APPENDIX F

GENERATION COST AND PERFORMANCE

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GENERATION COST AND PERFORMANCE

SUMMARY

Appendix F provides the analysis used to characterize the generating resource alternatives described in this draft plan. Table F-1 lists the types of resources analyzed and summarizes the resulting cost and resource potential. Following this overview are detailed descriptions of each resource. A brief description of the process used to analyze each resource follows.

Table F-1
Generating Resource Costs and Potential

Block Code	Resource	Base-Year Technology	Ref. Lev. Energy Costs (m/kWh, real):	Block Firm Energy (MWa)
GEO 1	Geothermal	1995 Flash or Binary	49.7	576
GEO 103	Geothermal	1995 Flash or Binary	49.7	576
GEO 2	Geothermal	1995 Flash or Binary	59.6	414
GEO 3	Geothermal	1995 Flash or Binary	72.8	86
GEO 1R	Geothermal	1995 Flash or Binary	49.7	576
GEO 1DR	Geothermal	1995 Flash or Binary	49.7	576
GEO 2R	Geothermal	1995 Flash or Binary	59.6	414
BIO 1	Black Liquor	1995 20MW Recovery	22.5	195
BIO 2	Mixed Wood	1995 25 MW Stoker	40.0	300
BIO 3	Landfill Gas	1995 Engine-Generator	31.1	126
BIO 4	Forest Residue	1995 10MW Stoker	68.9	28
BIO 5	Forest Residue	1995 25 MW Stoker	79.4	664
HYD 1	Hydropower	Conventional	19.9	64
HYD 2	Hydropower	Conventional	46.9	89
HYD 3	Hydropower	Conventional	78.2	45
SOL 1	Solar	1995 Fixed Flat Plate	210.0	30
WIN 1	Wind	350kW VS HAWT	40.9	46
WIN 2	Wind	350kW VS HAWT	40.2	75
WIN 3R	Wind	350kW VS HAWT	56.1	227
WIN 3DR	Wind	350kW VS HAWT	56.1	227
WIN 4	Wind	350kW VS HAWT	63.5	152
WIN 1A	Wind	1995 350kW VS HAWT	40.6	46
WIN 2A	Wind	1995 350kW VS HAWT	46.7	32
WIN 3A	Wind	1995 350kW VS HAWT	41.0	117
WIN 4A	Wind	1995 350kW VS HAWT	49.4	116
WIN 5	Wind	1995 350kW VS HAWT	63.5	79
WIN 6R	Wind	1995 350kW VS HAWT	55.8	358
WIN 6DR	Wind	1995 350kW VS HAWT	55.8	358
CC 1	Natural Gas	1995 7FA CCCT	29.3	3,356
CC 2	Natural Gas	1995 7FA CCCT	29.9	3,356
CC 3	Natural Gas	1995 7FA CCCT	30.8	4,140

[1] All resource levelized costs were developed assuming 100 percent investor-owned utility financing except wind resources WN1 and WN1A, which are assumed to be financed with 27 percent public utility, 53 percent investor-owned utility and 20 percent independent capital resources.

ANALYTICAL APPROACH

The analysis of alternative generating resources required a four-step process. The first step in the process was to characterize the existing generating plants that are part of the Northwest power system. The second step was to analyze the potential for further development of the particular resource. The third step was to analyze the currently available technologies for converting the resource to electric power. The fourth step was to match the potential for further development with the technologies most appropriate for the Northwest. This last step includes calculation of the cost of energy and capacity, as well as an estimate of the environmental impacts of resource development.

To analyze each of these resources in a way that provides a fair comparison, a common set of financial assumptions was used in the last step of the characterization process. Table F-2 summarizes these assumptions. For purposes of developing representative resource costs, financing was assumed to be 100 percent investor-owned utility, except for currently committed wind resources WN1 and WN1A, which are assumed to be financed with 27 percent public utility, 53 percent investor-owned utility and 20 percent independent capital resources.

Table F-2
Financial Assumptions for Generating Resource Cost Analysis

	Public Utility		**Investor-Owned Utility**		**Unregulated Independent**	
Financial Parameter	Base Resource	Renew-ables	Base Resource	Renew-ables	Base Resource	Renew-ables
Federal Income Tax Rate (%)	n/a	n/a	34.0%	34.0%	34.0%	34.0%
Federal Investment Tax Credit (%)	n/a	n/a	10.0%	10% G,S	10.0%	10% G,S
Accelerated Depreciation Recovery (Years)	n/a	n/a	20	20	20	20
Renewable Production Incentive/Tax Credit	n/a	B,G,S,W	n/a	W	n/a	W
State Income Tax Rate (%)	n/a	n/a	3.7%	3.7%	3.7%	3.7%
State Investment Credit (%)	n/a	n/a	0.0%	0.0%	0.0%	0.0%
Gross Revenue Tax (%)	2.2%	2.2%	2.1%	2.1%	2.1%	2.1%
Property Tax Rate (%)	0.0%	0.0%	1.4%	1.4%	1.4%	1.4%
Insurance Rate (%/yr)	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
Municipal Bond Term (years)	15	30	n/a	n/a	n/a	n/a
Financial Life (years)	15	30	15	30	15	15
Debt Ratio (%)	100%	100%	50%	50%	80%	80%
Debt Interest Rate (nominal. %/yr)	7.5%	7.5%	9.7%	9.7%	9.7%	9.7%
Return on Equity (nominal. %/yr)	n/a	n/a	11.3%	11.3%	18.3%	18.3%
Debt Financing Fee (%)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Discount Rate (real, %/yr)	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%
Inflation Rate (%/yr)	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%

CODING: B-Biomass, G-Geothermal, S-Solar, W-Wind. n/a-not applicable.

Representative Resource Characterizations

Because the computational time required by the integrated-system acquisition analysis model is a function of the number of resource choices available to it, it is desirable to limit the total number of resource characterizations to the minimum amount that still accurately represents available resources. To satisfy this need for simplification, individual resources selected from the last step of the resource analysis have been chosen to represent discrete "blocks" of resource potential in the system model. Table F-3 summarizes the key physical and economic characteristics of the resources included in these blocks. Table F-4 summarizes the impacts of resource development on air, water and land use. Impacts on fish and wildlife are not quantified here, but are discussed in more detail in each resource section.

Table F-3
Generating Resources Plant Cost and Capacities Used in the Integrated System Analysis

Block Code	Resource Description	Block Rated Capacity (MW)	Block Peak Capacity (MW)	Equivalent Availability (%)	Dis patch[2]	Mini mum Load (%)	No. of Units	Unit Rated Capac. (MW)	Avg. Heat Rate (Btu/ kWh)	Forced Outage Rate (%)	Siting & Licen sing ($/kW)	S&L Hold Cost ($/kW/yr)	Con struction Cost ($/kW)	Variable Fuel (m/kWh)	Fixed O&M ($/kW/yr)	Variable O&M (m/kWh)
GEO 1	Shield Complexes @ Main Grid	640	630	90.0%	D	25%	21	30	9,300	6.0%	$80	$2.60	$2,724	0.0	$80	7.8
GEO	Shield Complexes @ Main Grid - 2003	640	630	90.0%	D	25%	21	30	9,300	6.0%	$80	$2.60	$2,724	0.0	$80	7.8
GEO 2	Basin & Range Areas @ Main Grid	458	458	90.3%	D	25%	15	31	9,300	6.0%	$85	$2.90	$3,283	0.0	$108	7.9
GEO 3	B&R Areas & Composite Centers @	95	95	90.2%	D	25%	3	32	9,300	6.0%	$102	$4.00	$4,054	0.0	$140	7.9
GEO	Shield Complexes @ Main Grid -	640	630	90.0%	D	25%	21	30	9,300	6.0%	$80	$2.60	$2,724	0.0	$80	7.8
GEO	Shield Complexes @ Main Grid - Pilots	640	630	90.0%	D	25%	21	30	9,300	6.0%	$80	$2.60	$2,724	0.0	$80	7.8
GEO	Basin & Range Areas @ Main Grid -	458	458	90.3%	D	25%	15	31	9,300	6.0%	$85	$2.90	$3,283	0.0	$108	7.9
BIO 1	Chemical Recovery Boiler Upgrades	260	260	75.0%	MR	n/a	13	20	4,500	10.0%	$31	$3.00	$588	0.0	$0	14.4
BIO 2	Clean wood residues from MSW stream	375	375	80.0%	D	66%	15	25	14,400	10.0%	$130	$13.00	$2,470	-11.1	$99	2.3
BIO 3	Landfill Gas Recovery	140	140	90.0%	MR	n/a	28	5	11,000	5.0%	$62	$6.00	$1,176	0.0	$0	15.5
BIO 4	Eastside forest restoration residues -	35	35	80.0%	D	66%	5	7	14,420	10.0%	$43	$13.00	$817	28.8	$180	2.3
BIO 5	Eastside forest restoration residues -	830	830	80.0%	D	66%	33	25	14,400	10.0%	$130	$13.00	$2,470	28.8	$99	2.3
HYD 1	New Small Hydropower	195	195	33.0%	MR	n/a	20	10	0	1.1%	$59	$2.10	$789	0.0	$17	0.0
HYD 2	New Small Hydropower	223	223	40.0%	MR	n/a	22	10	0	1.1%	$105	$3.80	$1,400	0.0	$30	0.0
HYD 3	New Small Hydropower	107	107	42.2%	MR	n/a	11	10	0	1.1%	$185	$6.60	$2,463	0.0	$53	0.0
SOL 1	Rooftop Photovoltaics	145	145	21.0%	MR	n/a	145	1	0	1.0%	$250	$94.00	$4,250	0.0	$10	0.0
WIN 1	Scheduled, @ Main Grid (to be	129	65	35.9%	MR	n/a	4	32	0	0.0%	$0	$2.50	$984	0.0	$54	-4.9
WIN 2	New, Low Cost @ Main Grid (to be	230	108	32.5%	MR	n/a	8	29	0	0.0%	$28	$2.90	$946	0.0	$27	3.0
WIN	New, Med Cost @ Main Grid -	797	362	28.5%	MR	n/a	16	30	0	0.0%	$21	$2.60	$988	0.0	$47	3.1
WIN	New, Med Cost @ Main Grid - Pilots @	797	362	28.5%	MR	n/a	16	30	0	0.0%	$21	$2.60	$988	0.0	$47	3.1
WIN 4	Blackfeet 500 @ Main Grid	465	101	32.6%	MR	n/a	9	52	0	0.0%	$23	$2.50	$1,554	0.0	$31	3.1
WIN 1A	Scheduled, @ Main Grid	129	65	38.3%	MR	n/a	4	32	0	0.0%	$17	$2.50	$985	0.0	$54	-4.9
WIN 2A	New, Low Cost Spring - Summer Peak	120	34	26.3%	MR	n/a	4	30	0	0.0%	$3	$2.50	$923	0.0	$26	3.0
WIN 3A	New, Low Cost Winter Peak @ Main	365	161	32.0%	MR	n/a	12	30	0	0.0%	$22	$2.80	$950	0.0	$28	3.0
WIN 4A	New, Med Cost Winter Peak @ Main	307	217	37.7%	MR	n/a	10	31	0	0.0%	$17	$2.80	$1,029	0.0	$69	3.1
WIN 5	New, High Cost Spring - Summer Peak	350	68	22.5%	MR	n/a	12	29	0	0.0%	$36	$3.00	$1,046	0.0	$32	3.0
WIN 6R	New, High Cost Winter Peak @ Main	1,318	558	27.2%	MR	n/a	26	51	0	0.0%	$37	$1.80	$983	0.0	$40	3.4
WIN	New, High Cost Winter Peak @ Main	1,318	558	27.2%	MR	n/a	26	51	0	0.0%	$37	$1.80	$983	0.0	$40	3.4
CC 1	New CC, Permitted Sites @ Main Grid	3,648	3,854	92.0%	D	70%	16	228	7,215	5.0%	$0	$0.80	$665	8.13	$19	1.0
CC 2	New CC, Unpermitted Sites @ Main	3,648	3,921	92.0%	D	70%	16	228	7,346	5.0%	$14	$0.80	$670	8.22	$20	1.0
CC 3	High-cost Placeholder	4,500	4,753	92.0%	D	70%	20	225	7,436	5.0%	$18	$0.90	$774	8.32	$20	1.0

[2] Coding: D-Dispatchable, MR-Must Run.
[3] Fixed fuel cost is assumed to be $27.50 per kWh per year.

Table F-4

Environmental Impacts of Resource Blocks Included in the System Analysis

	Criteria Air Pollutants (T/GWh):							Other Air Emissions (T/GWh):			Water use (T/GWh):			Solid Waste (T/GWh):			Land Use (Acres/annual GWh):	
Block Code	**NOx (as NO2)**	**SOx (as SO2)**	**CO (as CO)**	**Particulates (TSP)**	**VOC**	**NH3**	**Lead**	**CO2 Produced (As CO2)**	**CO2 Net (As CO2)**	**H2S**	**Makeup (lb/hr)**	**Discharge (lb/hr)**	**Net Evap. loss**	**Municipal Solid Waste**	**Ash & Other**	**Total**	**Preempted Land**	**Potentially Affected Land**
GEO 1	0	0.028	0	0.002	4.05E-07	0.002	0	3	3	0.015	n/avail	n/avail	4595	0.4	0.3	0.8	1.2	8.2
GEO 103	0	0.028	0	0.002	4.05E-07	0.002	0	3	3	0.015	n/avail	n/avail	4595	0.4	0.3	0.8	1.2	8.2
GEO 2	0	0.028	0	0.002	4.05E-07	0.002	0	3	3	0.015	n/avail	n/avail	4595	0.4	0.3	0.8	1.2	8.2
GEO 3	0	0.028	0	0.002	4.05E-07	0.002	0	3	3	0.015	n/avail	n/avail	4595	0.4	0.3	0.8	1.2	8.2
GEO 1R	0	0.028	0	0.002	4.05E-07	0.002	0	3	3	0.015	n/avail	n/avail	4595	0.4	0.3	0.8	1.2	8.2
GEO 1DR	0	0.028	0	0.002	4.05E-07	0.002	0	3	3	0.015	n/avail	n/avail	4595	0.4	0.3	0.8	1.2	8.2
GEO 2R	0	0.028	0	0.002	4.05E-07	0.002	0	3	3	0.015	n/avail	n/avail	4595	0.4	0.3	0.8	1.2	8.2
BIO 1	0	0	0	0	0	0	0	0	0	n/avail	n/avail	n/avail	0	0.0	0.0	0.0	0.0	0.0
BIO 2	0.719	0.925	1.798	0.194	1.556	0	n/avail	1519	0	n/avail	n/avail	n/avail	3486	7.2	28.6	35.7	0.3	0.0
BIO 3	n/avail	n/avail	n/avail	n/avail	n/avail	0	n/avail	n/avail	0	n/avail	n/avail	n/avail	5550	0.0	0.0	0.0	0.0	0.0
BIO 4	0.719	0.925	1.798	0.194	1.556	0	n/avail	1519	0	n/avail	n/avail	n/avail	3486	7.2	28.6	35.7	0.3	50.0
BIO 5	0.719	0.925	1.798	0.194	1.556	0	n/avail	1519	0	n/avail	n/avail	n/avail	3486	7.2	28.6	35.7	0.3	50.0
HYD 1	0	0	0	0	4.05E-07	0	0	0	0	0.000	n/avail	n/avail	0	0.0	0.0	0.0	1.5	3.0
HYD 2	0	0	0	0	4.05E-07	0	0	0	0	0.000	n/avail	n/avail	0	0.0	0.0	0.0	1.5	3.0
HYD 3	0	0	0	0	4.05E-07	0	0	0	0	0.000	n/avail	n/avail	0	0.0	0.0	0.0	1.5	3.0
SOL 1	0	0	0	0	0	0	0	0	0	0.000	n/avail	n/avail	Negligible	0.0	0.0	0.0	0.0	0.0
WIN 1	0	0	0	0	0	0	0	0	0	0.000	0	0	0	0.0	0.0	0.0	750.0	15000.0
WIN 2	0	0	0	0	0	0	0	0	0	0.000	0	0	0	0.0	0.0	0.0	750.0	15000.0
WIN 3R	0	0	0	0	0	0	0	0	0	0.000	0	0	0	0.0	0.0	0.0	750.0	15000.0
WIN 3DR	0	0	0	0	0	0	0	0	0	0.000	0	0	0	0.0	0.0	0.0	750.0	15000.0
WIN 4	0	0	0	0	0	0	0	0	0	0.000	0	0	0	0.0	0.0	0.0	750.0	15000.0
WIN 1A	0	0	0	0	0	0	0	0	0	0.000	0	0	0	0.0	0.0	0.0	750.0	15000.0
WIN 2A	0	0	0	0	0	0	0	0	0	0.000	0	0	0	0.0	0.0	0.0	750.0	15000.0
WIN 3A	0	0	0	0	0	0	0	0	0	0.000	0	0	0	0.0	0.0	0.0	750.0	15000.0
WIN 4A	0	0	0	0	0	0	0	0	0	0.000	0	0	0	0.0	0.0	0.0	750.0	15000.0
WIN 5	0	0	0	0	0	0	0	0	0	0.000	0	0	0	0.0	0.0	0.0	750.0	15000.0
WIN 6R	0	0	0	0	0	0	0	0	0	0.000	0	0	0	0.0	0.0	0.0	750.0	15000.0
WIN 6DR	0	0	0	0	0	0	0	0	0	0.000	0	0	0	0.0	0.0	0.0	750.0	15000.0
CC 1	0.065	0.020	0.016	0.033	0.011	0.051	n/est	497	497	n/avail	1438	435	1004	0.0	0.0	0.0	n/est	n/est
CC 2	0.065	0.020	0.016	0.033	0.011	0.051	n/est	497	497	n/avail	1438	435	1004	0.0	0.0	0.0	n/est	n/est
CC 3	0.065	0.020	0.016	0.033	0.011	0.051	n/est	497	497	n/avail	719	0	719	0.0	0.0	0.0	n/est	n/est

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APPENDIX FBI
BIOMASS

BIOMASS

SUMMARY

Biomass fuels are any organic matter that is available on a renewable basis. This includes forest residues, wood product residues, agricultural field residues and processing waste, animal wastes, agricultural and forest crops grown for fuel and the renewable organic component of municipal solid waste.

Largely because of the abundance of Northwest forest resources, biomass plays an important role in meeting the region's energy needs. Most of this contribution is from the direct use of biomass for industrial process heating and residential space heating. However, about 950 megawatts of electrical generating capacity (about four percent of total regional generating capacity) is partially or wholly fueled by biomass. Nearly 90 percent of this capacity serves some cogeneration load, most in the pulp and paper industry. If fully dispatched, the biomass-fueled power plants of the Northwest could produce about 760 average megawatts of energy. The actual energy production of these plants varies year to year depending on fuel cost and availability, electricity prices and, for cogeneration plants, the need for steam. About 13 percent of the region's biomass capacity has been brought into service or placed under construction within the past five years

Biomass residues could provide a sustainable though limited source of additional electricity for the Northwest. Our estimates suggest that from about 900 to 1,600 average megawatts of additional electrical energy from biomass fuels could be produced at costs ranging from 2.4 to 6.3 cents per kilowatt-hour. This represents from four to seven percent of current regional electricity requirements. Additional potential could be available, though at higher cost, from dedicated energy crops. Most biomass fuels are low in sulfur and nitrogen, and have minimal atmospheric impact when burned correctly. Furthermore, because these fuels are available on a renewable basis, carbon dioxide produced from combustion will be recycled by new growth.

It appears unlikely that any significant expansion in the use of biomass to generate electric power will occur in the near future. Cost is the principal constraint. Of the several biomass resources assessed here, only one, retrofit of generation to chemical recovery boilers not so equipped, appears to be able to compete with near-term wholesale power prices. Power from landfill gas is not much more expensive than power from new natural gas-fueled combined-cycle gas turbines, and may prove to be competitive by the time new generating resources are needed. Power from the other biomass resources is much more expensive than current wholesale electricity and it is unlikely to be competitive for many years.

The development of some biomass generation, not otherwise competitive, may be motivated by environmental benefits. For example, animal manure energy recovery is being considered where field application of manure has become environmentally unsound. The use of biomass residues as fuel is often an alternative to other, less satisfactory disposal methods.

Because of public resistance to new power plants burning unsorted municipal solid waste, it appears unlikely that additional plants of this type will be built in the future. It is more likely that woody debris and other clean combustibles will be separated from the municipal solid waste stream and used to fuel existing or new power plants.

Most biomass applications to date have used boiler steam-electric generating technology. The federal government and the Electric Power Research Institute have sponsored the development of biomass gasification technology. Gasification would permit the use of solid biomass fuels with higher efficiency combined-cycle power plants, and eventually, fuel cells. Commercialization of biogasification technology is expected to lower the cost of producing power from biomass fuels, extend the fuel supply and permit the use of biomass fuels such as agricultural crop residues that are unsuited for use in conventional furnaces.

The focus of this assessment is on biomass residue fuels. However, electric power can also be produced from dedicated energy crops. But hybrid cottonwood, the energy crop most suited for the Northwest, has greater value as pulp feedstock than as fuel.

This section is based on an assessment of biomass resource potential in the Northwest prepared for the Council by the Washington State Energy Office (Kerstetter, 1994). Additional information regarding biomass fuels and power plant options are provided in that paper, available on request from the Council.

Biomass Fuel Supply and Price

The production and consumption of food, fiber and materials results in the generation of residues that often end up as waste material. Much of this material is combustible and may be used as fuel. Combustible residues that are potentially available in significant quantities for electric power generation in the Northwest include forest residues, mill residues, spent pulping liquor, municipal solid waste, agricultural field residues, animal manure and landfill gas. Biomass fuels could also be obtained from dedicated energy crops.

The quantity of residue material available for energy production depends on the level of economic activity, the "residue fraction" (amount of residue produced per unit of process feedstock), and competing uses for the material. Production levels have generally declined in the forest products industry, have been stable in the other natural resources industries and have increased for municipal solid waste. In general, residue fractions have declined for all sources, and competing uses for residue materials have increased.

Prices for biomass residues are set by the interaction of factors including their value for competing uses, the cost of alternative disposal and the cost of transportation. Fuel is the lowest value use for many of these materials, and competing uses will preempt the resource. For example, the pulp value of clean wood chips nearly always exceeds value as fuel. Environmental considerations generally require special disposal of unmerchantable residues. The avoided cost of disposal will set a negative value on some materials. Biomass fuels have a fairly low heat value and are often dispersed. Thus, transportation costs have an important influence on the delivered cost of fuel and the value of competing uses.

The principal biomass fuels available for electric power generation in the Northwest are described below. The estimated supply and price of these fuels are summarized in Table FBI-1.

Forest Residues

Forest residues encompass several sources of potential biomass fuels including logging residues, stagnant or dying timber, hardwood stand conversions and pre-commercial thinnings. These materials have an as-received higher heat value ranging from about 3,600 to 5,800 Btu/kWh and make excellent fuel. Two are considered here -- logging residues and thinnings from proposed forest restoration efforts.

Historically, the quantities of logging residues have varied widely. The quantity of logging residues generated over the next 20 years will depend on the harvest levels and the quantity of residue generated per volume of harvested material. A decline in annual harvest volume of 20 percent is forecast for the Northwest for this period, from 174 to 138 trillion Btu.

Prediction of price is difficult because of the cost-supply relationships of recovery and transportation. Estimates are available of the volume of logging residue fuel that could be recovered and transported 50 miles to a power plant at a cost of $4.50 per million Btu, or less. These are the amounts shown in Table FBI-1.

Many of the ponderosa pine forests of the Northwest has been severely degraded by high-grade logging and fire suppression. Some proposals for restoring these forests involve selective removal of invasive species and thinning of ovestocked stands. The thinnings would be marketed as saw logs or pulping chips where possible. Unmerchantable materials could be chipped and distributed on-site, or alternatively, used as power plant fuel.

Table FBI-1
Supply and price of biomass fuels available for power generation

	Total Annual Fuel Supply (trillion Btus per year)					Representative Cost ($/MMBtu)[1]
	1986-90	1991-95	1996-00	2001-05	2006-09	
Logging residue	48	34	29	28	27	$0.65 - $4.50
Forest thinning residue	n/a	n/a	39 - 125 (84)	39 - 125 (84)	39 - 125 (84)	$0.65
Mill residue	100	45	38	25	18	$0.0 - $1.70[2]
Recovery boilers	86	80	80	80	80	$0.00
Municipal solid waste[3]	64 (45)	64 (45)	64 (45)	64 (45)	64 (45)	($2.22) - ($4.44)[4]
Agricultural field residues	134	134	134	134	134	$2.20
Animal manure	2	2	2	2	2	$0.00[5]
Landfill gas	6	7	16	18	18	$0.00
Hybrid cottonwood residue	0	0.8	2.4	3.0	3.0	$0.90
Dedicated hybrid cottonwood	0	0	0	Not estimated	Not estimated	$3.55

Residue supplies are a function of the extent of affected forest available for entry, portion of affected forest suitable for thinning and unmerchantable material recovery rate. Experience in California provides a basis for estimating the supply and cost of merchantable materials and residues available from typical forest restoration activities. However, because of controversy regarding thinning as a forest management tool on public lands, there is great uncertainty regarding the forest area that might be open for treatment in the Northwest. Opening of one-third of affected national forest lands to thinning over a twenty-year management cycle would annually yield an estimated 39 to 125 trillion Btu of fuel.

The delivered price of fuel from forest thinning is a function of the cost of transportation, incremental administration and the avoided cost of dispersing material at the site. Other costs of the thinning operation are expected to be offset by the value of sawlogs and pulp chips. The cost of dispersing unmerchantable material at the site is assumed to roughly equal the cost of collection and loading for transportation (chipping is assumed to be required in both cases). The resulting incremental cost of providing fuel to a power plant 50 miles from the restoration site is estimated to be $0.65 per million Btu.

Mill Residue

Mill residues are the residues of lumber and wood product manufacturing activities, consisting of sawdust, shavings, bark and trimmings. These materials have an as-received higher heat value ranging from

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[1] Delivered to the power plant, except as indicated.
[2] Average price, 1996 - 2000, at the mill.
[3] First number is total available combustibles. Number in parentheses is recoverable clean woody and paper residue.
[4] Avoided disposal cost at the landfill and transfer station, respectively.
[5] Cost of the manure feedstock. Cost of the product gas is a function of gasifier costs.

about 3600 to 5,800 Btu/kWh and make excellent fuel. Mill residue (except sawdust) intended for fuel use is typically fed through a chipper (hog) to produce relatively uniform chips or shreds. The product is known as hogged fuel.

The quantity of mill residues available for electric power generation in the Northwest is declining. Several factors are at work. The wood products industry, as a whole, is expected to continue to decline until sustainable timber harvest levels are reached. More efficient and innovative uses of wood fiber continue to reduce the residue fraction. Finally, competing uses for the residue materials continue to emerge. The annual supply of mill residue fuel in the Northwest is estimated to be 45 trillion Btu in 1995, declining to 18 trillion Btu in 2006-2009 period.

Historically, the supply and price of mill residues has varied widely, with a fairly good inverse relation between supply and price. Using this correlation, average prices at the mill are forecast to increase about 5 percent per year, on average, from about $1.50 in 1995 to about $2.95 per million Btu in the 2006-2009 period. But there is no single market price for mill residues. The price paid at a specific location will depend on the local supply and demand situation and the cost of alternative fuels.

Chemical Recovery Boilers

Chemical recovery boilers are used to dispose of the spent pulping liquor used in chemical pulping. The spent liquor, which contains lignins and other combustible materials, has a heat value ranging from about 6,500 to 8,000 Btu/lb (dry), depending on the pulping process. Steam from recovery boilers is used for pulp and paper making and for electric power generation.

There are 19 operating mills with chemical recovery boilers in the Pacific Northwest. Ten of these have cogenerating equipment already installed (Lockwood-Post's, 1994). A turbine-generator is being installed at one of the mills not presently equipped. The extent to which this existing cogeneration equipment operates from steam generated by chemical recovery boilers is not known. Though the chemical recovery boilers must operate when the mill operates, turbine-generators are not necessarily operated unless they are backpressure or extraction machines. Furthermore, steam is also supplied from power boilers fueled by wood residues, natural gas or other fuels.

The Washington State Energy Office has estimated that an additional 280 average megawatts of electric energy could be produced from installation of cogeneration equipment at recovery boilers not having such equipment. The thermal energy equivalent of this electricity is shown in Table FBI-1. The incremental cost of this energy is assumed to be zero.

Municipal Solid Waste

Municipal solid waste consists of residential, commercial and institutional discards, and construction and demolition wastes. Non-hazardous byproducts from manufacturing activities are also considered to be municipal solid waste, except for the waste products of the lumber and wood product, and paper and allied product sectors. The discards from these two sectors are classified as wood biomass residues. Most of the materials in a typical municipal solid waste stream are combustible and can be used as fuel. For example, 76 percent of the metropolitan Portland as-delivered waste stream consists of paper, plastic, wood, food or other organic materials (Metro, 1995). The average higher heat value of unsorted municipal solid waste is estimated to be 4,500 Btu/lb.

Source-separation and post-collection recycling efforts have stabilized per-capita waste production and have shifted waste composition. But the combustible component of the waste stream remains high. A second factor affecting the availability of solid waste for alternative uses is the consolidation of landfills. A greater proportion of regional solid waste is now brought to central collection points where it can be more economically processed. A stable annual supply of 70 trillion Btu of combustible municipal solid waste is forecast to be available in the Northwest. Currently operating power plants using municipal solid waste consume about 6 trillion Btu of this total. An annual supply of about 64 trillion Btu remains available (Table FBI-1).

In the past, unsorted municipal solid waste has been burned in “mass-burn” or “refuse-derived fuel” power plants. But public resistance to the construction of power plants burning unsorted municipal solid waste has increasingly delayed or prevented the construction of these plants. In this assessment we assume that only sorted clean woody and paper material would be used as fuel. We assumed that 70 percent of the available combustible waste stream could be recovered for fuel in this manner.

The cost of fuel derived from municipal solid waste is a function of avoided disposal costs plus incremental transportation and processing costs. Avoided disposal costs are assumed to average $20 per ton at the landfill and $40 per ton at the transfer station. This equates to $2.22 per million Btu at the landfill and $4.44 per million Btu at the transfer station, assuming 4,500 Btu/lb.

Agricultural Field Residues

Agricultural field residues are primarily the stalk and chaff residues of grain and seed production. These residues have a heat value of about 8,500 Btu per pound (dry) and could serve as power generation fuel. Although used to a small degree in California and elsewhere, agricultural field residues are not currently recovered for electric power generation in the Pacific Northwest. Moreover, the high silica content of these materials has prevented them from being used as the primary fuel for conventional boiler steam-electric power plants.

The amount of agricultural residues available for electric power generation is determined by volume of the crops from which they are derived; the yield, which varies annually; the residue factor for particular crops; competing uses (such as erosion control and nutrient recycling); and constraints on traditional means of disposal (such as field burning).

There is considerable annual variation in the availability of field residues. Weather, demand for the primary crop and the value of competing crops influence residue availability. The quantity of agricultural residues that will be produced over the next two decades is assumed to be similar to production over the past decade. The annual supply of agricultural residues in the Northwest in excess of agronomic requirements is estimated to average 134 trillion Btu over the next 20 years (Table FBI-1).

The cost of producing fuel from agricultural residues includes collection, transportation, storage and the cost of fertilizers added to replace the nutrients which would have been provided by the residues. The cost is estimated to average $2.20 per million Btu.

Animal Manure

A combustible gas consisting of about 60 percent methane and 40 percent carbon dioxide can be produced from anaerobic decomposition of animal manure. Manure feedstock is available from livestock operations where the animals are concentrated and the manure easily recovered.

Dairy farms are the most promising source in the Northwest. Because small herds may not produce economically recoverable amounts of manure, the regional potential depends on assumptions regarding economic herd size. The annual economically recoverable gas supply from herds exceeding 500 animals in the Northwest is 2 trillion Btu.

The cost of the manure feedstock is essentially zero, and may even be negative, if water quality concerns require manure disposal methods other than direct field application. The cost of the product gas is a function of the incremental cost of constructing and operating the manure gasification system. In this analysis, these costs are included in the power plant cost estimates (See below).

Landfill Gas

Anaerobic decomposition of the organic matter in landfills produces a combustible gas consisting of about 50 percent methane and 50 percent carbon dioxide. Biogas production typically begins one or two years after waste placement and may last for decades. Biogas production may vary significantly from landfill to landfill and within individual landfills. This variability is due to factors such as waste quantity and composition, moisture temperature and pH. About 70 percent of the waste placed in landfills is organic material suitable for production of landfill gas.

The annual gas production from 23 landfills in Washington and Oregon is estimated to be 7.4 trillion Btu. Landfill gas recovery systems are installed at two of these landfills; these consume about 0.6 trillion Btu annually. Not included in this estimate is the future production of gas from the two large regional landfills recently opened in eastern Oregon and Washington. An additional 10.6 trillion Btu could be produced annually from these landfills. The undeveloped supply of landfill gas in Oregon and Washington is estimated to be 7.0 trillion Btu in 1995, increasing to 18 trillion Btu in 2001, thereafter stabilizing (Table FBI-1).

Landfill gas is produced naturally and must be collected and disposed of whether or not used for electric power generation. The alternatives to power generation are flaring, or cleaning and injection into the natural gas supply system. Because the gas is collected in any event, the net cost of the raw gas for power generation is close to zero.

Energy Crops

Dedicated feedstock supply systems are energy crops grown on agricultural land with the whole plant being harvested and utilized for the production of energy. Hybrid cottonwood trees have been identified as the preferred feedstock for the Pacific Northwest. Hybrid varieties of the native black cottonwood can be grown to merchantable size on favorable sites within five to seven years.

Nearly 25,000 acres of cottonwood plantations in Oregon and Washington have been established by the pulp industry for fiber production. Over 50,000 additional acres are planned for development over the next several years. The primary market for short rotation cottonwood will be as feedstock for the pulp and paper industry.

The cost of growing black cottonwood exclusively for fuel is estimated to be $3.55 per million Btu. However, hybrid cottonwood has higher value for pulp feedstock than for energy. At harvest, 30 tons of pulp chips and 13 tons of unmerchantable material are recovered per acre. The unmerchantable material is available as fuel for the cost of transportation, estimated to be $0.90 per million Btu. The annual supply of hog fuel from cottonwood plantations is estimated to be 0.8 trillion Btu in 1995, increasing to 3 trillion Btu in 2001, and thereafter stabilizing.

Electric Generating Technologies Using Biomass Fuels

Most biomass fuels (most of which originate as solids) can be burned directly in a boiler to generate steam to operate a steam-turbine generator. This is the conventional approach to using biomass fuels to generate or cogenerate electricity. A variation of boiler-steam technology includes the furnaces used for the recovery of chemicals and energy contained in spent pulping liquor. Atmospheric fluid bed boilers are increasingly being used to improve the efficiency and environmental performance of boiler-steam power plants.

Work is underway to broaden the range of power generation technologies that could be fueled by solid biomass. The general approach is to convert solid biomass fuels to liquid or gaseous forms. This enables biomass fuels to be used in reciprocating engine power plants, gas turbine plants (simple or combined-cycle) and fuel cells. These technologies offer improved thermodynamic efficiency and emission control compared to conventional steam-electric technology, and may broaden the range of biomass fuels used for power generation to include high-silica content annual growth.

Below are described the principal technologies used to generate or cogenerate electricity from biomass fuels. Table FBI-2 summarizes representative examples of these technologies.

Direct-Fired Steam-Electric Power Plants

Most generation or cogeneration of electricity using biomass is accomplished using direct-fired steam-electric power plants. The basic stoker-fired furnace design has been widely used for small to medium scale generation and cogeneration applications for many years. A special type of direct-fired boiler -- chemical recovery boilers -- is used to dispose of spent pulping liquor in the chemical pulping industry. Fluid bed firing, a newer technology, broadens fuel flexibility and provides improved combustion and air emission control.

Stoker steam-electric plant: A stoker-fired steam-electric power plant consists of a stoker-fired furnace and steam-generator, a steam turbine-electric generator and a condenser cooling system. Other facilities at the site generally include fuel unloading, processing and storage facilities, stack gas cleanup equipment, administrative and control buildings and a switchyard. Steam from the steam generator drives a steam turbine generator. Exhaust steam from the turbine is condensed and returned to the steam generator. A cooling system, generally employing a cooling tower, is used for condenser cooling. Steam may be bled from the steam-generator, turbine extraction ports or turbine exhaust to serve cogeneration loads. These plants generally use fuels that have been chipped or shredded to uniform size.

Because of the expense of transporting biomass fuels, biomass-fired steam-electric generating plants are relatively small, from 5 to 50 megawatts. Thermodynamic efficiencies are fairly low, ranging from 17 to 25 percent. They are best suited for steady-state operation. Cogeneration applications are common. These plants are not suited for fuel containing a large proportion of high-silica annual growth, such as agricultural field residues. These fuels foul boiler surfaces. Performance and cost characteristics of a representative biomass-fueled stoker-fired steam electric plant are provided in Table FBI-2.

The principal environmental concern associated with steam-electric generating plants using clean biomass residue are air-borne particulate materials. Cyclones, fabric filters or precipitators are used to remove particulates from the flue gas. Other environmental impacts of potential concern include carbon monoxide, sulfur oxides, and solid waste disposal. The environmental characteristics of a representative plant are provided in Table I-X of Appendix I.

Table FBI-2

Representative Power Plants Using Biomass Fuels

	Stoker-fired Steam-Electric Plant	**Fluid-bed Steam-Electric Plant**	**Gasification Combined-Cycle Power Plant (Year 2000)**	**Chemical recovery Boiler Cogeneration Retrofit**	**Landfill Gas Recovery Power Plant**	**Animal Manure Energy Recovery Power Plant**
Configuration	One 25 MW unit, no cogeneration	One 25 MW unit, no cogeneration	One 25 MW unit, no cogeneration	CRB upgrade, turbine-generator and associated equipment	In-situ gasification with twin 2.5 MW reciprocating engines	"Complete mix" anaerobic digester with 0.5 MW reciprocating engine
Application	Forest thinning residue	Forest thinning residue	Forest thinning residue	CRB Cogeneration	Landfill gas energy recovery	Animal manure energy recovery
Unit Capacity, net (MW)	25	25	25	25	5	0.5
Availability (%)	80%	80%	80%	80%	90%	90%
Heat Rate (Btu/kWh)	14,390	14,360	10,700	4500[1]	11,100[2]	11800
Overnight Cost ($/kW)[3]	$2600	$3100	$1900[4]	$620	$1240	$2840
Fixed Operating Cost ($/kW/yr)[2]	$99	$108	$181	Included in variable	$114	$61
Variable Operating Cost (mills/kWh)[5]	2.3	2.7	3.5	Less than 14[6]	1.0	0.0
Development & Construction Lead Time (Months)	24/24	24/24	24/24	24/24	12/12	24/12
Cash Flow (%/yr)	2.5/2.5/47.5/47.5	2.5/2.5/47.5/47.5	2.5/2.5/47.5/47.5	2.5/2.5/47.5/47.5	10/90	2.5,2.5,95
Service Life (Years)	30	30	30	30	20	20
Comparative Levelized Energy Cost (cents/kWh)[7]	6.3	7.2	6.3	2.4	3.1	5.0

[1] Fuel chargeable to electric power.
[2] 5300 Btu/kWh fuel charged to electricity production.
[3] Lifetime average capacity basis.
[4] Cost goal.
[5] Exclusive of property tax and insurance. See Financial Assumptions section for assumptions regarding property taxes and insurance.
[6] Incremental O&M cost of the turbine-generator.
[7] 15 year IOU financing, medium gas price forecast, year 2000 service, baseload service.

Chemical Recovery Boilers: Chemical recovery is the process by which the inorganic chemicals used in chemical pulp making are recovered from spent pulping ("black") liquor. The process simultaneously disposes of the other constituents of the liquor and recovers the energy contained therein. (Biermann, 1993). Dilute black liquor is collected from the pulp washing process. The dilute black liquor is concentrated by evaporation to achieve a solids content of about 70% to increase the efficiency of combustion. Concentrated black liquor is sprayed into the furnace, the water evaporates and the organic components char and burn. The inorganic chemicals are reduced to smelt in the oxygen-deficient lower section of the furnace.

Recovery boilers in the Northwest for which information is available range in size from 240,000 to 740,000 pounds of steam per hour (Sufficient to generate approximately 25 to 75 megawatts if entirely used for electricity generation). The additional regional electric generating potential from pulping chemical recovery is not from installation of new boiler capacity, because these boilers currently exist at chemical pulping plants in the Northwest. Rather the potential would be from upgrading existing cogeneration installations with newer equipment and from addition of electric power generation to existing recovery boilers that supply steam to mill processes but that do not cogenerate.

Because of the nature of the chemicals contained in the black liquor, recovery boilers have the potential to release several air pollutants of concern. These may include odor from reduced sulfur compounds, particulate matter, sulfur oxides, carbon monoxide and nitrogen oxides. Reduced sulfur compounds are controlled by weak liquor oxidation, liquor pH control and alkaline scrubbing of exhaust gasses. Particulates are controlled using venturi scrubbers, and more recently, electrostatic precipitators. Sulfur oxides are controlled by maintaining proper combustion conditions to maximize reduction of sulfur to the solid sulfur compounds contained in the smelt. Carbon monoxide and nitrogen oxides are controlled by combustion temperature and excess air. The environmental characteristics of chemical recovery boilers are not influenced by the decision to cogenerate electricity from steam produced by these boilers.

Atmospheric fluid bed steam-electric plant: Fluid bed furnaces improve combustion efficiency, fuel flexibility and pollutant control. A fluid bed furnace has a refractory-lined combustion chamber with a floor of perforated air distribution plates. The chamber is filled with sand. Combustion air is introduced under pressure, lifting and "fluidizing" the mass of sand. Fuel is injected and combustion occurs within the sand bed. Bubbling bed designs have lower combustion air velocities to prevent the sand and uncombusted fuel from becoming entrained in the effluent gas. Circulating bed designs have much higher combustion air velocities, and the sand and uncombusted fuel are recovered from the effluent gas using cyclones. Performance and cost characteristics of a representative biomass-fired atmospheric fluid bed steam electric plant are provided in Table FBI-2.

Sulfur oxide formation is controlled at the point of combustion by injecting limestone into the fluidized bed. This can eliminate the need for post-combustion gas cleanup for sulfur-containing fuels. Nitrogen oxide formation is inherently less than with conventional furnaces, though ammonia injection can be used to further reduce emissions of nitrogen oxides. Particulate control is by cyclones, fabric filters or precipitators. The environmental characteristics of a representative plant are provided in Table I-X of Appendix I.

Anaerobic Gasification

Anaerobic gasification is a biological process that converts many biomass materials into a mixture of methane and carbon dioxide. This process is used for treating municipal wastewater, and more recently, animal waste. This process occurs naturally in-situ in landfills. The product gas can be used to generate or cogenerate electricity or can be injected into the natural gas system.

Wastewater treatment energy recovery and generation: Anaerobic gasification and energy recovery is accomplished at nearly all large wastewater treatment plants in the Northwest. Less than a megawatt of undeveloped electric generation potential is thought to remain.

Animal manure methane recovery and generation: The type of gasification system depends on the farm size, number of animals, livestock production characteristics, manure management system, climate and on-farm energy requirements. Reciprocating engine-generator sets (see natural gas section) are typically used for power generation. Three types of gasification systems are currently used in the United States: covered lagoons, plug flow digesters and complete mix digesters. Covered lagoon systems consist of a manure collection system, a solids separator, a digester lagoon, and a water withdrawal system. The lagoon is covered with an air-tight expandable membrane to maintain anaerobic conditions and to contain the product gas. The product gas is collected for supply to the power plant.

Plug flow digester systems consist of a manure collection system, a mixing pit, a digester trough, and an effluent removal system The trough is covered with an air-tight expandable membrane to maintain anaerobic conditions and to contain the product gas. A "plug" of manure is periodically added to one end of the trough, pushing earlier additions down the trough. The product gas is collected for supply to the power plant.

"Complete mix" digester systems, used for larger volume operations, consist of a manure collection system, a digester vessel, and an effluent removal system The digesters are large concrete or steel vessels. Manure is mixed within the vessel. The vessel is heated with heat recovered from the engine-generator cooling system. The product gas is collected from the digester for supply to the power plant.

The performance and cost characteristics of a representative animal manure methane recovery and generation plant are provided in Table FBI-2.

Landfill gas recovery and generation: The landfill gas is produced in situ by microorganisms. Water must be present, and may be added in controlled amounts to promote gasification. The gas is collected by a system of wells and piped to a centrally located power plant, usually a reciprocating engine. (The collection and combustion of landfill gas is required, whether or not the gas is to be used as fuel, because of the combustible nature of the substance and because methane is a potent greenhouse gas.)

The performance and cost characteristics of a representative landfill methane recovery and generation plant are provided in Table FBI-2.

Partial Combustion Gasification

Controlled partial combustion of biomass can yield carbon monoxide, hydrogen, methane, carbon dioxide and nitrogen. The exact composition of the product depends on the biomass feedstock and the oxidant. If air is used for combustion, a low heating value (200 Btu/scf) fuel is produced. Using pure oxygen for combustion produces a fuel of intermediate heating value (600 Btu/scf). For comparison, natural gas has a heating value of about 1,000 Btu/scf. The resulting fuels generally can be used in the same type of generating equipment as natural gas, although low-Btu gasses may require co-firing with fuel oil to maintain ignition.

Pressurized, air-blown fluidized-bed gasification is the biomass gasification technology closest to commercialization. A typical pressurized fluidized bed gasification power plant consists of a fuel dryer, gasifier, product gas cooler and scrubber, a gas turbine generator and heat recovery steam generator and a steam turbine. The gasifier is supplied with pressurized combustion air from the gas turbine, dry fuel from the fuel dryer, steam from the heat recovery steam generator and limestone. The product gas is cooled and scrubbed and supplied to the combustor of the gas turbine. The gas turbine, heat recovery steam generator and steam turbine operate as a combined-cycle power plant (see the Natural Gas section of this appendix).

