 15 MW to 150 MW. The CT considered to be the most likely candidate for acquisition by a utility is based on a study performed by Seattle City Light. This CT has a 70 MW capacity and has an installed cost of approximately $420/kW (1990 $).

Environmental Characteristics

CT's that use natural gas are relatively clean burning. Only NO_x emissions tend to be a problem because of high combustion temperatures, but significantly less so than in coal combustion. NO_x can be controlled with water or steam injection into the CT combustor, eliminating up to 80% of the NO_x. Water use and visible steam plumes in this case become an environmental concern, but water use can be minimized by re-using the condensed exhaust steam for steam injection.

If oil fuels are used, there is some sulfur dioxide pollution. Exhaust gas SO_x can be mitigated with scrubbers, which adds to CT costs. As in all combustion technologies, significant amounts of CO_2, a "greenhouse" gas, and waste heat are produced. Simple cycle CT's release waste heat directly to the atmosphere, so cooling water is not required.

Since CT's tend to be sited close to where transportation and transmission lines meet, effects on urban environments need to be considered. As with jet planes at airports, CT noise can be a problem. Typical noise levels at 1200 feet from operating CT's run 65-70 decibels. Silencing packages can reduce this to 51 decibels at 400 feet.

Table 4
Costs - Combustion Turbines

	Simple Cycle	Combined Cycle
Capital Cost ($/kW)	389	620
O&M Cost		
Fixed ($/kW-yr)	2.32	7.51
Variable (mills/kWh)	3.14	0.10
Real Levelized Costs (mills/kWh)	a	a
Nominal Levelized Costs (mills/kWh)	a	a

[a] Combustion turbine cost depends on how they are used. When displaced by non-firm hydro power, combined cycle CT's have a cost of 26-34 mills/kWh(real). If installed for capacity only, simple cycle CT's have a capital cost of 400-500 $/kW.

Environmental impacts for combined cycle plants are the combined impacts of steam power plants and combustion turbines, both described in previous sections of this appendix. For the amount of fuel combusted, though, plant efficiencies are proportionately higher and therefore the environmental impacts are proportionately less.

Supply Forecast

The combustion turbine assumptions listed in the Scoping Report were based on large frame units that are just now entering the market. They are characterized by very high efficiencies and relatively large unit sizes. Discussions among members of the Local Generation and Evaluation teams resulted in a reassessment of the type of units that should be assumed for the Puget Sound study. As a result of these discussions, it was decided to use CT assumptions based on a study prepared by Seattle City Light for its Strategic Corporate Plan. It was felt that this more accurately reflected the conditions in the Puget Sound area.

The quantity of combustion turbines installed is not inherently limited. Constraints that are typically discussed include ability to site and availability of fuel supply. These constraints will not impose an impediment for the first several hundred megawatts. It is assumed that 420 MW of simple cycle CT's could be installed in the Puget Sound area without significant difficulty. The first 350 MW of combustion turbines installed could be used for firming non-firm energy. This translates to a capacity factor of approximately 15%. Any additional CT's that are installed are assumed to be for peaking purposes only. Peaking CT's are assumed to have a capacity factor of approximately 5%.

B. Coal

Conventional Coal

Technical Description

Conventional coal plants use the same technology as steam cycle plants fueled with oil, biomass, natural gas or municipal solid waste. One important distinction between coal-fired plants and other steam cycle plants using these fuels is the significant effort required to treat emissions, process fuel, and dispose of wastes that are peculiar to coal.

In a conventional steam cycle coal plant, heat from coal combustion is transferred to water in a boiler. The boiler raises water under high pressure to high temperature steam. The steam expands through a turbine, which drives a generator. After passing through the turbine, the steam is condensed to water again, then pumped back into the boiler with a feedwater pump to complete the cycle.

The same technologies used to increase efficiencies in steam cycle plants--regenerative cycles, superheat, and reheat--are used in coal plants. For more information on improving thermodynamic efficiencies in steam cycle plants, see the discussion of these technologies in the "Oil and Gas Combustion" section in this appendix.

Coal deposits are found in seams. Coal comes in many varieties and grades with varying concentrations of sulfur and ash content. Major categories include lignite, bituminous and anthracite. Because coal is a solid, it is pulverized and then blown into special burners to fire steam boilers.

Coal technology is well established and a prominent power source world-wide. During 1988, 56.9% of the electricity generated in the U.S. came form coal plants. Coal plants are generally designed as large centralized units, typically sized to 250 MW or more. Often, plants are located near mining sites for easy access to the fuel, or near large transmission lines.

Operating Characteristics

Coal plants are designed as baseload power generators, with optimum performance at design load. Part load operation is less efficient, and coal plants are not designed for short term peaking operation. The thermal inertia of getting boilers, turbines and condenser up to temperature inhibits quick response to variations in load. Availability factors in percent range from the mid 70s to the high 80s, and capacity factors generally exceed 65%. Capacity factors are assumed to equal 70% for planning purposes. Current generation coal plants have heat rates less than 10,000 Btu/kWh at design load.

Costs

Cost estimates for coal fired coal resources are derived from documentation prepared for Bonneville's 1990 Resource Program. Fuel costs assume delivery of coal from the East Kootenay coal field to the Puget Sound area.

Table 5
Costs - Conventional Coal

Capital Cost ($/kW)	1663
O&M Cost	
Fixed ($/kW-yr)	31.48
Variable (mills/kWh)	3.8
Fuel Cost ($/MMBtu)	1.61
Real Levelized Costs (mills/kWh)	49
Nominal Levelized Costs (mills/kWh)	97

Environmental Characteristics

What distinguishes coal plants from steam cycle plants fired with other fuels are the subsystems built in to accommodate the quantities and concentrations of pollutant emissions.

Among the greatest environmental concerns in using coal are the emissions of oxides of sulfur and nitrogen (SO_x and NO_x) and CO_2. SO_x, and NO_x to some extent, are the culprits of acid rain. CO_2 introduces a "greenhouse" gas which may have environmental impacts. Although there are ways to scrub exhaust gases to reduce SO_x and NO_x, there is no effective way to mitigate CO_2 pollution. The region currently has about 3,200 average MW of coal-fired generation, much without significant scrubbing capability. Adding scrubbers would reduce SO_x emissions by about 70%.

Coal combustion produces particulates; most can be removed with filters and electrostatic precipitators. Coal is also contaminated with trace amounts of heavy metals and radionuclides, such as lead, cadmium, arsenic and radium-226, which vary with the source of coal.

Plants, called "minemouth" generators, are often sited near the coal source. If plants are far from transmission grids, transmission lines must be built. Construction of power lines and substations introduces a secondary environmental impact.

Centralized thermal plants also require large quantities of cooling water to carry waste heat from plant condensers. There is a large localized effect of a central power plant. Air quality, transportation, burner waste, ash disposal, cooling water, noise, and land disruption are all expected impacts.

Supply Forecast

The region has one large coal plant located west of the Cascade Mountains at Centralia, Washington. This plant is a minemouth plant designed to use the coal at that site. No new additional plants are considered to be available for the Puget Sound area because of difficulties in siting a large coal facility in the Puget Sound area, as well as the lead time required. A large thermal facility such as this would take ten years to site and construct.

Advanced Coal - (Fluidized Bed Combustion, Gasification)

Technical Description

There are several advanced coal technologies that offer better heat rates (higher thermal efficiencies) and greatly reduced emissions compared to the conventional steam cycle coal plant.

Atmospheric fluidized-bed combustion (AFBC) is an advanced coal technology that is gaining wide acceptance throughout the world. In a fluidized bed a fluid such as air, steam, or oxygen is blown into a reactor vessel. With the help of a fluidizing agent such as sand, the fluid entrains fuel particles in its stream and bubbles or fluidizes them in the combustion zone of the reactor. This fluidizing effect promotes effective heat transfer and complete combustion. Limestone is mixed with coal in the fluidized bed to trap the sulfur. Removing much of the sulfur with this design reduces or eliminates flue gas clean up of the combustion gases.

Pressurized fluidized-bed combustion (PFBC) reactors are operated at high pressures; the exhaust gases can then be used to supply a combustion turbine. Typical reactor conditions may be 16 atmospheres of pressure with a bed temperature of 1580^{o}F. PFBC technology is now progressing to the demonstration stage, but still lags behind AFBC technology.

Coal gasification technology thermally decomposes solid coal into a high quality fuel that can be burned in a combustion turbine. In gasification, the coal is partially oxidized producing mostly CO and H_2, which are combustible gases. A subsequent acid process removes the sulfur from the gas stream and converts the reactants to hydrogen sulfide, which is easily removed. Gasification provides a clean, combustible gas, referred to as "syngas," that is almost entirely sulfur-free.

One of the most efficient coal combustion systems is a combined cycle plant that uses a combustion turbine as the topping cycle and a steam cycle plant as the bottoming cycle, with a gasifier as the fuel processor. The 100 MW Coolwater plant near Barstow, California has successfully demonstrated this design using an oxygen-blown gasifier. Compared to an air-blown gasifier, the BTU content of syngas from an oxygen-blown gasifier is higher.

A combined cycle plant like Cool Water could be developed in stages. The first phase would be a combustion turbine, initially using natural gas or distillate oil as the fuel source. Phase two would add a steam cycle plant to take advantage of the exhaust heat from the gas turbine to generate steam for a steam turbine. Lastly, a gasification plant could be added and syngas from coal would become the final energy source.

Operating Characteristics

Advanced design coal plants are designed as baseload power generators, with optimum performance at design load. Part load operation is less efficient, and plants are not designed for short term peaking operation. The thermal inertia of getting boilers, turbines and condenser up to temperature inhibits quick response to variations in load. Availability factors in per cent range from the mid 70s to the high 80s, and capacity factors generally exceed 65%. Capacity factors are assumed to equal availabilities for planning purposes. Fluidized bed designs have capacity factors that range from 9,800 to 10,300 Btu/kWh. Coal gasification plants have heat rates under 9,500 Btu/kWh.

Costs

Cost estimates for coal fired coal resources are derived from documentation prepared for Bonneville's 1990 Resource Program. Fuel costs assume delivery of coal from the East Kootenay coal field to the Puget Sound area.

Table 6
Costs - Advanced Coal

	AFBC	Gasification
Capital Cost ($/kW)	1755	2276
O&M Cost		
Fixed ($/kW-yr)	37.10	52.32
Variable (mills/kWh)	4.8	0.8
Fuel Cost ($/MMBtu)	1.61	1.61
Real Levelized Costs (mills/kWh)	47	48
Nominal Levelized Costs (mills/kWh)	83	85

Environmental Characteristics

Because of combustion characteristics of fluidized beds and gasifiers, NO_x emissions are inherently low and SO_x emission are dramatically reduced compared to conventional coal. However, European experience with fluidized bed combustion suggests that these systems may actually produce higher NO_x concentrations than conventional coal plants. Studies are underway to investigate this concern.

Environmental controls can cost as much as 40% of the capital cost and 35% of the operating costs of a modern coal plant, and consume 3 to 8% of the energy generated.

Other pollutants and emissions from advanced coal systems are similar to conventional coal. Mining, transportation, fuel handling, ash disposal, and cooling water problems are similar for both conventional and advanced coal technologies.

Supply Forecast

Several small (less than 250 MW) atmospheric fluidized bed facilities are operating worldwide. The large and stable supply of coal, as well as the superior emission characteristics of the AFBC technology has been a catalyst for this development. Developers have been investigating the Northwest for potential application of this technology with cogeneration applications.

Because of this developer interest, small plant size, relatively short lead times, and superior air emission effects, 200 MW of supply is considered to be available to the Puget Sound area. This could be one or two small plants. The ability to site such plants is considered to be easier than a large conventional facility. Lead times, 7 years, are also shorter.

C. Nuclear Fission - Completion of WNP-3

Technical Description

When atoms of radioactive uranium-235 are spilt in a controlled fission reaction, the heat energy can be released in a reactor to generate electricity.

Commercial nuclear power plants use the steam cycle and have two basic designs: the pressurized water reactor (PWR) and the boiling water reactor (BWR). The PWR design uses three separate, sequential heat transfer systems. The first is the reactor coolant system that circulates high pressure hot water from the hot reactor core to the steam generator heat exchanger. The steam generator heat exchanger is the second system, where heat from the reactor coolant boils water to steam, which is then used to drive the turbines. The third system condenses the steam from the turbine. None of the fluids in any of these three systems ever comes into contact with the fluid in another; only heat is transferred between each system.

Boiling water reactor designs use two sequential systems. The first system circulates water through the reactor core itself, where steam is generated then introduced directly to the steam turbines. After expanding through the turbines, the steam proceeds to the condensers. A separate water system brings cooling water to the condenser.

In both the BWR and PWR systems, heat from the condensers is discharged to the atmosphere via cooling towers. Cooling towers eliminate heat by evaporating water.

Nuclear fission power is a proven commercial technology and reactors have been on-line since the 1950s. As of mid-1989 there were 110 reactors operating in the U.S. with a combined capacity of 97,000 MW, producing nearly 20% of the country's electricity. There are only two commercial nuclear plants operating in the Pacific Northwest: the Trojan plant near Ranier, Oregon on the Columbia River, and the Washington Nuclear Power Plant (WNP-2) on the Hanford Reservation near Tri-Cities, Washington. The Trojan plant is a 1216 MW (gross) pressurized water reactor plant in service since 1976. The 1154 MW (gross) WNP-2 facility is a boiling water reactor plant in-service since 1984.

The proposed WNP-3 facility is a 1250 MW net capacity PWR commercial nuclear plant designed by Combustion Engineering, located near Satsop in Grays Harbor County, Washington. WNP-3 is about 75% completed. It has been in a preserved state since July, 1983 when construction was suspended.

Operating Characteristics

Nuclear plants are best operated in baseload mode at their rated MW output. Like all steam cycle plants, nuclear plants have a large start-up inertia and cannot respond quickly to changes in load demands. WNP-3 would, therefore, not be a peaking facility.

Historic data show expected availability factors for PWR nuclear power plants are between 60 and 65%. Availability for plants designed by Combustion Engineering--and WNP-3 is included in these--tends to be on the high end of this range. Capacity factors, always less than availability, range in percent from the low 30s to almost as high as the availability.

Costs

WNP-3 - As a result of public input that BPA received during the review of its draft 1990 Resource Program, BPA recommended deferral of a new comprehensive study of the future of WNP-3 until significant information becomes available or conditions change sufficiently to warrant a new study. Both cost-to-complete and O&M cost assumptions would be reviewed as part of a study.

Detailed cost to complete construction estimates were prepared by the Supply System owners of WNP-3 and its contractors in 1984. In 1986 the Supply System updated the 1984 estimates in support of Bonneville's 1987 Resource Strategy. Operation and maintenance (O&M) cost estimates were also reviewed in 1986. The Power Planning Council reviewed O&M cost for nuclear power plants for its Draft 1991 Northwest Conservation and Electric Power Plan. It reported that although O&M cost have escalated rapidly from 1974 to 1984, escalation has peaked and declined in later years. The Council assumes that the real rate of operating and maintenance cost escalation will decline from 3.5 percent annually in 1986 to zero percent (real) by 2000.

The 1986 cost estimates (in 1988 $) are shown in Table 7. Due to power flows, only 60 percent of the capacity of WNP-3 is available to the Puget Sound area. For analysis purposes the capital cost is spread over this reduced capacity resulting in a capital cost of

1899 $/kW (1990 $). The O&M costs were also adjusted and lumped into the fixed component, yielding an O&M cost of 193 $/kW-yr (1990 $).

Table 7
Costs - WNP-3

Capital Cost ($/kW)	1054
O&M Cost	
Fixed ($/kW-yr)	84.15
Variable (mills/kWh)	6.75
Real Levelized Costs (mills/kWh)	34
Nominal Levelized Costs (mills/kWh)	65

Environmental Characteristics

The environmental impacts of nuclear energy fall into the categories of mining uranium ore and fuel processing, plant construction, electricity production, and waste disposal.

Uranium is mined in open pits. Exploration, drilling, and blasting in mining operations can disrupt local ecology and contaminate groundwater. Land reclamation problems are similar to those of coal mining, but on a much smaller scale comparatively because the energy content of uranium ore is of a much higher density than that of coal. Miners must take precautions to avoid the risk of inhaling radioactive material. Radioactive uranium tailings can contaminate water supplies and be borne on the wind and must be disposed of properly.

During construction, there are land erosion and dust pollution impacts and disruptions to the local economy. These are transitory and typical of large construction projects. Since WNP-3 is already about 75% complete, the Satsop community has already experienced many of these construction impacts.

The primary impacts from operations at a nuclear plant are the release of heat and moisture from the plant cooling system, cooling tower drift, and airborne radioactive materials. With the exception of the airborne radioactive emissions, heat released in large clouds of condensed steam from cooling towers is a common effluent from large thermal generating plants. Even coal-fired plants release some radioactive materials in minute concentrations.

Radioisotopes are fission products formed as a result of uranium and plutonium fission in the reactor. These include actinides and activation products. Actinides are the isotopes of elements having atomic weight of 89 and greater. Activation products include radioisotopes formed by the neutron flux during reactor operation.

The containment building of a nuclear reactor is designed to withstand severe natural forces, especially seismic, to contain any released radionuclides in the event of a loss in reactor cooling. There is the potential for the core to overheat, but redundancy is built in to back up the primary cooling system.

Gaseous radioactive effluents include fission product isotopes of noble gases, krypton, neon, and argon--the primary source of direct, external radiation emanating from a plant's effluent plume--and carbon-14, tritium and radioiodines. These products can be controlled through filtration and by collecting them and allowing them to decay to acceptable radiation levels before they are released. Particulates--such as the fission products of cesium and barium, and activated products of cesium and barium, and activated corrosion products such as cobalt and chromium--are controlled by filtration in high efficiency filters.

Besides airborne gases and particulates, there may be some release of waterborne radioactive materials including fission products such as nuclides of strontium, and activation products such as sodium and manganese, and tritium.

Experience designing, constructing and operating nuclear power plants indicates that the average annual release of these kinds of radioactive materials and effluents typically will be a small percentage of the limits specified by federal safety regulations. All aspects of nuclear power plants are continuously monitored to ensure allowable limits are not exceeded.

