1992 Generation Resource Supply Document

This document is a product of the
Energy Resources Development
and Implementation Process:

Define Situation
Identify Alternatives
Select Strategies
Implement Strategies
Evaluate Performance

Bonneville
POWER ADMINISTRATION

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Energy Resources Development and Implementation Process

The flow chart below illustrates how the Energy Resources Program works. Broadly speaking, the program has two primary functions—resource planning and resource management. The first three blocks in the chart cover most of the planning tasks.

What Are the Needs of Our Customers?

To define the overall situation, BPA first assesses what the energy needs of customer utilities are likely to be over a 20-year planning horizon. Projections are developed and published jointly with the Northwest Power Planning Council. Also part of this initial step are forecasts of how much energy is available from existing Federal resources. BPA then compares demand and supply estimates in a regional Loads and Resources Study, also known as the "White Book."

Define Picture/ Situation

Customer/Public Involvement

LOAD FORECAST LOAD/RESOURCE STUDY

What Choices Do We Have to Meet those Needs?

The second step is to identify all the available alternatives for meeting customer needs. BPA develops Resource Supply Forecasts for both generation and conservation resources. These studies also consider such factors as environmental and regulatory constraints, new technologies, and public opinion. Other efforts include examining opportunities for coordinating hydro system operations with Canada and arranging power purchases and transfers with Canadian and Southwest utilities.

Identify Alternatives

Customer/Public Involvement

ANALYSIS OF RESOURCE SUPPLY ALTERNATIVES

How Can We BEST Meet those Needs?

Step three involves weighing the available alternatives and their consequences to arrive at the most appropriate and cost-effective resource mix for the short-term. Developing the Resource Program is a public review process in which BPA's customer utilities and other interested parties have an opportunity to influence resource decisions. The process focuses on a 2-year planning period—i.e., the 1990 Resource Program covers 1992-1993.

Select Strategies

Customer/Public Involvement

RESOURCE PROGRAM

What Are We Doing to Meet Customer Needs?

From planning and strategy BPA then moves to step four—meeting customer power needs. Based upon the policies and directives in the Resource Program, managers draw up an overall plan to capture the conservation available in the region's homes, factories, and offices. This results in many programs and projects, ranging from about 25 to 40 in any year. In the past, BPA teams have designed and managed most conservation programs. Now utilities and other power producers are sponsoring their own programs with BPA support.

Bonneville is responsible for planning and acquiring generating resources—both conventional and renewable resources. Another part of step four is BPA's oversight function—seeing that BPA gets value from contracts for generated power.

Implement Strategies

Customer/Public Involvement

PROGRAM DESIGN AND IMPLEMENTATION

How Well Did We Meet those Needs?

Finally, in step five BPA looks at how well it is doing its job. It is agency policy to evaluate all programs. Evaluation provides a means of comparing initial objectives with actual results. It is essential for verifying the energy savings from conservation programs and understanding the quality of our actions to acquire the energy.

Evaluate Performance

Customer/Public Involvement

EVALUATION

1992 Generation Resource Supply Document

EXECUTIVE SUMMARY

The Generation Resources Supply Document supports BPA's 1992 Resource Program. This is the final 1992 update to the Generation Resources Supply document that was published in December 1991. It reflects public comments and other changes made since a draft version was published in December 1991.

BPA estimates the cost and potential for several generating technologies. The generating resources that are considered available for the Resource Program stack of resources are described in Chapter 3 of this document. Generating technologies that are not considered to be available or are otherwise excluded from the Resource Program are described in Chapter 4.

The forecast supply of the available resources is presented as achievable potential rather than technical potential. Achievable potential reflects several constraints and market conditions that limit the amount of resource that can prudently be assumed to be available. The fact that resource is considered to be available does not mean that the potential will be achieved. These estimates are used as upper limits for resource expansion planning. Generation resources actually acquired or built by utilities can be expected to reflect, in general, the types of resources described in this document. Market conditions at the time that a utility is acquiring resources will dictate the specific resources that are acquired. The resources available in BPA's Resource Program stack do not dictate what specific resources will be acquired.

Table ES.1 summarizes supply forecast information. The figures in the table are based on the year 2000 on-line date for reference purposes. Resources have varying construction lead times; however, most could be on-line by 2000. The table lists all of the generation resource types. The complete stack of resources used for planning is documented in the Draft 1992 Resource Program. The resource stack includes both conservation and generation resources and is ordered principally by cost.

The resource identifiers in Table ES.1 (in column 1) are the same as those used on the data sheets that are included in the Appendices. Both real and nominal levelized costs are shown (columns 2 and 3). Real levelized costs are used by planners to compare resources with different cost and benefit patterns on an equivalent basis. The nominal levelized cost convention was developed by the Northwest Power Planning Council to allow an approximate comparison to the current price of electricity. For resources that have primarily capital costs, such as conservation and hydropower, the rule of thumb is that levelized costs in nominal dollars will be approximately twice as much as they would be in real dollars. Installed costs ($/kW) are not used to compare resources because they do not reflect the fuel costs and do not account for other resource characteristics such as different lifetimes.

While levelized cost is not the only criterion used in the resource mix selection, it does provide a preliminary view of the resources relative to each other. It should be noted that when calculating a levelized cost, BPA assumes a combined 50% public/50% private ownership except where ownership is explicit (e.g., WNP-1 & -3).

Table ES.1 shows both the regional and BPA supply forecasts. The regional estimates represent the amount that is projected to be available for the Pacific Northwest, whereas the BPA estimates reflect the amount that is assumed to be available to BPA. BPA's 1992 Resource Program is based on the latter. BPA's estimates are less than the regional estimates because it is assumed that BPA will be competing with other Northwest utilities for the same supply of resources. All of the resources are generic in nature in that they are not associated with specific sites.

BPA's generation resource supply forecasts are based on, and are consistent with, the generation resource data used by the Northwest Power Planning Council in its 1991 Northwest Conservation and Electric Power Plan (1991 Power Plan). Some figures have been adjusted to reflect different assumptions used by BPA or to add information developed after the release of the 1991 Power Plan.

TABLE ES.1

LIST OF GENERATION RESOURCES
COST AND AVAILABILITY-YEAR 2000

Resource [a]	Real 1990 Lev Cost (mills/kWh)	Nominal Lev Cost (mills/kWh)	Regional Supply (aMW)	BPA Supply (aMW)
Hydro-1W	21	40	36	9
Hydro-1E	22	44	55	14
WNP-3L	34	65	806	806
WNP-1L	35	67	813	813
Hydro-2W	35	67	41	10
Hydro-2E	37	72	62	15
Cogen-1W	38	74	240	60
Cogen-2W	39	76	29	7
Cogen-1E	39	76	240	60
Comb Cycle CT [b]	39	76	NA	NA
Cogen-2E	40	78	29	7
Mun Solid Waste	41	80	30	30
WNP-3H	42	82	806	806
WNP-1H	43	83	813	813
Hydro-3W	46	90	50	13
Wind-1	47	92	29	7
Hydro-3E	48	94	76	19
Geo	51	100	350	88
Coal-1T	52	101	1800	450
Single Cycle CT [b]	52	101	NA	NA
Cogen-3W	53	103	563	141
Cogen-3E	54	105	563	141
Coal-2T	55	105	750	188
Hydro-4W	58	112	36	9
Cogen-4W	58	113	269	67
Cogen-4E	59	115	269	67
Coal-3T	60	115	750	188
Hydro-4E	60	116	53	13
Coal-4T	61	118	750	188
Coal-5T	63	121	750	188
Wind-2	64	123	381	95
Wind-3	72	140	253	63
Biomass	75	145	23	23
Solar	86	166	480	120

[a] Codes: Several resources are divided into east (E) and west (W) of the Cascades for transmission planning purposes. WNP-1 & -3 costs were developed with low (L) and high (H) O&M cost estimates. The coal resource estimates are temporary (T) pending an update of the coal conversion technology update.

[b] The cost shown for CTs assume baseload operation. The actual cost of power resulting from using nonfirm energy with CTs is dependent on the amount of nonfirm energy available, the value of nonfirm energy, the cost and avaiability of fuel, and nonfirm pricing policies.

GENERATION RESOURCES SUPPLY
DOCUMENT

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CHAPTER 1

INTRODUCTION

The Bonneville Power Administration (BPA) has been publishing forecasts of the cost and availability of generating resources since 1985. These forecasts have been updated approximately every two years. Currently, updates are scheduled to coincide with major revisions to BPA's Resource Program.

The Generation Resources Supply Document summarizes all of the generation resource cost and supply assumptions used by BPA for its Resource Program and other planning activities. The document looks at different types of generation resources and also provides a technical description of each resource type as well as cost, operating, and environmental characteristics. With the exception of the nuclear plants WNP-1 & -3, generic resources are used. Generic resources are resources that do not have a specific site associated with them.

The capital and O&M cost data as well as supply availability are based on, and are consistent with, the generation resource data used by the Northwest Power Planning Council (Council) in its 1991 Northwest Conservation and Electric Power Plan (Power Plan). Some figures have been adjusted to reflect different assumptions used by BPA or to add information developed after the release of the 1991 Power Plan.

Resources are grouped into two chapters. The resources that are considered available for the Resource Program stack of resources are described in Chapter 3 of this document. Generating resources and technologies that are not considered to be available or are otherwise excluded from the Resource Program are described in Chapter 4. This "other resource" information in Chapter 4 is included for reference, and documents what is and is not known about these resources. Why they are excluded from consideration in the Resource Program is also explained.

The resource supply information in this document is organized in the following way:

Chapter 2 describes the general methodology for projecting supply and explains the adjustments BPA made to figures used in the Council's 1991 Power Plan.

Chapter 3 describes each type of generation resource that is considered in BPA's Resource Program, including a technical description, basic operating characteristics, costs, environmental characteristics, and a supply forecast. A table for each generation resource summarizes the cost and achievable potential of that resource.

Chapter 4 documents data for several resources that are not considered in the Resource Program. The data for these resources is not as comprehensive as the data for resources considered in Chapter 3.

The Appendices contain detailed data sheets for most of the resources as well as other information referenced in the body of the document.

CHAPTER 2

GENERAL METHODOLOGY FOR PROJECTING GENERATION SUPPLY

BPA's generation resource supply forecasts are based on, and are consistent with, the generation resource data used by the Northwest Power Planning Council (Council) in its 1991 Northwest Conservation and Electric Power Plan (Power Plan). Since the Council's 1991 Power Plan and BPA's 1992 Resource Program overlapped, BPA and the Council collaborated on the development of supply forecasts in an effort to eliminate possible duplication as well as help build a regional consensus regarding assumptions.

There are, however, some differences in assumptions either because more current information became available after the 1991 Power Plan was issued or because of differing objectives of the Council and BPA. This chapter highlights the different assumptions as well as provides an overview of supply curves in general.

WHAT IS A SUPPLY CURVE?

A supply curve provides an estimate of the cumulative potential of a resource as a function of cost. When portrayed as a graph, the vertical axis shows the total resource potential and the horizontal axis displays the cost at which this potential is available. Supply curves are used in resource planning to provide estimates of the quantity of a resource that is available in the menu of acquisition options and the cost of acquiring these resources.

Supply curves are developed to display a forecast of the energy available and its cost. Separate supply curves are developed for each different generating technology. The supply forecasts in this document are rough approximations of a true supply curve in that they are not a continuous function. For example, their are five categories of the hydroelectric resource. These categories are differentiated by cost. Consequently the supply curve for the hydroelectric resource actually consists of five discrete points, each point higher in cost and potential than the previous point. For some resources only one point is provided (e.g., biomass) because the potential is small enough to be represented by one potential at one price. This simplifies analysis and modeling without significant distortions.

ADJUSTMENTS

Some adjustments have been made to the figures used in the Council's 1991 Power Plan. These adjustments reflect different assumptions used by BPA or additional information that was developed subsequent to the release of the 1991 Power Plan. The adjustments are described below.

Resource Availability

Not all of the regional potential of a resource is available to BPA. Availability of generic resources to BPA, referred to as supply forecast in the cost and achievable potential tables, was set to 25% of the regional supply. This is the same figure that was used in the 1990 and 1992 Resource Programs. Exceptions to this are noted in the individual data sheets in Appendix C.

Transmission Adjustment

The capital cost of resources is adjusted to reflect their location. These adjustments are based on the distance of the general location of the generation resource from the west side load centers. Where specific sites are identified an adjustment is made that is based on the distance from the site to the Puget Sound area. Where specific sites are not identified, an adjustment is made based on which zone the resource is assumed to be located in. For generic resources located west of the Cascades no adjustment is made. For resources located between the Cascades and the eastern edge of the transmission grid an increment of 128 $/kW is added to the capital cost. For resources located east of the grid a 438 $/kW adder is used. These zonal factors are generic and are based on BPA estimates for construction of new transmission lines. These adjustments are explicitly shown on each data sheet in Appendix C. See Appendix B for background information regarding the transmission adjustment calculation.

The lead times shown for each generation resource type are based on estimates to license and construct a generation facility. If extensive transmission integration is required then the transmission line itself may determine the project lead time. The transmission adjustments also reflect economies of scale in the construction of transmission facilities. Specific projects may incur higher costs depending on how much of the transmission cost is allocated to the project.

Coal Gasification

In addition to the transmission adjustment, capital costs were arbitrarily reduced by 10% in anticipation of updated costs. Updated capital and operating and maintenance costs are currently being developed. In addition, a revised coal fuel forecast became available since the Draft Generating Resources document was published in December 1991. This revised forecast was incorporated into the coal gasification resource estimates contained in this document as well as the 1992 Resource Program.

WNP-1 & -3

Data for a high and a low cost estimate are included. The high case reflects a higher fixed O&M value with a 1.5%, versus a 0.7% real escalation. These high and low estimates are based on fixed O&M only. They do not represent the full range of high and low potential because they do not incorporate the cost-to-complete nor the variable operating expenses. An additional change in the WNP-1 & -3 assumptions in this document and consequently for the 1992 Resource Program is variable fuel cost that is lower in real terms than was used in BPA's 1990 Resource Program.

Financial Factors

Financial assumptions used by Bonneville may differ from those used by the Council. When calculating a levelized cost (see Table 1.1) BPA assumes a combined 50% public/50% private ownership except where ownership is explicit (e.g., WNP-1 & -3). Table 2.1 summarizes the financial assumptions that BPA uses and shows real escalation rates, tax rates, the real discount rate, and the inflation rate.

TABLE 2.1

FINANCIAL FACTORS

	Percent
REAL ESCALATION RATES	
Capital	1.2
O&M	0.7
Fuel	0.7
Coal	1.0
Natural Gas	3.1
TAX RATES	
Federal	34.0
State	3.7
Insurance	0.25
Gross Revenue	
Public	2.2
Private	2.1
FINANCIAL ASSUMPTIONS	
Price Level: 1990	
Nominal Debt Interest Rate	
Public	7.3
Private	9.7
Nominal Return on Equity Rate	
Private	12.5
REAL DISCOUNT RATE	3.0
INFLATION RATE	5.0

CHAPTER 3

GENERATION RESOURCES (RESOURCE PROGRAM)

This chapter documents those resources that are included in the list of available resources that were used in the analyses performed for the 1992 Resource Program. These resources are considered to be available for planning purposes at the costs described in the following pages.

Each resource is described in a self-contained section that includes a Technical Description, and contains information regarding Operating Characteristics, Costs, Environmental Characteristics, and a Supply Forecast. These sections provide background information on the figures that are included in the accompanying tables.

Cost and achievable potential tables are given for each type of resource. These tables show figures that BPA uses in resource planning. The figures include plant characteristics; capital, operating, and fuel costs; leadtimes; levelized costs; and a supply forecast.

Plant characteristics include assumptions regarding the physical aspects of the technology. The costs portion represents overnight construction costs and starting fuel prices in 1990. The leadtimes indicate how long it would take to bring a resource on-line (completing both the pre-construction and construction phases) once a decision was made to construct. The levelized cost information represents the cost to own and operate the resource over its lifetime. These levelized cost calculations assume an on-line date of 2000 for reference purposes. Supply forecast figures project how much energy is assumed to be available over a twenty-year period. (Because of the methodology used, the cogeneration supply forecast tables do not include overnight construction costs.)

For ease of reference, each cost and achievable potential table follows the first page on which the description for that resource type appears. Tables of supplementary information are provided for some resources where required for clarity.

STAND-ALONE BIOMASS

Technical Description

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

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

As with coal, gasification of biomass produces CO and H2, the primary constituents of syngas. The gas needs to be cleaned, both to reduce sulfur and to eliminate the tars and lignins that plague biomass gasifier piping and contaminate the syngas. Biomass syngas can be introduced as a fuel directly into a gas turbine or internal combustion engine that is coupled to a generator. However, wood biomass yields a syngas with a much lower BTU content compared to coal syngas.

The primary source of biomass fuel is mill and logging residues, but there are also landfill byproducts such as methane, agricultural residues from fields, and municipal solid waste.

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

At many mills, wood residue is burned to fire a boiler and generate steam for a turbine-generator. In some instances, cogeneration is an attractive option for producing both electricity and process steam at these sites. (See the "Cogeneration" section for more information on this resource.)

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

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

TABLE 3.1

PROJECTED COST AND ACHIEVABLE POTENTIAL
STAND ALONE BIOMASS
FY 1991 THROUGH 2010

PLANT CHARACTERISTICS	
Operating Life (years)	30
Unit Size (MW) [a]	29
Equivalent Availability	80%
Anticipated Capacity Factor	80%
Heat Rate (Btu/kWh)	15000
COSTS (1990 $)	
Capital ($/kW)	1710
Fixed O&M ($/kW/yr)	44.00
Variable O&M (mills/kWh)	3.7
Fixed Fuel ($/kW/yr)	0
Fuel ($/MMBtu)	2.60
LEADTIMES (years)	
Preconstuction	2
Construction	3
LEVELIZED REAL COST (1990 mills/kWh) [b]	
Public Financing	72
Private Financing	77
LEVELIZED NOMINAL COST (mills/kWh) [b]	
Public Financing	141
Private Financing	150
SUPPLY FORECAST (aMW)	
Regional	113
BPA	113

[a] Data for other sizes of biomass plants have not been developed. As the size increases, per unit fuel houling costs increase because of the longer hauling distances.
[b] Year 2000 on-line date.

Operating Characteristics

As long as an adequate supply of fuel is available, biomass-fired steam-cycle plants may be operated as baseload systems. Since they are steam boilers, they are not amenable to load following applications.

The size of a plant is a function of the location and transportation of fuel that is required. Plants in the 20-50 MW range are the most feasible. Larger plants require transportation of fuel over longer distances. This rapidly degrades the economics of a facility. For a plant with access to a reliable fuel supply, availability factors should run in the 70-80% range.

Heat rates are somewhat high (15,000 BTU/kWh) because of the moisture content of the fuel. If biomass gasifiers are coupled to engines or combustion turbines, all the syngas fuel produced must be used as it is generated.

Costs

Cost data for a stand-alone biomass fired steam boiler is presented in Table 3.1. These estimates, including the cost of fuel, are derived from the Draft 1991 Northwest Conservation and Electric Power Plan. Estimates for a gasification plant are not available. Such a plant would not, however, be competitive with a natural gas fired facility due to the low BTU content of the fuel.

Environmental Characteristics

Environmental impacts of air emissions from biomass combustion are relatively less severe than from fossil fuels. Still, the impacts are substantial.

Pollutants include CO_2 and some CO, particulates, hydrocarbons, NO_x and SO_x. NO_x and SO_x emissions are on the order of 50% and 25%, respectively, compared to coal combustion on a per MW-hour basis.

CO and hydrocarbon emissions are controlled by better burners by adjusting the air/fuel ratio to complete combustion. Particulates can be reduced with baghouse filters, scrubbers, and precipitators. As long as the amount of biomass fuel used is replenished by the same amount at the same rate by new growth, the net contribution of CO_2 is zero.

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

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

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

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

Supply Forecast

Logging residue is the most likely fuel to consider available for a stand-alone biomass plant. Mill residue is already consumed for other products or to produce steam for mill use. Cogeneration applications are already common for large mills.

On a regional basis, 15-30 trillion BTUs of logging residue is available at an average cost of $2.60/MMBTU. This would be adequate for 100-300 MW of stand-alone generation. The amount that could be developed, however, would have to compete with cogeneration applications. This would likely limit the amount that would be economic to develop. Cogeneration would also be a more efficient use of the fuel. For planning purposes, 113 aMW are assumed to be available to the region and the entire amount is assumed to be available to BPA.

COAL GASIFICATION

Technical Description

There are several advanced coal technologies that offer better heat rates (higher thermal efficiencies) and greatly reduced emissions compared to the conventional steam cycle coal plant. BPA assumes that future coal plants in the Northwest will reflect the advanced technology that has the best environmental characteristics. This is the same assumption that is used by the Council.

Coal gasification technology thermally decomposes solid coal into a high quality fuel that can be burned in a combustion turbine. In the gasification process, the coal is partially oxidized producing mostly the combustible gases CO and H_2. Subsequently sulfur is removed from the gas stream. Gasification provides an almost entirely sulfur-free syngas with high BTU.

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

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

Operating Characteristics

A coal gasification facility would be designed as a baseload power generator, with optimum performance at design load. Part load operation is less efficient, and plants are not designed for short-term peaking operation. The thermal inertia of getting boilers, turbines and condenser up to temperature inhibits quick response to variations in load. Availability factors in percent range from the mid 70s to the high 80s, and capacity factors generally exceed 65%. Capacity factors are assumed to equal availability factors for planning purposes. Coal gasification plants have heat rates under 9,500 BTU/kWh.

Costs

Cost estimates for coal resources are derived from documentation prepared for BPA's 1990 Resource Program and updated to reflect current costs and assumptions. The coal resource is described as five blocks, each block representing a different site. These sites represent five potential areas in the Northwest that could support coal development. These include Colstrip, Montana;Creston and Centralia in Washington; Boardman, Oregon; and Thousand Springs,

TABLE 3.2

DERIVATION OF FUEL COSTS FOR
COAL GASIFICATION-DRAFT 1992 RESOURCE PROGRAM

IDENTIFIER [a]	Coal-1T	Coal-2T	Coal-3T	Coal-4T	Coal-5T
SURROGATE SITE	Colstrip	Creston	Boardman	Thosand Springs	Western OR/WA
ASSUMED COAL FIELD	Colstrip	East Kootenay	East Kootenay	Uinta	East Kootenay
COST OF FUEL ($/MMBtu)					
Minemouth	0.52	0.95	0.95	1.06	0.95
Track Upgrade	0.00	0.00	0.00	0.00	0.00
Rail Haul	0.00	0.35	0.50	0.30	0.71
Rolling Stock	0.00	0.04	0.05	0.03	0.08
TOTAL	0.52	1.34	1.50	1.39	1.74
REAL ESCALATION	1.0%	1.0%	1.0%	1.0%	1.0%

[a] The designation (i.e. COAL-1T) distinguishes different cost categories. The "T" suffix indicates that estimates are temporary pending an update of coal gasification technology cost estimates.