Biogasification power plants are expected to be relatively small (10 to 100 megawatts) because of the expense of transporting biofuels. These plants are currently in the demonstration stage. The first generation is expected to be commercially available about 2000. Size will be about 25 megawatts with thermodynamic efficiencies of 30 to 34 percent. Cost is anticipated to be $1,800 to $2,000 per kilowatt. Second-generation plants will be larger and have increased turbine firing temperatures to improve efficiencies to the high 30 percent range. Costs are anticipated to be $1,500 to $2,000 per kilowatt. Third-generation plants may be to 100 megawatts in size and have thermal efficiencies to 42 percent.

The performance and cost characteristics of a representative wood gasification combined-cycle power plant are provided in Table FBI-2. Environmental characteristics of this plant are shown in Table I-1 of Appendix I.

Biomass Liquefaction

Processes are under development for the production of liquid fuels from biomass products. Many processes involve the addition of hydrogen to a carbon-rich feedstock to produce an oil with a high hydrogen-to-carbon ratio. One benefit of liquefaction is the ability to use biomass materials to fuel a wider variety of end uses (for example, transportation applications). A second benefit would be the improved ability to store the product. This would provide a means of smoothing the seasonal fluctuations in annual biofuel crops.

Development Issues

The principal factor currently constraining development of biomass power is cost. Issues that might become more significant if the cost-effectiveness of biomass generation improves include the effect of competing uses on the availability of biomass fuels, the costs of collecting and transporting these fuels, seasonal and interannual fluctuation in fuel supply and air quality impacts. Because the biomass fuels most likely to be used for power generation are residues of some other production activity, incremental effects on land use and wildlife habitat are expected to be minor. The exception could be if the value added by electricity production significantly increases the demand for raw material.

Additional factors influence the development of cogeneration. These are described in the natural gas section of this appendix. Issues specific to biomass fuels are described below.

Cost

The primary factor currently constraining the development of biomass power resources is the cost of power from these resources compared to current and forecasted wholesale electricity prices. There are a few special situations where electricity from new biomass-fueled power plants is nearly competitive with current wholesale electricity prices. For example, in landfill gas recovery the gas is produced naturally, in situ, and the gas collection system must be installed, whether power is generated, or not. However, the power from the majority of biomass generation options would be far more expensive than current wholesale power prices due to the relatively high capital and operating costs of these plants. Some biomass residue plants constructed in the 1980's following PURPA legislation have been closed because of inability to compete with current power costs. Even if the current generating surplus is eventually worked off, new natural gas-fueled combined cycle gas turbine power plants will likely be able to supply electricity at costs less than the cost of producing power from most biomass resources.

Competing Uses

The amount of residue available as fuel for electric power generation is constrained by competing uses for these materials. Use of the material as fuel often has the lowest economic value of several possible uses for these materials. For example, residential firewood is a higher value use for some logging residues; pulp chips are a higher value use for some mill residues; and erosion control may be a higher value use for some agricultural wastes. Improvements in collection and transportation methods would not only contribute to an increased supply of these materials for bulk power plant fuel use, but also would expand markets for competing uses. The strength of markets for competing uses adds to the uncertainties regarding the future cost and availability of these materials for electric power generation. For example, increasing restrictions on the use of wood stoves for residential heating in urban areas would depress the market for residential fuel wood and thereby increase the availability of logging residue for bulk fuel. Strong demand for paper will depress the availability and increase the cost of mill residue.

Fuel Collection and Transportation

Biomass residues are produced at many scattered locations. Use of this material for electric power generation requires systems for the collection and transportation of these materials to a central power plant. The significance of transportation is increased by the low energy density of biomass residues. This increases the bulk of materials needing to be handled. Logging residues present a further problem in that logging sites are not constant, but move from year to year. In general, it is not economically feasible to haul biomass residue fuels farther than about 50 miles by truck (farther if by rail or water). This limits the size of biomass-fired power plants, and indirectly increases the cost of these facilities because of foregone economies of scale. Complex fuel sourcing and transportation systems have been established for many existing biomass power plants, but do add to the cost of operation. Collection and transportation is less of a problem with mill residues, because these are generated at mill sites and often may be used for cogeneration at these same sites.

Fuel Supply Fluctuation

Because biomass residues are produced as a by-product of other activities, and are subject to competing uses, the supply of biomass fuels may vary significantly, both seasonally and annually. Logging activity varies seasonally and annually as the market for wood products fluctuates and, with it, the supply of logging residue. The production of mill residue also varies with the wood products market, and its availability is further influenced by competition for wood chips by the paper industry. The production of agricultural residues varies with the seasonal harvest cycle, the agricultural economy and shifts in crop patterns and weather.

Air Quality Impacts

The principal air quality problems associated with the use of biomass fuels involve nitrogen oxides, uncombusted hydrocarbons and particulate material. As described in the technology section, above, air emissions can be controlled to regulated levels with proper emission control technology.

Combusting logging and agricultural crop residues under the controlled conditions of a power plant may benefit air quality by reducing the amount of these materials that otherwise would be disposed of using uncontrolled, open burning.

Potential for Additional Biomass Power Generation

The potential supply and cost of power from biomass fuels is a function of the applications and technology. The thermodynamic efficiency of the generating technology influences both the supply and the cost of power from a given biomass resource. The capital and operating cost of the technology will influence the cost of power. Five applications of the biomass resources of Table FBI-1 were considered as representative of year 2000 potential:

Chemical recovery boilers: All operating recovery facilities not currently equipped with cogeneration were assumed to be retrofitted at the representative cost described in Table FBI-2. This would yield an estimated 195 average megawatts of electric power at an average cost of 2.4 cents per kilowatt-hour. This, in general, is the lowest cost resource of the biomass resources assessed (Table FBI-3 and Figure FBI-1). Actual costs would vary widely because each installation would be unique.

Landfill gas energy recovery: All landfills not currently equipped with energy recovery were assumed to be so retrofitted with the representative system described in Table FBI-2. This would yield an estimated 126 average megawatts of electric power at an average cost of 3.1 cents per kilowatt-hour. This is the second lowest cost resource of the biomass resources assessed, roughly competitive with power from new gas-fired combined-cycle power plants.

Animal manure energy recovery: All dairy operations with herds of 500 animals or more not currently equipped with energy recovery were assumed to be retrofitted with the representative system described in Table FBI-2. This would yield 10 average megawatts of electric power at an average cost of 5.0 cents per kilowatt-hour. Actual costs would vary widely because of unique conditions.

Mixed wood residue cogeneration: Mill residues, residues from pulp feedstock cottonwood plantations and clean combustibles sorted from municipal solid waste were assumed to be used, as a group for cogeneration fuel. This potential was estimated using the Cogeneration Regional Forecasting Model, described in the Natural Gas section of this appendix. The model was set to consider conventional boiler steam-electric cogeneration applications of a range of possible sizes in the lumber and wood products and paper and allied products sectors. The resulting cogeneration potential is shown in Table FBI-3 and Figure FBI-1. The resource would be available at costs of 5.0 cents per kilowatt-hour, and greater. A total of 267 megawatts of potential is estimated to be available at costs ranging from 5.0 to 6.0 cents per kilowatt-hour, and at an average cost of 5.6 cents. The potential supply of electricity from these fuels would expand, and costs might decline if gasification-combined-cycle technology becomes commercially available.

Forest thinning residues: Forest thinning residues were assumed to be used in conventional, non-cogenerating boiler steam-electric power plants. Some cogeneration opportunities might be available, but in general, this resource originates in fairly remote areas. The availability of this resource is quite uncertain, as described earlier. The estimated supply ranges from 310 to 990 average megawatts. Average power costs, if new power plants are built, are estimated to be 6.3 cents per kilowatt-hour. A small portion of this resource might be used to produce power at somewhat lower cost by rehabilitating several existing small biomass power plants that have been idled in recent years. The potential supply of electricity from forest thinning residue would expand, and costs might decline if gasification-combined-cycle technology becomes commercially available.

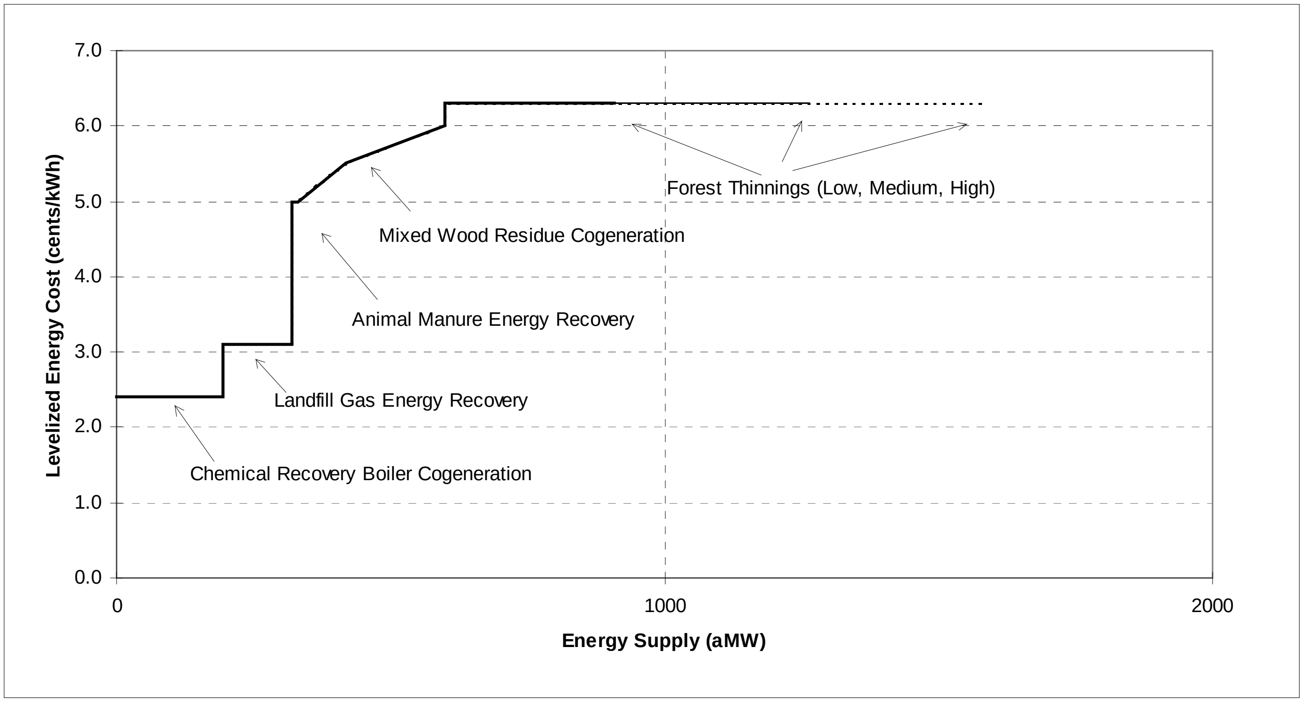
Table FBI-3

Potential supply and cost of additional generation using biofuels

	Supply (aMW)	**Cost (cents/kWh)**	**Resource Block**
Chemical recovery boiler cogeneration	195	2.4	BIO-1
Landfill gas energy recovery	126	3.1	BIO-2
Animal manure energy recovery	10	5.0	BIO-3
Mixed wood residue cogeneration	267	5.0 - 6.0 (5.6)	BIO-4
Forest thinning generation	310 - 990 (670)	6.3	BIO-5

The levelized energy costs of table FBI-3 and Figure FBI-1 are based on a 30-year project life and unregulated financing described elsewhere in this appendix. Because the specific sites where these resources might be developed are not known, the cost and losses of interconnection to the central grid are not included.

Figure FBI-1
Potential Supply and Cost of Additional Generation Using Biofuels



Planning Model Data

The Council's power system models require aggregated resource data. The block assignments used for modeling studies are shown in the far right column of Table FBI-3. These correspond to the block codes appearing in Table F-1.

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APPENDIX FCO
COAL

COAL

SUMMARY

Though not the most cost-effective or environmentally desirable of resources, coal is available in abundance compared to other resource alternatives. In earlier power plans, the Council viewed coal as a "backstop" resource that could be developed if growing loads exceeded the supply of other more desirable, but more limited resources. The role of coal remains similar, though perhaps diminished in importance because of expectations of continued low natural gas prices.

As of January 1996, 6,835 megawatts of electric generating capacity primarily burning coal was operating in the Northwest and adjacent areas.[1] More than 99 percent of this capacity is central station generation; the balance consists of small industrial cogeneration facilities. Fully dispatched, these projects can generate about 6,100 average megawatts of energy, 27 percent of the forecasted 1996 regional electric energy requirements.[2] Most of this capacity was brought into service between 1971 and 1986. More than 99 percent of this capacity uses pulverized coal steam electric technology.

At least 5,000 additional megawatts of energy could be obtained by development of new coal-fired power plants. This is equivalent to about 22 percent of forecast 1996 regional electric energy requirements. This energy, delivered to the regional transmission grid, would cost from 3.8 to 4.9 cents per kilowatt-hour.

Although an essentially unlimited supply of low-cost, low-sulfur coal is available to the Northwest, siting difficulties, public resistance to new transmission lines and atmospheric emissions may constrain the development of new coal-fired power plants. Water supply may be a concern in arid areas. Air emissions, except for carbon dioxide, could be mitigated by the use of low-emission/high efficiency generating technologies or by securing offsets at existing plants. Water supply concerns can be mitigated by use of zero-discharge designs and dry cooling.

An important issue pertaining to development of any new coal-fired capacity is the possible significance of carbon dioxide production in contributing to global climate change. Some mitigation may be feasible through biological carbon fixation (e.g., reforestation), use of high-quality coals and high-efficiency technologies. The best strategy at present appears to be deferral of decisions to construct additional coal-fired capacity until better understanding of global climate change is achieved.

Coal Supply and Price

Abundant supplies of low-sulfur coal are available in the western United States and Canada. A 1988 Bonneville study (BPA, 1983) examined sources of coal for new Northwest coal-fired power plants. These coal sources (see Figure FCO-1) include the Powder River Basin fields of eastern Wyoming and Montana, the East Kootenay region of British Columbia, the Green River Basin of southwestern Wyoming and the Uinta Basin of northeastern Utah and northwestern Colorado. Coal also could be obtained from Alberta or, by barge, from the Vancouver Island Quinsam mines or the Chuitna mines of Alaska. Coal from fields near Centralia in western Washington is used to fire the nearby Pacific Power and Light Centralia project; however, this coal is of low grade, and its continued availability in quantities sufficient to support additional large-scale, coal-fired plants is questionable.

Most observers believe that we will see continued low and stable coal prices. Fluctuations due to short-term supply and demand imbalance will occasionally occur, but competition with natural gas will continue to suppress sustained increases in real prices.

[1] The four Northwest states plus Nevada and Wyoming.
[2] Not all of the output of these plants is dedicated to serving Northwest loads.

The coal price forecast used for this plan was prepared by the Bonneville Power Administration. This forecast is described in Appendix C.

Figure FCO-1

Coal fields and existing and potential coal-fired power plant sites in the Pacific Northwest

Electric Generating Technologies using Coal

The pulverized coal steam-electric power plant is the established technology for producing electricity from coal. Advanced coal generating technologies, including atmospheric fluid bed steam electric power plants and gasifier combined-cycle power plants are now commercially available. A more advanced technology, pressurized fluidized bed combustion is in the demonstration stage. Research on coal-fired magnetohydrodynamic plants has been under way for decades. Coal-fired magnetohydrodynamic plants have not been demonstrated.

Pulverized Coal Steam-Electric Power Plants

A pulverized coal steam-electric power plant is a boiler-steam turbine power plant distinguished by the method of firing the fuel. Coal is ground to a dust-like consistency, blown into the furnace and burned in suspension. A typical pulverized-coal plant consists of a coal-handling and preparation section, a furnace/boiler and a steam turbine generator. Coal is pulverized in the preparation section and burned in the furnace/boiler, generating steam. The steam operates the steam turbine-generator, producing electricity. A cooling system transfers waste heat from the steam turbine to the atmosphere, and an emission control system removes particulates, sulfur oxides and other air pollutants from the combustion gasses.

Pulverized coal steam-electric plants are a mature technology. Thousands of megawatts of capacity are installed in the United States and elsewhere. Unit sizes ranging from tens of megawatts to hundreds of megawatts can be constructed. Smaller plant sizes have somewhat shorter construction lead times and greater reliability, but they are generally more costly (per unit capacity) to build and operate, and have somewhat lower efficiency. Improved thermodynamic efficiency is possible by designing plants to operate under supercritical steam conditions. Supercritical plants were constructed in the 1950s, but did not prove to be reliable. Improved materials may permit supercritical pulverized coal plants of improved efficiency and reliability to be constructed. Performance and cost characteristics of a representative pulverized coal steam-electric power plant are provided in Table FCO-1.

Atmospheric Fluid-Bed Steam-Electric Power Plants

A coal-fired atmospheric fluid-bed combustion (AFBC) steam-electric power plant is similar in overall configuration to a pulverized coal steam-electric plant, but uses a different type of furnace to combust the coal. A fluid-bed furnace burns coarsely ground coal in a bed of limestone particles suspended by continuous injection of air from below. The limestone scavenges sulfur directly from the burning coal. With many coals, fluid-bed furnaces can meet federal "New Source Performance Standards" without use of flue-gas desulfurization equipment. Elimination or reduction of flue-gas desulfurization equipment saves capital and operating costs and improves plant efficiency. Also, the lower combustion temperatures of AFBC plants reduce formation of nitrogen oxides. AFBC plants eliminate the need for coal pulverizers. These plants produce a dry solid waste instead of a wet flue-gas desulfurization sludge.

Table FCO-1
Representative Coal Generating Technologies

	Pulverized Coal Steam-Electric	Atmospheric Fluid-Bed Steam-electric Power Plant	Coal Gasifier Combined-cycle Power Plant	Pressurized Fluid-Bed Combined-cycle Power Plant
Configuration	1x300	1x200, circulating bed	1x540, Destec process	1x340, bubbling bed, supercritical
Status	Mature commercial	Mature commercial	Early commercial	Demonstration
Typical Application	Bulk power supply	Bulk power supply	Bulk power supply	Bulk power supply
Unit Capacity (MW)	300	200	540	340
Availability (%)	85%	90%	86%	81%
Heat Rate (Btu/kWh)	10,070	10,290	8,490	8,510
Overnight Cost ($/kW)	$1,650	$1,930	$1,480	$1,340
Fixed Operating Cost ($/kW/yr)	$48	$39	$15	$39
Variable Operating Cost (mills/kWh)[3]	1.1	1.3	5.4	1.0
Development & Construction Lead Time (Months)	48/36	48/36	36/38	36/36
Cash Flow (%/yr)	1/1/1/2/25/45/25	1/1/1/2/25/44/25	1/1/2/25/45/25	1/1/2/25/45/25
Service Life (Years)	40	40	30	30
Comparative Levelized Energy Cost (cents/kWh)[4]	4.4	4.7	3.9	3.5

AFBC technology has been employed in the non-utility industry for many years, but utility use is recent in the United States. Tacoma Light and Power's 38-megawatt Steam Plant No. 2 was repowered with fluid bed furnaces that are capable of burning coal, wood refuse and municipal solid waste. The independently owned 30-megawatt Montana One plant at Colstrip is an atmospheric fluid bed plant.

Performance and cost characteristics of a representative coal-fired atmospheric fluid-bed steam-electric power plant are provided in Table FCO-1.

Coal Gasifier Combined-Cycle Power Plants

A gasifier combined-cycle (GCC) power plant consists of a coal gasification plant that produces low or medium-Btu synthetic gas that is used to fuel a combined-cycle combustion-turbine power plant. The coal gasifier is one approach to utilizing coal with the highly efficient gas turbine combined-cycle power plant. GCC plants feature a high degree of modularity, significantly improved control of atmospheric emissions and high energy conversion efficiencies. The combustion turbine and combined-cycle sections can be installed

[3] Exclusive of property tax and insurance. See Financial Assumptions section for assumptions regarding property taxes and insurance.
[4] 15 year investor-owned utility financing, medium gas price forecast, year 2000 service, baseload service.

prior to the gasification plant and operated on natural gas until fuel prices or load conditions warrant installation of the gasification section.

Coal gasification technology has been available for many years and was once widely used to produce "town gas" in cities (including several in the Northwest) where natural gas was not locally available. The technology fell into disuse as the long-distance natural gas transmission system was constructed, but was resurrected as interest in substitutes for natural gas arose in the 1970s. Improved versions of the technology have been developed since then. Utility-scale application of the coal gasifier, combined-cycle plant concept was demonstrated at the 100-megawatt Coolwater plant in California, and more recently at the 253-megawatt Demkolec project in The Netherlands. Though current commercial coal gasifier power plants use conventional gas turbine combined-cycle technology for power production, the development of power generation units of greater efficiency is possible. Among the concepts being investigated are combined-cycle configurations using humid air turbines and molten carbonate fuel cells.

Performance and cost characteristics of a representative coal gasifier combined-cycle power plant are provided in Table FCO-1. These are based on a 1993 study of coal gasification power generation alternatives (BPA, 1993). This study considers the improvements in gasifier and gas turbine performance that have occurred since the 1991 Power Plan assessment was completed.

Pressurized Fluid-Bed Steam-Electric Power Plants

In pressurized fluid-bed combustion (PFBC) designs, fuel is burned in a pressurized chamber using a fluidized bed. The hot combustion gases power a gas turbine prior to final heat recovery in a steam boiler. This is another approach to using coal to fuel highly efficient gas turbine combined-cycle power plants. A second advantage of pressurized fluid bed plants is, like atmospheric fluid bed plants, compliance with emission standards without flue gas control equipment. Third, because the combustion gasses are pressurized, the overall unit size is smaller than AFBC or pulverized coal plants of similar capacity.

Demonstration plants using bubbling bed PFBC technology are operating in Sweden, Spain, Japan and the United States. Two alternative PFBC designs, the circulating PFBC and a pyrolyzing PFBC, are being investigated.

Performance and cost characteristics of a representative pressurized fluid-bed combined-cycle power plant are provided in Table FCO-1.

Coal-Fired Magnetohydrodynamic Plants

Magnetohydrodynamics (MHD) is a process for converting heat energy directly into electricity. Magnetohydrodynamic technology could provide high combustion temperatures, combined-cycle operation and direct conversion of thermal to electrical energy for achieving high energy conversion efficiency. The MHD concept also promises improved control of atmospheric emissions.

An MHD power plant would consist of a combustor, an MHD "channel," a heat-recovery boiler and a steam turbine generator. Pulverized coal would be burned at high temperature and pressure in the combustor. Potassium "seed," injected to ionize the hot gas, would create electrically conductive plasma. The plasma, passing through the MHD channel, where a strong magnetic field would be established by use of superconducting magnets, would create an electrical potential across electrodes installed in the channel. The plasma would discharge from the channel to a heat-recovery boiler. Steam from this boiler would drive a conventional steam turbine-generator, augmenting the power production of the MHD channel.

A proposed utility-scale magnetohydrodynamics demonstration project in Montana has not been funded.

Development Issues

This section presents an overview of the principal issues associated with large-scale development of coal-fired plants. These issues include air quality impacts, carbon dioxide and global climate change, water impacts, solid waste, site availability, coal transportation and electric power transmission.

Air Quality Impacts

Air quality concerns regarding coal-fired power plants include sulfur oxides, nitrogen oxides and particulates.

Sulfur dioxide: Sulfur is a naturally occurring constituent of coal. Sulfur concentrations range from about .5 to 4 percent. Western coals usually have a low sulfur content (less than 1 percent). The sulfur in coal is oxidized to sulfur dioxide, a gas, in the combustion process. The sulfur dioxide that is released to the atmosphere is transported, sometimes over large distances, and is gradually converted to sulfuric acid or sulfate. Acid precipitation forms in the atmosphere from chemical conversion of sulfur and nitrogen compounds, under the influence of oxygen, water and sunlight, to form sulfuric acid and nitrous and nitric acids. Hydrochloric acid, created from combustion of coals that contain chlorine, may also contribute to acid precipitation formation. The resulting acidic precipitation from rain, snow, dust, etc., has an adverse impact on terrestrial and aquatic life. The potential impacts resulting from these emissions and secondary products include human health effects, crop and forest damage, corrosion of metallic and masonry structural materials and visibility degradation.

Low sulfur coals (less than 1 percent sulfur) are widely available in the West and are used to reduce sulfur dioxide emissions on existing and new plants. The most common method used today to reduce sulfur dioxide emissions from pulverized coal-fired power plants is wet lime or limestone flue-gas scrubbing. In flue-gas scrubbing systems, the flue gas is exposed to a slurry of lime or limestone that absorbs the sulfur dioxide and reacts with it to form calcium sulfite or sulfate. These reaction products and unreacted limestone are dewatered for disposal, generally in landfills, although some is recycled for its gypsum content. Flue-gas desulfurization systems can remove more than 95 percent of the sulfur dioxide content of raw flue gas.

Advanced coal-based technologies offer alternative ways to control sulfur dioxide emissions. In fluidized bed plants, lime is supplied to the fluidized bed to scavenge sulfur prior to formation of sulfur dioxide. Coal gasification plants incorporate sulfur removal equipment in the product gas cleanup section to remove sulfur from the product gas prior to combustion. Marketable pure sulfur can be produced as a byproduct of gasification plant sulfur removal operations.

Oxides of nitrogen: Fuel combustion oxidizes nitrogen occurring in the fuel and in the combustion air. The products of concern include nitric oxide (NO) and nitrogen dioxide (NO_2), collectively referred to as NO_x. Nitric oxide is a gas that can irritate membranes and cause coughs and headaches. Furthermore, nitrogen oxide can react with moisture to form nitric acid, which can acidify rain. Both nitrogen oxide and nitrogen dioxide can form nitrosamines, potent carcinogens in aqueous solution. Nitrogen oxides are of concern in many metropolitan areas where ambient concentrations of ozone often approach or exceed air quality standards.

The production of nitrogen oxides is controlled by reducing the availability of atmospheric nitrogen in the combustion process, by reducing combustion temperatures, and by removal of nitrogen oxides from exhaust gasses. Combustion modification techniques that reduce the availability of nitrogen include low-excess air firing and staged combustion. Advanced coal-based technologies provide additional ways to control nitrogen oxide formation. Combustion temperatures of fluidized bed plants are lower than for conventional furnaces, retarding formation of nitrogen oxide. Medium-Btu coal gasification plants use pure oxygen for the gasification process, thus avoiding introduction of nitrogen to the combustion process and consequent formation of nitrogen oxide. Nitrogen oxide, however, can be formed during the combustion of coal-derived fuel gas in the combustion turbine section of the gasification combined-cycle power plant.

Nitrogen oxide formation in the combustion turbine can be controlled by low-excess air burners and water injection (to reduce combustion temperatures). Nitrogen oxide in the combustion turbine exhaust can be further lowered by catalytic reduction.

Particulates: Small solid particles formed during combustion, varying in size from 0.01 to 10 microns in diameter, can be carried out in the flue gas. These very small particles can be inhaled and can affect human health. Electrostatic precipitators, baghouses, and scrubbers are the typical emission control systems employed to collect particulates. Precipitators and baghouses are typically more than 99 percent efficient.

Carbon Dioxide and Global Climate Change

Carbon dioxide is produced by combustion of any fossil fuel. Carbon dioxide is a ”greenhouse” gas (i.e., it allows short wave-length solar radiation to pass, but absorbs longer wave-length outgoing radiation with the net effect of warming the earth’s surface and lower-level atmosphere). Atmospheric levels of carbon dioxide and other greenhouse gasses are increasing and, if the increase continues, it may raise the average temperature at the earth’s surface. While scientific consensus on the certainty of global climate change and its implications has not been reached, scientific opinion is moving in this direction.

Factors affecting the carbon dioxide release per unit of electrical energy output are the heat content of the coal, the carbon content of the coal and the efficiency of the energy conversion process. Carbon dioxide releases therefore can be reduced somewhat, but not eliminated by coal and technology selection. Removal and disposal of carbon dioxide from flue gas is possible in theory. But it is thought to be very expensive, perhaps doubling the cost of electricity from a conventional pulverized coal-fired plant.

Alternatively, carbon dioxide releases can be mitigated by biologically fixing atmospheric carbon dioxide through reforestation and other processes, or by control of other greenhouse gasses, such as methane.

Water Impacts

Potential water impacts may result from cooling tower blowdown, ash handling, waste waters and water consumption.

Cooling tower blowdown: Steam-electric power plant condenser cooling water typically is cooled using evaporative cooling towers or cooling ponds. Due to partial evaporation of this cooling water, contaminants, such as mineral salts that enter the system with the makeup water, become more concentrated. In addition, chlorine or other biocides usually are added to control biofouling. Thus, portions of the cooling water must be withdrawn and replaced with fresh water to prevent salt buildup. The water that is withdrawn (“blowdown”) could damage adjacent property, surface water or groundwater. Waste water treatment techniques that can be used include chemical precipitation or sedimentation and dechlorination. “Zero discharge” plant designs are available that do not discharge the blowdown directly, but use it for scrubber makeup, ash sluice water and other in-plant purposes. Also, fully closed-cycle condenser cooling systems are available that require little makeup and blowdown. Because closed-cycle systems are somewhat less effective than evaporative cooling systems, plant efficiency is penalized.

Ash handling waste waters: Bottom ash (residue accumulating at the bottom of the furnace) and fly ash (residue in the flue-gas stream) are produced during combustion. Gasification systems produce a waste slag from the gasifiers and ash removed from the product gas stream. Ash is typically transported as a slurry. These wet ash handling systems produce waste waters that are discharged as blowdown. Dissolved heavy metals can accumulate in the ash ponds and cause adverse effects to ground or surface waters and to aquatic organisms. Ash handling waste water treatment includes chemical precipitation, sedimentation and neutralization and use of lined ash disposal pits.

Water consumption: Water is required for general plant services, boiler makeup and condenser cooling. The amount of water required for a coal plant could cause potential conflicts over water rights, especially for plants sited in arid sections of Montana and Wyoming. Water consumption also could reduce instream flows, which could reduce the amount of water available for other users and adversely affect water quality and fish populations.

Cooling systems constitute a large part of in-house water needs. Evaporative cooling systems result in continuous loss of water to the atmosphere. This loss can be reduced using full closed-cycle (dry) cooling. Gasification combined-cycle power plant designs further reduce cooling water requirements, because of the greater efficiency of these plants.

Withdrawal of water from a river, lake or ocean for power plant services and condenser cooling can impinge fish on intake screens. The rate of this impingement is directly related to intake velocity at and around the intake structure, as well as other physical and biological phenomena. The highest impingement rates occur in areas with concentrations of juvenile fish near high-volume shoreline intakes. Potential impacts depend on the intake design.

Solid Waste

The three significant solid waste materials produced by pulverized coal plants are fly ash, bottom ash and scrubber sludge. The bottom ash from a fluidized bed plant contains the sulfur compounds resulting from in-bed removal of sulfur. Gasification produces a slag, equivalent to bottom ash, and fly ash collected during product gas cleanup. Scrubber sludge is not produced in gasification systems because the sulfur is converted to elemental sulfur upon removal from the product gas streams. The potential impacts of these products depend on their chemical composition (largely determined by the coal composition), their physical characteristics, the manner of disposal, and the location of the disposal site. Some by-product applications are available for gasifier slag and some ashes.

Ash: Bottom ash and fly ash collected dry with electrostatic precipitators or baghouses can be disposed of directly or added to scrubber sludge for stabilization. Typically, disposal is in ponds or landfills.

Fly ash could leach out of the ponds or landfills, causing possible accumulations of trace elements and salts in surface water and/or groundwaters. Leaching can be managed by proper site selection and pond lining.

Scrubber sludge: Scrubber sludge consists of chloride, calcium and sulfate. Disposal options for scrubber sludge consist of direct ponding and dewatering followed by landfilling. Direct ponding requires large areas of land and also poses a leaching problem. Pond lining can prevent such leaching.

Site Availability

The availability of sites for coal-fired power plants is more constrained than for any other generating technology, with the possible exception of nuclear. Factors that must be considered include the ability of the airshed to absorb the atmospheric discharges of the plant, availability of water for cooling and other plant uses, proximity to the transmission grid, proximity of rail or water transportation for coal (if remote from the minemouth), and availability of land for disposal of ash and flue-gas desulfurization products.

The amount of land required for a 500-megawatt coal-fired steam-electric plant is approximately 650 acres, including land for solid waste disposal. Co-siting of units will reduce the amount of land required per unit due to the sharing of facilities. Land requirements are relatively insensitive to coal-fired power plant design. Most of this land would be lost as natural habitat.

Coal Transportation

Because of the large volumes of coal required by a central-station coal-fired power plant, rail or water transportation must be available if the plant is to be remotely sited from coal mines (a 500-megawatt coal project would require about 75 rail cars of coal per day when in full operation). Upgrades to the coal transportation route such as rail and roadbed improvements, double track, additional sidings, improved signal systems, grade separation and urban bypass lines might be required for safe and reliable operation.

Electric Power Transmission

An alternative to transportation of coal into the region would be the siting of coal plants at the minemouth. This would require construction of long-distance, high-voltage transmission lines to tie the plants into the regional grid. A 1,200-megawatt coal project would require a 500-kilovolt single-circuit alternating current transmission intertie, and possibly a second circuit for reliability purposes. Direct-current transmission may be economical for interconnection of very remote sites, such as in eastern Montana or Wyoming. Direct-current transmission requires only two conductors in lieu of the three conductors required for alternating-current transmission. This may reduce aesthetic impacts and right-of-way requirements. Construction of transmission lines can be expensive, and their siting can be extremely difficult.

Impacts of Coal Mining and Transportation

The mining and transportation of coal may produce significant environmental, land use, safety and aesthetic impacts. Nearly all western coal is mined using surface mining techniques. Overburden is removed, the coal is stripped out and the overburden and soil are replaced and recontoured. Efforts are made to restore original land use and habitat. Reclamation regulations require that the surface be recontoured and restored, but the process profoundly modifies the land use, biological habitat, surface hydrology and surface geology of the site.

Coal transportation produces additional increments of air pollution, noise and safety hazards associated with railroad operations.

Potential for Additional Coal-fired Power Generation

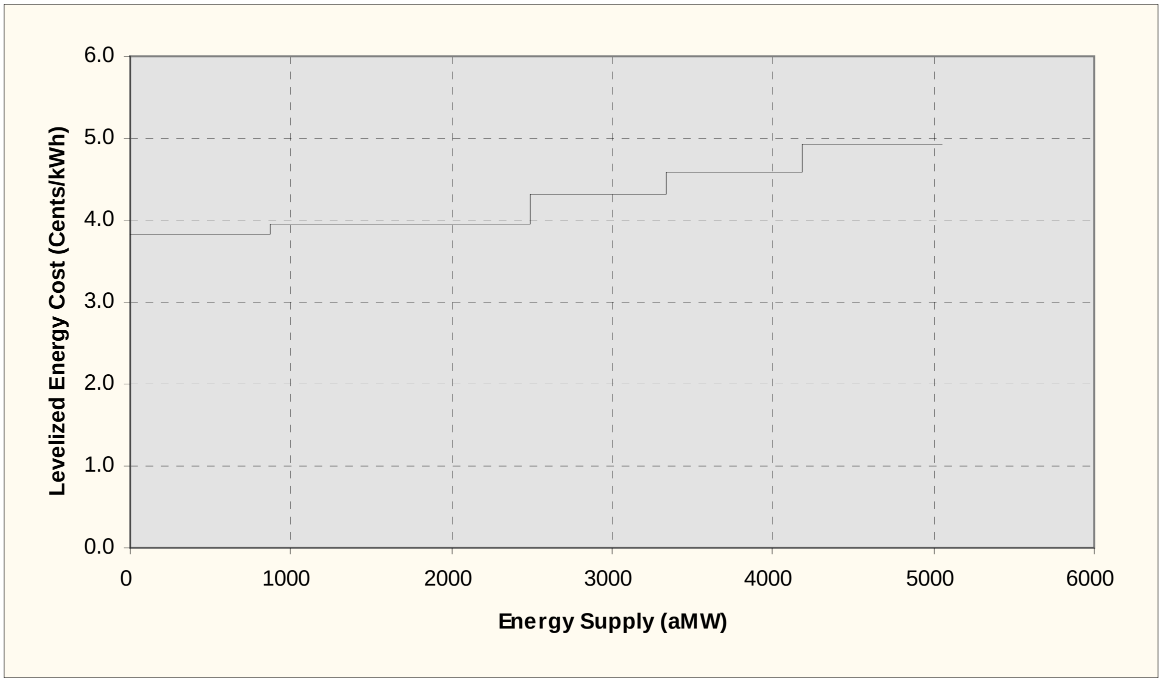
Though not the most cost-effective or environmentally desirable of resources, coal is available in abundance compared to other resource alternatives. In earlier power plans, coal was viewed as a “backstop” resource that could be developed if growing loads exceeded the supply of more desirable, but more limited resources.

Because of the increasing attractiveness of natural gas, the role of coal in the 1991 Power Plan was as a backup to natural gas. Gas-fired combined-cycle power plants could be retrofitted with coal gasifiers if natural gas price increases warranted such action. The use of coal gasification equipment to supply fuel to combined cycle combustion turbines would also provide an environmentally superior method of using coal to generate electricity.

It is now more generally agreed that natural gas prices will remain relatively low through the near term and longer. The amount of power potentially available from natural gas is now accepted to be considerably greater than in the 1991 plan (See the Natural Gas section of the appendix). The role of coal as a backup to other, more attractive resources remains similar, though perhaps diminished in importance.

The revised estimate of new bulk generating potential using coal is illustrated in Figure FCO-2. It is estimated that at least 6,300 megawatts of new coal-fired power plants could be developed at Northwest sites, using gasification combined-cycle technology. This amount of generation could produce about 5,000 average megawatts of energy. The levelized cost of this power would range from about 3.8 to 4.9 cents per kilowatt-hour with current technology and if medium coal price forecasts are realized.

Figure FCO-2
Estimated Cost and Potential Supply of Electricity From Coal



Approach to the Assessment

The general approach to assessing future coal development potential was conceived by the Council's Generating Resources Advisory Committee for the Council's 1991 Power Plan. That approach simulates the likely future cost and availability of power from new coal-fired power plants by assessing the costs and limits to development at prospective sites in the Northwest. All major foreseeable economic costs are considered, including:

- fuel cost;
- fuel transportation cost;
- fuel transportation system upgrade cost;
- power plant siting and licensing cost;
- power plant construction cost;
- environmental compliance cost;
- power plant operation and maintenance cost;
- transmission grid interconnection cost;
- transmission losses; and
- decommissioning.

The assessment prepared for the 1991 Power Plan was updated for this plan using a modified set of potential coal-fired power plant sites, revised coal price forecasts, and updated cost and performance information for coal gasification combined-cycle power plants. These modifications are discussed below. Additional information regarding the approach to the assessment can be obtained from Chapter 8 of Volume II of the 1991 Power Plan.

Prospective sites: The sites selected for the 1991 assessment were Centralia, Washington; Boardman, Oregon; Colstrip, Montana; Thousand Springs, Nevada and Creston, Washington. Creston was dropped from this assessment because permits held by the Washington Water Power Company for the construction of coal-fired power plants at Creston were relinquished. A developer is currently seeking permits for a gas-fired combined-cycle plant at Creston, and that site is included in the assessment of gas-fired combined-cycle power plant potential (see the Natural Gas section of this appendix). Added to the set of sites is Valmy, Nevada. Two coal-fired units are located at Valmy and Idaho Power Company, co-owner of the existing units has indicated that additional units could be constructed at the site.

The potential plant sites are shown in Figure FCO-1. The assumptions regarding the possible development of these sites are summarized in Table FCO-2.

Coal supply and price: Delivered coal prices were developed using a coal price forecasting model developed by Bonneville. This model incorporates uncertainty into 20-year projections of delivered coal prices. An annual series of point estimates of coal commodity and rail transportation costs are multiplied by pricing factors taken randomly from specified probability distributions. This process is repeated several hundred times for each year of the price series using a "Monte Carlo" simulation. The mean and standard deviation of the resulting distribution describe the distribution of possible delivered coal costs for each year of the resulting price series. The updated price series are summarized in Appendix C.

Power Plants: Integrated coal gasification combined-cycle power plants were assumed in this analysis. These plants appear to offer the best opportunity both to reduce economic risks associated with expansion of natural gas use for electricity generation, and the least environmental impact of currently available coal technologies. Characteristics of a typical plant are described in Table FCO-1. Improvements to nitrogen oxide control technology since development of the 1991 plan result in a reduction in base-case nitrogen oxide emissions.

Findings

Capital, fuel and operating and maintenance costs were estimated for power plant development at each site. All major costs required to deliver power to the central grid were included. Power delivery to the main grid was calculated using estimated transmission intertie losses. The resulting power production and cost estimates are shown in Table FCO-3. Levelized energy costs for the five sites were calculated using the project development assumptions described in the introduction to this chapter.

Planning Model Data

The Council's power system models require aggregated resource data. The block assignments used for modeling studies are shown in the far right column of Table FBI-3. These correspond to the block codes appearing in Table F-1.

Table FCO-2
Assumptions Used to Estimate the Supply and Cost of Additional Electricity From Coal

Site	Coal Source	Fuel transport	Rail Upgrade (miles)	Generating Tech-nology[1]	New capacity (Units x [2]MW)[3]	SO_2 Control (%)	NO_x Control (ppm)	Emissions Offset	Cooling	Trans-mission Intercon-nection (mi)
Boardman, OR	Powder River Basin (WY)	Rail	None	540 MW IGCC	2 x 542 MW	99%	9 ppm	SO_x	Mechanical Draft (Wet)	0
Centralia, WA	Powder River Basin (WY)	Rail	None	540 MW IGCC	2 x 542 MW	99%	9 ppm	SO_x	Mechanical Draft (Wet)	0
Colstrip, MT	Powder River Basin (MT)	Truck or conveyor	None	540 MW IGCC	4 x 537 MW	99%	9 ppm	SO_x	Mechanical Draft (Dry)	2x500kV, 650 mi
Thousand Springs, NV	Uinta	Rail	14	540 MW IGCC	2 x 537 MW	99%	9 ppm	SO_x	Mechanical Draft (Dry)	1x500kV, 105 mi
Valmy, NV	Uinta	Rail	None	540 MW IGCC	2 x 537 MW	99%	9 ppm	SO_x	Mechanical Draft (Dry)	1x500kV, 265 mi

[1] Nominal capacity w/ wet mechanical draft cooling.
[2]
[3] Net, at busbar.

Table FCO-3
Supply and Cost of Power From New Coal Generation

Site	Capacity to the Central Grid (MW)	Energy to the central Grid (aMW)	Development and Construction Cost[4] ($/kW)	Fixed O&M Cost ($/kW/yr)[5]	Variable O&M Cost ($/kWh)	Fixed Fuel Cost ($/kW/yr)[6]	First Year Variable Fuel Cost ($/MMBtu)	Estimated Cost of Energy at Central Grid (cents/kWh)	Resource Planning Block
Valmy	1051	841	$1748	$16.80	$0.0055	$0.00	$1.17	4.3	COL-3
Colstrip	2034	1627	$2035	$18.40	$0.0057	$0.00	$0.34	4.0	COL-1
Boardman	1084	867	$1503	$15.00	$0.0054	$0.00	$1.06	3.8	COL-4
Thousand Springs	1065	852	$1632	$15.80	$0.0055	$1.27	$1.40	4.6	COL-5
Centralia	1084	867	$1552	$15.00	$0.0054	$0.00	$1.50	4.9	COL-2

[4] "Overnight" cost, exclusive of escalation and interest during construction.
[5] Exclusive of property taxes and insurance.
[6] Rail upgrades.

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APPENDIX FGT
GEOTHERMAL

GEOTHERMAL

SUMMARY

Geothermal energy may provide an abundant and sustainable source of baseload electricity for the Northwest. Though highly uncertain, our estimates suggest that from 340 to 3,300 average megawatts of energy could be produced at costs of six cents per kilowatt-hour, or less from Northwest geothermal resources. This amount represents from 1 to 15 percent of current regional power requirements. Because geothermal power plants, except for transmission, are wholly contained at the site, there are no upstream environmental impacts associated with fuel production or transportation. Furthermore, little carbon dioxide is produced.

However, sustained production of commercial-scale quantities of electricity from Northwest geothermal resources remains to be demonstrated. Moreover, anticipated cost of electricity from even the best Northwest geothermal resources would be about five cents per kilowatt-hour, much greater than the price of electricity from alternative sources. Though the cost of producing geothermal power is expected to decline, it is unlikely that geothermal energy could compete with alternative bulk power sources for the next five to ten years, or longer. Finally, geothermal development is not completely free of potential environmental impacts. Localized air quality effects, some solid waste production, habitat disturbance, water quality, noise and visual impacts can result from geothermal development. Careful siting and design can generally reduce these impacts to acceptable levels.

To resolve some of the great uncertainties regarding the cost and feasibility of generating electric power from Northwest geothermal resources, the 1991 Power Plan recommended development of pilot projects at promising geothermal resource areas. Each project would include a commercial-scale generating plant and exploration to confirm an additional 100 megawatts of developable resource. These projects are intended to confirm the feasibility of generating electricity from Northwest geothermal resources, to encourage further resource exploration, to identify and resolve environmental issues and to facilitate additional development as geothermal power becomes cost-effective. Two pilot projects are being developed at present.

Pacific Northwest Geothermal Resources

Current technology does not permit tapping the subcrustal zone that provides the ultimate source of geothermal energy. Geothermal development is feasible only where special geologic conditions have created a near-surface magmatic heat source supporting an overlying hydrothermal circulation system. A promising resource for geothermal electricity generation requires temperatures of about 300^{o} Fahrenheit or higher, water, and fractured or otherwise highly porous rock, coincidental at depths of about 10,000 feet, or less.

Several types of geologic structures found in the Northwest are thought to have potential for geothermal electricity generation. In the Basin and Range physiographic province of southeastern Oregon and southern Idaho, (Figure FGT-1) crustal spreading has produced deep vertical faults parallel to the valleys and ranges of this region. Water circulation within these faults brings heated water to or near the surface. Basin and Range geothermal resources are used for electric power generation in Nevada, Utah and eastern California but have not been developed on a commercial scale in the Northwest.