Other potential water-related effects of nuclear power plant operation include thermal discharges, water consumption and release of waterborne chemical pollutants. Make up water in cooling towers tends to concentrate mineral salts and other contaminants in the coolant system over time. These are controlled with periodic "blow down" to introduce fresh coolant. Blowdown can be environmentally damaging but can also be treated to remove impurities.

Radioactive waste disposal, however, continues to be a problem. Waste is classified as high-level, transuranic or low-level. High-level waste has high concentration of beta and gamma emitting isotopes and significant concentrations of transuranic materials, including plutonium. Spent fuel is the only reactor product that falls in this category. Reactors produce about 400 ft^3 per year of spent fuel. Fuel is placed in rods separated by graphite. The graphite absorbs radiation and modulates the reaction. In a typical commercial reactor, about 1/4 of the fuel is replaced each year.

Transuranic wastes have low levels of beta and gamma emissions but significant concentration of transuranic isotopes. Transuranic waste are produced during reactor operation but contained within fuel elements unless the cladding is broached.

Finally, low-level waste are characterized by a low-level of beta or gamma emissions and insignificant concentrations of transuranic materials. These wastes may become radioactive during normal operations. Low-level wastes include clothing, paper, spent ion-exchange resins, filters and evaporator concentrates from isolated parts of the reactor building. Generally, these wastes are disposed of by allowing them to decay and diluting them to acceptable concentrations that are much less than those found naturally.

Although operational and safety risks can be addressed, long-term disposal of nuclear wastes remains an unresolved problem. In 1982, Congress passed the Nuclear Waste Policy Act making the federal government responsible for the ultimate disposal of high-level nuclear wastes, which includes the spent fuel from power plants. There have been delays due to state resistance and management problems, and the siting and use of a long-term repository still remains a problem.

Supply Forecast

As a result of public input that BPA received during the review of its draft 1990 Resource Program, BPA recommended deferral of a new comprehensive study of the future of WNP-1 & -3 until significant information becomes available or conditions change sufficiently to warrant a new study. Both cost-to-complete and O&M cost assumptions would be reviewed as part of a study. The 1990 Resource Program indicated that a new study would be deferred at least until 1991. The scoping process for the 1992 Resource Program is currently underway. This process will consider how WNP-1 & -3 will be treated. For Puget Sound Electric Reliability Plan study purposes, WNP-3 was considered to be available. This is the same assumption that was used in BPA's 1990 Resource Program. Actual disposition of WNP-3, however, is not determined in Puget Sound Electric Reliability Plan.

D. Nuclear Fusion

Technical Description

Fusion, the energy that fuels the sun, is an inexhaustible energy source researchers are trying to harness on earth. But the high pressure, high temperature conditions on the sun required to fuse atomic nuclei, are difficult to duplicate on earth. Deuterium, an isotope of hydrogen with one extra neutron, is the best candidate for a fusion fuel. One out of every 6000 water molecules found in nature contains deuterium. Water made up of molecules with deuterium is referred to as "heavy water."

At high enough temperatures, electrons orbiting gas molecules have enough energy to leave their orbits, creating matter of charged ions called a plasma. These charged ions can be contained by an electromagnetic field. If the energy is high enough, plasma ions can overcome the tremendous force that keeps atomic nuclei apart and fuse when they collide. In the process, mass is lost and energy is released. Two deuterium ions fuse to form a helium ion with one neutron. The residual neutron is freed up, carrying with it most of the energy released in the fusion.

There are two principle fusion technologies being developed: the tokamak magnetic confinement and the laser pulse inertial confinement. At the Princeton Plasma Physics Laboratory, a toroid-shaped chamber resembling a doughnut serves as a reactor chamber. Using timed magnetic pulses the generator can heat a plasma gas to 670 million degrees--25 times hotter than the interior of the sun. The magnetic coils generate a magnetic field 100,000 times stronger than the earth's own magnetic field to confine the plasma.

Lawrence Livermore Laboratory in California is the site of an inertial confinement project. Rather than trying to contain a plasma in a magnetic field, inertial confinement concentrates tremendous energy in a short amount of time at deuterium pellet. The trick is to focus all the energy simultaneously from all sides to get the pellet to absorb all the energy. The deuterium experiences temperatures of 10 to 50 million degrees and enormous pressure in less than a billionth of a second. The resulting implosion fuses the atoms of the energy pellet. Vast capacitor banks are needed to supply the electricity used for short laser pulses. These synchronized pulses are on the order of 60 trillion watts per square inch for each of the ten beams used in the Nova system at the Lawrence Livermore Laboratory.

In March, 1989 University of Utah chemists Stanley Pons and Martin Fleischmann reported that they had achieved fusion at room temperature, using electrolysis with a palladium catalyst. Subsequent experiments trying to duplicate their tell-tale products of fusion, high neutron flux and a net gain in energy, have not been successful. Since other researchers have been unable to corroborate Pons and Fleischmann's results, the Utah team's discovery has been largely discredited.

Controlled fusion is still a long ways off, at least two to four decades. Researchers have yet to reach a "break even" point, where the energy used to produced a fusion reaction is balanced by the fusion energy generated in the reaction. Right now, researchers are setting their sights on a more modest goal of "ignition"--to produce enough fusion energy to sustain a fusion reaction.

Operating Characteristics

It is premature to estimate the operating capabilities of fusion power reactors since the technology does not even exist yet. If fusion technology becomes commercially available for electric power generation, it will likely supply baseload capacity.

Costs

No reliable cost information is available for this technology.

Environmental Characteristics

Many people believe that fusion energy would be the panacea to all our energy problems, especially the environmental ones. Although a fusion reactor would generate radiation, reactor walls could be adequately shielded to absorb it. The containment walls would then become radioactive, but this radioactivity would be relatively short-lived and low-level compared to fission byproducts.

Supply Forecast

Fusion is considered to be in an early stage of development. It is not considered to be an available resource.

E. Geothermal

Technical Description

Geothermal energy taps the heat available from within the earth's core. Heat, water, and permeable rock found in combination are the requirements for a hydrothermal resource for power generation. Generally, wherever tectonic plates abut against each other there is the potential for geothermal resources. At these points, the earth's mantle is relatively thin and fault systems give way to earth quakes and volcanoes; magma protrudes close to the surface, bringing geothermal heat with it. High temperature gradients found in drilling, hot springs and geysers, and certain kinds of geologic formations and geochemistry provide strong evidence of the possibility of hydrothermal systems lurking beneath the earth's surface. The biggest problem with developing geothermal resources is first finding the resource.

Drilling to depths as much as 10,000 feet is often required to locate a production well to bring the geothermal steam or fluid to the surface where it can be processed through a power plant. Prospecting for high quality geothermal reservoirs is a risky and expensive business.

There are three principal types of geothermal conversion technologies used in power generation: (1) dry steam, (2) flash, and (3) binary cycle plants. In dry steam systems the geothermal resource is a gas at temperatures in excess of 350°F. High pressure geothermal steam is drawn up through wells as a gas and goes directly through a turbine; then it condenses to a liquid to be injected back into the reservoir.

In flash systems, the geothermal resource is found as a pressurized liquid brine at temperatures greater than 350°F. Because the resource is a fluid under high pressure, it must be "flashed" or depressurized to a gas state, before it can be processed through a turbine. When geothermal fluid flashes, only a portion of the liquid becomes steam, the rest remains as a high pressure liquid. Depending on the temperature and pressure of the brine as it leaves the well head, geothermal fluid may be flashed twice in sequence to maximize the "quality" or proportion of steam possible from the fluid.

Binary systems extract heat from geothermal fluids that have relatively low temperatures, less than 300°F. A binary system must use another working fluid besides the geothermal brine, such as Freon, that has a low boiling point compared to water. In a binary system there is the geothermal loop, a working fluid loop, and a cooling loop--all three are separate and do not mix. The geothermal loop imparts heat to the working fluid in an evaporator where the working fluid boils to a gas. The hot gas expands through a turbine-generator. Finally, the cooling loop runs through a heat exchanger and condenses the working fluid. Binary systems have used geothermal resources with temperatures as low as 177°F.

Temperature and pressure of the resource dictate the choice of technology employed at a particular geothermal site. Geothermal energy is being used world-wide with a high degree of success. In California, at the Geysers field alone, there are about 2000 MW on-line tapping a dry steam geothermal reservoir. Other active geothermal regions in the U.S. include the Basin and Range geologic province covering parts of Utah, Nevada, and Idaho, and California's Imperial Valley.

Typically, geothermal plants are sited in 20 to 50 MW units, but modular systems as small as 5 MW have been developed. One advantage of small-scale modular units is that they can be used to help evaluate a reservoir's characteristics while generating power.

Operating Characteristics

Geothermal power is a highly reliable baseload energy source, with high availability and high capacity factors ranging from 90-95%. The high capacity factors experienced at plants in California, Nevada, and Utah are due in part to a combination of redundant equipment, conservative nameplate ratings, and contractual incentives.

Costs

The cost data for the geothermal resource used the Power Planning Council's Staff Issues Paper 89-36, Geothermal Resources as its source. This data reflects a range of geothermal conversion technologies at sites with defined geothermal resources. Costs would be expected to vary depending on site specific conditions.

Table 8
Costs - Geothermal

Capital Cost ($/kW)	2670-2920
O&M Cost	
Fixed ($/kW-yr)	86.00-95.00
Variable (mills/kWh)	1.3
Real Levelized Costs (mills/kWh)	42-74
Nominal Levelized Costs (mills/kWh)	64-113

Environmental Characteristics

Depending on the kind of conversion technology and the size of the facility, geothermal resource development can have significant environmental impacts. Some of the environmental impacts described here may only apply to binary, flashed, or dry steam systems, but not all three. Plant size, siting, and operation and maintenance practices also affect the magnitudes and kinds of impacts that may be expected. Many of these impacts, however, can be mitigated and geothermal energy can provide a reliable, relatively clean generation alternative.

Geothermal energy conversion requires processing large quantities of fluids and gases. Dry steam systems, and flash steam systems to some extent, introduce non-condensible gases into the environment, particularly hydrogen sulfide, H_2S. In small concentrations, H_2S has an unpleasant odor like rotten eggs. In large concentrations, the gas paralyzes the olfactory nerves and becomes undetectable; it is lethal at high enough concentrations. H_2S can accumulate in low pockets and threaten plant species and wildlife. Carbon dioxide, another non-condensible gas, is also discharged into the atmosphere in significant amounts. But the concentration of CO_2 is about 1/30th that emitted by a coal plant per kilowatt-hour. Other contaminants from geothermal steam pose a less serious hazard compared to hydrogen sulfide. In dry steam, there are small concentrations of boron, arsenic and mercury.

Waste heat in condensing steam from turbines poses another environmental concern. Large quantities of waste heat are dumped into the environment, mainly from cooling towers. Clouds of condensing steam from the towers may affect local climates producing fog and causing a visibility hazard, especially on roads. Large quantities of cooling water are needed to operate the cooling system. Condensed steam can be used as a coolant, augmented by some additional water supply. Water needs for power generation, particularly in arid areas, may conflict with local agriculture, mining, or public uses.

Water quality can be a problem at a geothermal site. Brine coming to the surface from supply wells and returning through injection wells has the potential to contaminate local water tables. Most geothermal fluids are highly saline and contain trace toxic elements such as boron, mercury, lead, ammonia, and arsenic. Manganese and iron also may be found, which makes water acidic. Also, there is the potential for leakage into shallow aquifers or accidental release of brine into streams or lakes.

Waste products pose problems unique to geothermal energy. There are hazardous wastes from drilling, hydrogen sulfide abatement, and concentrated scaling from brine residue. Containment, processing, and removing these chemicals pose risks in transportation and handling.

Like any major construction activity, developing geothermal sites has a major impact on local communities. There is heavy road use, land erosion, disruption of local ecosystems, and noise. Some of these effects are transitory while others are ongoing during plant operations. Energy reproduction may require only about 20 to 100 acres for a 50 MW plant, but the exploration, drilling, construction and operation facilities may encompass from 500 to 3000 acres.

Another concern in geothermal operations is the maintenance of the geothermal reservoir. Normally, re-injection of the brine helps recharge fluids into a geothermal reservoir and prevent subsidence of the well field. Injection, on the other hand, also may induce seismic activity due to high local pressures from the reentering fluid.

There are also social and economic effects of geothermal development. Rapid, intense development in a locale can tax a community's resources to provide schools, housing, and other essential services. Finally, aesthetics are a major concern. The visual impact of a well field and power plant facilities may be objectionable, especially in pristine areas such as the Cascades where many potential geothermal sites exits.

By far, the most pronounced environmental impact from dry steam and flashed steam plants is the emission of hydrogen sulfide. Mitigation measures include abatement using the Stretford process to trap nearly 99% of the non-condensible H_2S emissions, reducing the compound to elemental sulfur and hydrogen. Other control methods include a hydrogen peroxide/iron catalyst process to remove 90 to 98% of the hydrogen sulfide left in steam condensate. Control of well head ventilation and burning vent gas also can reduce H_2S. H_2S emissions, though, are not a problem in binary power systems because the geothermal fluid remains in a closed loop in a binary system.

Alternatives to using water for wet cooling are dry cooling towers, which are large and expensive, and reusing of the geothermal steam after it condenses as a cooling water source. Slant drilling to locate several wells from one pad reduces land impacts. Loud noise, caused by steam release at wells can be muffled to avoid hearing injury to field workers. Risks associated with hazardous wastes can be minimized by good safety practices and accident prevention in transportation and handling. Some wastes can be incinerated and rendered harmless.

In general, geothermal steam or brine chemistry, the conversion technology used, and the characteristics of the geothermal reservoir will dictate the primary environmental concerns associate with a particular plant. Each site will pose its own peculiar environmental problems, which must be dealt with on a site-specific basis.

Supply Forecast

The technology of geothermal energy is well established and demonstrated. It can, however, only be applied where a recoverable geothermal heat source exists. The only demonstrated use of geothermal energy in the Northwest is a now defunct binary cycle demonstration plant at Raft River, Idaho.

The most likely locations in the Northwest for geothermal development are the Basin and Range province (southeastern Oregon and southern Idaho) and the high Cascades of southern Oregon. The closest potential to the Puget Sound area is in the Cascades (Mt Baker area). However, there are no confirmed electricity grade geothermal sources in the area. Consequently, no supply is projected to be available in the Puget Sound area.

F. Hydroelectric

Conventional

Technical Description

Water power is one of the oldest, simplest forms of power. In its modern manifestation, the potential energy of water is released as it drops a significant elevation through a turbine to generate electricity. Water is piped to the turbine through a "penstock," starting at the "forebay," or entrance to the penstock. Available energy is proportional to the elevation difference between the forebay and the turbine blades. This height is often referred to as feet of "head."

Hydroelectric projects can have dams associated with them to store water and create head, or they may be "run of river" plants that take a portion of a river's flow out at a high elevation, drop it through a penstock and turbine, and release it at a lower level. Most of the potential projects in the Puget Sound area are small run of river designs.

Planners make a distinction between firm and non-firm energy generated by the hydro system. Firm energy is energy that is available under critical water conditions. The critical water condition for a particular project is determined by examining the flow records available for the particular river or stream and assessing the historical low flows. This determines how much flow and hence energy can be planned. Non-firm energy is produced by water flows that are above the critical flows. Since firm energy is planned for, it has a higher value than non-firm. Because stream flows vary greatly from year to year, the non-firm energy is also quite variable.

Operating Characteristics

To determine the operating characteristics at a particular site, information on the local hydrology must be examined. If not provided by the developer, planning models have the capability to estimate flows based on existing records of such information as the drainage areas above the site, precipitation records, and information on local groundwater conditions. Hydrologic conditions vary greatly over the region, even within basins and sub-basins. In the west, winter storms produce immediate high flows, and in the east, flows are predominantly from melting snow in the spring. A particular project's elevation will also affect the shape of its output. For the Puget Sound Electric Reliability Plan, however, it is the cumulative peaking capability of the total potential that is of interest. For purposes of this study, the peaking capability is assumed to equal the installed capacity of the potential.

A logical question to ask regards the impact of extreme cold weather on the operation of small hydro plants and the consequent effect on the estimate of hydro potential in the Puget Sound area. It is possible for extreme cold conditions to degrade performance or to halt the output of a small hydro facility. However, the projects most likely to be affected by these conditions are at higher elevations. Projects at higher elevations tend to be smaller and account for a small portion of the total population of hydro sites. This, in conjunction with the development probabilities that are applied to the individual projects, results in an insignificant reduction in the peak availability that is being projected.

Costs

The cost projections shown in Table 9 are either supplied by potential developers or calculated by an algorithm (Hydropower Analysis Model-HAM) contained within the Northwest Hydroelectric Supply (NWHS) model. This algorithm uses individual developer estimates if they are available from permit and license applications. When consistent estimates are not available, the model develops a cost estimate from the physical characteristics contained in the application. All of the cost estimates are then aggregated into generic cost categories.

Table 9
Costs - Hydroelectric

Capital Cost ($/kW)	985-2000
O&M Cost	
Fixed ($/kW-yr)	21.00-44.00
Variable (mills/kWh)	0
Real Levelized Costs (mills/kWh)	16-55
Nominal Levelized Costs (mills/kWh)	32-110

Environmental Characteristics

As noted earlier, none of the projects that are considered in the potential for the Puget Sound area are located in the Northwest Power Planning Council's Protected Areas. This screens out any projects that might have an impact on anadromous fish populations.

A hydrolelectric project that has an impoundment (the capability to store water) associated with it would generally have a more severe impact than a run of river project. This would especially be true for large impoundments (> 100 acres). A review of the 150 sites in the Puget Sound area identified three sites that have existing impoundments and three that have potential impoundments. Of the three with potential impoundments one has had the license withdrawn, one is not being pursued by the developer, and one is relatively small (5 MW capacity). If these three sites were eliminated from the data set the effect on the overall estimate of potential would be insignificant (<5 MW drop in capacity) because of the development probabilities that are already assigned to these projects.