TABLE 3.3

REVISED FUEL AND LEVELIZED COSTS FOR COAL GASIFICATION-FINAL 1992 RESOURCE PROGRAM

IDENTIFIER	Coal-1T	Coal-2T	Coal-3T	Coal-4T	Coal-5T
SURROGATE SITE	Colstrip	Creston	Boardman	Thousand Springs	Western OR/WA
ASSUMED COAL FIELD	Colstrip	Colstrip	Colstrip	Uinta	Colstrip
COST OF FUEL ($/MMBtu)					
Minemouth	0.28	0.28	0.28	0.76	0.28
Transport	0.00	0.96	1.16	0.47	1.41
TOTAL	0.28	1.24	1.44	1.23	1.69
REAL ESCALATION	1.54%	1.48%	1.63%	1.23%	1.66%
LEVELIZED COST (mills/kWh) [a]					
Real	52	55	60	61	63
Nominal	101	105	115	118	121

[a] Levelized costs assumed 50% public/50% private financing. Year 2000 on-line date.

TABLE 3.4

PROJECTED COST AND ACHIEVABLE POTENTIAL
COAL GASIFICATION-DRAFT 1992 RESOURCE PROGRAM
FY 1991 THROUGH 2010

	Coal-1T	Coal-2T	Coal-3T	Coal-4T	Coal-5T
PLANT CHARACTERISTICS					
Operating Life (years)	30	30	30	30	30
Unit Size (MW) [a]	420(428)	420(357)	420(357)	420(357)	420(357)
Equivalent Availability	70%	70%	70%	70%	70%
Anticipated Capacity Factor	70%	70%	70%	70%	70%
Heat Rate (Btu/kWh)	9490	9455	9455	9490	9455
COSTS (1990 $)					
Capital ($/kW)	2817	2209	2492	2546	2493
Fixed O&M ($/kW/yr)	70.10	65.00	65.00	69.70	64.20
Variable O&M (mills/kWh)	0.9	0.8	0.8	0.9	0.8
Fixed Fuel ($/kW/yr)	0	0	0	0	0
Fuel ($/MMBtu)	0.52	1.34	1.50	1.39	1.74
LEADTIMES (years)					
Preconstuction	2	2	2	2	2
Construction	5	5	5	5	5
LEVELIZED REAL COST (1990 mills/kWh) [b]					
Public Financing	50	50	54	57	57
Private Financing	60	59	62	66	65
LEVELIZED NOMINAL COST (mills/kWh) [b]					
Public Financing	97	98	105	111	110
Private Financing	116	115	121	128	126
SUPPLY FORECAST (aMW)					
Regional	1800	750	750	750	750
BPA	450	188	188	188	188

[a] Unit sizes shown in parentheses reflect adjustments made for modeling purposes.
[b] Year 2000 on-line date.

Nevada. Although specific sites are identified, they represent surrogates for five different areas and should be considered as generic sites. Along with each site is a corresponding fuel source. These fuel sources were selected as the most inexpensive sources based on existing mining and transportation costs. Fuel costs used in the Draft 1992 Resource Program are summarized in Table 3.2.

Subsequent to the publication of the draft document, revised coal fuel forecasts became available. These revised forecasts are summarized in Table 3.3. Table 3.3 also shows revised levelized cost that resulted from the change to the fuel cost forecast. These revised costs were reflected in the final 1992 Resource Program. Although the five surrogate sites remain the same, the assumed coal field did change for some of the sites.

The capital and operating cost for the gasification technology is the same for each site. These costs are based on the estimates published in the 1991 Power Plan. Capital costs are based on estimates originally developed in 1985. Several improvements in both combustion turbine and gasification technologies have occurred since that time. Estimates are currently being updated to reflect these changes. Revised estimates are expected to be available in January 1993. The capital costs reported in Table 3.4 reflect a 10% reduction from the estimates reported in the 1991 Power Plan. This adjustment was made in anticipation of lower capital costs that are expected to be reflected in the revised estimates.

Environmental Characteristics

Because of combustion characteristics of gasifiers, NO_X emissions are inherently low and SO_X, carbon monoxide, and particulate emissions are dramatically reduced compared to conventional coal conversion technologies. Solid wastes are also less hazardous. Of all the available coal conversion technologies, coal gasification is the cleanest. Appendix A summarizes the projected emissions of coal gasification relative to other conversion technologies.

Mining, transportation, and fuel handling problems are similar for both conventional and advanced coal technologies.

Supply Forecast

Table 3.4 summarizes the availability of the coal resource at each of the five surrogate sites. These estimates are from the 1991 Power Plan and are consistent with BPA's assumptions in its 1990 Resource Program. These supply forecasts were not affected by the revised coal fuel forecasts that were discussed under the costs section.

COGENERATION

Technical Description

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

Cogeneration is not new. Before large central generating plants came into vogue in the 1930s, as much as 50% of the electricity generated in this country came from cogenerators. Historically, most cogeneration plants involved large units in industrial facilities, from 5 to 50 MW. Today, cogeneration plants are as diverse as the industries and commercial applications where they are found and the technology employed is as varied as the kinds of fuels used. In wood industry plants, for example, wood waste must be disposed of and is used as an energy source. But a whole variety of fuel types can be used in cogeneration. The breakdown of fuels for proposed cogeneration projects nationwide is as follows: follows: natural gas, 58%; coal, 19%; biomass waste and other fuels, 23%.

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

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

Operating Characteristics

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

TABLE 3.5

PROJECTED COST AND ACHIEVABLE POTENTIAL
COGENERATION-EAST
FY 1991 THROUGH 2010

	Cogen-1E	Cogen-2E	Cogen-3E	Cogen-4E
PLANT CHARACTERISTICS				
Operating Life (years)	40	40	40	40
Unit Size (MW) [a]	25(33)	10(12)	10(12)	10(12)
Equivalent Availability	80%	80%	80%	80%
Anticipated Capacity Factor	80%	80%	80%	80%
LEADTIMES (years)				
Preconstuction	2	2	2	2
Construction	2	2	2	2
LEVELIZED REAL COST (1990 mills/kWh) [b]				
Price	39	40	54	59
LEVELIZED NOMINAL COST (mills/kWh) [b]				
Price	76	78	105	115
SUPPLY FORECAST (aMW)				
Regional	240	29	563	269
BPA	60	7	141	67

[a] Unit sizes shown in parentheses reflect adjustments made for modeling purposes. The sizes reflect the smallest increment that cogeneration can be added for modeling purposes. The cost estimates for cogeneration reflect all sizes.
[b] Year 2000 on-line date.

TABLE 3.6

PROJECTED COST AND ACHIEVABLE POTENTIAL
COGENERATION-WEST
FY 1991 THROUGH 2010

	Cogen-1W	Cogen-2W	Cogen-3W	Cogen-4W
PLANT CHARACTERISTICS				
Operating Life (years)	40	40	40	40
Unit Size (MW) [a]	25(33)	10(12)	10(12)	10(12)
Equivalent Availability	80%	80%	80%	80%
Anticipated Capacity Factor	80%	80%	80%	80%
LEADTIMES (years)				
Preconstuction	2	2	2	2
Construction	2	2	2	2
LEVELIZED REAL COST (1990 mills/kWh) [b]				
Price	38	39	53	58
LEVELIZED NOMINAL COST (mills/kWh)				
Price	74	76	103	112
SUPPLY FORECAST (aMW)				
Regional	240	29	563	269
BPA	60	7	141	67

[a] Unit sizes shown in parentheses reflect adjustments made for modeling purposes. The sizes reflect the smallest increment that cogeneration can be added for modeling purposes. The cost estimates for cogeneration reflect all sizes.
[b] Year 2000 on-line date.

technology. Since cogeneration tends to be developed by third parties, the operating characteristics from the utility perspective can be negotiated.

Costs

Regional estimates of cogeneration prepared by BPA and the Council used output of the Cogeneration Regional Forecasting Model (CRFM) as the principle source. This model matches cogeneration technologies with facility types for subregions in the Pacific Northwest. The program performs a cost/benefit analysis for a subset of the configurations appropriate for each facility type. The objective is to find the configuration, operating mode, and system size that maximizes the internal rate of return as seen by the project sponsor. This process yields a distribution for a supply of cogeneration as a function of internal rate of return. This is then converted to a quantity of cogeneration at different sell-back prices. These prices, which a utility has to pay for cogeneration, are treated as a cost from a supply forecast perspective. Tables 3.5 and 3.6 show the prices of cogeneration east and west, respectively.

For planning purposes, the cogeneration potential was divided into four price blocks. Each block represents a quantity of cogeneration potential at a given price as defined by the CRFM. These four blocks were then divided into two groups, one east and one west of the Cascades. The group east of the Cascades reflects the transmission adjustment described in Chapter 2.

Environmental Characteristics

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

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

Another issue, sometimes overlooked, is that packaged cogeneration units developed to provide small-scale electricity supplies for buildings may miss the opportunity to concentrate on energy efficiency in buildings. Gains in energy efficiency are also likely to reduce pollution because less generation, and therefore less fuel combustion, is required to meet an equivalent level of electrical service. It is also expected that new installations will require best available control technology (BACT) regardless of emissions.

Supply Forecast

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

Assumptions are made regarding penetration rates (actual decisions to install the cogeneration equipment) at different levels of return. This penetration curve is used to reduce the distribution of supply to an expected value for developed cogeneration and the results are aggregated to a regional level. The output of this process is truly a generic estimate of the potential cogeneration. There is no site or project specific information in the output.

Tables 3.5 and 3.6 show the cost and availability of cogeneration east and west, respectively. Over 2,200 aMW of regional potential is considered to be available. The 50/50 east/west division was based on the relative distribution of potential cogeneration facilities. The estimates are from the 1991 Power Plan and are consistent with BPA's assumptions in its 1990 Resource Program.

Recent acquisition activity among Pacific Northwest utilities has generated substantial activity in the cogeneration area. All of the utilities' requests for resources received cogeneration proposals. It is hoped that subsequent updates to the cogeneration supply forecast can utilize information that is available from these bid processes.

COMBUSTION TURBINES & OTHER DISPLACEABLE RESOURCES

Technical Description

Combustion turbines (or CTs, also called gas turbines) are based on the same technology used in jet engines. Large CTs designed for utility applications, known as frame machines, are configured for heavy duty use. Weight is not a primary consideration. In the basic CT design, air enters a compressor which packs large amounts of air into a combustor at high pressure. In the combustor fuel is added to the air and burned, releasing heat energy and producing a high temperature, high pressure exhaust gas. This gas is expanded through a turbine, which powers the compressor and generator.

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

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

CT efficiencies can also be improved by using multistage compressors with inter-cooling between stages and by operation at higher turbine inlet temperatures. Currently, advanced turbines operate at temperatures around 2300^{o}F.

The high thermal energy in the turbine exhaust makes CTs ideal in cogeneration applications where high grade process heat is used in addition to electricity. Another way to take advantage of the energy in the exhaust gases is to use the combustion turbine as the "topping cycle" in a combined cycle plant.

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

Combined cycle plants are designed to maximize the thermal efficiency of a power plant by using the available energy in the combustion turbine's high temperature exhaust gases. The

TABLE 3.7

PROJECTED COST AND ACHIEVABLE POTENTIAL
COMBUSTION TURBINES
FY 1991 THROUGH 2010

	SCCT	CCCT
PLANT CHARACTERISTICS		
Operating Life (years)	30	30
Unit Size (MW)	139	420
Equivalent Availability	84%	83%
Anticipated Capacity Factor	84%	83%
Heat Rate (Btu/kWh)	11480	7620
COSTS (1990 $)		
Capital ($/kW)	788	894
Fixed O&M ($/kW/yr)	2.20	5.80
Variable O&M (mills/kWh)	0.2	0.4
Fixed Fuel ($/kW/yr)	0	0
Fuel ($/MMBtu)	1.72	1.72
LEADTIMES (years)		
Preconstuction	2	2
Construction	2	2
LEVELIZED REAL COST (1990 mills/kWh) [a]		
Public Financing - See Text	51	38
Private Financing - See Text	53	40
LEVELIZED NOMINAL COST (mills/kWh) [a]		
Public Financing - See Text	99	74
Private Financing - See Text	103	78
SUPPLY FORECAST (aMW)		
Regional	See	Text
BPA	See	Text

[a] Year 2000 on-line date.

key to the combined cycle is the heat recovery steam generator system, which takes the place of the steam cycle boiler. Typical steam conditions in a heat recovery steam generator are 900-1000^{o}F and 1,000-1,500 psi. Instead of rejecting heat to the environment at gas turbine temperatures of more than 1000^{o}F, the combined cycle eliminates heat at the steam cycle condenser temperature, which is the temperature of available cooling water--around 50-70^{o}F.

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

Operating Characteristics

Combustion turbines can be operated to meet both peak and energy loads. CTs can quickly respond to load demand changes; however maximum efficiencies are obtained when operating at design capabilities. Because of high fuel costs, CTs tend to be used at a constant rate for a limited period of time. CTs can be quickly fired up and have proved effective in meeting needle peak loads and load fluctuations due to extreme weather conditions.

CT availability factors run 80-90%. CTs are candidates for meeting baseloads and can also be used in firming applications. Simple CTs operate at heat rates of 11,000-12,000 BTU/kWh. CTs used to "firm up" or supplement the nonfirm hydropower operate at capacity factors of 15-40%. When operated to meet short duration capacity needs, CTs operate at relatively low capacity factors, on the order of 5%.

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

Costs

Table 3.7 shows capital and operating costs for both single cycle and combined cycle combustion turbines. These costs are based on the General Electric MS7001F combustion turbine. Both the single and combined cycle configurations have dual fuel capability as well as 14 days of oil storage capability. Since CTs would normally be run to displace other higher cost resources, capacity factor is not an accurate measure of their performance. If CTs were run in a baseload mode their capacity factor would equal their availability. The levelized costs shown in Table 3.7 reflect this baseload operation.

Environmental Characteristics

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

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

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

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

Supply Forecast

How many CTs are installed is not inherently limited by ability to site, fuel, or hardware availability. Projecting supply is therefore dependent upon how CTs are to be used in the existing power system. CTs would be used in the Federal power system in conjunction with nonfirm power.

The amount of power available from the Pacific Northwest hydro system varies from year to year. Firm energy is defined as the amount of energy the system can produce during a recurrence of critical water conditions. In most years, the hydropower system generates more than firm energy. Any generation in excess of firm energy is called nonfirm energy. The Federal hydro system produces between 2,600 and 3,000 aMW of nonfirm energy in an average water year. Over the past 10 years BPA has sold an average of over 1,000 aMW outside the region and 5,550 aMW within the region as nonfirm power, in addition to serving the direct service industry (DSI) top quartile. The available nonfirm energy can be used in conjunction with another resource to serve BPA's firm loads.

Use of nonfirm in conjunction with other resources can be accomplished with a number of strategies. These include coordination with Canada; additions of displaceable firm resources, such as CTs, to the system; load management techniques; supplemental energy contracts with the Pacific Southwest; or adding reservoir capacity to the existing Federal System. The cost of any strategy in meeting BPA loads depends on the value and availability of nonfirm, and the feasibility and costs associated with operating the strategy. The 1990 Resource Program estimated that 1,500 aMW nonfirm could be converted to firm energy through a combination of 1,000 aMW of Pacific Northwest CTs, and 500 aMW of extraregional resources. Extraregional resources consist of contractual arrangements with out-of-region parties, specifically the Pacific Southwest. BPA could arrange to purchase energy from the Pacific Southwest when water conditions on BPA's system are insufficient to meet BPA's firm loads.

BPA might pay a small reservation charge for this privilege, and then pay the costs the Pacific Southwest would incur to produce and transmit energy when needed by BPA. Since the costs for obtaining power from the Pacific Southwest are uncertain, the analysis assumes that costs are equal to 32 mills, the cost of building a CT in the Pacific Northwest. This assumption is based on the premise that the Southwest market price will be determined by the Pacific Northwest's alternative resource.

The quantity of combustion turbines installed is not inherently limited. Constraints that are typically discussed include ability to site and availability of fuel supply. These constraints will pose less of an impediment for the first increment of turbines installed than subsequent turbines.

GEOTHERMAL

Technical Description

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

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

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

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

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

TABLE 3.8

PROJECTED COST AND ACHIEVABLE POTENTIAL
GEOTHERMAL
FY 1991 THROUGH 2010

PLANT CHARACTERISTICS	
Operating Life (years)	30
Unit Size (MW) [a]	25(27)
Equivalent Availability	90%
Anticipated Capacity Factor	90%
Heat Rate (Btu/kWh)	0
COSTS (1990 $)	
Capital ($/kW)	3107
Fixed O&M ($/kW/yr)	116.00
Variable O&M (mills/kWh)	6.5
Fixed Fuel ($/kW/yr)	0
Fuel ($/MMBtu)	0.00
LEADTIMES (years)	
Preconstuction	2
Construction	2
LEVELIZED REAL COST (1990 mills/kWh) [b]	
Public Financing	48
Private Financing	55
LEVELIZED NOMINAL COST (mills/kWh) [b]	
Public Financing	92
Private Financing	107
SUPPLY FORECAST (aMW)	
Regional	350
BPA	88

[a] Unit sizes shown in parentheses reflect adjustments made for modeling purposes.
[b] Year 2000 on-line date.

Temperature and pressure of the resource dictate the choice of technology employed at a particular geothermal site. Geothermal energy is being used worldwide with a high degree of success. In California, at the Geysers field alone, there are about 2,000 MW on-line tapping a dry steam geothermal reservoir. Other active geothermal regions in the United States include the Basin and Range geologic province covering parts of Utah, Nevada, and Idaho, and California's Imperial Valley.

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

Operating Characteristics

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

Costs

The Council developed a range of costs based on geothermal conversion technologies at sites with defined geothermal resources (Staff Issue Paper 89-36, Geothermal Resources). Costs would be expected to vary depending on site specific conditions. Table 3.8 shows the cost data used by BPA and the Council for the geothermal resource. These costs are based on the representative Basin and Range plant used in the 1991 Power Plan.

Environmental Characteristics

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

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

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

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

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

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

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

Aesthetics are a major concern. The visual impact of a well field and power plant facilities may be objectionable, especially in pristine areas such as the Cascades where many potential geothermal sites exist.

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

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

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

Supply Forecast

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

The most likely locations in the Pacific Northwest for geothermal development are the Basin and Range province (southeastern Oregon and southern Idaho) and the high Cascades of southern Oregon. Table 3.8 shows 350 aMW of regional geothermal resource to be available. This is based on the representative Basin and Range plant used in the 1991 Power Plan. For planning purposes, 88 aMW is assumed to be available to the region and the entire amount is assumed to be available to BPA.

HYDROELECTRIC

Technical Description

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

Hydroelectric projects can have large dams associated with them to store water and create head, or they may be run-of-river plants that use a smaller dam (or diversion) to take a portion of a river's flow out at a high elevation, drop it through a penstock and turbine, and release it at a lower level. Most of the potential projects in the region are small hydro, run-of-river designs.

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

Operating Characteristics

To determine the operating characteristics at a particular site, information on the local hydrology must be examined. If flow information is not provided by the developer, planning models have the capability to estimate flows based on existing records of such information as the drainage areas above the site, precipitation records, and information on local groundwater conditions. Hydrologic conditions vary greatly over the region, even within basins and sub-basins. In the west, winter storms produce immediate high flows, and in the east, flows are predominantly from melting snow in the spring. A particular project's elevation will also affect the shape of its output.

Costs

Hydroelectric cost estimates for this document are generic cost categories aggregated from individual project cost estimates in the Pacific Northwest Power Data Base and Analysis System (NWHS). The cost projections for individual projects in the data base are either supplied by potential developers or calculated by an algorithm (Hydropower Analysis Model, or HAM) contained within the NWHS. The data base includes data on all projects for which

TABLE 3.9

PROJECTED COST AND ACHIEVABLE POTENTIAL
NEW HYDROELECTRIC - EAST
FY 1991 THROUGH 2010

	Hydro-1E	Hydro-2E	Hydro-3E	Hydro-4E
PLANT CHARACTERISTICS				
Operating Life (years)	50	50	50	50
Unit Size (MW) [a]	10(11)	10(11)	10	10
Equivalent Availability	48%	36%	37%	36%
Anticipated Capacity Factor	48%	36%	37%	36%
Heat Rate (Btu/kWh)	0	0	0	0
COSTS (1990 $)				
Capital ($/kW)	1188	1457	1959	2344
Fixed O&M ($/kW/yr)	23.00	29.00	39.00	48.00
Variable O&M (mills/kWh)	0	0	0	0
Fixed Fuel ($/kW/yr)	0	0	0	0
Fuel ($/MMBtu)	0.00	0.00	0.00	0.00
LEADTIMES (years)				
Preconstuction	3	3	3	3
Construction	3	3	3	3
LEVELIZED REAL COST (1990 mills/kWh) [b]				
Public Financing	20	33	43	53
Private Financing	25	42	54	67
LEVELIZED NOMINAL COST (mills/kWh) [b]				
Public Financing	38	63	83	103
Private Financing	49	81	105	131
SUPPLY FORECAST (aMW)				
Regional	55	62	76	53
BPA	14	15	19	13

[a] Unit sizes shown in parentheses reflect adjustments made for modeling purposes.
[b] Year 2000 on-line date.

TABLE 3.10

PROJECTED COST AND ACHIEVABLE POTENTIAL
NEW HYDROELECTRIC - WEST
FY 1991 THROUGH 2010

	Hydro-1W	Hydro-2W	Hydro-3W	Hydro-4W
PLANT CHARACTERISTICS				
Operating Life (years)	50	50	50	50
Unit Size (MW) [a]	10(7)	10(11)	10(13)	10
Equivalent Availability	48%	36%	37%	36%
Anticipated Capacity Factor	48%	36%	37%	36%
Heat Rate (Btu/kWh)	0	0	0	0
COSTS (1990 $)				
Capital ($/kW)	1060	1329	1831	2216
Fixed O&M ($/kW/yr)	23.00	29.00	39.00	48.00
Variable O&M (mills/kWh)	0	0	0	0
Fixed Fuel ($/kW/yr)	0	0	0	0
Fuel ($/MMBtu)	0.00	0.00	0.00	0.00
LEADTIMES (years)				
Preconstuction	3	3	3	3
Construction	3	3	3	3
LEVELIZED REAL COST (1990 mills/kWh) [a]				
Public Financing	18	31	41	51
Private Financing	23	39	52	65
LEVELIZED NOMINAL COST (mills/kWh) [b]				
Public Financing	35	59	79	99
Private Financing	45	75	100	125
SUPPLY FORECAST (aMW)				
Regional	36	41	50	36
BPA	9	10	13	9

[a] Unit sizes shown in parentheses reflect adjustments made for modeling purposes.
[b] Year 2000 on-line date.

permit and license applications have been filed with the Federal Energy Regulatory Commission (FERC). When consistent estimates are not available, the model develops a cost estimate from the physical characteristics of the project. The generic estimates are shown in Tables 3.9 and 3.10.