The Cascade Range is an active volcanic arc derived from subduction of oceanic plates. Earlier models of Cascades geology suggested the presence of a very large geothermal potential, possibly as much as several hundred thousand megawatts. One model, for example, postulates an extensive heat source lying at approximately ten kilometers depth. Cool, near-surface groundwater is thought to mask surface hydrothermal expression of this heat source, accounting for the scarcity of hot springs in the Cascades. Such an extensive heat source, if it existed, could support tens of thousands of megawatts of geothermal potential. An alternative model postulates large, but more discrete partly molten intrusive bodies at depths of ten kilometers, or less beneath the major volcanic centers. This model, while precluding extremely large geothermal potential, suggests the possibility of substantial geothermal potential at numerous volcanic centers. The estimates of geothermal potential appearing in earlier power plans were based on these models.

Figure FGT--1

Physiographic Areas of the Pacific Northwest

More recent research suggests that while several major high-temperature hydrothermal systems may exist in the Cascades, geothermal potential suitable for electric power generation outside of these areas is likely to be limited or absent (Muffler and Guffanti, 1995; Guffanti and Muffler, 1995). This model rules out the presence of a large single underlying heat source, but identifies four types of volcanic structures with geothermal potential:

- The stratovolcanos (Mounts Baker, Adams, Rainier, Hood, St. Helens, Shasta and Glacier Peak) are viewed as having only small volumes of magma near the surface, stored in relatively narrow conduits. Long-lived high-temperature hydrothermal systems at the stratovolcanos are thought unlikely. Deep undiscovered hydrothermal resources might underlie certain stratocones, particularly Mount Shasta, Mount St. Helens and Glacier Peak. Much of the stratovolcano potential, if present, would be precluded from development by land use restrictions.
- Shallow intrusions underlying the Three Sisters and Mount Lassen composite centers might provide effective heat sources for high-temperature hydrothermal systems. Much of the composite center potential, if present would also be precluded from development by land use restrictions.
- The potent heat source once present at Crater Lake was largely removed by the catastrophic eruption forming the collapsed caldera. Low to intermediate temperature hydrothermal systems may originate from the remaining portion of the magma chamber and in discrete pre-caldera intrusive bodies. Much of the Crater Lake potential, if present, would be precluded from development by the national park.
- Known high temperature systems are present at the Newberry Volcano and Glass Mountain/Medicine Lake shield complexes. These systems might be capable of supporting hundreds of megawatts of geothermal generation. Much of the Newberry potential, if present, would be precluded by the national monument. The Glass Mountain potential would generally be available for development.

In addition to the Cascades resources described above, a developed intermediate-temperature hydrothermal system exists at Klamath Falls, Oregon. Higher-temperature fluids may exist at depth but have not been confirmed.

Low and intermediate temperature thermal features of the Snake River Plain are thought to be relics of past magmatic influence of the crustal “hot spot” now underlying Yellowstone National Park. The Island Park Caldera west of Yellowstone may hold a high-temperature resource, but lease applications were withdrawn because of concerns regarding effects on the hydrothermal features of the Park.

There are many hundred sites in the Northwest with evidence of geothermal potential (Bloomquist, et.al., 1985) Several assessments of this geothermal resource potential have been performed with the objective of identifying the most promising areas (Muffler, et. al. 1979, Fassbender, 1982, Bloomquist, et.al. 1985, GeothermEx, 1987, Guyer, 1989, EIA, 1991, Black 1994). Of the many hundreds of sites showing some evidence of geothermal resource potential, these assessments have identified, with reasonable consistency, those sites thought to have the greatest potential for geothermal resource development. Listed in Table FGT-1 are the sites identified as most promising in the comprehensive assessment of Northwest geothermal resource potential, prepared for the Council’s 1991 Plan (Guyer, 1989). Also included in Table FGT-1 are two stratovolcano areas (Mount Hood area and Mount Shasta area) discussed by Muffler and Guffanti, and the large and largely unknown Island Park Caldera and promising northern Nevada sites considered in GeothermEx. The sites listed in Table FGT-1 are shown on Figure FGT-2.

Figure FGT-2

Potential Geothermal Resource Areas

Table FGT-1
Potential Geothermal Resource Areas of the Pacific Northwest

Resource Area	State	County	Type	Estimated Energy[1] (aMW)	Estimated Temperature (°F)[2]	Post-1991 Assessments	Development Issues
Alvord Desert	OR	Harney	Basin & range	95, 180	330-440		Borax Lake, Steens viewshed. Site of terminated pilot project.
Bearwallow Butte	OR	Deschutes	Cascades (blind resource)	400	446[3]	Low potential for high temperature hydrothermal system (Guffanti & Muffler, 1995).	Scenic, recreational area
Big Creek	ID	Lemhi	Northern Rocky Mountains	23	310		
Cappy-Burn Butte	OR	Klamath	Cascades (blind resource)	378	400	Low potential for high temperature hydrothermal system (Guffanti & Muffler, 1995).	
Cove-Crane Creek	ID	Washington	Snake River Plain	179	330		
Crater Lake	OR	Klamath	Cascades (collapse caldera)	400	266[3]	Deep (7.5kM+) residual heat source; peripheral shallow low to intermediate temperature sources (Guffanti & Muffler, 1995).	Adjacent to Crater Lake National Park
Crump	OR	Lake	Basin & range	63	350		
Glass Buttes	OR	Lake	Columbia Plateau (blind resource)	278	450[4]		
Island Park Caldera	ID	Fremont	Snake River Plain (relic "hot spot")	1000	400		Close to Yellowstone National Park
Medicine Lake (Glass Mountain)	CA	Siskiyou	Cascades (shield complex)	2000[5]	500	High potential. Shallow intrusive plexuses of sill & dikes favorable to formation of high temperature hydrothermal systems (Guffanti & Muffler, 1995).	Confirmed resource. Site of proposed Glass Mountain pilot project
Klamath Falls	OR	Klamath	Cascades	160, 450	380		
Klamath Hills	OR	Klamath	Basin & range	240	360[3]		

[1] Recent estimates. Except as noted, first is Guyer, 1989; second is capacity equivalent at 90% capacity factor of EIA, 1991.
[2] GeothermEx, 1987, except as noted.
[3] Guffanti and Muffler, 1995.
[4] Bloomquist, et.al., 1985.
[5] EIA, 1991.

Lakeview	OR	Lake	Basin & range	8	300		
Melvin-Three Creek Butte Area	OR	Deschutes	Cascades (blind resource)	400	400	Low potential for high temperature hydrothermal system (Guffanti & Muffler, 1995).	
Mt. Adams Area	WA	Yakima	Cascades (stratovolcano)	400	400?	Modest potential. Small near-surface magma conduit with small hydrothermal system; possible very deep high temperature magma body with possible hydrothermal system (Guffanti & Muffler, 1995).	Adjacent to Mt. Adams
Mt. Baker Area	WA	Whatcom	Cascades (stratovolcano)	400, 180	400?	Modest potential. Small near-surface magma conduit with small hydrothermal system; possible very deep high temperature magma body with possible hydrothermal system (Guffanti & Muffler, 1995).	Adjacent to Mt. Baker
Mt. Hood Area	OR	Clackamas	Cascades (stratovolcano)	6-59[6]	248[3]	Modest potential. Small near-surface magma conduit with small hydrothermal system; possible deep high temperature magma body with possible hydrothermal system (Guffanti & Muffler, 1995).	Adjacent to Mt. Hood
Mt. Shasta Area	CA	Siskiyou	Cascades (stratovolcano)	None	None	Modest potential. Small near-surface magma conduit with small hydrothermal system; possible deep high temperature magma body with possible hydrothermal system (Guffanti & Muffler, 1995).	Adjacent to Mt Shasta
Newberry Volcano	OR	Deschutes	Cascades (shield complex)	250[7], 200-2000[5]	500	High potential. Shallow intrusive plexuses of sill & dikes favorable to formation of high temperature hydrothermal systems (Guffanti & Muffler, 1995).	Adjacent to Newberry National Volcanic Monument. Site of proposed Newberry pilot project.
Raft River	ID	Cassia	Basin & range	12, 176	300		Confirmed resource. Site of Raft River demonstration project (dismantled).
Three Sisters-Santiam Pass Area	OR	Deschutes	Cascades (composite center)	400	400	Possible high temperature hydrothermal system (Guffanti & Muffler, 1995).	Mt. Jefferson, Mt. Washington, Three Sisters wilderness areas
Surprise Valley	CA	Modoc	Basin & range	20, 450	350		
Vale	OR	Malheur	Snake River Plain	130, 956	350	Proposed pilot project terminated because of	

[6] Black, 1994.
[7] Resource accessible from outside Newberry NVM.

						unfavorable exploration results.	
Wart Peak Caldera	OR	Lake	Cascades (blind resource)	116	400?	Low geothermal potential because of age (Duffield, 1994).	
Tuscarora	NV	Elko	Basin & range	27[8]	380		

[8] Muffler, et.al., 1978.

Geothermal Power Plants

Commercially-available geothermal generating technologies include dry steam, flashed-steam and binary-cycle power plants. Dry steam plants are used for vapor-dominated hydrothermal resources, such as at The Geysers in California. No vapor-dominated resource is known to exist in the Northwest. Flash steam or binary generating technology are likely to be used for Northwest applications. Advanced geothermal generating technologies with prospects of introduction within the next decade include rotary separator turbines and the Kalina cycle.

Flash-steam power plants: A flashed-steam geothermal power plant uses a steam turbine-generator to produce electric power. Flashed-steam geothermal power plants may be used for liquid-dominated hydrothermal resources of about 300^{o} Fahrenheit, and greater. In a flashed-steam plant, the geothermal fluid is brought to the surface via production wells and is directed into steam separators. Here, the fluid is throttled to reduce its pressure, causing a portion of the water to flash to steam. Flash systems are designed to use one or two stages of separation. In a single-flash system (Figure FGT-2a), about 15 to 20 percent of the geothermal fluid is converted to steam. Residual moisture and non-condensable gasses (typically carbon dioxide and hydrogen sulfide) are removed from the steam flow, and the steam is supplied to a steam turbine-generator to produce electric power. Noncondensibles from the separator are treated before release, if necessary. The steam turbine exhaust is directed to a condenser. The condenser is cooled by a cooling tower and circulating water system. The condensed water and residual liquid from the steam separator are pressurized and returned to the reservoir by injection wells. The thermodynamic efficiency of a single-flash plant is about 35 percent.

Figure FGT-3a

Geothermal Power Plant Technologies

Figure FGT-3b
Geothermal Power Plant Technologies

Figure FGT-3c
Geothermal Power Plant Technologies

Double-flash plants (Figure FGT-2b) are used for hot water reservoirs having temperatures of 150^{o}C (300^{o}F) and above. These plants are similar to the single-flash systems, except they incorporate a second-stage separator where the residual fluid from the first-stage separator is flashed again at a lower pressure. This second, lower-pressure steam flow is directed into either a low-pressure stage of a compound turbine or a separate low-pressure turbine. Double-flash plants have a thermodynamic efficiency of about 40 percent.

Binary-cycle power plants: Binary-cycle power plants (see Figure FGT-2c) are used for low-temperature geothermal fluids, generally below 193^{o}C (380^{o}F). These plants use separate, closed geothermal fluid and working fluid loops (hence the name "binary"). The geothermal fluid loop consists of production wells equipped with downhole pumps that circulate geothermal fluid through heat exchangers. Here heat is transferred to a working fluid having a low boiling point, such as isobutane or freon. Once the useful heat has been extracted, the geothermal fluid is returned to the reservoir using an injection well. The vaporized working fluid is used to turn a turbine-generator, then is discharged to a condenser. A feed pump returns the condensed working fluid to the heat exchanger. The condenser is cooled by a cooling tower and circulating water system.

Binary plant components often are modular in design and lend themselves to factory prefabrication. Thus, they usually can be installed rapidly at relatively low costs. The thermodynamic efficiency of binary plants is lower than for other designs, partly because of greater pump and auxiliary equipment loads. For certain geothermal resources, however, binary plants may provide the most efficient use of the resource in terms of net power per unit mass of fluid. Small binary units are suited to wellhead tests, to low and moderate temperature geothermal resources, or to resources or locations where environmental factors preclude the use of other technologies.

Advanced technologies : Advanced geothermal technologies include rotary separator turbines and Kalina cycles. Rotary separator turbines recover the kinetic energy of two-phase geothermal fluid flow while separating the gas from the liquid component. The residual fluid is pressurized to reinjection pressure. Rotary separator turbines may be substituted for the steam separators and brine reinjection pumps of a flashed-steam power plant. The separator turbine may produce excess shaft power that can be used to drive an electric generator. A 20-percent improvement in the thermal efficiency of a single-stage flash plant has been demonstrated by use of a rotary separator turbine. Rotary separator turbines are commercially available but have not been widely installed.

A Kalina cycle employs a two-component working fluid for its thermodynamic cycle. The two liquids have different boiling points, which improves thermodynamic cycle efficiency by 10 to 20 percent. Ammonia and water have been proposed for Kalina cycle working fluid components. The Kalina cycle is in the development stage as a development for single fluid binary cycle machines.

Geothermal Development Issues

The principal issues currently constraining development of geothermal power are the surplus of generating capacity and the low value of power. Other issues associated with geothermal power development include resource confirmation issues, resource sustainability, certain potential environmental impacts and land use conflicts.

Value of Electricity and the Cost of Geothermal Power

The primary factor currently constraining the development of geothermal power generation is the low price of wholesale electricity. Though the cost of generating electricity from Northwest geothermal resources has not been confirmed, evidence suggests that geothermal power costs are likely to be much higher than current wholesale power costs. Even if the current generating surplus is worked off over the next several years, it appears that new natural gas-fueled combined cycle gas turbine power plants will be able to supply electricity at costs less than the cost of producing power from geothermal resources.

Resource Confirmation Costs and Risks

More than for most other resources, confirming the quantity and quality of a geothermal resource is a difficult, expensive and risky business. The resource is hidden and must be identified and characterized through expensive geologic exploration techniques, including costly thermal-gradient and production wells. Exploration simply may confirm that a potential resource is not developable. Furthermore, the characteristics of geothermal fluids at a new area cannot be inferred easily from experience at apparently similar resource areas. Although the general potential for producing useful energy at a new location can be inferred from experience at areas of similar geology, extensive exploration within the new area is required to confirm its potential for geothermal development.

Bonneville and other Northwest utilities are developing geothermal pilot projects to confirm the feasibility of generating electric power from Northwest resources. The concept involves the development and operation of commercial-scale pilot projects at promising Northwest geothermal resource areas and the confirmation of additional resource potential. If successful, these projects will confirm the feasibility, cost and sustainability of generating electric power from Northwest geothermal resources, encourage exploration and help identify and resolve environmental issues. Successful pilots are expected to facilitate future development of additional generating capacity, as needed, at these resource areas. Unsuccessful projects will focus future geothermal exploration and development efforts to more promising areas. While there is no technical reason that these projects should not move forward, declining wholesale electricity prices have greatly increased the difficulty of continued utility support for these projects. Means of continuing resource research, development and demonstration activities in a more competitive industry must be devised if projects such as the geothermal pilot projects are to be completed.

Sustainability

Geothermal is generally considered a renewable resource. However, experience in other regions indicates that the resource can be depleted either by depleting the supply of water in the reservoir or by cooling of the crustal heat source. Because Northwest geothermal resources are not well understood, long-term operation of geothermal power plants at these areas will be required to determine whether the resource is sustainable.

Environmental Effects

The key environmental concerns resulting from geothermal development are release of hydrogen sulfide, disposal of geothermal fluid, noise, wildlife habitat disturbance and water pollution.

Hydrogen sulfide: Hydrogen sulfide is a non-condensable gas apparently present to some degree in all geothermal fluids. The major concern regarding hydrogen sulfide is its effect on human health. At low concentrations, hydrogen sulfide has an offensive rotten-eggs odor. At high concentrations, hydrogen sulfide has virtually no odor, but it is toxic and can cause death quickly by respiratory paralysis. If present, some releases may occur during well development and testing. Hydrogen sulfide releases are controlled during power plant operation by collection and reinjection of non-condensable gasses.

Geothermal fluid toxins: Geothermal fluids may be contaminated naturally with toxins such as heavy metals that could contaminate surface and ground waters. Wells are encased to protect near-surface aquifers, and most of the spent geothermal fluids are reinjected rather than released at the surface[1]. Reinjection also replenishes reservoir fluid. Cooling tower makeup water is often obtained from condensed geothermal fluid in areas of inadequate surface supplies. Secondary pollution of water and land can result from cooling tower drift deposition. Closed-cycle convective ("dry") cooling can be used if condensed geothermal fluids are unavailable or unsuitable for cooling tower makeup.

[1] Some of the condensed geothermal fluid may be diverted for cooling tower makeup in areas without adequate surface water supplies.

Noise: High noise levels occur during well drilling and testing. Moderate noise is produced by cooling towers and other aspects of plant operation. Noise from well drilling and testing is of relatively short duration and can be partly controlled by the use of mufflers.

Wildlife habitat disturbance: Most geothermal sites are in relatively isolated locations, some of which may be ecologically sensitive. Exploration, drilling construction and operation may involve 500 to 600 acres, or more for a 30 megawatts project. Though a much smaller area is physically disturbed by construction (for example, 100 acres for a 30 megawatts plant, excluding transmission and road access corridors), wildlife disturbance may be more widespread because of noise and human presence.

Water pollution: Secondary pollution of water and land can result from deposition of some materials released by geothermal plants. Drift deposition of pollutants can cause acidification of lakes and streams and can introduce toxins such as arsenic and boron into water. Geothermal plants may be located in arid or semi-arid regions where water used on-site, such as for condenser cooling, may be a scarce and valuable resource for fish and wildlife. Water consumption may be reduced by use of dry cooling towers.

Disturbance of natural geothermal features: Geothermal development may adversely affect nearby natural geothermal features such as hot springs. This concern, for example, has curtailed exploration of the Island Park Caldera near Yellowstone National Park. Development near important thermal features should include provisions for monitoring these features during project development and operation with provision for curtailing operations, if necessary to prevent damage.

Land Use Conflicts

Many of the most promising Northwest geothermal resource areas are located within or near lands of great environmental or aesthetic value. For example, the geothermal resources of the Cascade Mountains are related to the presence of volcanic activity. Volcanic features, however, often are the focus of national parks, monuments, wilderness areas or recreational areas. The potential for land use conflict is obvious. Geothermal development, an industrial activity, near these sensitive areas must be managed to avoid unacceptable land-use conflicts.

Geothermal Power Potential in the Pacific Northwest

For many years the Northwest has been viewed as having good potential for geothermal electric power generation. But, because of the high financial risks of geothermal development and low power prices, commercial-scale development of the Northwest's geothermal resources has never occurred. Though exploration has been widespread and several successful production-scale wells have been completed, the feasibility and long-term sustainability of generating electricity from Northwest geothermal resources is yet to be demonstrated.

As described above, the 1991 Power Plan recommended development of pilot projects at promising geothermal resource areas to confirm the feasibility of commercial-scale generation of electricity from Northwest geothermal resources. Four pilot projects have been initiated since the 1991 Plan. Planning is proceeding for the two projects described in Table FGT-3. Work on a third project was terminated when the resource proved not suitable for development. Development of the fourth project was halted because of environmental controversy.

Table FGT-3
Geothermal Power Projects Planned for the Northwest

Project	Resource Area	Proposed Technology	Installed Capacity (MW)	Energy (aMW)	Developer	Power Purchaser
Glass Mountain Geothermal Pilot Project	Glass Mountain/ Medicine Lake, CA	Not determined	41[2]	33[2]	Calpine Corporation	BPA, Eugene Water & Electric Board
Newberry Geothermal Pilot Project	Newberry Volcano, OR	Double-flash	33	27	CE Exploration Company	BPA, Springfield Utility Board

Numerous geothermal resource areas have been identified in the Northwest, but, with minor exceptions the feasibility of generating electric power from these areas has not been confirmed. For this reason, the regional geothermal potential is highly uncertain with respect to both cost and supply. Because of the uncertainty associated with geothermal potential, pessimistic, expected and optimistic geothermal cases were considered for this assessment. The recent articles of Muffler and Guffanti, described earlier, influenced the development of the following cases:

Pessimistic case: Small developable resources are present at the Newberry Volcano and Glass Mountain shield complexes, and developable resources are present at some basin and range sites.

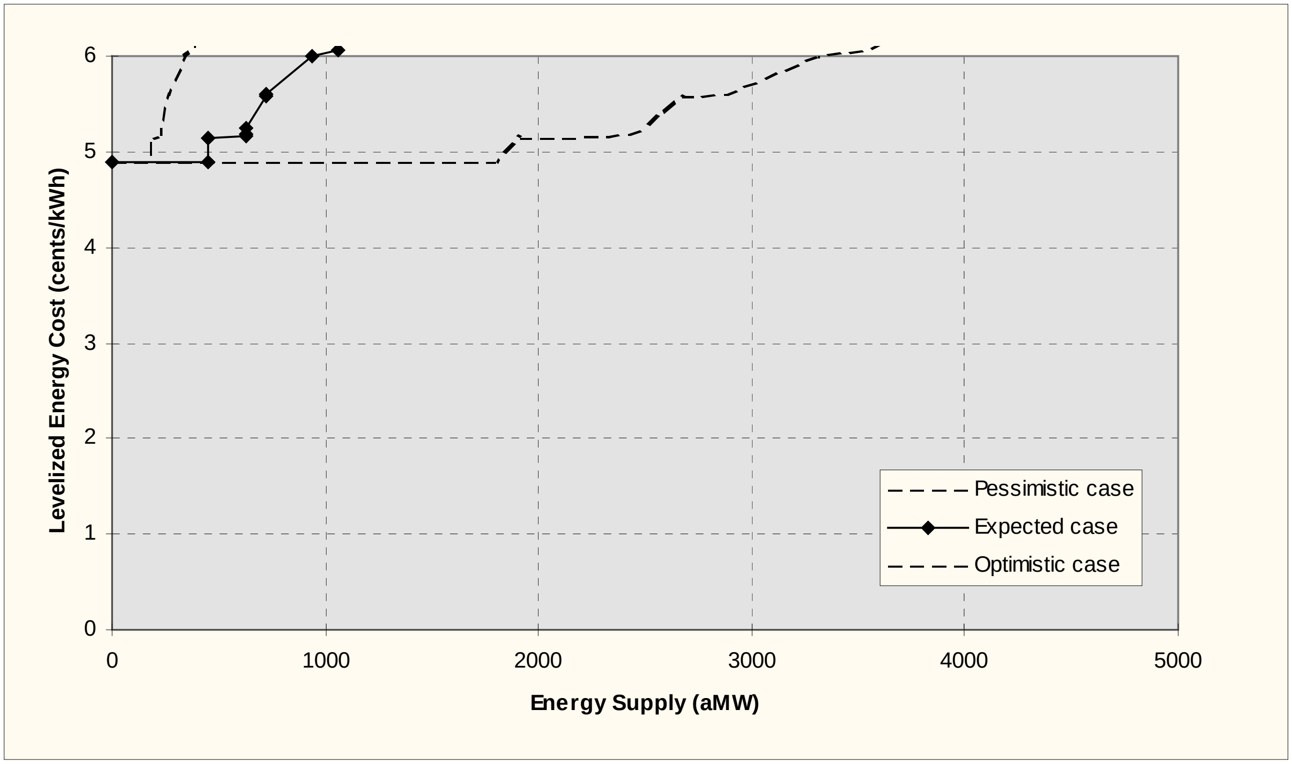
Expected case: Moderate-size developable resources are present at Glass Mountain and Newberry Volcano. Many basin and range sites have developable resources. Small developable resources are present at accessible Cascade stratovolcanos and the Santiam Pass Three Sisters composite center.[3]

Optimistic case: Large developable resources are present at Glass Mountain and at Newberry. The Newberry resource is limited to that accessible from outside the national monument. Many basin and range resource areas have developable resources. Developable resources of moderate size are present at accessible Cascade stratovolcanos and the Santiam Pass Three Sisters composite center. Some developable potential is available at other potential resource areas.

The results of this assessment are shown in Figure FGT-4. Under the "expected" case, 1,050 megawatts of geothermal capacity, yielding about 940 average megawatts of energy, could be obtained by the development of areas producing energy at costs of six cents per kilowatt-hour, or less. These amounts decrease to about 380 megawatts of capacity and about 340 megawatts of energy for the pessimistic case, and increase to about 3,670 megawatts of capacity and about 3,300 average megawatts of energy for the optimistic case. The least cost resource area for all scenarios is Glass Mountain at an estimated levelized energy cost of 4.9 cents per kilowatt-hour.

[2] Preliminary.
[3] Reources that might be present at Lassen are assumed to be precluded from development.

Figure FGT-4
Estimated Cost and Potential Supply of Geothermal Electricity



Development of the Supply Estimates

The potential supply of geothermal energy from a resource area was estimated as a function of the size of the developable geothermal resource and the probability of its existence. The product yields a probable contribution, that summed for all resource areas provides an estimate of regionwide potential. Size and probability were varied systematically to create pessimistic, expected and optimistic cases of geothermal resource availability. The assumptions and resulting estimates of the potential capacity contribution for each resource area are shown in Table FGT-3. The energy contribution of each resource area (not shown in Table FGT-3) was based on a 90-percent capacity factor.

Development of the Cost Estimates

The estimated cost components and resulting levelized energy costs for project development at geothermal resource areas are shown in Table FGT-4. The cost components are as follows:

Project development costs: Project development costs include the federal geothermal lease payments during the exploration, permitting and construction period; and resource exploration, environmental assessment, permits, geotechnical, and developer's administrative costs. Project development costs are combined with project construction costs in Table FGT-4.

Construction cost: Construction costs include the cost of final engineering, equipment procurement, construction management, installation and testing for the wellfield, production and injection facilities and the power plant. Construction cost was estimated for each resource area using the CENTPLANT model (Bloomquist, et. al., 1985). CENTPLANT parameters were updated using cost information from recently completed projects and planned project estimates. The basic costs of power plant, production and injection facilities are separately estimated using equations of the following form:

Base Power Plant Cost ($ million) = $a\ (MW_{net})^b$

where:

MW_{net} is the net capacity of the plant,

a is the base capital cost variable, and varies with resource temperature range and technology type,

b accounts for economies of project scale and varies with technology type.

The wellfield cost is separately estimated and is based on an estimate of the number of production and injection wells required and a typical well cost.

These base costs are adjusted by the following factors, as appropriate:

Difficult terrain labor and site preparation premiums
Remote site labor premium
Dry cooling
Hydrogen sulfide abatement

To the resulting plant construction cost were added the following costs for ancillary features and services:

Transmission interconnection facilities
Impact mitigation fund
Spare parts
Startup costs
Working capital

Table FGT-3
Geothermal Resource Areas of the Pacific Northwest: Potential Contribution

Resource Area	Capacity (Pessimistic) (MW)	Capacity (Expected) (MW)	Capacity (Optimistic) (MW)	Probability (Pessimistic) (%)	Probability (Expected) (%)	Probability (Optimistic) (%)	Potential Contribution (Pessimistic) (MW)	Potential Contribution (Expected) (MW)	Potential Contribution (Optimistic) (MW)
Alvord Desert Area	150	200	250	25%	50%	75%	38	100	188
Baltazor	40	50	60	25%	50%	75%	10	25	45
Bearwallow Butte	0	0	500	0%	0%	25%	0	0	125
Big Creek	0	0	30	0%	0%	25%	0	0	8
Cappy-Burn Butte	0	0	420	0%	0%	25%	0	0	105
Crane Creek	0	0	200	0%	0%	25%	0	0	50
Crater Lake	Not estimated	Not estimated	Not estimated	0%	0%	0%	0	0	0
Crump Hot Springs	50	70	90	25%	50%	75%	13	35	68
Glass Buttes	0	0	310	0%	0%	25%	0	0	78
Glass Mountain (Medicine Lake)	200	500	1000	100%	100%	100%	200	1000	2000
Island Park Caldera	0	0	1000	0%	0%	25%	0	0	250
Klamath Falls	0	0	500	0%	0%	25%	0	0	125
Klamath Hills	200	270	340	25%	50%	75%	50	135	255
Lakeview	20	30	40	25%	50%	75%	5	15	30
Melvin Butte	0	0	500	0%	0%	25%	0	0	125
Mt Hood Area	0	30	50	0%	0%	100%	0	0	50
Mt. Adams Area	0	30	50	0%	0%	100%	0	0	50
Mt. Baker Area	0	30	50	0%	0%	100%	0	0	50
Mt. Shasta Area	0	30	50	0%	0%	100%	0	0	50
Newberry Volcano	50	200	350	100%	100%	100%	50	200	350
Raft River	15	15	15	25%	50%	75%	4	8	11
Santiam Pass/Three Sisters (ex. Bearwallow)	0	60	100	0%	100%	100%	0	60	100
Surprise Valley	380	500	630	25%	50%	75%	95	250	473
Tuscarora	20	30	40	25%	50%	75%	5	15	30
Wart Peak Caldera	Not estimated	Not estimated	Not estimated	0%	0%	0%	0	0	0

The resulting construction cost estimates are shown in Table FGT-4. Not included in these costs are financing fees. These, estimated at 2 percent, are separately calculated by the Council's models.

Fixed operating and maintenance costs: Fixed operating and maintenance costs include powerplant and wellfield labor and maintenance materials, well replacement, interconnection maintenance, wheeling costs, decommissioning fund payments, property tax and insurance. Labor and maintenance materials were calculated using CENTPLANT equations. Functions for well replacement, interconnection maintenance and decommissioning fund costs were added to the original CENTPLANT model. The sum of these costs appears in Table FGT-4. The cost (and capacity and energy losses) of wheeling from the point of interconnection to the central grid were separately estimated. Wheeling costs are shown separately in Table FGT-4. Property tax and insurance are separately calculated by the Council's models and are not included in the operating and maintenance costs of Table FGT-4.

Variable operating and maintenance costs: Variable operating and maintenance costs include federal geothermal lease payments during the operating period and consumables.

Financing assumptions: The unregulated developer financing assumptions of Table F-2 were used to calculate the levelized energy costs appearing in Table FGT-4. A 10-percent federal investment tax credit is available for geothermal projects and was included in the levelized energy cost calculations. A 30-year project life was assumed.

Future cost expectations: Geothermal costs are expected to continue to slowly decline as a result of improvements to exploration, production and power plant technology. This base rate of cost reduction was projected to average 0.4 percent annually for the period 1995 to 2015. The development of a pilot project should lead to an incremental reduction of subsequent project development costs at that resource area by improving understanding of the character of the geothermal resource of the area and by reducing subsequent exploration and development risk. The incremental benefit of pilot projects was estimated to be 0.5 percent annual cost reduction in the cost of subsequent projects for the five-year pilot project development and construction period and 2.4 percent annual cost reduction for the first five years of pilot project operation. The costs of Table FGT-4 are for projects entering service in 2000.

Planning Model Data

The Council's power system models require aggregated resource data. For modeling purposes, supply, performance and cost estimates for individual geothermal resource areas were aggregated into resource supply blocks using energy cost as the primary criterion. The block assignments used for the draft plan modeling studies are shown in the right-most column of Table FGT-4. These correspond to the block codes appearing in Table F-1. Because of currently low wholesale power costs and the abundant supply of low-cost energy available from other new resource alternatives, only those geothermal resources appearing in the "expected" case and estimated to produce energy at eight cents per kilowatt-hour, or less were included in the base case planning model resource blocks.

Table FGT-4
Pacific Northwest Geothermal Resource Areas: Estimated Costs

Resource Area	Development and Construction Cost ($/kW)	Fixed O&M Cost ($/kW/yr)	Variable O&M Cost ($/kWh)	Wheeling Cost ($/kW/yr)	Estimated Cost of Energy at Central Grid (cents/kWh)	Resource Planning Block
Alvord Desert Area	$3,069	$110	$0.0079	$11	5.6	GEO-2
Baltazor	$4,352	$165	$0.0079	$12	7.7	
Bearwallow Butte	$2,906	$84	$0.0078	$1	5.1	
Big Creek	$5,951	$232	$0.0080	$13	10.4	
Cappy-Burn Butte	$2,912	$88	$0.0079	$3	5.2	
Crane Creek	$3,829	$124	$0.0080	$14	6.7	
Crump Hot Springs	$4,101	$140	$0.0079	$4	7.2	GEO-3
Glass Buttes	$2,974	$85	$0.0078	$0	5.2	
Glass Mountain (Medicine Lake)	$2,763	$77	$0.0078	$0	4.9	GEO-1
Island Park Caldera	$3,081	$117	$0.0081	$30	5.6	
Klamath Falls	$3,526	$107	$0.0079	$2	6.2	
Klamath Hills	$3,457	$107	$0.0079	$2	6.1	GEO-2
Lakeview	$4,644	$200	$0.0079	$4	8.5	
Melvin Butte	$2,903	$86	$0.0079	$3	5.2	
Mt Hood Area	$4,247	$164	$0.0079	$2	7.6	
Mt. Adams Area	$3,808	$137	$0.0078	$1	6.8	
Mt. Baker Area	$3,488	$133	$0.0078	$0	6.4	
Mt. Shasta Area	$3,311	$137	$0.0079	$5	6.2	
Newberry Volcano	$2,922	$86	$0.0079	$3	5.2	GEO-1
Raft River	$4,993	$337	$0.0078	$0	10.3	
Santiam Pass/Three Sisters	$4,187	$140	$0.0079	$2	7.3	GEO-3
Surprise Valley	$3,411	$108	$0.0079	$4	6.0	GEO-2
Tuscarora	$4,769	$209	$0.0080	$21	8.7	

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APPENDIX FHY
HYDROPOWER

HYDROPOWER

SUMMARY

Hydropower is an abundant, emissions-free and sustainable source of electricity. No carbon dioxide or other greenhouse gasses are produced during plant operation, and there are no environmental impacts associated with fuel production or transportation. However, hydropower development can produce significant hydrologic and water quality impacts, changes in erosion and sedimentation patterns and fish, wildlife and other ecological impacts.

Hydropower operating costs are low compared to other generating alternatives and free of fuel price escalation risk. But, project capital costs are often high, and this capital-intensive technology may be difficult to finance in the more competitive electricity industry of the future. Hydropower uses proven and reliable technology, but long-term financial risks may result from unanticipated environmental impacts or evolving environmental values.

The streams and rivers of the Pacific Northwest provide abundant opportunities for generation of electric power. More than 33,000 megawatts of hydropower have been developed in the Pacific Northwest, representing about 77 percent of the electrical generating capacity dedicated to Northwest loads. This hydropower capacity provides about 16,500 megawatts of energy, on average, and 11,700 megawatts of firm energy, available in all but the driest years. On average, more than 60 percent of regional electrical load is met by hydropower.

Though the theoretically remaining hydropower potential of the Northwest is large, most economically feasible hydropower sites have been developed. The remaining opportunities for hydropower development, though numerous, are for the most part small-scale and fairly expensive. Among these are additions of generating equipment to irrigation, flood control and other non-power water projects, incremental additions of generation to existing power project with surplus streamflow, and projects at some undeveloped sites. The Council estimates that about 480 megawatts of additional hydropower capacity is available for development at costs ranging from less than a cent to 8.0 cents per kilowatt-hour. This capacity could produce about 200 megawatts of energy on average, 160 megawatts of which would be firm. The cost of electricity from most of the remaining feasible sites is higher than the current price of electricity from alternative sources and few of remaining development opportunities are likely to be constructed in the near future.

More promising than new projects in the immediate future may be improvements in equipment and operational efficiencies at existing hydropower projects. Many projects date from a time when the cost of electricity and equipment efficiency were lower than they are now. Moreover, modern data processing and communications technologies allow more sophisticated control of hydropower generation than previously possible. Hydropower efficiency upgrades often can be installed at relatively low cost, and even a few tenths of a percent improvement in project efficiency on the large existing resource base can provide significant increases in energy production. Many project owners have improved the efficiency of their projects during the last several years and interest in securing additional improvements appears to be high. The Council plans to assess the status of hydropower efficiency improvements and remaining potential during the summer of 1996.

PACIFIC NORTHWEST HYDROPOWER RESOURCES

Considerable topographic relief and high levels of precipitation, much of which falls as snow, produce the fundamental conditions of sustained large volumes of annual runoff and vertical drop that create the great hydropower potential of the Pacific Northwest. The theoretical hydropower potential in the Pacific Northwest has been estimated to be about 68,000 megawatts of capacity and 40,000 megawatts of energy.[1]

Hydropower is by far the most important generating resource in the Pacific Northwest. Nearly 33,000 megawatts of hydropower capacity at 359 projects have been developed, representing about 77 percent of the generating capacity dedicated to Northwest loads. This hydropower, on average, provides about 16,500 megawatts of energy. About 11,700 megawatts of this energy is considered "firm" (available in all but the driest years). On average, more than 60 percent of the electricity consumed in the Northwest is from hydropower. Nearly 95 percent of this capacity is located on the Columbia River system; the balance is located on coastal streams, tributaries to Puget Sound, and the Klamath and Bear river basins. An inventory of existing Northwest hydropower projects is provided in Appendix A.

Little of the remaining theoretical hydroelectric potential of the Northwest is likely to be developed. Hydropower is a mature technology, and most of the larger-capacity, more economical sites have been developed. Much of the remaining potential is simply uneconomic to develop. Suitable topography or geology are absent, flows are of insufficient volume or intermittent. Some of the remaining potential is located in areas with incompatible management objectives, such as national parks, or on stream segments with other, more important biological, recreational, cultural or scenic values. Environmental considerations are far more important now than when most of the large-scale Northwest hydropower projects were constructed. Changing environmental values, environmental impacts whose magnitude was not fully evident when large-scale development occurred, increasing river-oriented recreation and the scarcity of wild, undeveloped streams have lead to stringent environmental criteria for new hydroelectric development.

The most promising hydropower development opportunities are those combining favorable flow characteristics, minimal incremental environmental impacts and characteristics leading to economical construction. For example:

- Existing power projects with surplus stream flow adequate to support additional generating capacity.
- Non-power water project features with sufficient flow and elevation drop to provide opportunities for power generation. Examples include irrigation storage dams, canal drops and wasteways, and municipal water supply pressure reduction valves.
- Retired hydropower projects that may be rehabilitated.
- New sites with attractive topography, geology, streamflow and environmental characteristics, for example, high-head diversion projects above the limit of anadromous fish migration.
- Existing projects with opportunities for equipment upgrades. Many existing projects were built at a time when the value of power and equipment efficiencies were both lower than at present.

One measure of new hydroelectric potential is the capacity and energy of projects for which prospective developers have filed permit and license applications with the Federal Energy Regulatory Commission (FERC).[2] Table FHY-1 is a list of these projects in the Northwest. Excluded from the table are projects that would conflict with the Council's protected areas policy.

[1] Sum of the estimated of remaining 39,000 megawatts of hydropower capacity and 25,000 average megawatts of energy for Idaho, Washington, Oregon and the portions of Montana and Wyoming included in the Columbia River Basin (Synergic Resources Corporation, 1981) plus the approximately 29,000 megawatts of capacity and 15,000 average megawatts of energy developed at the time..

[2] Non-federal hydroelectric projects, if located on navigable waters, are required to be licensed or exempted from licensing by the Federal Energy Regulatory Commission (FERC). The definition of navigable waters is broad and includes most economic sites. The FERC licensing process is a two-phase process. A developer first applies for a preliminary permit, which reserves the site for a period of time while the developer conducts additional feasibility and licensing studies. The second step consists of the application, evaluation and issuance (or denial) of a license or exemption.

HYDROELECTRIC POWER PLANTS

In conventional hydropower projects, water from a higher level is delivered under pressure to a hydraulic turbine. The turbine converts the energy of the pressurized flowing water into rotational mechanical energy. The turbine drives an electrical generator to produce electricity. Hydropower projects take many forms, depending upon the source of water and the physical characteristics of the site, but generally include the following components: 1) a dam or weir to collect water, and often, to raise its elevation and to provide storage; 2) a system of intakes and canals, pipes or tunnels to deliver the water to the turbines; 3) a powerhouse containing one or more hydraulic turbines coupled to electric generators; 4) a switchyard and substation to raise the generator output voltage to the transmission voltage; 5) access roads and transmission interconnections; and 6) fish bypass facilities.

Projects may be classified as instream, diversion, canal or conduit and pumped-storage projects:

For instream projects, a dam raises the elevation of water at the site to create operating pressure. Penstocks convey the water from the reservoir to turbines in an adjacent powerhouse. Sometimes the reservoir may impound sufficient water to permit regulation of streamflow so power can be generated as needed. Habitat requirements and other uses of the stream also determine the extent of regulation. Projects without significant storage ("run-of-river" projects) generate power as streamflows permit.

In a diversion project, water is diverted from the stream by a diversion structure (generally a low dam or weir) and conveyed to a downstream powerhouse by canals and conduits. The distance between the diversion structure and the powerhouse may be very short, as in a diversion around a natural waterfall, or may be many miles. The water pressure at the turbines is determined by the difference in elevation between the diversion structure and the powerhouse. Sometimes the diversion structure is a high dam that may provide additional operating head or water storage. Flows are maintained in the bypassed natural channel to sustain habitat or to support non-power uses of the stream.

A canal or conduit hydropower project uses operating head created by water conveyance structures installed primarily for non-power purposes. These include irrigation and municipal water supply systems.

Pumped-storage hydropower projects are used to store energy for times of greater need. A pumped-storage project includes upper and lower reservoirs. Water is pumped by means of reversible pump-turbines from the lower to the upper reservoir at times of surplus electricity production. Water is released from the upper reservoir to the lower reservoir to generate power at times of greater demand. Pumped storage hydropower is generally designed to cycle on a daily basis.

An unconventional form of hydropower, not in current use in the Northwest is the water current turbine. A water current turbine converts the kinetic energy of flowing water into electricity. No operating head (pressure) is developed. Because of the low energy content of moving water, current turbines are physically large in proportion to the amount of electric energy produced. For this reason, they have not been economical to construct.

Measures to improve the efficiency of existing hydropower projects take many forms. Measures include turbine runners (blade and hub assembly) of improved design and materials, electronic turbine governors, low-friction generator cooling systems, improved generator windings, solid-state generator exciters, high-efficiency transformers, reduced bypass water losses, installation of generation on unavoidable bypass water systems, such as those for fish attraction flows, improved station motor, pumping and lighting efficiencies and increased turbine operating head through reservoir elevation. Generating unit dispatch and project coordination through integrated systemwide operational control may offer an attractive opportunity to increase overall hydropower system efficiency.

HYDROPOWER DEVELOPMENT ISSUES

Many factors may affect hydropower development. These include the high fixed-cost of hydropower, seasonal coincidence to load, environmental impacts and land use conflicts. In addition, siting, licensing and design are typically complex and frequently require a long lead time. Hydropower sites often are remote from load centers and may require long transmission lines. Transmission and road access costs can render small remote projects economically infeasible. Because streamflows are affected by annual weather conditions, a portion of the output of most hydropower projects is "nonfirm," that is, energy that cannot be counted on with certainty to meet customers' demand. The seasonal energy production of a project is also important in determining its value. Some projects may generate most of their energy in the spring, when the value of their energy is generally low due to large flows in the Columbia River system. Conversely, winter-peaking projects may have extra value because of the increased demand for power at that time.

Fixed Costs

Essentially all the cost of energy from a typical hydropower project is fixed. Though this high fixed-cost component contributes to long-term electricity price stability, fixed assets are viewed as risky by investors in an industry undergoing fundamental restructuring and subject to increasing competition. Without long-term power purchase contracts, it is unlikely that power suppliers will be willing to undertake the substantial capital investments required for hydropower until the future structure of the electric power industry is clarified.

Seasonal Energy Production

The power output of most hydropower projects varies seasonally with streamflow. The streamflow at some sites, for example, westside sites fed by rainfall, will be coincident with seasonal loads. The power generated by these projects should have high value. Other sites, for example, those fed by melting snowpack produce power at times of seasonal surplus, reducing the value of project output

Environmental Impacts

The principal environmental concerns regarding hydroelectric development are hydrology impacts, water quality impacts, changes in erosion and sedimentation patterns, and fish and wildlife impacts.

Hydrology Impacts

Possible changes in the hydrologic regime resulting from hydroelectric development include converting a portion of a free-flowing stream into backwater, diverting water from its natural course and altering the natural groundwater recharge pattern. These primary hydrologic impacts may also create secondary impacts of even greater significance. For example, creation of a reservoir may have a major impact on stream ecology and water quality.

Water Quality Impacts

Chemical, biological or thermal impacts on water quality may result from the construction and operation of hydroelectric projects. These impacts may be experienced downstream of the project or in the backwater caused by the project. Water quality changes, although not always adverse, are of concern because of effects on the aquatic environment and on the beneficial uses of water. For hydroelectric development, the primary water quality concerns are thermal changes, nitrogen supersaturation, turbidity and oxygen depletion.

Thermal changes: Changes in the thermal characteristics of downstream flow are most likely to result from operation of large storage projects with deep, poorly mixed reservoirs. Thermal changes can have a pronounced impact on the resident fishery as well as on the anadromous fishery. Many species are intolerant to wide fluctuations in stream temperature. Multiport intake structures, which mix the water from several different reservoir layers, can be included in the design of storage projects. In this manner, stream temperature can be better held within required tolerances for fisheries.

Nitrogen supersaturation: Nitrogen supersaturation is a serious water quality problem below many of the dams on the Columbia and lower Snake rivers. Air entrained in spill over the dams is carried to depths in the plunge pools below the dams, where hydrostatic pressure causes the nitrogen to dissolve above normal saturation levels. The increased nitrogen concentrations can cause lethal respiratory effects in fish.

Turbidity: Large quantities of suspended material can enter waterways as a result of disturbance of the natural terrain during construction. Not only are the visual effects of high turbidity displeasing, but significant turbidity also may impair development of nutrient-assimilating plant life on the bottom of streams and reservoirs.

Oxygen depletion: Although most dissolved oxygen problems are caused by improperly or inadequately treated sewage discharged into the water course, impoundments also can have a significant impact on dissolved oxygen concentrations. Salmonid fish require dissolved oxygen concentrations in excess of five milligrams per liter for migration and higher levels for spawning and rearing. Intense algal blooms can cause extreme diurnal fluctuations in dissolved oxygen concentrations in impoundments, thus causing stress on the fishery.