The data set shows an additional 22 sites that have no indication whether or not they have an impoundment. Only three of these 22 sites are of a significant size (> 10 MW capacity). Of these three, two have had the license dismissed and the third has no impoundment per the developer. The remaining 19 sites are small in size and can be assumed to have no impoundments.

The conclusion that should be drawn from this discussion is that the 240 MW potential (see the supply forecast section below) identified for the Puget Sound area essentially contains no new large impoundments. Even if the data base were purged of the sites with identified new impoundments, the effect on the 240 MW estimate would not be significant.

Supply Forecast

The procedure used to generate the Puget Sound estimates is the same as that used by Bonneville and the Power Planning Council to generate regional estimates used for power planning purposes. This procedure uses the Pacific Northwest Hydro Power Site Data Base which includes data on all projects that have been filed with the Federal Energy Regulatory Commission (FERC). The data base analysis system has the capability to estimate project cost, capacity, and output where this information was not provided by developers. The Protected Areas identified by the Council defines those areas which should not be developed due to anadromous fish impacts.

The procedure used to develop estimates of potential for this study involves several steps:

a. All sites not in the Puget Sound study area were eliminated from the supply data set.

b. Sites that were located in the Power Planning Council's Protected Areas were screened out of the analysis.

c. About 150 sites passed these two screens. However, even projects passing these screens could have environmental problems that may preclude development. In addition, the technical characteristics of many of these sites have not been fully explored, leading to the possibility that development may not be feasible for engineering, environmental, or economic reasons. To account for these factors, probabilities of completion were assigned based on the stage at which the project stands in the regulatory process (permit pending to license granted), the layout of the project (diversion to canal), and the status of the waterway structure (existing to undeveloped).

c. These probabilities (ranging from 20% to 95%) were applied to the capacity and energy potential of each project to obtain a probable contribution. The probable contributions of individual projects are then summed to obtain the Puget Sound potential.

This method produces a statistical estimate of the expected developable hydropower (240 MW) without the need to determine if specific individual projects should be developed--a determination that would be inappropriate given the limited information available on a specific project and stream reach.

It is important to remember that even though a specific project is included in the estimate of potential in the Puget Sound area it does not mean the site will or will not be developed. This methodology is intended to provide a macro assessment of the potential in the area. The presence or absence of a specific project has a minor effect on the overall projection for the small hydro resource.

The Puget Sound Area Electric Reliability Plan is not the forum for deciding whether a specific project will or will not be developed. The FERC licensing process, with its extensive public review process provides this forum on a project by project basis.

Other Hydroelectric Technologies

Pumped Storage

Like most utility storage technologies, off-peak energy is used to "charge" or fill a reservoir, which is then discharged during peak demand periods in a cyclic fashion. A typical pumped storage system uses a reversible pump/turbine and a reversible motor/generator. During off-peak charging, the motor drives the pump and delivers water to an elevated reservoir. During peak periods, the water is released and runs back through the reversible pump, which serves as the turbine. The turbine drives the electric motor in reverse, which works as the generator.

A modular energy storage system uses a closed pumped hydro technology. It differs from the traditional pumped storage in that it uses groundwater to charge a relatively small closed system, thereby avoiding fish impacts. Since it does not depend on surface water flow, its location is more flexible than traditional hydro or pumped hydro. A typical installation would have a 100 MW capacity (twin 50 MW units) and would cost $700/kW (turn-key installation). There are several potential sites in the Puget Sound area where modular systems could be installed.

A disadvantage of any pumped hydro system in the Northwest is that it is a net energy loser. Since the Northwest is an energy deficit region, the loss of energy makes pumped hydro systems an expensive alternative to more traditional ways (e.g., combustion turbines) of acquiring capacity. Although there may be specific applications where such facilities make economic sense, such facilities are not considered to be a competitive resource for Puget Sound capacity needs.

Water Supply (Pressure Reduction)

Many water districts have pressure reduction valves located in their distribution pipelines. If these valves could be replaced with small hydro turbines, there would be additional generating capacity from municipal water districts. A detailed assessment of the potential of this type of conversion was not performed for the Puget Sound area, although the potential is anticipated to be small. A characteristic of this type of installation is its operation would be a function of the water system demand and would not be available for dispatch based on the need for electric power.

G. Biomass Fired - Direct Combustion or Gasification

Technical Description

Direct combustion and gasification are two technologies used to convert biomass into electrical energy. Biomass energy conversion technologies and power plant systems are very similar to those used in coal combustion or coal gasification. Just like coal, biomass can be burned in a fluidized bed reactor, incinerated in a waterwall steam boiler, or gasified. (See also the "Coal" and "Municipal Solid Waste" sections of this appendix for more information on these conversion technologies).

Direct combustion burns the biomass fuel and transfers the combustion heat directly in a boiler to make steam. Because biomass moisture content may be highly variable, pre-drying is often prescribed so that the fuel can be introduced to the boiler within an acceptable range of moisture content.

Like coal, wood can be gasified, producing CO and H_2, the primary constituents of syngas as a fuel. When gasified, biomass yields a syngas with a much lower BTU content compared to coal. Biomass syngas can be introduced as a fuel directly into a gas turbine or internal combustion engine that is coupled to a generator. The gas needs to be cleaned, both to reduce sulfur and to eliminate the tars and lignins that plague biomass gasifier piping and contaminate the syngas.

The primary source of biomass fuel is mill and logging residues, but there are also landfill byproducts such as methane, agricultural residues from fields, and municipal solid waste. (Municipal solid waste is dealt with in a separate section in this appendix.)

Wood sources tend to have high ash content as well as a high moisture content. The higher the moisture content, the lower heating value because boiling off water absorbs some of the heat of combustion. Compared to coal, though, biomass fuels are relatively clean burning with much lower concentrations of sulfur and nitrogen, therefore producing less SO_x and NO_x emissions.

At many mills, wood residue is burned to fire a boiler and generate steam for a turbine-generator. In some instances, cogeneration is an attractive option for producing both electricity and process steam at these sites. (Cogeneration is covered in a subsequent section of this appendix.)

Fuel preparation is a problem compared to liquid or gas combustion fuels, or even compared to pulverized coal. "Hog fuel" or chipped and split chunks of wood can be fed to boilers or gasifiers; sometimes more thorough preparation, such as drying and pelletizing, is done to ensure a more uniform combustion or gasification. Various types of grates and hoppers are used to continuously supply the burner or reactor with fuel.

Biomass power plant technology is available and widely used. The most critical requirement for operating a biomass plant is the assurance of a stable fuel supply.

Operating Characteristics

As long as an adequate supply of fuel is available, biomass-fired steam-cycle plants may be operated as baseload systems. Since they are steam boilers, they are not amenable to load following applications. The size of a plant is a function of the location and transportation of fuel that is required. Plants in the 25-50 MW range are the most feasible. Larger plants require transportation of fuel over longer distances. This rapidly degrades the economics of a facility. For a plant with access to a reliable fuel supply availabilities should run in the 70-80% range. Heat rates are somewhat high (15,000 Btu/kWh) because of the moisture content of the fuel. If biomass gasifiers are coupled to engines or combustion turbines, all the syngas fuel produced must be used as it is generated.

Costs

Cost data for a stand alone biomass fired steam boiler is presented in Table 10.

Table 10

Costs - Biomass Fired Steam Boiler [a]

Capital Cost ($/kW)	1500
O&M Cost	
Fixed ($/kW-yr)	41.30
Variable (mills/kWh)	3.5
Real Levelized Costs (mills/kWh)	40-70
Nominal Levelized Costs (mills/kWh)	61-107

[a] Data from Draft Northwest Conservation and Electric Power Plan

Estimates for a gasification plant are not available. Such a plant would not, however, be competitive with a natural gas fired facility due the low Btu content of the fuel.

Environmental Characteristics

Environmental impacts of air emissions from biomass combustion are relatively less severe compared to fossil fuels. Still, the impacts are substantial. Pollutants include CO_2 and some CO, particulates, hydrocarbons, NO_x and SO_x. Both NO_x and SO_x emissions are on the order of 50% and 25%, respectively, those for coal combustion per MW-hour. CO and hydrocarbon emissions are controlled by better burners by adjusting the air/fuel ratio to complete combustion. Particulates can be reduced with baghouse filters, scrubbers and precipitators.

As long as the amount of biomass fuel used is replenished by the same amount at the same rate by new growth, the net contribution of CO_2 is zero.

Aside from combustion pollutants, there are environmental concerns associated with gathering, transporting, and processing biomass resources and disposing of biomass wastes.

Removing forest or agricultural residues after timber cutting or crop harvesting can impact soils. Since the harvesting cycle for agricultural residues is more frequent than for forests, the soil impacts may be concentrated in a shorter time span.

Dust from wood stockpiles can be a problem, and problems inherent in transporting large quantities of residue form source to plant are always present: excessive use of roads and undesirable traffic through populated areas.

Cooling water required for turbine condensers can be significant, imparting thermal pollution to the water source, be it lake or stream. Biomass has a relatively high ash content and residue must be disposed of properly in landfills.

Supply Forecast

Logging residue is the most likely fuel to consider available for a stand alone biomass plant. Mill residue is already consumed for other products or to produce steam for mill use. Cogeneration applications are already common for large mills. About 15-30 trillion Btu's of logging residue is available on a regional basis at a cost of $3.30/MMBtu. This would be adequate for 100-300 MW of stand alone generation. The amount that could be developed in the Puget Sound area would be a minor portion of this. For purposes of the Puget Sound Area Electric Reliability Plan stand alone biomass is not considered to be significant. It is more likely that the fuel that is available would be used in a cogeneration facility. This would also be a more efficient use of the fuel.

H. Municipal Solid Waste - Mass Burn, Refuse Derived Fuel (RDF) or Gasification

Technical Description

Municipal solid waste (MSW), more commonly known as garbage, can be burned without sorting in a "mass burn" facility. A common technology for mass burn is the European waterwall incinerator. In this design, MSW fuel is pushed on to a sloping reciprocating grate by a hydraulic ram. After the fuel is introduced into the incinerator, it passes through a drying zone, a combustion zone, and finally a burnout zone. The waterwall is the heat transfer surface in the incinerator where water is heated to steam at 835°F and 900 psia. This steam drives a turbine-generator.

Flue gases, coming out of the incinerator, pass through a lime scrubber to remove the SO_2, HCl and other gases, then through a baghouse to eliminate fly ash containing heavy metals, furans, dioxins, and other toxic compounds. Bottom ash off the incinerator grate and captured fly ash are disposed of in a lined ash monofill. The MSW fuel in this case contains 25% ash and 4500 BTU/lb. The low heating value is due to high moisture and low grade fuel quality. Both lignite coal and biomass have higher BTU content.

Mass burning is the most common MSW technology and is currently being used in Japan, at hundreds of sites in Europe, and at a few in the United States. An alternative to raw MSW is to refine the combustible materials by removing undesirable components such as metals, plastics, and excessive moisture. This higher quality fuel is referred to as refuse-derived fuel or RDF.

The key to a RDF plant operation is the front-end waste separation process. In one design flailing, trommell screening, magnetic separation of metals, and size reduction prepare a fuel that contains about 15% ash and 5900 BTU/lb. At some sites, the major problem with RDF is securing an assured supply of the fuel. RDF is also used to supplement other fuels, such as hog fuel wood burners.

Gasification may be another option for burning MSW. Gasification first converts a fuel into a product rich in H_2 and CO called syngas. H_2 and CO gases are the main constituents that have a significant heating value; they can be burned cleanly in a boiler or gas turbine. SO_x and other pollutant compounds can be filtered or scrubbed from the syngas, and diverted away from the combustion burners. The advantages of gasification is that it separates the fuel processing from the actual combustion and provides a clean-burning fuel.

Operating Characteristics

Most MSW plants in the United States are sized between 40 and 60 MW. Expectations are for smaller sized plants in the region of about 10 MW, operating between 65 and 80% capacity. There is a plant near Salem now operating at 12 MW; Forecasters estimate as much as 380 MW may be regionally available by 2000. By design, MSW plants--whether mass burn, RDF, or gasification--will be baseload operations. Consistency and availability of fuel are key factors in determining plant availability and capacity factors.

Costs

Table 11 shows the capital and operating cost of a hypothetical 10 MW MSW plant. These costs reflect the total cost to construct and operate a facility. The cost of electricity is a function of the tipping fee that is charged haulers for receiving wastes. The cost of electricity is determined by the avoided costs of the utilities serving the area where the plant is located. The tipping fee is then determined. If the fee is higher than other disposal alternatives, then the MSW plant would not be economic to build.

Table 11
Costs - Municipal Solid Waste [a]

Capital Cost ($/kW)	3500
O&M Cost	
Fixed ($/kW-yr)	188
Variable (mills/kWh)	14.3
Real Levelized Costs (mills/kWh)	b
Nominal Levelized Costs (mills/kWh)	b

[a] Data from Draft Northwest Conservation and Electric Power Plan.
[b] The cost of electricity is dependent on the tipping fee charged for taking fuel. See text for discussion.

Environmental Characteristics

MSW plants are primarily garbage reduction sites, helping communities with an alternative to a growing environmental problem. In this respect, MSW plants are an environmental credit. But the pollutants from air emissions are significant. In some locales, there has been vociferous campaigning against siting MSW plants. Municipalities burning solid waste have been concerned primarily with toxic emissions, especially the dioxins and furans that originate from plastics.

Dioxins are very stable and may be taken up thorough the food chain, and absorbed in animal fatty tissue. The Environmental Protection Agency has classified dioxins as "probable" human carcinogens. One form of dioxin, 2,3,7,8-tetrachlorodibenzo-p-dioxin, is potentially one of the most potent human carcinogens. However, studies of operating MSW plants linking furans and dioxin deposits to local emissions are inconclusive.

Because of the diversity of materials comprising the fuel, there is also the potential to discharge of trace amounts of metals such as arsenic, cadmium, nickel, mercury, cadmium, and other chemical compounds such as fluorides and polychlorinated biphenyls (PCB's). Sixty percent of the cadmium and mercury discharge from MSW plants comes from nicad, alkaline, and mercury batteries.

Some pre-sorting of waste would help to cut ash residue and diminish emissions of HCl, HF, CO, NO_x and heavy metals. Refuse-derived fuel eliminates some unacceptable garbage. Many of the compound chemical pollutants can be eliminated by exposing them to high burn temperatures of 1800-2000°F in baghouses for several seconds and using electrostatic precipitators.

RDF, rather than mass burn MSW, would be a better environmental choice simply because the fuel source is better controlled to eliminate unacceptable elements such as plastics and metals.

Ash byproducts, which may be toxic in concentrated amounts, must be disposed of in a lined landfill. If not disposed of carefully, leachates from ash deposits can contaminate water tables or streams and lakes.

There are also technologies being developed that can degrade HCl and may be useful in the future to better control MSW air pollution. These include electron beam radiation and selective catalytic converter technologies.

Supply Forecast

MSW plants are built principally to help alleviate a local community's waste disposal problem. In order for a plant to be viable, many factors including tipping, fees, electricity avoided costs, disposal alternatives, and community support must all be lined up in favor of the plant. These plants have historically required long lead times and have met with public opposition. Because of these factors and the relatively low avoided costs in the Puget Sound area, it would not be prudent to plan for any significant development of this resource.

I. Cogeneration

Technical Description

Cogeneration is the sequential production of more than one form of energy output from one energy source. Cogeneration is particularly well-suited to process industries, such as pulp and paper, and lumber and food processing, where large quantities of steam or heat are used for drying or to process materials where plant electric loads are high. Typically, high pressure, high temperature steam can be used first in an electricity generation process, then bled off from a turbine for process heat.

Cogeneration is not new. Before large central generating plants came into vogue in the 1930s, as much as 50% of the electricity generated in this country came from cogenerators. Historically, most cogeneration plants involved large units in industrial facilities, from 5 to 50 MW. Today, cogeneration plants are as diverse as the industries and commercial applications where they are found and the technology employed is as varied as the kinds of fuels used.

In wood industry plants, for example, wood waste must be disposed and is used as an energy source. But a whole variety of fuel types can be used in cogeneration. The breakdown of fuels for proposed cogeneration projects nationwide is as follows: natural gas, 58%; coal, 19%; biomass waste and other fuels account for the rest. Burning municipal solid waste at garbage sites or using the methane produced at sewage treatment plants are two possible applications for waste fuels.

Since the Public Utilities Regulatory Policy Act of 1978 (PURPA) has encouraged independent power production, smaller packaged system units that can be fueled with natural gas have entered the market. These modules may be rated from 4 to 20 MW, suitable for hospitals, schools, prisons, hotels and other small commercial and institutional establishments. Rather than the traditional boiler-turbine arrangement of larger cogeneration systems, these packaged units may employ reciprocating internal combustion engines. They are likely to use heat recovery of the exhaust gases to serve the secondary energy need for hot water, drying, or space heating, as well as for refrigeration and space cooling. These cooling applications use some of the heat recovery to drive absorption chillers.

Cogeneration technologies have reached commercial maturity and can be operated reliably with high availability and high capacity factors. As electricity prices increase, there is a threshold where it makes economic sense to operate a cogeneration plant. At mills where process heat is needed as well as electricity, and wood residue is both a waste problem and a fuel opportunity, cogeneration can be an attractive solution. The option may not be as straightforward at a hospital or a university. Fuel sources must be stable in both price and availability to induce potential cogenerators to opt for generating their own electricity.

Operating Characteristics

Cogeneration is particularly suited to sites that have a relatively constant thermal load, which requires a stable fuel supply. For this reason, cogeneration makes a good baseload technology.

Costs

Regional estimates of cogeneration prepared by BPA and the Power Planning Council used output of the Cogeneration Regional Forecasting Model (CRFM) as the principle source. This model matches cogeneration technologies with facility types for subregions in the Northwest. The program performs a cost/benefit analysis for a subset of the configurations appropriate for each facility type. The objective is to find the configuration, operating mode, and system size that maximizes the internal rate of return as seen by the project sponsor. This process yields a distribution for a supply of cogeneration as a function of internal rate of return. This is then converted to a quantity of cogeneration at different sell-back prices. These prices, which a utility has to pay for cogeneration, are treated as a cost from a supply forecast perspective.