Environmental Characteristics

No sites that are considered in projection of potential are located in the Council's Protected Areas. This screens out any projects that might have an impact on anadromous fish populations or other critical fish and wildlife habitat.

A hydroelectric project that has an impoundment (the capability to store water) associated with it would generally have a more severe impact than a run-of-river project. This would especially be true for large impoundments (> 100 acres).

Supply Forecast

Tables 3.9 and 3.10 summarize the projected potential for the hydroelectric resource. The procedure used to generate estimates of potential uses the Pacific Northwest Hydropower Supply Model. This model uses data from the NWHS on cost, capacity, and output, combined with regional environmental information from the Northwest Environmental Data Base.

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

a. Sites located in the Council's Protected Areas were screened out of the analysis.

b. Even projects passing this screen could have environmental problems that may preclude development. In addition, the technical characteristics of many of the sites have not been fully explored, leading to the possibility that development may not be feasible for engineering, environmental, or economic reasons. To account for these factors, probabilities of completion were assigned based on the stage at which the project stands in the regulatory process (permit pending to license granted), the layout of the project (diversion to canal), the status of the waterway structure (existing to undeveloped), and the value of the environmental resources at the site which would be impacted by development.

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

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

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

MUNICIPAL SOLID WASTE

Technical Description

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

Flue gases, coming out of the incinerator, pass through a lime scrubber to remove the SO_2, HCl, and other gases, then through a baghouse to eliminate fly ash containing heavy metals, furans, dioxins, and other toxic compounds. Bottom ash off the incinerator grate and captured fly ash are disposed of in a lined ash monofill. The MSW fuel in this case contains 25% ash and 4,500 BTU/lb. The low heating value is due to high moisture and low grade fuel quality. Both lignite coal and biomass have higher BTU content.

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

The key to a RDF plant operation is the front-end waste separation process. In one design, flailing, trommell screening, magnetic separation of metals, and size reduction prepare a fuel that contains about 15% ash and 5,900 BTU/lb. At some sites, the major problem with RDF is securing an assured supply of the fuel. RDF is also used to supplement other fuels, such as hog fuel (chipped and split chunks of wood) burners.

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

Operating Characteristics

Most MSW plants in the United States are 40-60 MW in size. Expectations are for smaller sized plants in the Pacific Northwest of about 10 MW, operating at 65-80% capacity. There is a plant near Salem now operating at 12 MW. Forecasters estimate as much as

TABLE 3.11

PROJECTED COST AND ACHIEVABLE POTENTIAL
MUNICIPAL SOLID WASTE
FY 1991 THROUGH 2010

PLANT CHARACTERISTICS	
Operating Life (years)	30
Unit Size (MW) [a]	10(12)
Equivalent Availability	80%
Anticipated Capacity Factor	80%
Heat Rate (Btu/kWh)	0
COSTS (1990 $) - See Text	
Variable (mills/kWh)	41
LEADTIMES (years)	
Preconstuction	2
Construction	3
LEVELIZED REAL COST (1990 mills/kWh) [b]	
Price	41
LEVELIZED NOMINAL COST (mills/kWh) [b]	
Price	81
SUPPLY FORECAST (aMW)	
Regional	30
BPA	30

[a] Unit sizes shown in parentheses reflect adjustments made for modeling purposes.
[b] Year 2000 on-line date.

380 MW may be regionally available by 2000. By design, MSW plants--whether mass burn, RDF, or gasification--will be baseload operations. Consistency and availability of fuel are key factors in determining plant availability and capacity factors.

Costs

Table 3.11 shows the price of energy from a hypothetical 10 MW MSW plant. This price is not calculated directly from the cost to construct and operate an MSW facility, but rather it is based on the region's long-term avoided cost. The reason for this is that an MSW plant is designed to dispose of wastes. Electric power is generated and sold to help offset the cost of waste disposal. The price that the electric power can be sold for is determined by the avoided costs of the utilities serving the area where the plant is located.

It is economic to build an MSW plant if the revenue received from the sale of electric power plus the revenue received from the fees charged haulers for receiving wastes (tipping fee) is large enough to offset the cost to build and operate the facility.

Environmental Characteristics

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

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

Because of the diversity of materials comprising the fuel, there is also the potential of discharging trace amounts of metals such as arsenic, cadmium, nickel, mercury, and other chemical compounds such as fluorides and polychlorinated biphenyls (PCBs). Of the cadmium and mercury discharge from MSW plants, 60% comes from nicad, alkaline, and mercury batteries.

Some pre-sorting of waste would help to cut ash residue and diminish emissions of HCl, HF, CO, NO_x, and heavy metals. Refuse-derived fuel eliminates some unacceptable garbage. Many of the compound chemical pollutants can be eliminated by exposing them to high burn temperatures of 1800-2000°F in baghouses for several seconds and using electrostatic precipitators. RDF, rather than mass burn MSW, would be a better environmental choice simply because the fuel source is better controlled to eliminate unacceptable elements such as plastics and metals.

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

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

Supply Forecast

MSW plants are built principally to help alleviate a local community's waste disposal problem. In order for a plant to be viable, many factors including tipping, fees, electricity avoided costs, disposal alternatives, and community support must all be lined up in favor of the plant. These plants have historically required long lead times and have met with public opposition. Because of these factors and the relatively low avoided costs in the region, significant development is not expected. For planning purposes, however, Table 3.11 shows 30 aMW assumed to be available to the region. For planning purposes this regional figure is assumed to be accessible to BPA also.

SOLAR

Technical Description

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

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

The best example of a central receiver station is the 10 MW plant in Barstow, California, which has operated since 1982. The system has 1,818 individual tracking heliostats with 766,000 square feet of reflective surface. In its operating history the plant has produced 11.7 MW peak power, with a 10% capacity factor and a maximum annual output of 8,816 MW-hours.

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

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

Point-focus parabolic dish systems are single dish units, focusing the solar energy to a single focal point where the receiver is located, like a flashlight reflector in reverse.

TABLE 3.12

PROJECTED COST AND ACHIEVABLE POTENTIAL
SOLAR
FY 1991 THROUGH 2010

PLANT CHARACTERISTICS	
Operating Life (years)	30
Unit Size (MW)	80
Equivalent Availability	28%
Anticipated Capacity Factor	28%
Heat Rate (Btu/kWh)	0
COSTS (1990 $)	
Capital ($/kW)	2764
Fixed O&M ($/kW/yr)	16.00
Variable O&M (mills/kWh)	0
Fixed Fuel ($/kW/yr)	0
Fuel ($/MMBtu)	0.00
LEADTIMES (years)	
Preconstuction	2
Construction	2
LEVELIZED REAL COST (1990 mills/kWh) [a]	
Public Financing	75
Private Financing	97
LEVELIZED NOMINAL COST (mills/kWh) [a]	
Public Financing	145
Private Financing	187
SUPPLY FORECAST (aMW)	
Regional	480
BPA	120

[a] Year 2000 on-line date.

Unlike the in-line troughs, the parabolic reflector must track the sun continuously on two axes. One axis allows for tracking east to west during the day; the other axis allows for tracking north to south as the sun's declination angle changes with the seasons. Because of this system's requirement for accuracy and reliability in order to work effectively, fabrication is difficult and expensive.

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

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

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

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

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

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

Operating Characteristics

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

Luz's systems use natural gas as a backup fuel to boost peak or maintain capacity during cloudy periods and late in the day. In Luz's California plants, the proportion of energy contributed by gas in a solar energy system is constrained to no more than 25%. If solar thermal plants were used to supply capacity, as Luz's plants are in California, the situation would be analogous to gas-fired systems backing up nonfirm hydro in the Pacific Northwest. Without a fuel backup, a solar thermal station's capacity factor is diminished significantly.

For eight of Luz's Solar Electric Generating Stations typical capacity factors range from 25% for a 13.11 MW plant to 36% for a larger 80 MW plant. First costs range from $4500/kW to $2800/kW for these same plants. There are 6,000 to 8,000 square meters of collector area per MW of capacity. Luz's has an installed capacity of over 160 MW at six sites, with another almost 500 MW planned. Luz plants operate in latitudes and climates where the available insolation is much higher than that available in the Pacific Northwest. In the Pacific Northwest, however, the most likely locale for solar generating plants would be areas east of the Cascades.

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

Solar radiation is very dispersed and varies significantly with latitude and climate. The average daily total solar radiation in Phoenix is about twice that of Seattle. The most promising PV sights in the region are east of the Cascades. Although about 1 kW of solar radiation falls on a square meter at noon on a sunny day, a typical PV array can generate only about 120 W/m^2. A 50 MW power installation would require about 90 acres of PV cells. This is peak capacity and does not take into account diminished performance under cloudy skies or early or late in the day. PV system capacity factors for future concentrating PV plants may reach as high as 33%.

Costs

The cost estimates in Table 3.12 reflect the solar thermal technology. Photovoltaic facilities are more costly.

Environmental Characteristics

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

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

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

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

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

Supply Forecast

The best potential solar site in the Pacific Northwest is the Whitehorse Ranch in southeastern Oregon. However, because of its latitude, this site receives only 70% of the solar energy of the best sites in the Pacific Southwest. Although the cost of solar generation is significantly higher than other resources the physical resource is available in the portions of the Pacific Northwest in significant enough quantity to include it as an available resource for planning purposes. Table 3.12 shows 480 aMW available to the region based on Council projections. For planning purposes, BPA assumes 120 aMW available. Because of the high cost of the resource and the higher avoided cost of Pacific Southwest utilities, it is likely that development will occur in that area before it occurs in the Pacific Northwest.

WIND

Technical Description

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

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

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

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

Wind power technologies have undergone substantial development since the early 1980s, and the technology has now reached the status of a mature industry. In California today, there are about 17,000 wind turbines operating with an installed capacity of 1500 MW at three

TABLE 3.13

PROJECTED COST AND ACHIEVABLE POTENTIAL [a]
WIND
FY 1991 THROUGH 2010

	Wind-1	Wind-2	Wind-3
PLANT CHARACTERISTICS			
Operating Life (years)	40	40	40
Unit Size (MW) [b]	20(23)	30	30
Equivalent Availability (%)	31%	26%	18%
Anticipated Capacity Factor (%)	31%	26%	18%
Heat Rate (Btu/kWh)	0	0	0
COSTS (1990 $)			
Capital ($/kW)	1236	1577	1239
Fixed O&M ($/kW/yr)	16.00	17.00	17.00
Variable O&M (mills/kWh)	12.1	12.4	12
Fixed Fuel ($/kW/yr)	0	0	0
Fuel ($/MMBtu)	0.00	0.00	0.00
LEADTIMES (years)			
Preconstuction	1	1	1
Construction	2	2	2
LEVELIZED REAL COST (1990 mills/kWh) [c]			
Public Financing	44	58	66
Private Financing	51	69	79
LEVELIZED NOMINAL COST (mills/kWh) [c]			
Public Financing	85	112	128
Private Financing	99	134	153
SUPPLY FORECAST (aMW)			
Regional	29	381	253
BPA	7	95	63

[a] Please see Appendix D for cost calculations and supply projections based on an Oregon Department of Energy scenario of wind turbine costs. This alternate projection is included for information purposes.
[b] Unit sizes shown in parentheses reflect adjustments made for modeling purposes.
[c] Year 2000 on-line date.

principle sites, which is about 90 to 95% of the installed capacity in the world. The California experience has been a proving ground for the developing wind industry. Initial problems with fatigue failures and reliability are now being addressed with better aerodynamic and structural designs, and improved controls.

Operating Characteristics

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

Although wind cannot be counted on for peak loads, it can displace some capacity load. Turbine units with good mechanical design and regular maintenance are showing equivalent availability factors better than 92% but they vary widely in output. Typical capacity factors for on-line units range from 20% to 35%, depending on the average wind speed. Today, wind machines being installed tend to be scaled at 150-600 kW, and are lighter in weight with improved efficiency compared to their predecessors.

Costs

The cost of electricity from a wind facility is a function of the wind conversion technology cost as well as the wind resource present at the site. A wind facility is capital intensive; however variable costs are low and fuel price escalation is not an issue. The costs shown in Table 3.13 reflect capital and operating costs from the 1991 Power Plan and capacity factors in the 18-31% range. (Please see Appendix D for cost calculations and supply projections based on an Oregon Department of Energy (ODOE) scenario of wind turbine costs. This alternate projection is included for information purposes.) Rapidly changing turbine cost estimates as well as a significant increase in utility and developer interest in the Pacific Northwest will require a re-examination of the supply forecast estimates prior to the next Resource Program.

Environmental Characteristics

Wind energy has no air emissions problems associated with thermal resources. However, there are some distinct environmental impacts in siting wind turbines. Utility application wind farms require the development of large overall tracts of land, although only about 3% of the land area is taken out of service. Wind development is compatible with agricultural uses. Some of the sites are adjacent to scenic areas along the Pacific coast and adjacent to the Columbia Gorge where aesthetics may be an environmental concern. Turbines can pose a hazard to bird; however this impact appears to be site specific.

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

Supply Forecast

In 1985, BPA completed a 5-year resource assessment (WIND REAP) of over 300 wind sites in the Pacific Northwest. Of these, 39 sites were identified as having potential for future commercial development. Since BPA's assessment was completed several thousand turbines have been installed in California. This combination of potential sites and substantial experience with integration of wind turbines into an electrical grid forms a basis for including wind energy as an available resource to the Pacific Northwest. Table 3.13 summarizes the supply potential. The regional estimates are based on the 1991 Power Plan. (Please see Appendix D for cost calculations and supply projections based on an Oregon Department of Energy scenario of wind turbine costs. This alternate projection is included for information purposes.) Rapidly changing turbine cost estimates as well as a significant increase in utility and developer interest in the Pacific Northwest will require a re-examination of the supply forecast estimates prior to the next Resource Program.

WNP-1 & -3

Technical Description

WNP-1 is a 1,250 MW nuclear project located on land leased from the U.S. Department of Energy on the Federal Hanford Reservation about 10 miles north of Richland, Washington. The plant's nuclear supply system includes a pressurized water reactor made by Babcock and Wilcox (B&W 205). Westinghouse designed the turbine generator. A project of similar design in Germany is complete and was operated at full power before being shut down due to political processes.

WNP-3 is a 1,240 MW nuclear project near Satsop, Washington, 16 miles east of Aberdeen in Grays Harbor County. It is a pressurized water reactor called a System 80, produced by Combustion Engineering, Inc. Palo Verde 1, 2, and 3 nuclear plants in Arizona, which came on-line in 1985, 1986, and 1988, respectively, are of the same design.

Operating Characteristics

Nuclear plants are best operated in baseload mode at their rated MW output. Like all steam cycle plants, nuclear plants have a large start-up inertia and cannot respond quickly to significant changes in load demands.

Costs

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

Detailed cost to complete construction estimates were prepared by the Supply System owners of WNP-3 and its contractors in 1984. In 1986 the Supply System updated the 1984 estimates in support of BPA's 1987 Resource Strategy. O&M cost estimates were also reviewed in 1986. The Council reviewed O&M costs for nuclear power plants for its Draft 1991 Power Plan. It reported that although O&M costs had escalated rapidly from 1974 to 1984, escalation declined after 1984. The Council assumed that the real rate of operating and maintenance cost escalation would decline from 3.11% annually in 1986 to 0% (real) by 2000.

Table 3.14 shows high and low cost estimates for both WNP-1 and WNP-3. These high and low estimates were developed to show the uncertainty surrounding the projected fixed operating costs. The low cases reflect no real escalation applied to the fixed O&M estimates. The high cases reflect a real escalation based on WNP-2/Trojan experience between 1986 and 1990. These high and low estimates, developed by BPA, are based on fixed O&M only.

TABLE 3.14

PROJECTED COST AND ACHIEVABLE POTENTIAL NUCLEAR WNP-1 & -3 FY 1991 THROUGH 2010

	WNP-1L Low	WNP-1H High	WNP-3L Low	WNP-3H High
PLANT CHARACTERISTICS				
Operating Life (years)	40	40	40	40
Unit Size (MW)	1250	1250	1240	1240
Equivalent Availability	65%	65%	65%	65%
Anticipated Capacity Factor	65%	65%	65%	65%
Heat Rate (Btu/kWh)	0	0	0	0
COSTS (1990 $)				
Capital ($/kW)	1430	1430	1137	1137
Fixed O&M ($/kW/yr)	84.59	109.21	90.26	116.53
Variable O&M (mills/kWh)	5.4	5.4	5.4	5.4
Fixed Fuel ($/kW/yr)	0	0	0	0
Fuel ($/MMBtu)	0.00	0.00	0.00	0.00
LEADTIMES (years)				
Preconstuction	0	0	0	0
Construction	7	7	7	7
LEVELIZED REAL COST (1990 mills/kWh) [a]				
Public Financing	35	43	33	42
Private Financing	N/A	N/A	34	43
LEVELIZED NOMINAL COST (mills/kWh) [a]				
Public Financing	67	83	65	81
Private Financing	N/A	N/A	66	83
SUPPLY FORECAST (aMW)				
Regional	813	813	806	806
BPA	813	813	806	806

[a] Year 2000 on-line date.

They do not represent the full range of high and low potential because they do not incorporate the cost-to-complete nor the variable operating expenses. An additional change in the WNP-1 & -3 assumptions in this document and consequently for the 1992 Resource Program is variable fuel cost. This cost is lower in real terms than was used in BPA's 1990 Resource Program.

Environmental Characteristics

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

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

The primary impacts from operations at a nuclear plant are the release of heat and moisture from the plant cooling system, cooling tower drift, and airborne radioactive materials. Heat released in large clouds of condensed steam from cooling towers is common to all large thermal generating plants.

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

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

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

Besides airborne gases and particulates, there may be some release of waterborne radioactive materials including fission products such as nuclides of strontium, and activation products such as sodium, manganese, and tritium. Experience designing, constructing, and operating nuclear power plants indicates that the average annual release of waterborne radioactive materials and effluents typically will be a small percentage of the limits specified by federal safety regulations. All aspects of nuclear power plants are continuously monitored to ensure allowable limits are not exceeded.

Other potential water-related effects of nuclear power plant operation include thermal discharges, water consumption, and release of waterborne chemical pollutants. Make-up water in cooling towers tends to concentrate mineral salts and other contaminants that are already in the water. These are controlled with continuous "blow down" to introduce fresh coolant. Blowdown can be environmentally damaging but can also be treated to remove impurities. Blowdown limits and controls are established by NPDEP (National Pollution Discharge Elimination Program) permits. These effects are also common to other thermal resources.

Lack of a facility for radioactive waste disposal, however, continues to be a problem. Waste is classified as high-level, transuranic, or low-level. High-level waste has high concentrations of beta and gamma emitting isotopes and significant concentrations of transuranic materials, including plutonium. Spent fuel is the only reactor product that falls in this category. Reactors produce about 400 ft^3 per year of spent fuel. In a typical commercial reactor, about 1/4 of the fuel is replaced each year.

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

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

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

Supply Forecast

As a result of public input that BPA received during the review of its Draft 1990 Resource Program, BPA recommended deferral of a new comprehensive study of the future of WNP-1 & -3 until significant information becomes available or conditions change sufficiently to warrant a new study. Both cost-to-complete and O&M cost assumptions would be reviewed as part of such a study. The 1990 Resource Program indicated that a new study would be deferred at least until 1991. The scoping process for the 1992 Resource Program determined that WNP-1 & -3 would be treated as available resources for planning purposes. Prior to a decision to take specific action regarding either WNP-1 or WNP-3, it is anticipated that a complete review of cost data will be completed and that a regional consensus will be developed through a public involvement process. Table 3.14 shows the size of WNP-1 & -3 that are assumed in the 1990 Resource Program.

CHAPTER 4

GENERATION RESOURCES (OTHER RESOURCES)

Generating resources and technologies that are not considered to be available or are otherwise excluded from the Resource Program are described in this Chapter. Resources are excluded because: (1) their commercial availability or cost is highly uncertain, (2) the Resource Program has used equivalent technologies (e.g., combustion turbines), or (3) environmental concerns dictate a substitute resource (i.e., coal gasification rather than conventional pulverized coal). This "other resource" information is included for reference and documents what is and is not known about these resources. The specific reason for their exclusion from consideration in the Resource Program is also explained.

For each resource, a summary is provided including a Technical Description, and contains information regarding Operating Characteristics, general cost information, Environmental Characteristics, and a Supply Forecast.

The information in this chapter is an addition to the information in the 1990 Generating Resource Supply Document. The information provided is on resources that are considered in some analyses but are not included in the Resource Program.

COAL, CONVENTIONAL AND ADVANCED

Technical Description

Conventional

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

In a conventional steam cycle coal plant, heat from coal combustion is transferred to water in a boiler. The boiler raises water under high pressure to high temperature steam. The steam expands through a turbine, which drives a generator. After passing through the turbine, the steam is condensed to water again, then pumped back into the boiler with a feedwater pump to complete the cycle. The same technologies used to increase efficiencies in steam cycle plants--regenerative cycles, superheat, and reheat--are used in coal plants.

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

Advanced

Atmospheric fluidized-bed combustion (AFBC)

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

Pressurized fluidized-bed combustion (PFBC)

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

Operating Characteristics

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

Costs

Cost estimates for conventional coal-fired plants are less than the gasification plants described in Chapter 3. Using the same fuel costs and surrogate site locations described in Table 3.2, energy from a conventional pulverized coal plant would range from 40 mills/kWh to 54 mills/kWh, as reported in the 1990 Resource Program. Costs for AFBC and PFBC stand-alone plants fall generally between conventional and gasification technologies.

Environmental Characteristics

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

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

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

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

See Appendix A for a relative comparison of air emissions between pulverized coal, fluidized bed, and other technologies.

Supply Forecast

Pulverized coal plants could be constructed in the same quantities as the gasification technology described in Chapter 3. For planning purposes, however, no pulverized coal facilities are assumed to be available. AFBC facilities are smaller than pulverized coal plants and are likely to be found in cogeneration applications. The PFBC technology has not advanced to the point of general commercial application.