Erosion and Sedimentation

Changes in erosion and sedimentation patterns may occur during construction of hydroelectric projects and continue after the project is in operation. Naturally free-flowing water has a certain sediment-carrying capacity, which normally is in near-term dynamic equilibrium with hydrologic and geologic processes. A change in the hydrology or a change in the sediment load will upset this equilibrium, resulting in increased channel scour or sediment deposition.

Hydroelectric developments, depending on design and scale, tend to affect erosion and sedimentation patterns in different ways. In general, increased sedimentation occurs in the backwater formed by the reservoir. Mudflats and bars may develop, and reservoir storage capacity is lost. Consequently, the water released from the reservoir has a reduced sediment load. Because the released water can carry a greater sediment load, channel scour may occur downstream of the dam. Channel scour may have a significant impact on aquatic biota and channel stability.

Fish and Wildlife Impacts

Migration impacts: Many hydroelectric dams in the Pacific Northwest present migration barriers to the passage of upstream (adult) and downstream (juvenile) anadromous fish. Juvenile downstream migrants are killed at each dam as they pass through the turbines, are exposed to water supersaturated with air, are delayed in time of migration and are fed on by predators. Returning adults face migration delays, loss of energy reserves, physical injury and disease exposure at each dam when traversing fishways.

Impoundment changes to habitat: The filling of an impoundment behind a hydroelectric dam inundates large areas of land and transforms a free-flowing river into a lake-like environment. The result is a transition of habitat, a change in composition of terrestrial and aquatic biota at the site and a change in usage by man. Changes resulting from habitat transition may be beneficial or detrimental for wildlife. Spawning and rearing areas used by salmonid fishes (salmon, seagoing trout) in free-flowing rivers can be destroyed by water impoundment. Impounded waters can also inundate islands that are important breeding areas for certain species of birds, such as Canadian geese and gulls.

Operations impacts: Operation of hydroelectric facilities to meet peak energy demands causes fluctuations of water level in both the impoundment and the stream below. Typical dam operations tend to reduce these fluctuations on a seasonal basis compared to naturally occurring stream flows. However, on a diurnal basis, dam operations often increase fluctuations relative to natural stream flows. These variations in stream flows can have both positive and negative impacts on fish and wildlife. Greater diurnal fluctuations can preclude development of shoreline vegetation, reduce shoreline use by riparian species of wildlife, and lower reproductive success of fish species that spawn near the impoundment margin. Below the dams, greater diurnal fluctuations can strand immature fish on shorelines or in shallows and may expose eggs of shoreline spawners and intergravel nests of salmonids. On the other hand, reduced seasonal fluctuations can make the riparian zone more stable for some species.

Land Use Conflicts

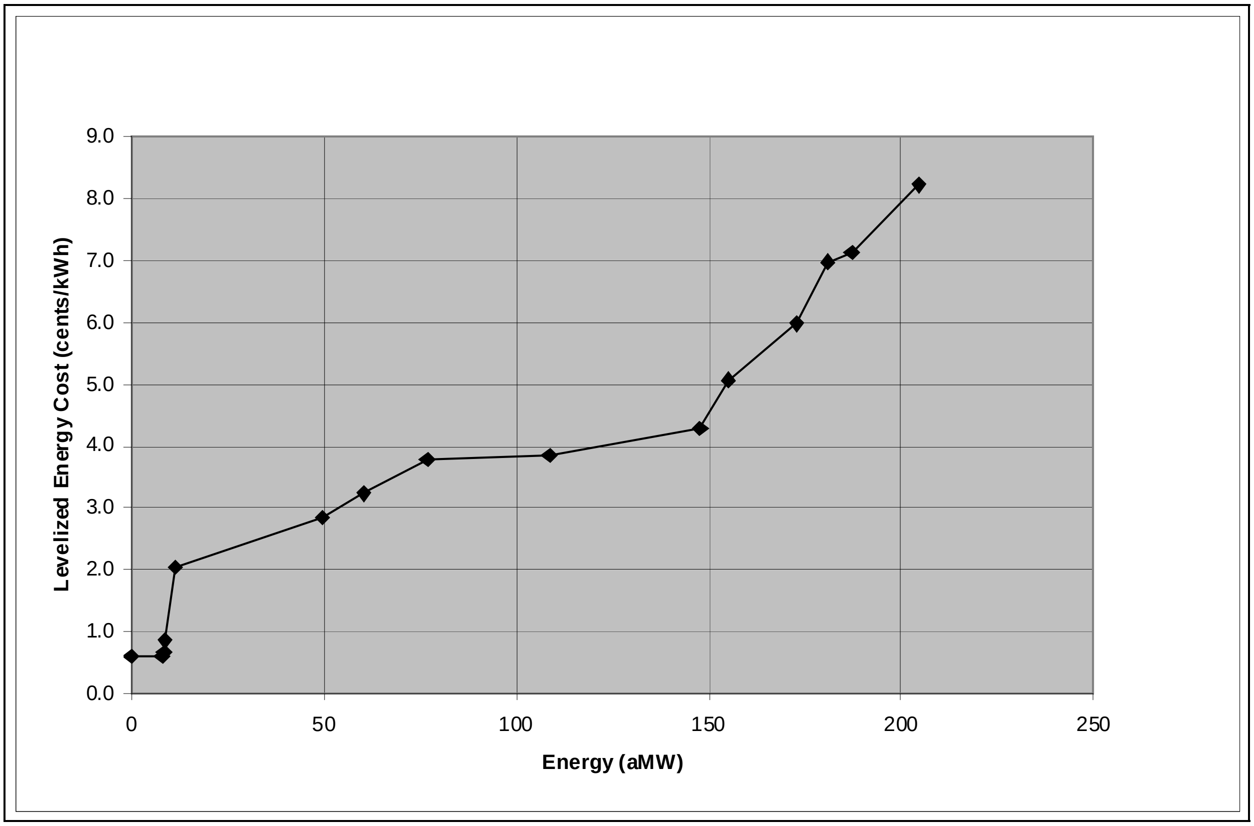
The amount of land required for a hydroelectric project depends on the type and size of the development. For large storage projects, a tremendous amount of acreage may be required. For instance, the area of the reservoir established by Grand Coulee Dam exceeds 80,000 acres (125 square miles) at normal reservoir elevation. But no new project proposals are of this magnitude. Many new development opportunities consist of addition or retrofit of generation at existing water control structures so the incremental changes in land use would be minimal. New small-scale diversion projects require land for the impoundment, diversion right-of-way, powerhouse and road and transmission access.

HYDROPOWER POTENTIAL IN THE PACIFIC NORTHWEST

In its 1991 Power Plan, the Council estimated that about 1,060 megawatts of new hydropower capacity could be developed at levelized energy costs of 7.8 cents per kilowatt-hour, or less. This capacity would supply about 510 megawatts of average energy and about 410 megawatts of firm energy. During the ensuing five years, approximately 520 megawatts of new hydropower, producing about 290 average megawatts of energy have been brought into service or placed under construction. Because of the development of hydropower since the 1991 Power Plan, and improved information regarding new project opportunities, the potential supply and cost of new hydropower was re-estimated for this draft plan.

The revised estimate of new hydropower potential is illustrated in Figure FHY-1. Approximately 480 megawatts of new hydropower capacity producing about 200 average megawatts of energy are estimated to be available at an energy cost of 8.0 cents per kilowatt-hour, or less. This capacity is estimated to be capable of producing about 160 average megawatts of firm energy. As expected, the estimated remaining potential has declined from the estimate in the 1991 plan because of the subsequent hydropower development.

Figure FHY-1
Estimated Cost and Potential Supply of New Hydropower



The levelized energy costs of Figure FHY-1 are based on a 50-year project life and the investor-owned utility financing described elsewhere in this appendix. Unlike the other resource assessments of this appendix, the cost and losses of interconnection to the central grid are not included. The costs are based on service in year 2000, but they do not include projected technology improvements or cost reductions. Tax-free municipal financing would reduce these costs by about 28 percent. Because of the capital-intensive nature of hydropower projects and the relatively short-term 15-year financing used for these estimates, costs early in the project life can be significantly greater than later-year project costs.

These estimates include some additions to existing hydropower projects, but do not include possible efficiency upgrades to existing projects. Currently available estimates of the potential for hydropower efficiency improvements are a decade old and do not reflect the upgrades that project owners have undertaken over the past decade. Nor do they reflect new technologies for improving the efficiency of hydropower projects and system operations that have become available since that time. For this reason, the Council will be reassessing the status and potential for hydropower efficiency improvements during the summer of 1996 and will report on this at a later date.

Development of the Supply Estimates

The estimate of new hydropower potential uses the approach and models developed for earlier power plans. The approach is based on estimating the probability of development for each of an inventory of potential Northwest hydropower projects. The output of each project is multiplied by this probability to obtain a probable capacity and energy contribution. These probable contributions are summed to obtain an estimate of regionwide supply potential.

The inventory of potential hydropower projects includes proposed projects within the four-state region, west of the Continental Divide that have been active in the Federal Energy Regulatory Commission licensing process. These projects are included on the Pacific Northwest Hydropower Site Data Base.[3] Physically competing proposals were excluded, as were pumped storage projects, since the latter are not net-energy producers. Projects proposed primarily for their capacity value were also excluded. The projects were screened to eliminate those likely to conflict with current federal stream protection and the Council's protected areas policy. It was assumed that no future development would occur in areas currently having federal protection, including wilderness areas, national parks, and stream reaches included in the National Wild and Scenic Rivers System. Projects not complying with the Council's protected areas policy also were eliminated from further consideration. The protected areas policy permits no new hydropower development within protected stream reaches, except for projects meeting the following criteria:

- Projects located within protected reaches, but licensed or exempted prior to August 10, 1989.
- Power additions to existing power or non-power water control structures located within protected areas.

The projects listed in Table FHY-1 passed the screens described above.

Even projects passing these screens could have environmental problems that may preclude development. Moreover, the technical characteristics of many of these sites have not been fully explored, and development may not be feasible for engineering or economic reasons. To account for these factors, probabilities of development were estimated for each project passing the institutional screens.

The development probabilities were estimated using the Hydropower Supply Model[4] developed by the Bonneville Power Administration. The Hydropower Supply Model calculates two probabilities of development for each project. One probability is based on the river resource values of the affected stream reach, taken from the River Resource Data Base.[5] The second is based on the current permitting or licensing status of the project. The lower of the two probabilities was selected as the likely probability of development for the project. This probability is shown in Table FHY-1. The likely probability of development is applied to the energy potential of the project to obtain the probable energy contribution of the project (right-hand column of Table FHY-1). The probable contributions of the individual projects are summed to obtain the regionwide potential.

Development of the Cost Estimates

Developer-supplied project cost information is available from the Northwest Hydropower Data Base for some sites where project studies have advanced to the feasibility study level. But these represent only a small proportion of the sites of Table FHY-1. Where developer-supplied information is not available, a cost model associated with the Hydropower Site Data Base was used to estimate project development costs. Neither developer-supplied nor model-estimated costs were available for some projects. The capital costs of these projects were assumed to be distributed in proportion to the capital costs of projects having capital cost estimates. As described earlier, certain projects, even though located in protected stream reaches, can be developed if they meet certain criteria. The estimated cost of developing these projects was increased by 10

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[3] The Pacific Northwest Hydropower Site data base contains the location, cost and performance information on proposed hydropower projects in the Pacific Northwest that have been submitted to the Federal Energy Regulatory Commission for permitting, licensing or exemption. The data base also includes existing hydropower projects and sites identified by the Corps of Engineers' National Hydropower Survey. Associated with the site data base are computer models for estimating project capacity, energy production and cost, where developer-supplied estimates of these parameters are unavailable. The hydro site database is part of the Northwest Environmental Infomation System maintained by the Bonneville Power Administration and the Council.

[4] Bonneville Power Administration. *Pacific Northwest Hydropower Supply Model Doumentation.* Prepared by CWC-HDR, Inc. June 1988.

[5] The River Resources data base contains stream reach ranking indices established from surveys of anadromous fish, resident fish, wildlife, natural features, cultural features, recreation and Indian cultural sites. All stream reaches most likely to be affected by new hydropower development are included in this data base. Not included are most streams that are currently protected from hydropower development by federal legislation (for example, streams located within National Wilderness Areas), and small headwater streams.

percent, because it is expected that the costs for licensing and engineering these projects would be greater than if the projects were not located in protected areas.

Project levelized energy costs were calculated using the reference financial assumptions described in the introduction to this chapter.

Planning Model Data

The Council's power system models require aggregated resource data. The estimated supply potential was aggregated into the three resource blocks described in Table F-1 for use in the Council's resource portfolio.

Table FHY-1
Potentially Developable Hydroelectric Projects

Project	FERC ID	State	County	Basin	License	Water Way	Type	Capacity (MW)	Energy (aMW)	Capital Cost ($/kW)	O&M Cost ($/kW/yr)	Energy Cost (Cents/ kWh)	Prob. of Dev.	Probable Energy Contrib.
A J Wiley	11020	ID	Twin Falls	Upper Snake	PP-EXP	Stream	New	86.0	55.4	927	19	1.5	0.10	5.5
Aldrich Creek	4295	WA	Whatcom	Puget Sound	PP-SUR	Stream	New	0.6	0.4	4102	82	6.3	0.10	0.0
Alfred Teufel Nursery	7089	OR	Washington	Willamette	LC-WDN	Stream	New	0.0	0.0	3778	76	13.1	0.85	0.0
Aloma 1 (Conconully Dam)	8677	WA	Okanogan	Upper Columbia	PP-SUR	Stream	Ex Str	0.6	0.2	4962	99	13.8	0.25	0.1
Ana Springs	5299	OR	Lake	Oregon Closed	PP-EXP	Stream	Ex Str	0.4	0.3	5752	115	8.5	0.25	0.1
Anderson Creek	10425	WA	Whatcom	Puget Sound	PP-EXP	Stream	New	2.0	1.0	2480	50	5.0	0.10	0.1
Applegate Lake	4732	OR	Jackson	Coastal	LC-DIS	Stream	Ex Str	9.1	4.3	1857	37	4.1	0.60	2.6
Arbo Creek	5486	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.2	0.1	3976	80	8.4	0.10	0.0
Arena Drop	4858	ID	Canyon	Middle Snake	EX-GTD	Canal	Ex Str	0.5	0.2	2199	44	6.7	0.95	0.2
Arrow Creek	7598	WA	Skagit	Puget Sound	PP-EXP	Stream	New	1.0	0.4	5258	105	13.9	0.10	0.0
Arrowrock Dam	04656	ID	Elmore	Middle Snake	LA-GTD	Stream	Ex Str	60.0	19.1	1196	24	4.0	0.93	17.8
Ashley Creek	7627	MT	Flathead	Kootenai	PP-EXP	Stream	New	0.4	0.2	2523	50	4.4	0.10	0.0
Bagley Creek	6415	WA	Whatcom	Puget Sound	EX-REV	Stream	Ex Str	1.9	0.8	1851	37	4.7	0.60	0.5
Barclay Creek	06310	WA	Snohomish	Puget Sound	LA-GTD	Stream	New	6.8	2.4	1568	31	4.6	0.64	1.5
Barnum Creek	5094	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.3	0.2	4169	83	8.8	0.10	0.0
Barrier Dam	11076	WA	Lewis	Lower Columbia	LC-DIS	Stream	Ex Str	9.0	6.3	3732	75	5.7	0.60	3.8
Basin Creek	06832B	MT	Silver Bow	Kootenai	PP-EXP	Stream	New	0.1	0.1	6032	121	8.0	0.10	0.0
Battle Ridge	6667	ID	Idaho	Lower Snake	LC-DIS	Stream	Ex Str	0.9	0.8	4176	84	5.0	0.51	0.4
Bear Creek	10148	WA	Snohomish	Puget Sound	PP-EXP	Stream	New	2.7	1.3	2715	54	5.7	0.10	0.1

Project	FERC ID	State	County	Basin	License	Water way	Type	Capacity (MW)	Energy (aMW)	Capital cost ($/kW)	O&M Cost ($/kW/yr)	Energy Cost (Cents/ kWh)	Prob. of Dev.	Probable Energy Contrib.
Bear Creek	10371	WA	Skagit	Puget Sound	LC-GTD	Stream	Ex Str	4.0	2.0	1130	23	2.3	0.95	1.9
Bethal Creek	5522	MT	Lake	Kootenai	PP-SUR	Stream	New	0.3	0.2	4297	86	6.6	0.10	0.0
Beulah (Agency Valley)	7286	OR	Malheur	Middle Snake	PP-SUR	Stream	Ex Str	2.0	0.6	7558	151	26.9	0.25	0.1
Beyer	6481	OR	Clackamas	Willamette	EX-SUR	Stream	Ex Str	0.0	0.0	n/av	n/av	n/av	0.97	0.0
Big Quilcene	9377	WA	Jefferson	Puget Sound	PP-SUR	Stream	Ex Str	1.0	5.7	8062	161	1.5	0.25	1.4
Birch Creek	5279	WA	Whatcom	Puget Sound	EX-REV	Stream	Ex Str	0.0	0.0	27367	547	42.1	0.60	0.0
Bitton	6742	ID	Caribou	Bear	PP-CAN	Stream	New	3.1	1.4	n/av	n/av	n/av	0.20	0.3
Black Canyon	5903	ID	Gem	Middle Snake	PP-EXP	Stream	Ex Str	24.0	7.1	1227	25	4.4	0.25	1.8
Black Creek	10950	WA	Snohomish	Puget Sound	PP-SUR	Stream	New	1.9	0.9	2932	59	6.5	0.73	0.7
Black Creek	5851	OR	Lane	Willamette	PP-SUR	Stream	New	9.0	4.6	5049	101	10.4	0.10	0.5
Blackfoot Dam	6741	ID	Caribou	Upper Snake	PP-EXP	Stream	Ex Str	1.0	0.7	5293	106	8.2	0.25	0.2
Blue Sky Creek	5664	MT	Lincoln	Kootenai	PP-SUR	Stream	New	1.0	0.7	3858	77	5.9	0.10	0.1
Bob Moore Creek	7039	ID	Lemhi	Lower Snake	PP-REJ	Stream	New	0.6	0.3	4625	93	9.4	0.20	0.1
Bond Creek	5095	MT	Lake	Kootenai	PP-SUR	Stream	New	0.3	0.2	4323	86	7.2	0.10	0.0
Bonneville Fish Attraction	07846A	OR	Multnomah	Lower Columbia	PP-REJ	Stream	Ex Str	4.0	2.5	320	6	0.5	0.20	0.5
Bonneville Fish Attraction	07846B	OR	Multnomah	Lower Columbia	PP-REJ	Stream	Ex Str	1.6	1.1	3551	71	5.4	0.20	0.2
Bonneville Fish Attraction	07846C	OR	Multnomah	Lower Columbia	PP-REJ	Stream	Ex Str	3.0	2.0	2973	59	4.6	0.20	0.4
Bonneville Fish Attraction	07846D	WA	Skamania	Lower Columbia	PP-REJ	Stream	Ex Str	3.0	2.0	2950	59	4.6	0.20	0.4
Boulder Creek	7978	MT	Granite	Kootenai	LC-DND	Stream	New	0.5	0.2	3469	69	9.4	0.10	0.0
Boulder Creek	10122	MT	Lake	Kootenai	EX-SUR	Stream	New	0.1	0.1	1549	31	2.4	0.10	0.0
Boulder Creek	5823	OR	Lane	Willamette	PP-SUR	Stream	New	4.9	2.7	2520	50	4.8	0.10	0.3
Boulder Creek	5478	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.8	0.4	n/av	n/av	n/av	0.60	0.2
Boulder Creek	6007	WA	Mason	Puget Sound	PP-EXP	Stream	New	3.0	1.4	#N/A	#N/A	#N/A	#N/A	#N/A
Boulder Creek	10213	WA	Snohomish	Puget Sound	PP-EXP	Stream	New	1.4	0.7	3603	72	7.6	0.82	0.6

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Box Creek	10816	ID	Valley	Middle Snake	PP-CAN	Stream	New	3.1	0.7	1757	35	8.6	0.20	0.1
Brown's Pond	6854	ID	Valley	Middle Snake	PP-EXP	Stream	Ex Str	0.8	0.3	7153	143	19.6	0.25	0.1
Brush Creek	5102	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.1	0.1	5909	118	10.9	0.10	0.0
Brush Creek	8130	ID	Valley	Middle Snake	PP-CAN	Stream	New	2.0	0.6	2878	58	10.6	0.20	0.1
Bull Run Creek	10115	ID	Clearwater	Lower Snake	PP-CAN	Stream	New	4.0	2.6	4059	81	6.4	0.20	0.5
Bullbucker Creek	10216	WA	Snohomish	Puget Sound	PP-CAN	Stream	New	1.5	0.8	3096	62	6.5	0.20	0.2
Bumping Lake	4890	WA	Yakima	Yakima	PP-EXP	Stream	Ex Str	31.0	18.5	1212	24	2.1	0.25	4.6
Burn Creek	10189	WA	King	Puget Sound	PP-EXP	Stream	New	3.4	1.8	1501	30	3.1	0.10	0.2
Cabin Creek	6151	WA	Jefferson	Puget Sound	LC-DIS	Stream	New	2.9	1.4	1647	33	3.7	0.60	0.8
Cadette Creek	5491	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.2	0.1	4692	94	13.8	0.10	0.0
Calligan Creek	08864	WA	King	Puget Sound	LC-GTD	Stream	New	5.4	2.5	1542	31	3.5	0.77	1.9
Camp Creek	5479	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.2	0.1	5910	118	14.8	0.10	0.0
Canyon Creek	5113	ID	Bonner	Kootenai	PP-SUR	Stream	New	0.1	0.0	7980	160	19.1	0.10	0.0
Carmen Creek	7859	ID	Lemhi	Lower Snake	PP-EXP	Stream	New	2.3	1.0	2693	54	6.6	0.10	0.1
Cascade Creek	09424	ID	Boundary	Kootenai	LC-CAN	Stream	New	0.9	0.4	2388	48	5.6	0.60	0.2
Cascade Ranch	11194B	OR	Jackson	Coastal	PP-SUR	Canal	Ex Str	0.5	0.2	2534	51	6.5	0.30	0.1
Cascade Ranch	11194A	OR	Jackson	Coastal	PP-SUR	Stream	Ex Str	0.5	0.2	3989	80	10.2	0.25	0.1
Ccl4	4887	WA	Grant	Upper Columbia	PP-SUR	Canal	Ex Str	0.6	0.4	8595	172	15.4	0.30	0.1
Cedar Creek	5780	MT	Lake	Kootenai	PP-REJ	Stream	New	0.2	0.1	7527	151	15.9	0.20	0.0
Cedar Creek	6444	MT	Lincoln	Kootenai	EX-CAN	Stream	New	1.3	1.3	3198	64	3.4	0.60	0.8
Challis Canal	9693	ID	Custer	Lower Snake	PP-SUR	Canal	New	1.6	1.3	5501	110	7.1	0.30	0.4
Chamberlin Dit Ppl Co	8150	OR	Wallowa	Lower Snake	EX-SUR	Conduit	Ex Str	0.1	0.1	8746	175	11.2	0.95	0.0
Cherry Creek	9103	OR	Benton	Willamette	LC-SUR	Stream	New	0.0	0.0	827	17	2.1	0.85	0.0
Chicopee Creek	4772	ID	Bonner	Kootenai	PP-SUR	Stream	New	0.1	0.0	15076	302	39.1	0.10	0.0

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Circle Arrow	09319	MT	Missoula	Kootenai	LC-CAN	Stream	Ex Str	0.2	0.1	1795	36	3.4	0.60	0.1
Clackamas Creeks	11265B	OR	Clackamas	Willamette	PP-PND	Stream	Ex Str	1.3	0.6	4045	81	9.7	0.25	0.1
Clark Fork Diversion	6997	MT	Mineral	Kootenai	PP-CAN	Stream	New	100.0	37.7	n/av	n/av	n/av	0.20	7.5
Clear Creek	7452	OR	Baker	Middle Snake	EX-SUR	Stream	New	0.5	0.5	6051	121	7.3	0.82	0.4
Clear Lake	4539	WA	Yakima	Yakima	LC-DIS	Stream	Ex Str	1.2	0.4	2032	41	5.9	0.60	0.3
Clearwater D + Chamberlin	8151	OR	Wallowa	Lower Snake	EX-SUR	Conduit	Ex Str	0.1	0.0	8741	175	11.2	0.95	0.0
Coffee Pot	5584	OR	Lake	Oregon Closed	PP-SUR	Stream	New	3.8	1.0	10878	218	41.9	0.10	0.1
Cold Creek	5558	MT	Missoula	Kootenai	PP-EXP	Stream	New	0.9	0.6	3219	64	4.9	0.10	0.1
Columbia Southern Canal	03466C	OR	Deschutes	Middle Columbia	PP-SUR	Canal	Ex Str	2.4	1.2	3407	68	7.3	0.30	0.4
Columbia Southern Canal	03466A	OR	Deschutes	Middle Columbia	PP-SUR	Canal	Ex Str	3.2	1.6	3480	70	7.5	0.30	0.5
Columbia Southern Canal	03466B	OR	Deschutes	Middle Columbia	PP-SUR	Stream	Ex Str	3.2	1.6	3610	72	7.7	0.25	0.4
Como Lake	9602	MT	Ravalli	Kootenai	PP-SUR	Stream	New	3.6	1.6	2518	50	6.2	0.10	0.2
Cot Creek	11127	OR	Clackamas	Willamette	PP-SUR	Stream	New	1.2	0.4	2145	43	6.8	0.10	0.0
Cottage Grove Dam	7028	OR	Lane	Willamette	PP-CAN	Stream	Ex Str	1.4	0.6	3567	71	8.4	0.20	0.1
Cotten	8082	WA	Lewis	Lower Columbia	EX-DIS	Stream	New	0.0	0.0	n/av	n/av	n/av	0.60	0.0
Cottrell	07174	WA	Skamania	Lower Columbia	LA-GTD	Stream	New	4.4	1.1	2281	46	9.8	0.49	0.5
Cougar Creek	4790	ID	Bonner	Kootenai	EX-REJ	Stream	New	0.1	0.1	n/av	n/av	n/av	0.60	0.0
Cougar Creek	7839	WA	Snohomish	Puget Sound	PP-CAN	Stream	New	1.3	0.5	4588	92	12.1	0.20	0.1
Cox's	6850	ID	Twin Falls	Upper Snake	EX-GTD	Stream	New	0.3	0.1	n/av	n/av	n/av	0.75	0.1
Crane Creek	5932	MT	Lake	Kootenai	PP-SUR	Stream	New	0.2	0.1	3425	69	5.2	0.10	0.0
Crane Prairie	3446	OR	Deschutes	Middle Columbia	PP-SUR	Stream	Ex Str	0.6	0.3	7630	153	14.6	0.25	0.1

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Crooked River	05507A	OR	Deschutes	Middle Columbia	PP-EXP	Canal	Ex Str	2.2	1.0	5876	118	14.1	0.30	0.3
Crooked River	05507B	OR	Deschutes	Middle Columbia	PP-EXP	Canal	Ex Str	1.4	0.7	3578	72	7.8	0.30	0.2
Cross Cut Diversion	03991	ID	Fremont	Upper Snake	LC-SUR	Stream	Ex Str	1.8	1.2	3833	77	5.7	0.90	1.1
Crossroads Conduit	11468	ID	Idaho	Upper Snake	PP-PND	Canal	New	3.2	1.3	n/av	n/av	n/av	0.30	0.4
Crystal Springs Hatchery	6711	ID	Gooding	Upper Snake	LC-REJ	Conduit	Ex Str	0.2	0.2	3755	75	4.4	0.60	0.1
Cummings	7817	ID	Lemhi	Lower Snake	EX-REJ	Stream	New	0.0	0.0	n/av	n/av	n/av	0.60	0.0
Curley Creek	5108	ID	Boundary	Kootenai	EX-DIS	Stream	New	0.5	0.3	3094	62	5.7	0.60	0.2
Curry Ditch	7315	OR	Baker	Middle Snake	EX-DIS	Stream	New	0.4	0.3	9007	180	15.9	0.60	0.2
Curtis Creek	5110	ID	Bonner	Kootenai	PP-SUR	Stream	New	0.1	0.0	9291	186	15.3	0.10	0.0
Cyclone Creek	5489	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.2	0.1	4722	94	11.6	0.10	0.0
Dailey Creek	7402	OR	Douglas	Coastal	EX-DIS	Stream	New	0.3	0.1	4177	84	16.5	0.60	0.0
Dalles Dam Jbs	11430	WA	Klickitat	Middle Columbia	PP-PND	Stream	Ex Str	4.0	3.4	2024	40	2.5	0.25	0.9
Damfino Creek	8479	WA	Whatcom	Puget Sound	PP-SUR	Stream	New	4.3	2.1	2520	50	5.6	0.10	0.2
Davis Creek	7182	WA	Lewis	Lower Columbia	EX-SUR	Stream	New	1.6	0.7	1338	27	3.0	0.77	0.6
Deadhorse Creek	7324	ID	Valley	Middle Snake	LC-DIS	Stream	New	0.4	0.1	2708	54	6.9	0.60	0.1
Deadwood Dam	10178	ID	Valley	Middle Snake	PP-CAN	Stream	Ex Str	5.2	2.1	1639	33	4.4	0.20	0.4
Deep Creek	5660	MT	Lincoln	Kootenai	PP-SUR	Stream	New	1.5	1.1	8441	169	12.7	0.10	0.1
Deep Creek	7836	WA	Pierce	Puget Sound	PP-CAN	Stream	New	1.3	5.0	3260	65	0.9	0.10	0.5
Deep Creek	5101	WA	Stevens	Upper Columbia	PP-SUR	Stream	New	0.2	0.1	n/av	n/av	n/av	0.75	0.1
Deep Creek	6788	ID	Twin Falls	Upper Snake	EX-SUR	Stream	New	0.3	0.1	2902	58	6.7	0.20	0.0
Deep Creek	11259	ID	Twin Falls	Upper Snake	PP-CAN	Stream	New	2.0	0.0	n/av	n/av	n/av	0.20	0.0
Deer Creek	08121	ID	Boise	Middle Snake	LC-SUR	Stream	New	0.4	0.3	957	19	1.4	0.85	0.2

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Deer Creek	8314	WA	Snohomish	Puget Sound	PP-SUR	Stream	New	2.6	1.5	1572	31	2.8	0.10	0.2
Deschutes-Tumwater	5364	WA	Thurston	Puget Sound	EX-REV	Stream	Ex Str	2.5	0.9	2309	46	6.8	0.60	0.5
Diamond Cogeneration	7166	OR	Hood River	Middle Columbia	EX-REJ	Stream	Ex Str	0.1	0.0	6486	130	9.6	0.56	0.0
Ditch Creek	6434	ID	Valley	Lower Snake	LC-PND	Stream	New	0.4	0.3	6526	131	11.1	0.85	0.2
Dodge Creek	5877	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.8	0.5	3514	70	5.4	0.10	0.1
Dorena Dam	3111	OR	Lane	Willamette	PP-SUR	Stream	Ex Str	2.9	1.7	3605	72	6.5	0.20	0.3
Dot Diversion	10928	WA	King	Puget Sound	PP-SUR	Stream	New	4.7	1.9	2861	57	7.3	0.10	0.2
Downing Creek	6804	OR	Linn	Willamette	PP-SUR	Stream	New	3.3	1.8	1886	38	3.6	0.10	0.2
Drews	05301A	OR	Lake	Sacramento	PP-EXP	Stream	New	0.3	0.1	4135	83	12.6	0.10	0.0
Drews	05301B	OR	Lake	Sacramento	PP-EXP	Canal	Ex Str	0.2	0.1	4401	88	11.0	0.30	0.0
Dry Creek	2907	MT	Mineral	Kootenai	LC-SUR	Stream	Ex Str	0.0	0.0	1830	37	2.0	0.92	0.0
Dry Creek	6460	OR	Baker	Middle Snake	EX-SUR	Stream	New	0.4	0.2	#N/A	#N/A	#N/A	#N/A	#N/A
Dry Creek (A)	05656A	MT	Lake	Kootenai	PP-DIS	Stream	Ex Str	0.5	0.2	3336	67	8.1	0.20	0.0
Dry Creek (B)	05656B	MT	Lake	Kootenai	PP-DIS	Canal	Ex Str	5.0	2.3	4285	86	9.7	0.20	0.5
Dry Ridge	6921	OR	Clackamas	Willamette	PP-SUR	Stream	New	1.4	0.9	2185	44	3.7	0.10	0.1
Dryden	7030	WA	Chelan	Upper Columbia	PP-WDN	Stream	Ex Str	4.0	2.5	4117	82	6.9	0.25	0.6
Dupris Hydro	6169	WA	Whatcom	Puget Sound	EX-REJ	Stream	New	0.0	0.0	n/av	n/av	n/av	0.60	0.0
Eagle Creek	9336	WA	Okanogan	Upper Columbia	PP-REJ	Stream	New	0.4	0.1	n/av	n/av	n/av	0.20	0.0
East Fork (B)	3891B	OR	Hood River	Middle Columbia	PP-SUR	Canal	Ex Str	3.9	2.2	1956	39	3.6	0.30	0.7
East Twin River	4735	WA	Clallum	Puget Sound	PP-EXP	Stream	New	1.5	1.0	2337	47	3.6	0.10	0.1
Easton Dam	3486	WA	Kittitas	Yakima	LC-DIS	Stream	Ex Str	1.5	0.8	2858	57	5.4	0.60	0.5
Ebey Hill	10428	WA	Snohomish	Puget Sound	EX-GTD	Stream	Ex Str	0.1	0.1	4550	91	6.9	0.92	0.1

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Eilerston Meadow	3912	OR	Baker	Middle Snake	EX-DIS	Stream	New	1.3	0.4	2478	50	7.6	0.60	0.3
El 68 Station 135+76.24	4766	WA	Adams	Upper Columbia	PP-EXP	Canal	Ex Str	0.4	0.1	11305	226	33.2	0.30	0.0
El 68 Station 31+00	4764	WA	Adams	Upper Columbia	PP-EXP	Canal	Ex Str	0.4	0.2	10749	215	29.8	0.30	0.0
El 68 Station 65+54.65	4765	WA	Adams	Upper Columbia	PP-EXP	Canal	Ex Str	0.4	0.1	12120	242	33.6	0.30	0.0
El 85 Station 125+25	4763	WA	Adams	Upper Columbia	PP-EXP	Canal	Ex Str	0.4	0.1	10146	203	28.8	0.30	0.0
El 85 Station 140+10	4768	WA	Adams	Upper Columbia	PP-EXP	Canal	Ex Str	0.4	0.2	8291	166	24.1	0.30	0.0
El85-Station 100+29.6	4762	WA	Adams	Upper Columbia	PP-EXP	Canal	Ex Str	0.4	0.1	9377	188	26.7	0.30	0.0
El85-Station 676+50	4761	WA	Franklin	Upper Columbia	PP-SUR	Canal	Ex Str	0.3	0.1	5832	117	16.7	0.30	0.0
Elk Creek Lake	10815	OR	Jackson	Coastal	PP-CAN	Stream	Ex Str	7.0	2.5	943	19	2.8	0.20	0.5
Eltopia Branch Canal 625+	4750	WA	Franklin	Upper Columbia	LC-SUR	Canal	Ex Str	0.7	0.4	2101	42	4.3	0.95	0.3
Emigrant Dam	07829B	OR	Jackson	Coastal	LA-CAN	Canal	Ex Str	0.3	0.2	2017	40	3.3	0.60	0.1
Emigrant Dam	07829A	OR	Jackson	Coastal	LA-CAN	Stream	Ex Str	1.7	0.5	3011	60	9.9	0.60	0.3
Enloe Dam	10536	WA	Okanogan	Upper Columbia	LC-PND	Stream	Ex Str	4.1	3.1	2928	59	4.1	0.70	2.1
Enterprise	10208	ID	Fremont	Upper Snake	PP-EXP	Stream	Ex Str	1.2	0.6	1895	38	3.8	0.25	0.2
Evans Lake	7834	WA	King	Puget Sound	PP-CAN	Stream	New	1.0	0.4	3966	79	10.5	0.20	0.1
Evergreen Creek	10214	WA	Snohomish	Puget Sound	PP-EXP	Stream	New	1.7	0.9	4511	90	9.5	0.10	0.1
Excelsior Creek	10152	WA	Snohomish	Puget Sound	PP-EXP	Stream	New	1.6	0.8	1250	25	2.6	0.10	0.1
Experimental Forest Hydro	4776	ID	Bonner	Kootenai	PP-SUR	Stream	New	0.1	0.0	9122	182	20.2	0.10	0.0
Fairwell Bend	5396	OR	Jackson	Coastal	PP-WDN	Stream	New	3.1	2.0	3530	71	5.8	0.10	0.2
Fall Creek	7276	ID	Power	Upper Snake	LC-DIS	Stream	New	0.2	0.1	2115	42	2.4	0.60	0.1
Fall Creek	8524	ID	Valley	Middle Snake	PP-SUR	Stream	New	3.9	0.8	1208	24	6.2	0.10	0.1
Fall Creek	9491	OR	Lane	Willamette	PP-SUR	Stream	Ex Str	1.4	0.7	6001	120	12.3	0.20	0.1
Fall Creek (Lower)	05652B	ID	Power	Upper Snake	EX-SUR	Stream	Ex Str	0.1	0.1	8035	161	11.0	0.87	0.1
Fall Creek (Upper)	05652A	ID	Power	Upper Snake	EX-SUR	Stream	Ex Str	0.1	0.0	7429	149	11.1	0.87	0.0

Project	FERC ID	State	County	Basin	License	Water way	Type	Capacity (MW)	Energy (aMW)	Capital cost ($/kW)	O&M Cost ($/kW/yr)	Energy Cost (Cents/ kWh)	Prob. of Dev.	Probable Energy Contrib.
Falls Creek	5112	ID	Bonner	Kootenai	PP-SUR	Stream	New	0.1	0.1	7266	145	13.7	0.10	0.0
Falls Creek	7674	WA	Grays Harbor	Coastal	PP-CAN	Stream	New	1.6	0.6	2894	58	7.6	0.20	0.1
Falls Creek	7969	WA	Whatcom	Puget Sound	LC-DIS	Stream	New	0.4	0.2	5618	112	11.8	0.60	0.1
Fargo Drop	5040	ID	Canyon	Middle Snake	EX-GTD	Canal	Ex Str	0.2	0.1	5153	103	12.6	0.95	0.1
Fargo Drop	5042	ID	Canyon	Middle Snake	EX-GTD	Canal	Ex Str	0.7	0.3	2089	42	5.2	0.95	0.3
Fern Ridge Dam	7029	OR	Lane	Willamette	PP-SUR	Stream	Ex Str	2.7	1.1	3357	67	8.8	0.25	0.3
Fisher Creek	6895	ID	Valley	Middle Snake	LC-DIS	Stream	New	4.8	3.2	4524	90	7.2	0.60	1.9
Flat Creek	5483	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.2	0.1	16414	328	32.4	0.10	0.0
Flower Creek	5468	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.4	0.2	5541	111	12.3	0.10	0.0
Foundation Creek	5663	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.4	0.2	4351	87	6.6	0.10	0.0
Freeman Creek	8229	ID	Lemhi	Lower Snake	PP-SUR	Stream	New	1.2	0.9	2958	59	4.4	0.10	0.1
Freeway Drop	11179	ID	Elmore	Upper Snake	PP-SUR	Canal	New	1.6	0.9	n/av	n/av	n/av	0.30	0.3
French Cabin Creek	9584	WA	Kittitas	Yakima	PP-WDN	Stream	New	2.9	1.2	2635	53	6.9	0.10	0.1
Frenchman Hills Wasteway	6118	WA	Grant	Upper Columbia	PP-SUR	Canal	New	0.2	0.1	6249	125	12.8	0.30	0.0
Frenchman Hills Wasteway	6121	WA	Grant	Upper Columbia	PP-SUR	Canal	New	0.4	0.2	4058	81	7.7	0.30	0.1
Galbraith/Wria 010373	10932	WA	Whatcom	Puget Sound	PP-SUR	Stream	New	3.4	1.6	2104	42	4.7	0.10	0.2
Gerber Reservoir	6406	OR	Josephine	North Coastal	PP-SUR	Stream	Ex Str	0.7	0.2	3041	61	11.4	0.25	0.0
Gill Creek	7833	WA	Chelan	Upper Columbia	PP-CAN	Stream	New	1.0	0.4	3713	74	9.8	0.20	0.1
Glenwood A	11483A	WA	Klickitat	Middle Columbia	PP-PND	Stream	Ex Str	0.1	0.0	n/av	n/av	n/av	0.25	0.0
Glenwood B	11483B	WA	Klickitat	Middle Columbia	PP-PND	Stream	Ex Str	0.1	0.0	n/av	n/av	n/av	0.25	0.0
Goblin Creek	10398	WA	Snohomish	Puget Sound	PP-SUR	Stream	New	0.8	0.4	8093	162	17.2	0.10	0.0
Gold Creek	5482	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.2	0.1	9298	186	30.5	0.10	0.0

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Gold Hill	3210	OR	Jackson	Coastal	LC-DIS	Stream	Ex Str	3.0	2.4	1377	28	1.8	0.53	1.3
Gold Ray	3918	OR	Jackson	Coastal	PP-SUR	Stream	Ex Str	9.0	4.6	544	11	1.1	0.25	1.1
Golden Gate	5039	ID	Canyon	Middle Snake	EX-GTD	Conduit	Ex Str	0.7	0.3	2970	59	7.0	0.95	0.3
Goldsborough Creek	7018	WA	Mason	Puget Sound	PP-EXP	Stream	Ex Str	0.4	0.2	4010	80	10.7	0.25	0.0
Grand View	11075	ID	Owyhee	Middle Snake	PP-GTD	Canal	New	0.9	0.3	2972	59	8.2	0.65	0.2
Grandy Creek Trib No 1	10287A	WA	Skagit	Puget Sound	PP-SUR	Stream	New	2.5	1.3	1963	39	4.1	0.10	0.1
Granite Peak	5939	WA	Ferry	Upper Columbia	EX-REJ	Stream	Ex Str	0.1	0.0	9205	184	24.3	0.60	0.0
Greenwood	8667	ID	Jerome	Upper Snake	EX-REJ	Canal	New	2.4	2.4	6138	123	6.7	0.60	1.4
Greider Creek	7644	WA	Snohomish	Puget Sound	PP-CAN	Stream	New	0.9	0.3	3006	60	8.0	0.20	0.1
Gresham Bros Lake Creek 3	7032	ID	Shoshone	Kootenai	PP-SUR	Stream	New	0.2	0.1	3573	71	5.6	0.10	0.0
Groom Creek	5733	MT	Lake	Kootenai	PP-SUR	Stream	New	0.4	0.3	2957	59	4.5	0.10	0.0
Haggerman	6157	ID	Gooding	Upper Snake	LC-DIS	Conduit	New	0.1	0.1	6262	125	7.4	0.60	0.1
Hall Creek	5098	MT	Lake	Kootenai	PP-EXP	Stream	New	0.4	0.2	3577	72	6.3	0.10	0.0
Hancock Creek	9025	WA	King	Puget Sound	LC-GTD	Stream	New	6.3	2.6	1625	33	4.1	0.77	2.0
Hansen Creek	7840	WA	King	Puget Sound	PP-CAN	Stream	New	1.4	0.5	2970	59	7.9	0.20	0.1
Harry Nelson	10540	ID	Washington	Middle Snake	PP-EXP	Stream	Ex Str	4.5	2.3	852	17	1.7	0.25	0.6
Harvey Creek	7606	WA	Pend Oreille	Kootenai	PP-SUR	Stream	New	0.7	0.5	4946	99	7.5	0.10	0.0
Haystack	3827	OR	Jefferson	Middle Columbia	PP-EXP	Canal	Ex Str	2.5	1.0	1749	35	4.5	0.30	0.3
Headworks Conduit	11469	ID	Jerome	Upper Snake	PP-GTD	Canal	Ex Str	4.5	2.1	7749	155	17.2	0.65	1.4
Helena Creek	10194	WA	Snohomish	Puget Sound	PP-EXP	Stream	New	2.2	1.7	3579	72	4.9	0.10	0.2
Hellroaring Creek	5109	ID	Boundary	Kootenai	PP-SUR	Stream	New	0.1	0.1	7346	147	14.9	0.10	0.0
Hertzinger	11204	ID	Twin Falls	Upper Snake	PP-EXP	Stream	Ex Str	0.2	0.0	n/av	n/av	n/av	0.25	0.0
Hidden Springs	7878	ID	Gooding	Upper Snake	EX-SUR	Stream	Ex Str	0.1	0.0	4700	94	10.3	0.87	0.0