For purposes of the Puget Sound Electric Reliability Plan study the cogeneration potential was divided into two cost blocks. A weighting factor, based on the regional potential, was then applied to the Puget Sound potential to allocate this potential to the cost blocks. The mills/kWh is then converted to average $/kW and adjusted by the plant factor. Table 12 shows the results of this calculation.

Environmental Characteristics

Environmental effects of cogeneration depend primarily on the type of fuel used. Plant emissions for biomass, coal, natural gas, or other fuels would be similar to any combustion facility using these fuels. Compared to large central power stations, though, emissions would be of much smaller scale and very much localized. Emissions may be less concentrated and more dispersed, but are likely to be found within large population areas, whereas large central power plants are often remote from population centers.

Table 12
Costs - Cogeneration

	Cogen-1	Cogen-2
Price (mills/kWh)[a]	35[a]	55[a]
O&M Cost	inc in price	inc in price
Quantity (aMW)	320	780
Real Levelized Costs (mills/kWh)	35[b]	55[b]
Nominal Levelized Costs (mills/kWh)	54[b]	84[b]

[a] The CFRM projected supply in price categories ranging from 35-55 mills/kWh(1988 $).

[b] The price paid for a cogeneration resource is treated as a cost.

Because cogeneration plants satisfy thermal energy as well as electricity needs with a single energy source, there is less overall pollution than if these sites used separate energy sources for these two purposes. Cogeneration fuel sources tend to get stretched to maximize the use of the available energy. Less energy is wasted. On the other hand, multiple small units may be less efficient than a large single unit for the same level of MW production. This may be the case for installations that produce excess electricity, beyond the amount matched to the secondary thermal load for a site. In this case, the byproduct thermal energy made available through cogeneration is not used as efficiently.

Another issue, sometimes overlooked, is that developing small scale electricity supplies for buildings such as packaged cogeneration units may miss the opportunity to concentrate on energy efficiency in buildings. Gains in energy efficiency are also likely to be reductions in pollution because less generation and, therefore, less fuel combustion is required to meet an equivalent level of electrical service.

Supply Forecast

Regional estimates of cogeneration prepared by BPA and the Power Planning Council used output of the Cogeneration Regional Forecasting Model (CRFM) as the principle source. This model contains a database of facilities which could potentially install cogeneration equipment. These facility types range from refineries and paper mills to hospitals and commercial buildings. When the model is run it attempts to match various cogeneration technologies with each facility. Additional economic assumptions are made regarding fuel prices and the price at which the facility could sell electricity back to the utility. The model's objective is to find the configuration, operating mode, and system size that maximized the internal rate of return as seen by the developer. This process yields a distribution for a supply of cogeneration as a function of internal rate of return. Assumptions are made regarding penetration rates (actual decisions to install the cogeneration equipment) at different levels of return. This penetration curve is used to reduce the distribution of supply to an expected value for developed cogeneration and the results are aggregated to a regional level.

In order to develop an estimate of potential in the Puget Sound area the CRFM was run for only Whatcom, Skagit, Snohomish, King, and Pierce counties. This produced a potential of 1100 MW of capacity and 950 aMW of energy.

The output of this process is truly a generic estimate of the potential cogeneration. There is no site or project specific information in the output. Such an estimate has value as a planning tool. This estimate was compared against lists of known projects. Although these lists were incomplete they did provide a check for consistency of the overall estimate with known projects.

The Environmental Team has distinguished between "normal" cogeneration which would be defined as a facility that was roughly in thermal balance, and "new" cogeneration which would be built to generate electric power as its principal product while satisfying the PURPA requirement of a 5% thermal load. The specific question requested an estimate of the breakdown of the Puget Sound area cogeneration potential into these two categories. The generic nature of the estimate of potential for the Puget Sound area makes it difficult to answer this question directly. However, several qualitative statements can be made based on the current knowledge of the cogeneration facilities in the Northwest.

First, one must be cautious with the term "thermal balance." Although it seems intuitive that a cogenerator would design a system that is in thermal balance and thus achieving maximum efficiency, it is likely that equipment capital cost and availability will dictate the actual design. Systems, therefore, may not be optimally matched.

The bulk of the existing cogeneration that exists in the Northwest is focused in large industries, i.e., pulp and paper, lumber, chemical, refineries. With some exceptions, this existing cogeneration would tend to be thermally balanced. The reason for this is that this cogeneration is being sold to utilities with relatively low avoided costs. One can conclude that the incentive to cogenerate is only partially driven by marketing of electric power. The existing cogeneration could, therefore, be characterized as "normal." As the regional economy grows over the next two decades, the avoided costs of the region's utilities will rise and provide an increased incentive to cogenerators. This increased incentive may then prompt some cogenerators to increase their electric output relative to their thermal loads. The relevant question for the Puget Sound study is what will be the effect of this additional incentive during the next few years. Current avoided costs in the Northwest range from 16 to 26 mills per kWh for a ten year resource. The regional estimates produced by the CFRM do not show a sharp increase in cogeneration potential until the levelized prices exceed 55 mills per kWh. This increase is interpreted as being caused by introducing of cogenerators who exist primarily to sell electric power and consequently do not have systems in thermal balance. This level of price is not likely to be reached in this region in the near term. Therefore, for the purposes of the Puget Sound Electric Reliability Study, it can be assumed that the cogeneration forecasted as available in the Puget Sound area in the near term is all thermally balanced. If systems are thermally balanced, then the incremental fuel use can, in general, be assumed to be negligible. For the purposes of the Puget Sound Electric Reliability Study, it should be assumed that systems are in thermal balance.

J. Wind

Technical Description

Wind turbines convert the kinetic energy of wind into electrical energy by transferring the momentum of air to the rotation of wind turbine blades. There is a great variety of wind turbine designs and design variations, but the most common is the horizontal axis turbine, which has the axis of blade rotation oriented perpendicular to the ground like an airplane propeller. The turbine axis is connected directly to a gear box, which is connected to a generator. Gears step up the blade RPM to a rate nearly matching the 1800 RPM needed to synchronize a generator, which is connected through switch gear to a utility grid. In the horizontal axis design, the rotor blades, turbine, gears, and generator are all mounted on a horizontal axis set atop a tower and contained within a housing as a single unit.

Engineers have devised two principle means to regulate blade speed for controlling power output: variable pitch and stall regulation. With variable pitch, a wind machine's blades adjust so that the turbine begins generating at a cut-in speed, then rises to a rated power output, and finally holds this level until the wind reaches a cut-out speed. With stall regulation, blades are aerodynamically designed to lose their lift at a certain rotation speed. Turbine housings are also designed with passive or active yaw control to swivel on the vertical axis and align the turbine in the direction of the wind.

The power generated from a wind stream is proportional to the cube of the wind velocity; as the wind speed doubles, output available increases by a factor of eight. Because the amount of energy extracted from wind is extremely sensitive to wind speed, optimum siting of individual turbine units requires a substantial amount of data describing how wind speeds are distributed over the site as well as over time. There is even significant variation of wind strength as height varies above ground. Winds aloft tend to be more stable than near the ground. Potential sites must have average wind speeds in excess of 12 miles per hour to be considered worth developing.

Wind machines are generally grouped together into arrays at a site called a wind farm or wind park. A typical arrangement is to place turbine units in rows about 10 rotor diameters apart, and adjacent turbines within the rows about three rotor diameters apart--although optimum siting must take into account terrain and the interactive affects among turbines. Wake disturbance and turbulence from one wind machine can severely limit the energy extracting potential of other machines downwind. Array losses due to energy extraction by upwind turbines can drop energy production as much as 15% to 20%.

Wind power technologies have undergone substantial development since the early 1980s, and the technology has now reached the status of a mature industry. In California today, there are about 17,000 wind turbines operating with an installed capacity of 1500 MW at three principle sites, which is about 90 to 95% of the installed capacity in the world. The California experience has been a proving ground for the developing wind industry. Initial problems with fatigue failures and reliability are now being addressed with better aerodynamic and structural designs and improved controls.

Operating Characteristics

Wind power is dependent on the availability of wind. Despite wind's unpredictability, this renewable resource does exhibit certain patterns. Sites in the Columbia Gorge for example, where winds are geographically induced, peak in the spring and summer when cooler air on the west side of the Cascades moves eastward to displace warmer air inland. At other sites, such as those at the southern Oregon coast and along mountain ridges in Montana, winds are driven by storms which tend to occur in winter time.

Although wind cannot be counted on for peak loads, it can displace some capacity load. Turbine units with good mechanical design and regular maintenance are showing equivalent availability factors better than 92% but they vary widely in output. Typical capacity factors for on-line units range form 10% to 35%, depending on the average wind speed. Today, wind machines being installed tend to be scaled at 150 to 600 Kw, and are lighter in weight with improved efficiency compared to their predecessors.

Costs

The cost of electricity from a wind facility is a function of the wind conversion technology cost as well as the wind resource present at the site. The costs shown in Table 13 assume a capacity factor of 25%.

Table 13
Costs - Wind

Capital Cost ($/kW)	1200-1600
O&M Cost	
Fixed ($/kW-yr)	15.00-16.00
Variable (mills/kWh)	11-12
Real Levelized Costs (mills/kWh)	53-58
Nominal Levelized Costs (mills/kWh)	81-89

Environmental Characteristics

Although wind energy is environmentally benign, there are some distinct environmental impacts in siting wind turbines. Wind parks of any sizable megawatt capacity require the development of large tracts of land. Some of the best sites are in the most scenic areas along the Pacific coast and in the Columbia Gorge where aesthetics may be an environmental concern. Furthermore, wind turbines do generate audio noise, which can be objectionable to nearby residents, and electromagnetic "noise" which can interfere with television reception.

Some wind sites may pose a hazard to both birds and aircraft. Some sites may be in the path of migratory birds. Secondary impacts would be caused by constructing transmission systems to bring electricity from wind sites to transmission connection points. Siting impacts can be mitigated with good planning.

Supply Forecast

In 1985, BPA completed a 5-year resource assessment (WIND REAP) of over 300 wind sites in the Pacific Northwest. Of these, thirty-nine sites were identified to have potential for future commercial development. Researchers continue to gather data at five of these sites for long-term analysis. The Power Planning Council used this data as well as technology data from California to project regional supply. Of all the sites considered to be available for development, only one, Cape Flattery is close to the Puget Sound area and it has a potential of only 13 MW. Because of the small size of the site and its distance from the Puget Sound area, no wind resource is considered to be available to the Puget Sound area.

K. Solar

Technical Description

Solar Thermal - Solar thermal plants are similar to other thermal generating plants--they convert heat energy into electricity through a turbine-generator. Solar energy is highly variable both during the day and between seasons. It is not available at night and it is greatly diminished during cloudy weather. Because solar radiation is widely dispersed, it must be gathered and concentrated to be useful in a solar thermal system. This requires large arrays of panels with controls and mechanisms to reflect and focus the incident light and direct it to a heating unit. The heating unit of a solar thermal station has high absorptivity for trapping and retaining incident radiation, then transferring it to a working fluid.

Collectors for solar thermal generators are characterized by large surface areas for capturing sunlight and specific geometric shapes for concentrating the radiant energy. There are three main types of collectors: central station receivers, line-focus parabolic troughs and point-focus parabolic dishes. In central station receivers movable mirrors, called heliostats, track the sun and reflect the sun's energy to a central receiver mounted on a tower.

The best example of a central receiver station is the 10 MW plant in Barstow, California which has operated since 1982. The system has 1,818 individual tracking heliostats with 766,000 square feet of reflective surface. In its operating history the plant has produced 11.7 MW peak power, with a 10 per cent capacity factor and a maximum annual output of 8816 MW-hours.

Parabolic in-line troughs are the solar thermal power technology most used by utilities. The reflective trough is bent into a parabolic shape the entire length of the trough and concentrates the sun's energy along a line parallel to the parabolic trough. Along this line, receivers are run to capture the concentrated energy. Because many of these systems are designed to be stationary, elaborate tracking mechanisms and controls are not needed. Troughs are typically oriented north-to-south and lie horizontally. This configuration tends to offer the best tradeoff between maximizing capacity and keeping first costs and maintenance costs down. If energy is to be maximized instead of capacity, other orientations--such as tilting or tracking the troughs toward the sun--can be considered.

Receivers for in-line parabolic troughs are a specially coated pipe inside a glass vacuum tube. One company, Luz International--which operates the world's seven largest solar thermal plants--uses a synthetic oil as a heat transfer fluid in the pipes. The oil reaches 753^{o}F which then runs through a heat exchanger and super heats the steam that drives a turbine-generator. With this design, solar thermal conversion efficiency has improved to about 29%.

Point-focus parabolic dish systems are single dish units, focusing the solar energy to a single focal point where the receiver is located, like a flashlight reflector in reverse. Unlike the in-line troughs, the parabolic reflector must track the sun continuously on two axes. One axis allows for tracking east to west during the day; the other axis allows for tracking north to south as the sun's declination angle changes with the seasons. Because of this system's requirement for accuracy and reliability to work effectively, fabrication is difficult and expensive.

Some point-focus systems have external heat engines, such as a reciprocating Stirling, that absorb heat directly and turn generators. Others have a system of fluid lines connecting each receiver and carrying a heat transfer fluid, which in turn is used in a turbine-generator. Compared to the in-line parabolic reflectors, the point-focus systems can concentrate much more energy. As of 1987, there were four point-focus reflector pilot projects testing various engine and generation technologies.

Photovoltaic - Photovoltaic cells (PV's) use the photoelectric effect to convert the sun's radiation directly into DC power. In photovoltaic cells, sunlight strikes a semiconductor material, typically a treated silicon, and frees up electrons which generate a DC current. The DC power is then conditioned through an invertor with controls to produce AC current.

There are two main types of PV systems: flat-plate and concentrating. Flat-plate systems are usually deployed as a groups of cells in stationary panels. Thus, the incident sunlight upon the cells varies markedly throughout the day and with the season as the angle of the sun's rays change. Concentrating systems, on the other hand, track the sun throughout the day and are outfitted with lenses to concentrate the sunlight.

PV cells are usually grouped together into water proof modules that range from 0.1-2 m^2 and laid out side by side in banks to form arrays. A typical PV cell produces less than 2 amps at about 0.6 Volts or about 1.2 Watts. Commercial PV flat-plate cells can achieve about 12% efficiency in converting sunlight into electrical energy; concentrating systems have reached better than 26% efficiency using a single-crystal silicon material. Multiple thin-film layered cells currently under development can theoretically reach 42%.

Although the costs of producing PV's are coming down and efficiencies are going up, the technology is still very expensive. Single-layer thin film cells, the least costly to manufacture, also have very low conversion efficiency, about 4 to 6%. For this technology to reach wide market acceptance, analysts estimate that efficiencies would have to reach a threshold conversion efficiency of 15%; laboratory versions have reached 12%. As more and more PV's are manufactured--there were only 30 MW produced in 1988--industry will be able to reduce costs even further. Expectations are that costs will drop from a current 55 cents/kW-hour down to 8 cents/kW-hour by 2010.

Photovoltaics are a proven technology and there are many applications currently in use, such as calculators, range fences, and remote lighting and signaling stations. Flat-plate PV's have low operating and maintenance costs, minimal environmental impacts, a free energy source, and very high reliability. Concentrating PV's have a lower reliability because they are mechanically more complex and therefore subject to failures.

Operating Characteristics

Solar Thermal - A solar thermal system's capacity is dependent on the sun. Solar insolation has a daily peak in early afternoon, and of course is not available at night. There is also seasonal variation due to the change in the sun's declination angle, where the angle is greatest in early summer. Any transient cloud cover also affects the amount of energy available from the sun.

Luz's systems use natural gas as a back up fuel to boost peak or maintain capacity during cloudy periods and late in the day. In Luz's California plants, the proportion of energy contributed by gas in a solar energy system is constrained to no more than a 25%. If solar thermal plants were used to supply capacity, as Luz's plants are in California, the situation is analogous to gas-fired systems backing up non-firm hydro in the Pacific Northwest. A fossil fuel used as a back up opens up the question of whether this fuel wouldn't be better used in other applications, such as space heating. Without a fuel backup, a solar thermal station's capacity factor is diminished significantly.

For eight of Luz's Solar Electric Generating Stations typical capacity factors range from 25% for a 13.8 MW plant to 36% for a larger 80 MW plant. First costs range from $4500/kW to $2788/kW for these same plants. There are about 6000-8000 square meters of collector area per MW of capacity. Luz's has an installed capacity of over 160 MW at six sites, with almost another 500 MW planned. Luz plants operate in latitudes and climates where the available insolation is much higher than that available in the Pacific Northwest. The most promising locale for solar generating plants are areas east of the Cascades.

Photovoltaics - As with solar thermal, a PV system's capacity is dependent on the sun. Solar insolation has a daily peak in early afternoon, and of course is not available at night. As with solar thermal, a PV system's capacity is dependent on the sun. Solar insolation has a daily peak in early afternoon, and of course is not available at night. There is also seasonal variation due to the change in the sun's declination angle, where the angle is greatest in early summer. Any transient cloud cover also affects the amount of energy available from the sun.

Solar radiation is very dispersed and varies significantly with latitude and climate. The average daily total solar radiation in Phoenix is about twice that of Seattle. Consequently, the most promising PV sights in the region are east of the Cascades. Although about 1 kW of solar radiation, called insolation, falls on a square meter at noon on a sunny day, a typical PV array can generate only about 120 W/m^2. A 50 MW power installation would require about 90 acres of PV cells. This is peak capacity and does account for diminished performance under cloudy skies or early or late in the day. PV system capacity factors for future concentrating PV plants may reach as high as 33%.

Costs

The cost estimates in Table 14 cover both solar thermal and photovoltaic facilities. Photovoltaic facilities are the most costly.

Table 14
Costs - Solar

Capital Cost ($/kW)	3000-4000
O&M Cost	
Fixed ($/kW-yr)	44.00
Variable (mills/kWh)	0.8
Real Levelized Costs (mills/kWh)	78[a]-111
Nominal Levelized Costs (mills/kWh)	119[a]-170

a The low end of costs is for a solar plant with a gas backup. The gas fired portion of the plant lowers the overall levelized cost.