COMBUSTION TURBINES, AERODERIVATIVE

Technical Description

Aeroderivative combustion turbines are not only based on the same technology used in jet engines, but their design begins with the same components that are used in aircraft designs. Their size is smaller than frame machines, described in Chapter 3 in Combustion Turbines & Displaceable Resources section, but their per unit installed cost is also lower. In the basic CT design, air enters a compressor which packs large amounts of air into a combustor at high pressure. In the combustor, fuel is added to the air and burned, releasing heat energy and producing a high temperature, high pressure exhaust gas. This gas is expanded through a turbine, which powers the compressor and generator.

Natural gas or distillate oils are the primary fuels used in aeroderivative combustion turbines. The heat rate (BTU/kWh) for simple cycle gas turbines is about the same as for steam turbine generation; however CT technology and performance continue to improve. Please refer to Chapter 3 for a detailed description of the CT technology.

Operating Characteristics

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

Aeroderivative CTs can be designed and operated to phase in the CT first, with a heat recovery steam generator added later for combined cycle operation with its consequent improvement in efficiency.

Costs

Aeoderivative combustion turbine capital costs run $330-$700/kW. A CT that is likely to be acquired by a utility for peaking operation can be expected to cost $420/kW installed, as reported in the Puget Sound Area Electric Reliability Plan, Local Generation Options (September 1991). A typical size for such a turbine would be 70 MW. Fixed O&M would be $2.32/kW/year and variable O&M would equal 3.14 mills/kWh.

Since CTs would normally be run to displace other higher cost resources, capacity factor is not an accurate measure of their performance. If CTs were run in a baseload mode their capacity factor would equal their availability (80-90%).

Environmental Characteristics

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

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

Since CTs tend to be sited close to where transportation and transmission lines meet, effects on urban environments need to be considered. As with jet planes at airports, CT noise can be a problem. Typical noise levels at 1,200 feet from operating CTs run 65-70 decibels. Silencing packages can reduce this to 51 decibels at 400 feet.

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

Supply Forecast

The quantity of combustion turbines installed is not inherently limited. Constraints that are typically discussed include ability to site, fuel, and hardware availability. These constraints will pose less of an impediment for the first increment of turbines installed than subsequent turbines.

FUEL CELLS

Technical Description

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

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

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

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

Operating Characteristics

Fuel cells have excellent load following ability; they can adjust output quickly and over a broad range. However, they do require a substantial amount of time (>40 hours) to come on-line from a cold start. If an adequate fuel supply is available, fuel cells can provide baseload service. Projected availabilities are greater than 90%.

Costs

Projected capital costs goals for fuel cells are \$1300/kW. Fixed O&M is estimated to be \$5.43/kW/year and variable O&M is 9 mills/kWh. Levelized energy costs given current natural gas prices would be 54 mills/kWh(real) and 83 mill/kWh(nominal). These estimates are based on forecasted operation. Fuel cells have not yet achieved these cost levels.

Environmental Characteristics

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

Supply Forecast

Although simple and compact, fuel cells have not yet reached commercial maturity. Reliability and durability of the fuel cell stacks themselves as well as relatively high manufacturing costs have slowed commercial implementation. Therefore fuel cells are not considered to be available for planning purposes.

HYDROGEN

Technical Description

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

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

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

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

There is a net energy loss in producing hydrogen as fuel then generating electricity compared to direct hydroelectric conversion. First, the electrolysis conversion efficiency is about 80%; then converting the energy in hydrogen gas into electricity carries an additional penalty. Per kilowatt-hour, the electrical energy produced from a combustion turbine or fuel cell using hydrogen fuel would be about 15-30% that produced directly from a hydroelectric turbine.

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

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

Operating Characteristics

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

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

Costs

Costs for a hydrogen electrolysis plant were developed from data obtained from the Pacific Northwest Hydrogen Feasibility Study, March 1991, prepared for BPA by Fluor Daniel Inc. These costs are based on an electrolyzer-fuel cell combination. Capital cost projections are $4100/kW; fixed O&M is $8.26/kW/year; variable O&M is 28 mills/kWh. This would yield a real levelized cost of 158 mills/kWh (242 mills/kWh nominal levelized). These cost levels were calculated assuming an input power cost of 14 mills/kWh.

Environmental Characteristics

Hydrogen has two principle benefits as a fuel. First, the main byproduct of combustion is water and second, no greenhouse gases (e.g., CO_2) are formed. These benefits continue to attract considerable attention to the potential use of hydrogen rather than carbon based fuels. Up to this point, the environmental benefits of a hydrogen-based economy have not matched the costs of developing additional infrastructure for the production, storage, and distribution of the hydrogen fuel.

Supply Forecast

Hydrogen fueled resources are not assumed to be available from a utility perspective. This is principally due to the high projected costs over the 20 year planning period.

OCEAN TECHNOLOGIES

Technical Description

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

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

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

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

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

In contrast, tidal power plants are a demonstrated and mature technology with several commercial plants in operation today, including a 240 MW installation at the Rance River estuary on the north coast of France--fully operational since 1967. Another site, Annapolis Royale, Nova Scotia, has operated since 1984 and generates 18 MW.
The key requirement for a successful tidal power plant is a large mean tidal range, preferably 20 feet or more. Tides of this magnitude can be found in only a few places worldwide where geography amplifies the tidal range. Tidal electric plants also require a large bay or estuary

with a narrow, relatively shallow entrance suitable for construction of a dam. Several sites exist in North America, but none of them are in the Pacific Northwest. The largest mean tidal variation in the region can be found in the bays and inlets of Puget Sound. Oakland Bay, at Shelton, Washington, has a mean tidal range of only 10.6 feet.

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

Operating Characteristics

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

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

Costs

Cost estimates for wave and tidal technologies range from $2000/kW to $7000/kW. These estimates are preliminary in nature and have a high uncertainty associated with them.

Environmental Characteristics

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

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

Supply Forecast

Tidal ranges of 20 feet are required for an effective tidal resource. The largest tidal ranges in the Pacific Northwest are less than 11 feet. No tidal resource is considered to be available in the Northwest. Although wave power is considered to be technically available in the Northwest, there is a high degree of uncertainty associated with its cost and feasibility. It is not considered to be a mature technology. For these reasons, ocean power is not considered to be an available resource.

OIL AND GAS COMBUSTION

Technical Description

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

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

Boilers can use almost any combustion fuel, but gas, distillate oils, and coal are the most common.

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

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

Operating Characteristics

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

Costs

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

Environmental Characteristics

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

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

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

Supply Forecast

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

OTHER HYDROELECTRIC TECHNOLOGIES

Pumped Storage

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

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

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

Water Supply (Pressure Reduction)

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

STORAGE SYSTEMS

Technical Description

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

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

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

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

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

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

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

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

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

Operating Characteristics

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

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

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

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

Costs

The costs of adding compressed air capability to a combustion turbine includes clutches and peripheral equipment to permit the compression and recovery of air, as well as the storage medium. The capital costs for compressed air equipment run $460-$580/kW. Battery costs range from $460/kW for advanced batteries to $920/kW for lead acid batteries.

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

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

Environmental Characteristics

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

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

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

Supply Forecast

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

ACRONYMS & ABBREVIATIONS

BACT	best available control technology
CCCT	Combined Cycle Combustion Turbine
CRFM	Cogeneration Regional Forecasting Model
CO	carbon monoxide
Council	Northwest Power Planning Council
FERC	Federal Energy Regulatory Commission
HCl	hydrochloride
H_2S	hydrogen sulfide
kWh	kilowatt-hour
MMBTU	one million BTU
MW	megawatt
MWh	megawatt-hour
MSW	municipal solid waste
NOx	oxides of nitrogen
NWHS	Pacific Northwest Power Data Base and Analysis System
O&M	Operation & Maintenance
ODOE	Oregon Department of Energy
PURPA	Public Utilities Regulatory Policy Act of 1978
SCCT	Single Cycle Combustion Turbine
SMES	Superconducting Magnetic Energy Storage

SO_X oxides of sulfur

WNP-1 Washington Public Power Supply System's unfinished nuclear project located in Richland Washington

WNP-3 Washington Public Power Supply System's unfinished nuclear project located near Satsop, Washington

GLOSSARY

availability - The percent of time that a generating resource is available for use. Availability is expressed as an annual percentage. It is calculated by subtracting the annual number of hours that a resource is out of service due to planned and forced outages, and dividing the result by 8760 hours. (See also, equivalent availability)

average megawatt (aMW) - A unit of energy output. One aMW equals one megawatt for one year or 8,760 megawatt hours. It is generally used on an annual basis (e.g. aMWs per year).

base loaded - Generating resources that are generally operated continuously except for maintenance and unscheduled outages.

capacity - The maximum power that a machine or system can produce or carry under specified conditions. The capacity of generating equipment is generally expressed as kilowatts.

capacity factor - The ratio of annual Firm Energy output (MWh) to the product of Installed Capacity (MW) times 8760 hours per year (MWh/(MWx8760)).
British Thermal Unit (BTU) - The amount of heat energy necessary to raise the temperature of one pound of water one degree Fahrenheit (3,413 BTUs are equal to one kilowatt hour).

construction lead-time - The length of time between a decision to construct a resource and when the resource is expected to deliver power to the grid.

discount rate - The rate used in a formula to convert costs or benefits to their present value.

equivalent availability - The ratio of the maximum amount of energy a generating unit can produce in a fixed period of time, after adjustment for expected maintenance and forced outage, to the maximum energy it could produce if it ran continuously over the fixed time period. This represents the upper limit for a long-run (annual or longer) capacity factor for a generating unit.

firm energy - The quantity of electric energy which is intended to have assured availability over a defined period.

head - The vertical height of water in a reservoir above the turbine.

heat rate - The amount of input (fuel) energy required by a power plant to produce one kilowatt-hour of electrical output. Expressed as Btu/kWh.

insolation - The rate of energy from the sun falling on the earth's surface, typically measured in watts per square meter.

ISAAC - A computer model used by BPA to simulate system operation, decisions to option and build resources, and the associated costs of providing power across a large number of possible load forecasts.

levelized life-cycle cost - The present value of a resource's cost (including capital, financing and operating costs) converted into a stream of equal annual payments. This stream of payments can be converted to a unit cost of energy by dividing them by the number of kilowatt-hours produced in associated years. By levelizing costs, resources with different lifetimes and generating capabilities can be compared.

megawatt (MW) - The electrical unit of power that equals one million watts or one thousand kilowatts.

nominal dollars - Dollars that include the effects of inflation. These are dollars that, at the time they are spent, have no adjustments made for the amount of inflation that has affected their value over time.

nonfirm energy - Energy produced by the hydropower system that is available with water conditions better than critical and after reservoir refill is assured. It is available in varying amounts depending on the season and weather conditions.

real dollars - Dollars that do not include the effects of inflation. They represent constant purchasing power.

tipping fee - The fee assessed for disposal of waste. This fee is used when estimating the cost of producing electricity from municipal solid waste.

turn-key installation - An installation that includes all costs from design to construction up to operation.

APPENDICES

APPENDIX A

Air Emission data for Thermal Resources

Air emission data ishown in this Appendix is based on data developed for Bonneville by Fluor Daniel Inc. This data is from a draft report, *Environmental Data For Thermal Resources*, January 1992. The data shows the relative air emissions of various technologies. Actual emissions from any technology can vary greatly depending on the controls used and other factors regarding plant design and fuel source.

TABLE A1

AIR EMISSION DATA FOR THERMAL RESOURCES
lbs/MMBtu

	CO2	SOx	NOx	VOC	CO	TSP	PM10
Stand Alone Biomass	230	0.025	0.350	0.210	5.900	0.220	NA
Coal Gasification	220	0.015	0.350	0.005	0.015	0.005	NA
Coal, Pulverized	220	0.074	0.450	0.014	0.047	0.023	NA
Coal, Fluidized Bed	220	0.150	0.150	0.010	0.100	14.000	NA
Cogeneration	128	-	0.170	0.012	0.080	0.010	NA
Combustion Turbines							
Single Cycle	128	0.001	0.090	0.009	0.033	0.005	NA
Combined Cycle	128	0.001	0.024	0.008	0.018	0.004	NA
Geothermal	8	-	-	-	-	-	NA
Municipal Solid Waste	192	0.066	0.202	0.011	0.096	0.028	0.015

scair.xls

TABLE A2

AIR EMISSION DATA FOR THERMAL RESOURCES
lbs/MWh

	CO2	SOx	NOx	VOC	CO	TSP	PM10
Stand Alone Biomass	3400	0.37	5.2	3.2	88	3.3	NA
Coal Gasification	1900	0.140	3.100	0.047	0.130	0.043	NA
Coal, Pulverized	2000	0.690	4.000	0.130	0.420	0.210	NA
Coal, Fluidized Bed	2200	1.500	1.500	0.100	1.000	140	NA
Cogeneration	1483	-	1.973	0.139	0.928	0.116	NA
Combustion Turbines							
Single Cycle	1500	0.009	1.064	0.109	0.387	0.060	NA
Combined Cycle	1460	0.009	0.277	0.091	0.207	0.041	NA
Geothermal	160	-	-	-	-	-	
Municipal Solid Waste	3747	1.28	3.94	0.22	1.87	0.54	0.28

scair.xls

Note: SOURCE: DRAFT Report - Environmental Data for Thermal Resources, Sept 17, 1991, Fluor Daniel Inc. for Bonniville Power Administration.

Note: STAND ALONE BIOMASS: Electrostatic Precipitator case.

Note: COAL GASIFICATION: 99% sulfur removal case.

Note: PULVERIZED COAL: 95% sulfur removal base case.

Note: COAL, FLUIDIZED BED (AFBC): 90% sulfur removal case.

Note: COGENERATION: Natural Gas, PURPA steam exported, low NOx burners case.

Note: SINGLE CYCLE CT: Natural Gas dry low NOx burners case.

Note: COMBINED CYCLE CT: Selective Catalytic Reduction case.

Note: GEOTHERMAL: Single Flash case.

Note: MUNICIPAL SOLID WASTE: Dry Scrubber case.

APPENDIX B

Transmission Adjustment Calculation

This Appendix contains detail of the transmission costs that were used to establish the transmission cost adjustment used for resources included in the *1992 Resource Program*. The preliminary estimates shown in Table 1 on the following page were used in this document.

Transmission Adjustments Applied to Generation Resources

Table 1
Cost of 2000 MW Transmission Line
(Preliminary Estimates)[1]

Zone	1990 $ x10^6	1990 $ $/kW	1988 $ $/kW
West of Cascades	0	0	0
California	0	0	0
Canada			
From Peace Site C	875	438	400
System Sale	0	0	0
East of Cascades (BPA network)	256	128	120
East of BPA Network	900	450	410

[1]Preliminary estimates form Don Matheson, EOB, August 31, 1990.

Table 2
Cost of 2000 MW Transmission Line
(Final Estimates)[2]

Zone	1990 $ x10^6	1990 $ $/kW
West of Cascades	0	0
California	0	0
Canada		
From Peace Site C	915	458
System Sale	0	0
East of Cascades (BPA network)	258	129
East of BPA Network	1016	508

[2]"Cost of Transmission Facilities," Matheson to Rohe, Apr 26, 1991.
(This reference is included in this appendix to show methodology.)

BPA F 1325.01
(01-89)
(Previously BPA 1100)

U.S. DEPARTMENT OF ENERGY – BONNEVILLE POWER ADMINISTRATION

Memorandum

DATE : APR 2 6 1991

FROM : Don Matheson, Electrical Engineer
Advanced Planning Staff - EOB Don Matheson

SUBJECT: Cost of Transmission Facilities

TO : Kristina Rohe, Public Utility Specialist
Resource Strategy Section - RPPD

Attached is Office of Engineering input to the Resource Program EIS. As a rule of thumb, it can be assumed the cost of integrating a resource into the transmission system will be proportional to the capacity of the resource and the distance from a major center of load growth. Specific information as to the size, location, and operating characteristics of a proposed resource is required to produce a precise cost estimate for transmission additions that may be needed to integrate the resource into the transmission network.

The transmission cost estimates contained herein will provide the basis for producing costs to be added to the cost of resources to take into account the need for integrating resources into the transmission system.

Attachment

DMatheson:ch:4417 (VS16-EOB-2975m)

cc:
T. McKinney - EFBG
M. Berger - RPE
Official File - EOB

ENGINEERING INPUT TO RESOURCE PROGRAM EIS

Introduction

Historically, when considering resource acquisitions, the cost of transmission has been largely ignored. This treatment was considered reasonable since the cost of transmission was small when compared to the cost of constructing and operating the resource. However, as the transmission system becomes increasingly complex, and resources are distributed and sited farther from load centers, the cost of transmission is becoming more significant. The cost of transmission could become the basis for favoring one resource over another when all other cost factors are similar.

To make an accurate estimate of the cost for transmission to integrate any particular resource, transmission planners would need to know the capacity of the resource, location, and operating characteristics. Since this information is not available in sufficient detail at the Resource EIS planning level, a novel, more general approach needs to be taken. The approach is to add some cost to each resource to account for the cost of transmission, and to do this in a way that recognizes large resources far from load centers are more costly to integrate than small resources near load centers. Also, it would be desirable to recognize resources that can take advantage of surplus capacity of existing facilities.

Location Impacts

For transmission cost estimates, resources are divided into five location categories: resources sited West of the Cascades, resources East of the Cascades but within the BPA's existing network, resources East of the BPA network, resources in Canada, and resources in California.

In the existing Northwest power system, the major load centers are located West of the Cascade mountain range and centered around the population centers of Seattle and Portland. The greatest load growth is in the Seattle area. For this analysis, greatest load growth is expected to continue West of the Cascades, particularly in the Seattle area.

The cost of transmission in $/kW is assumed to be the same for any resource within a category. To develop a $/kW figure, each location was studied. Where several transmission alternatives were examined within a location category, the middle of the cost range was selected.

West of the Cascades

Since most of the load and expected load growth in the northwest system is located west of the Cascades, integrating resources sited west of the Cascades requires only localized transmission reinforcements. For purposes of this study, the cost of these investments is assumed to be zero.

East of the Cascades

The Puget Sound Area Electric Reliability Plan is examining alternatives for resolving existing reliability problems in the Seattle area. Due to the load centers and resources being separated by a mountain range, a significant problem is transmitting power from resources through a limited number of mountain passes to the load centers west of the Cascades.

New resources sited east of the Cascades will cause the need for new cross mountain transmission lines. For estimating purposes, a typical new resource was assumed at Creston, a site approximately 40 miles east of Grand Coulee. A typical capacity was assumed to be 2000 MW. An estimate of the cost of transmitting 2000 MW from Creston was prepared. From this estimate a cost per kW can be calculated. This cost, then, can be assigned to any resource sited east of the Cascades, but within the BPA network.

East of the BPA Network

Resources east of the BPA transmission system will require the construction of large interties. The most probable resources developed will be coal plants developed in the Powder River Basin, or Thousand Springs coal fields. For estimating purposes, a 2000 MW coal plant is assumed at Colstrip. An estimate of the cost of transmitting 2000 MW from Colstrip to Seattle was prepared. From this estimate, the cost of transmission per kW can be calculated. This cost, then, can be assigned to any resource sited east of the BPA network.

Resources in Canada

Canada could possibly develop resources for export to the US. In order for Canada to provide firm resources to the US, significant transmission problems in the Vancouver B.C. area would need to be resolved, or new transmission lines would need to connect the Eastern BC Hydro system to load centers West of the Cascades in the US. To provide a basis for a transmission estimate, a 2000 MW resource is assumed on the Peace River near Gordon Shrum, even though no resource of this size is planned. An estimate of the cost of transmitting 2000 MW from the Peace River to Seattle was prepared. From this estimate, the cost of transmission was calculated. The cost may be assigned to any resource sited in Canada.

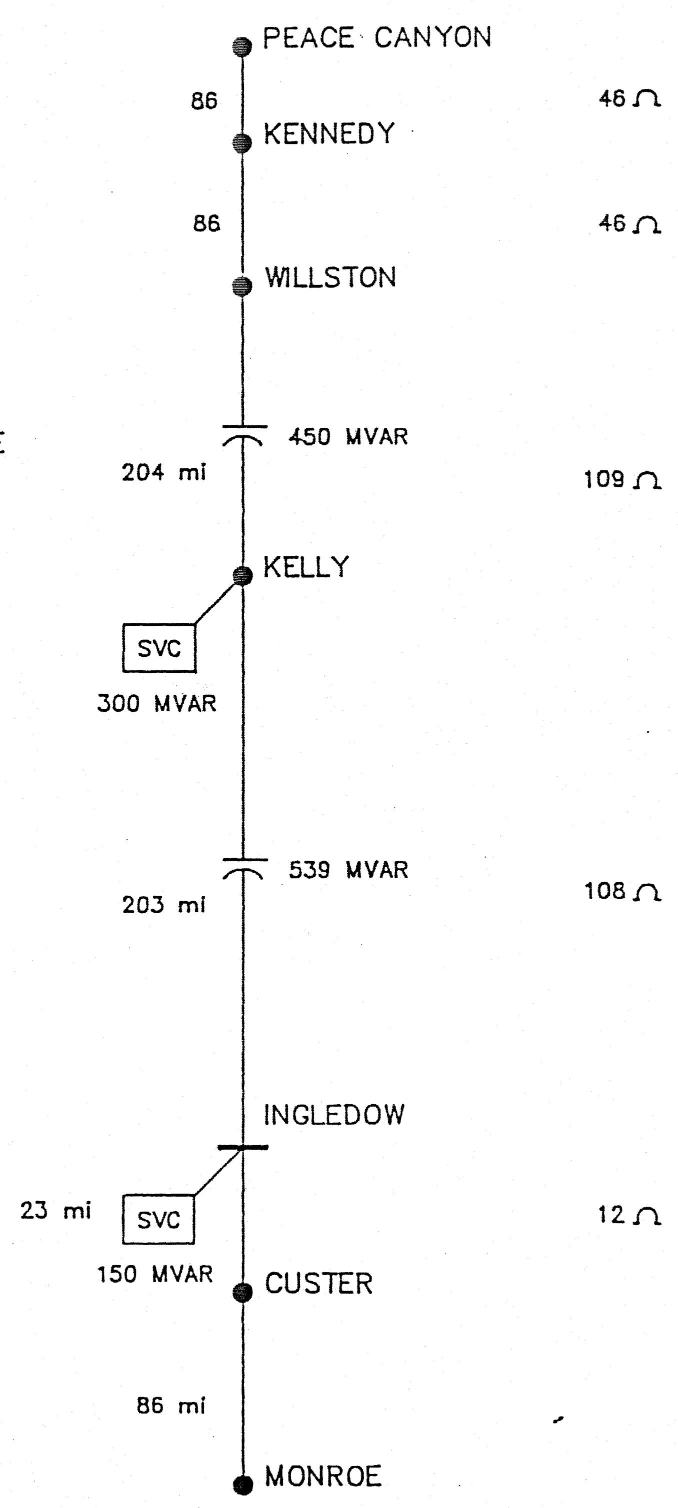
Resources in California

The south to north transfer capability on the existing interties with California is approximately 4400 MW. The transfer capability will be increased with the Third AC Intertie. Roughly three-fourths of the capacity is available to BPA. New transmission construction would not be required for resources from California to the northern terminal of the intertie. Since the Northern terminal of the intertie is East of the Cascades, the transmission cost for resources from California to load centers West of the Cascades would be the same as for resources sited east of the Cascades.