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Highland Creek	5106	ID	Boundary	Kootenai	PP-SUR	Stream	New	0.2	0.1	4404	88	8.7	0.10	0.0
Hill-Hagerman	8481	ID	Gooding	Upper Snake	EX-REJ	Stream	New	0.1	0.1	11288	226	11.9	0.60	0.0
Hiram M Chittenden Locks	3733	WA	King	Puget Sound	PP-SUR	Stream	Ex Str	5.0	2.6	3562	71	7.1	0.25	0.7
Hollister	11098	ID	Twin Falls	Upper Snake	PP-SUR	Canal	Ex Str	4.9	1.3	n/av	n/av	n/av	0.30	0.4
Home	8202	WA	Lewis	Lower Columbia	EX-DIS	Stream	New	0.0	0.0	n/av	n/av	n/av	0.60	0.0
Honeymoon Creek	6858	MT	Sanders	Kootenai	PP-EXP	Stream	New	1.0	0.3	2716	54	8.3	0.10	0.0
Howard Creek	10151	WA	Snohomish	Puget Sound	PP-EXP	Stream	New	3.8	1.7	1259	25	2.9	0.10	0.2
Howard Hanson	09975A	WA	King	Puget Sound	PP-EXP	Stream	Ex Str	2.5	1.6	2068	41	3.4	0.20	0.3
Howard Prairie	4479	OR	Jackson	North Coastal	PP-EXP	Stream	Ex Str	0.2	0.1	14620	292	23.3	0.25	0.0
Hubbart Dam	5654	MT	Flathead	Kootenai	PP-SUR	Stream	Ex Str	0.3	0.1	9867	197	37.4	0.20	0.0
Huckleberry Creek	6979	OR	Lane	Willamette	PP-REJ	Stream	New	5.7	5.6	1433	29	1.5	0.20	1.1
Independence Creek	5487	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.1	0.1	6709	134	14.1	0.10	0.0
Indian Springs	5100	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.4	0.2	3250	65	7.6	0.10	0.0
Irene Creek	10100	WA	Skagit	Puget Sound	LC-PND	Stream	New	6.5	3.0	1392	28	3.2	0.85	2.6
Iron Creek	7600	WA	Skagit	Puget Sound	PP-CAN	Stream	New	2.8	1.1	1561	31	4.1	0.20	0.2
Jim Creek	6540	WA	Snohomish	Puget Sound	PP-CAN	Stream	New	3.8	2.3	1484	30	2.6	0.20	0.5
Johnson Creek	10217	WA	Snohomish	Puget Sound	PP-EXP	Stream	New	2.5	1.3	1808	36	3.8	0.10	0.1
Jones + Sandy Ranch	4188	ID	Gooding	Upper Snake	EX-GTD	Stream	Ex Str	0.1	0.1	4764	95	4.7	0.92	0.1
Jore	8601	MT	Lake	Kootenai	LC-SUR	Stream	New	1.0	0.4	1425	29	4.2	0.85	0.3
Jug Creek	8523	ID	Valley	Middle Snake	PP-SUR	Stream	New	1.5	0.3	1878	38	9.6	0.10	0.0
Juntura	7289	OR	Malheur	Middle Snake	PP-SUR	Stream	Ex Str	3.0	0.8	1336	27	5.3	0.25	0.2
K.I.D. Upper 'C' Drop	6407	OR	Josephine	North Coastal	PP-EXP	Canal	Ex Str	0.8	0.3	3037	61	7.9	0.30	0.1
Kachess Dam	8713	WA	Kittitas	Yakima	PP-SUR	Stream	Ex Str	4.4	1.2	1605	32	6.3	0.25	0.3
Keechelus To Kachess	8706	WA	Kittitas	Yakima	PP-SUR	Stream	Ex Str	3.3	2.5	7546	151	10.4	0.20	0.5

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Kelley Creek	5099	ID	Shoshone	Kootenai	PP-SUR	Stream	New	0.1	0.1	23176	464	42.9	0.10	0.0
Keokee Creek	4780	ID	Bonner	Kootenai	PP-EXP	Stream	New	0.1	0.0	17725	355	43.3	0.10	0.0
Kidney Creek	5204	WA	Whatcom	Puget Sound	PP-EXP	Stream	New	4.0	1.7	4704	94	11.6	0.10	0.2
Kilborn Creek	6477	WA	Lewis	Lower Columbia	EX-DND	Stream	New	0.9	0.7	2621	52	3.7	0.60	0.4
King Hill/Draper	6472	ID	Elmore	Middle Snake	EX-SUR	Canal	New	0.2	0.1	2979	60	6.3	0.95	0.1
Kinney Lake	8040	OR	Wallowa	Lower Snake	PP-CAN	Canal	Ex Str	1.3	0.6	3152	63	7.1	0.20	0.1
Kirby Dam	10111	ID	Elmore	Middle Snake	LC-DIS	Stream	Ex Str	0.7	0.2	2311	46	8.4	0.60	0.1
Kirtley-York	7318	ID	Blane	Upper Snake	EX-REV	Stream	Ex Str	0.6	0.4	370	7	0.6	0.60	0.2
Kootenai Creek	8370	MT	Ravalli	Kootenai	PP-CAN	Stream	New	1.8	0.8	1080	22	2.7	0.20	0.2
Kopsi Creek	5661	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.5	0.3	3091	62	4.7	0.10	0.0
Ktfi Creek	6663	ID	Twin Falls	Upper Snake	EX-SUR	Stream	Ex Str	0.0	0.0	n/av	n/av	n/av	0.87	0.0
Lava Creek	7819	ID	Butte	Upper Snake	PP-SUR	Stream	New	0.5	0.3	3888	78	7.1	0.10	0.0
Lemah Creek	6382	ID	Valley	Middle Snake	EX-REJ	Stream	New	0.6	0.3	1231	25	2.7	0.60	0.2
Lena Creek	6287	WA	Jefferson	Puget Sound	LC-DND	Stream	New	5.0	2.7	1611	32	3.2	0.60	1.6
Lime Creek	5097	MT	Lake	Kootenai	PP-SUR	Stream	New	0.1	0.1	8652	173	16.0	0.10	0.0
Lincoln Bypass	11063B	ID	Lincoln	Upper Snake	PP-EXP	Canal	New	2.5	0.9	1552	31	4.5	0.30	0.3
Lincoln Bypass	11063A	ID	Lincoln	Upper Snake	PP-EXP	Canal	Ex Str	3.8	1.4	2694	54	7.8	0.30	0.4
Little Goose Creek	6381	ID	Adams	Lower Snake	EX-WDN	Stream	New	0.7	0.3	2412	48	6.1	0.82	0.3
Little Mashel	10987	WA	Pierce	Puget Sound	PP-SUR	Stream	Ex Str	2.0	0.9	n/av	n/av	n/av	0.25	0.2
Little North Fork	5467	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.2	0.1	n/av	n/av	n/av	0.10	0.0
Little Rattler	4606	WA	Yakima	Yakima	PP-SUR	Stream	Ex Str	12.4	6.8	n/av	n/av	n/av	0.25	1.7
Little Sardine Creek	6989	OR	Marion	Willamette	PP-SUR	Stream	New	0.3	0.2	5382	108	11.4	0.10	0.0
Little Wolf Creek	6286	WA	Okanogan	Upper Columbia	PP-EXP	Canal	Ex Str	0.1	0.1	8986	180	9.5	0.30	0.0
Loch Katrine	7602	WA	King	Puget Sound	PP-CAN	Stream	New	1.1	0.5	4129	83	10.9	0.20	0.1

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Long Canyon Creek	7952	ID	Boundary	Kootenai	PP-CAN	Stream	New	6.5	2.2	4417	88	14.0	0.20	0.4
Long Canyon Creek	9475	ID	Boundary	Kootenai	PP-CAN	Stream	New	6.5	2.2	2507	50	7.9	0.20	0.4
Long Lake	4767	WA	Lincoln	Upper Columbia	PP-SUR	Canal	Ex Str	67.6	30.5	1691	34	3.9	0.30	9.2
Long Lake Dam(Pinto)	7065	WA	Lincoln	Upper Columbia	PP-WDN	Canal	Ex Str	67.6	30.5	991	20	2.3	0.30	9.2
Long Lake Second Powerhouse	10711	WA	Lincoln	Kootenai	PP-EXP	Stream	Ex Str	50.0	10.7	n/av	n/av	n/av	0.20	2.1
Longmire	3889	WA	Lewis	Puget Sound	PP-DND	Stream	Ex Str	0.8	0.6	1175	24	1.7	0.20	0.1
Lookout-Fossil Creek	10432	WA	Whatcom	Puget Sound	PP-CAN	Stream	New	1.5	0.6	2455	49	6.7	0.20	0.1
Lost Creek	6799	OR	Lane	Willamette	PP-EXP	Stream	New	3.2	2.8	4089	82	4.9	0.20	0.6
Lost Creek	6529	WA	Snohomish	Puget Sound	PP-CAN	Stream	New	2.3	1.2	4029	81	8.5	0.10	0.1
Louie Creek	8379	ID	Valley	Middle Snake	PP-SUR	Stream	New	3.6	1.8	3319	66	7.0	0.10	0.2
Low Head	10237	WA	Adams	Upper Columbia	LC-WDN	Canal	Ex Str	0.2	0.1	1117	22	2.9	0.95	0.1
Low Head 2	10238	WA	Adams	Upper Columbia	LC-WDN	Canal	Ex Str	0.2	0.1	19543	391	51.6	0.95	0.1
Low Head 3	10239	WA	Adams	Upper Columbia	LC-WDN	Canal	Ex Str	0.2	0.1	1117	22	2.9	0.95	0.1
Low Line No 8	5056	ID	Canyon	Middle Snake	EX-GTD	Canal	Ex Str	0.4	0.2	3841	77	8.9	0.95	0.2
Lowe Creek	10145	WA	King	Puget Sound	PP-EXP	Stream	New	1.7	0.9	2573	51	5.4	0.10	0.1
Lower Bagley Creek	7393	WA	Whatcom	Puget Sound	LC-DIS	Stream	New	1.5	0.6	2548	51	7.1	0.60	0.3
Lower Berry Creek	5880	ID	Bonner	Kootenai	PP-SUR	Stream	New	0.3	0.1	4457	89	10.0	0.10	0.0
Lower Cedar Creek	11062	ID	Custer	Upper Snake	PP-PND	Stream	New	2.7	1.7	3960	79	6.7	0.10	0.2
Lower Crow Creek	05208B	MT	Lake	Kootenai	PP-DIS	Stream	Ex Str	1.3	0.5	1654	33	4.2	0.20	0.1
Lower Crow Creek	05208A	MT	Lake	Kootenai	PP-DIS	Stream	New	1.0	0.5	4174	83	8.8	0.20	0.1
Lower Deer	9496	ID	Canyon	Middle Snake	PP-SUR	Canal	New	1.3	0.5	3368	67	9.3	0.30	0.1
Lower Horton Creek	4777	ID	Bonner	Kootenai	EX-REJ	Stream	New	0.3	0.1	2984	60	11.3	0.60	0.1
Lower Jerome Conduit	11470B	ID	Jerome	Upper Snake	PP-PND	Canal	Ex Str	1.4	3.6	n/av	n/av	n/av	0.30	1.1

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Lower South Lion Creek	4775	ID	Bonner	Kootenai	EX-REJ	Stream	New	0.6	0.2	2048	41	7.3	0.60	0.1
Lower Tenmile Creek	5476	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.2	0.1	12854	257	30.0	0.10	0.0
Magic Dam	03407	ID	Blane	Upper Snake	LA-GTD	Stream	Ex Str	9.0	3.2	825	17	2.5	0.93	2.9
Magic Springs	4159	ID	Gooding	Upper Snake	PP-REJ	Stream	Ex Str	10.0	2.3	n/av	n/av	n/av	0.20	0.5
Magic Water	11454	ID	Twin Falls	Upper Snake	PP-PND	Stream	Ex Str	0.1	0.1	4373	87	5.1	0.25	0.0
Mahoney Springs Minor	1815	MT	Lincoln	Kootenai	RL-SUR	Stream	New	0.0	0.0	n/av	n/av	n/av	0.85	0.0
Main Canal No 10	5041	ID	Canyon	Middle Snake	EX-GTD	Canal	Ex Str	0.5	0.2	5490	110	12.0	0.95	0.2
Main Canal No 6	5038	ID	Ada	Middle Snake	EX-GTD	Conduit	Ex Str	1.1	0.5	3524	70	8.2	0.95	0.5
Malad High Drop	11134	ID	Gooding	Upper Snake	PP-EXP	Stream	New	5.9	2.4	1051	21	2.7	0.10	0.2
Mann Creek	6400	ID	Washington	Middle Snake	PP-EXP	Stream	Ex Str	0.4	0.2	4010	80	9.7	0.25	0.0
Manson	4269	WA	Chelan	Upper Columbia	PP-EXP	Stream	Ex Str	1.8	1.6	n/av	n/av	n/av	0.25	0.4
Marble Creek	09656	ID	Shoshone	Kootenai	LA-GTD	Stream	New	3.2	1.1	3594	72	10.6	0.65	0.7
Marsh Valley	8871	ID	Bannock	Upper Snake	EX-REJ	Canal	Ex Str	1.7	0.8	1772	35	3.9	0.60	0.5
Mason Dam	03459	OR	Baker	Middle Snake	LA-GTD	Stream	Ex Str	2.6	0.8	1171	23	4.0	0.94	0.8
McCoy Creek	10558	WA	Snohomish	Puget Sound	PP-WDN	Stream	Ex Str	0.2	0.2	4147	83	4.4	0.20	0.0
McCully Creek	5608	OR	Wallowa	Lower Snake	EX-REV	Canal	Ex Str	0.2	0.1	7787	156	19.7	0.60	0.1
McFadden	5080	ID	Gooding	Upper Snake	EX-SUR	Stream	Ex Str	0.2	0.1	5844	117	10.4	0.80	0.1
McGowan Hydro	6331	WA	Pacific	Lower Columbia	EX-SUR	Stream	Ex Str	0.0	0.0	15912	318	22.7	0.87	0.0
McKay Dam	3867	OR	Umatilla	Middle Columbia	PP-EXP	Stream	Ex Str	2.3	0.5	1497	30	6.7	0.25	0.1
Meadow Creek	7666	WA	Snohomish	Puget Sound	PP-CAN	Stream	New	3.5	1.4	3268	65	8.6	0.20	0.3
Middle Fork Snoqualmie R.	10356D	WA	King	Puget Sound	PP-CAN	Stream	New	2.1	1.0	4342	87	9.2	0.20	0.2
Middle Parsnip Creek	5481	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.1	0.0	50545	1011	109.1	0.10	0.0
Mile-28	10552	ID	Jerome	Upper Snake	LC-GTD	Canal	New	1.5	0.8	4914	98	9.8	0.95	0.8

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Mill City Diversion	4408	OR	Marion	Willamette	PP-WDN	Stream	Ex Str	60.0	30.1	1654	33	3.5	0.25	7.5
Mill Creek Waterpower	5899	WA	Kittitas	Yakima	PP-EXP	Stream	New	0.2	0.1	5848	117	13.9	0.10	0.0
Mission Dam	5653	MT	Lake	Kootenai	PP-DIS	Stream	Ex Str	0.3	0.1	5178	104	11.0	0.20	0.0
Mora Canal Drop	3403	ID	Ada	Middle Snake	EX-GTD	Canal	Ex Str	1.9	0.9	2623	52	5.7	0.95	0.9
Morris Creek	4778	ID	Bonner	Kootenai	PP-SUR	Stream	New	0.2	0.1	9815	196	20.4	0.10	0.0
N Unit Canal Mile 45	03828A	OR	Jefferson	Middle Columbia	PP-EXP	Canal	Ex Str	2.2	0.9	1641	33	4.4	0.30	0.3
N Unit Canal Mile 51	03828B	OR	Jefferson	Middle Columbia	PP-EXP	Canal	Ex Str	1.9	0.7	1871	37	5.1	0.30	0.2
Nampa	09121A	ID	Canyon	Middle Snake	PP-WDN	Canal	Ex Str	4.0	1.8	1777	36	4.1	0.30	0.5
Nampa	09121B	ID	Canyon	Middle Snake	PP-WDN	Canal	Ex Str	4.0	1.8	1735	35	4.0	0.30	0.5
Nancy No 3	7788	WA	Pend Oreille	Kootenai	PP-SUR	Stream	New	0.2	0.2	4948	99	6.1	0.10	0.0
Napoleon Gulch	5513	MT	Lincoln	Kootenai	PP-WDN	Stream	New	0.1	0.1	4085	82	9.0	0.10	0.0
Nespelem River	5711	WA	Okanogan	Upper Columbia	PP-SUR	Stream	Ex Str	1.8	1.0	2636	53	4.9	0.25	0.3
Nevada Creek	4698	MT	Powell	Kootenai	PP-SUR	Stream	Ex Str	1.5	0.3	869	17	4.2	0.25	0.1
New Prospect	10206	OR	Jackson	Coastal	PP-CAN	Stream	New	16.0	11.1	1881	38	2.9	0.20	2.2
New Willamette Falls	5830	OR	Clackamas	Willamette	PP-SUR	Stream	Ex Str	60.0	34.9	2617	52	4.7	0.25	8.7
Newman Ranch	9867	ID	Lemhi	Upper Snake	EX-REJ	Stream	Ex Str	0.1	0.1	11811	236	20.3	0.60	0.1
Ng Rock Creek #5	7185	ID	Shoshone	Kootenai	PP-SUR	Stream	New	0.2	0.1	3836	77	4.8	0.10	0.0
North Boulder Creek	9060	OR	Clackamas	Lower Columbia	PP-SUR	Stream	New	3.1	1.7	1480	30	2.8	0.10	0.2
North Fork	7294	OR	Jackson	Coastal	EX-SUR	Stream	New	3.4	2.1	2609	52	4.4	0.69	1.5
North Fork Flume Creek	5278	WA	Pend Oreille	Kootenai	EX-SUR	Stream	Ex Str	0.1	0.1	11836	237	20.8	0.87	0.1
North Fork Payette	9120	ID	Valley	Middle Snake	PP-WDN	Stream	New	13.0	6.8	2945	59	5.9	0.10	0.7
North Fork Snoqualmie-Tokul	05926B	WA	King	Puget Sound	LC-REJ	Stream	Ex Str	20.0	14.8	8823	176	12.6	0.60	8.9

Project	FERC ID	State	County	Basin	License	Water way	Type	Capacity (MW)	Energy (aMW)	Capital cost ($/kW)	O&M Cost ($/kW/yr)	Energy Cost (Cents/ kWh)	Prob. of Dev.	Probable Energy Contrib.
North Meadow Creek	5470	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.2	0.1	7155	143	14.9	0.10	0.0
North Side Jerome	11050A	ID	Jerome	Upper Snake	EX-PND	Canal	New	4.3	2.1	3975	80	8.4	0.95	2.0
North Side Jerome	11050C	ID	Jerome	Upper Snake	EX-PND	Canal	New	3.7	1.9	3075	62	6.2	0.95	1.8
North Sitkum Hydroelectric	7098	WA	Clallum	Coastal	EX-SUR	Stream	New	2.7	1.9	4551	91	6.9	0.82	1.5
O'brien Creek	5475	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.3	0.1	5540	111	12.1	0.10	0.0
Oakley Dam	5407	ID	Cassia	Upper Snake	PP-SUR	Stream	Ex Str	0.8	0.3	3417	68	9.3	0.25	0.1
Ochoco	3378	OR	Crook	Middle Columbia	PP-EXP	Stream	Ex Str	2.4	0.6	2019	40	8.6	0.25	0.1
Ochoco Dam	3532	OR	Crook	Middle Columbia	PP-SUR	Stream	Ex Str	1.6	0.5	3285	66	12.1	0.25	0.1
Ollalie Creek	6692	OR	Linn	Willamette	PP-SUR	Stream	New	4.6	3.9	1908	38	2.4	0.10	0.4
Olson Creek	10141	WA	Skagit	Puget Sound	LC-GTD	Stream	New	0.2	0.1	5251	105	8.0	0.64	0.1
Orofino Falls	11208	ID	Clearwater	Lower Snake	PP-REV	Stream	New	2.2	1.0	n/av	n/av	n/av	0.20	0.2
Overholt Creek	7831	OR	Grant	Middle Columbia	EX-DIS	Stream	New	0.0	0.1	63608	1272	7.5	0.60	0.1
Owsley Feeder	11492	ID	Jefferson	Upper Snake	PP-PND	Canal	New	1.0	0.6	5247	105	8.8	0.30	0.2
Oxbow Bypass	11123	OR	Baker	Middle Snake	PP-GTD	Stream	Ex Str	0.8	0.8	2032	41	2.2	0.50	0.4
P.E. 16.4 Wasteway Hendricks	04355B	WA	Franklin	Upper Columbia	PP-EXP	Canal	Ex Str	0.3	0.3	10527	211	12.2	0.30	0.1
P.E. 16.4 Wasteway Hendricks	7092	WA	Franklin	Upper Columbia	PP-EXP	Canal	Ex Str	0.8	0.6	5505	110	7.8	0.30	0.2
P.E.C. Station 1973+00	4749	WA	Franklin	Upper Columbia	LC-SUR	Canal	Ex Str	1.9	0.9	4055	81	8.9	0.95	0.9
Painted Rocks Dam	9364	MT	Ravalli	Kootenai	LC-WDN	Stream	Ex Str	5.0	1.5	748	15	2.6	0.90	1.4
Palisades Capacity Add.	11131	ID	Bonneville	Upper Snake	PP-PND	Stream	Ex Str	90.0	18.0	998	20	5.3	0.20	3.6
Panhandle	8737	ID	Boundary	Kootenai	PP-CAN	Stream	New	2.0	1.2	2949	59	5.2	0.20	0.2

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Payette Lake Outlet	11129	ID	Valley	Middle Snake	PP-EXP	Stream	Ex Str	0.2	0.1	29856	597	67.1	0.20	0.0
Peek-A-Boo Creek	7601	WA	Snohomish	Puget Sound	PP-EXP	Stream	New	0.9	0.4	4300	86	11.3	0.10	0.0
Pheasant Creek	5480	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.1	0.1	n/av	n/av	n/av	0.10	0.0
Phillips Ditch	8917	OR	Baker	Middle Snake	PP-CAN	Stream	New	0.3	0.2	5533	111	9.9	0.20	0.0
Pine Creek	8094	OR	Baker	Middle Snake	PP-CAN	Stream	New	1.7	1.1	3356	67	5.5	0.20	0.2
Pines Hydro	9940	ID	Custer	Lower Snake	PP-CAN	Stream	New	0.9	0.6	7925	159	12.0	0.20	0.1
Porcupine Creek	5521	MT	Lake	Kootenai	PP-SUR	Stream	New	0.3	0.2	3717	74	5.7	0.10	0.0
Post Creek	05655B	MT	Lake	Kootenai	PP-DIS	Stream	Ex Str	1.5	0.8	3891	78	7.8	0.20	0.2
Post Creek	05655A	MT	Lake	Kootenai	PP-DIS	Stream	New	0.4	0.2	2729	55	7.5	0.20	0.0
Potholes Canal Chute	4748	WA	Franklin	Upper Columbia	PP-REJ	Canal	Ex Str	10.2	4.3	1235	25	3.1	0.20	0.9
Potholes E Canal Sta 1720+44	4711	WA	Franklin	Upper Columbia	PP-EXP	Canal	Ex Str	0.7	0.3	3642	73	8.9	0.30	0.1
Potholes Headwork Sta 134+52	4760	WA	Grant	Upper Columbia	PP-REJ	Canal	Ex Str	8.0	3.6	2244	45	5.3	0.20	0.7
Prairie Creek	9495	WA	Pierce	Puget Sound	PP-WDN	Stream	Ex Str	4.2	2.2	2653	53	5.5	0.25	0.5
Pratt Creek	9247	ID	Lemhi	Lower Snake	EX-SUR	Stream	Ex Str	0.3	0.2	3814	76	6.7	0.87	0.2
Price Creek	7940	WA	Whatcom	Puget Sound	EX-DIS	Stream	New	1.9	1.1	3077	62	5.7	0.60	0.6
Prineville	10998	OR	Crook	Middle Columbia	PP-SUR	Stream	Ex Str	2.9	1.9	1728	35	2.7	0.20	0.4
Prospect No 5	11004	OR	Jackson	Coastal	PP-EXP	Stream	New	12.5	10.4	4238	85	5.4	0.10	1.0
Railroad Creek	6758	WA	Chelan	Upper Columbia	LC-SUR	Stream	New	0.3	0.3	14143	283	16.2	0.85	0.3
Rainbow Creek	7097	WA	Clallum	Coastal	EX-SUR	Stream	New	3.0	2.1	2985	60	4.5	0.82	1.7
Rangen Research	4160	ID	Gooding	Upper Snake	PP-SUR	Canal	Ex Str	0.2	0.2	3732	75	4.4	0.30	0.1
Rattlesnake Mile 4	8117	WA	Yakima	Yakima	PP-EXP	Stream	Ex Str	3.0	1.5	n/av	n/av	n/av	0.25	0.4
Ray Miller Creek	5096	ID	Shoshone	Kootenai	PP-SUR	Stream	New	0.2	0.1	5494	110	9.7	0.10	0.0

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Reeds Creek	10607	ID	Clearwater	Lower Snake	PP-EXP	Stream	New	4.8	1.7	3455	69	10.1	0.10	0.2
Resort Creek	5883	WA	Kittitas	Yakima	PP-SUR	Stream	New	0.4	0.2	4337	87	9.7	0.10	0.0
Rim View	9543	ID	Gooding	Upper Snake	EX-GTD	Conduit	Ex Str	0.3	0.2	3686	74	4.5	0.95	0.2
Rim View	09543B	ID	Gooding	Upper Snake	EX-GTD	Conduit	Ex Str	0.3	0.2	3301	66	4.0	0.95	0.2
Ririe	10750	ID	Bonneville	Upper Snake	PP-CAN	Stream	Ex Str	4.0	2.3	1385	28	2.6	0.20	0.5
Riser Creek	8251	ID	Bonner	Kootenai	PP-EXP	Stream	New	0.5	0.2	2787	56	6.5	0.10	0.0
Riverdale	10777	ID	Franklin	Bear	PP-CAN	Stream	Ex Str	5.2	2.2	941	19	2.3	0.20	0.4
Roaring Creek	5882	WA	Chelan	Upper Columbia	PP-SUR	Stream	New	0.6	0.3	3162	63	7.1	0.10	0.0
Roaring River	7176	OR	Clackamas	Willamette	PP-SUR	Stream	New	7.0	3.4	2295	46	4.9	0.10	0.3
Rock Creek	4217	WA	Mason	Puget Sound	PP-EXP	Stream	New	1.8	0.7	3776	76	10.3	0.10	0.1
Rock Creek	8658	MT	Powell	Kootenai	PP-SUR	Stream	Ex Str	2.6	2.3	1679	34	2.0	0.25	0.6
Rocky Coolee	07474A	WA	Grant	Upper Columbia	PP-EXP	Canal	Ex Str	3.5	1.5	2485	50	6.0	0.30	0.5
Rocky Coulee Wasteway Lower	07474B	WA	Grant	Upper Columbia	PP-EXP	Canal	Ex Str	3.8	1.6	1896	38	4.6	0.30	0.5
Rocky Run Cr	5884	WA	Kittitas	Yakima	PP-SUR	Stream	New	0.5	0.2	3863	77	10.4	0.10	0.0
Royal Catfish	8795	ID	Jerome	Upper Snake	LC-DIS	Conduit	Ex Str	3.1	2.8	1989	40	2.3	0.60	1.7
Royal Lake	8172	WA	Adams	Upper Columbia	PP-SUR	Canal	Ex Str	0.3	0.2	4632	93	8.1	0.30	0.1
Ruby Creek	5104	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.3	0.1	3750	75	8.0	0.10	0.0
Ruth Creek	04587	WA	Whatcom	Puget Sound	LA-PND	Stream	New	2.8	1.3	2458	49	5.5	0.65	0.9
Ryegrass	11416	ID	Lincoln	Upper Snake	PP-GTD	Stream	Ex Str	2.1	0.9	2772	55	6.5	0.55	0.5
Saddle Springs	4243	ID	Gooding	Upper Snake	PP-REJ	Stream	New	0.1	0.1	n/av	n/av	n/av	0.20	0.0
Sahko	11060	ID	Twin Falls	Upper Snake	LC-PND	Canal	New	0.5	0.1	2215	44	8.7	0.95	0.1
Salmon Creek	10187	WA	Snohomish	Puget Sound	PP-EXP	Stream	New	2.9	1.4	1552	31	3.3	0.10	0.1
San Juan Creek	10146	WA	Snohomish	Puget Sound	PP-EXP	Stream	New	2.2	1.1	1131	23	2.5	0.10	0.1

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Sand Hollow	4886	WA	Grant	Upper Columbia	PP-SUR	Canal	Ex Str	1.7	1.0	3733	75	6.7	0.30	0.3
Sardine Creek	6659	OR	Marion	Willamette	PP-EXP	Stream	New	1.7	0.9	2052	41	4.1	0.10	0.1
Savage Rapids	9904	OR	Josephine	Coastal	PP-SUR	Stream	Ex Str	12.0	5.9	938	19	2.0	0.25	1.5
Scoggins Water Power	10019	OR	Washington	Willamette	PP-CAN	Stream	Ex Str	1.5	0.5	1277	26	4.3	0.20	0.1
Scooteney Inlet	4358	WA	Franklin	Upper Columbia	PP-EXP	Canal	Ex Str	2.8	1.1	3236	65	8.4	0.30	0.3
Scooteney Wasteway Sta.	5506	WA	Adams	Upper Columbia	PP-REJ	Canal	Ex Str	0.3	0.2	6241	125	9.8	0.20	0.0
Scootnay Wasteway	4132	WA	Franklin	Upper Columbia	PP-EXP	Stream	New	1.0	0.6	1814	36	3.2	0.10	0.1
Scout Creek	5517	MT	Lake	Kootenai	PP-SUR	Stream	New	0.4	0.3	2691	54	4.1	0.10	0.0
Shannon Creek	10273	WA	Whatcom	Puget Sound	PP-EXP	Stream	New	2.4	1.2	3280	66	6.9	0.10	0.1
Shelley	05090B	ID	Bingham	Upper Snake	LC-PND	Stream	Ex Str	1.4	1.3	5275	106	6.1	0.90	1.1
Shingle Creek	7589	ID	Idaho	Lower Snake	LC-PND	Stream	New	0.6	0.2	2375	48	7.2	0.85	0.2
Sixmile Creek	6769	MT	Lake	Kootenai	PP-EXP	Stream	New	0.2	0.1	#N/A	#N/A	#N/A	#N/A	#N/A
Sky Creek	6616	WA	Skagit	Puget Sound	EX-CAN	Stream	New	1.9	1.4	3954	79	5.6	0.60	0.9
Skykomish Tributaries	10197	WA	Snohomish	Puget Sound	PP-CAN	Stream	New	4.4	2.6	1310	26	2.3	0.20	0.5
Sloan Peak	7675	WA	Snohomish	Puget Sound	PP-CAN	Stream	New	1.2	0.5	2119	42	5.6	0.20	0.1
Smc Lake	7620	WA	King	Puget Sound	PP-CAN	Stream	New	1.7	0.7	2105	42	5.6	0.20	0.1
Snake River Trout	4227	ID	Gooding	Upper Snake	PP-REJ	Conduit	Ex Str	0.2	0.1	n/av	n/av	n/av	0.20	0.0
Snoqualmie Falls 1 & 2	02493	WA	King	Puget Sound	RL-PND	Stream	Ex Pwr	-10.4	-18.6	203	4	0.1	0.61	-11.4
Snow Creek	7622	WA	Jefferson	Puget Sound	PP-EXP	Stream	New	1.3	0.5	4840	97	12.8	0.10	0.1
Sonny Boy Creek	10258	WA	Skagit	Puget Sound	PP-SUR	Stream	New	3.5	1.8	2219	44	4.6	0.10	0.2
South Creek	10106	ID	Butte	Upper Snake	PP-EXP	Stream	New	0.3	0.2	4345	87	5.8	0.10	0.0
South Fork Eagle Creek	6874	OR	Clackamas	Willamette	PP-EXP	Stream	New	7.0	4.5	3070	61	5.0	0.10	0.4
South Fork Woodward Creek	5556	MT	Lake	Kootenai	PP-EXP	Stream	New	1.4	1.0	2810	56	4.3	0.10	0.1
South Hunt Creek	4789	ID	Bonner	Kootenai	EX-REJ	Stream	New	0.5	0.2	3093	62	10.6	0.60	0.1

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South Indian Creek	4782	ID	Bonner	Kootenai	EX-REJ	Stream	New	0.3	0.1	4603	92	15.3	0.60	0.1
Spread Creek	7926	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.7	0.5	9173	183	13.8	0.10	0.0
Springfield Canal	5600	OR	Lane	Willamette	PP-SUR	Canal	Ex Str	0.3	0.3	7122	142	8.6	0.30	0.1
Spruce Creek Water Power	5107	ID	Boundary	Kootenai	PP-SUR	Stream	New	0.2	0.1	4832	97	11.7	0.10	0.0
Squirrel Creek	7134	OR	Marion	Willamette	PP-CAN	Stream	New	0.5	0.3	6440	129	10.9	0.20	0.1
St Anthony Canal	9998	ID	Fremont	Upper Snake	PP-CAN	Stream	Ex Str	0.8	0.6	5974	119	8.0	0.20	0.1
Stahl Creek	5658	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.8	0.5	3105	62	4.7	0.10	0.1
Stanton Creek	7255	MT	Flathead	Kootenai	PP-EXP	Stream	New	0.1	0.1	6166	123	8.1	0.10	0.0
Star Creek	6468	MT	Lincoln	Kootenai	EX-DIS	Stream	New	2.0	0.6	2523	50	9.3	0.60	0.3
Star Falls	05797A	ID	Twin Falls	Upper Snake	LC-PND	Stream	New	35.8	12.2	927	19	2.9	0.75	9.2
Star Falls	05797B	ID	Twin Falls	Upper Snake	LC-PND	Stream	New	1.0	0.8	1406	28	1.8	0.75	0.6
Stillaguamish Tributaries	07036A	WA	Snohomish	Puget Sound	PP-CAN	Stream	New	1.6	0.8	2992	60	6.3	0.20	0.2
Stillaguamish Tributaries	07036C	WA	Snohomish	Puget Sound	PP-CAN	Stream	New	0.8	0.4	2876	58	6.1	0.20	0.1
Stillaguamish Tributaries	07036E	WA	Snohomish	Puget Sound	PP-CAN	Stream	New	1.8	0.9	2684	54	5.7	0.20	0.2
Stillaguamish Tributaries	07036G	WA	Snohomish	Puget Sound	PP-CAN	Stream	New	3.6	1.8	2105	42	4.4	0.20	0.4
Strawberry Flats	8804	OR	Jackson	Coastal	PP-SUR	Stream	Ex Str	20.0	8.0	848	17	2.2	0.25	2.0
Suiattle Mountain	6982	WA	Skagit	Puget Sound	PP-SUR	Stream	New	6.0	5.8	1862	37	2.0	0.10	0.6
Sullivan Creek	5485	MT	Lincoln	Kootenai	PP-EXP	Stream	Ex Str	0.5	0.3	1140	23	2.3	0.90	0.2
Sullivan Creek	2225	WA	Pend Oreille	Kootenai	LA-GTD	Stream	New	3.3	1.0	3171	63	11.0	0.10	0.1
Sutton Creek	5484	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.3	0.2	10767	215	19.4	0.10	0.0
Swamp Creek	04586	WA	Whatcom	Puget Sound	LA-PND	Stream	New	3.5	1.7	2259	45	4.9	0.76	1.3
Sweeney Creek	8378	MT	Ravalli	Kootenai	PP-CAN	Stream	New	3.2	2.5	2075	42	2.8	0.20	0.5
Taneum Chute	10625	WA	Kittitas	Yakima	LC-PND	Canal	Ex Str	0.8	0.2	2383	48	9.0	0.95	0.2
Tarlac Creek	4771	ID	Bonner	Kootenai	PP-EXP	Stream	New	0.1	0.0	16164	323	42.6	0.10	0.0

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Ten Mile	7336	ID	Idaho	Lower Snake	EX-REJ	Stream	Ex Str	0.5	0.3	4461	89	6.9	0.60	0.2
Ten Springs	5422	ID	Gooding	Upper Snake	EX-SUR	Conduit	New	0.2	0.2	2786	56	2.9	0.95	0.2
Thorp Creek	7741	WA	Kittitas	Yakima	PP-CAN	Stream	New	2.4	1.0	3531	71	9.3	0.20	0.2
Tieton	03701	WA	Yakima	Yakima	LA-GTD	Stream	Ex Str	13.6	5.7	1534	31	3.9	0.69	3.9
Tieton Canal Drop	5116	WA	Yakima	Yakima	PP-EXP	Canal	Ex Str	10.5	3.0	1367	27	5.0	0.30	0.9
Timberline	7311	OR	Clackamas	Lower Columbia	PP-EXP	Stream	New	0.4	0.3	4496	90	5.3	0.10	0.0
Tomtit Lake	7562	WA	Snohomish	Puget Sound	PP-EXP	Stream	Ex Str	0.3	0.2	5897	118	8.2	0.25	0.1
Tomyhoi Creek	5544	WA	Whatcom	Puget Sound	PP-EXP	Stream	New	3.2	1.5	3715	74	8.4	0.10	0.1
Tony Creek	9643	MT	Sanders	Kootenai	PP-EXP	Stream	Ex Str	0.1	0.1	3986	80	7.4	0.25	0.0
Trail Creek	5415	ID	Blane	Upper Snake	PP-SUR	Stream	Ex Str	0.3	0.0	n/av	n/av	n/av	0.25	0.0
Trout Creek	10610	ID	Caribou	Bear	EX-GTD	Stream	Ex Str	0.3	0.2	3575	72	6.8	0.92	0.2
Tumalo Creek	9006	OR	Deschutes	Middle Columbia	PP-SUR	Stream	Ex Str	7.3	3.3	3080	62	7.2	0.25	0.8
Tumwater Canyon	7212	WA	Chelan	Upper Columbia	PP-SUR	Stream	Ex Str	24.0	16.0	1924	38	3.0	0.25	4.0
Tunnel Cr	7659	WA	King	Puget Sound	PP-EXP	Stream	New	0.9	0.4	2702	54	7.1	0.10	0.0
Tunnel Creek	6798	OR	Marion	Willamette	PP-EXP	Stream	New	1.1	0.6	2213	44	4.4	0.10	0.1
Twelvemile Creek	8950	ID	Lemhi	Lower Snake	PP-SUR	Stream	New	0.5	0.3	6190	124	8.7	0.10	0.0
Twin Creek	5508	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.1	0.0	7647	153	17.3	0.10	0.0
Twin Lakes Canal	8745	ID	Franklin	Bear	EX-REJ	Canal	Ex Str	0.7	0.0	n/av	n/av	n/av	0.60	0.0
Tyee/Jumbo Basin	6401	ID	Valley	Middle Snake	EX-REJ	Stream	New	0.7	0.3	3727	75	9.8	0.60	0.2
U-3	11409	ID	Jerome	Upper Snake	EX-PND	Canal	New	3.2	1.3	n/av	n/av	n/av	0.95	1.2
Uleda Creek	4773	ID	Bonner	Kootenai	PP-EXP	Stream	New	0.2	0.1	9901	198	25.2	0.10	0.0
Unity	3840	OR	Baker	Middle Snake	PP-EXP	Stream	Ex Str	0.5	0.2	3321	66	10.2	0.25	0.0
Upper Berry Creek	5879	ID	Bonner	Kootenai	PP-SUR	Stream	New	0.2	0.1	4406	88	9.0	0.10	0.0

Project	FERC ID	State	County	Basin	License	Water way	Type	Capacity (MW)	Energy (aMW)	Capital cost ($/kW)	O&M Cost ($/kW/yr)	Energy Cost (Cents/ kWh)	Prob. of Dev.	Probable Energy Contrib.
Upper Hat Creek	9593	ID	Idaho	Lower Snake	PP-SUR	Stream	New	3.5	0.8	1322	26	5.8	0.10	0.1
Upper Hunt Creek	4781	ID	Bonner	Kootenai	EX-REJ	Stream	New	0.6	0.2	3364	67	12.0	0.60	0.1
Upper Jerome Conduit	11470A	ID	Idaho	Upper Snake	PP-PND	Canal	Ex Str	9.9	4.2	2601	52	6.5	0.30	1.2
Upper Salmon Creek	11122	ID	Twin Falls	Upper Snake	PP-GTD	Stream	Ex Str	48.0	13.5	2963	59	11.1	0.50	6.7
Upper South Fork Snoqualmie	10984	WA	King	Puget Sound	PP-EXP	Stream	New	4.2	1.7	2968	59	7.5	0.10	0.2
Upper Tenmile Creek	5471	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.3	0.1	9952	199	28.6	0.10	0.0
Valsetz	7217	OR	Polk	Coastal	EX-SUR	Stream	Ex Str	4.0	1.9	3225	65	7.0	0.72	1.4
Vance Creek	4089	WA	Mason	Puget Sound	PP-SUR	Stream	New	1.3	0.5	4649	93	12.4	0.10	0.1
Wagner Enterprises	7368	OR	Clackamas	Willamette	EX-WDN	Stream	Ex Str	0.0	0.0	n/av	n/av	n/av	0.72	0.0
Waldvogel Bluff	5043	ID	Ada	Middle Snake	EX-GTD	Canal	Ex Str	0.3	0.1	5519	110	13.4	0.95	0.1
Wallace Creek	8120	ID	Lemhi	Lower Snake	EX-REJ	Stream	New	0.0	0.0	n/av	n/av	n/av	0.60	0.0
Wardenhoff Creek	6231	ID	Valley	Lower Snake	EX-SUR	Stream	New	0.4	0.1	2326	47	8.0	0.82	0.1
Warm Springs Creek	9067	OR	Douglas	Coastal	PP-CAN	Stream	New	3.0	1.4	2183	44	5.0	0.20	0.3
Waste Waterway 68d Dike # 10	6249	WA	Adams	Upper Columbia	PP-SUR	Canal	Ex Str	0.2	0.1	6567	131	15.2	0.30	0.0
Waste Waterway 68d Dike # 6	6264	WA	Adams	Upper Columbia	PP-SUR	Canal	Ex Str	0.2	0.1	9988	200	21.4	0.30	0.0
Waste Waterway 68d Dike # 8	6263	WA	Adams	Upper Columbia	PP-SUR	Canal	Ex Str	0.2	0.1	6041	121	12.9	0.30	0.0
Waste Waterway 68d Dike # 9	6248	WA	Adams	Upper Columbia	PP-SUR	Canal	Ex Str	0.3	0.1	7873	157	18.2	0.30	0.0
Waterwheel East	11210	ID	Canyon	Middle Snake	PP-CAN	Canal	New	0.2	0.1	5757	115	16.9	0.20	0.0
Watson Creek	6003	WA	Mason	Puget Sound	PP-SUR	Stream	New	1.0	0.4	3631	73	9.1	0.10	0.0
Whiskey Creek	10611	ID	Caribou	Bear	EX-GTD	Stream	Ex Str	0.6	0.3	1947	39	4.8	0.91	0.2
White River	11491	OR	Wasco	Middle Columbia	PP-PND	Stream	Ex Str	9.0	2.3	1713	34	7.1	0.25	0.6
White Salmon Creek	5545	WA	Whatcom	Puget Sound	EX-DIS	Stream	New	1.3	0.8	4666	93	8.4	0.60	0.5

Project	FERC ID	State	County	Basin	License	Water way	Type	Capacity (MW)	Energy (aMW)	Capital cost ($/kW)	O&M Cost ($/kW/yr)	Energy Cost (Cents/ kWh)	Prob. of Dev.	Probable Energy Contrib.
White Water Creek	6800	OR	Marion	Willamette	PP-EXP	Stream	New	3.6	1.9	4546	91	9.1	0.10	0.2
White Water Ranch	06271B	ID	Gooding	Upper Snake	EX-GTD	Stream	New	0.0	0.0	n/av	n/av	n/av	0.90	0.0
Whitetail Creek	5477	MT	Lincoln	Kootenai	PP-SUR	Stream	New	0.1	0.0	8404	168	20.7	0.10	0.0
Willow Creek	8946	ID	Cassia	Upper Snake	PP-CAN	Stream	New	0.7	0.3	4034	81	10.2	0.20	0.1
Wind River	6385	WA	Skamania	Middle Columbia	PP-EXP	Stream	Ex Str	0.2	0.2	66152	1323	70.7	0.25	0.0
Wishkah	8790	WA	Grays Harbor	Coastal	LC-SUR	Stream	Ex Str	0.3	0.2	13585	272	21.5	0.69	0.2
Woodcock Creek	6582	OR	Clackamas	Willamette	EX-REJ	Stream	New	0.1	0.0	13788	276	26.1	0.60	0.0
Woodward Tributary	5783	MT	Lake	Kootenai	PP-SUR	Stream	New	0.2	0.1	6103	122	12.9	0.10	0.0
Wright Creek	7111	WA	Grays Harbor	Coastal	EX-DIS	Stream	New	0.5	0.3	3238	65	6.8	0.60	0.2
Yakima Diversion Dam	6857	WA	Yakima	Yakima	PP-SUR	Stream	Ex Str	0.7	0.4	11270	225	19.3	0.25	0.1
Yellowstone	10767	ID	Fremont	Upper Snake	PP-EXP	Stream	Ex Str	4.5	3.2	3945	79	5.9	0.25	0.8
Youngs Creek	10359	WA	Snohomish	Puget Sound	LA-GTD	Stream	New	7.5	3.4	1683	34	4.0	0.95	3.2

APPENDIX FNG

NATURAL GAS

NATURAL GAS

SUMMARY

Natural gas is a flexible, low-cost, abundant and relatively clean burning fuel that can be used with a variety of electric power generating technologies. These technologies, which include gas turbines, boiler steam turbines, reciprocating engines and fuel cells, can be used for both generation and cogeneration applications. In recent years, natural gas-fired combined-cycle gas turbine power plants have become the least-cost new generating resource in the Pacific Northwest and elsewhere. These plants now define the marginal economic cost of new resources. Factors that have lead to this development include continuing decline in current and forecasted natural gas prices, low-cost firm gas transportation, emergence of financial instruments to hedge natural gas price risk, continuing improvements in combustion turbine performance, decline in equipment and construction prices, apparent ease of project permitting and a short, predictable construction process.

The principal issues constraining the development of natural gas generation in the past were fuel price and availability and equipment reliability. These issues have largely disappeared. Remaining issues include air emissions, water consumption, the environmental consequences of supplying natural gas and the global climate change implications of carbon dioxide production. Sulfur dioxide emissions can be of concern for plants using oil as a backup fuel. Several additional issues are specific to cogeneration.

As of January 1996, 2,880 megawatts of electric generating capacity using natural gas as a primary fuel was operating, or under construction in the Northwest. Fully dispatched, these projects can generate about 2,600 average megawatts of energy, 12 percent of forecasted 1996 regional electric energy requirements. About 58 percent of this capacity has been brought into service or placed under construction within the past five years. About 44 percent serves some cogeneration load and nearly all (97 percent) uses gas turbine technology, either in simple or combined-cycle form.

Power plant development has recently declined because of the surplus of generating capacity on the western interconnected system and consequently low wholesale electricity prices. This situation is expected to persist for several years or longer. If natural gas prices remain low, as forecasted, it is likely that gas-fired combined-cycle gas turbines will continue to be the “technology of choice” for new bulk power generation. Some will serve cogeneration loads, but the proximity of gas pipelines, airshed quality and the availability of water will be important determinants of project location and design. In the long term, small-scale packaged fuel cell cogeneration plants could see increasingly wide use as total energy supply systems at the point of energy use.