Environmental Characteristics

Solar Thermal - Although the energy source for solar thermal systems is free and environmentally benign, plant siting and operations do have some environmental impacts. All turbine-generators require some cooling to condense working fluids, whether the fluid be steam in central station systems or Freon in a closed loop reciprocating engine. Dry cooling with air may be the heat sink of choice, but even this air must be conditioned, usually with a cooling tower or cooling pond. Ultimately some makeup cooling water is required to cool the air. In hot, dry climates where solar thermal plants are most likely to be located, water for cooling comes at a premium.

Because of the very diffuse nature of solar radiation, large sections of land are required for developing solar thermal sites, which has a localized effect on the ecology of land taken out of use.

If natural gas is used as a back up energy source, then plant operators must deal with the impacts of natural gas combustion. Lastly, the working fluids used in engines and turbine-generators such as oils or freons must be managed and contained to prevent inadvertent escape into the environment.

Photovoltaic - The only significant environmental impacts of PV's are in the industrial processing of the PV materials, where such chemicals as gallium arsenide and cadmium sulfide are used, and in the large surface areas of land required to set up a PV plant.

Because of the very diffuse nature of solar radiation, large sections of land are required for developing PV sites, which has a localized effect on the ecology of land taken out of use.

Supply Forecast

The best potential solar site in the Northwest is the Whitehorse Ranch in southeastern Oregon. However, because of its latitude, it receives only 70% of the solar energy of the best sites in the Pacific Southwest. The Puget Sound area receives only 75% of the solar energy that Whitehorse Ranch receives. Because of this scarcity of the solar resource in the Puget Sound area, and the relatively high cost of solar in good solar areas, it is unlikely that central station solar will be sited west of the Cascades. Consequently, no solar is considered to be available in the Puget Sound area

L. Ocean - Wave and Tidal

Technical Description

The earth's oceans are a vast repository of energy. Waves are stirred up by wind forces which are a manifestation of the sun's energy, and the ebb and flow of tidal forces are the expression of the moon's gravitational energy. With over 350 miles of coastline, the Pacific Northwest is a logical area to investigate the potential for ocean energy.

Engineers have invented a variety of devices capable of harnessing the energy in waves. These devices can be classified by three criteria: the type of mechanism used to absorb the wave energy, the type of working fluid used in the device (hydraulic or pneumatic), and whether the device is fixed or floating.

Heaving float devices take advantage of the effects of vertical motion of a wave-driven buoy to operate a pump. As the buoy moves up and down it pumps a working fluid which operates a turbine-generator. Pitching devices capture energy from wave-induced pitching motion, or the swaying back and forth as waves pass underneath. These devices also use hydraulic pumps to drive a turbine-generator. There are devices that combine heaving and pitching; these are theoretically more efficient than either heaving or pitching devices because they use more of a wave's energy.

Oscillating water column devices use wave motion to establish an oscillating water column that moves up and down in an enclosed chamber. Surge devices extract energy from the forward horizontal wave forces. One surge design uses an air bag that alternately compresses and re-inflates with successive incident waves. The compressed air drives a turbine-generator. Another surge design directs waves through a tapered channel where the water spills into a reservoir. As the water in the reservoir flows out between surges it drives a turbine-generator.

There are tested prototypes for the designs of many wave energy devices, but only the shore-mounted Norwegian Kvaerner oscillating water column and the Norwave tapered channel plants have been commercially demonstrated. Before large-scale deployment of wave energy devices can be expected, major technical problems remain to be solved, including the demonstration of mooring and electrical power transmission systems, and the development of reliable power conversion equipment such as the pumps, generators, and turbines. The harsh salt environment of the oceans and the severe weather on the open waters compound the problem of reliability.

In contrast, tidal power plants are a demonstrated and mature technology with several commercial plants in operation today, including a 240 MW installation at the Rance River estuary on the north coast of France--fully operational since 1967. Another site, Annapolis Royale, Nova Scotia, has operated since 1984 and generates 18 MW.

The key requirement for a successful tidal power plant is a large mean tidal range, preferably 20 feet or more. Tides of this magnitude can be found in only a few places worldwide where geography amplifies the tidal range. Tidal electric plants also require a large bay or estuary with a narrow, relatively shallow entrance suitable for construction of a dam. Several sites exist in North America, but none of them are in the Pacific Northwest. The largest mean tidal variation in the region can be found in the bays and inlets of Puget Sound. Oakland Bay, at Shelton, Washington has a mean tidal range of only 10.6 feet.

Tidal power plants use a variation of conventional hydro power technology. A typical plant consist of a barrage (or dam), sluice gates and a power house with low-head turbines. The barrage is constructed across the mouth of a bay or estuary to form a controlled basin. Sluice gates admit water during the flood tide and then are closed near high tide after the basin has filled. When the ebbing tide creates sufficient water head between the basin and the sea, water from behind the barrage is released through the turbines to generate electricity.

Operating Characteristics

Although storms that produce waves are winter peaking, wave energy is intermittent and highly variable in magnitude. The winter capacity may vary from the summer capacity by a factor of 4 to 6.

The tidal power design described here will produce power only when the tide ebbs, which is slightly less than twice a day on average. The resulting power is firm and predictable but cyclical. Tidal power can offset capacity, but synchronizing tidal power with peak demands is not practical. There is also a tidal shift about an hour per day.

Costs

Cost estimates for wave and tidal technologies are shown in Table 15. These estimates are preliminary in nature and have a high uncertainty associated with them.

Environmental Characteristics

If deployed in large numbers, near-shore wave energy conversions devices may act as breakwaters and create "wave shadows" that may affect the shoreline environments. Sections of shoreline may change from high energy to low energy. This may well affect sediment transport along the shore and beach stability. Near-shore ecosystems may also be affected. And, of course, large-scale deployment of these devices will present aesthetic and navigation impacts.

Table 15
Costs - Ocean Energy [a]

	Wave	Tidal
Capital Cost ($/kW)	2-7000	4000
O&M Cost		
Fixed ($/kW-yr)	75-120	20
Variable (mills/kWh)	in fixed	in fixed
Real Levelized Costs (mills/kWh)	b	b
Nominal Levelized Costs (mills/kWh)	b	b

[a] Data from Draft Northwest Conservation and Electric Power Plan.

[b] Levelized cost not calculated due to the high uncertainty associated with estimates.

Environmental impact for tidal power facilities in Cook Inlet, Alaska have been assessed for several potential sites. Findings there may apply here. The most significant impact results from modifying the tidal ebb and flow with the barrage structure. A barrage would significantly alter the flow and circulation patters generated by natural tides. Alterations due to the presence of the barrage would probably lead to water quality changes, including concentrations of pollutants, and increased salt deposits within the tidal basin. A tidal power plant would change a basin from a high-energy to a low-energy marine environment with consequent environmental and aesthetic effects. Passage of salmonids, plankton, larval fish and marine mammals would be restricted.

Supply Forecast

Tidal ranges of 20 feet are required for an effective tidal resource. The largest tidal ranges in the Northwest are less than 10 feet. No tidal resource is considered to be available in the Northwest. Although wave power is considered to be technically available in the Northwest, there is a high degree of uncertainty associated with its cost and feasibility. It is not considered to be a mature technology. For these reasons, as well as the distance from ocean sites to the Puget Sound area, ocean power is not considered to be an available Puget Sound area resource.

M. Hydrogen

Technical Description

Hydrogen gas is a highly combustible, but environmentally acceptable fuel. Decomposing water through electrolysis is the principal means of producing hydrogen. If there were enough off-peak or surplus power available, hydroelectric energy could be used to produce hydrogen. This fuel could be used later in a combustion turbine, fuel cell, or other engine to generate electricity during peak periods.

An electrolyzer cell consists of an electrolyte, electrodes, a water porous separator, and a container. In electrolysis, a direct current is passed between two electrodes immersed in a water-based electrolyte. Water molecules dissociate into hydrogen and hydroxyl (H^+ and OH^-) ions. The hydrogen ions migrate toward the cathode and form H_2 gas while the OH^- ions migrate toward the anode. At the anode the hydroxyl ions decompose to O_2, giving up their hydrogen atoms to other hydroxyls which form water.

The anode and cathode electrodes are usually catalytic metals that help accelerate the reactions and therefore are a critical factor in effective electrolysis. The electrolyte is also critical because it should not react with the hydrogen and hydroxyl ions, not decompose under the voltages induced in the cell, be chemically stable, and resist pH changes. For most practical applications sulfuric acid, H_2SO_4, meets all these criteria.

Electrolysis conversion efficiency is determined by the amount of kilowatt hours used in electrolysis compared to the heating value (in BTU) of the hydrogen fuel. Since electrolysis is the reverse of the hydrogen combustion reaction, the theoretical maximum heating value of hydrogen would exactly equal the kWh of electrical energy is used in the electrolysis. However, parasitic loads--mainly for pumps to circulate cooling fluid, electrolyte and gas products--account for about 5% of the total system energy. The rest is the electric power used in electrolysis. Even some of the resistance heat in the cell helps induce the electrolysis reaction.

There is a net energy loss in producing hydrogen as fuel then generating electricity compared to direct hydroelectric conversion. First, the electrolysis conversion efficiency is about 80%;

then converting the energy in hydrogen gas into electricity carries an additional penalty. Per kilowatt-hour, the electrical energy produced from a combustion turbine or fuel cell using hydrogen fuel would be about 15 to 30% that produced directly from a hydroelectric turbine.

Reliable technologies for electrolyzing, storing, and using hydrogen exists. The principal technical obstacle in using hydrogen for peak power is to understand the adequacy of reservoirs where the hydrogen might be stored. Underground natural gas reservoirs might be an option. Compared to natural gas, hydrogen has about 1/3 the energy content per cubic foot so would take about three times the storage volume as natural gas. Two Northwest sites have been identified as possible hydrogen storage reservoirs: Jackson Prairie, Washington, and Mist, Oregon.

Pipeline or transport arrangements would be needed to move the hydrogen from storage to a combustion turbine for peak load generation. However, electrolysis generation of hydrogen only makes sense when there is surplus hydropower and the overall conversion efficiency of storing hydrogen fuel and regenerating electricity with it is economical.

Operating Characteristics

Hydrogen as a fuel would most likely be used in combustion turbines for peaking power. Fuel cell use of hydrogen is also a possibility. The generation profiles of either of these applications would depend on how CT's or fuel cells are used.

The idea behind hydrogen energy storage would be to produce hydrogen gas during the spring and summer months when the Columbia River system water runs high and electricity demand is low, store the hydrogen, then use it during winter peak periods as a combustion fuel in combustion turbine peaking plants.

Costs

Costs for a hydrogen electrolysis plant were developed from data obtained from the Pacific Northwest Hydrogen Feasibility Study, March 1991, prepared for BPA by Fluor Daniel Inc. These cost are based on a electrolyzer-fuel cell combination.

Table 16
Costs - Hydrogen Electrolysis

Capital Cost ($/kW)	4100
O&M Cost	
Fixed ($/kW-yr)	8.26
Variable (mills/kWh)	28
Real Levelized Costs (mills/kWh)	158[a]
Nominal Levelized Costs (mills/kWh)	242[a]

[a] These cost levels were calculated assuming an input power cost of 14 mills/kWh.

Environmental Characteristics

The primary concern with hydrogen is safety. Hydrogen is highly combustible and there is a risk of explosion. Using the same kinds of precautions applied to propane handling and use would help to mitigate risks with hydrogen.

Hydrogen is a very clean burning fuel; the combustion product is simply water. If hydrogen were to be used in a combustion turbine, the environmental impacts would be similar to those of CT's (see also the section on "Combustion Turbines," covered in a previous section of this appendix). As in all combustion turbines, high temperatures can produce NO_x, and CT's are quite noisy. Hydrogen might also be used as a chemical feedstock for fuel cells. In either case, CO_2 is a byproduct which is a "greenhouse gas" that would contribute to global warming.

If the hydro system were to be used to produce hydrogen, an additional environmental consideration would need to be addressed: the water flowing through hydro turbines to generate the electricity for electrolysis may have competing uses, including spill for fish migration.

Supply Forecast

Although hydrogen electrolysis is technically feasible, it is prohibitively expensive when compared to other alternatives. It is also a net energy loser due to conversion inefficiencies. Although it may have future applications in the region, it is not considered to be a reasonable local generation option for the Puget Sound area.

N. Fuel Cells

Technical Description

Fuel cells are similar to batteries; they convert the energy released in chemical reactions into electricity. Electric current passes between anode and cathode, with hydrogen gas oxidized at the anode and oxygen gas reduced at the cathode, and an electrolyte solution in between. Although one cell produces less than one volt, current densities in fuel cells are quite high, on the order of hundreds of amperes per square foot of electrode area. These densities are possible when groups of cells are formed into stacks to provide high power levels.

There are three major types of fuel cells under development, named for the type of electrolyte used--phosphoric acid, molten carbonate, and solid oxide. Aside from different electrolytes, a key distinction among these three types is their different operating temperatures. Phosphoric acid cells operate at 400°F, molten carbonate cells at 1200°F, and solid oxide cells at 1800°F. Waste heat energy from the chemical reactions can be used as a heat source for steam or in low-temperature bottoming cycle cogeneration. Fuel cells operate at a constant temperature and pressure, regardless of load.

Fuel cell power plants have a fuel processing system and three subsystems--a fuel stack subsystem, a power conditioning subsystem, and a balance of plant subsystem. A fuel processing system may convert natural gas or petroleum distillate into a fuel rich in hydrogen to supply the cathode. Ultimately, coal gasification may be used to generate this fuel, but catalytic reforming is the commercial process currently employed. The fuel stack subsystems generate DC electricity while removing the CO_2 and H_20 byproducts. The power conditioning subsystem converts DC to AC current and also modulates the fuel cell's power factor. The balance of plant subsystem has the controls, water and heat management, cooling and heat recovery.

Conversion efficiencies in theory are near 80%, but in practice are reduced to about 60% because of parasitic losses, especially electrical resistance. Since fuel cells are a direct conversion technology, they do not suffer the efficiency penalties of other electric generation technologies such as steam and gas turbines that convert heat energy into electrical energy.

Operating Characteristics

Fuel cells have excellent load following ability; they can adjust output quickly and over a broad range. If an adequate fuel supply is available, fuel cells can provide baseload service. Projected availabilities should be greater than 90%.

Costs

The costs shown in Table 17 are based on forecasted operation. Fuel cells have not yet achieved these cost levels.

Table 17
Costs (projected) - Fuel Cells

Capital Cost ($/kW)	1300
O&M Cost	
Fixed ($/kW-yr)	5.43
Variable (mills/kWh)	8.6
Real Levelized Costs (mills/kWh)	54
Nominal Levelized Costs (mills/kWh)	83

Environmental Characteristics

For the most part, environmental impacts of fuel cells are related primarily to the fuel type used to provide the hydrogen for the electrochemical reaction. If gasified coal is the source, sulfur removal at the gasification side will be a significant environmental concern. Waste products, including ash and contaminated effluent from gasifier cooling systems, must be treated. If water cooling systems are used to remove heat from the fuel cells there may be some thermal pollution where the cooling water is discharged.

Supply Forecast

Although simple and compact, fuel cells have not yet reached commercial maturity. Reliability and durability of the fuel cell stacks themselves as well as relatively high manufacturing costs have slowed commercial implementation. Therefore fuel cells are not considered to be a local generation measure in the Puget Sound area.

O. Storage Systems

Technical Description

Compressed Air - A compressed air storage system uses off-peak power to run a compressor motor to compress air and store it under high pressure. A typical system combines a compressor and a turbine, each coupled by a clutch to a motor/generator. When there is a peak demand, the compressed air is released and mixes with a fuel in the turbine's combustor. The design is very similar to a combustion turbine except the turbine uses compressed air from storage instead of air from a compressor.

In the air compression mode during off-peak, a clutch couples the motor/generator to the compressor to compress air, and the motor generator operates as a motor. In the power generation mode during peak demand, another clutch engages the turbine to the generator, and the motor generator operates as a generator.

Compressed air may be stored in any suitable geologic formation such as a salt cavern, a mined rock cavern, or an aquifer reservoir.

Utility Batteries - Batteries are one utility option that can serve as an instantaneous electrical energy source and be modulated over a broad power range. A battery system can be built in modular units to almost any size capacity, and requires a DC to AC power converter. Rechargeable lead acid, sodium-sulfur and zinc-bromide battery technologies are currently available. Batteries are recharged during off-peak periods and discharged during peak demand.

Superconducting Magnetic Energy Storage (SMES) - At low enough temperatures many materials exhibit a phenomenon called "superconductivity," where electrical resistance decreases to zero. The threshold temperature for superconductivity depends on the material. In the past few years many ceramic materials have demonstrated superconductivity at relatively high temperatures, around 70 degrees Kelvin, but these materials are brittle and not yet reliable.

If maintained at low enough temperatures, superconducting systems can circulate a current indefinitely. Current is inversely proportional to resistance; as resistance goes to zero, current density increases greatly, limited only by the structural integrity of the system and the magnetic "braking" effect circulating currents have on superconducting circuit.

High superconducting DC currents generate large magnetic fields. A superconducting magnetic energy storage system stores energy in a magnetic field, which is induced by a superconducting current. The energy is proportional to the magnetic coil's inductance and the square of the current flowing. SMES technology has already been demonstrated successfully in a 30 MJ prototype at Tacoma in 1984.

A SMES would be rated both for its total storage capacity (in megawatt-hours) and for its release rate (in megawatts). For example, a SMES may store 20 MWh of energy but release it at limited rate of 400 MW. At this rate the SMES energy supply would be depleted in 3 minutes.

A recent study by the Battelle Pacific Northwest Laboratory (June 1990) mapped out eight scenarios for possible SMES sites and applications. The scenarios ranged form a small 20 MWh/400 MW system designed for system stability to a large 1500 MWh/3100 MW system designed to enhance the DC intertie transmission system. A proposed utility SMES system at Hanford would be 100 meters in diameter buried in a trench about 9 meters deep. The system would have cryogenic capability (very low temperature) to maintain the temperature of liquid helium, about 4 degrees Kelvin, and use niobium-titanium (NiTi) wire as the superconducting material. Both the cryogenic and control technologies exist to implement such a design SMES.