CANADA TO SEATTLE
500-KV DOUBLE CIRCUIT

ASSUME SERIES COMP AS SHOWN
IN DRAWING

ASSUME 70% SHUNT COMP
688 MILES
Q chg = 2 MVAR/MILE
688 * 2 = 1376
.7 * 1376 = 963 MVAR/LINE
ASSUME 5 180 MVAR BANKS/LINE



COST ESTIMATE
PEACE CANYON-SEATTLE DOUBLE CIRCUIT 500-KV

TRANSMISSION	Miles	$/mile	Total
EIS Process			$1 M
ROW - 125ft	688	$20,000	$14 M
Double Circuit 500-kV '3-Seahawk	688	$908,950	$625 M

SUBSTATION EQUIPMENT

TERMINALS	# unit	$/unit	Total
12 3-Breaker bays	12	$3,620,000	$43 M

COMPENSATION	# bank	MVAR	$/bank	$/MVAR	
Series comp	4	1978	$2,950,000	9230	$30 M
SVC	2	300	$20,240,000		$40 M
70% Shunt Reactive	10	1926	$6,290,000		$63 M

OPERATION AND MAINTENANCE

TRANSMISSION	miles	$/mile	Total/yr
Transmission O&M	688	$1,568	$1.08 M

SUBSTATION	# units	$/unit	
Circuit Breakers	36 breakers	$36,469	$1.31 M
Series caps	1978 MVAR	$227	$0.45 M
Shunt Reactors	1926 MVAR	$213	$0.41 M

INITIAL INVESTMENT	$817 M
Administrative and General Expense (12%)	$98 M

TOTAL INITIAL INVESTMENT	$915 M
	======
ANNUAL MAINTENANCE	$3.25 M
Administrative and General Expense (15%)	$0.49 M

TOTAL ANNUAL MAINTENANCE	$3.74 M
	=======

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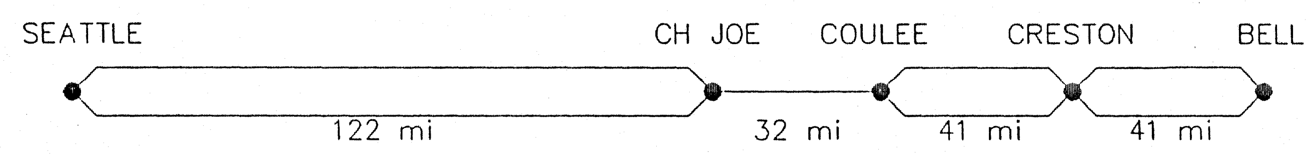
ESTIM2

EAST OF CASCADES TO SEATTLE
ASSUME CRESTON INTEGRATION



COST ESTIMATE
EAST OF THE CASCADES TO SEATTLE
(assumes Creston Integration)

TRANSMISSION	Miles	$/mile	Total
EIS Process			$1 M
ROW - 115ft	32	$18,400	$1 M
ROW - 125ft	204	$20,000	$4 M
Single Circuit 500-kV '3-Seahawk	32	$499,960	$16 M
Double Circuit 500-kV '3-Seahawk	204	$908,950	$185 M

SUBSTATION EQUIPMENT

TERMINALS	# units	$/unit	Total
19 Circuit Breakers	19	$1,210,000	$23 M

OPERATION AND MAINTENANCE

TRANSMISSION	miles	$/mile	Total/yr
Transmission O&M	32	$980	$0.03 M
	204	$1,586	$0.32 M
SUBSTATION	# units	$/unit	
Circuit Breakers	19 breakers	$36,469	$0.69 M

INITIAL INVESTMENT	$230 M
Administrative and General Expense (12%)	$28 M
TOTAL INITIAL INVESTMENT	$258 M
ANNUAL MAINTENANCE	$1.05 M
Administrative and General Expense (15%)	$0.16 M
TOTAL ANNUAL MAINTENANCE	$1.20 M

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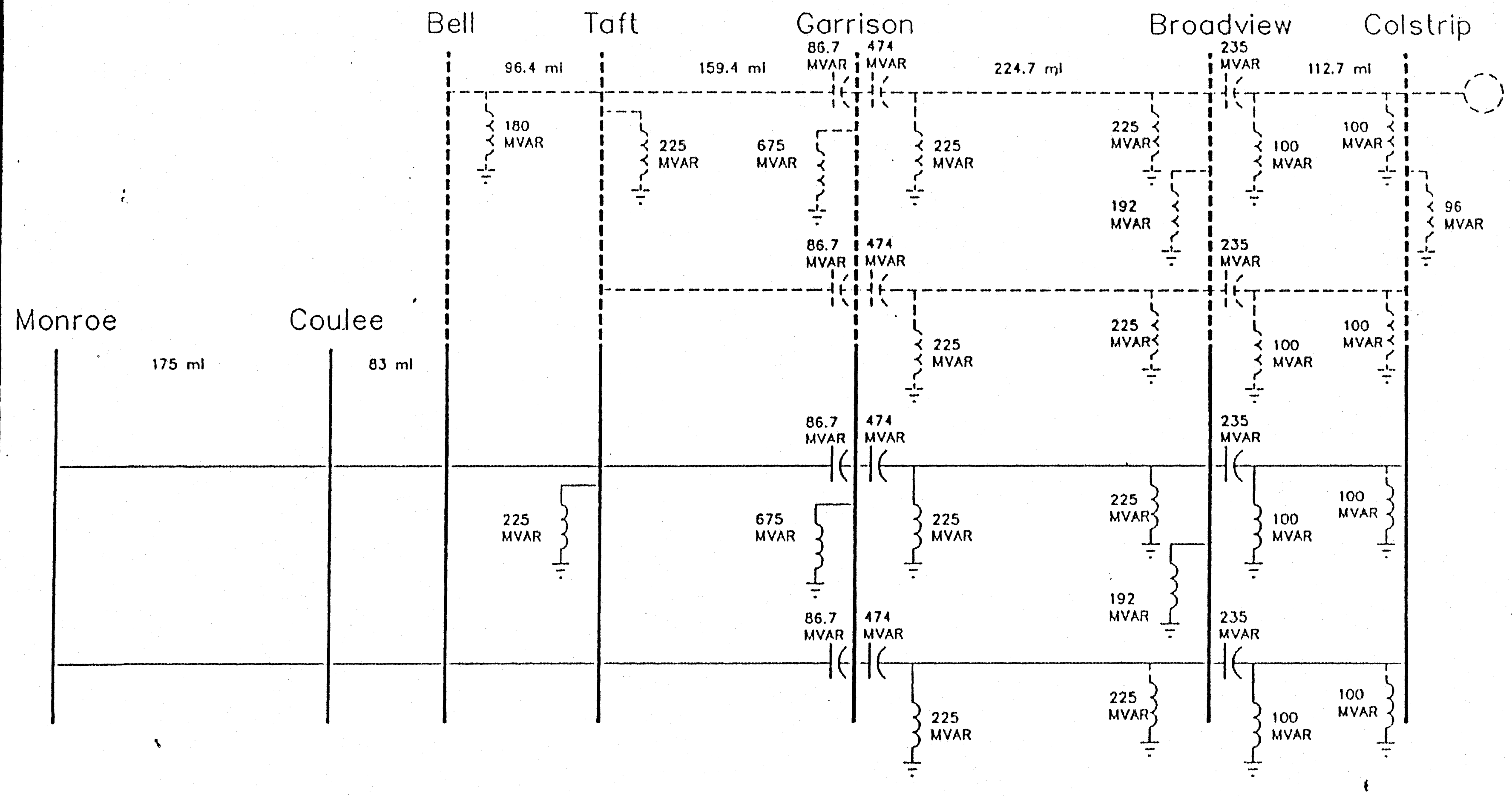
eastofca

Colstrip Integration

Double Circuit 500-kV



DRM 5/29/90
COLSTRP2

COST ESTIMATE
COLSTRIP-SEATTLE DOUBLE CIRCUIT 500-kV

INITIAL INVESTMENT

TRANSMISSION	Miles	$/mile			Total
EIS Process					$1 M
ROW - 125ft	851	$20,000			$17 M
Double Circuit 500-kV '3-Seahawk	851	$908,950			$774 M

SUBSTATION EQUIPMENT

TERMINALS	# unit	$/unit			Total
12 3-Breaker bays	12	$3,400,000			$41 M

COMPENSATION	# bank	MVAR	$/bank	$/MVAR	
35% Series comp Colstrip-Taft	6	1591	$2,800,000	7500	$29 M
100% Shunt Reactive Colstrip-Taft	14	2463	$3,320,000		$46 M

OPERATION AND MAINTENANCE

TRANSMISSION	miles	$/mile	Total/yr
Transmission O&M	851	$1,568	$1.33 M

SUBSTATION	# units	$/unit	
Circuit Breakers	36 breakers	$29,276	$1.05 M
Series caps	1591 MVAR	$227	$0.36 M
Shunt Reactors	2463 MVAR	$213	$0.53 M

INITIAL INVESTMENT	$908 M
Administrative and General Expense (12%)	$109 M
TOTAL INITIAL INVESTMENT	$1,016 M
ANNUAL MAINTENANCE	$3.27 M
Administrative and General Expense (15%)	$0.49 M
TOTAL ANNUAL MAINTENANCE	$3.77 M

DMatheson 6/25/90
estimate

APPENDIX C

ISAAC Model Input Data Sheets

This Appendix contains the detailed data sheets that are used to document the generation resource assumptions for the *1992 Resource Program*. These sheets are used to generate the data files that are used by the ISAAC planning model.

Resource	Data Sheet	Revision Date
Biomass	DTBIO.XLS	29-Jun-91
Coal Gasification	DTCOALBC.XLS	30-Jun-91
Cogeneration East	DTCOGEA.XLS	29-Jun-91
Cogeneration West	DTCOGWA.XLS	29-Jun-91
Combustion Turbines	DTCTA.XLS	29-Jun-91
Geothermal	DTGEOB.XLS	29-Jun-91
Hydroelectric East	DTHYDEABXLS	18-Jul-91
Hydroelectric West	DTHYDWB.XLS	18-Jul-91
Municipal Solid Waste	DTMSW.XLS	29-Jun-91
Solar	DTSOLB.XLS	29-Jun-91
Wind	DTWINB.XLS	29-Jun-91
WNP-1 & -3	DTWNPC.XLS	1-Dec-91

Resource: **BIOMASS**
File: **DTBIO.XLS**
Date: **6/29/91**
Revision: **None**

RESOURCE DATA SHEET

INPUTS:

% of Regional Supply Allocated to BPA	100%

RESOURCE IDENTIFIER	Biomass
PLANT CHARACTERISTICS	
Site	West
Fuel Source	West
Operating Life (yrs)	30
Unit Size (MW)	22.5
Equivalent Availability (%)	80%
Anticipated Capacity Factor (%)	80%
Heat Rate (Btu/kWh)	15000
Energy by Month (% of total)	
Jan	8.3%
Feb	8.3%
Mar	8.3%
Apr	8.3%
May	8.3%
Jun	8.3%
Jul	8.3%
Aug	8.3%
Sep	8.3%
Oct	8.3%
Nov	8.3%
Dec	8.3%

Resource: **BIOMASS**
File: **DTBIO.XLS**
Date: **6/29/91**
Revision: **None**

	Biomass
COSTS (1990 Dollars)	
Financial Life (years)	30
Siting & Licensing ($/kW)	33
Construction ($/kW)	1677
Transmission Adjustment ($/kW)	0
Total Capital Cost ($/kW)	1710
Siting & Licensing Hold Cost ($/kW/yr)	3.00
Fixed O&M ($/kW/yr)	44
Variable O&M (mills/kWh)	3.7
Fixed Fuel ($/kW/yr)	0
Variable Fuel ($/million Btu)	2.60
Variable Fuel (calc mills per kWh)	39.0
CONSTRUCTION CASH FLOW (% of Capital)	
1	0.0%
2	0.0%
3	25.0%
4	50.0%
5	25.0%
6	0.0%
7	0.0%
8	0.0%
9	0.0%
10	0.0%
Total	100.0%
LEAD TIMES	
Siting & Licensing (years)	2
Probability of S&L Success (%)	75%
Probability of Hold Success (%)	75%
Construction Lead Time (years)	3
Total Lead Time (years)	5
Maximum Option Shelf Life (years)	5

Resource: **BIOMASS**
File: **DTBIO.XLS**
Date: **6/29/91**
Revision: **None**

	Biomass
REGIONAL SUPPLY (incremental aMW by year)	
1991	0
1992	0
1993	0
1994	0
1995	0
1996	22.5
1997	22.5
1998	22.5
1999	22.5
2000	22.5
2001	0
2002	0
2003	0
2004	0
2005	0
2006	0
2007	0
2008	0
2009	0
2010	0
SUPPLY AVAILABLE TO BPA (incremental aMW by year)	
1991	0
1992	0
1993	0
1994	0
1995	0
1996	23
1997	23
1998	23
1999	23
2000	23
2001	0
2002	0
2003	0
2004	0
2005	0
2006	0
2007	0
2008	0
2009	0
2010	0

Resource: BIOMASS
File: DTBIO.XLS
Date: 6/29/91
Revision: None

	Biomass
REGIONAL SUPPLY (cumulative aMW by year)	
1991	0
1992	0
1993	0
1994	0
1995	0
1996	23
1997	45
1998	68
1999	90
2000	113
2001	113
2002	113
2003	113
2004	113
2005	113
2006	113
2007	113
2008	113
2009	113
2010	113
SUPPLY AVAILABLE TO BPA (cumulative aMW by year)	
1991	0
1992	0
1993	0
1994	0
1995	0
1996	23
1997	45
1998	68
1999	90
2000	113
2001	113
2002	113
2003	113
2004	113
2005	113
2006	113
2007	113
2008	113
2009	113
2010	113

Note: SOURCE: 1991 Northwest Conservation and Electric Power Plan.

Note: EQ. AVAILABILITY: These figures were set equal to the capacity factor.

Note: TRANSMISSION ADJ: Transmission adjustment is based on the distance of the site from the west side of the Cascades. Source: Matheson to Rohe, 28 Apr 91 "Cost of Transmission Facilities." Figures in DTCOALBA.WK1 were escalated from 1988 to 1990 by 1.079.

Resource: COAL-INTERIM
File: DTCOALBC.XLS
Date: 6/30/91
Revision: C

RESOURCE DATA SHEET

INPUTS:
% of Regional Supply Allocated to BPA 25%

RESOURCE IDENTIFIER	Coal-1T	Coal-2T	Coal-3T	Coal-4T	Coal-5T
PLANT CHARACTERISTICS					
Site	Colstrip	Creston	Boardman	Thou Spg	West WA
Fuel Source	Colstrip	E. Koot.	E. Koot.	Uinta	E. Koot.
Operating Life (yrs)	30	30	30	30	30
Unit Size (MW)	420	420	420	420	420
Equivalent Availability (%)	70%	70%	70%	70%	70%
Anticipated Capacity Factor (%)	70%	70%	70%	70%	70%
Heat Rate (Btu/kWh)	9490	9455	9455	9490	9455
Energy by Month (% of total)					
Jan	8.3%	8.3%	8.3%	8.3%	8.3%
Feb	8.3%	8.3%	8.3%	8.3%	8.3%
Mar	8.3%	8.3%	8.3%	8.3%	8.3%
Apr	8.3%	8.3%	8.3%	8.3%	8.3%
May	8.3%	8.3%	8.3%	8.3%	8.3%
Jun	8.3%	8.3%	8.3%	8.3%	8.3%
Jul	8.3%	8.3%	8.3%	8.3%	8.3%
Aug	8.3%	8.3%	8.3%	8.3%	8.3%
Sep	8.3%	8.3%	8.3%	8.3%	8.3%
Oct	8.3%	8.3%	8.3%	8.3%	8.3%
Nov	8.3%	8.3%	8.3%	8.3%	8.3%
Dec	8.3%	8.3%	8.3%	8.3%	8.3%

Resource: COAL-INTERIM
File: DTCOALBC.XLS
Date: 6/30/91
Revision: C

	Coal-1T	Coal-2T	Coal-3T	Coal-4T	Coal-5T
COSTS (1990 Dollars)					
Financial Life (years)	30	30	30	30	30
Siting & Licensing ($/kW)	43	19	40	43	40
Construction ($/kW)	2336	2069	2341	2098	2381
Transmission Adjustment ($/kW)	438	121	111	405	72
Total Capital Cost ($/kW)	2817	2209	2492	2546	2493
Siting & Licensing Hold Cost ($/kW/yr)	0.60	0.60	0.60	0.60	0.60
Fixed O&M ($/kW/yr)	70.10	65.00	65.00	69.70	64.20
Variable O&M (mills/kWh)	0.9	0.8	0.8	0.9	0.8
Fixed Fuel ($/kW/yr)	0	0	0	0	0
Variable Fuel ($/million Btu)	0.52	1.34	1.5	1.39	1.74
Variable Fuel (calc mills per kWh)	4.9	12.7	14.2	13.2	16.5
CONSTRUCTION CASH FLOW (% of Capital)					
1	0.0%	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.0%	12.0%	0.0%	0.0%	0.0%
4	0.0%	48.0%	0.0%	0.0%	0.0%
5	12.0%	40.0%	12.0%	12.0%	12.0%
6	48.0%	0.0%	48.0%	48.0%	48.0%
7	40.0%	0.0%	40.0%	40.0%	40.0%
8	0.0%	0.0%	0.0%	0.0%	0.0%
9	0.0%	0.0%	0.0%	0.0%	0.0%
10	0.0%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%
LEAD TIMES					
Siting & Licensing (years)	2	2	2	2	2
Probability of S&L Success (%)	70%	70%	70%	70%	70%
Probability of Hold Success (%)	75%	75%	75%	75%	75%
Construction Lead Time (years)	5	5	5	5	5
Total Lead Time (years)	7	7	7	7	7
Maximum Option Shelf Life (years)	10	10	10	10	10

Resource: COAL-INTERIM
File: DTCOALBC.XLS
Date: 6/30/91
Revision: C

	Coal-1T	Coal-2T	Coal-3T	Coal-4T	Coal-5T
REGIONAL SUPPLY (incremental aMW by year)					
1991	0	0	0	0	0
1992	0	0	0	0	0
1993	0	0	0	0	0
1994	0	0	0	0	0
1995	0	0	0	0	0
1996	0	250	0	0	0
1997	0	250	0	0	0
1998	0	250	250	250	250
1999	0	0	250	250	250
2000	600	0	250	250	250
2001	600	0	0	0	0
2002	600	0	0	0	0
2003	0	0	0	0	0
2004	0	0	0	0	0
2005	0	0	0	0	0
2006	0	0	0	0	0
2007	0	0	0	0	0
2008	0	0	0	0	0
2009	0	0	0	0	0
2010	0	0	0	0	0
SUPPLY AVAILABLE TO BPA (incremental aMW by year)					
1991	0	0	0	0	0
1992	0	0	0	0	0
1993	0	0	0	0	0
1994	0	0	0	0	0
1995	0	0	0	0	0
1996	0	63	0	0	0
1997	0	63	0	0	0
1998	0	63	63	63	63
1999	0	0	63	63	63
2000	150	0	63	63	63
2001	150	0	0	0	0
2002	150	0	0	0	0
2003	0	0	0	0	0
2004	0	0	0	0	0
2005	0	0	0	0	0
2006	0	0	0	0	0
2007	0	0	0	0	0
2008	0	0	0	0	0
2009	0	0	0	0	0
2010	0	0	0	0	0

Resource: COAL-INTERIM
File: DTCOALBC.XLS
Date: 6/30/91
Revision: C

	Coal-1T	Coal-2T	Coal-3T	Coal-4T	Coal-5T
REGIONAL SUPPLY (cumulative aMW by year)					
1991	0	0	0	0	0
1992	0	0	0	0	0
1993	0	0	0	0	0
1994	0	0	0	0	0
1995	0	0	0	0	0
1996	0	250	0	0	0
1997	0	500	0	0	0
1998	0	750	250	250	250
1999	0	750	500	500	500
2000	600	750	750	750	750
2001	1200	750	750	750	750
2002	1800	750	750	750	750
2003	1800	750	750	750	750
2004	1800	750	750	750	750
2005	1800	750	750	750	750
2006	1800	750	750	750	750
2007	1800	750	750	750	750
2008	1800	750	750	750	750
2009	1800	750	750	750	750
2010	1800	750	750	750	750
SUPPLY AVAILABLE TO BPA (cumulative aMW by year)					
1991	0	0	0	0	0
1992	0	0	0	0	0
1993	0	0	0	0	0
1994	0	0	0	0	0
1995	0	0	0	0	0
1996	0	63	0	0	0
1997	0	125	0	0	0
1998	0	188	63	63	63
1999	0	188	125	125	125
2000	150	188	188	188	188
2001	300	188	188	188	188
2002	450	188	188	188	188
2003	450	188	188	188	188
2004	450	188	188	188	188
2005	450	188	188	188	188
2006	450	188	188	188	188
2007	450	188	188	188	188
2008	450	188	188	188	188
2009	450	188	188	188	188
2010	450	188	188	188	188

Note: SOURCE: 1991 Northwest Conservation and Electric Power Plan. Capital cost were reduced for use in the Draft 1992 Resource Program.

Note: EQ. AVAILABILITY: These figures were set equal to the capacity factor. The Council's data files show a higher value for availability.

Note: CONSTRUCTION COSTS: Construction cost does not include Power Planning Council's offset ($36/kW). The Council's transmission adjustment was backed out and replaced by BPA's adjustment shown below the construction cost estimate. Construction costs have been arbitrarily reduced by 10% for use in the Draft 1992 Resource Program. This is in anticipation of a reduction of costs based on input received by the Power Planning Council during thier public comment period, as well as other data showing a reduction in coal technologies.