NATURAL GAS SUPPLY AND PRICE

The Northwest has excellent pipeline access to important western North American natural gas resource areas. These areas include the Western Canada Sedimentary Basin of Alberta and British Columbia, the Rocky Mountain Basins of Wyoming and Colorado, and the San Juan Basin of New Mexico. Little natural gas of commercial potential has been found within the Northwest itself.

Raw gas is processed near its place of production to remove excess water, liquid hydrocarbons, hydrogen sulfide and carbon dioxide. Clean water and carbon dioxide are released to the environment, the natural gas liquids are converted to liquid fuels and the majority of the hydrogen sulfide is converted to merchantable elemental sulfur and hydrogen. Some hydrogen sulfide is still flared to water and sulfur dioxide, but this practice is declining because the sulfur dioxide is an acid rain precursor. For example, about 98 percent of the sulfur compounds contained in western Canadian raw gas are recovered.

The resulting natural gas product is generally shipped to customers by pipeline. Two major interstate pipelines, Northwest Pipeline and Pacific Gas Transmission serve the Northwest (Figure FNG-1). The

Northwest is favorably located relative to natural gas transmission. It is midway between major producing fields, midway between producing fields and the major California market, and includes areas served by two interstate pipelines, including the crossover point near Stanfield, Oregon. These conditions maintain competitive pressure on wholesale gas prices, enhance reliability of supply and provide motivation for timely expansion of pipeline capacity to serve need.

Figure FNG-1
Major Natural Gas Pipelines of the Pacific Northwest

Actual and forecasted natural gas prices have steadily declined over the past several years. As recently as the early 1990s, it was generally accepted that a temporary excess of production and transportation capacity (the "gas bubble") would soon be exhausted, and prices would rise abruptly as a declining resource base became evident. However, restructuring of the industry has improved incentives for exploration and production, and a sophisticated commodity market for natural gas has evolved that enables price risk to be managed with financial instruments. Improved exploration and production technology has increased the success rate and efficiency of locating and producing natural gas and appears to have offset any effects of a declining resource base.

As a result, most observers believe that we have entered a period of relatively stable natural gas prices. Fluctuations due to short-term supply and demand imbalance will occasionally occur, but sustained increases in real prices are unlikely in the near-term. Even long-term replacement costs are thought to be lower than the $3.00 per million Btu commonly accepted a few years ago.

Because of these changes, the Council prepared a revised natural gas price forecast for this power plan. This forecast is described in Appendix C.

ELECTRIC GENERATING TECHNOLOGIES USING NATURAL GAS

Natural gas is a flexible fuel, usable by a variety of electric generating technologies. These include gas turbine power plants, boiler-steam turbine power plants, reciprocating engine-generators and fuel cells. Low natural gas prices combined with the high thermal efficiency, reliability, modular design, low capital cost, operational flexibility and modest environmental impacts of combined-cycle gas turbine power plants have made this technology the bulk power generating technology of choice.

Gas Turbines

Gas ("combustion") turbine power plants are based on the technology originally developed to power jet aircraft. A gas turbine power plant consists of a gas compressor, a fuel combustor and a gas turbine. Air is compressed in the gas compressor. Energy is added to the compressed air by combusting gaseous or liquid fuel and the high-pressure, hot combustion gas is expanded through a gas turbine. The gas turbine drives both the compressor and a load, which may be an electric generator. Gas turbine power plants are available as heavy-duty "frame" engines specifically designed as stationary industrial engines, or as "aero-derivative" machines - lighter weight units derived from aircraft engines. Various refinements, such as inter-cooling, regeneration and steam injection can be used to improve performance.

Gas turbine power plants can be equipped with a heat recovery boiler on the exhaust to produce steam for cogeneration. The steam from a heat recovery steam generator may also be used to drive a steam turbine-generator, in which case the unit becomes a combined-cycle power plant (see below). Because of their low capital cost, quick start capability, load following ability and ability to burn a wide variety of liquid and gaseous hydrocarbon fuels, combustion turbine power plants are valued for serving peaking and emergency loads. Low gas prices have enabled operators of these units to use them for intermediate load service.

Gas turbine power plants are available in a range of unit sizes from about one to 160 megawatts, and more. Thermal efficiency increases, and per-megawatt costs generally decline with increasing capacity. For example, 1.5- to 5-megawatt units will have thermal efficiencies of about 26 percent and cost $1,700 to $2,100 per kilowatt. In comparison, 30- to 60-megawatt units will have thermal efficiencies of about 34 percent and costs in the range of $800 to $1,000 per kilowatt.[1] Performance and cost characteristics of a representative industrial-grade gas turbine power plant are provided in Table FNG-1.

The principal environmental concerns associated with combustion turbines operating on natural gas are nitrogen oxides and carbon monoxide emissions, carbon dioxide production and noise. Fuel oil operation may also produce sulfur dioxide. The water consumption of water- or steam-injected machines may be significant. The nitrogen oxide emissions of earlier designs were very high - 200 ppm, or greater. Water or steam injection and, more recently, "dry low-NOx" combustors, enable nitrogen oxide emissions to be controlled to 10 ppm, or less. Noise is controlled by use of enclosures, inlet air silencers and exhaust mufflers. The environmental characteristics of a representative plant are provided in Table I-1 of Appendix I.

Gas turbine technology development is strongly driven by the military, aerospace, petrochemical and utility industries and continues to evolve rapidly. Improvements in thermal efficiency, reliability and nitrogen oxide control technology continue. Larger unit sizes continue to be introduced. Costs are expected to be stable. We assume continued thermal efficiency improvements of 0.5 percent per year.

[1] Overnight costs, cogeneration applications.

Table FNG-1

Representative Natural Gas Generating Technologies

	Simple-cycle Combustion turbine	**Combined-cycle Combustion turbine**	**Reciprocating Engine**	**Fuel Cell**
Configuration	Two-unit industrial-grade, no cogeneration load	Two-unit industrial-grade, no cogeneration	Single unit, w cogeneration load	Single unit phosphoric acid w/cogeneration load
Typical Application	Peaking, emergency and intermediate power supply	Bulk power supply	Backup power and hot water supply	Backup power and hot water supply
Unit Capacity, lifetime average (MW)	80 (new) 78 (lifetime)	230 (new) 224 (lifetime)	1	0.2
Availability (%)	87%[2]	92%	90%	95%
Heat Rate (Btu/kWh)[3]	11,900 (new) 12,150 (lifetime)	7,200 (new) 7,350 (lifetime)	11,100[4]	9,480[5]
Overnight Cost ($/kW)[6]	$423	$637 (first unit) $547 (second unit)	$1100	$3,400
Fixed Operating Cost ($/kW/yr)[2]	$16.20	$20.40 (first unit) $16.50 (second unit)	$6.40	$71
Variable Operating Cost (mills/kWh)[7]	0.1	1.0	0.4	7.5[8]
Development & Construction Lead Time (Months)	24/12	24/24	12/12	Less than 12
Cash Flow (%/yr)	1.5/1.5/97	1/1/48/51	10/90	100
Service Life (Years)	30	30	20	20
Comparative Levelized Energy Cost (cents/kWh)[9]	3.2	2.6	3.1/4.1[10]	6.6/7.3[9]

[2] Assuming peaking duty and routine maintenance. The availability of a gas turbine power plant is strongly influenced by duty and maintenance. An irregularly maintained unit in peaking duty will generally have a lower availability than a routinely maintained unit in baseload duty.
[3] Based on the higher heating value (HHV) of the fuel.
[4] 5300 Btu/kWh fuel allocated to electricity production with 5800 Btu/kWh fuel allocated to hot water production
[5] 5480 Btu/kWh fuel allocated to electricity production and 4000 Btu/kWh fuel allocated to hot water production.
[6] Lifetime average capacity basis.
[7] Exclusive of property tax and insurance. See Financial Assumptions section for assumptions regarding property taxes and insurance.
[8] Cost includes replacement of cell stacks twice and reformer catalyst once during plant life.
[9] 15 year IOU financing, medium gas price forecast, year 2000 service, baseload service.
[10] First figure w/cogeneration credit; second figure, no cogeneration credit.

Combined-cycle Gas Turbines

A combined-cycle gas turbine power plant consists of a gas turbine with a heat recovery steam generator to capture the energy contained in the hot turbine exhaust gas. Steam produced in the heat recovery steam generator is used to power a steam turbine generator. Typical projects consist of one or two units of 220- to 250-megawatt capacity each. Each unit is comprised of a heavy-duty gas turbine-generator set, a heat recovery steam generator and a steam turbogenerator. Other site features include a switchyard, water treatment plant, condenser cooling towers and control and maintenance facilities. Cogeneration loads can be served using steam bled from the heat recovery steam generator or the steam turbine.

The great advantage of the combined-cycle power plant is the improved thermal efficiency resulting from use of energy contained within the hot exhaust of the gas turbine. The higher heating-value thermal efficiencies of a contemporary combined-cycle plant are about 46 to 47 percent, compared to about 28 to 30 percent for equivalent simple-cycle machines.[11] Combined-cycle efficiencies are greater than any other commercially available thermal power plant, making these units highly desirable for baseload service. Combined-cycle combustion turbines are operationally flexible and can be used for load-following. Declining natural gas prices, combined with improvements in plant thermal efficiency, reliability and environmental performance have made combined-cycle combustion turbine power plants the new resource of choice for supplying base-load electrical power

Combined-cycle gas turbine power plants are available in unit sizes ranging from 10 to 250 megawatts, or more. Generally, thermal efficiency improves, and unit capital and operating costs decline with increasing unit size. Performance and cost characteristics of a representative combined-cycle power plant are provided in Table FNG-1.

The principal environmental issues associated with combined-cycle combustion turbines operating on natural gas are nitrogen oxide emissions, carbon dioxide, water use and noise. Dry low-NOx combustors, water injection and selective catalytic reduction enable nitrogen oxide emissions to be controlled to 4.5 ppm, and less. Noise is controlled by use of enclosures, inlet air silencers and exhaust mufflers. Though large quantities of water are required for evaporative cooling of the steam turbine condenser, cooling water requirements per kilowatt are less than coal or nuclear plants because of the lower thermal efficiencies of the latter. Cooling water requirements may be significantly reduced by use of dry-convective cooling towers.[12] The environmental characteristics of a representative plant are provided in Table I-1 of Appendix I.

Boiler-steam Turbines

A boiler steam turbine power plant consists of a steam boiler, fired by coal, oil, natural gas or biomass, and a steam turbine generator. Other plant equipment includes a switchyard, water treatment plant, condenser cooling towers and control and maintenance facilities. Steam can be bled from the boiler or the turbine to supply cogeneration loads.

Boiler-steam turbine power plants have been used since the beginning of the industry to generate electrical power and to supply cogenerated steam. Thousands of megawatts of dual fuel (oil and natural gas) electrical generating plants of this type are common in California, where they were constructed until the 1970s. Operated primarily as emergency and peaking units for many years because of high fuel prices, these units have become economical to operate as baseload units because of declining natural gas prices

[11] These efficiencies are based on the higher heating value of the fuel. The often-quoted lower heating value efficiencies will be about 10 percent higher for comparable equipment. Recently announced advanced technology using steam-cooled blading will have somewhat greater efficiencies.

[12] Dry-convective cooling uses heat exchangers where the cooling water is circulated entirely in enclosed pipes. Traditional wet-cooling relies on evaporation to chill the cooling water. Since water is lost in the evaporation process, wet-cooling uses more water than dry-cooling.

New natural gas-fired boiler-steam turbine power plants are unlikely because of the superior performance and economics of alternative technologies. Existing units may continue to operate as long as gas prices remain low, but may need to be upgraded or re-powered to reduce nitrogen oxide emissions. In particular, units located in emissions-controlled areas of Southern California will either have to be modified, purchase emission credits, or go out of service as the air-quality standards tighten over the next decade.

Reciprocating Engines

Reciprocating engine generator sets use reciprocating internal combustion engines derived from transportation applications. These plants are generally supplied as packaged units and may be equipped with heat exchangers on the cooling and exhaust systems to supply cogeneration loads.

Engine generator units are small, compared with other generating technologies, ranging from several kilowatts to 10 to 12 megawatts. Their small size, reliability and rapid start capability are desirable for emergency and isolated load service. Cogeneration applications are not widespread because of the expense and bother of maintaining a continuously operating engine-generator set. Performance and cost characteristics of a representative engine-generator set are provided in Table FNG-1.

The principal environmental concerns associated with reciprocating engines operating on natural gas are nitrogen oxide emissions, carbon dioxide production and noise. The environmental characteristics of a representative plant are provided in Table I-1 of Appendix I.

Fuel Cells

A fuel cell is solid-state device that produces electrical energy, water and heat by the electrochemical combination of hydrogen and oxygen. Although the fuel cells currently in operation use natural gas, fuel cell power plants have the potential for using other hydrogen-containing fuels. A single fuel cell consists of an anode and a cathode separated by an electrolyte with provisions for fuel supply and cooling. A single fuel cell operates at low voltage, and individual fuel cells are assembled into a "stack" to obtain useful output voltage. In addition, a fuel cell power plant includes a fuel reformer to convert hydrogen contained in the fuel to elemental form, a power conditioner to convert the direct current output of the fuel cell stack to alternating current, and heat rejection equipment. The reject heat may be used for cogeneration applications.

Several fuel cell technologies are under development. Fuel cell power plants using phosphoric acid electrolyte were introduced to the market in 1992. These units operate at thermal electrical conversion efficiencies of about 36 percent (HHV[13]). A heat exchanger supplies hot water at temperatures to 250^{o}F for space and water heating cogeneration applications. Overall thermal efficiency is about 77 percent (HHV). Fuel cell technologies using molten carbonate and solid oxide electrolytes are at the pilot plant stage. These types of fuel cells are expected to operate at higher efficiencies. Also, the higher operating temperatures of these technologies will expand cogeneration applications. Commercial introduction of molten carbonate and solid oxide designs is expected during the late 1990s.

Fuel cell power plants are expected to be produced in factory-assembled modules ranging from 50 kilowatts to several megawatts. Multiple modules could be assembled for greater output. Performance and cost characteristics of a currently available phosphoric acid fuel cell power plant are provided in Table FNG-1.

Site environmental impacts are few. Nitrogen oxide emissions of current models are about one part per million. Sufficient water for cooling system makeup is produced by fuel combustion. Minor fan and pump

[13] Higher heating value (of the fuel).

noise is produced. The environmental characteristics of a representative plant are provided in Table I-1 of Appendix I.

At current costs, fuel cell power plants clearly cannot provide economic bulk power generation. But the size, reliability, environmental qualities and cogeneration potential of these plants may allow them to penetrate the backup or quality power market, especially at environmentally sensitive sites. The low environmental emissions of these units allow continuous-duty operation, compared to alternatives such as engine-generator sets, whose permitted operation is often constrained because of environmental concerns.

Because of their potential for production economies and technological improvement, fuel cell costs are expected to decline once a market is established. The extent of potential cost reductions is debated. Commercial introduction of advanced fuel cell technologies is expected to improve thermal efficiencies and broaden cogeneration applications. Some see an ultimate role of fuel cells as packaged "total energy" units for commercial and residential applications. Such products could supply all end use electrical and thermal needs. The resulting shift of generation to the end-user could significantly affect the structure of the electric power industry.

DEVELOPMENT ISSUES

Issues common to all forms of natural gas generation include the price and availability of natural gas and the environmental implications of natural gas exploration, production, processing and transportation. Some natural gas technologies can produce nitrogen oxides and carbon monoxide at levels of potential concern. The combustion of natural gas, like other carbon-based fuels, produces carbon dioxide, implicated in global warming. Finally, there are a set of unique development issues associated with cogeneration.

Natural Gas Price and Availability

As described above, earlier concerns regarding the long-term price and availability of natural gas have eased. Factors contributing to the prevailing optimistic outlook include the continued success of natural gas exploration, stability of gas replacement costs and demonstrated success in expanding the gas transportation capacity. While short-term price fluctuations resulting from supply demand imbalances may occasionally occur, most observers expect natural gas prices to remain generally stable for the next several years. Moreover, improved exploration and production technology is expected to result in replacement prices lower than formerly forecast, slowing the rate of any future price increase. A final factor contributing to the lessening of concern regarding future gas prices is the nature of the power plant technology itself. Gas turbine power plants are relatively low cost, and less capital is at risk if fuel prices unexpectedly increase.

Environmental Impacts

The principal environmental concerns regarding natural gas generation are nitrogen oxides, carbon monoxide, carbon dioxide, water requirements and impacts of fuel production, processing and transportation. Emission production rates typical of the representative technologies of Table FNG-1 are compiled in Table I-1 of Appendix I.

Oxides of nitrogen: Fuel combustion oxidizes nitrogen occurring in the fuel and in the combustion air. The products of concern include nitric oxide (NO) and nitrogen dioxide (NO_2), collectively referred to as NO_x. Nitric oxide is a gas that can irritate membranes and cause coughs and headaches. Furthermore, nitrogen oxide can react with moisture to form nitric acid, which can acidify rain. Both nitrogen oxide and nitrogen dioxide can form nitrosamines, potent carcinogens in aqueous solution. Nitrogen oxides are of concern in many metropolitan areas where ambient concentrations of ozone often approach or exceed air quality standards.

Nitrogen oxide production increases with combustion temperature. Unfortunately, this characteristic conflicts with efforts to increase power plant thermal efficiency by raising the temperature of combustion gas. However, significant progress in controlling power plant nitrogen oxide production has been made in recent years. Nitrogen oxide control is accomplished by steam or water injection, "low NO_x" combustor designs and by catalytic reduction of nitrogen oxides in the plant exhaust. Steam or water injection can control nitrogen oxide production from gas turbine power plants to about 25 parts per million. Steam or water injection also increases power output and makeup water requirements. Low-NOx combustors control excess combustion air and reduce firing temperatures. Current designs can control nitrogen oxide formation in gas turbines to less than 9 parts per million and can eliminate the need for steam or water injection. Nitrogen oxide levels of 4.5 ppm or less can be achieved by use of selective catalytic reduction "on the tailpipe." Selective catalytic reduction technology is temperature-sensitive and currently cannot be used with simple-cycle gas turbines. Because catalytic reduction requires the injection of ammonia into the exhaust stream, some unreacted ammonia (up to 10 ppm) escapes to the atmosphere.

Carbon monoxide: Carbon monoxide is formed by partial oxidation of carbon-bearing fuels. Carbon monoxide interferes with delivery of oxygen in the body and can cause headaches, nausea, irregular heart beat, weakness, confusion and vision and brain dysfunction. Carbon monoxide is of particular concern in some metropolitan areas where the ambient concentrations of carbon monoxide approach or exceed air quality standards.

Efforts to improve thermal efficiency generally reduce carbon monoxide production, as the presence of carbon monoxide is indicative of inefficient fuel use. However, nitrogen oxide controls that reduce excess combustion air and firing temperature may increase carbon monoxide production. Carbon monoxide can be controlled by maintaining design combustion conditions and be further reduced, if necessary, by catalytic oxidation.

Carbon dioxide: Combustion of carbon-based fuels produces carbon dioxide, a greenhouse gas whose increasing concentration in the atmosphere may lead to global climate change. While scientific consensus on the certainty of global climate change and its implications has not been reached, scientific opinion is moving in this direction. The possible role of natural gas in a global climate change control strategy is not yet clear. Natural gas combustion produces carbon dioxide, and additional carbon dioxide is produced while supplying the energy required to process sour natural gasses and to operate gas pipeline compressors. Furthermore, methane, the principal constituent of natural gas, is also a greenhouse gas, many times more potent than carbon dioxide. Some methane is lost to the atmosphere during natural gas production, processing, transportation and use. On the other hand, the generation of electricity using natural gas can produce far less carbon dioxide than the generation of electricity using other fossil fuels because of the lower carbon content of natural gas and the higher thermal efficiency of gas-fired generating equipment. Moreover, natural gas can be used in direct applications, avoiding not only the carbon dioxide production of coal-fired generation, but electrical transmission and distribution energy losses as well. For these reasons, increased use of natural gas conceivably could be an element of a global-warming response strategy.

Water requirements: Combined-cycle gas turbine power plants use water for boiler makeup, water or steam injection, if used, and steam condenser cooling. The water consumption of a 230-megawatt unit may approach 1.4 million gallons per day. Most of this is lost through evaporative condenser cooling and can be significantly reduced, though at additional cost and some loss of efficiency, by use of dry cooling towers.

Impacts of natural gas production, processing and transportation: The environmental impacts of a natural gas power plant itself are minor compared to thermal power plants using other fuels, however, gas exploration, production, processing and transportation may result in "upstream" environmental effects of concern, including the following:

- Fragmentation of natural habitat, aesthetic impacts and human intrusion from exploration, drilling and production in wilderness portions of the Western Canada Sedimentary Basin;
- Fugitive methane releases;

- Production of sulfur dioxide from flaring of hydrogen sulfide at sour gas processing plants (H_2S flaring has nearly been phased out);
- Release of carbon dioxide stripped from raw gas containing high concentrations of carbon dioxide;
- Indirect impacts of the production of energy for powering processing plants and pipeline compressor stations; and
- Forest clearing and aesthetic impacts of pipeline rights-of-way.

Special Issues Affecting Cogeneration Development

There are several special issues that relate to the development of cogeneration. Most significant at present is the cost of cogenerated electricity compared to current wholesale energy prices. Issues that may resurface if electricity prices strengthen include the cost of cogeneration compared to stand-alone combined-cycle plants, competition with alternative investments, conflict of host facility and electricity production schedules, lack of information and experience regarding cogeneration opportunities and the effect of the less stringent environmental controls that may be applicable to small-scale cogeneration installations. Some issues formerly perceived as impediments to cogeneration development, such as the lack of marginal cost pricing, may be resolved by the expected advent of retail wheeling and unbundling of power products. Two issues that have received attention in the past from a public policy perspective are cogeneration "oversizing" and competition with conservation.

Value of electricity and the cost of cogeneration: The primary factor currently constraining the development of cogeneration is the low price of wholesale electricity. A surplus of generating capacity has deferred the need for new generating projects, and the surplus is manifested as low wholesale electricity prices. Most potential cogeneration projects cannot be economically developed for current wholesale electricity prices. Even if wholesale prices eventually rise, it appears that large combined-cycle gas turbines can produce power at lower cost than smaller-scale cogeneration installations.

Competition with alternative investments: Cogeneration is but one of many investment opportunities for the limited funds available to the owner of a potential host facility. Investments required to maintain or improve the fundamental production process, to expand capacity in a growing market or to develop promising new products take precedence over cogeneration investments. Moreover, the payback periods expected by industry are typically shorter than the 10- to 15-year paybacks currently expected for generating project development. Third-party or utility developers can help provide financing for cogeneration development.

Conflict of host facility and electricity production schedules: The host facility schedule may conflict with economically optimal electricity generation schedules. Steam may be required even if the economics of electricity production indicate that generation be curtailed, and vice-versa. This issue has contributed to the oversizing of cogeneration power plants (see below). The steam load can be easily varied without significantly affecting power plant operation. Surplus steam simply increases electricity generation capacity. A backup steam generator, small relative to the power plant, can be installed to meet thermal loads when the power plant is displaced or in maintenance.

Lack of experience: New technology, such as fuel cells, presents cogeneration opportunities in industries that have not traditionally cogenerated. Demonstration projects may be needed to prove the reliability and performance of the technology and to provide credible information regarding the technology and application to prospective host facility owners.

Environmental considerations: Though in theory environmental emissions are potentially lower with cogeneration than if the thermal energy and electricity were generated separately, actual emissions depend on the level of emission control, which may be less stringent for cogeneration plants than for central-station electric generating plants. Also, if the thermal and electric loads are not matched, and the cogeneration plant does not use all of the waste heat, then the emissions might be greater than if the electricity were produced in a larger and more efficient central-station combined-cycle gas turbine. The emissions of small-scale cogeneration may be closer to densely populated areas.

A factor that has promoted development of cogeneration in some cases has been the occasional need of industry to upgrade older equipment to mitigate the environmental impact of its operation.

Oversizing: If high prices are available for cogenerated electricity, developers may install facilities that will produce more electricity than is consistent with the host's thermal load requirements. Under these conditions, the plant becomes a power generator, not just a cogenerator. This is known as "oversizing." Historically, under the Public Utilities Regulatory Policy Act (PURPA) of 1978, plants with even a small percentage of their fuel input converted to steam or hot water to serve thermal loads could qualify for special power sales contracts. In areas with high avoided costs of new generation, the difference in price for cogenerated electricity was high and encouraged oversizing of these facilities.

Though oversizing dilutes the non-economic benefits of cogeneration, it is not clear that oversizing is necessarily undesirable. One view holds that there is no harm in allowing cogenerators to maximize return by installing oversized systems when it is economical to do so. Arguments in favor of allowing oversizing include:

- Anticipated future growth in thermal requirements may call for installing oversized systems today that will be balanced systems in the future.
- The electricity sales from oversizing can provide enhanced economic vitality for a facility and provide secondary economic benefits.
- Oversizing may promote installation of cogeneration systems which, although oversized, retain improved overall fuel-use efficiencies and other benefits compared to stand-alone generation.
- Oversizing, by encouraging installation of new equipment designed and operated to current regulations, may promote reduction in environmental impacts.

Others argue that oversizing should be discouraged for the following reasons:

- Significant oversizing can lead to reductions in overall fuel-use efficiency. Once the point of thermal balance has been exceeded, there is no use for the additional waste heat from the electrical generation process. The excess generating capability has the same characteristics of a stand-alone electrical generating station. If its marginal efficiency is less than that of central-station technologies that can utilize the same fuel, efficiency can be improved by limiting the cogeneration facility to thermal balance, and developing additional capacity using central-station electrical generation.
- Control of emissions can be easier at central-station generating plants. There are fewer point sources for emissions, and central-station facilities often are monitored and regulated more closely than smaller industrial and commercial facilities.

After passage of the Energy Policy Act of 1992 and the opening of the transmission system for wholesale power transmission, the whole issue of oversizing becomes very different. Since all power will sell on the wholesale market without differentiation due to source, the decision to over-size or not will be driven by the developer's assessment of the future power sales market, the cost of power production, and the physical constraints on the operation resulting from local electrical or thermal energy needs.

Competition with conservation: End-use efficiency improvements may be more cost-effective than small-scale cogeneration, and the attractiveness of cogeneration projects diminishes when applied to more efficient buildings. Conversely, conservation might appear less cost-effective in a building with an existing cogeneration system.

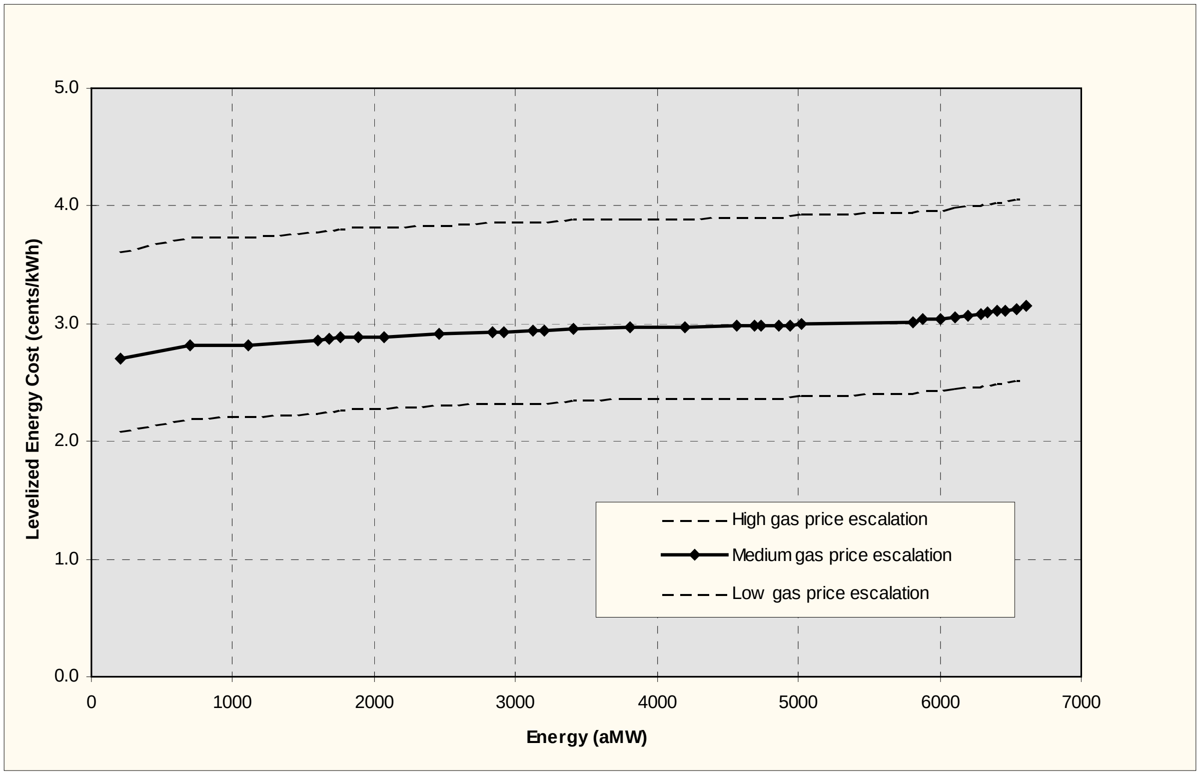
Potential for Additional Gas-fired Bulk Power Generation

The emerging competitiveness of bulk electric power generation using natural gas and combined-cycle gas turbines was evident at the time the 1991 Power Plan was developed. Forecasted gas price escalation rates had declined since the mid-1980s, and advanced high-efficiency combustion turbines were entering the market. The low fixed costs of combined-cycle equipment suggested an economical match to the Northwest power system, with its swings in annual hydropower availability. The analysis of resource alternatives for the 1991 Plan indicated that new gas-fired, combined-cycle plants could produce electricity at a levelized cost of about 5.4 cents per kilowatt-hour, if operated as independent, baseload power plants. If operated in conjunction with the hydro system, the melded cost of firm power would be less. The 1991 analyses indicated that at least 3,000 megawatts of energy from gas-fired, combined-cycle power plants could be developed at costs less than that of conventional new resources such as coal. The 3,000-average-megawatt limit of the 1991 Plan resulted from concerns regarding the ability to develop additional long-distance gas transmission capacity.

Because of the emerging importance of natural gas as a fuel for future power generation, the Council convened an advisory committee to reassess the future cost and availability of natural gas for electric power generation. The resulting estimates of future gas cost (Appendix C) include the estimated cost of expanding the long-distance gas transmission system to supply natural gas for future generating resource additions. This assessment of the likely cost and supply of bulk power from gas-fired generation considered other factors that might constrain development during the 20-year assessment period -- specifically the availability of suitable generating plant sites.

The revised estimate of new bulk generating potential using natural gas is illustrated in Figure FNG-2. It is estimated that at least 7,200 megawatts of new gas-fired combined-cycle gas turbine power plants could be developed at Northwest sites. This amount of generation could produce about 6,600 average megawatts of energy if fully dispatched. The levelized cost of this power would range from about 2.7 to 3.2 cents per kilowatt-hour if medium gas price forecasts are realized. Power costs could range as low as 2.1 to 2.5 cents per kilowatt-hour if gas prices followed the low forecast, and 3.6 to 4.1 cents per kilowatt-hour if gas prices escalated at forecast high rates. The range of energy costs within any one gas price forecast is not great because of the small capital cost component at even the least favorable sites.

Figure FNG-2
Estimated Cost and Potential Supply of Electricity From Natural Gas



The levelized energy costs of Figure FNG-1 are based on a 30-year project life and unregulated financing described elsewhere in this appendix. The cost and losses of interconnection to the central grid are included. The costs are based on service in year 2000, with projected technology improvements and cost reductions. Because capital costs represent a small portion of overall energy costs of a combined-cycle gas turbine power plant, tax-free municipal financing would reduce levelized energy costs by only about 7 percent.

Approach to the Assessment

This assessment is based on the availability of suitable sites for combined-cycle gas turbine power plants. Sufficient natural gas appears to be available to meet credible Pacific Northwest electrical needs for the next 20 years. Long distance gas transmission capacity is currently in surplus, and opportunities for continued expansion of long-distance transmission capacity within existing corridors are available. Combined-cycle gas turbine technology appears likely to continue as the preferred technology for new gas-based bulk power generation during the 20-year period of this assessment. The principal factor that is likely to affect the supply and cost of bulk electrical power using natural gas appears to be the availability of power plant sites.

Possible sites were identified, and the probability of being able to develop power plants at these sites estimated. The cost of development was based on base power plant costs adjusted by the cost of developing needed site services and the incremental cost of adapting the base technology to fit specific site constraints. Levelized power cost was estimated using the forecast “utility” natural gas prices of Appendix C.

A set of 37 possible sites for additional combined-cycle power plants in the Northwest was identified. These were compiled from an inventory of existing and proposed gas-fired power plant sites. Several sites that have not been proposed for plant development, but which appear to be feasible for the development of such facilities were also included. These latter sites appear to meet the following requirements: Reasonable distance from gas transmission mainlines; reasonable distance from electrical transmission lines of sufficient size to support at least one 230-megawatt unit; water to support at least one 230-megawatt plant operating on wet cooling; and airsheds in full compliance with ambient air quality criteria. This set of sites is shown in Figure FNG-3.

Figure FNG-3

Existing and Potential Gas-fired Power Plant Sites in the Pacific Northwest

The total number of combined-cycle gas turbine units that could be developed at each site (in addition to any units currently scheduled for construction) was estimated. Factors considered included water availability, air quality, current and adjacent land uses, existing project proposals and accessible transmission capacity. The estimated number of potential units at each site ranged from one to four.

Because of the limited information upon which this assessment was based, there is no certainty that plants could actually be developed at many of these sites (On the other hand, additional suitable sites, not included in this set are likely to be present in the region). To account for development uncertainties, a probability of successful development was estimated for each site. These probabilities were based on the current permitting status and use of the site. Probabilities ranged from 20 percent for non-industrial sites that have never been proposed for power plant development, to 98 percent for sites where permits for new plant construction have been issued. The capacity of potential new units at each site was multiplied by the corresponding estimated development probability and the products summed for a regional potential.

The cost of development was next estimated for each site. To the base capital and operating costs of a one- or two-unit combined cycle gas turbine power plant (Table FNG-1), were added estimated site-specific incremental costs. These included the following:

- Permitting costs (in addition to current permits)
- Secondary fuel oil system (sites in SO_x and particulate attainment areas)
- Weather enclosure (sites east of the Cascades)
- Noise abatement (sites 0.5 miles from residential uses)

- Dry cooling (sites with no apparent bulk water supply)
- Gas pipeline lateral (from nearest natural gas mainline)
- Transmission interconnection (from nearest substation of 230 kV, or greater)
- Water pipeline and pretreatment (sites not in industrial parks)
- On-site wastewater disposal (sites not in industrial parks)
- Incremental selective catalytic reduction to 3.0 ppm (sites in ozone non-attainment areas)
- Carbon monoxide oxidation catalyst (sites in carbon monoxide non-attainment areas)
- Transmission wheeling (point of interconnection to the central grid)

Levelized costs were computed from the resulting capital and operating costs and medium gas price forecast. Upper and lower cost boundaries were also computed using forecasted low and high gas price escalation rates.

Planning Model Data and Additional Increment

For the purpose of providing input data for the Council's system models, the resulting supply curve was split into two blocks, one consisting of sites where construction permits are currently held, or are being sought, and one consisting on sites with no permitting activity. These blocks are shown in Table F-1.

The sites considered in the foregoing analysis are primarily limited by the availability of cooling water. To represent the possible cost of gas-fired power plant development beyond these sites, a "high-cost" block was created. The cost of this block was based on the use of dry cooling. Dry cooling would substantially reduce the amount of water required to support a plant and would open up the possibility of many additional sites. Characteristics of the "high-cost" dry cooling block are shown in Table F-1.

Potential for Additional Gas-fired Cogeneration

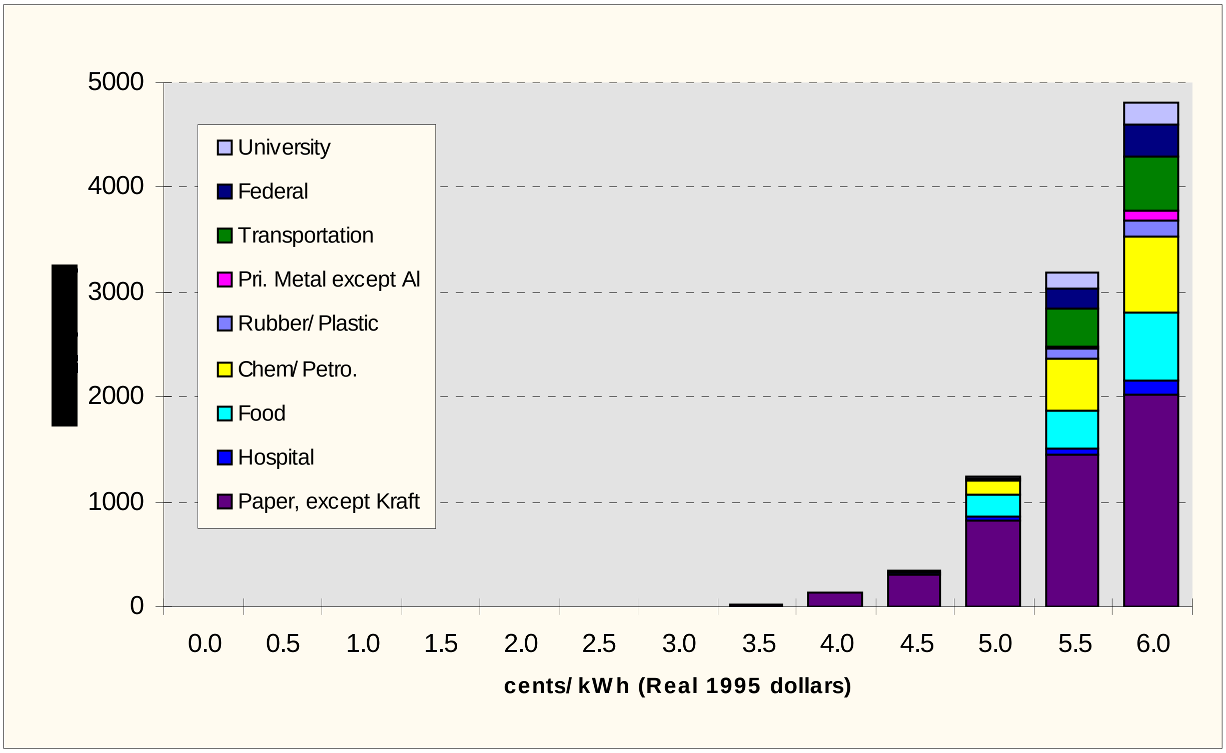
In its 1991 Power Plan, the Council estimated that 1,720 megawatts of energy could be secured from new natural gas-fired cogeneration at levelized energy costs ranging from 3.4 to 6.9 cents per kilowatt-hour. During the ensuing five years, approximately 1,270 megawatts of new cogeneration capacity using natural gas as the primary fuel has been brought into service or placed under construction. Because of the decline in forecasted natural gas prices since the 1991 Power Plan, and the type and extent of cogeneration development that has occurred since 1991, the potential supply and cost of new gas-fired cogeneration was re-estimated.

The revised estimate of natural gas-fired cogeneration potential is illustrated in Figure FNG-4. It is estimated that approximately 4,800 average megawatts of energy could be secured from additional natural gas-fired cogeneration over the next 20 years. Approximately 4,170 megawatts of this total could be obtained from industrial applications, and the balance from commercial facilities. The levelized cost of this energy would range from 2.5 to 6.0 cents per kilowatt-hour, with most being above 4.0 cents. This estimate is larger than the cogeneration supply estimate developed for the 1991 Plan because of lower gas prices and relaxation of the thermal load-matching requirements used for the base case of the 1991 Plan.

The sector appearing to have the greatest cogeneration potential is pulp and paper. This is the industrial sector with the greatest amount of cogeneration currently installed. Other sectors appearing to have large cogeneration potential include food processing, the chemical and petroleum sector, transportation as well as large military and other federal facilities.

The results of this assessment cannot simply be added to results of the assessment of bulk power generating potential for a regional total. Some of the potential host facilities considered in the cogeneration assessment are located at sites included in the assessment of bulk power generation potential. Because of the economics of cogeneration, some of the applications included in the cogeneration assessment are oversized. Possible cooling water and air quality limits are not considered. Finally, though the natural gas price forecasts include the cost of incremental long-distance gas transmission, it is not clear that gas could be expanded at those prices to the extent required to support the combined resource potential identified here.

Figure FNG-4
Estimated Cost and Supply of Natural Gas Cogeneration



Approach to the Assessment

This assessment of cogeneration potential used the approach developed by Bonneville, PNUCC and the Council for joint development of cogeneration supply curves for the 1991 Plan. Central to this approach is the Cogeneration Regional Forecasting Model (CRFM), a computer model developed for the Bonneville Power Administration. Several upgrades and refinements were incorporated into this model before this re-assessment. Model input data, including the cost and performance of representative cogeneration systems and the population estimates for potential cogeneration host facilities were also reviewed and updated where necessary.

CRFM forecasts the economic and technical circumstances and technology options likely to be available to potential cogeneration project owners. Project economics are evaluated and used to simulate project development decisions. The model estimates cogeneration cost and potential for individual categories of potential host facilities. The cogeneration potential of each category of facility is then scaled using facility population estimates to derive regionwide cogeneration potential. This approach is similar to that used for development of conservation supply curves. Both methods require a forecast of a diverse set of facilities, estimation of their energy use patterns, and simulation of decision-maker behavior.

In the CRFM, the Pacific Northwest is divided into 23 subregions. These subregions were selected with consideration of electricity prices, climate zone, type of serving utility (consumer-owned or investor-owned), and the boundaries of the Bonneville service territory. Facilities that potentially could install cogeneration equipment are grouped into 25 types, based on energy use patterns. Eleven of the facility types are industrial plants, the remaining 14 are commercial facilities. Each of the facility types is further broken down into four typical size categories. The combination of subregions, facility types, and facility sizes yields 2,300 separate facility categories that are individually evaluated for cogeneration potential. The model includes a data base of the estimated current number of existing commercial and industrial facilities that fall into each of these 2,300 categories. In addition to the number and type of facilities, representative electrical and thermal energy use patterns are defined for each facility type within each subregion. These are differentiated seasonally and are assembled into load duration curves.

The model attempts to match a cogeneration technology with each of the 2,300 facility categories. The model chooses from a set of representative technologies, including various sizes and configurations of reciprocating engines, gas turbines, boiler-steam turbines and combined-cycle gas turbines. Each has different capabilities with respect to electrical and thermal outputs and the applications and modes of operation they are best suited for. Using assumptions regarding fuel prices and the price at which the facility could sell electricity, the model performs a rate of return analysis to determine the system technology, size, configuration and operation most appropriate for each facility type.

When cogeneration systems have been selected for all of the facility categories, the results are scaled up by the expected number of facilities existing in the 20th year. Checks are made at this point to ensure that minimum present value savings and internal rates of return are attained. This process yields a distribution for a supply of cogeneration as a function of internal rate of return. Assumptions are made about penetration (decisions to install the cogeneration equipment) at different levels of internal rates of return. Typically, the higher the internal rate of return, the greater the penetration. These penetration limits are used to reduce the economic potential to an achievable potential.

This entire procedure is run for various electricity sell-back prices (the price utilities will pay for cogenerated electricity) to produce a supply curve for cogeneration electric energy potential as a function of sell-back price.

The model requires several key assumptions, including the price of fuels; the allowed electrical/thermal output ratio; decision-makers' propensity to install cogeneration at different internal rates-of-return, and industrial growth forecasts.

Natural gas prices were set to be consistent with the sector and size of the cogeneration system. Gas prices for small-scale cogeneration in commercial sectors, for example, were based on the commercial gas price forecast described in Appendix C.

The base case described here is intended to simulate market-driven development of cogeneration. This case uses a minimum electrical/thermal output ratio of 19:1 (the minimum established by PURPA). In contrast, the base case assumption of the 1991 Plan was a 50:50 electrical/thermal output ratio, intended to simulate thermally matched cogeneration. Though thermal match is viewed as desirable because the resulting non-power benefits (offsetting net air emissions, for example), a market-driven base case was sought here for use as the basis for exploring the costs and benefits of policies to encourage thermally matched cogeneration.

The model requires penetration be defined as a function of internal rate-of-return. There appears to be very little empirical data on this subject, and the public review process conducted in conjunction with development of the 1991 Plan provided only qualitative input. The base case assumptions of the 1991 Plan were retained.

The results of the base case analysis are shown in Figure FNG-3. The energy values represent the amount of energy that could be available by the end of the 20-year planning period. The electricity sell-back prices shown are real levelized cents per kilowatt-hour and are expressed in January 1995 dollars.

APPENDIX FNU

NUCLEAR POWER

NUCLEAR POWER

SUMMARY

Energy can be produced by the controlled fissioning (splitting) of isotopes of heavy elements such as uranium, thorium and plutonium. At its inception, commercial nuclear power promised to be an economical, abundant and non-polluting source of electric power. But the commercial history of this technology has been troubled. Construction cost overruns, failure of many plants to perform reliably, catastrophic plant failures at Three Mile Island and Chernobyl, seemingly intractable problems with establishing a permanent high-level waste repository and escalating operation and maintenance costs have diminished the promise of this technology.

These factors have led to intense controversy regarding commercial nuclear power. No plants have been ordered in the United States since 1978, and all orders placed since 1973 have been canceled. Nonetheless, 110 operable reactors, amounting to 100,929 megawatts of capacity, are licensed for commercial operation in the United States (Uranium Information Centre, 1996). These plants produce about 20 percent of the electricity consumed in the United States. The performance of most of these plants has been slowly improving as their owners face the need to reduce costs to survive in an increasingly competitive environment.

There are no plans to construct additional nuclear plants in the United States. Furthermore, factors, including the anticipated restructuring of the electric power generation industry into unregulated competitive firms, continued vocal public opposition to nuclear power, inability to resolve the high-level waste disposal issue and alternative lower-cost sources of energy, make construction of new nuclear power plants in the United States highly unlikely for the foreseeable future. The industry remains viable in countries with limited fossil fuel supplies, high energy costs, public support and the governmental and industrial structure and commitment to support the scale of construction required to build these plants.