Operating Characteristics

Compressed Air - The operating characteristics of compressed air systems would be similar to those of combustion turbines except that they would have a limited availability depending on the amount of storage that is assumed. For more information, see the section in this appendix on combustion turbines. Approximately 25% of the energy used to charge the system is lost in each charge cycle. A portion of this is regained in the form of more efficient heat rate during the discharge cycle.

Utility Batteries - would be used to serve peak loads any time of day. Part load for batteries is inherently better than full load operation. Batteries can come up to full load in less than 20 milliseconds.

SMES - Like all storage technologies a SMES can be charged with off-peak power and discharged during peaks. The great advantage of a SMES is its load leveling and load following capabilities, allowing generation plants to approach a constant load operation and to operate at maximum efficiency. SMES systems could well serve to dispatch peak loads and serve as a flexible dynamic brake for system stability.

Other SMES system benefits include: less cycling and reduced ramping rates for conventional generators; integrating independent power producers that use intermittent technologies such as wind or solar; providing stability control by both absorbing and generating power; damping low power frequency oscillations from transient disturbances in the power system; picking up a portion of required "spinning reserve" (unloaded standby generation); VAR control by acting as a capacitor or inductor to modulate real and reactive power independently; and providing "black start" capability to start up a large generating unit without using power from the grid.

Costs

The costs of adding compressed air capability to a combustion turbine includes clutches and peripheral equipment to permit the compression and recovery of air, as well as the storage medium.

Reliable cost estimates for magnetic storage are not available. This technology is considered to be in its very early development stages.

Table 18
Costs - Storage Technologies

	Compressed Air	Batteries
Capital Cost ($/kW)	480-580	460-920[a]
O&M Cost		
Fixed ($/kW-yr)	1.5-3.0	0.5-1.0
Variable (mills/kWh)	1.0-2.0	6.0-9.0
Real Levelized Costs (mills/kWh)	b	b
Nominal Levelized Costs (mills/kWh)	b	b

[a] The lower end of the range is a projected number for advanced battery systems. The higher end is for lead acid batteries.

[b] Levelized cost is not an appropriate measure for storage technologies. The capital cost, compared to alternatives, is a better measure.

The disadvantage of any storage technology is that they requires energy to charge the system. Energy in the Northwest has a relatively high value. This makes alternatives which can deliver energy, in addition to capacity, much more valuable. In a system that is capacity deficit, this is not as serious a problem since it may be cheaper to use excess energy in a storage system than to construct new capacity resources.

Environmental Characteristics

Compressed Air - Compressed air storage would have environmental concerns similar to those for combustion turbines using natural gas or distillate fuels. In addition, these facilities would have to be sited where air could be adequately stored. For more information about environmental impacts and mitigation see the section on combustion turbines in this appendix.

Utility Batteries - Environmental discharge from batteries is nil, although some gases might escape through leakage. The main environmental concern with batteries is the disposal or recycling of battery materials, especially those containing lead. Battery manufacturing produces hazardous or toxic chemicals that must be dealt with carefully.

SMES - Construction of a SMES facility would have the same environmental impacts as any large construction project: dust, noise, traffic, and potential soil effects. Once in operation, though, there would be some cooling water requirements to operate condensers in the cryogenic refrigeration systems, but no air emissions. There would be a high magnetic field in the vicinity of the SMES, but whether magnetic fields have harmful effects is an unresolved question still being researched.

Supply Forecast

A fundamental consideration is whether or not a storage system provides any special benefit from a capacity point of view. All of storage technologies require the consumption of energy to charge them. These energy losses have a relatively high value in an energy deficit region such as the Northwest. Storage devices would compete with more conventional methods of adding capacity (e.g., combustion turbines). No supply of storage capability is projected for the Puget Sound Area.

P. Standby Generation

Technical Description

Many hospitals, large office buildings and other institutions have standby generation capacity, to be used in the event of forced outage. Hospitals, in particular, must maintain and periodically test their standby generators to ensure generation capability under emergency conditions for life safety. These systems are usually set to kick in automatically if power is cut. Other facilities, not so much concerned with life safety, have generators as backup so they can continue to function if service is curtailed for any reason.

Utilities can use standby generators to meet peak loads by shifting some of their loads to standby generators. In effect, facilities with standby generation absorb some of their own loads, thus reducing utility peak demand. Many facilities not only have enough capacity to serve their own needs, but excess capacity as well.

To assure capacity is available, there must be a contractual relationship between the generation facility and the utility. This contract would define how much capacity, under what conditions, could be delivered by the standby unit. Integration and coordination, especially at a moment's notice, of so many varied and dispersed power generation resources presents some problems including reliable communications. It is also likely that under extraordinary conditions, such as power outages or natural disasters, when peak demand would require standby generation, the standby generators may already be in service.

Most of the standby generators that exist are designed to switch on and provide power to the facility independently from the utility. They are not connected to the utility system. Interconnection to permit the generators to provide power to the utility's distribution system would require additional protection and communication equipment.

Costs

Any generating resource that effectively reduces peak load in the Puget Sound area is inherently beneficial in mitigating the voltage collapse and transmission problem in that area. What makes one resource preferable to another depends on the relative costs, operating characteristics, and impacts of the resource alternatives. In order to evaluate diesel generators it is necessary to compare its costs and characteristics against the most likely alternative resource. For capacity resources the combustion turbine (CT) is commonly considered to be the alternative.

When evaluating capacity resources the most important factors to consider are installed costs, operating and maintenance costs, operating characteristics, and environmental impacts. The following paragraphs discuss these factors for both diesel generators and combustion turbines.

Capital Costs - Small diesel generator installed capital costs range from $210/kW for a 1000 kW unit to $240/kW for a 1600 kW unit. Combustion turbine installed capital costs range from $330/kW to $700/kW. The capacities for these CT's range from 15 MW to 150 MW. The CT considered to be the most likely candidate for acquisition by a utility is described in the Combustion Turbine portion of this appendix. It has 70 MW capacity and has an installed cost of $420/kW.

A direct comparison of capital cost between diesel generators and CT's is not possible because of different lifetimes. The diesel generator has a lifetime of 10 years whereas the CT has a life expectancy of 30 years. A valid comparison requires that the diesel unit be replaced in years 11 and 21. These replacement costs can then be discounted back to the present and added to the initial cost to obtain a rough comparison to the initial CT installed cost. Assuming a $210/kW expenditure in years 0, 11, and 21, and assuming a 5% inflation rate, yields an equivalent installed cost of $420/kW. This is the same as a combustion turbine. Consequently, from an installed cost standpoint, there is no effective difference between the diesel unit and a combustion turbine.

The capital costs above do not include communications and control to permit remote operation. A large number of diesel units at different locations would suffer a capital cost penalty compared to CT's because of the difference in unit size (1 MW versus 70 MW).

Operating and Maintenance Costs - Table 19 summarizes the plant and operating characteristics of the diesel generator and the combustion turbine;

Table 19
Costs & Characteristics - Diesel vs CT's

	Diesel	CT
Operating Life (years)	10	30
Capacity (MW)	1	70
Capacity Factor (%)	3%	3%
Heat Rate (Btu/kWh)	9900	11400
Capital Cost ($/kW)	210[a]	420
Fixed O&M ($/kW/yr)	6.18	2.33
Variable O&M	in fixed	in fixed
Fuel ($/MMBtu)	7.00	3.50

[a] Equals $420/kW when corrected to 30 year life. See text for discussion.

The heat rate for the diesel unit was calculated from a data sheet for a small (1.6 MW) diesel engine generator set. It is lower than heat rates reported for larger (7.5 MW) diesel units which run over 12,500 Btu/kWh as well as existing Northwest diesel units which have heat rates ranging from 10,050 to 13,200 Btu/kWh. However, for purposes of this evaluation, the 9900 Btu/kWh was assumed to reflect the performance of the smaller units. The variable operating costs (excluding fuel) were folded into the fixed costs since the capacity factor is set at 3% for both the diesel and the CT.

Fuel cost for the diesel unit is assumed to be $0.90/gal for #2 fuel oil. Cost of natural gas fuel for the CT is consistent with the long-term assumptions used in the Puget Sound Electric Reliability Study. These natural gas assumptions are considered conservative. Current natural gas prices are closer to $1.75/MMBtu.

Operating Costs - Using the plant and fuel costs described in the preceding section the following table shows the relative operating costs of the diesel and CT units. The calculations shown in the Table 20 assume units coming on-line in 1993.

Table 20
Operating Costs - Diesel and CT[a]
(1990 Real Levelized - mills/kWh)

	Diesel	CT
O&M Cost	25	12
Fuel	76	47
Total Operating Cost	101	59

[a] These costs were calculated assuming 250 hours of operation per year.

Operating Characteristics

The major problem with standby generation is dispatching load service among so many dispersed systems. Effective standby generation programs would require interconnection and communication equipment as well as a contractual arrangement between the utility and the owner of the standby generator.

Environmental Characteristics

Standby generation units tend to be diesel or internal combustion engines fired with natural gas or fuel oil, driving turbine-generators. Permitting and siting of each individual unit generally is part of the facility construction. Concerns about fuel storage, ventilation, and waste heat have usually been addressed by the time these units are in place.

Air emissions will be the primary concern with standby generators. Controls and mitigation of pollutants would be similar to those for motor vehicles.

Supply Forecast

20 MW of standby generation was initially identified as potentially available in the Puget Sound area. However two factors cause it to be considered as unavailable for purposes of the Puget Sound Electric Reliability Plan study: (1) the cost effectiveness of diesels compared to combustion turbines, and (2) interconnection, communications, and dispatching complexities associated with adding a substantial number of small units.

It is possible that a larger standby generator may make sense on a site specific basis. Such an installation should be pursued by the owner and the utility for potential integration. A large number of small generators, however, has enough complexity to it to make substantial acquisition levels unlikely in the near to mid-term planning horizon.

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Appendices

To Whom It May Concern:

Attached is a listing of the hydroelectric projects located within the Puget Sound basin or Washington Coastal drainage. These projects form the basis for the updated hydro developable potential for the Puget Sound load balance study. The source of this information is the Pacific Northwest Hydropower Data Base and Analysis System (NWHS).

The following information or definition will be helpful in understanding the listed material:

PROJECT NAME Name by which the existing or potential dam or water management project is commonly known.

APPLICANT DEVELOPER Name of hydroelectric project developer.

FERC NO For projects subject to FERC jurisdiction, this is the project identification number assigned by FERC (for example 02316B00, E F GRIFFIN CR).

CO Location of project, Primary County Code (see attached excerpt of Table 2.1 from Data Item Description Manual). For example, Code 033 for the State of Washington would identify King county.

HUC Hydrologic Unit Code - a nationally consistent designation of hydrologic cataloging units as defined by the Water Resources Council within which existing or potential projects are located. The first 2 digits identify a region and the second two digits identify a subregion (Puget Sound are all 1711, Washington Coastal are 1710).

Status For non-federal projects the FERC codes are used to identify the current project status (for example PP-PND Preliminary Permit Pending):

EX	Exemption	Can	Cancelled
LA	License Amendment	DIS	Dismissed
LC	License	DND	Denied
PP	Preliminary Permit	EXP	Expired
RL	Relicense	GTD	Granted
XX	Non-federal project not subject to FERC jurisdiction	OPP	Operating (was POL)
		PND	Pending
		REJ	Rejected
		REV	Revoked or Rescinded
		SUR	Surrendered
		UNK	Unknown
		VAC	Vacated
		WDN	Withdrawn

<u>PF</u> Status of new power facilities code

- AR Additional assured resource (includes projects for which a developer has obtained all licenses for construction and has made a commitment to proceed with construction).
- NE Non-existing power facilities.
- OL On-line
- UC Under Construction

<u>UCAPACITY</u> Installed capacity of new potential in kW. Information from developer permit or license application documents.

<u>MCAPACITY</u> Installed capacity of new potential in kW. Information is computer generated estimate in absense of developer input.

This information reflects the current data contained within the NWHS. The data base is undergoing complete project data review to complete records where data is missing or to correct data that is inaccurate. The review process was begun in July 1988 and is expected to take 2-3 years for all 4,500 projects. In looking through the data you will see many -1.0 entries. This can mean no applicant/developer input data available, no complete data coding originally performed, or no machine generated data done for this project.

Should information on this list be in error, please inform us so that corrections can be made as part of the review and update process.

RHoleman:3444:VS5-RMGB-1109g (06/13/90)

Location and Identification

* *

Table 2-1(concluded)

State Name: Oregon (cont)

Code	County Name
045	Malheur
047	Marion
049	Morrow
051	Multnomah
053	Polk
055	Sherman
057	Tillamook
059	Umatilla
061	Union
063	Wallowa
065	Wasco
067	Washington
069	Wheeler
071	Yamhill

State Name: Utah
State Abbreviation: UT
State Code: 49

Code	County Name
001	Box Elder
005	Cache
033	Rich

State Name: Washington
State Abbreviation: WA
State Code: 53

Code	County Name
001	Adams
003	Asotin
005	Benton
007	Chelan
009	Clallam
011	Clark
013	Columbia
015	Cowlitz
017	Douglas
019	Ferry
021	Franklin
023	Garfield
025	Grant

State: Name: Washington (cont)

Code	County Name
027	Grays Harbor
029	Island
031	Jefferson
033	King
035	Kitsap
037	Kittitas
039	Klickitat
041	Lewis
043	Lincoln
045	Mason
047	Okanogan
049	Pacific
051	Pend Oreille
053	Pierce
055	San Juan
057	Skagit
059	Skamania
061	Snohomish
063	Spokane
065	Stevens
067	Thurston
069	Wahkiakum
071	Walla Walla
073	Whatcom
075	Whitman
077	Yakima

State Name: Wyoming
State Abbreviation: WY
State Code: 56

Code	County Name
013	Fremont
023	Lincoln
029	Park
035	Sublette
039	Teton

* *

SUPPLY ANALYSIS
PUGET SOUND DRAINAGE PLUS WASHINGTON COASTAL STREAMS

INSTALLED CAPACITY (MW)

	Plant Unit Costs ($/kWa of Average Energy)				
	0 to 2500	2500 to 3500	3500 to 4500	4500 to 5500	
YEAR	MW	MW	MW	MW	MW Cum.
1988	0.0	0.3	0.1	0.0	0.4
1989	0.9	3.3	8.4	10.9	23.5
1990	6.7	11.0	22.0	0.1	39.8
1991	27.0	5.8	6.5	1.0	40.3
1992	4.6	3.7	3.5	1.0	12.8
1993	9.0	16.8	19.2	2.2	47.2
1994	0.0	4.5	2.4	1.5	8.4
1995	12.4	31.7	4.4	1.7	50.2
1996	0.0	0.0	0.0	0.0	0.0
1997	0.0	0.0	0.0	0.0	0.0
1998	0.0	7.0	3.7	2.3	13.0
1999	0.0	0.0	0.0	0.0	0.0
2000	0.0	0.0	0.0	0.0	0.0
2001	0.0	0.0	0.0	0.0	0.0
2002	0.0	0.0	0.0	0.0	0.0
2003	0.0	0.0	0.0	0.0	0.0
2004	0.0	0.0	0.0	0.0	0.0
2005	0.0	0.0	0.0	0.0	0.0
2006	0.0	0.0	0.0	0.0	0.0
2007	0.0	0.0	0.0	0.0	0.0
Totals (MW)	60.6	84.1	70.2	20.7	235.6

BLOCK CHARACTERISTICS

Plant Unit Costs ($/kWa Ave. Energy)	Total Capacity (MW)	Total Average Energy (MWa)	Total Firm Energy (MWa)	Levelized Energy Costs (mills/kWh)
0 - 2500	60.6	38.5	30.8	16.0
2500 - 3500	84.1	40.3	32.2	33.0
3500 - 4500	70.2	37.7	30.2	41.9
4500 - 5500	20.7	11.8	9.4	55.2
0 - 5500	235.6	128.3	102.6	