Note: TRANSMISSION ADJ: Transmission adjustment is based on the distance of the site from the west side of the Cascades. Source: Matheson to Rohe, 28 Apr 91 "Cost of Transmission Facilities." Figures in DTCAOLBA.WK1 were escalated from 1988 to 1990 by 1.079.

Resource: COGENERATION-EAST
File: DTCOGEA.XLS
Date: 6/29/91
Revision: A

RESOURCE DATA SHEET

INPUTS:
% of Regional Supply Allocated to BPA 25%

RESOURCE IDENTIFIER	Cogen-1E	Cogen-2E	Cogen-3E	Cogen-4E
PLANT CHARACTERISTICS				
Site	East	East	East	East
Fuel Source	N/A	N/A	N/A	N/A
Operating Life (yrs)	40	40	40	40
Unit Size (MW)	25	10	10	10
Equivalent Availability (%)	80%	80%	80%	80%
Anticipated Capacity Factor (%)	80%	80%	80%	80%
Heat Rate (Btu/kWh)	0	0	0	0
Energy by Month (% of total)				
Jan	8.3%	8.3%	8.3%	8.3%
Feb	8.3%	8.3%	8.3%	8.3%
Mar	8.3%	8.3%	8.3%	8.3%
Apr	8.3%	8.3%	8.3%	8.3%
May	8.3%	8.3%	8.3%	8.3%
Jun	8.3%	8.3%	8.3%	8.3%
Jul	8.3%	8.3%	8.3%	8.3%
Aug	8.3%	8.3%	8.3%	8.3%
Sep	8.3%	8.3%	8.3%	8.3%
Oct	8.3%	8.3%	8.3%	8.3%
Nov	8.3%	8.3%	8.3%	8.3%
Dec	8.3%	8.3%	8.3%	8.3%

Resource: COGENERATION-EAST
File: DTCOGEA.XLS
Date: 6/29/91
Revision: A

	Cogen-1E	Cogen-2E	Cogen-3E	Cogen-4E
COSTS (1990 Dollars)				
Financial Life (years)	30	30	30	30
Siting & Licensing ($/kW)	N/A	N/A	N/A	N/A
Construction ($/kW)	N/A	N/A	N/A	N/A
Transmission Adjustment ($/kW)	128	128	128	128
Total Capital Cost ($/kW)	N/A	N/A	N/A	N/A
Siting & Licensing Hold Cost ($/kW/yr)	N/A	N/A	N/A	N/A
Fixed O&M ($/kW/yr)	N/A	N/A	N/A	N/A
Variable O&M (mills/kWh)	N/A	N/A	N/A	N/A
Fixed Fuel ($/kW/yr)	N/A	N/A	N/A	N/A
Variable Fuel ($/million Btu)	N/A	N/A	N/A	N/A
Variable Fuel (real mills per kWh)	39.1	40.1	54.1	59.1
CONSTRUCTION CASH FLOW (% of Capital)				
1	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%
5	0.0%	0.0%	0.0%	0.0%
6	0.0%	0.0%	0.0%	0.0%
7	0.0%	0.0%	0.0%	0.0%
8	0.0%	0.0%	0.0%	0.0%
9	0.0%	0.0%	0.0%	0.0%
10	0.0%	0.0%	0.0%	0.0%
Total	0.0%	0.0%	0.0%	0.0%
LEAD TIMES				
Siting & Licensing (years)	2	2	2	2
Probability of S&L Success (%)	80%	50%	50%	50%
Probability of Hold Success (%)	90%	75%	75%	75%
Construction Lead Time (years)	2	2	2	2
Total Lead Time (years)	4	4	4	4
Maximum Option Shelf Life (years)	5	5	5	5

Resource: COGENERATION-EAST
File: DTCOGEA.XLS
Date: 6/29/91
Revision: A

	Cogen-1E	Cogen-2E	Cogen-3E	Cogen-4E
REGIONAL SUPPLY (incremental aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	0	0	0	0
1994	0	0	0	0
1995	26	0	0	0
1996	107	0	0	0
1997	107	0	0	0
1998	0	29	0	0
1999	0	0	563	0
2000	0	0	0	0
2001	0	0	0	0
2002	0	0	0	269
2003	0	0	0	0
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0
SUPPLY AVAILABLE TO BPA (incremental aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	0	0	0	0
1994	0	0	0	0
1995	7	0	0	0
1996	27	0	0	0
1997	27	0	0	0
1998	0	7	0	0
1999	0	0	141	0
2000	0	0	0	0
2001	0	0	0	0
2002	0	0	0	67
2003	0	0	0	0
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0

Resource: COGENERATION-EAST
File: DTCOGEA.XLS
Date: 6/29/91
Revision: A

	Cogen-1E	Cogen-2E	Cogen-3E	Cogen-4E
REGIONAL SUPPLY (cumulative aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	0	0	0	0
1994	0	0	0	0
1995	26	0	0	0
1996	133	0	0	0
1997	240	0	0	0
1998	240	29	0	0
1999	240	29	563	0
2000	240	29	563	0
2001	240	29	563	0
2002	240	29	563	269
2003	240	29	563	269
2004	240	29	563	269
2005	240	29	563	269
2006	240	29	563	269
2007	240	29	563	269
2008	240	29	563	269
2009	240	29	563	269
2010	240	29	563	269
SUPPLY AVAILABLE TO BPA (cumulative aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	0	0	0	0
1994	0	0	0	0
1995	7	0	0	0
1996	33	0	0	0
1997	60	0	0	0
1998	60	7	0	0
1999	60	7	141	0
2000	60	7	141	0
2001	60	7	141	0
2002	60	7	141	67
2003	60	7	141	67
2004	60	7	141	67
2005	60	7	141	67
2006	60	7	141	67
2007	60	7	141	67
2008	60	7	141	67
2009	60	7	141	67
2010	60	7	141	67

Note: SOURCE: Based on 1991 Northwest Conservation and Electric Power Plan.

Note: COSTS: Siting, construction, and operating costs are omitted from this table, because total energy prices from the Cogeneration Regional Forecasting Model (CFRM) were used for costing this resource.

Note: TRANSMISSION ADJ: Transmission adjustment is based on the distance of the site from the west side of the Cascades. Source: Matheson to Rohe, 28 Apr 91 "Cost of Transmission Facilities." A single transmission adjustment for cogeneration-east is assumed.

Note: VARIABLE COST: The total cost of this resource is assumed to be variable.

Note: SUPPLY: The regional supply is assumed to be distributed 50% west of the Cascades and 50% east of the Cascades.

Resource: COGENERATION-WEST
File: DTCOGWA.XLS
Date: 6/29/91
Revision: A

RESOURCE DATA SHEET

INPUTS:

% of Regional Supply Allocated to BPA	25%

RESOURCE IDENTIFIER	Cogen-1W	Cogen-2W	Cogen-3W	Cogen-4W
PLANT CHARACTERISTICS				
Site	West	West	West	West
Fuel Source	N/A	N/A	N/A	N/A
Operating Life (yrs)	40	40	40	40
Unit Size (MW)	25	10	10	10
Equivalent Availability (%)	80%	80%	80%	80%
Anticipated Capacity Factor (%)	80%	80%	80%	80%
Heat Rate (Btu/kWh)	0	0	0	0
Energy by Month (% of total)				
Jan	8.3%	8.3%	8.3%	8.3%
Feb	8.3%	8.3%	8.3%	8.3%
Mar	8.3%	8.3%	8.3%	8.3%
Apr	8.3%	8.3%	8.3%	8.3%
May	8.3%	8.3%	8.3%	8.3%
Jun	8.3%	8.3%	8.3%	8.3%
Jul	8.3%	8.3%	8.3%	8.3%
Aug	8.3%	8.3%	8.3%	8.3%
Sep	8.3%	8.3%	8.3%	8.3%
Oct	8.3%	8.3%	8.3%	8.3%
Nov	8.3%	8.3%	8.3%	8.3%
Dec	8.3%	8.3%	8.3%	8.3%

Resource: COGENERATION-WEST
File: DTCOGWA.XLS
Date: 6/29/91
Revision: A

	Cogen-1W	Cogen-2W	Cogen-3W	Cogen-4W
COSTS (1990 Dollars)				
Financial Life (years)	30	30	30	30
Siting & Licensing ($/kW)	N/A	N/A	N/A	N/A
Construction ($/kW)	N/A	N/A	N/A	N/A
Transmission Adjustment ($/kW)	0	0	0	0
Total Capital Cost ($/kW)	N/A	N/A	N/A	N/A
Siting & Licensing Hold Cost ($/kW/yr)	N/A	N/A	N/A	N/A
Fixed O&M ($/kW/yr)	N/A	N/A	N/A	N/A
Variable O&M (mills/kWh)	N/A	N/A	N/A	N/A
Fixed Fuel ($/kW/yr)	N/A	N/A	N/A	N/A
Variable Fuel ($/million Btu)	N/A	N/A	N/A	N/A
Variable Fuel (real mills per kWh)	38.0	39.0	53.0	58.0
CONSTRUCTION CASH FLOW (% of Capital)				
1	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%
5	0.0%	0.0%	0.0%	0.0%
6	0.0%	0.0%	0.0%	0.0%
7	0.0%	0.0%	0.0%	0.0%
8	0.0%	0.0%	0.0%	0.0%
9	0.0%	0.0%	0.0%	0.0%
10	0.0%	0.0%	0.0%	0.0%
Total	0.0%	0.0%	0.0%	0.0%
LEAD TIMES				
Siting & Licensing (years)	2	2	2	2
Probability of S&L Success (%)	80%	50%	50%	50%
Probability of Hold Success (%)	90%	75%	75%	75%
Construction Lead Time (years)	2	2	2	2
Total Lead Time (years)	4	4	4	4
Maximum Option Shelf Life (years)	5	5	5	5

Resource: COGENERATION-WEST
File: DTCOGWA.XLS
Date: 6/29/91
Revision: A

	Cogen-1W	Cogen-2W	Cogen-3W	Cogen-4W
REGIONAL SUPPLY (incremental aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	0	0	0	0
1994	0	0	0	0
1995	26	0	0	0
1996	107	0	0	0
1997	107	0	0	0
1998	0	29	0	0
1999	0	0	563	0
2000	0	0	0	0
2001	0	0	0	0
2002	0	0	0	269
2003	0	0	0	0
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0
SUPPLY AVAILABLE TO BPA (incremental aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	0	0	0	0
1994	0	0	0	0
1995	7	0	0	0
1996	27	0	0	0
1997	27	0	0	0
1998	0	7	0	0
1999	0	0	141	0
2000	0	0	0	0
2001	0	0	0	0
2002	0	0	0	67
2003	0	0	0	0
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0

Resource: COGENERATION-WEST
File: DTCOGWA.XLS
Date: 6/29/91
Revision: A

	Cogen-1W	Cogen-2W	Cogen-3W	Cogen-4W
REGIONAL SUPPLY (cumulative aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	0	0	0	0
1994	0	0	0	0
1995	26	0	0	0
1996	133	0	0	0
1997	240	0	0	0
1998	240	29	0	0
1999	240	29	563	0
2000	240	29	563	0
2001	240	29	563	0
2002	240	29	563	269
2003	240	29	563	269
2004	240	29	563	269
2005	240	29	563	269
2006	240	29	563	269
2007	240	29	563	269
2008	240	29	563	269
2009	240	29	563	269
2010	240	29	563	269
SUPPLY AVAILABLE TO BPA (cumulative aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	0	0	0	0
1994	0	0	0	0
1995	7	0	0	0
1996	33	0	0	0
1997	60	0	0	0
1998	60	7	0	0
1999	60	7	141	0
2000	60	7	141	0
2001	60	7	141	0
2002	60	7	141	67
2003	60	7	141	67
2004	60	7	141	67
2005	60	7	141	67
2006	60	7	141	67
2007	60	7	141	67
2008	60	7	141	67
2009	60	7	141	67
2010	60	7	141	67

Note: SOURCE: Based on 1991 Northwest Conservation and Electric Power Plan.

Note: COSTS: Siting, construction, and operating costs are omitted from this table, because total energy prices from the Cogeneration Regional Forecasting Model (CFRM) were used for costing this resource.

Note: TRANSMISSION ADJ: Transmission adjustment is based on the distance of the site from the west side of the Cascades. Source: Matheson to Rohe, 28 Apr 91 "Cost of Transmission Facilities." A single transmission adjustment for cogeneration-east is assumed.

Note: VARIABLE COST: The total cost of this resource is assumed to be variable.

Note: SUPPLY: The regional supply is assumed to be distributed 50% west of the Cascades and 50% east of the Cascades.

Resource: **COMBUSTION TURBINES**
File: **DTCTA.XLS**
Date: **6/29/91**
Revision: **A**

RESOURCE DATA SHEET

INPUTS:

% of Regional Supply Allocated to BPA	100%

RESOURCE IDENTIFIER	SCCT-1	CCCT-1
PLANT CHARACTERISTICS		
Site	East	East
Fuel Source	N/A	N/A
Operating Life (yrs)	30	30
Unit Size (MW)	139	420
Equivalent Availability (%)	84%	83%
Anticipated Capacity Factor (%)	84%	83%
Heat Rate (Btu/kWh)	11480	7620
Energy by Month (% of total)		
Jan	8.3%	8.3%
Feb	8.3%	8.3%
Mar	8.3%	8.3%
Apr	8.3%	8.3%
May	8.3%	8.3%
Jun	8.3%	8.3%
Jul	8.3%	8.3%
Aug	8.3%	8.3%
Sep	8.3%	8.3%
Oct	8.3%	8.3%
Nov	8.3%	8.3%
Dec	8.3%	8.3%

Resource: **COMBUSTION TURBINES**
File: **DTCTA.XLS**
Date: **6/29/91**
Revision: **A**

	SCCT-1	CCCT-1
COSTS (1990 Dollars)		
Financial Life (years)	30	30
Siting & Licensing ($/kW)	62	41
Construction ($/kW)	598	725
Transmission Adjustment ($/kW)	128	128
Total Capital Cost ($/kW)	788	894
Siting & Licensing Hold Cost ($/kW/yr)	2.50	1.80
Fixed O&M ($/kW/yr)	2.2	5.8
Variable O&M (mills/kWh)	0.2	0.4
Fixed Fuel ($/kW/yr)	0	0
Variable Fuel ($/million Btu)	1.72	1.72
Variable Fuel (calc mills per kWh)	19.7	13.1
CONSTRUCTION CASH FLOW (% of Capital)		
1	0.0%	0.0%
2	0.0%	0.0%
3	50.0%	50.0%
4	50.0%	50.0%
5	0.0%	0.0%
6	0.0%	0.0%
7	0.0%	0.0%
8	0.0%	0.0%
9	0.0%	0.0%
10	0.0%	0.0%
Total	100.0%	100.0%
LEAD TIMES		
Siting & Licensing (years)	2	2
Probability of S&L Success (%)	90%	90%
Probability of Hold Success (%)	90%	90%
Construction Lead Time (years)	2	2
Total Lead Time (years)	4	4
Maximum Option Shelf Life (years)	5	5

Resource: **COMBUSTION TURBINES**
File: **DTCTA.XLS**
Date: **6/29/91**
Revision: **A**

	SCCT-1	CCCT-1
REGIONAL SUPPLY (incremental aMW by year)		
1991	0	0
1992	0	0
1993	0	0
1994	0	0
1995	0	700
1996	0	0
1997	0	0
1998	0	0
1999	0	0
2000	0	0
2001	0	0
2002	0	0
2003	0	0
2004	0	0
2005	0	0
2006	0	0
2007	0	0
2008	0	0
2009	0	0
2010	0	0
SUPPLY AVAILABLE TO BPA (incremental aMW by year)		
1991	0	0
1992	0	0
1993	0	0
1994	0	0
1995	0	700
1996	0	0
1997	0	0
1998	0	0
1999	0	0
2000	0	0
2001	0	0
2002	0	0
2003	0	0
2004	0	0
2005	0	0
2006	0	0
2007	0	0
2008	0	0
2009	0	0
2010	0	0

Resource: **COMBUSTION TURBINES**
File: **DTCTA.XLS**
Date: **6/29/91**
Revision: **A**

	SCCT-1	CCCT-1
REGIONAL SUPPLY (cumulative aMW by year)		
1991	0	0
1992	0	0
1993	0	0
1994	0	0
1995	0	700
1996	0	700
1997	0	700
1998	0	700
1999	0	700
2000	0	700
2001	0	700
2002	0	700
2003	0	700
2004	0	700
2005	0	700
2006	0	700
2007	0	700
2008	0	700
2009	0	700
2010	0	700
SUPPLY AVAILABLE TO BPA (cumulative aMW by year)		
1991	0	0
1992	0	0
1993	0	0
1994	0	0
1995	0	700
1996	0	700
1997	0	700
1998	0	700
1999	0	700
2000	0	700
2001	0	700
2002	0	700
2003	0	700
2004	0	700
2005	0	700
2006	0	700
2007	0	700
2008	0	700
2009	0	700
2010	0	700

Note: SOURCE: 1991 Northwest Conservation and Electric Power Plan.

Note: CAPACITY FACTOR: The capacity factor of a combustion turbine is a function of how the turbine will be operated. The cost of power resulting from using nonfirm energy with CT's is dependent on the amount of nonfirm energy available, the value of nonfirm energy, the cost and availability of fuel to operate CT's and nonfirm pricing policies.

Note: TRANSMISSION ADJ: Transmission adjustment is based on the distance of the site from the west side of the Cascades. Source: Matheson to Rohe, 28 Apr 91 "Cost of Transmission Facilities." Figures in DTCAOLBA.WK1 were escalated from 1988 to 1990 by 1.079.

Note: FUEL COST: Source: Vena Lee, "Forecast of the Pacific Northwest Variable Fuel Costs-Medium Case."

Note: SUPPLY: The supply of combustion turbines is not inherently limited. The supply shown for the region represents two large facilities. Constraints that restrict thier availability include include siting, type of operation, fuel supply availability, and perceived trends in fuel costs.

Resource: GEOTHERMAL
File: DTGEOB.XLS
Date: 6/29/91
Revision: B

RESOURCE DATA SHEET

INPUTS:

% of Regional Supply Allocated to BPA	25%

RESOURCE IDENTIFIER	Geo
PLANT CHARACTERISTICS	
Site	East
Fuel Source	N/A
Operating Life (yrs)	30
Unit Size (MW)	25
Equivalent Availability (%)	90%
Anticipated Capacity Factor (%)	90%
Heat Rate (Btu/kWh)	0
Energy by Month (% of total)	
Jan	8.3%
Feb	8.3%
Mar	8.3%
Apr	8.3%
May	8.3%
Jun	8.3%
Jul	8.3%
Aug	8.3%
Sep	8.3%
Oct	8.3%
Nov	8.3%
Dec	8.3%

Resource: GEOTHERMAL
File: DTGEOB.XLS
Date: 6/29/91
Revision: B

	Geo
COSTS (1990 Dollars)	
Financial Life (years)	30
Siting & Licensing ($/kW)	65
Construction ($/kW)	2637
Transmission Adjustment ($/kW)	405
Total Capital Cost ($/kW)	3107
Siting & Licensing Hold Cost ($/kW/yr)	13.00
Fixed O&M ($/kW/yr)	116
Variable O&M (mills/kWh)	6.5
Fixed Fuel ($/kW/yr)	0
Variable Fuel ($/million Btu)	0.00
Variable Fuel (calc mills per kWh)	0.0
CONSTRUCTION CASH FLOW (% of Capital)	
1	0.0%
2	0.0%
3	50.0%
4	50.0%
5	0.0%
6	0.0%
7	0.0%
8	0.0%
9	0.0%
10	0.0%
Total	100.0%
LEAD TIMES	
Siting & Licensing (years)	2
Probability of S&L Success (%)	75%
Probability of Hold Success (%)	90%
Construction Lead Time (years)	2
Total Lead Time (years)	4
Maximum Option Shelf Life (years)	5

Resource: GEOTHERMAL
File: DTGEOB.XLS
Date: 6/29/91
Revision: B

	Geo
REGIONAL SUPPLY (incremental aMW by year)	
1991	0
1992	0
1993	0
1994	0
1995	0
1996	350
1997	0
1998	0
1999	0
2000	0
2001	0
2002	0
2003	0
2004	0
2005	0
2006	0
2007	0
2008	0
2009	0
2010	0
SUPPLY AVAILABLE TO BPA (incremental aMW by year)	
1991	0
1992	0
1993	0
1994	0
1995	0
1996	88
1997	0
1998	0
1999	0
2000	0
2001	0
2002	0
2003	0
2004	0
2005	0
2006	0
2007	0
2008	0
2009	0
2010	0

Resource: GEOTHERMAL
File: DTGEOB.XLS
Date: 6/29/91
Revision: B

	Geo
REGIONAL SUPPLY (cumulative aMW by year)	
1991	0
1992	0
1993	0
1994	0
1995	0
1996	350
1997	350
1998	350
1999	350
2000	350
2001	350
2002	350
2003	350
2004	350
2005	350
2006	350
2007	350
2008	350
2009	350
2010	350
SUPPLY AVAILABLE TO BPA (cumulative aMW by year)	
1991	0
1992	0
1993	0
1994	0
1995	0
1996	88
1997	88
1998	88
1999	88
2000	88
2001	88
2002	88
2003	88
2004	88
2005	88
2006	88
2007	88
2008	88
2009	88
2010	88

Note: SOURCE: 1991 Northwest Conservation and Electric Power Plan.

Note: EQ. AVAILABILITY: These figures were set equal to the capacity factor.

Note: TRANSMISSION ADJ: Transmission adjustment is the same as used for Thousand Springs, Nevada coal.