PACIFIC NORTHWEST NUCLEAR PROJECTS

One operating commercial nuclear power plant remains in service in the Pacific Northwest. That plant is the Washington Public Power Supply System's Nuclear Project 2 (WNP-2), located on the Hanford Reservation in Eastern Washington. WNP-2 is a 1,170-megawatt boiling water reactor plant that has been in service since 1984. This plant's expected energy production is 821 average megawatts. WNP-2 is owned and operated by the Supply System. The output of WNP-2 is assigned to 94 consumer-owned utilities, which have re-assigned their shares to Bonneville through net-billing agreements. The capacity of WNP-2 has been upgraded by 76 megawatts since the 1991 Power Plan.

Bonneville and the Supply System face a difficult economic situation with respect to continued operation of WNP-2. Though the Supply System has been making an intensive and largely successful effort to improve the performance and to reduce the operating costs of the plant, the long-term variable costs of operating WNP-2 remain higher than near-term wholesale power costs. Comparison of long-term forecasts of WNP-2 variable costs and wholesale power costs show no clear economic advantage in either terminating or continuing plant operation, unless plant performance deteriorates or costs increase unexpectedly.

The Trojan Nuclear Plant, located on the Columbia River near Rainier, Oregon, was a 1,152-megawatt capacity pressurized water reactor plant, in service from 1976 to 1993. During its last years of operation, the plant sustained continued leakage of steam generator tubes. Trojan was taken out of service in January 1993, after analysis indicated that there was little or no economic benefit to steam generator replacement and continued operation. The plant is being dismantled.

Eight additional commercial nuclear plants were at one time planned in the Northwest. Six were terminated when it became evident that their output would not be needed in the foreseeable future.

Construction of two others, WNP-1 and WNP-3, was suspended when these plants were about 65 and 75 percent complete, respectively. These plants were preserved by the Bonneville Power Administration for possible completion for many years. But declining natural gas prices and a growing surplus of capacity in the West has led to termination of these plants. Useful components and materials will be salvaged, and the sites will be converted to other uses.

ADVANCED NUCLEAR POWER PLANTS

The nuclear industry and governments of the United States, Canada, Japan, France, Russia and Germany are developing advanced nuclear power plant designs intended to address some of the problems confronting the nuclear power industry. Objectives of these advanced designs include improved economics, reduction in investment risk and improved safety. These objectives are expected to be accomplished by reducing plant sizes, increasing factory fabrication, increasing reliance on "passive" safety systems requiring no operator intervention, general simplification of design, increasing safety margins, improving maintainability and improving operator-machine interfaces. Guiding the development of advanced designs is a philosophy of avoiding revolutionary design changes in favor of an evolutionary approach that begins with refinement of current designs.

Three classes of advanced power reactors are under development in the United States. These include "large evolutionary" designs based on incremental improvements to light water reactor designs developed in the 1970s. A large evolutionary plant has been recently placed into service in Japan, and the design is anticipated to be certified for construction by the U.S. Nuclear Regulatory Commission in 1996. "Small evolutionary advanced" designs use light water reactor technology, but would incorporate significant downsizing and passive safety features. These designs may be available for order by the early 2000s. "Modular advanced" designs would use non-light water reactor technology and would incorporate extreme downsizing, a high degree of modularity and passive safety features. Modular advanced designs probably will not be available for order until 2010.

Large Evolutionary Plants

Two U.S. vendors are developing large evolutionary advanced designs. The models and vendors are General Electric's Advanced Boiling Water Reactor (ABWR) and the System 80+ by Asea Brown Bovari-Combustion Engineering. These designs are essentially refinements of these vendors' earlier light water reactor designs. They retain the large scale (1,200 megawatts capacity) and general engineering features of predecessor designs.

The Advanced Boiling Water Reactor is an evolutionary version of existing General Electric boiling water reactors such as WNP-2. Design of this plant has been under way since 1978, under the auspices of a consortium of U.S. and Japanese boiling water reactor vendors. Distinguishing features include a simplified coolant recirculation system, triple-redundant emergency core cooling, improved containment, and improved control and instrumentation systems. Two 1,365-megawatt units have been ordered by the Tokyo Electric Power Company for Kashiwazaki-Kariwa station. Construction began in 1991, and the first unit entered service in 1996.

The Combustion Engineering System 80+ is a refinement of the Combustion Engineering System 80 designs used at Palo Verde and at WNP-3. The principal design changes involve improvements to the containment building and the emergency core cooling system, a safety depressurization system, increased thermal margins and improved control room design. The System 80+ is expected to be certified by the Nuclear Regulatory Commission in 1996. Two System 80 reactors under construction in South Korea have been upgraded with some of the features of the System 80+. Design objectives for large evolutionary designs are shown in Table FNU-1.

Table FNU-1

Advanced Nuclear Plant Planning Goals

	Large Evolutionary Light Water Reactor	Small Evolutionary Light Water Reactor
Unit Capacity, net (MW)	1,100	600
Availability (%)	83	86
Heat Rate (Btu/kWh)	10,510	10,710
Overnight Cost ($/kW)	$1,500	$1,800
Fixed Operating Cost ($/kW/yr)[2]	$63	$78
Variable Operating Cost (mills/kWh)[1]	0.3	0.3
Fixed Fuel Cost ($/kW/yr)[2]	None (all treated as variable)	None (all treated as variable)
Variable Fuel Cost (mills/kWh)[2]	7.1	7.3
Development & Construction Lead Time (Years)	4/6	4/4
Cash Flow (%/yr, based on lead time above)[3]	2/2/2/2/10/15/21/21/15/10	2/2/2/2/18/28/28/18
Service Life (Years)	40	60
Comparative Levelized Energy Cost (cents/kWh)[4]	4.0	4.2

Small Evolutionary Advanced Plants

Small evolutionary advanced nuclear power plants would represent a major departure from contemporary nuclear power plant design. Despite their use of conventional light water reactor technology, these plants would be considerably smaller than current designs, would use greatly simplified mechanical and electrical systems, and would employ passive safety systems requiring no operator intervention for many hours following an abnormal occurrence. These designs are expected to have greatly improved performance and cost compared with contemporary designs. Design objectives for small evolutionary designs are shown in Table FNU-1.

One small evolutionary advanced design is currently being developed in the United States. The Westinghouse AP-600 would employ conventional pressurized light water technology in a 600-megawatt plant, featuring overall simplification, a passively actuated and operated emergency core cooling system, and advanced instrumentation and control systems. A three-year construction schedule is targeted, with a five-year overall lead time from order to commercial operation. Construction costs are expected to be about $1,700 per kilowatt. The AP-600 is being developed under a program partially funded by the U.S. Department of Energy.

[1] Exclusive of property tax and insurance. See Financial Assumptions section for assumptions regarding property taxes and insurance.
[2] Exclusive of property tax and insurance. See Financial Assumptions section for assumptions regarding property taxes and insurance.
[3] Council assumption for calculating reference levelized power cost.
[4] 15-year financing by unregulated developer, year 2000 service, levelized over a 30-year period.

Work on a second small evolutionary advanced design, the General Electric Small Boiling Water Reactor (SBWR) was terminated earlier this year.

Modular Advanced Plants

Modular advanced reactors would employ alternatives to the conventional light water reactor technologies used in the current generation of commercial nuclear plants to achieve the objectives of improved performance and safety, and lower construction and operating costs. Several concepts have been proposed, most highly modular, with unit sizes of 100 to 300 megawatts. These small sizes would permit greater factory fabrication, better quality control, shorter construction lead time and would allow for improved containment of radioactive materials. Several design concepts envision arrays of small reactors operated by a central control room and supplying a common turbine-generator to capture some of the economies of scale associated with larger plant sizes.

Through a joint venture, General Atomics (United States) and MINATOM (Russia) are developing the Modular High Temperature Gas-Cooled Reactor. This reactor would be built as modules of 250 to 285 megawatts each. Ceramic coated fuel would permit increased operating temperature and thermodynamic efficiency. The helium coolant would directly drive a gas turbine generator. It is not expected that this design will be available prior to 2010.

Other Advanced Fission Reactors

Canada has advanced versions of its CANDU series of heavy water moderated reactors under development. Nuclear Power International, a French and German joint venture, is developing a large (1,450 megawatt) pressurized water reactor intended to be a standard European design. Other advanced designs are being developed in Russia and Japan. Though current uranium prices are too low to justify the expense of breeder reactors, fast breeder research continues in France, India and Japan.

NUCLEAR FUSION

The energy released by the fusion of light elements powers the stars and thermonuclear devices. Nuclear fusion power plants would use controlled fusion reactions to produce useful power. Several fusion reactions are possible, but the one that has received the greatest attention for controlled power production, because it occurs at the lowest temperature, is the reaction of the hydrogen isotopes deuterium and tritium. Deuterium and tritium combine under extremely high temperature and pressure to produce helium and energy.

The difficulty in achieving controlled nuclear fusion has been to maintain sufficient temperature and pressure conditions to sustain fusion reactions while creating an overall surplus of energy. One approach that have been extensively researched is magnetic confinement of the deuterium and tritium fuel in a high temperature plasma. A second approach is sequential implosion of small beads of fuel by multiple lasers.

The development of a practical fusion reactor that produces a net power output on a continuous basis has proven to be far more formidable than was originally thought. Research and development have been under way for decades. Though controlled fusion reactions under laboratory conditions have been achieved, no process has yet yielded net energy production. The development of a practical fusion power reactor, once thought to be achievable within a decade or two is now thought to be a generation or more distant.

References

The Uranium Information Centre. 1996 *The International Status of Nuclear Power: Nuclear Issues Briefing Paper 7.* Melbourne, Australia.

The Uranium Information Centre. 1996 *Advanced Nuclear Power Plants: Nuclear Issues Briefing Paper 7.* Melbourne, Australia.

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APPENDIX FOE
OCEAN ENERGY

OCEAN ENERGY RESOURCES

SUMMARY

Because of their great surface area, the oceans and the overlying atmosphere absorb most of the solar energy intercepted by the Earth. The oceans also receive energy through the gravitational attraction of the moon and sun, and geothermal energy from the sea floor. Energy from these sources is manifested as wave power, marine biomass, oceanic winds, salinity gradients, thermal gradients, tidal power and ocean currents.

Many concepts have been advanced for producing useful power from ocean energy sources. Few of these proposals have achieved commercial viability. Although the absolute amount of energy from oceanic sources is very large, ocean energy resources are of low energy density. The equipment required to capture this energy and to convert it to a useful form must be massive and, therefore, costly. In addition, the ocean is a hostile environment. Storm surges, corrosion, moisture, motion and fouling by marine organisms place demanding requirements on the design and maintenance of marine energy conversion equipment. Finally, many sources of oceanic energy are intermittent and cyclical, lessening the value of power produced from these sources.

In the development of its 1991 Power Plan, the Council investigated the commercial status of ocean energy technologies and prospects of producing electric energy from the ocean energy resources of the Northwest. The conclusions of that analysis are reproduced below. Because there does not appear to have been substantial development of ocean energy technology since completion of that investigation, we believe that the conclusions of the 1991 Power Plan remain generally valid. A complete copy of the 1991 assessment is available from the Council on request.

Wave Power

The most promising of the oceanic energy resources for the Pacific Northwest appears to be ocean wave energy. The Pacific Northwest wave climate is the most energetic of any of the contiguous United States and is within the range of wave power levels considered suitable for wave energy development. Shore-mounted wave energy conversion devices are the most mature technologies available for wave energy power generation, having been demonstrated at the commercial scale. But, because of land use conflicts and aesthetic impacts, suitable sites for shore-mounted devices are likely to be few in the Pacific Northwest. Off-shore (floating) wave energy conversion systems hold more promise for widespread application in the Pacific Northwest, but this technology has not advanced beyond the scale model testing stage. Widespread commercial deployment of wave power devices in the Pacific Northwest would require these preconditions: development and testing of prototypes for operation under North Pacific conditions, demonstration of a commercial-scale project, and detailed resource and economic feasibility assessments. Rapid advancement of offshore wave energy technology is unlikely because of low levels of private and government research support.

Marine Biomass

Cultivation and gasification of marine biomass for production of methane may have future application in the Pacific Northwest. Because only very preliminary studies of this resource have been made, the applicability and cost-effectiveness of this concept in the region are very uncertain. It is unlikely that methane from ocean biomass will be economically competitive with natural gas for many years.

Salinity Gradient Power

Technologies for recovery of useful energy from salinity gradients are in their infancy, and it is not clear that the technology as presently conceptualized would be able to operate off naturally occurring salinity gradients between sea water and fresh water at stream estuaries. If salinity gradient energy conversion devices could operate on naturally occurring salinity gradients, the Pacific Northwest would have a large potential resource.

Tidal Power

Tidal hydroelectric power plants are a proven technology. Pacific Northwest tidal conditions, however, are inadequate to support cost-effective operation of currently available technology. Technological improvements that could allow use of Pacific Northwest tidal resources for electricity generation do not appear likely in the foreseeable future.

Ocean Current Power

Scale models of water current turbines suitable for capturing the energy of oceanic currents have been tested. The oceanic currents of the Pacific Northwest, however, are weak, poorly defined and incapable of powering proposed designs. There may be limited application of water-current turbines in the Northwest for extracting energy from stream currents and from local tidal currents in Puget Sound. Because the latter are cyclical and intermittent (though predictable), the cost-effectiveness of these applications likely would be poor.

Thermal Gradient Power

Megawatt-scale ocean thermal energy conversion (OTEC) power plants have been demonstrated, although major technical problems remain. Pacific Northwest ocean thermal gradients are insufficient to operating current OTEC technology. Technological improvements allowing use of Northwest thermal gradients are unlikely.

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APPENDIX FSO
SOLAR

SOLAR

SUMMARY

Solar energy is the most abundant renewable source of energy available to the Pacific Northwest. Although seasonally and geographically variable, solar energy is the one power source available virtually everywhere in the Northwest. It produces no carbon dioxide or other greenhouse gasses during operation and has no up-stream environmental impacts associated with fuel production and transportation. There are some environmental impacts associated with the land used for collector arrays and with the production of collector materials, particularly by-products of the manufacturing of semiconductors for photovoltaics.

There is enough solar energy falling within the geographic boundaries of the Pacific Northwest to supply all of the power needs of the region. Although there has been no formal site assessment for plant locations, a solar resource monitoring network has generated a significant amount of long-term data about the quantity and characteristics of solar energy in a number of locations.

While it is abundant, solar energy is also a very diffuse resource and, unlike the region's hydro and wind resources, solar does not have any naturally occurring features that concentrate the resource for collection. Therefore, the largest barriers to development of the resource are the cost of constructing the facilities to capture and convert solar to electric energy. Currently, the cost of the conversion devices makes it uneconomical as an alternative to other bulk-power generating resources. Costs range from 21 cents per kilowatt-hour using current technology for rooftop, grid-connected photovoltaic systems, to the projected cost of central station photovoltaic power plants at 16 cents per kilowatt-hour in the year 2000. Technology improvements and expansion of production capacity continue to reduce the cost of photovoltaic devices. If this cost reduction continues at the rates observed over the past decade, power costs from central station photovoltaic plants will decline to 5.8 cents per kilowatt-hour by 2015.

There are some applications where solar is cost-effective even at today's costs. These applications are in locations where the cost of connecting to the existing power system exceeds the cost of a stand-alone power system. These remote power applications of solar energy have been operating for many years in the region, and the market, though small, is growing.

Other issues slowing the development of the solar resource are also cost-related. Because the best sites are located a long distance from the load centers, central station solar will incur costs and energy losses to transmit the power to the existing system. This cost will be increased by the low capacity factor of the solar resource. Because solar is a summer-peaking resource, it provides a poor match to the winter-peaking loads of the Pacific Northwest, thus reducing the value of the annual energy output to the regional system.

Given the high cost of solar energy plants for bulk power production, it is unlikely that the region will pursue development of the resource in the near future. However, the number of remote photovoltaic applications is likely to increase and could be used as a vehicle to increase production-scale efficiencies. Technological advances, especially in the manufacture of semiconductors, could dramatically lower the cost of these devices and make them more applicable at the end-use where they are most valuable. Further characterization of the solar resource in the Pacific Northwest and its long-term availability and coincidence with hydro and wind resources should provide better understanding of how the resource could be valued in an integrated system application.

PACIFIC NORTHWEST SOLAR RESOURCES

Energy from the sun falls everywhere in the Pacific Northwest in the form of sunlight or "solar radiation," often referred to as insolation. However, the amount of solar radiation actually reaching the ground is a function of latitude, atmospheric conditions and local shading. The most significant factor affecting solar power generating potential in the Pacific Northwest is reduction due to atmospheric cloud cover. For this reason, the areas with the highest resource potential are east of the Cascade Mountains, where the annual cloud cover is significantly less than it is to the west of the mountains. Since latitude and shading are also important, the most promising sites tend to be along the southern geographic edge of the region, in relatively flat terrain, without significant shading from nearby mountains. Specifically, the best areas are in the inter-mountain basins of south-central and southeastern Oregon, the Snake River plateau of southern Idaho, and the high plains of south-central Montana. These areas receive about 75 percent of the insolation received in Barstow, California, the site of the Solar Two central solar thermal power demonstration facility. By comparison, Eugene, Oregon, west of the Cascades, receives about 47 percent of the insolation received in Barstow.

Because large-scale solar power plants have never approached cost-effectiveness in the Northwest, there have been no comprehensive studies of individual site suitability. However, there is a network of measurement stations monitoring solar in various places in the Northwest that permits the development of rough contour maps showing the general solar characteristics of the region.

Solar radiation arrives at the earth's atmosphere as "direct-beam" radiation; that is, all of the light is oriented in a specific direction as if it were drawn in straight lines from the sun to a given location on the earth. As the sunlight passes through the atmosphere, some of it is reflected in random patterns by dust and moisture and converted to "diffuse" or non-directional radiation. Thus, the solar energy actually reaching the earth is made up of both direct-beam and diffuse radiation. In areas with lots of cloud cover, almost all of the energy striking the earth is diffuse. In cloudless areas it may be almost totally direct-beam. This distinction is important in determining the type of solar energy collection devices that are most appropriate for a given location. Devices, such as parabolic trough collectors, which rely on focusing solar energy, use only the direct component of solar radiation. Non-focusing devices, such as flat-plate photovoltaics, capture both direct and diffuse radiation. Measurements of solar radiation potential must therefore consider both components.

Contour maps of solar radiation have been developed based on extrapolation and interpolation of data collected at specific sites. These maps are shown in Figures FSO-1 and FSO-2. Figure FSO-1 shows total daily radiation (direct-beam and diffuse) on a flat surface facing south and tilted by a number of degrees equal to the latitude of the site. This represents the most effective orientation for fixed flat-plate collectors. Figure FSO-2 shows daily direct-beam radiation, measured on a horizontal surface.

Figure FSO-1

Average Daily Total Solar Radiation on a Tilted South-facing Surface, Tilt Equal to Latitude (MJ/m^2)[1]

Figure FSO-2

Average Daily Direct-beam Normal Solar Radiation (MJ/m^2)

[1] One megajoule= 0.28 kilowatt-hour.

Because the contour lines of constant radiation levels of Figures FSO-1 and FSO-2 are interpolations of data collected at scattered sites, local variation in the solar resource may be missed. For example, though solar radiation levels in the Olympic rain shadows have been shown to be much higher than surrounding areas of western Washington, this local effect is not shown in Figures FSO-1 and FSO-2.

Figures FSO-1 and FSO-2 are based on the *Solar Radiation Energy Resource Atlas of the United States*, published in 1981. Since then, additional data have been collected by the University of Oregon Solar Monitoring Laboratory through work sponsored by Northwest utilities. This effort languished for several years, but has recently been expanded with the re-establishment of a regional solar monitoring network (Figure FSO-3).

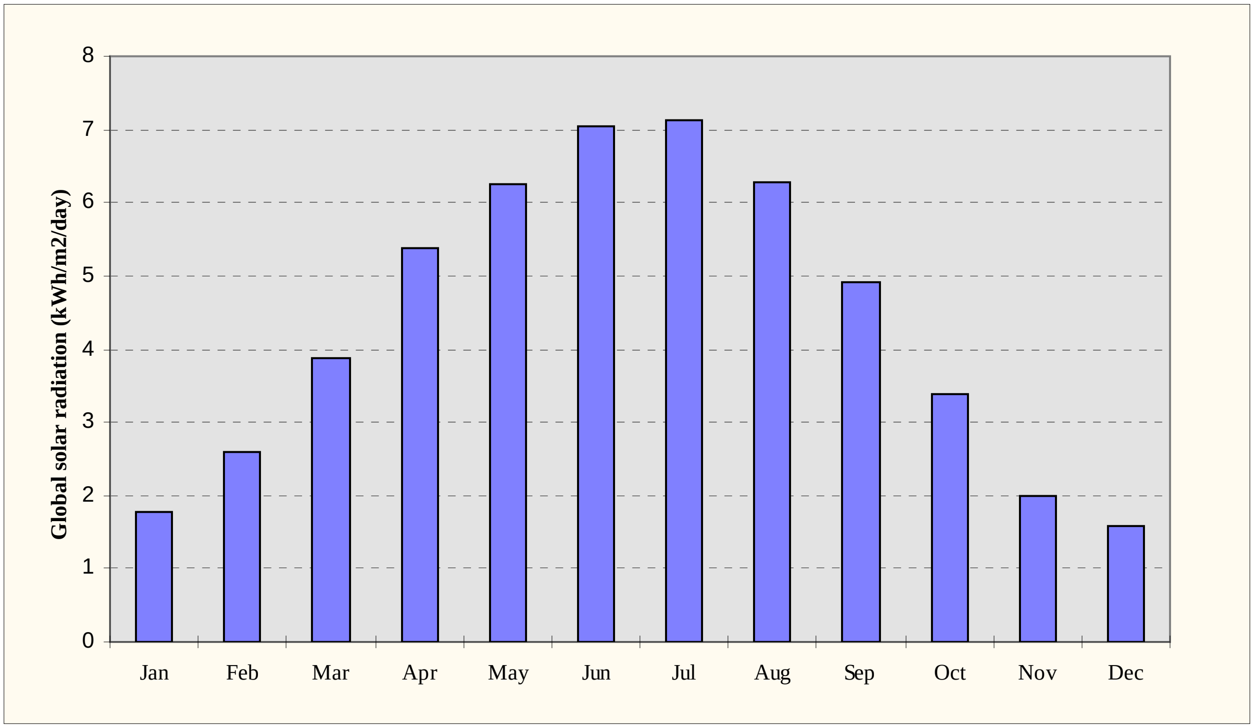
Figure FSO-3

Pacific Northwest Solar Radiation Monitoring Network (March 1996)

As might be expected, the seasonality of solar radiation in the Northwest exhibits a strong summer peak. For example, the average daily global insolation at Whitehorse Ranch, in southeastern Oregon, the best Northwest site for which records exist, is shown in Figure FSO-4. The strong summer seasonality of the northwest solar resource suggests that while the solar resource has potential for serving local summer-peaking loads, such as irrigation and air conditioning, it may be less suitable for central station power plants serving more general regional loads.

Figure FSO-4

Average Daily Global Insolation at Whitehorse Ranch in Southeastern Oregon (UOSML, 1989)



SOLAR POWER PLANTS

Solar-electric technologies are divided into two broad categories, solar-thermal energy systems and photovoltaics. Solar-thermal systems are similar to conventional generating plants in that heat generated by solar collectors is converted into electricity using a working fluid and heat engine, such as a turbine-generator. Photovoltaics is a solid state process that uses semiconductor materials to convert solar energy to electricity. Each of these categories encompasses several different technologies.

Described below are the principal technologies used to generate electricity from solar radiation. Table FSO-1 summarizes the characteristics of representative solar-thermal and photovoltaic power plants that are commercially available or are expected to be commercially available by 2000.

Solar Thermal Power Plants

All solar thermal technologies have collectors to concentrate solar energy, receivers to heat a working fluid and mechanical heat engines driving electric generators to convert the energy contained in the heated working fluid to electricity. Some solar-thermal designs incorporate an energy storage facility to smooth and shift the availability of energy from the plant.

The challenge for solar-thermal plants is to collect diffuse solar energy economically and to concentrate this energy to produce the high temperatures needed for efficient heat engine operation. Therefore, collectors are characterized by large surface area and a geometric configuration to allow them to focus the energy on a smaller receiver. The three leading solar-thermal power plant designs are distinguished by the geometrical arrangement of collectors and receivers. These are central receivers, line-focus parabolic troughs and point-focus parabolic dishes. These designs are illustrated in Figure FSO-5 and described below.

Figure FSO-5

Solar-thermal Technologies (USDOE, 1986)

Table FSO-1
Solar-thermal technologies

	Central Receiver Solar-thermal Power Plant[1]	**Parabolic Trough Solar-thermal Power Plant**	**Parabolic Dish Solar-thermal Power Plant**[2]	**Central-station Photovoltaic Plant**	**Rooftop Photovoltaics Installation**
Configuration	100 -200 MW w/thermal storage	80 MW w/supplemental gas firing	5 - 25 kW MW w/int. Stirling engine	100 MW Fixed flat-plate	5 kW rooftop array, grid-connected
Current Status	Demonstration	Early commercial	Demonstration	Demonstration	Commercial
Application	Bulk power production	Bulk power production	Remote service, distributed grid support, bulk power production	Bulk power production	Distributed grid support
Unit Capacity, net (MW)	100 - 200	80	0.005 - 0.025	101.5	0.005
Capacity Factor (%)	55 - 63 %	28%[3]	22 - 28 %	21%	21%
Heat Rate (Btu/kWh)	--	9,616	--	--	--
Overnight Cost ($/kW)[4]	$2,900 - 3,500	$3,900	$1,250 - 2,000	$3,820[5]	$4,500
Fixed Operating Cost ($/kW/yr)[2]	Included in variable O&M	$55	Included in variable O&M	$3.50	$10
Variable Operating Cost (mills/kWh)[6]	5.0 - 8.0	2.0	15 - 25	0.8	0.0
Development & Construction Lead Time (Months)	--	24/24	--	24/12	<12
Cash Flow (%/yr)	--	1/1/38/60	--	1/1/98	100
Service Life (Years)	30	30	30	30	20
Levelized Cost (cents/kWh)[7]	4.6 - 6.5	18[8]	5.5 - 10.6	16	21

[1] Cost and performance estimates from DeLaquil, et al., 1994 early mass production 2005 - 2010.
[2] Cost and performance estimates from DeLaquil, et al., 1994 early mass production 2005 - 2010.
[3] Solar operation.
[4] Lifetime average capacity basis.
[5] 2000 - 2005 cost.
[6] Exclusive of property tax and insurance. See Financial Assumptions section for assumptions regarding property taxes and insurance.
[7] 15 year financing by unregulated developer, year 2000 service, no incentives.
[8] Solar-only operation.

Parabolic Troughs

The concentrating collector of parabolic trough plants consists of a series of long troughs of parabolic cross-section. The troughs are formed of reflective material that focuses the solar radiation energy on an in-line (parallel to the trough) receiver located at the focal point of the trough. Troughs typically are mounted horizontally and aligned in a north-south direction. The troughs rotate about the long (north-south) axis to capture as much of the sun's energy as possible. The receiver in the commercial parabolic trough power plants is a coated pipe inside a glass vacuum tube. The heat transfer fluid contained in the pipes is a synthetic oil that is heated to 735^{o} Fahrenheit and passed through an oil/water heat exchanger. Superheated steam is generated in the heat exchanger and used to drive a steam turbine generator. A supplemental natural gas boiler allows operation to continue when solar energy is unavailable.

The parabolic trough solar-thermal technology is less efficient, but simpler, and less-costly than other solar-thermal technologies. However, little potential for improvement is foreseen.

Parabolic trough power plants have been commercially available, though the largest manufacturer of these plants, Luz International, is now out of business. Luz developed 354 megawatts of parabolic trough solar thermal plants in California between 1984 and 1991, but went out of business when the financial incentives needed to make these units competitive were terminated. The existing plants remain in operation. Characteristics of a representative parabolic trough power plant are shown in Table FSO-1.

Central Receivers

Central receivers are characterized by a tower-mounted, fixed central receiver and a surrounding field of flat-plate heliostats (essentially moveable mirrors). The heliostats individually track the sun and reflect the collected energy to the receiver. Fluid is heated in the receiver and used to drive a turbine-generator, either directly or indirectly. Early demonstration central receivers used water as the working fluid. The receiver acted as a boiler and the resulting steam was used to operate a steam turbine generator. The Solar Two demonstration plant, completed in early 1996, uses molten salt as the heat transfer and storage medium, and water as the working fluid. The salt is heated in the receiver and circulated to an insulated storage tank. Hot salt is drawn off the tank and circulated through a salt/water heat exchanger. Steam is produced in the heat exchanger and used to drive a conventional steam turbine-generator. Because this design incorporates thermal storage, extended and dispatchable power output can be obtained.

Central receiver technology has the potential of higher efficiency than parabolic trough units. Current designs decouple generation from collection, offering the advantages of dispatchability and shifted generation on solar power. Fossil fuel backup could also be provided. Central receivers are inherently large units and best suited to central-station applications. The Solar Two demonstration unit is 10 megawatts, and commercial units at the 100-megawatt scale are envisioned.

Central-receiver units are in the demonstration stage. Commercial units may be available by about 2005. Target electricity costs are 7 cents per kilowatt-hour.

Point-Focus Parabolic Dish

Point-focus parabolic dish power plants use a dish-shaped individual collector-concentrator that focuses solar energy on a receiver at the focal point of the dish. The collector has to be pointed directly at the sun at all times, requiring an accurate two-axis tracking system. Most parabolic dish concepts use a combined receiver and small individual engine-generator (usually a Stirling reciprocating engine) suspended at the focal point. Alternatively, heat transfer fluid could be circulated between the receivers of individual units and a central storage tank and heat exchanger to produce steam to run a turbine generator. A natural gas fueled backup source of heat could be provided with either design.

Because parabolic dish designs in theory can achieve higher receiver temperatures than other solar thermal designs, they have the potential to achieve greater thermodynamic efficiencies. Also, the two-axis tracking system enables more of the available annual solar energy to be captured than either single-axis tracking or fixed plate designs. Because of physical constraints imposed by the free-standing tracking collector, individual units will likely be small -- ranging from 5 to 50 kilowatts in capacity.

Though several demonstration units have been built, the development of reliable, low-cost parabolic dish power plants has been difficult, and parabolic dish power plants are not yet in commercial production. Areas of technical difficulty include economically fabricating reflective materials into the geometric shape needed to optimize the concentration of solar energy, and the development of accurate tracking systems, reliable, low-cost receivers, engine-generators and heat rejection equipment. It is unlikely that parabolic dish units will be commercially available prior to 2000.

Because of the unresolved problems associated with parabolic dish technology, reliable estimates of cost and performance are not available. Target electricity costs for commercial units are in the range of 5 to 25 cents per kilowatt-hour (in 1992 dollars). Parabolic dish power plants will likely enter the market as sources of high-value remote power. If costs can be reduced, applications might expand to include distributed grid-connected power plants and eventually, central stations consisting of arrays of individual parabolic dish units.

Photovoltaic Power Plants

Photovoltaic cells are solid-state electronic devices that produce direct current electricity from incident sunlight. Individual photovoltaic cells are relatively small and are assembled into modules of several square feet. A photovoltaic power plant consists of arrays of photovoltaic modules, a supporting framework, and inversion and transformation equipment to convert the direct current output of the photovoltaic cell to alternating current of the desired voltage. In addition, grid-independent plants may have batteries to provide energy storage and backup generation.

There are two broad categories of photovoltaic power plants: those using flat-plate modules and those using concentrating modules. Flat-plate modules use both direct-beam and diffuse solar energy. They may be mounted on either stationary or tracking devices. Concentrating modules optically concentrate solar radiation. They can therefore use only direct-beam radiation and are mounted on tracking supports to follow the sun.

Though most photovoltaic plants for bulk power production have been fixed flat-plate arrays of crystalline silicon cells -- a moderately expensive, moderately efficient design -- it is unclear what approach might eventually prove to be most cost-effective. Future plant designs, on the one hand, might consist of arrays of flat plate modules using low-cost thin film cell technology, mounted on inexpensive fixed supports. On the other hand, fully tracking arrays of high-efficiency concentrating modules may prove to be the most cost-effective design.

The market for photovoltaic devices could expand greatly if costs are further reduced. Though cost reduction can be achieved through improvements in cell efficiency and reduction in cell cost, these two objectives have been somewhat incompatible. Highly efficient, but costly, concentrating modules are available, as are (relatively) inexpensive, but inefficient, flat plate thin film modules. The contending technologies include crystalline silicon, thin-film devices and concentrators.

Crystalline Silicon Devices

Crystalline silicon devices are the technology currently used in most large scale photovoltaic applications. The typical cell is based on a thin (less than 0.5 millimeters thick) wafer of silicon crystal of about 100 square centimeters, producing about one watt of power. Cells are typically grouped into flat plate modules consisting of several hundred cells. Crystalline silicon technology is relatively efficient and has proved to be reliable in outdoor applications. The ultimate efficiency of crystalline silicon cells is in the 29 to

30 percent range and efficiencies of 23 to 24 percent have been achieved in the laboratory. Current production cells achieve efficiencies of about 15 percent and continued increases in efficiencies are expected. The cost of growing the silicon ingots from which the cells are made, and the cost of cutting the wafers upon which the individual cells are based contribute to the relatively high fabrication costs. Further cost reductions are expected and ultimately, module costs could be reduced to $2 per watt.

Thin-Film Devices

Thin-film photovoltaic technology is the basis of the photovoltaic devices used in consumer products, such as watches and calculators. Thin film technology is based on sheets of amorphous (non-crystalline) silicon, which can be deposited on inexpensive support materials. The lower costs of thin-film cells result from using less costly material than crystal-silicon cells and from using laser technology to lay down the electrical conductors of the cells. In addition, thin-film cells can be made in much larger sheets than can other cells. The structure of thin-film devices is more amenable to mass production than the laborious crystal growing and slicing operations required for crystalline silicon technology. Because it can be applied to a variety of substrates, thin film technology offers the prospect of structurally integrated photovoltaics to products such as roofing tiles and wall cladding.

The theoretical efficiency limit of single-junction thin-film cells is 28 percent. The efficiency of commercial cells, however, is lower than that of crystalline silicon devices and deteriorates for a period following production, before stabilizing. Currently, the stabilized efficiency of commercial thin-film devices is 8.5 to 9 percent.

Research is proceeding on multiple-layer (multijunction), thin-film cells, which have theoretical efficiencies as high as 42 percent and promise greater durability. The concept employed is the use of materials in successive layers, each absorbing a different part of the solar spectrum. The layering allows for more of the sun’s energy to be gathered and converted to electricity. Commercial multijunction modules of 18 percent stabilized efficiency are ultimately expected.

The ultimate production cost of thin-film devices is forecast to be about $0.50 per watt

Concentrator Photovoltaic Technology

Concentrator photovoltaic technology uses lenses to focus and intensify the sunlight on the photovoltaic cells. Their prime advantage over other technologies is the ability to leverage the cost of expensive, but highly efficient, individual photovoltaic cells against a lower cost collector concentrator system. Concentrator photovoltaic cells using single silicon-crystal material have achieved efficiencies of 28 percent. Multijunction materials that absorb a broader portion of the solar spectrum have been demonstrated to achieve efficiencies of 34 percent under high concentrations.

There are numerous difficulties realizing these high levels of efficiencies in actual field experience. First, these systems can only use the direct-beam component of solar radiation. The diffuse sunlight from cloudy skies cannot be effectively concentrated. This characteristic excludes this technology from cost-effective use west of the Cascade mountains in the Pacific Northwest

Second, these systems require the ability to target the concentrated sunlight accurately on a cell that is as much as 500 times smaller that the aperture of the module. This involves both a highly precise active tracking system and an optical system to focus the sun’s image onto the cell. Significant progress has been made on the optics required to focus the sunlight. Current designs include low-cost, plastic, fresnel lens technology coupled with a small secondary refractive-glass lens over the cell that effectively focus non-direct radiation. The best of these designs tolerates a greater range of tracking error while still maintaining high optical efficiencies. However, the cost of these auxiliary components limits the cost trade-off available for the photovoltaic cell.

Third, the high concentration of sunlight generates extremely high temperatures in the photovoltaic cells. To maintain the cells at their optimal temperature for efficient operation, a cooling system must be installed to remove excess heat. Some early designs used liquid cooling or separate, bolt-on, air-cooled heat sinks. Current designs have focused more on passive air-cooled strategies that are simpler and lower-cost, often integrating the heat sink into the metal enclosure for the module.

The best demonstrated module efficiencies for concentrators are in the 20 percent range using single-crystal silicon cells of 24 to 25 percent efficiency and up to 22 percent for a prototypical galium-arsenide cell with 28 percent efficiency. Although there are some demonstration arrays currently in use, there are no concentrator modules in commercial production at this time. Estimated costs for a utility scale plant are $1.86 per watt module costs and $3.72 per watt total plant costs (in 1995 dollars).

DEVELOPMENT ISSUES

The principal factor currently constraining development of solar power is the capital cost of solar power plants. Issues that might become more significant if the cost of solar power plants can be reduced include the cost of transmission, and intermittence and seasonality. The environmental effects of solar power production are expected to be minor, but the land conversion required for bulk power generation would be substantial.

Cost

The primary factor presently constraining the development of solar power resources is the cost of power from these resources compared to current and forecast wholesale electricity prices. There are a few special situations where electricity from photovoltaic power plants may be cost-effective. Remote loads, small isolated loads, and summer peaking grid-connected loads can be cost-effectively served by photovoltaics. But power from central-station solar plants in the Northwest is expected to continue to be far more expensive than power from other alternatives for the foreseeable future.

Bulk Power Transmission

A solar power plant at a good Northwest site would operate at a 20 to 30 percent capacity factor. Unless energy storage or backup power is provided near the location of the plant, the low capacity factor of the power plant translates to an equally low transmission capacity factor. Because transmission costs are almost entirely fixed, this would increase the cost of transmitting power to load centers from central-station solar power plants. Furthermore, the best solar resource areas are located at considerable distance from major loads.

On the other hand, distributed grid-support plants can actually offset voltage losses on long-distance transmission. These plants would be sited to augment transmission during periods of peak load. Rather than incurring transmission cost, these plants would actually offset transmission cost.

Seasonality and Intermittence

The output of a solar power plant varies diurnally and seasonally with the rising and setting of the sun and with changes in cloud cover. Power plant output that is not coincident with load must therefore be stored, or other resources displaced to make the most efficient use of the power plant investment. Though the Northwest hydropower system has some energy shaping and storage capability, it is unclear at this time how much energy from intermittent resources can be stored without conflict with other water uses. The emergence of a wholesale power market dealing in unbundled power products is expected to clarify the cost of shaping and storage.

The summer peak of solar power further disadvantages the development of this resource in the Northwest. The resource is at its minimum in winter, when regional loads are at their greatest and demands on the hydropower system are most severe.

Environmental Effects

Solar power plants are potentially among the most environmentally benign means of energy production. The major environmental concerns include water use, toxic materials, land use and aesthetic impacts. Possible air quality effects would have to be considered if supplemental gas firing were to be used for solar-thermal systems.

Water Use

Solar-thermal power plants are heat engines and therefore require waste heat rejection equipment. Small plants, such as parabolic dish Stirling engines might use dry radiative and convective cooling. But large, central receivers or parabolic trough plants would likely use wet or dry mechanical draft cooling towers for condenser cooling. Solar-thermal plant efficiencies are similar to, or less than fossil-fueled power plants, and therefore would require similar or slightly more water for comparable power production. Because of the intensity of the concentrated radiation, concentrator photovoltaic power plants require that the photovoltaic cells be cooled. All flat plate designs and most concentrator designs rely on air cooling.

Release of Toxic Materials

Heat exchange and storage fluids for solar-thermal power plants include sodium, organic oils and molten salts. Normal operation will result in very modest release. However, accidents could cause significant releases of such material. Containment of such releases, if they occur, must be considered in the design of systems using toxic fluids. Some of the materials used in the manufacturing of advanced photovoltaic cell designs include components of arsenic and cadmium. There may be cause for concern about the release of these materials either during manufacturing or disposal of used cell material. In application in the field, photovoltaics pose essentially no risk since the hazardous materials are contained within the crystalline structures of the semiconductor cells.

Land Use

A typical 100-megawatt central-receiver plant designed for rated output under average daily direct solar radiation in southeastern Oregon or southwestern Idaho would require approximately 300 acres of collector surface area, or 3 acres of collector area per megawatt of peak capacity. Because the collectors must be able to independently track the sun, an amount of land equal to the collector area itself is required for each collector. Additional land area is needed for service access to each collector, buildings that house the central receiver equipment, power transformer yards and thermal storage or gas combustion back-up equipment buildings. These additional land uses have typically amounted to two to three times the area of the collector alone. This translates to a land-use requirement of roughly 9 to 10 acres of land per megawatt of peak plant capacity. For the typical 100-megawatt plant described above, this would mean an area of roughly 1,000 acres.

The lower conversion efficiency of photovoltaic systems leads to somewhat greater unit area requirements for collectors; around 7.5 acres of collector area per megawatt of peak plant capacity. Currently, the most cost-effective applications of photovoltaics use fixed-geometry arrays that allow close spacing of collector surfaces. Because these fixed arrays are usually tilted at an angle, the area under the collector is available to house the power-conditioning equipment and provide access paths. The combination of these effects allow a fixed-geometry photovoltaic array to have a land-use area per unit capacity that is roughly equal to or perhaps even less than the collector area per unit capacity. This translates to a land-use requirement of roughly 6 to 8 acres of land area per megawatt of peak plant capacity.

Even at these ratios, given the availability of land in areas of the Pacific Northwest with the best solar resources, land use is not expected to be a significant obstacle to resource development.

Visual Impact

Solar-electric plants might result in major aesthetic intrusions in the desert areas favored for plant siting.

Fish and Wildlife

Overall land requirements for solar thermal and solar photovoltaic systems are in the same general range as the land requirements for other energy systems. The effects upon terrestrial habitat may, however, be very different than the effects of, for example, the buffer zone around a nuclear power plant. It is likely that the value of the station site as wildlife habitat would be essentially eliminated because areas not directly pre-empted by the "footprints" of collector-supporting structures and other plant equipment would likely be maintained in a vegetation-free condition to facilitate access to, and minimize interference with, collector surfaces and other plant equipment. Effects on overall biological productivity, however, are likely to be small, given the generally low productivity of the desert sites likely to be selected for solar power developments.

POTENTIAL APPLICATIONS FOR SOLAR POWER GENERATION IN THE PACIFIC NORTHWEST

Possible Applications of Solar Generation Technologies

Solar power technologies, as a group, could serve a variety of potential applications in the Pacific Northwest. Table FSO-2 illustrates the range of applications matched with the most likely technologies. Though photovoltaic technology for this full range of applications is commercially available, the current and projected costs preclude central station applications. Moreover, production capacity is currently insufficient to supply the needs of large central station installations. However, there is a growing market for remote power applications.

Table FSO-2
Potential Solar Power Applications

	Size	Photovoltaic power plants	Central receiver solar thermal	Parabolic trough solar thermal	Parabolic dish
Remote, off-grid loads	Tens of watts to tens of kilowatts	X			X
Distributed grid support	Tens of kilowatts to tens of megawatts	X			X
Central-station generation	Tens to hundreds of megawatts	X	X	X	X

Remote, Off-Grid Loads

In many cases, the cost of extending the existing distribution system to serve new, small loads becomes quite high even within a short distance from the last available connection point. A good example is vacation homes in remote areas where the existing distribution system is not geographically extensive. In these cases, stand-alone photovoltaic power plants, complete with battery storage and in some cases even back-up fossil generators, can be cost-effective today. There is at least one Northwest utility currently leasing stand-alone photovoltaic power systems as an alternative to grid-extensions for remote residential applications. In this program, residential customers that are located a certain distance from the existing grid are given the choice of bearing the up-front cost of extending power to their property or leasing a complete photovoltaic system from the utility. As other customers develop in the same area, they are also given the choice of paying for the interconnection or leasing the photovoltaic system. When the density of local loads reaches a point where the cost of interconnecting divided by the number of customers becomes economic, then the utility connects all of those customers and removes the photovoltaic systems to be used in another area.

This type of application is most likely to be served by photovoltaics in the near future and will probably expand as the cost of photovoltaic modules drops. For large loads, small parabolic dish systems may find a niche, although their requirement for direct sunlight combined with their added complexity reduces their desirability where reliability is a significant issue.

Distributed Grid Support

When a distribution system has become stressed from load growth, the local distribution company must either upgrade the equipment or install local generating equipment to meet peak demand. Traditionally, utilities have chosen to upgrade the equipment because of the operating costs of small generators. However, if the system is stressed due to peak loads that correspond well with peak solar radiation, photovoltaic arrays can provide the voltage support necessary to relieve the stress on the system and avoid the expense of an upgrade. One potential example of a Northwest application would be a substation east of the Cascade mountains where irrigation loads overwhelm the utility during the summer. A successful demonstration of photovoltaics providing local grid support in an agricultural area has been completed in the Sacramento Valley in California.

Another application would be similar to the remote system application described earlier. In a rural distribution system with one portion of the system experiencing severe voltage drops due to high loading, rooftop, grid-connected, photovoltaic systems provide a potentially cost-effective alternative to re-conductoring or other conventional remedies.

Central Station Generation

All four types of solar generation are capable of producing power in a central station generating plant. However, because of the site conditions in the Northwest, it is most likely that the simplicity and ability to generate power from diffuse sunlight indicate a more favorable environment for photovoltaics. However, in all cases, the current and projected costs of these resources make them unlikely to be serious alternatives to conventional or other renewable resources within the planning horizon.

Costs and Projected Power Production Levels

Each of these applications will have a different set of costs that are likely to vary over time due to projected cost declines, particularly for the photovoltaic-based applications. Table FSO-3 illustrates energy cost and power production levels for three of the most likely Northwest applications.