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PROJECT NAME	APPLICANT DEVELOPER	FERC NO	CO	HUC	STATUS	PF	UCAPACITY	MCAPACITY
E F GRIFFIN CR	WATER DISTRICT NO 97 KING CO	02316B00	033	1711	LC-WDN	NE	29380.6	-1.0
CARNATION	WATER DISTRICT NO 97 KING CO	02316C00	033	1711	LC-WDN	NE	34100.0	-1.0
WHITE RIVER	PUGET SOUND POWER & LIGHT	02494A02	053	1711	LC-PND	NE	14000.0	-1.0
THUNDER CREEK	SEATTLE CITY LIGHT APPL.-PRO	02657-00	073	1711	PP-EXP	NE	1305.0	-1.0
SF TOLT	CITY OF SEATTLE	02959-17	033	1711	LA-GTD	NE	15000.0	16967.1
KOMA KULSHAN	PUGET SOUND POWER + LIGHT CO	03239A09	073	1711	LA-GTD	NE	5600.0	5829.8
KOMA KULSHAN-SANDY CR	PUGET SOUND POWER + LIGHT CO	03239B09	073	1711	LA-GTD	NE	5600.0	-1.0
SUNSET FALLS WATER POWER PLT	JR BEEBE JR.	03347-01	061	1711	PP-DND	NE	7500.0	-1.0
THUNDER CREEK	PUGET SOUND P + L	03913-01	057	1711	LC-PND	NE	9425.0	9425.0
ROCK CREEK	MASON CO PUD NO 3	04217-00	045	1711	PP-EXP	NE	1800.0	1802.0
PARK CREEK	PUGET SOUND POWER &LIGHT	04220-01	073	1711	LC-WDN	NE	1900.0	-1.0
ALDRICH CR	HYDROKINETIC CO	04295-00	073	1711	PP-SUR	NE	575.0	527.0
MUD MOUNTAIN-WHITE R	CITY OF TACOMA DEPTOF PUB U	04308-01	033	1711	PP-EXP	NE	5800.0	-1.0
DAMNATION PEAK	DAMNATION PEAK POWER CO.	04435-05	057	1711	LC-DND	NE	5000.0	-1.0
SWAMP CREEK	MCGREW, MCMASTER + KOCH	04586-06	073	1711	LA-GTD	NE	3500.0	3177.8
RUTH CREEK	MCGREW, MCMASTER + KOCH	04587-07	073	1711	LA-GTD	NE	2800.0	1898.5
TWIN FALLS	SOUTH FORK RESOURCESINC	04885-20	033	1711	LA-GTD	NE	20000.0	-1.0
WARM CREEK	ANVIL POWER INC	05242-01	073	1711	PP-EXP	NE	3200.0	-1.0
BIRCH CREEK	YANKEE POWER CO	05279-05	073	1711	EX-GTD	UC	10.0	-1.0
PUGH CREEK	CITY OF DARRINGTON	05290-01	061	1711	PP-SUR	NE	2800.0	2802.0
MINERAL BUTTE	WESTERN POWER INC	05341-01	061	1711	EX-GTD	NE	5000.0	-1.0
SWIFT CREEK	GOAT MOUNTAIN MINING CO.	05349-00	073	1711	LC-WDN	NE	17500.0	-1.0
DESCHUTES-TUMWATER	OLYMPIA BREWING CO	05364-00	067	1711	EX-REV	NE	2500.0	2989.7
BIG CREEK	PHI SIG ASSOCIATES	05418-01	057	1711	LC-REJ	NE	17500.0	-1.0
FALLS CREEK SMALL HYDRO PROJ	A.H. HALEY	05497-04	009	1711	EX-GTD	UC	200.0	146.1
TOMYHOI CR	STEPHEN J GABER	05544-00	073	1711	PP-EXP	NE	3200.0	4190.0
WHITE SALMON CR	STEPHEN J GABER	05545-02	073	1711	EX-SUR	NE	1300.0	733.5
IRON MOUNTAIN PROJ	HURN SHINGLE CO, INC	05554-01	057	1711	EX-GTD	NE	1620.0	867.1
VICTOR FALLS	CITY OF BONNEY LAKE	05699-00	053	1711	EX-SUR	NE	125.0	-1.0
JOHNSON CR	WOODS CREEK INC	05819-00	061	1711	PP-SUR	NE	4700.0	4197.4
MAY CREEK	KEN COKE PE	05825-00	061	1711	PP-SUR	NE	800.0	800.0
BECKLER R HYDROELECTRIC PROJ	R H SHERMAN	05829-01	061	1711	EX-GTD	NE	3000.0	3578.1
OLNEY CREEK FALLS	WESTERN HYDRO ELECTRIC INC	05853-00	061	1711	LC-DND	NE	1500.0	-1.0
NF SNOQUALMIE R (A)	CITY OF BELLEVUE WA	05926A02	033	1711	LC-DIS	NE	14800.0	-1.0
NF SNOQUALMIE R (B)	CITY OF BELLEVUE WA	05926B02	033	1711	LC-DIS	NE	20000.0	-1.0
DIAMOND CR	GA CROMWELL	05978-03	073	1711	EX-GTD	NE	350.0	239.0
SMITH CR PROJECT	RB SHIPP	05982-00	073	1711	EX-GTD	NE	93.0	156.0
WATSON CREEK	JEFFERSON CO PUD NO 1	06003-00	045	1711	PP-SUR	NE	973.0	1204.0
BOULDER CREEK	MASON CO PUD NO 1	06007-00	045	1711	PP-EXP	NE	3000.0	1766.0
MT ROSE HYDROELECTRIC PROJ	LAKE CUSHMAN CO	06143-00	045	1711	PP-EXP	NE	200.0	371.8
CABIN CREEK	S V HYDROTECH INC	06151-06	031	1711	LC-GTD	NE	2890.0	2005.4
DUPRIS HYDRO	JC DUPRIS	06169-00	073	1711	EX-REJ	NE	9.0	-1.0
BLACK CREEK	WEYERHAEUSER CO	06221-01	033	1711	LC-GTD	NE	3700.0	2715.3
UPPER BIG CR	LAWRENCE J MCMURTREY	06247-00	057	1711	EX-DIS	NE	2700.0	-1.0
LOWER BIG CREEK	LAWRENCE J MCMURTREY	06254-00	057	1711	EX-DIS	NE	3610.0	-1.0
GRADE CREEK PROJ	LAWRENCE J MCMURTREY	06272-00	057	1711	EX-DIS	NE	3240.0	1951.6
BIG CREEK	WESTERN HYDRO ELECTRIC, INC	06273-00	057	1711	EX-REJ	NE	2600.0	5831.6
LENA CREEK	RAINSONG CO	06287-02	031	1711	LC-DND	NE	5000.0	-1.0
TROUT CREEK	WOODS CK INC & MURRAY PACIFI	06301-00	061	1711	EX-GTD	NE	5000.0	2500.0
CARROLL CR	WOODS CR INC	06316-00	033	1711	PP-DIS	NE	900.0	900.0
HARLAN CR	RAINSONG COMPANY	06348-01	033	1711	EX-DIS	NE	2000.0	-1.0
BAGLEY CREEK	SLUSH CUP CO	06415-03	073	1711	EX-REV	NE	3000.0	2089.0
UPPER GLACIER CREEK	WESTERN HYDRO ELECTRIC INC	06437-05	073	1711	EX-GTD	NE	3300.0	3710.1
MORSE CREEK	CITY OF PORT ANGELES	06461-08	009	1711	LA-GTD	UC	465.0	1677.0
SKYKOMISH TRIB. PROJECT	TOWN OF SKYKOMISH	06496-00	061	1711	PP-EXP	NE	3260.0	1186.0
UPPER FOUND CREEK	TOWN OF SKYKOMISH	06504-04	057	1711	EX-WDN	NE	1870.0	1606.0
HOWARD CREEK	TOWN OF SKYKOMISH	06505-00	061	1711	PP-EXP	NE	3450.0	2238.9

EXCELSIOR CREEK	TOWN OF SKYKOMISH	06506-00	061	1711	PP-EXP	NE	1630.0	1048.2
HELENA CREEK	TOWN OF SKYKOMISH	06538-00	061	1711	PP-CAN	NE	1810.0	1513.7
SKY CREEK	OLYMPUS ENERGY CORP	06616-00	057	1711	EX-CAN	NE	1900.0	-1.0
THUNDER CREEK NO 3	NW RESOURCES GENERATING CO	06717-00	073	1711	EX-WDN	NE	5000.0	5797.8
THUNDER CREEK NO 2	NW RESOURCES GENERATING CO	06719-00	073	1711	EX-WDN	NE	5000.0	6117.8
THUNDER CREEK NO 1	NW RESOURCES GENERATING CO	06737-00	073	1711	EX-WDN	NE	5000.0	6294.7
SILVER CREEK	COLENERGY, INC	06824-02	053	1711	LC-GTD	NE	3800.0	3439.2
WYNOOCHEE RIVER	CITY OF ABERDEEN	06842-14	027	1710	LA-GTD	NE	10800.0	11242.0
GOLDSBOROUGH CREEK	MASON COUNTY PUD #3	07018-00	045	1711	PP-EXP	NE	380.0	287.9
STILLAGUAMISH TRIBS (A)	GREAT NORTHERN HYDRO COMPANY	07036A00	061	1711	PP-CAN	NE	1600.0	-1.0
STILLAGUAMISH TRIBS(E)	GREAT NORTHERN HYDRO COMPANY	07036E00	061	1711	PP-CAN	NE	1810.0	-1.0
STILLAGUAMISH TRIBS(F)	GREAT NORTHERN HYDRO COMPANY	07036F00	061	1711	PP-CAN	NE	2340.0	-1.0
STILLAGUAMISH TRIBS(G)	GREAT NORTHERN HYDRO COMPANY	07036G00	061	1711	PP-CAN	NE	3580.0	-1.0
WALLACE-ISABEL (B)	GREAT NORTHERN HYDRO COMPANY	07038B00	061	1711	PP-CAN	NE	2628.0	2628.0
RAINBOW CR HYDRO	OLYMPUS ENERGY CORP.	07097-01	009	1710	EX-SUR	NE	3000.0	3003.6
WRIGHT CR	C WILLIAMS	07111-01	027	1710	EX-DIS	NE	500.0	403.4
SOUTH PRAIRIE CREEK	WP INC	07215-00	053	1711	PP-DIS	NE	5000.0	5000.0
BAGLEY CREEK WATER	ALPINE POWER CO	07393-02	073	1711	LC-DIS	NE	2500.0	1913.3
TRIPLE CREEK	COLENERGY INC	07455-00	061	1711	EX-REJ	NE	640.0	294.7
TOMTIT LK POWER PROJECT	GALE ASSOCIATES	07562-00	061	1711	PP-EXP	NE	300.0	-1.0
ARROW CREEK	WP INC	07598-00	057	1711	PP-EXP	NE	950.0	-1.0
IRON CREEK	WP INC	07600-00	057	1711	PP-CAN	NE	2800.0	2800.0
PEEK-A-BOO CREEK	WP INC	07601-00	061	1711	PP-EXP	NE	890.0	667.0
LOCH KATRINE	WP INC	07602-01	033	1711	PP-CAN	NE	1147.0	1147.0
SMC LAKE	WP INC	07620-00	033	1711	PP-CAN	NE	1700.0	1700.0
BLACK CREEK	WP INC	07641-00	061	1711	PP-DIS	NE	2040.0	2622.8
GREIDER CREEK WATER POWER	WP INC	07644-00	061	1711	PP-CAN	NE	860.0	860.0
MEADOW CREEK	WP INC	07666-00	061	1711	PP-CAN	NE	3470.0	-1.0
CANYON CREEK	WP INC	07672-00	053	1711	PP-CAN	NE	1960.0	3004.9
SLOAN PEAK WATER POWER PROJ	WP INC	07675-00	061	1711	PP-CAN	NE	1150.0	1150.0
EVANS LAKE	WP INC	07834-00	033	1711	PP-CAN	NE	1005.0	1005.0
COUGAR CREEK	WP INC	07839-00	061	1711	PP-CAN	NE	1334.0	1334.0
HANSEN CR	WP INC	07840-00	033	1711	PP-CAN	NE	1340.0	1340.0
PRICE CREEK	SJ GABER	07940-00	073	1711	EX-DIS	NE	1900.0	755.1
DEER CR	TOWN OF INDEX	08183-00	061	1711	PP-REJ	NE	2600.0	2600.0
NOISY CR	PUGET SOUND POWER &LIGHT CO	08289-08	073	1711	LA-GTD	NE	10700.0	10700.0
DEER CREEK	TOWN OF INDEX	08314-00	061	1711	PP-SUR	NE	2600.0	-1.0
DAMFINO CREEK	GARBER, S J	08479-00	073	1711	PP-SUR	NE	4300.0	4300.0
NORTH BEND	NORTH BEND ASSOCIATES	08547-00	033	1711	PP-WDN	NE	7700.0	7700.0
WISHKAH	CITY OF ABERDEEN	08790-00	027	1710	LC-GTD	NE	330.0	-1.0
CALLIGAN CREEK	WEYERHAEUSER CO	08864-03	033	1711	PP-GTD	NE	5050.0	-1.0
HANCOCK CREEK	WEYERHAEUSER CO	09025-00	033	1711	PP-GTD	NE	5220.0	-1.0
BIG QUILCENE	TACOMA/JEFFERSON PUD 1	09377-02	031	1711	PP-SUR	NE	1000.0	1000.0
BLACK CANYON	WEYERHAEUSER CO	09883-02	033	1711	PP-GTD	NE	2500.0	-1.0
HOWARD HANSON DAM	CITY OF TACOMA	09975-00	033	1711	PP-GTD	NE	24500.0	-1.0
LAKE ISABEL	AMERICAN POWER PRODUCERS INC	10002-00	061	1711	PP-GTD	NE	5000.0	-1.0
IRENE CREEK	CASCADE RIVER HYDRO	10100-00	057	1711	PP-GTD	NE	3680.0	-1.0
BLACK CREEK	CASCADE RIVER HYDRO	10101-00	061	1711	PP-GTD	NE	1230.0	-1.0
LOWE CREEK	SKYKOMISH RIVER HYDRO	10145-00	033	1711	PP-GTD	NE	1720.0	-1.0
SAN JUAN CREEK	SKYKOMISH RIVER HYDRO	10146-00	061	1711	PP-GTD	NE	2240.0	-1.0
BEAR CREEK	SKYKOMISH RIVER HYDRO	10148-00	061	1711	PP-GTD	NE	2700.0	-1.0
HOWARD CREEK	SKYKOMISH RIVER HYDRO	10151-00	061	1711	PP-GTD	NE	3500.0	-1.0
EXCELSIOR CREEK	SKYKOMISH RIVER HYDRO	10152-00	061	1711	PP-GTD	NE	1700.0	-1.0
PRESSENTIN CREEK	SKAGIT RIVER HYDRO	10184-00	057	1711	PP-GTD	NE	3160.0	-1.0
SLOAN CREEK	SAUK RIVER HYDRO	10186-00	061	1711	PP-GTD	NE	3620.0	3620.0
SALMON CREEK	SKYKOMISH RIVER HYDRO	10187-00	061	1711	PP-GTD	NE	2880.0	2880.0
BURN CREEK	SKYKOMISH RIVER HYDRO	10189-00	033	1711	PP-GTD	NE	3440.0	3440.0
CRYSTAL CREEK	SAUK RIVER HYDRO	10193-00	061	1711	PP-GTD	NE	2880.0	2880.0
HELENA CREEK	SAUK RIVER HYDRO	10194-00	061	1711	PP-GTD	NE	2200.0	2200.0

SKYKOMISH TRIBUTARIES	SKYKOMISH RIVER HYDRO	10197-00	061	1711	PP-GTD	NE	4408.0	-1.0
HARLAN CREEK	SKYKOMISH RIVER HYDRO	10210-00	033	1711	PP-GTD	NE	2330.0	-1.0
BOULDER CREEK 1	SKYKOMISH RIVER HYDRO	10213-00	061	1711	PP-GTD	NE	1362.0	-1.0
EVERGREEN CREEK	SKYKOMISH RIVER HYDRO	10214-00	061	1711	PP-GTD	NE	1701.0	-1.0
FOURTH OF JULY CREEK	SKYKOMISH RIVER HYDRO	10215-00	061	1711	PP-GTD	NE	1696.0	-1.0
BULLBUCKER CREEK	SKYKOMISH RIVER HYDRO	10216-00	061	1711	PP-GTD	NE	1548.0	-1.0
JOHNSON CREEK	SKYKOMISH RIVER HYDRO	10217-00	061	1711	PP-GTD	NE	2515.0	-1.0
BAROMETER CREEK 2	MOUNTAIN HYDRO CO	10222-00	073	1711	PP-GTD	NE	10700.0	-1.0
HOOD STREET RESERVOIR	CITY OF TACOMA PUD	10256-00	053	1711	EX-GTD	UC	800.0	-1.0
SONNY BOY CREEK	CASCADE RIVER HYDRO	10258-00	057	1711	PP-GTD	NE	3510.0	-1.0
FOUND CREEK 2	CASCADE RIVER HYDRO	10266-00	057	1711	PP-GTD	NE	4120.0	-1.0
THUNDER CREEK	WASHINGTON HYDRO DEVLP CO	10272-00	057	1711	PP-GTD	NE	2494.0	-1.0
SHANNON CREEK	WASH HYDRO DVLP CO	10273-00	073	1711	PP-GTD	NE	2430.0	-1.0
SIBLEY CREEK	CASCADE RIVER HYDRO	10274-00	057	1711	PP-GTD	NE	2980.0	-1.0
WELLS CREEK	NOOKSACK HYDRO DVLP CO	10277-00	073	1711	PP-REJ	NE	6514.0	-1.0
GRANDY CREEK TRIB 1	WASHINGTON HYDRO DEVELOP INC	10287A00	057	1711	PP-GTD	NE	2524.0	-1.0
GRANDY CREEK TRIB NO 2	WASHINGTON HYDRO DEVELOP INC	10287B00	057	1711	PP-GTD	NE	680.0	-1.0
SANDY + DILLARD CREEK	WASH HYDRO DEVELOPMENT CO	10290-00	073	1711	PP-GTD	NE	3787.0	-1.0
NOOKSACK RIVER TRIB	NOOKSACK RIVER HYDRO	10299-00	073	1711	PP-GTD	NE	5467.0	-1.0
HIDDEN CREEK	WASH HYDRO DVLP CO	10305-00	073	1711	PP-GTD	NE	4805.0	-1.0
ALMA/COPPER CREEK	SKAGIT RIVER HYDRO	10328-00	057	1711	PP-GTD	NE	10478.0	-1.0
MIDDLE FORK SNOQUALMIE RIVER	SNOQUALMIE RIVER HYDRO	10356E00	033	1711	PP-GTD	NE	1397.0	-1.0
MIDDLE FORK SNOQUALMIE RIVER	SNOQUALMIE RIVER HYDRO	10356G00	033	1711	PP-GTD	NE	2072.0	-1.0
UPPER SOUTH FORK SNOQUALMIE	SNOQUALMIE RIVER HYDRO	10360-00	033	1711	PP-GTD	NE	1838.0	1454.6
BEAR CREEK POWER	CPS PRODUCTS INC	10371-00	057	1711	PP-GTD	NE	2000.0	2000.0
N FK SNOQUALMIE (CALLIGAN)	SNOQUALMIE RIVER HYDRO	10382C00	033	1711	PP-REJ	NE	3583.0	3583.0
N FK SNOQUALMIE (HANCOCK)	SNOQUALMIE RIVER HYDRO	10382D00	033	1711	PP-REJ	NE	4328.0	6500.0
FALLS CREEK	SAUK RIVER HYDRO	10392-00	061	1711	PP-GTD	NE	3460.0	3262.9
GOBLIN CREEK	SKYKOMISH RIVER HYDRO	10398-00	061	1711	PP-GTD	NE	759.0	-1.0
ANDERSON CREEK	WASHINGTON HYDRO DEV CO	10416-00	073	1711	PP-GTD	NE	3094.0	3094.0
TYE RIVER	SKYKOMISH RIVER HYDRO	10420-00	033	1711	EX-REJ	NE	8000.0	-1.0
HOWARD CREEK	SKAGIT RIVER HYDRO	10421-00	057	1711	PP-GTD	NE	4230.0	1757.5
ANDERSON CREEK	ENERGY ALTERNATIVES	10424-00	073	1711	PP-DND	NE	3500.0	3500.0
EBEY HILL	K T + P G DUNCAN	10428-00	061	1711	EX-GTD	UC	100.0	59.2
LOOKOUT-FOSSIL CREEK	ENERGY ALTERNATIVES	10432-00	073	1711	PP-GTD	NE	1500.0	-1.0
BIG CREEK	SNOQUALMIE RIVER HYDRO	10496-00	033	1711	PP-GTD	NE	1183.0	1183.0
MCCOY CREEK	THELEN, EW	10558-00	061	1711	PP-WDN	NE	230.0	230.0

Puget Sound Electric Reliability Study
Local Generation Study Team

Meeting Summary
March 1, 1991
(Revised May 28, 1991)

Introduction - Since the distribution of the Puget Sound Electric Reliability Study Scoping Report, several questions have arisen regarding assumptions used by the The Local Generation Team for some of the local generation options. In addition some adjustments have been made to assumptions based on input from other teams. The Local Generation Team met on March 1, 1991 in order to validate changes that have been made and to discuss and resolve issues that have raised by other teams. This report summarizes the findings reached at this meeting. The following items are discussed in this summary:

1. Review of Environmental Impact Assessment Matrix and Analysis Package
2. Small Hydroelectric Resource
3. Refinement of Cogeneration Estimates
4. Coal Plant Environmental Data
5. Combustion Turbine Assumptions
6. Other Technologies

1. Review of Environmental Impact Assessment Matrix and Analysis Package

It is suggested that the large impoundment category for the hydroelectric resource be deleted. The reason is that the 250 MW of small hydro potential that is included in the local generation package contains no new large impoundments (>100 acres). See discussion below (#2) for rationale.