Resource: NEW HYDRO-EAST
File: DTHYDEB.XLS
Date: 7/18/91
Revision: B

RESOURCE DATA SHEET

INPUTS:

% of Regional Supply Allocated to BPA	25%

RESOURCE IDENTIFIER	Hydro-1E	Hydro-2E	Hydro-3E	Hydro-4E
PLANT CHARACTERISTICS				
Site	N/A	N/A	N/A	N/A
Fuel Source	N/A	N/A	N/A	N/A
Operating Life (yrs)	50	50	50	50
Unit Size (MW)	10	10	10	10
Equivalent Availability (%)	48%	36%	37%	36%
Anticipated Capacity Factor (%)	48%	36%	37%	36%
Heat Rate (Btu/kWh)	0	0	0	0
Energy by Month (% of total)				
Jan	6.0%	6.0%	6.0%	6.0%
Feb	7.0%	7.0%	7.0%	7.0%
Mar	8.0%	8.0%	8.0%	8.0%
Apr	12.0%	12.0%	12.0%	12.0%
May	12.0%	12.0%	12.0%	12.0%
Jun	12.0%	12.0%	12.0%	12.0%
Jul	13.0%	13.0%	13.0%	13.0%
Aug	7.0%	7.0%	7.0%	7.0%
Sep	6.0%	6.0%	6.0%	6.0%
Oct	5.0%	5.0%	5.0%	5.0%
Nov	6.0%	6.0%	6.0%	6.0%
Dec	6.0%	6.0%	6.0%	6.0%

Resource: **NEW HYDRO-EAST**
File: **DTHYDEB.XLS**
Date: **7/18/91**
Revision: **B**

	Hydro-1E	Hydro-2E	Hydro-3E	Hydro-4E
COSTS (1990 Dollars)				
Financial Life (years)	30	30	30	30
Siting & Licensing ($/kW)	80	100	138	167
Construction ($/kW)	980	1229	1693	2049
Transmission Adjustment ($/kW)	128	128	128	128
Total Capital Cost ($/kW)	1188	1457	1959	2344
Siting & Licensing Hold Cost ($/kW/yr)	3.00	3.00	3.00	3.00
Fixed O&M ($/kW/yr)	23	29	39	48
Variable O&M (mills/kWh)	0	0	0	0
Fixed Fuel ($/kW/yr)	0	0	0	0
Variable Fuel ($/million Btu)	0	0	0	0
Variable Fuel (calc mills per kWh)	N/A	N/A	N/A	N/A
CONSTRUCTION CASH FLOW (% of Capital)				
1	25.0%	25.0%	25.0%	25.0%
2	50.0%	50.0%	50.0%	50.0%
3	25.0%	25.0%	25.0%	25.0%
4	0.0%	0.0%	0.0%	0.0%
5	0.0%	0.0%	0.0%	0.0%
6	0.0%	0.0%	0.0%	0.0%
7	0.0%	0.0%	0.0%	0.0%
8	0.0%	0.0%	0.0%	0.0%
9	0.0%	0.0%	0.0%	0.0%
10	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%
LEAD TIMES				
Siting & Licensing (years)	3	3	3	3
Probability of S&L Success (%)	50%	50%	50%	50%
Probability of Hold Success (%)	75%	75%	75%	75%
Construction Lead Time (years)	3	3	3	3
Total Lead Time (years)	6	6	6	6
Maximum Option Shelf Life (years)	10	10	10	10

Resource: **NEW HYDRO-EAST**
File: **DTHYDEB.XLS**
Date: **7/18/91**
Revision: **B**

	Hydro-1E	Hydro-2E	Hydro-3E	Hydro-4E
REGIONAL SUPPLY (incremental aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	11	12	15	11
1994	11	12	15	11
1995	11	12	15	11
1996	11	12	15	11
1997	11	12	15	11
1998	0	0	0	0
1999	0	0	0	0
2000	0	0	0	0
2001	0	0	0	0
2002	0	0	0	0
2003	0	0	0	0
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0
SUPPLY AVAILABLE TO BPA (incremental aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	3	3	4	3
1994	3	3	4	3
1995	3	3	4	3
1996	3	3	4	3
1997	3	3	4	3
1998	0	0	0	0
1999	0	0	0	0
2000	0	0	0	0
2001	0	0	0	0
2002	0	0	0	0
2003	0	0	0	0
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0

Resource: NEW HYDRO-EAST
File: DTHYDEB.XLS
Date: 7/18/91
Revision: B

	Hydro-1E	Hydro-2E	Hydro-3E	Hydro-4E
REGIONAL SUPPLY (cumulative aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	11	12	15	11
1994	22	25	30	21
1995	33	37	45	32
1996	44	49	60	43
1997	55	62	76	53
1998	55	62	76	53
1999	55	62	76	53
2000	55	62	76	53
2001	55	62	76	53
2002	55	62	76	53
2003	55	62	76	53
2004	55	62	76	53
2005	55	62	76	53
2006	55	62	76	53
2007	55	62	76	53
2008	55	62	76	53
2009	55	62	76	53
2010	55	62	76	53
SUPPLY AVAILABLE TO BPA (cumulative aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	3	3	4	3
1994	5	6	8	5
1995	8	9	11	8
1996	11	12	15	11
1997	14	15	19	13
1998	14	15	19	13
1999	14	15	19	13
2000	14	15	19	13
2001	14	15	19	13
2002	14	15	19	13
2003	14	15	19	13
2004	14	15	19	13
2005	14	15	19	13
2006	14	15	19	13
2007	14	15	19	13
2008	14	15	19	13
2009	14	15	19	13
2010	14	15	19	13

Note: SOURCE: Based on 1991 Northwest Conservation and Electric Power Plan.

Note: EQ. AVAILABILITY: These figures were set equal to the capacity factor. The Council's data files show a lower value for availability.

Note: CAPACITY FACTOR: The figures listed represent the firm energy output of the resource.

Note: TRANSMISSION ADJ: Transmission adjustment is based on the distance of the site from the west side of the Cascades. Source: Matheson to Rohe, 28 Apr 91 "Cost of Transmission Facilities." Figures in DTCAOLBA.WK1 were escalated from 1988 to 1990 by 1.079.

Note: LEADTIME: DTHYDEB.XLS corrects total leadtime.

Note: SUPPLY: The regional supply is assumed to be distributed 40% west of the Cascades and 60% east of the Cascades. Per memo dated 29 Aug 90, Holeman to Berger, "Hydropower Potential-East/West Split

Resource: NEW HYDRO-WEST
File: DTHYDWB.XLS
Date: 7/18/91
Revision: B

RESOURCE DATA SHEET

INPUTS:
% of Regional Supply Allocated to BPA 25%

RESOURCE IDENTIFIER	Hydro-1W	Hydro-2W	Hydro-3W	Hydro-4W
PLANT CHARACTERISTICS				
Site	N/A	N/A	N/A	N/A
Fuel Source	N/A	N/A	N/A	N/A
Operating Life (yrs)	50	50	50	50
Unit Size (MW)	10	10	10	10
Equivalent Availability (%)	48%	36%	37%	36%
Anticipated Capacity Factor (%)	48%	36%	37%	36%
Heat Rate (Btu/kWh)	0	0	0	0
Energy by Month (% of total)				
Jan	6.0%	6.0%	6.0%	6.0%
Feb	7.0%	7.0%	7.0%	7.0%
Mar	8.0%	8.0%	8.0%	8.0%
Apr	12.0%	12.0%	12.0%	12.0%
May	12.0%	12.0%	12.0%	12.0%
Jun	12.0%	12.0%	12.0%	12.0%
Jul	13.0%	13.0%	13.0%	13.0%
Aug	7.0%	7.0%	7.0%	7.0%
Sep	6.0%	6.0%	6.0%	6.0%
Oct	5.0%	5.0%	5.0%	5.0%
Nov	6.0%	6.0%	6.0%	6.0%
Dec	6.0%	6.0%	6.0%	6.0%

Resource: **NEW HYDRO-WEST**
File: **DTHYDWB.XLS**
Date: **7/18/91**
Revision: **B**

	Hydro-1W	Hydro-2W	Hydro-3W	Hydro-4W
COSTS (1990 Dollars)				
Financial Life (years)	30	30	30	30
Siting & Licensing ($/kW)	80	100	138	167
Construction ($/kW)	980	1229	1693	2049
Transmission Adjustment ($/kW)	0	0	0	0
Total Capital Cost ($/kW)	1060	1329	1831	2216
Siting & Licensing Hold Cost ($/kW/yr)	3.00	3.00	3.00	3.00
Fixed O&M ($/kW/yr)	23	29	39	48
Variable O&M (mills/kWh)	0	0	0	0
Fixed Fuel ($/kW/yr)	0	0	0	0
Variable Fuel ($/million Btu)	0	0	0	0
Variable Fuel (calc mills per kWh)	N/A	N/A	N/A	N/A
CONSTRUCTION CASH FLOW (% of Capital)				
1	25.0%	25.0%	25.0%	25.0%
2	50.0%	50.0%	50.0%	50.0%
3	25.0%	25.0%	25.0%	25.0%
4	0.0%	0.0%	0.0%	0.0%
5	0.0%	0.0%	0.0%	0.0%
6	0.0%	0.0%	0.0%	0.0%
7	0.0%	0.0%	0.0%	0.0%
8	0.0%	0.0%	0.0%	0.0%
9	0.0%	0.0%	0.0%	0.0%
10	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%
LEAD TIMES				
Siting & Licensing (years)	3	3	3	3
Probability of S&L Success (%)	50%	50%	50%	50%
Probability of Hold Success (%)	75%	75%	75%	75%
Construction Lead Time (years)	3	3	3	3
Total Lead Time (years)	6	6	6	6
Maximum Option Shelf Life (years)	10	10	10	10

Resource: **NEW HYDRO-WEST**
File: **DTHYDWB.XLS**
Date: **7/18/91**
Revision: **B**

	Hydro-1W	Hydro-2W	Hydro-3W	Hydro-4W
REGIONAL SUPPLY (incremental aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	7	8	10	7
1994	7	8	10	7
1995	7	8	10	7
1996	7	8	10	7
1997	7	8	10	7
1998	0	0	0	0
1999	0	0	0	0
2000	0	0	0	0
2001	0	0	0	0
2002	0	0	0	0
2003	0	0	0	0
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0
SUPPLY AVAILABLE TO BPA (incremental aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	2	2	3	2
1994	2	2	3	2
1995	2	2	3	2
1996	2	2	3	2
1997	2	2	3	2
1998	0	0	0	0
1999	0	0	0	0
2000	0	0	0	0
2001	0	0	0	0
2002	0	0	0	0
2003	0	0	0	0
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0

Resource: NEW HYDRO-WEST
File: DTHYDWB.XLS
Date: 7/18/91
Revision: B

	Hydro-1W	Hydro-2W	Hydro-3W	Hydro-4W
REGIONAL SUPPLY (cumulative aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	7	8	10	7
1994	15	16	20	14
1995	22	25	30	21
1996	29	33	40	28
1997	36	41	50	36
1998	36	41	50	36
1999	36	41	50	36
2000	36	41	50	36
2001	36	41	50	36
2002	36	41	50	36
2003	36	41	50	36
2004	36	41	50	36
2005	36	41	50	36
2006	36	41	50	36
2007	36	41	50	36
2008	36	41	50	36
2009	36	41	50	36
2010	36	41	50	36
SUPPLY AVAILABLE TO BPA (cumulative aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	2	2	3	2
1994	4	4	5	4
1995	5	6	8	5
1996	7	8	10	7
1997	9	10	13	9
1998	9	10	13	9
1999	9	10	13	9
2000	9	10	13	9
2001	9	10	13	9
2002	9	10	13	9
2003	9	10	13	9
2004	9	10	13	9
2005	9	10	13	9
2006	9	10	13	9
2007	9	10	13	9
2008	9	10	13	9
2009	9	10	13	9
2010	9	10	13	9

Note: SOURCE: Based on 1991 Northwest Conservation and Electric Power Plan.

Note: EQ. AVAILABILITY: These figures were set equal to the capacity factor. The Council's data files show a lower value for availability.

Note: CAPACITY FACTOR: The figures listed represent the firm energy output of the resource.

Note: TRANSMISSION ADJ: Transmission adjustment is based on the distance of the site from the west side of the Cascades. Source: Matheson to Rohe, 28 Apr 91 "Cost of Transmission Facilities." Figures in DTCAOLBA.WK1 were escalated from 1988 to 1990 by 1.079.

Note: LEADTIME: DTHYDWB.XLS corrects total lead time.

Note: SUPPLY: The regional supply is assumed to be distributed 40% west of the Cascades and 60% east of the Cascades. Per memo dated 29 Aug 90, Holeman to Berger, "Hydropower Potential-East/West Split

Resource: MSW
File: DTMSW.XLS
Date: 6/29/91
Revision: None

RESOURCE DATA SHEET

INPUTS:

% of Regional Supply Allocated to BPA	100%

RESOURCE IDENTIFIER	MSW
PLANT CHARACTERISTICS	
Site	West
Fuel Source	West
Operating Life (yrs)	30
Unit Size (MW)	10
Equivalent Availability (%)	80%
Anticipated Capacity Factor (%)	80%
Heat Rate (Btu/kWh)	0
Energy by Month (% of total)	
Jan	8.3%
Feb	8.3%
Mar	8.3%
Apr	8.3%
May	8.3%
Jun	8.3%
Jul	8.3%
Aug	8.3%
Sep	8.3%
Oct	8.3%
Nov	8.3%
Dec	8.3%

Resource: MSW
File: DTMSW.XLS
Date: 6/29/91
Revision: None

	MSW
COSTS (1990 Dollars)	
Financial Life (years)	30
Siting & Licensing ($/kW)	N/A
Construction ($/kW)	N/A
Transmission Adjustment ($/kW)	0
Total Capital Cost ($/kW)	N/A
Siting & Licensing Hold Cost ($/kW/yr)	N/A
Fixed O&M ($/kW/yr)	N/A
Variable O&M (mills/kWh)	N/A
Fixed Fuel ($/kW/yr)	N/A
Variable Fuel ($/million Btu)	N/A
Variable Fuel (real mills per kWh)	41.0
CONSTRUCTION CASH FLOW (% of Capital)	
1	0.0%
2	0.0%
3	0.0%
4	0.0%
5	0.0%
6	0.0%
7	0.0%
8	0.0%
9	0.0%
10	0.0%
Total	0.0%
LEAD TIMES	
Siting & Licensing (years)	2
Probability of S&L Success (%)	75%
Probability of Hold Success (%)	75%
Construction Lead Time (years)	3
Total Lead Time (years)	5
Maximum Option Shelf Life (years)	5

Resource: MSW
File: DTMSW.XLS
Date: 6/29/91
Revision: None

	MSW
REGIONAL SUPPLY (incremental aMW by year)	
1991	0
1992	0
1993	0
1994	0
1995	0
1996	0
1997	0
1998	0
1999	0
2000	10
2001	20
2002	0
2003	0
2004	0
2005	0
2006	0
2007	0
2008	0
2009	0
2010	0
SUPPLY AVAILABLE TO BPA (incremental aMW by year)	
1991	0
1992	0
1993	0
1994	0
1995	0
1996	0
1997	0
1998	0
1999	0
2000	10
2001	20
2002	0
2003	0
2004	0
2005	0
2006	0
2007	0
2008	0
2009	0
2010	0

Resource: MSW
File: DTMSW.XLS
Date: 6/29/91
Revision: None

	MSW
REGIONAL SUPPLY (cumulative aMW by year)	
1991	0
1992	0
1993	0
1994	0
1995	0
1996	0
1997	0
1998	0
1999	0
2000	10
2001	30
2002	30
2003	30
2004	30
2005	30
2006	30
2007	30
2008	30
2009	30
2010	30
SUPPLY AVAILABLE TO BPA (cumulative aMW by year)	
1991	0
1992	0
1993	0
1994	0
1995	0
1996	0
1997	0
1998	0
1999	0
2000	10
2001	30
2002	30
2003	30
2004	30
2005	30
2006	30
2007	30
2008	30
2009	30
2010	30

Note: SOURCE: 1991 Northwest Conservation and Electric Power Plan.

Note: COST: The power purchase price is negotiated between the MSW plant operators and utililities. For planning purposes they are set at the regional avoided cost for power.

Note: VARIABLE COST: The total cost of this resource is assumed to be variable.

Resource: SOLAR
File: DTSOLB.XLS
Date: 6/29/91
Revision: B

RESOURCE DATA SHEET

INPUTS:

% of Regional Supply Allocated to BPA	25%

RESOURCE IDENTIFIER	Solar-1	Solar-2
PLANT CHARACTERISTICS		
Site	East	East
Fuel Source	N/A	N/A
Operating Life (yrs)	30	30
Unit Size (MW)	80	80
Equivalent Availability (%)	28%	28%
Anticipated Capacity Factor (%)	28%	28%
Heat Rate (Btu/kWh)	9616	0
Energy by Month (% of total)		
Jan	4.4%	4.4%
Feb	4.8%	4.8%
Mar	6.8%	6.8%
Apr	9.0%	9.0%
May	9.6%	9.6%
Jun	11.9%	11.9%
Jul	13.4%	13.4%
Aug	13.2%	13.2%
Sep	10.8%	10.8%
Oct	7.4%	7.4%
Nov	4.5%	4.5%
Dec	4.1%	4.1%

Resource: SOLAR
File: DTSOLB.XLS
Date: 6/29/91
Revision: B

	Solar-1	Solar-2
COSTS (1990 Dollars)		
Financial Life (years)	30	30
Siting & Licensing ($/kW)	5	13
Construction ($/kW)	730	2623
Transmission Adjustment ($/kW)	128	128
Total Capital Cost ($/kW)	863	2764
Siting & Licensing Hold Cost ($/kW/yr)	3.00	0.00
Fixed O&M ($/kW/yr)	32	16
Variable O&M (mills/kWh)	30.4	0
Fixed Fuel ($/kW/yr)	0	0
Variable Fuel ($/million Btu)	0	0
Variable Fuel (calc mills per kWh)	0.0	0.0
CONSTRUCTION CASH FLOW (% of Capital)		
1	0.0%	0.0%
2	0.0%	0.0%
3	40.0%	40.0%
4	60.0%	60.0%
5	0.0%	0.0%
6	0.0%	0.0%
7	0.0%	0.0%
8	0.0%	0.0%
9	0.0%	0.0%
10	0.0%	0.0%
Total	100.0%	100.0%
LEAD TIMES		
Siting & Licensing (years)	2	2
Probability of S&L Success (%)	90%	90%
Probability of Hold Success (%)	90%	90%
Construction Lead Time (years)	2	2
Total Lead Time (years)	4	4
Maximum Option Shelf Life (years)	5	5

Resource: SOLAR
File: DTSOLB.XLS
Date: 6/29/91
Revision: B

	Solar-1	Solar-2
REGIONAL SUPPLY (incremental aMW by year)		
1991	0	0
1992	0	0
1993	0	0
1994	0	0
1995	0	480
1996	0	0
1997	0	0
1998	0	0
1999	0	0
2000	0	0
2001	0	0
2002	0	0
2003	0	0
2004	0	0
2005	0	0
2006	0	0
2007	0	0
2008	0	0
2009	0	0
2010	0	0
SUPPLY AVAILABLE TO BPA (incremental aMW by year)		
1991	0	0
1992	0	0
1993	0	0
1994	0	0
1995	0	120
1996	0	0
1997	0	0
1998	0	0
1999	0	0
2000	0	0
2001	0	0
2002	0	0
2003	0	0
2004	0	0
2005	0	0
2006	0	0
2007	0	0
2008	0	0
2009	0	0
2010	0	0

Resource: SOLAR
File: DTSOLB.XLS
Date: 6/29/91
Revision: B

	Solar-1	Solar-2
REGIONAL SUPPLY (cumulative aMW by year)		
1991	0	0
1992	0	0
1993	0	0
1994	0	0
1995	0	480
1996	0	480
1997	0	480
1998	0	480
1999	0	480
2000	0	480
2001	0	480
2002	0	480
2003	0	480
2004	0	480
2005	0	480
2006	0	480
2007	0	480
2008	0	480
2009	0	480
2010	0	480
SUPPLY AVAILABLE TO BPA (cumulative aMW by year)		
1991	0	0
1992	0	0
1993	0	0
1994	0	0
1995	0	120
1996	0	120
1997	0	120
1998	0	120
1999	0	120
2000	0	120
2001	0	120
2002	0	120
2003	0	120
2004	0	120
2005	0	120
2006	0	120
2007	0	120
2008	0	120
2009	0	120
2010	0	120

Note: SOURCE: 1991 Northwest Conservation and Electric Power Plan.

Note: PLANT DESCRIPTION: Solar-1 is a gas fired power block. Solar-2 is the solar component of the total plant. The total plant uses the gas fired portion to back-up the solar portion.

Note: TRANSMISSION ADJ: Transmission adjustment is based on the distance of the site from the west side of the Cascades. Source: Matheson to Rohe, 28 Apr 91 "Cost of Transmission Facilities." Figures in DTCAOLBA.WK1 were escalated from 1988 to 1990 by 1.079.