Table FSO-3
Potential Supply and Cost of Electricity from Solar Power

	Supply (aMW)	Cost (cents/kWh)	Resource Block
Rooftop, grid-connected photovoltaics	Tens of megawatts	21	SOL-1
Central-station photovoltaic power plant (PNW site, ca. 2000)	Thousands of megawatts	16	Not included
Central-station photovoltaic power plant (Nevada site, ca. 2000)	Thousands of megawatts	15	Not included
Central-station photovoltaic power plant (PNW site, ca. 2015)	Thousands of megawatts	5.8	Not included
Central-station photovoltaic power plant (Nevada site, ca. 2015)	Thousands of megawatts	6.0	Not included
Parabolic trough solar thermal power plant (PNW site, ca. 2000)	Thousands of megawatts	18	Not included

Some of the results from Table FSO-3 are revealing. First, the current cost of rooftop, grid-connected photovoltaics exceeds even the highest cost generating alternatives and would need to offset substantial local distribution upgrade costs to be cost-effective. Second, there is not a significant advantage to a Nevada location compared to a regional site when the costs of transporting the power are figured in. Third, central station photovoltaics in the near term (year 2000 timeframe) are more cost-effective than parabolic trough technology, which has reached a relatively mature level of technological development. Fourth, by the year 2015, projected costs of central station photovoltaics put that technology within reach of more conventional alternatives and costs could decline further if technological breakthroughs spill-over from the semiconductor industry.

Non-Forecasted Future Technology Impacts

Although the current projections of both the near- and long-term costs of solar generation exceed those of conventional generation, there is reason to believe there may be technological breakthroughs available that are not incorporated in the current forecasts of technology development. Just as the combustion turbine industry has benefited indirectly from research and development of high performance jet engines, the solar photovoltaic industry may benefit from advances in the production of semiconductor materials developed for the computer and electronics industries. While there is no guarantee of developments in the one industry spilling over into the other, it is quite possible that breakthroughs in any one of several areas could dramatically lower the cost of production for photovoltaics.

One example exists in the technology surrounding production of silicon ingot and wafer production. This process forms the basis for single-crystal silicon solar cells, but it is also the raw material for all of the chips used in microelectronics industry. The first commercial scale photovoltaic modules were based on wafers sliced from 4 inch diameter ingots because that was the size available from equipment manufactured for the microelectronics industry. However, since those first solar modules, forces completely unrelated to the photovoltaics industry have pushed the size of the ingots from 4 to 6 and now to 8 inches in diameter. This has effectively increased the output per wafer four-fold over the initial product. Further increases in diameter are projected to occur in the microelectronics industry to lower production costs and allow greater integration of functions on single chips. It is possible, and perhaps even probable, that the photovoltaics industry will benefit from these advances.

Technology development in manufacturing processes completely unrelated to semiconductors may provide opportunities for spill-over into photovoltaics as well. For example, the demand for high-performance, heat-reflective coatings in windows has caused the development of manufacturing technologies that can vacuum-deposit atom-thick layers of silver-oxide on 20-foot wide rolls of polyester film at incredibly high speeds. There are similar processes that deposit these films directly on the surface of huge sheets of glass that are shipped to window manufacturers to be cut into heat reflective windows. The potential for technology spill-over into the production of amorphous silicone panels is not clear, but there are similarities that could be exploited if the technological links could be made.

Another example can be found in the area of high-speed communications. Much of the newest wireless communications equipment, such as cellular phones and packet-switching radios, relies on gallium-arsenide power transistors. Because of the explosion of growth in the wireless communications industry, new production techniques have been developed to increase the production rate and lower the cost of equipment capable of producing gallium-arsenide semiconductor material. Gallium-arsenide happens to be the most efficient material available for photovoltaic cells and is well suited for concentrator applications. The main obstacle to using this material in commercial photovoltaic applications has been its high cost. With the advent of consumer electronics manufacturing, it is quite likely that the cost of gallium arsenide based photovoltaic cells will drop substantially.

Although it is impossible at this time to forecast the impacts of developments in these other industries on the cost of photovoltaics cells, it is important to recognize their potential impact and to adjust the cost estimates as these developments arise.

Planning Model Data

The block assignments used for modeling studies are shown in the far-right column of Table FSO-3. These correspond to the block codes appearing in Table F-1.

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APPENDIX FWN
WIND

WIND

SUMMARY

Wind power is an abundant, pollution-free and sustainable source of electricity. Furthermore, no carbon dioxide or other greenhouse gasses are produced during plant operation. Because wind power plants, except for remote controls and transmission, are wholly contained at the site, there are no upstream environmental impacts associated with fuel production or transportation. Once installed, wind power plant operating costs are low compared to other generating alternatives and free of fuel price escalation risk.

However, wind power costs remain higher than the price of electricity from alternative sources. Moreover, this capital-intensive technology may be difficult to finance in the more competitive electricity industry of the future. Questions regarding equipment reliability have resurfaced following recently publicized turbine failures. Moreover, wind development can produce avian injuries and mortality, habitat disturbance and erosion; aesthetic impacts, and impacts on Native American cultural sites.

Though several hundred to several thousand megawatts of energy could be obtained by development of Northwest wind resources, there has been no significant development of wind power in the Northwest. Currently planned are four commercial-scale wind projects, primarily intended to demonstrate the development and operation of wind power plants under Northwest conditions and to satisfy demand for "green" power.

Using currently available commercial technology, we estimate that electricity could be produced and delivered to the central grid from the best Northwest wind resource areas at levelized costs as low as 3.8 cents per kilowatt-hour.[1] About 300 megawatts of energy[2] could be obtained at levelized costs less than five cents per kilowatt-hour. The large, but electrically isolated Blackfoot[3] wind resource area could provide 2,000 average megawatts of energy or more at costs ranging from five to six cents. However, this would require construction of new high-voltage transmission to the central grid.

The cost of wind-generated electricity, though continuing to decline, remains higher than the current wholesale price of electricity, and the cost of electricity from new natural gas-fired combined-cycle power plants. Absent adoption of mandatory controls on greenhouse gas emissions, unanticipated increases in natural gas prices, extension of federal production incentives, or other economic incentives, significant development of Northwest wind resources is unlikely for the next decade. Limited wind power development to meet demand for "green power" may occur during this period. The cost of wind-generated electricity is expected to continue to decline over the longer-term, providing that incentives for research and development continue.

Pacific Northwest Wind Resources

Winds blow everywhere, and a few very windy days annually may earn a windy reputation. But only areas with sustained strong winds are suitable for electricity generation. Other characteristics of a good wind resource area include smooth topography and low vegetation to minimize turbulence; sufficient developable area to achieve economies of scale; daily and seasonal wind characteristics coincident to electrical loads; road and transmission access; complementary land uses and absence of sensitive species and habitat. Because the typically low capacity factors of wind power plants may result in high transmission costs, the distance to the electrical load is important.

[1] Unless otherwise noted, the costs cited in this section are include estimated wheeling costs for delivery to the central grid.
[2] Unless otherwise noted, the capacity and energy values cited in this section are net of estimated electrical losses incurred for delivery to the central grid.
[3] The Blackfoot wind resource area is within and adjacent to the Blackfoot Indian Reservation. The name of the wind resource area stems from the wind monitoring station formerly located at the town of Blackfoot.

Table FWN-1
Known Wind Resource Areas of the Pacific Northwest

Resource Area	State	County	Mean Annual Wind Speed (mph)	Terrain	Land Area (sq mi, mi)[1]	Reference Elevation (ft)	Peak Wind Seasons	Development Issues	Land Use Issues
Adel	OR	Lake	14.5	Ridge	14 (mi)	6,571	Winter-Spring	Snow	
Albion Butte	ID	Cassia	17.0	Ridge	13 (mi)	7,110	Winter	Severe wind, ice, flyway	
Beezely Hills	WA	Grant	13.0	Ridge	17 (mi)	2,600	Spring-Summer		
Bennet Peak	ID	Elmore	16.0	Ridge	8 (mi)	7,440	Winter	Severe wind, snow, ice, significant raptor population	
Blackfoot	MT	Glacier, Pondera, Toole	12 -18	Rolling	3,250	4,500; 4,875; 4,920	Winter	Severe wind, snow	
Boylston Mtn	WA	Kittitas	12.0	Ridge	8 (mi)	2,400	Spring-Summer		
Burdoin Mountain			12.0						Columbia River Gorge NSA
Burns Butte	OR	Harney	13.0	Ridge	8 (mi)	5,307	Spring		
Cape Blanco	OR	Curry	12.5	Flat	3	217	Winter	Salt spray, severe wind	
Cape Flattery	WA	Clallum	16.0	Ridge	13 (mi)	1,000	Winter	Severe wind	
Cascade Locks			15.0						Columbia River Gorge NSA
Columbia Hills East	WA	Klickitat	15.4 -18.0	Ridge	1 (mi)	2,600; 2,800	Spring-Summer	Severe wind, ice	Site of proposed Columbia Hills and Columbia Windfarm projects
Columbia Hills West	WA	Klickitat	14.3	Ridge	20 (mi)	2,500	Spring-Summer	Severe wind, ice	Columbia River Gorge NSA (Part)
Coyote Hills	OR	Lake	15.6	Rolling	5	6,367	Spring	Snow	
Duncan Mtn	ID	Owyhee	11.6	Rolling	90	6,240	Spring	Ice	
Florence Jetty	OR	Lane	12.1	Flat	6 (mi)	13	Summer	Salt spray, severe wind	Oregon Dunes NRA
Foote Creek Area	WY	Carbon	21.5		97	5,000	Winter		Foote Creek Rim project site
Gold Beach Area	OR	Curry	12.5	Ridge	3 (mi)	720	Winter	Salt spray, severe wind	
Goodnoe Hills	WA	Klickitat	14.0	Ridge	6 (mi)	2,640	Spring-Summer		Columbia Hills project site
Great Falls	MT	Cascade	14.4	Flat	75	3,688	Winter	Occasional ice or severe	Small existing wind power

[1] The estimated area of non-linear sites is given in square miles. The estimated length of linear sites is given in miles.

								wind	project at Ulm
Hampton Butte	OR	Deschutes, Crook	15.2	Ridge	4 (mi)	6,344	Winter-Spring	Infrequent snow or ice	
Horse Heaven	WA	Benton	13.4	Ridge	34 (mi)	2,200	Winter-Spring		
Kittitas Valley East	WA	Kittitas	11.9	Flat	12	2,660	Spring-Summer		
Klondike	OR	Sherman	14.0/12.0	Rolling	15/200	1,540; 2,000	Spring-Summer	Severe wind, ice	
Langlois	OR	Coos, Curry	12.0	Flat	4	20	Winter	Salt spray, flooding, severe wind	
Langlois Mountain	OR	Coos, Curry	14.0	Ridge	4 (mi)	1,120	Winter	Severe wind	
Livingston	MT	Park	15.5	Flat	25	4,632	Winter	Severe wind, ice	
Murdock Area	WA	Klickitat	13.0	Flat	5	400	Summer		Columbia River Gorge NSA (Development Zone)
Norris Hill	MT	Madison	17.0	Rolling	21	5,675	Winter	Snow	
Pequop Summit	NV	Elko	15.0	Ridge	8 (mi)	7,540	Winter	Snow	
Prairie Mtn	OR	Benton, Lane	14.3	Ridge	4 (mi)	3,200	Fall-Winter	Severe wind, ice	
Pueblo and Steens Mountains	OR	Harney	17.0	Ridge	18 (mi)	7,000	Winter	Snow, high wind	Steens Mountain has been proposed as a National Park
Pyle Canyon	OR	Union	11.4	Rolling	12	3,860	Winter	Snow	
Rattlesnake Mtn East	WA	Benton, Yakima	18	Ridge	7 (mi)	3,400	Winter-Spring	Severe wind	Partly within the Hanford National Environmental Research Park
Rattlesnake Mtn West	WA	Yakima	13	Ridge	16 (mi)	3,000	Spring	Severe wind	
Roosevelt	WA	Klickitat	13.8	Ridge	2	1,706	Summer		
Sevenmile Hill	OR	Wasco	15.3	Rolling	3	1,880	Spring-Summer	Ice	Columbia River Gorge NSA (Part)
Sieban	MT	Lewis & Clark	13.5-15	Rolling	15/35	5,600	Winter	Snow	
Strevell	ID	Cassia	12.7	Flat	8	5,276	Winter		
Tule Hills	WA	Yakima, Klickitat	12.3	Flat	6	2,750	Winter		
Upper Pyle Canyon	OR	Union	13.4	Rolling	6	3,660	Winter	Snow	
Vansycle Ridge	OR	Umatilla	16.5	Ridge	24	1,590	Winter-Spring		Vansycle Ridge project site
Wells West	NV	Elko	12.5	Rolling	4	5,960	Winter-Spring		
Winter Ridge	OR	Lake	14.9	Ridge	27 (mi)	7,060	Winter	Snow, ice, severe wind	

Because of its complex topography, only relatively localized areas of the Northwest have winds potentially suitable for wind power development. Intensive prospecting and monitoring are required to identify these areas. The most extensive effort of this kind in the Northwest was conducted by the Bonneville Power Administration (Baker, 1985). The State of Montana also developed a wind resource assessment of that state (GeoResearch, 1987). Additional assessment has been undertaken by private developers, but much of that information remains proprietary. Known wind resource areas of the Northwest are listed in Table FWN-1 and located on Figure FWN-1. Other areas suitable for bulk wind power development undoubtedly exist, but have yet to be identified. In addition, these are likely to be locations where wind power could serve small local loads.

Figure FWN--1

Wind Resource Areas of the Pacific Northwest

Many of the wind resource areas of the Northwest, though local in extent, have common origin. Open coastal sites such as Gold Beach and Florence Jetty receive sustained, strong storm-driven oceanic winds. Though these winds diminish inland, prominent inland ridgelines, such as Prairie Mountain and at Cape Flattery see sustained strong winds. Gaps in the Cascade Range, especially the Columbia River Gorge and Snoqualmie Pass concentrate westerly storm-driven winds, producing favorable wind regimes on ridges adjacent to and to the east of these gaps. Examples include Columbia Hills, Vansycle Ridge and Boylston Mountain. Likewise, gaps in the Rocky Mountains create favorable sites to the east. For example, westerly winds channeled through Marias Pass spread out on the high plains east of the Rocky Mountains forming the extensive Blackfoot wind resource area. Wind resource areas also appear on basin and range ridgelines in southern Oregon and Idaho and northern Nevada.

Because of land use restrictions, some of the wind resource areas of Table FWN-1 are unlikely to be available for development. The Cascade Locks and Burdoin Mountain areas lie within the Columbia River Gorge National Scenic Area, as do portions of Columbia Hills West and Sevenmile Hill. Most of Florence Jetty lies within the Oregon Dunes National Scenic area.

Wind Power Plants

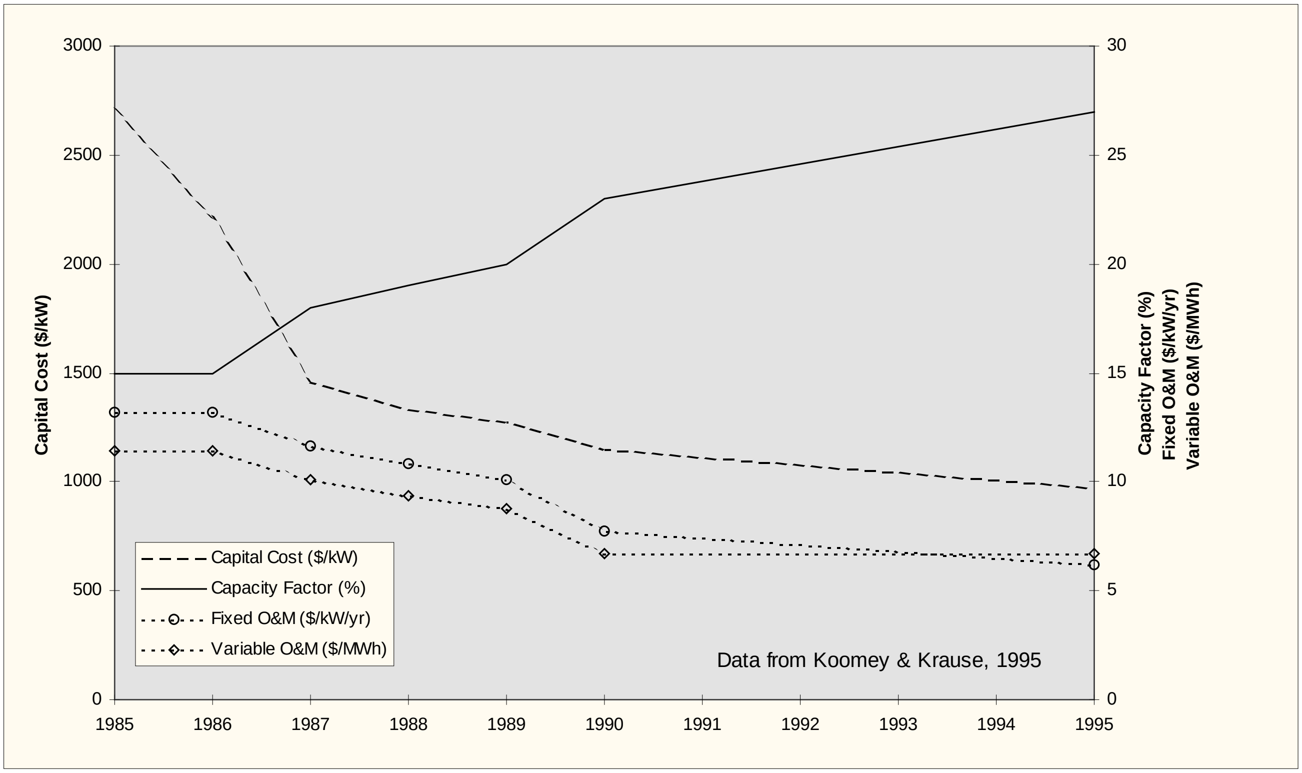
Wind energy is converted to electricity by wind turbine generators - electric generators driven by rotating airfoils. Because of the low energy density of wind, bulk electricity production requires tens or hundreds of wind turbine generators arrayed in a wind power plant. A wind power plant (often called a “wind farm”) includes meteorological towers, strings of wind turbine generators, turbine service roads, a communication system interconnecting individual turbines with a central control station, a voltage transformation and transmission system connecting the individual turbines to a central substation, a substation to step up voltage for long-distance transmission and an intertie to the main transmission grid. On-site maintenance and control structures may be provided, but the plants are often remotely controlled.

The typical commercial state-of-the-art wind turbine generator is a horizontal axis machine of 250 to 500 kilowatts rated capacity with a two- or three-bladed rotor 85 to 150 feet in diameter. The machines are mounted on tubular or lattice towers ranging from 80 to 140 feet in height. Because the energy content of wind is a cube function of velocity, low-speed wind has very little energy and very high speed winds can be damaging. As a result, machines are designed to operate at wind speeds ranging from about 9 to 65 miles per hour. Rated power is typically achieved at speeds of about 30 miles per hour. Some models use constant-speed operation with power frequency controlled by generator speed. Other manufactures offer variable speed machines with power electronic frequency control. Variable speed operation reduces component stress and permits better control of power quality, but may be more complex in terms of components.

Trends in machine design have included improved airfoils; larger machines; taller, tubular towers and lighter and simplified design. Improved airfoils increase energy capture. Larger machines provide manufacturing and installation economies. Also, because wind speed generally increases with elevation above the surface, taller towers and larger machines intercept more energy. Tubular towers are not only considered to be more aesthetically pleasing than lattice towers, but also eliminate perching opportunities for birds. Simplified design reduces manufacturing and maintenance costs and may improve machine reliability; lighter design reduces material costs.

As shown in Figure FWN-2, wind turbine generator cost and performance have continued to improve since the first large-scale development in California in the early 1980s. Though the rates of improvement have declined in recent years, continued improvement is expected due to technology refinement and production economies, providing that strong markets or other research and development incentives continue to exist.

Figure FWN-2
Historical Improvements in Wind Generation Technology



Wind Power Development Issues

Factors other than cost may affect the extent of wind power development. These include the high fixed cost of wind power, the cost of transmission to loads, the cost of storing and shaping intermittent wind power, questionable long-term equipment reliability, seasonal coincidence of wind with load, certain environmental impacts, aesthetic impacts and Native American cultural issues.

Fixed Costs

About 90 percent of the cost of wind-generated electricity from a typical site is fixed. Though this high fixed cost component contributes to long-term electricity price stability, fixed assets are viewed as risky by investors in an industry undergoing fundamental restructuring and subject to increasing competition. Furthermore, equipment reliability and other performance risk factors assume a greater significance for a technology having a high fixed-cost component. Without long-term power purchase contracts, it is unlikely that power suppliers will be willing to undertake the substantial capital investments required for wind power until the future structure of the electric power industry is clarified.

Transmission

A wind power plant at a good site will operate at a 30- to 35-percent capacity factor. Unless energy storage or backup power is provided near the wind resource area, the low capacity factor of wind power plants translates to an equally low transmission capacity factor. Because transmission costs are almost entirely fixed, this increases the cost of transmitting power to load centers from wind resource areas, many of which are located at considerable distance from major loads.

Seasonality and Intermittence

The power output of a wind power plant varies diurnally and seasonally with the wind. Some wind resource areas such as Altamont Pass in California have winds coincident with local loads. Northwest wind resources, however, appear to be generally unpredictable on a daily basis, though some areas may coincide well with seasonal loads. Wind power output must therefore be stored, or other resources displaced to make the most efficient use of the wind power investment. Northwest hydropower capacity may be able to provide relatively low-cost shaping and storage for some amount of wind power generation in the Northwest, though the amount is uncertain. The emergence of a wholesale power market dealing in unbundled power products, and operating experience to be gained from planned demonstration wind power plants are expected to clarify the cost of shaping and storage.

Equipment Reliability

Widespread equipment failure experienced during the rapid development of wind power in California in the early 1980s gave wind power a reputation for unreliability that has yet to be fully overcome. Even today, some commercial wind turbines are experiencing severe component failures. Of concern in the Northwest is the ability of wind turbines to operate reliably in the cold climate of the eastern front of the Rocky Mountains, and to withstand the occasionally violent storm-driven winds of many northwest wind resource areas. Equipment reliability is exceedingly important for a capital-intensive product such as wind power, as return on the investment depends upon long and reliable equipment life. One purpose of the wind projects listed in Table FWN-2 is to demonstrate long-term equipment reliability under Northwest environmental conditions.

Environmental Impacts

Wind power is a pollution-free source of electricity. Furthermore, no carbon dioxide or other greenhouse gasses are produced during plant operation. Because wind power plants, except for remote controls and transmission, are wholly contained at the site, there are no upstream environmental impacts associated with fuel production or transportation. However, like any form of development, wind power development brings environmental impacts. The principal potential environmental impacts of wind power generation are habitat disturbance, bird injuries and deaths, soil erosion and aesthetic effects.

Habitat disturbance: Though turbine footings, service roads and transmission towers preempt only a small portion of the land occupied by a wind power plant, these structures in the aggregate can fragment the habitat of the site. Moreover, surface disturbance can introduce noxious species, which may be sustained by continued disturbance associated with roads and turbine service pads. Habitat disturbance is unlikely to be of concern for a site in agricultural use, but can be significant for a site with native vegetation. Undisturbed examples of native vegetation are becoming increasingly rare and the isolated windswept ridges comprising many of the better wind resource areas often retain good examples of native vegetation.

Avian mortality: Birds can be killed or injured when passing through rotating turbine blades. In some wind developments, raptors have been attracted by the perching opportunities offered by wind turbine generators. Bird injuries and deaths have resulted from birds foraging among the wind turbines and stooping for prey from wind turbine perches. Much effort has been devoted to controlling avian injuries and mortality. Perching is discouraged by substituting tubular for latticework towers, eliminating horizontal structural members and removal of handrails. Blade visibility has been augmented by bold color patterns. Populations of prey species have been reduced by eliminating suitable habitat. Turbines can be sited to avoid areas frequented by sensitive species. While reduced, avian injuries and mortality are unlikely to be fully eliminated by these measures.

Erosion: Because of cost considerations, service roads and turbine pads are generally not paved. Wind and precipitation can rapidly erode unprotected road and working pad surfaces and associated cutbanks.

Aesthetic Impacts

Several wind turbine generators may be a curiosity, but the hundreds of turbines with unsynchronized rotating blades comprising a commercial wind power plant create a significant visual impact and a major modification to the aesthetics of a place. Aesthetic impacts can be reduced, though not eliminated, by use of tubular rather than lattice towers; non-reflective, earth-tone paint schemes; underground collection and transmission lines; and turbine siting and road alignments that conform to the landscape and avoid prominent viewshed areas. Turbine noise is generally not excessive much beyond plant boundaries, but could present a problem at sensitive locations adjacent to wind plant sites.

Land Use Conflicts

Several otherwise attractive wind resource areas are wholly or partially located within areas managed for scenic or recreational values. It is unlikely that extensive wind power development would be permitted within these areas. Other wind resource areas are in close proximity to residential areas. Wind power development would likely be restricted at these locations as well.

Native American Cultural Issues

The prominent topography of many prime wind resource areas may contain promontories of spiritual importance to Native Americans of the Northwest. Wind farm development is unlikely to be compatible with the spiritual character of these sites.

Wind Power Potential in the Pacific Northwest

There has been no significant development of wind power in the Pacific Northwest. A small wind farm operated at Whisky Run on the southern Oregon coast for several years. A cluster of small turbines is located near Ulm, Montana. Several experimental wind turbine installations and a scattering of micro turbines have also been located in the region.

Four commercial-scale wind power plants are planned for the Northwest over the next several years (Table FWN-2). Though the cost of power from these projects is not expected to be competitive with alternative sources, at least in the near-term, these plants will demonstrate state-of-the-art wind turbine generators, provide operating experience with typical Northwest wind regimes and illuminate environmental issues. The experience gained from these projects is expected to facilitate future development of wind power.

Estimates of the potential supply and cost of electricity from known Northwest wind resource areas are provided in Tables FWN-3 (supply) and FWN-4 (cost), and illustrated in Figure FWN-3. A discussion of wind power potential in the Northwest must consider the role of the large, but electrically isolated Blackfoot wind resource area. Excepting the Blackfoot area, the known wind resource areas of the Northwest could supply several hundred megawatts of energy. In contrast, several thousand megawatts of energy could be secured by development of the Blackfoot area, but would require the development of new transmission interconnections to the central grid. The lowest curve of Figure FWN-3 shows the estimated wind power potential without expansion of Blackfoot intertie capability. An estimated 1,340 megawatts of wind capacity, producing about 420 average megawatts of energy[1] could be developed at costs of six cents per kilowatt-hour, or less. Of this, Blackfoot could supply only about 100 megawatts of capacity and 34 megawatts of energy without significant transmission upgrades. The middle curve includes the greater Blackfoot contribution

[1] The capacity and energy values of this paragraph are for energy delivered to the "main grid". See the discussion of the main grid at the introduction to this appendix.

resulting from construction of a new 500 megawatt intertie to the central grid. This would increase regional potential to an estimated 1,820 megawatts of wind capacity, and about 590 average megawatts of energy. The top curve shows regional potential with construction of a new 3,000 megawatt intertie (a double-circuit 500 kilo-volt transmission line) from Blackfoot to the main grid. This would increase regional wind power potential to an estimated 4,280 megawatts of wind capacity, and about 1,430 average megawatts of energy. Even at this level, the contribution of Blackfoot would be transmission-constrained.

Table FWN-2

Wind Power Projects Planned for the Northwest

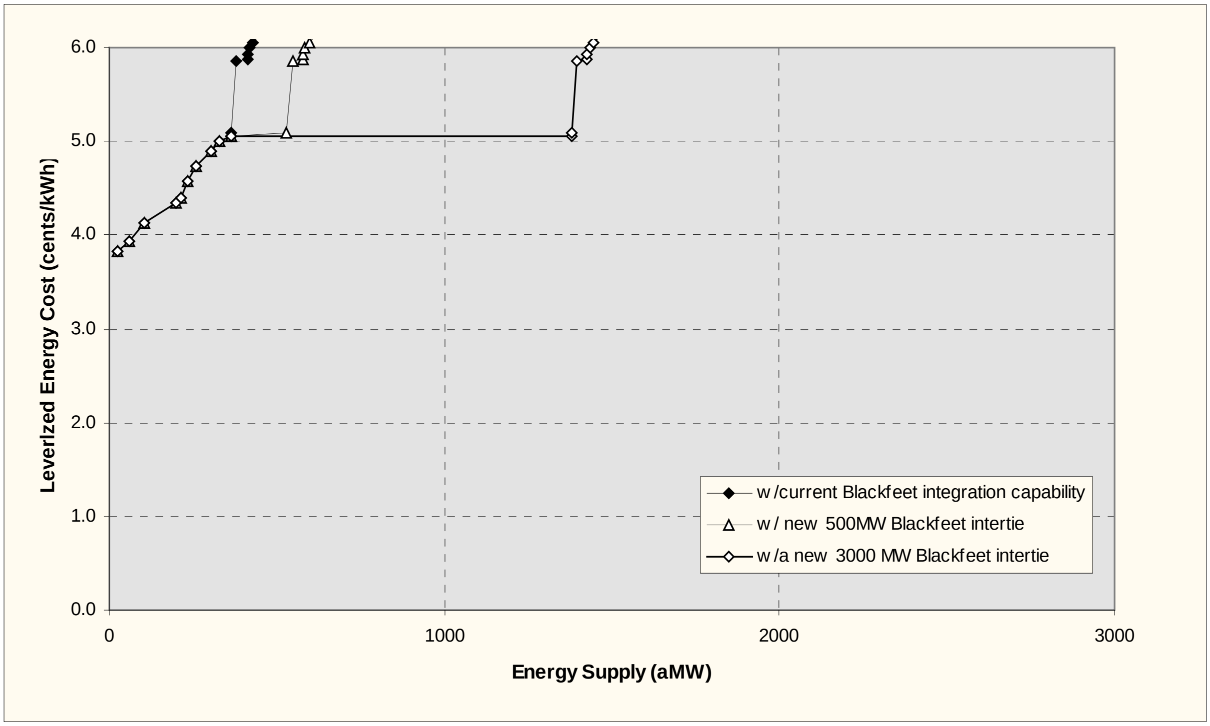
Project	**Wind Resource Area**	**Propose d WTG**	**Capacity (MW)**	**Energy (aMW)**	**Developer**	**Power Purchaser**
Columbia Hills	Columbia Hills East, Goodnoe Hills, WA	KVS-33	31.2	8.8	Kenetech Windpower	PacifiCorp, Portland General Electric
Columbia Windfarm	Columbia Hills East, WA	AWT-26	25	7.4	CARES[2]/ FloWind Corporation	BPA
Foote Creek Rim	Foote Creek Rim Area, WY	KVS-33	68.1	25	Kenetech Windpower	PacifiCorp/BPA, Eugene Water & Electric Board/BPA, Tri-state G&T, Public Service of Colorado[3]
Vansycle Ridge	Vansycle Ridge, OR	KVS-33	25	7.5	Kenetech Windpower	Portland General Electric

The best wind resource areas in the Northwest are estimated to yield electricity at a levelized costs as low as 3.8 cents per kilowatt hour. This is a 30-percent decline in constant-year dollars from the cost assessed for the same area in the Council's 1991 Power Plan. The cost of power from the most favorable (western) portion of the Blackfoot area is estimated to be about 5.0 cents per kilowatt-hour, delivered to the central grid.

The levelized energy costs of Table FWN-3 are exclusive of the federal renewables production credit and are based on a 30-year project life and investor-owned utility financing assumptions. These costs are based on year 2000 initial service and include the effect of projected cost reductions to that time. Alternative financing assumptions could lower these costs. For example, the federal production tax credit, currently available for a 10-year period to projects placed in service prior to July 1999, reduces project levelized costs by about 0.8 cents per kilowatt-hour. Tax-free municipal financing would reduce levelized costs roughly 25 percent, compared to investor-owned utility financing. Federal production incentives for tax-exempt owners are authorized, though appropriations are uncertain. This incentive would reduce the levelized cost of a tax-exempt project by about 0.3 cents. Because of the capital-intensive nature of wind projects, short-term amortization can significantly increase early-year project costs.

[2] The Bonneville Power Administration has agreed to purchase the energy output of the project from the CARES (Conservation and Renewable Energy System) utilities who will own the project.
[3] The Bonneville Power Administration has agreed to purchase a portion of the energy output to be taken by PacifiCorp and by Eugene Water and Electric Board.

Figure FWN-3
Estimated Cost and Potential Supply of Wind-generated Electricity



Development of the Supply Estimates

The estimates of wind power supply were developed using methods originally developed for the 1991 Power Plan (Bain, 1989). The potential installed wind generating capacity of each wind resource area is a function of the amount of land having suitable wind, the amount of this land that could be developed for wind power, the dimensions and capacity of the wind turbines used and the arrangement of wind turbines. In-plant and intertie electrical losses will reduce the amount of capacity actually delivered to the load. The potential energy production of a wind resource area is a function of the installed capacity and the performance curve of the turbines. The performance curve is the relationship of wind speed to electrical output. In-plant and intertie electrical losses reduce the amount of energy delivered to the load.

Reconnaissance-level estimates of the geographic extent of each known wind resource area are shown in Table FWN-2. Land within the Columbia River Gorge Scenic Area and the Oregon Dunes National Recreation Area is excluded. Topography, existing structures, vegetation, legal restrictions and aesthetics will limit the amount of land within the resource area on which turbines could be sited. Estimates of the amount of developable land, based on the size and topography of the resource areas are shown in Table FWN-3

In an actual development, wind turbine location is determined by topography, prevailing winds and environmental considerations and may be quite irregular. For this regional-scale analysis, however, wind turbine spacing, though assumed to vary with topography and prevailing wind also was assumed to be regular over the land available for development (Table FWN-3).

The developable land and array density determine the number of turbines that could be sited in each wind resource area. This number is multiplied by an assumed rated capacity per turbine (350 kW), and reduced by an assumed 2 percent in-farm loss to arrive at the potential net capacity in Table FWN-2. Electrical losses will be incurred delivering the capacity to the central grid. The estimated capacity at the central grid is also shown in Table FWN-3.

Table FWN-3

Wind Resource Areas of the Pacific Northwest: Potential Capacity and Energy

Resource Area	Land Area (sq mi, mi)[1]	Estimated Developable Area (%)	Turbine Array (CWxDWRD)[2]	Potential Capacity @ Interconnection (MW)	Potential Energy @ Interconnection (aMW)	Plant Capacity Factor[3] (%)	Potential Capacity @ Central Grid (MW)	Potential Energy @ Central Grid (aMW)
Adel	0.1x14	80%	5x10	37	7.4	19.7%	37	7.4
Albion Butte	0.75x13	80%	8x8	130	31.9	24.5%	123	30.9
Beezely Hills	0.5x17	80%	5x10	91	15.3	16.8%	91	15.3
Bennet Peak	1x8	60%	5x10	48	11.5	23.9%	46	11.3
Blackfoot Central	750	10%	5x10	1220	344	28.1%	1160	334
Blackfoot East	1000	10%	5x10	1630	341.0	20.9%	1550	331
Blackfoot West	1500	20%	5x10	4890	1690	34.6%	4650	1642
Boylston Mtn	0.1x8	80%	5x10	27	3.6	13.6%	27	3.6
Burns Butte	0.1x8	80%	8x8	27	4.1	15.2%	26	4.0
Cape Blanco	3	60%	5x10	24	4.8	19.8%	24	4.8
Cape Flattery	0.5x13	40%	8x8	54	16.5	30.4%	53	16.3
Columbia Hills East 1	0.5x4	80%	5x10	64	22.5	35%	64	22.5
Columbia Hills East 2	0.5x7	80%	5x10	112	28.8	25.6%	112	28.8
Columbia Hills West	0.5x20	80%	5x10	55	11.7	21.5%	54	11.7
Coyote Hills	5	60%	8x10	30	7.1	23.1%	30	7.0
Duncan Mtn	90	20%	8x10	182	23.5	12.8%	175	22.9
Florence Jetty	0.33x6	27%	5x10	27	4.2	15.7%	27	4.2
Foote Creek Area	97	14%	5x10	213	94.1	44.1%	192	88.6
Gold Beach Area	0.75x3	80%	5x10	72	11.7	16.2%	71	11.6
Goodnoe Hills	0.5x6	80%	5x10	96	23.5	24.4%	96	23.5

[1] The estimated area of non-linear sites is given in square miles. The estimated width and length of linear sites is given in miles. land within scenic management zones of the Columbia River Gorge NSA and the Oregon Dunes NRA is excluded.
[2] The first dimension given is for turbine spacing perpendicular to prevailing wind direction (crosswind), in rotor diameters. The second figure is spacing parallel to prevailing wind direction (downwind).
[3] Ratio of annual energy production at the grid interconnection to the capacity at the grid interconnection.

Great Falls	75	20%	8x10	152	33.1	21.6%	144	32.0
Hampton Butte	0.1x4	80%	8x8	13	2.9	21.4%	13	2.9
Horse Heaven	0.1x34	80%	8x8	114	34.9	30.7%	113	34.8
Kittitas Valley E	12	40%	5x10	78	16.1	20.5%	78	16.1
Klondike 1	15	40%	8x10	61	13.4	21.8%	61	13.4
Klondike 2	200	20%	8x10	407	59.8	14.7%	407	59.8
Langlois	4	80%	5x10	52	7.8	15%	51	7.8
Langlois Mountain	1x4	60%	8x8	35	7.5	21.5%	35	7.5
Livingston	25	40%	8X10	102	24.5	24%	96	23.6
Murdock Area	5	60%	5x10	49	9.2	18.8%	49	9.2
Norris Hill	21	40%	5x10	137	43.9	32%	130	42.5
Pequop Summit	0.1x8	80%	5x10	21	4.7	21.8%	20	4.5
Prairie Mtn	0.5x4	60%	5x10	16	3.4	21%	16	3.4
Pueblo/Steens	0.1x18	43%	5x10	36	9.6	26.7%	35	9.5
Pyle Canyon	12	40%	10x10	39	5.7	14.5%	39	5.6
Rattlesnake Mtn East	0.1x16	80%	8x8	53	18.2	34.1%	53	18.2
Rattlesnake Mtn West	0.1x7	80%	8x8	23	3.9	16.5%	23	3.9
Roosevelt	2	60%	5x10	20	4.0	20.3%	20	4.0
Sevenmile Hill	3	44%	5x10	22	6.3	29.1%	22	6.3
Sieban 1	15	40%	8x10	61	13.1	21.5%	58	12.8
Sieban 2	35	40%	8x10	143	24.3	17%	136	23.7
Strevell	8	60%	8x8	61	9.0	14.8%	58	8.7
Tule Hills	6	60%	8x8	46	6.8	14.8%	46	6.8
Upper Pyle Cyn	6	40%	10x10	24	4.1	20.8%	24	4.0
Vansycle Ridge	0.5x24	60%	8x8	150	46.1	30.6%	149	45.9
Wells West	4	60%	8x8	31	4.1	13.3%	29	3.9
Winter Ridge	1x27	80%	5x10	216	46.1	21.3%	214	45.8

Energy production is a function of the annual distribution of wind speeds at hub height, air density at hub height, and turbine performance curve. The annual energy production of a representative turbine at each site was estimated, then extrapolated to the site as a whole and corrected for in-plant losses to obtain potential annual energy production for each wind resource area. Divided by the capacity of the site, the annual energy production yields plant capacity factor, an index of site quality. The estimated annual energy production and plant capacity factor for each site are shown in Table FWN-3. Electrical losses will be incurred delivering energy to the central grid. The estimated energy delivered to the central grid is also shown in Table FWN-3.

Development of the Cost Estimates

The principal cost components and resulting levelized energy costs for wind power development at Northwest wind resource areas are shown in Table FWN-4. The costs were obtained as follows (additional detail is available from the Council upon request):

- Project development costs include land options, additional wind resource assessment, environmental assessment, securing permits, turbine siting, and developer's administrative costs. Project development costs are combined with project construction costs in Table FWN-4.
- Project construction costs include engineering, procurement, construction management, equipment, installation and testing. The base construction costs were estimated for each plant using a model accounting for economies of project scale. For example, the base costs of 25 MW and 50 MW plants would be estimated to be $996/kilowatts and $909/kilowatts, respectively. The base cost is adjusted to account for the costs imposed by difficult site conditions, including difficult terrain, remote sites, difficult access, cold climate, corrosion and icing. To the resulting plant construction cost were added costs for ancillary features and services, including interconnection, impact mitigation, spare parts, startup costs and working capital.
- Fixed operating and maintenance costs include labor, maintenance materials, decommissioning fund payments, property tax and insurance. Labor costs are a function of staffing requirements, annual salaries and benefits, administrative and general costs as well as premiums for difficult site conditions. Maintenance material costs are based on capital investment, administrative and general costs, plus difficult-site premiums.
- Variable operating costs consist of land-lease payments.

Financing assumptions: The investor-owned utility financing assumptions of Table F-2 were used to calculate levelized energy costs. Alternative financing can significantly affect energy costs because of the capital-intensive nature of wind power development. No federal or state tax incentives were considered in these estimates. A 30-year project life was assumed.

Future cost expectations: Wind power costs are expected to continue to decline provided that incentives for research and development continue to be present. The Council projected the following rates of constant dollar cost reductions, based on historical experience and turbine design trends:

1996 - 2000	5 percent/year
2001 - 2005	4 percent/year
2006 - 2010	3 percent/year
2011 - 2015	1 percent/year

The costs of Table FWN-4 are for projects entering service in 2000.

Table FWN-4
Pacific Northwest Wind Resource Areas: Estimated Costs

Resource Area/Case	Development and Construction Cost ($/kW)	Fixed O&M Cost ($/kW/yr)	Variable O&M Cost ($/kWh)	Wheeling Cost ($/kW/yr)	Estimated Cost of Energy at Central Grid (cents/kWh)	Resource Planning Block
Adel	$1,350	$42	$0.003	$4	8.8	
Albion Butte	1,031	$29	$0.003	$30	6.8	WSpH
Beezely Hills	1,031	$29	$0.003	$1	7.6	
Bennet Peak	1,336	$44	$0.003	$21	8.4	
Blackfoot Central - 3000	1,243[1]	$28[1]	$0.003	$0[2]	5.9	
Blackfoot East - 3000	1,243[1]	$28 [1]	$0.003	$0[2]	7.9	
Blackfoot West - 100	1,017	$27	$0.003	$27	5.1	WSpL
Blackfoot West - 500	1,547[3]	$31[3]	$0.003	$0[2]	5.1	WSpH
Blackfoot West - 3000	1,244[1]	$28[1]	$0.003	$0[2]	5.1	BW30
Boylston Mtn	1,295	$42	$0.003	$1	12.1	
Burns Butte	1,368	$53	$0.003	$7	12.7	
Cape Blanco	1,419	$52	$0.003	$0	9.6	
Cape Flattery	1,079	$32	$0.003	$0	4.6	WSpM
Columbia Hills East 1	1,030	$32	$0.003	$0	3.8	SpSL
Columbia Hills East 2	967	$28	$0.003	$0	4.7	SpSL
Columbia Hills West	1,169	$35	$0.003	$1	6.9	SpSH
Coyote Hills	1,346	$45	$0.003	$4	7.8	
Duncan Mtn	1,037	$30	$0.003	$22	12.0	
Florence Jetty	1,410	$52	$0.003	$0	11.9	
Foote Creek Area	925	$25	$0.003	$54	4.3	WSpM
Gold Beach Area	1,195	$38	$0.003	$0	9.3	

[1] Includes project share of 3,000MW intertie to main grid.
[2] Wheeling cost included in capital and fixed O&M cost.
[3] Includes project share of 500MW intertie to main grid.

Goodnoe Hills	994	$26	$0.003	$0	5.0	SpSH
Great Falls	1,038	$29	$0.003	$29	7.6	WSpH
Hampton Butte	2,127	$94	$0.003	$4	14.2	
Horse Heaven	956	$25	$0.003	$1	3.9	WSpL
Kittitas Valley E	932	$25	$0.003	$1	5.6	SpSH
Klondike 1	1,044	$31	$0.003	$1	6.1	SpSH
Klondike 2	960	$26	$0.003	$0	7.9	
Langlois	1,120	$34	$0.003	$0	9.4	
Langlois Mountain	1,179	$37	$0.003	$0	7.1	WSpH
Livingston	1,014	$27	$0.003	$32	6.9	WSpH
Murdock Area	1,138	$36	$0.003	$1	7.7	
Norris Hill	952	$25	$0.003	$29	4.9	WSpM
Pequop Summit	2,344	$91	$0.003	$26	16.1	
Prairie Mtn	2,805	$119	$0.003	$0	18.4	
Pueblo/Steens	1,208	$40	$0.003	$11	6.4	WSpH
Pyle Canyon	1,114	$36	$0.003	$5	10.2	
Rattlesnake Mtn East	1,148	$34	$0.003	$2	4.4	WSpL
Rattlesnake Mtn West	1,455	$51	$0.003	$2	11.5	
Roosevelt	1,343	$53	$0.003	$2	9.1	
Sevenmile Hill	1,277	$50	$0.003	$1	6.0	SpSH
Sieban 1	1,173	$35	$0.003	$24	8.3	
Sieban 2	957	$26	$0.003	$24	8.7	
Strevell	1,053	$30	$0.003	$30	11.4	
Tule Hills	1,095	$33	$0.003	$1	9.2	
Upper Pyle Canyon	1,616	$55	$0.003	$5	10.3	WSpH
Vansycle Ridge	988	$26	$0.003	$3	4.1	WSpL
Wells West	1,384	$51	$0.003	$26	16.3	
Winter Ridge	1,159	$33	$0.003	$4	6.9	WSpH

Wheeling: Many wind resource areas are remote from major load centers. The cost of wheeling power from the point of grid interconnection to the central grid was estimated using the formula described in *Transmission and Wheeling*. The exception was for the Blackfoot wind area. In 1991, the Pacific Northwest Utilities Conference Committee released a study assessing the problem of transmitting bulk quantities of wind-generated electricity from the Blackfoot area (PNUCC, 1991). This study assessed available transmission capability from the Blackfoot area to the main grid, and the cost of 500- and 3,000-megawatt expansions. These estimates have been used for the Blackfoot area in lieu of the standard wheeling cost formula.

Planning Model Data

The Council's power system models require aggregated resource data. For modeling purposes, data and estimates for individual wind resource areas were aggregated into wind resource supply blocks using energy cost, seasonality and Blackfoot transmission increments as criteria. The block assignments used for the draft plan modeling studies are shown in the far right column of Table FWN-4. These correspond to the block codes appearing in Table F-1.

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