2. Small Hydroelectric Resource

Several questions have been raised regarding the small hydro resource estimates that are included in the Puget Sound Area Electric Reliability Plan, Scoping Report, Part B. In order to respond to these questions it is helpful to review the methodology that was used to develop the estimates.

Methodology - The procedure used to generate the Puget Sound estimates is the same as that used by Bonneville and the Power Planning Council to generate regional estimates used for power planning purposes. This procedure uses the Pacific Northwest Hydro Power Site Data Base which includes data on all projects that have been filed with the Federal Energy Regulatory Commission (FERC). The data base analysis system has the capability to estimate project cost, capacity, and output where this information was not provided by developers. The Protected Areas identified by the

Council defines those areas which should not be developed due to anadromous fish impacts.

The procedure used to develop estimates of potential for this study involves several steps:

a. All sites not in the Puget Sound study area were eliminated from the supply data set.

b. Sites that were located in the Power Planning Council's Protected Areas were screened out of the analysis.

c. About 150 sites passed these two screens. However, even projects passing these screens could have environmental problems that may preclude development. In addition, the technical characteristics of many of these sites have not been fully explored, leading to the possibility that development may not be feasible for engineering, environmental, or economic reasons. To account for these factors, probabilities of completion were assigned based on the stage at which the project stands in the regulatory process (permit pending to license granted), the layout of the project (diversion to canal), and the status of the waterway structure (existing to undeveloped).

c. These probabilities (ranging from 20% to 95%) were applied to the capacity and energy potential of each project to obtain a probable contribution. The probable contributions of individual projects are then summed to obtain the Puget Sound potential.

This method produces a statistical estimate of the expected developable hydropower without the need to determine if specific individual projects should be developed--a determination that would be inappropriate given the limited information available on a specific project and stream reach.

It is important to remember that even though a specific project is included in the estimate of potential in the Puget Sound area it does not mean the site will or will not be developed. This methodology is intended to provide a macro assessment of the potential in the area. The presence or absence of a specific project has a minor effect on the overall projection for the small hydro resource.

The Puget Sound Area Electric Reliability Plan is not the forum for deciding whether a specific project will or will not be developed. The FERC licensing process, with its extensive public review process provides this forum on a project by project basis.

Hydro Projects with Impoundments - The Environmental Team raised a question regarding the number of projects that have large impoundments (> 100 acres). A review of the 150 sites in the Puget Sound area identified three sites that have existing impoundments and three that have potential impoundments. Of the three with potential impoundments one has had the license withdrawn, one is not being pursued by the developer, and one is relatively small (5 MW capacity). If these three sites were eliminated from the data set the effect on the overall estimate of potential would be insignificant (<5 MW drop in capacity) because of the development probabilities that are already assigned to these projects.

The data set shows an additional 22 sites that have no indication whether or not they have an impoundment. Only three of these 22 sites are of a significant size (>10 MW capacity). Of these three, two have had the license dismissed and the third has no impoundment per the developer. The remaining 19 sites are small in size and can be assumed to have no impoundments.

The conclusion that should be drawn from this discussion is that the 250 MW potential identified for the Puget Sound area essentially contains no new large impoundments. Even if the data base were purged of the sites with identified new impoundments, the effect on the 250 MW estimate would not be significant.

Operation During Extreme Weather Conditions - A recurring question has been asked about the impact of extreme cold weather on the operation of small hydro plants and the consequent effect on the estimate of hydro potential in the Puget Sound area. It is possible for extreme cold conditions to degrade performance or to halt the output of a small hydro facility. However, the projects most likely to be affected by these conditions are at higher elevations. Projects at higher elevations tend to be smaller in size and account for a small portion of the total population of hydro sites. This, in conjunction with the development probabilities that are applied to the individual projects, results in an insignificant reduction in the peak availability that is being projected.

Location of Hydro Projects - A paper describing the location assumptions used by Systems Analysis Team was distributed. This distribution of generic resources was developed from the data set that forms the foundation for the generic estimates reported in the Scoping Report. All data set projects were plotted geographically. Those projects with a high probability of development were located and then divided into six groups, separated by natural barriers and by how they would likely be integrated into the transmission system. Each of these groups have similar amounts of generation.

3. Refinement of Cogeneration Estimates

Two questions regarding the characteristics of the cogeneration resource were brought to the Local Generation Team for response: (1) The desire for additional breakdown of the cogeneration resource, and (2) an estimate of the incremental fuel consumption increase of a typical cogeneration facility. As in the case of the hydro resource, it is necessary to understand how the cogeneration estimates were developed before attempting to answer these questions.

Methodology - Regional estimates of cogeneration prepared by BPA and the Power Planning Council used output of the Cogeneration Regional Forecasting Model(CRFM) as the principle source. This model contains a data base of facilities which could potentially install cogeneration equipment. These facility types range from refineries and paper mills to hospitals and commercial buildings. When the model is run it attempts to match various cogeneration technologies with each facility. Additional economic assumptions are made regarding fuel prices and the price at which the facility could sell electricity back to the utility. The model's objective is to find the configuration, operating mode, and system size that maximized the internal rate of return as seen by the developer. This process yields a distribution for a supply of cogeneration as a function of internal rate of return. Assumptions are made regarding penetration rates (actual decisions to install the cogeneration equipment) at different levels of return. This penetration curve is used to reduce the distribution of supply to an expected value for developed cogeneration and the results are aggregated to a regional level.

In order to develop an estimate of potential in the Puget Sound area the CRFM was run for only Whatcom, Skagit, Snohomish, King, and Pierce counties.

The output of this process is truly a generic estimate of the potential cogeneration. There is no site or project specific information in the output. Such an estimate has value as a planning tool. This estimate was compared against lists of known projects. Although these lists were incomplete they did provide a check for consistency of the overall estimate with known projects.

"Normal" versus "New" Cogeneration - The Environmental Team has distinguished between "normal" cogeneration which would be defined as a facility that was roughly in thermal balance, and "new" cogeneration which would be built to generate electric power as its principal product while satisfying the PURPA requirement of a 5% thermal load. The specific question requested an estimate of the breakdown of the Puget Sound area cogeneration potential into these two categories. The generic nature of the estimate of potential for the Puget Sound area makes it difficult to answer this question directly. However, several qualitative statements can be made based on the current knowledge of the cogeneration facilities in the Northwest.

First, one must be cautious with the term "thermal balance." Although it seems intuitive that a cogenerator would design a system that is in thermal balance and thus achieving maximum efficiency, it is likely that equipment capital cost and availability will dictate the actual design. Systems, therefore, may not be optimally matched.

The bulk of the existing cogeneration that exists in the Northwest is focused in large industries, i.e. pulp and paper, lumber, chemical, refineries. With some exceptions, this existing cogeneration would tend to be thermally balanced. The reason for this is that this cogeneration is being sold to utilities with relatively low avoided costs. One can conclude that the incentive to cogenerate is only partially driven by marketing of electric power. The existing cogeneration could, therefore, be characterized as "normal." As the regional economy grows over the next two decades, one can expect the avoided costs of the region's utilities will rise and provide an increased incentive to cogenerators. This increased incentive may then prompt some cogenerators to increase their electric output relative to their thermal loads. The relevant question for the Puget Sound study is what will be the effect of this additional incentive during the next few years. Current avoided costs in the Northwest range from 16 to 26 mills per kWh for a ten year resource. The regional estimates produced by the CFRM do not show a sharp increase in cogenertion potential until the levelized prices exceed 55 mills per kWh. This increase is interpreted as being caused by the introduction of cogenerators who exist primarily to sell electric power and consequently do not have systems in thermal balance. This level of price is not likely to be reached in this region in the near-term.

Therefore, for the purposes of the Puget Sound Electric Reliability Study, it can be assumed that the cogeneration forecasted as available in the Puget Sound area in the near term is all thermally balanced.

Incremental Fuel Use - For the purposes of the Puget Sound Electric Reliability Study, it should be assumed that systems are in thermal balance. Incremental heat rates for cogeneration systems run from 1300 Btu/kWh for steam turbines to 5800 Btu/kWh for combined cycle CT systems.

Location of Cogeneration Projects - A paper describing the location assumptions used by Systems Analysis Team was distributed. For transmission modelling purposes 500 MW was located at Ferndale, Washington. This portion of the cogeneration potential was assumed to be developable by 1997. Other cogeneration development would be located at other sites in the Puget Sound area.

4. Coal Plant Environmental Data - The environmental team has requested assistance in locating emission data for the type of coal plant characterized in the Scoping Report. This coal plant is an atmospheric fluidized bed design. Two sources of data are readily available: (1) the estimates used by BPA in the calculation of environmental costs and benefits. (Environmental Costs and Benefits: Documentation and Supplementary Information, February 22, 1991, Bonneville Power Administration), and (2) permitted values for a sample of AES Corporation fluidized bed plants (see attachment). The following table summarizes the air emissions from these two sources.

Air Emissions for Fluidized Bed Coal Facility
(Heat Rate = 9885 MMBtu/kWh)

Pollutant	BPA lbs/MMBtu	AES lbs/MMBtu
NO_X	0.134	0.11-0.50
SO_X	0.08	0.30-0.60
TSP	0.015	0.015-0.03
CO_2	205	N/A

The AES estimates are permitted values. AES indicates that actual performance would be expected to be better than the permitted values. It is recommeded that the BPA values be used for estimating air emission impacts of the coal resource potential projected in the Puget Sound Electric Reliability Study.

5. Combustion Turbine Assumptions - The combustion turbine assumptions listed in the Scoping Report were based on large frame units that are just now entering the market. They are characterized by very high efficiencies and relatively large unit sizes. Discussions between members of Local Generation and Evaluation teams, resulted in a reassessment of the type of units that should be assumed for the Puget Sound Study. As a result of these discussions, it was decided to use CT assumptions based on a firming study prepared by Seattle City Light for its Strategic Corporate Plan. It was felt that this more accurately reflected the conditions present in the Puget Sound area. The following CT assumptions (1990 $) are to be used for this study:

Combustion Turbine Assumptions
(1990 $)

UNIT SIZE	70 MW
CAPITAL COST	$419 per kW
FIXED O&M	2.50/kW-yr
VARIABLE	3.39 mills/kWh

In addition, it is assumed that the first 350 MW of combustion turbine installed will be used in a firming non-firm mode. This translates to a capacity factor of 15%. Any additional CTs that are installed are assumed to be for peaking purposes only. Peaking CTs are assumed to have a capacity factor of 4%.

6. Other Technologies - Since the Scoping Report was published, several technologies have been suggested for possible application in the Puget Sound area. These include:

Modular Pumped Hydro
Advanced Battery Storage Systems
Adaptive Power Factor Controller
Dispersed Diesel Generators

Modular Pumped Hydro - A presentation was made by Mr. David Olson, Pacific Turbine Systems, San Francisco. Mr. Olson described a modular energy storage system which uses a closed pumped hydro technology. It differs from the traditional pumped storage in that it uses ground water to charge a relatively small closed system, thereby avoiding fish impacts. Since it does not depend on surface water flow, its location is more flexible than traditional hydro or pumped hydro. A typical installation would have a 100 MW capacity (twin 50 MW units) and would cost $700/kW (turn-key installation). A disadvantage of such a system in the Northwest is that it is a net energy looser. Pacific Turbine Systems had done some preliminary work re possible locations in the Puget Sound area. Mr. Olson gave a brief overview of these locations for consideration.

Advanced Battery Storage Systems - A paper describing an outline of a study by Sandia Labs for application of an advanced battery storage system to the Northwest and specifically to the Puget Sound area. Sandia will be preparing a short study and will probably be presenting results in 2-3 months.

Adaptive Power Factor Controller - A paper describing the development and field testing of a closed-loop adaptive power factor controller was distributed to members for their consideration as a technology that may have application in mitigating the Puget Sound voltage stability problem. Members indicated that such a device may have end use applications but they were not sure of its application for the regional problem. The paper will be carried back to each member's utility and circulated.

Ohop Mutual Standby Diesel Generator Proposal - A proposal for utilizing standby diesel generators as a partial solution to the Puget Sound area voltage stability problem was distributed to members. This proposal was forwarded to the Local Generation Team for its review. The team's response to this proposal is due by mid April.

BPA-RPE (4/3/91)
PSMEMO3.DOC

ATTACHMENT

AES Projects with CFB Boilers
Permitted Air Emission Rates
(lbs/ MMBtu)

	% Sulfur in Coal	S O2 3 hr	S O2 Annual	NOx	CO	TSP	VOC
AES Thames 180 MW -- Operating Uncasville, CT	1.95	0.32	0.32	0.29	0.11	0.015	0.0095
AES Shady Point 320 MW -- Operating Poteau, OK	3.2	N/A	0.60	0.50	0.20	0.03	0.006
AES Barbers Point 180 MW -- Under Construction Oahu, HI	<1.5	0.30	0.30	0.11	0.19	0.015	0.015
AES Cedar Bay 250 MW -- In Development Jacksonville, FL	1.7	0.60	0.31	0.29	0.19	0.02	0.015

Courtesy of AES, John Stanley Miller, April 2, 1991.
NOTE: These are permitted values. Actual plants are expected to perform better than these values. Assume heat rate of 10,300 mmbtu/kWh. Shady Point is 11,100 mmbtu/kWh but is not representative of a stand alone plant.

aescoal.xls:psmemo3.doc

PUGET SOUND REINFORCEMENT PROJECTS WITH IMPOUNDMENT

AS OF 02/13/1991

FERC NO	PROJECT NAME	SUR AREA	CAPACITY	ENERGY
02316B00	E F GRIFFIN CR	140.	29380.6	-1.0
02316C00	CARNATION	-1.	34100.0	149358.0
02494A02	WHITE RIVER	-1.	14000.0	83500.0
02657-00	THUNDER CREEK	1577.	1305.0	114000.0
04308-01	MUD MOUNTAIN	970.	5800.0	26000.0
05241-01	WALLACE CR HYDROELEC PROJ	0.	3000.0	13000.0
05364-00	DESCHUTES-TUMWATER	1.	2500.0	7800.0
05699-01	VICTOR FALLS	0.	125.0	615.8
05853-00	OLNEY CREEK FALLS	0.	1500.0	9300.0
05926A02	NF SNOQUALMIE R (A)	0.	14800.0	-1.0
05926B02	NF SNOQUALMIE R (B)	-1.	20000.0	-1.0
06316-00	CARROLL CR	-1.	900.0	7744.0
06505-00	HOWARD CREEK	0.	3450.0	15130.0
06842-20	WYNOOCHEE DAM	1170.	10800.0	42140.0
07018-00	GOLDSBOROUGH CREEK	0.	380.0	1320.0
07672-01	CANYON CREEK	1.	1960.0	6870.6
09377-02	BIG QUILCENE	-1.	1000.0	50000.0
09975-00	HOWARD HANSON DAM	1750.	24500.0	-1.0
10002-05	LAKE ISABEL	265.	5000.0	-1.0
10210-02	HARLAN CREEK	0.	2330.0	10200.0
10217-00	JOHNSON CREEK	0.	2515.0	11020.0
[illegible]360-01	UPPER SOUTH FORK SNOQUALMIE	0.	1838.0	8050.0
[illegible]1-03	BEAR CREEK	0.	2000.0	12000.0
1[illegible]20-00	TYE RIVER	-1.	8000.0	34900.0
10421-00	HOWARD CREEK	-1.	4230.0	18530.0
10428-00	EBEY HILL	4.	100.0	613.6
10432-03	LOOKOUT-FOSSIL CREEK	0.	1500.0	5100.0
10558-00	MCCOY CREEK	-1.	230.0	2000.0

* FERC # 06842 : ENERGY VALUE IS 34510. MWH (REVIEWED)
FERC # 09975 : 2 PROJECTS - 09975A & 09975B
09975A : CAPACITY VALUE IS 2500. KW
ENERGY VALUE IS 14000. MWH
09975B : CAPACITY VALUE IS 24500. KW
ENERGY VALUE IS 80000. MWH
FERC # 10002 : ENERGY VALUE IS 43800. MWH (REVIEWED)