Resource: WIND
File: DTWINB.XLS
Date: 6/29/91
Revision: B

RESOURCE DATA SHEET

INPUTS:

% of Regional Supply Allocated to BPA 25%

RESOURCE IDENTIFIER	Wind-1	Wind-2	Wind-3
PLANT CHARACTERISTICS			
Site			
Fuel Source	N/A	N/A	N/A
Operating Life (yrs)	40	40	40
Unit Size (MW)	20	30	30
Equivalent Availability (%)	31%	26%	18%
Anticipated Capacity Factor (%)	31%	26%	18%
Heat Rate (Btu/kWh)	0	0	0
Energy by Month (% of total)			
Jan	6.0%	14.3%	14.3%
Feb	6.0%	9.2%	9.2%
Mar	6.0%	9.9%	9.9%
Apr	9.0%	8.7%	8.7%
May	7.0%	4.2%	4.2%
Jun	11.0%	5.8%	5.8%
Jul	12.0%	5.6%	5.6%
Aug	12.0%	4.3%	4.3%
Sep	11.0%	5.8%	5.8%
Oct	8.0%	7.1%	7.1%
Nov	6.0%	12.3%	12.3%
Dec	6.0%	12.8%	12.8%

Resource: **WIND**
File: **DTWINB.XLS**
Date: **6/29/91**
Revision: **B**

	Wind-1	Wind-2	Wind-3
COSTS (1990 Dollars)			
Financial Life (years)	30	30	30
Siting & Licensing ($/kW)	16	17	16
Construction ($/kW)	1109	1174	1095
Transmission Adjustment ($/kW)	111	386	128
Total Capital Cost ($/kW)	1236	1577	1239
Siting & Licensing Hold Cost ($/kW/yr)	4.00	4.00	4.00
Fixed O&M ($/kW/yr)	16	17	17
Variable O&M (mills/kWh)	12.1	12.4	12.0
Fixed Fuel ($/kW/yr)	0	0	0
Variable Fuel ($/million Btu)	0	0	0
Variable Fuel (calc mills per kWh)	0.0	0.0	0.0
CONSTRUCTION CASH FLOW (% of Capital)			
1	0.0%	0.0%	0.0%
2	40.0%	40.0%	40.0%
3	60.0%	60.0%	60.0%
4	0.0%	0.0%	0.0%
5	0.0%	0.0%	0.0%
6	0.0%	0.0%	0.0%
7	0.0%	0.0%	0.0%
8	0.0%	0.0%	0.0%
9	0.0%	0.0%	0.0%
10	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%
LEAD TIMES			
Siting & Licensing (years)	1	1	1
Probability of S&L Success (%)	90%	90%	90%
Probability of Hold Success (%)	90%	90%	90%
Construction Lead Time (years)	2	2	2
Total Lead Time (years)	3	3	3
Maximum Option Shelf Life (years)	5	5	5

Resource: **WIND**
File: **DTWINB.XLS**
Date: **6/29/91**
Revision: **B**

	Wind-1	Wind-2	Wind-3
REGIONAL SUPPLY (incremental aMW by year)			
1991	0	0	0
1992	0	0	0
1993	0	0	0
1994	0	0	0
1995	0	0	0
1996	0	0	0
1997	29	381	0
1998	0	0	0
1999	0	0	0
2000	0	0	0
2001	0	0	253
2002	0	0	0
2003	0	0	0
2004	0	0	0
2005	0	0	0
2006	0	0	0
2007	0	0	0
2008	0	0	0
2009	0	0	0
2010	0	0	0
SUPPLY AVAILABLE TO BPA (incremental aMW by year)			
1991	0	0	0
1992	0	0	0
1993	0	0	0
1994	0	0	0
1995	0	0	0
1996	0	0	0
1997	7	95	0
1998	0	0	0
1999	0	0	0
2000	0	0	0
2001	0	0	63
2002	0	0	0
2003	0	0	0
2004	0	0	0
2005	0	0	0
2006	0	0	0
2007	0	0	0
2008	0	0	0
2009	0	0	0
2010	0	0	0

Resource: WIND
File: DTWINB.XLS
Date: 6/29/91
Revision: B

	Wind-1	Wind-2	Wind-3
REGIONAL SUPPLY (cumulative aMW by year)			
1991	0	0	0
1992	0	0	0
1993	0	0	0
1994	0	0	0
1995	0	0	0
1996	0	0	0
1997	29	381	0
1998	29	381	0
1999	29	381	0
2000	29	381	0
2001	29	381	253
2002	29	381	253
2003	29	381	253
2004	29	381	253
2005	29	381	253
2006	29	381	253
2007	29	381	253
2008	29	381	253
2009	29	381	253
2010	29	381	253
SUPPLY AVAILABLE TO BPA (cumulative aMW by year)			
1991	0	0	0
1992	0	0	0
1993	0	0	0
1994	0	0	0
1995	0	0	0
1996	0	0	0
1997	7	95	0
1998	7	95	0
1999	7	95	0
2000	7	95	0
2001	7	95	63
2002	7	95	63
2003	7	95	63
2004	7	95	63
2005	7	95	63
2006	7	95	63
2007	7	95	63
2008	7	95	63
2009	7	95	63
2010	7	95	63

Note: SOURCE: 1991 Northwest Conservation and Electric Power Plan.

Note: EQ. AVAILABILITY: These figures were set equal to the capacity factor.

Note: ENERGY DISTRIBUTION: Seasonal distributions were taken from DTWINA.WK1.

Note: TRANSMISSION ADJ: Transmission adjustment is based on the distance of the site from the west side of the Cascades. Source: Matheson to Rohe, 28 Apr 91 "Cost of Transmission Facilities." The weighted average costs is calculated based on which zones that the sites are located. See WIND.XLS for calcultion.

Resource: WNP-1 & -3
File: DTWNPC.XLS
Date: 12/1/91
Revision: C

RESOURCE DATA SHEET

INPUTS:
% of Regional Supply Allocated to BPA 100%

RESOURCE IDENTIFIER	WNP-1L	WNP-1H	WNP-3L	WNP-3H
PLANT CHARACTERISTICS				
Site	Hanford	Hanford	Satsop	Satsop
Fuel Source	N/A	N/A	N/A	N/A
Operating Life (yrs)	40	40	40	40
Unit Size (MW)	1250	1250	1240	1240
Equivalent Availability (%)	65%	65%	65%	65%
Anticipated Capacity Factor (%)	65%	65%	65%	65%
Heat Rate (Btu/kWh)	0	0	0	0
Energy by Month (% of total)				
Jan	10.0%	10.0%	10.0%	10.0%
Feb	10.0%	10.0%	10.0%	10.0%
Mar	10.0%	10.0%	10.0%	10.0%
Apr	0.0%	0.0%	0.0%	0.0%
May	0.0%	0.0%	0.0%	0.0%
Jun	10.0%	10.0%	10.0%	10.0%
Jul	10.0%	10.0%	10.0%	10.0%
Aug	10.0%	10.0%	10.0%	10.0%
Sep	10.0%	10.0%	10.0%	10.0%
Oct	10.0%	10.0%	10.0%	10.0%
Nov	10.0%	10.0%	10.0%	10.0%
Dec	10.0%	10.0%	10.0%	10.0%

Resource: WNP-1 & -3
File: DTWNPC.XLS
Date: 12/1/91
Revision: C

	WNP-1L	WNP-1H	WNP-3L	WNP-3H
COSTS (1990 Dollars)				
Financial Life (years)	30	30	30	30
Siting & Licensing ($/kW)	0	0	0	0
Construction ($/kW)	1302	1302	1137	1137
Transmission Adjustment ($/kW)	128	128	0	0
Total Capital Cost ($/kW)	1430	1430	1137	1137
Siting & Licensing Hold Cost ($/kW/yr)	0.00	0.00	0.00	0.00
Fixed O&M ($/kW/yr)	84.59	109.21	90.26	116.53
Variable O&M (mills/kWh)	5.4	5.4	5.4	5.4
Fixed Fuel ($/kW/yr)	0	0	0	0
Variable Fuel ($/million Btu)	0	0	0	0
Variable Fuel (calc mills per kWh)	0	0	0	0
CONSTRUCTION CASH FLOW (% of Capital)				
1	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%	0.0%
3	11.0%	11.0%	4.0%	4.0%
4	23.0%	23.0%	24.0%	24.0%
5	29.0%	29.0%	33.0%	33.0%
6	24.0%	24.0%	29.0%	29.0%
7	13.0%	13.0%	10.0%	10.0%
8	0.0%	0.0%	0.0%	0.0%
9	0.0%	0.0%	0.0%	0.0%
10	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%
LEAD TIMES				
Siting & Licensing (years)	N/A	N/A	N/A	N/A
Probability of S&L Success (%)	100%	100%	100%	100%
Probability of Hold Success (%)	90%	90%	90%	90%
Construction Lead Time (years)	N/A	N/A	N/A	N/A
Total Lead Time (years)	7	7	7	7
Maximum Option Shelf Life (years)	N/A	N/A	N/A	N/A

Resource: WNP-1 & -3
File: DTWNPC.XLS
Date: 12/1/91
Revision: C

	WNP-1L	WNP-1H	WNP-3L	WNP-3H
REGIONAL SUPPLY (incremental aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	0	0	0	0
1994	0	0	0	0
1995	0	0	0	0
1996	0	0	0	0
1997	0	0	0	0
1998	813	813	806	806
1999	0	0	0	0
2000	0	0	0	0
2001	0	0	0	0
2002	0	0	0	0
2003	0	0	0	0
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0
SUPPLY AVAILABLE TO BPA (incremental aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	0	0	0	0
1994	0	0	0	0
1995	0	0	0	0
1996	0	0	0	0
1997	0	0	0	0
1998	813	813	806	806
1999	0	0	0	0
2000	0	0	0	0
2001	0	0	0	0
2002	0	0	0	0
2003	0	0	0	0
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0

Resource: WNP-1 & -3
File: DTWNPC.XLS
Date: 12/1/91
Revision: C

	WNP-1L	WNP-1H	WNP-3L	WNP-3H
REGIONAL SUPPLY (cumulative aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	0	0	0	0
1994	0	0	0	0
1995	0	0	0	0
1996	0	0	0	0
1997	0	0	0	0
1998	813	813	806	806
1999	813	813	806	806
2000	813	813	806	806
2001	813	813	806	806
2002	813	813	806	806
2003	813	813	806	806
2004	813	813	806	806
2005	813	813	806	806
2006	813	813	806	806
2007	813	813	806	806
2008	813	813	806	806
2009	813	813	806	806
2010	813	813	806	806
SUPPLY AVAILABLE TO BPA (cumulative aMW by year)				
1991	0	0	0	0
1992	0	0	0	0
1993	0	0	0	0
1994	0	0	0	0
1995	0	0	0	0
1996	0	0	0	0
1997	0	0	0	0
1998	813	813	806	806
1999	813	813	806	806
2000	813	813	806	806
2001	813	813	806	806
2002	813	813	806	806
2003	813	813	806	806
2004	813	813	806	806
2005	813	813	806	806
2006	813	813	806	806
2007	813	813	806	806
2008	813	813	806	806
2009	813	813	806	806
2010	813	813	806	806

Note: SOURCE: WNP-1 & -3 Study, 1986. Costs inflated to 1990 dollars.

Note: EQ. AVAILABILITY: These figures were set equal to the capacity factor.

Note: REVISION C: This revision corrects the planned maintenance outage period as well as the probabilities of siting and hold success.

Note: TRANSMISSION ADJ: Transmission adjustment is based on the distance of the site from the west side of the Cascades. Source: Matheson to Rohe, 28 Apr 91 "Cost of Transmission Facilities."

Note: FIXED O&M: Ranges for the fixed O&M estimates were developed by BPA Richland office. Fised O&M costs assume no real escalation for the low case; high case is based on WNP-2/Trojan experience between 1986 and 1990.

Note: VARIABLE O&M: Variable O&M reflects real decrease in projected fuel costs over the period 1986-90.

APPENDIX D

ODOE Wind Resource Scenario

This appendix contains the results of calculating the levelized cost of wind energy based on data supplied by Oregon Department of Energy (ODOE). These calculations and the background data are provided in this document for review and comment.

This appendix contains the following:

(1) A summary sheet comparing the current assumptions against the ODOE assumptions.

(2) ODOE's memo describing the alternative assumptions as well as rationale for these assumptions.

(3) The resource data sheet (DTBAIN.XLS) containing the assumptions proposed by ODOE.

(4) The Microfin spreadsheets showing the inputs and results.

ODOE Wind Resource Scenario
Summary Sheet

Table 1 compares the levelized cost of the wind resource using BPA/Council assumptions compared to ODOE's projections of wind turbine cost and performance.

Table 1
Levelized Cost of Wind Resource - On-Line 2000
(mills/kWh)

	Real	Real	Nominal	Nominal
	BPA/Council[1]	ODOE Scenario	BPA/Council	ODOE Scenario
Wind-1	47	32	92	63
Wind-2	63	42	123	81
Wind-3	72	46	140	89

[1] Figures reported by the Council may differ slightly due to different financing assumptions and different on-line dates.

Table 2
Regional Supply of Wind Resource
(aMW)

	BPA/Council	ODOE Scenario
Wind-1	29	40
Wind-2	381	153
Wind-3	253	269
Total	663	462

INTEROFFICE MEMO

TO: Mike Berger, BPA 9/16/91

FROM: Don Bain, ODOE

RE: <u>SITE, TRANSMISSION COST AND SEASONALITY ADJUSTMENTS</u>

In reviewing the data on worksheet WIND.XLS, I noticed several figures that should be changed. The net result is that the transmission cost adders for Wind 1, 2 & 3 are different. It appears that some transmission costs were misapplied and some sites incorrectly rated. Also, the monthly energy distribution for Wind-1 is not right. These errors should be corrected for the 1992 resource program calculations.

<u>Recommended Site Changes</u>

Four sites should be changed - Cape Flattery, Sevenmile Hill, Coyote Hills, and Sieban 2. Except for Sieban 2, each site was rated for significantly less installed capacity that the referenced NPPC wind sites. The changes are:

Cape Flattery

This site should be rated at 27 MW and 9 AMW.

Sevenmile Hill

This site, after deducting 25% for Gorge Scenic Area siting restrictions, should be 21 MW and 6 AMW.

Coyote Hills

This site should be 26 MW and 6 AMW.

Sieban 2

This site should be deleted and Sieban 1 substituted at 98 MW and 23 AMW.

<u>Recommended Transmission Cost Changes</u>

There are three categories of transmission changes. First, information from the Montana Power Company RFP and PNUCC's <u>Blackfeet Area Wind Integration Study</u> should be used. Second, low capacity sites in central Washington with BPA lines in close proximity should have different figures. Third, the transmission cost for Sieban 1 should be $450/kW, not $128/kW.

During the PNUCC study, BPA transmission staff determined that approximately 100 MW of wind capacity could be exported west from Blackfeet 1 with existing transmission facilities, i.e., the transmission cost adjustment for the first 100 MW should be 0. At $450/kW, $45 M should be deducted from the $202.5 M figure used on WIND.XLS.

The Montana Power Company has released an RFP for resource needs in the '96 - '00 time frame. MPC will need 152 MW of capacity and 115 AMW primarily to replace expiring contracts. Because this amount is currently being delivered, existing transmission capacity is sufficient for at least 152 MW in '96, i.e., the first increment of wind capacity should have a transmission adder of 0. Sites Sieban 1 & 2 , Livingston, and Great Falls are within MPC's service territory, and are adjacent to its lines and major load centers. Their potential is 813 MW. The wind data and land area at Livingston and Great Falls (715 MW potential) will attract developers in the near term and I would be surprised if MPC did not get at least one wind proposal. Assuming that the first 150 MW of wind potential split between Livingston and Great Falls has 0 transmission adder, $33.75 M each should be deducted from their cost on WIND.XLS.

Sieban 1 & 2 are within Montana, east of the Continental Divide. To be consistent in the application of transmission adjustment costs, it should have a transmission cost adjustment of $450/kW.

The sites in the Columbia River gorge and central Washington are less than 80 MW each, and large BPA lines through each site or very close by. The sites run east along the Columbia River from Sevenmile Hill at The Dalles to Roosevelt. Further east, Horse Heaven hills near Kennewick has major BPA lines through it as does Rattlesnake Mountain just north. None of these sites should have adjustments for extra transmission to the I-5 corridor, i.e., their $128/kW adder should be $0. The sites are Columbia Hills West, East 1 & 2; Rattlesnake Mountain 1 & 2; Sevenmile Hill; Goodnoe Hills; Klondike 1; and Kittitas Valley East. Klondike 2 should remain $128/kW due to its size.

There are several reasons the adder for these central sites should be 0. First, the size of the projects and their low average power is not likely to need grid reinforcements given the number and capacity of adjacent lines. Second, during hours when peak power exceeds capacity to I-5, the energy can be stored as water behind the dams to be released later in the diurnal cycle. There is much hydro capacity in the immediate area. Third, loss of main stem water for fish will release capacity for alternative generation in the area.

<u>Net Affects Of Site & Cost Changes</u>

Wind 1, 2, & 3 have changes in the MW of wind, total transmission adjustment and the resultant $/kW adjustment. Wind 1 now has 124 MW & $2432 or $20/kW transmission adjustment. Wind 2 has 1458 MW & $424678 or $291/kW. Wind 3 has 1230 MW & $177348 or $144/kW. The $/kW adjustments should be carried through on page 2 of DTWINB.XLS.

Monthly Energy Distributions

I checked the distribution of monthly energy generation for Wind-1 in DTWINB.XLS. It caught my eye because all figures were rounded differently than used in Wind-2 or Wind-3. I believe that the stated figures are an eyeball estimate based on monthly average wind speeds for one of the 6 sites in Wind-1. Unfortunately, the relationship between reported average wind speeds and energy production is not that simple.

There often is a linear relationship between average wind speed at a turbine's hub height and capacity factor (over the 12 to 18 mph range). However, the relationship is unique for each turbine. Derivation and use of such a function requires that all else be held equal including wind shear, measurement height, and wind speed distribution. Unless these conditions are met, estimates made by this method are bound to be way off, with a corresponding effect on cost of energy. Among the forty sites in the NPPC's supply curve there are significant variations in all these factors.

Two years ago I calculated the monthly "spread factors" for a number of wind sites for the NPPC. They are based on rerunning the wind turbine performance model using each month's wind data at each of the sites where the data exists. All else was held equal at each site relative to the annual calculations used for the supply curves. Spread factors are a multiple of 1/12 of the annual energy production. They can be converted to monthly percentages by multiplying them by 1/12. I was able to compute the monthly energy percentages for Wind-1 using 5 of it's 6 sites or 75 percent of Wind-1's AMW. The amounts that should be used in DTWINB.XLS Energy by Month are:

Jan	4.7%
Feb	7.6%
Mar	9.3%
Apr	9.2%
May	10.9%
Jun	9.9%
Jul	9.0%
Aug	9.3%
Sep	7.9%
Oct	6.5%
Nov	7.7%
Dec	8.1%

I did not check Wind-2 or Wind-3 but can do so. They should not be identical. Monthly spread factors exist for 98% of Wind-2's AMW and 87% of Wind-3's AMW.

cc: J. King, NPPC
S. Bailey, BPA
P. Carver, ODOE

Resource: **WIND**
File: **DTBAIN.XLS**
Date: **12/1/91**
Revision: **None**

RESOURCE DATA SHEET

INPUTS:
% of Regional Supply Allocated to BPA 25%

RESOURCE IDENTIFIER	Wind-1	Wind-2	Wind-3
PLANT CHARACTERISTICS			
Site			
Fuel Source	N/A	N/A	N/A
Operating Life (yrs)	40	40	40
Unit Size (MW)	20	30	30
Equivalent Availability (%)	33%	30%	22%
Anticipated Capacity Factor (%)	33%	30%	22%
Heat Rate (Btu/kWh)	0	0	0
Energy by Month (% of total)			
Jan	4.7%	14.3%	14.3%
Feb	7.6%	9.2%	9.2%
Mar	9.3%	9.9%	9.9%
Apr	9.2%	8.7%	8.7%
May	10.9%	4.2%	4.2%
Jun	9.9%	5.8%	5.8%
Jul	9.0%	5.6%	5.6%
Aug	9.3%	4.3%	4.3%
Sep	7.9%	5.8%	5.8%
Oct	6.5%	7.1%	7.1%
Nov	7.7%	12.3%	12.3%
Dec	8.0%	12.8%	12.8%

Resource: **WIND**
File: **DTBAIN.XLS**
Date: **12/1/91**
Revision: **None**

	Wind-1	Wind-2	Wind-3
COSTS (1990 Dollars)			
Financial Life (years)	30	30	30
Siting & Licensing ($/kW)	16	17	16
Construction ($/kW)	887	939	876
Transmission Adjustment ($/kW)	20	291	144
Total Capital Cost ($/kW)	923	1247	1036
Siting & Licensing Hold Cost ($/kW/yr)	4.00	4.00	4.00
Fixed O&M ($/kW/yr)	5	5	5
Variable O&M (mills/kWh)	10.3	10.5	10.2
Fixed Fuel ($/kW/yr)	0	0	0
Variable Fuel ($/million Btu)	0	0	0
Variable Fuel (calc mills per kWh)	0.0	0.0	0.0
CONSTRUCTION CASH FLOW (% of Capital)			
1	10.0%	10.0%	10.0%
2	90.0%	90.0%	90.0%
3	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%
5	0.0%	0.0%	0.0%
6	0.0%	0.0%	0.0%
7	0.0%	0.0%	0.0%
8	0.0%	0.0%	0.0%
9	0.0%	0.0%	0.0%
10	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%
LEAD TIMES			
Siting & Licensing (years)	1	1	1
Probability of S&L Success (%)	90%	90%	90%
Probability of Hold Success (%)	90%	90%	90%
Construction Lead Time (years)	1	1	1
Total Lead Time (years)	2	2	2
Maximum Option Shelf Life (years)	5	5	5

Resource: **WIND**
File: **DTBAIN.XLS**
Date: **12/1/91**
Revision: **None**

	Wind-1	Wind-2	Wind-3
REGIONAL SUPPLY (incremental aMW by year)			
1991	0	0	0
1992	0	0	0
1993	0	0	0
1994	20	0	0
1995	20	62	0
1996	0	60	20
1997	0	31	34
1998	0	0	115
1999	0	0	50
2000	0	0	50
2001	0	0	0
2002	0	0	0
2003	0	0	0
2004	0	0	0
2005	0	0	0
2006	0	0	0
2007	0	0	0
2008	0	0	0
2009	0	0	0
2010	0	0	0
SUPPLY AVAILABLE TO BPA (incremental aMW by year)			
1991	0	0	0
1992	0	0	0
1993	0	0	0
1994	5	0	0
1995	5	16	0
1996	0	15	5
1997	0	8	9
1998	0	0	29
1999	0	0	13
2000	0	0	13
2001	0	0	0
2002	0	0	0
2003	0	0	0
2004	0	0	0
2005	0	0	0
2006	0	0	0
2007	0	0	0
2008	0	0	0
2009	0	0	0
2010	0	0	0

Resource: **WIND**
File: **DTBAIN.XLS**
Date: **12/1/91**
Revision: **None**

	Wind-1	Wind-2	Wind-3
REGIONAL SUPPLY (cumulative aMW by year)			
1991	0	0	0
1992	0	0	0
1993	0	0	0
1994	20	0	0
1995	40	62	0
1996	40	122	20
1997	40	153	54
1998	40	153	169
1999	40	153	219
2000	40	153	269
2001	40	153	269
2002	40	153	269
2003	40	153	269
2004	40	153	269
2005	40	153	269
2006	40	153	269
2007	40	153	269
2008	40	153	269
2009	40	153	269
2010	40	153	269
SUPPLY AVAILABLE TO BPA (cumulative aMW by year)			
1991	0	0	0
1992	0	0	0
1993	0	0	0
1994	5	0	0
1995	10	16	0
1996	10	31	5
1997	10	38	14
1998	10	38	42
1999	10	38	55
2000	10	38	67
2001	10	38	67
2002	10	38	67
2003	10	38	67
2004	10	38	67
2005	10	38	67
2006	10	38	67
2007	10	38	67
2008	10	38	67
2009	10	38	67
2010	10	38	67

Note: SOURCE: Memo from Don Bain, ODOE, to Mike Berger, BPA, dated September 16, 1991,"Site and Transmission Cost Adjustments." This memo recommended changes to DTWINB.XLS.

Note: EQ. AVAILABILITY: These figures were set equal to the capacity factor.

Note: ENERGY DISTRIBUTION: Seasonal distributions were taken from DTWINA.WK1.

Note: TRANSMISSION ADJ: Transmission adjustment is based on the distance of the site from the west side of the Cascades. Source: Matheson to Rohe, 28 Apr 91 "Cost of Transmission Facilities." The weighted average costs is calculated based on which zones that the sites are located. See WINDA.XLS for calculation. Original figures from WIND.XLS were adjusted based on source document.

RESOURCE:	MICROFIN Version 2.0MT	RUN TIME:
DTBAIN.XLS Wind-1		08-Dec-91 5:20:17 PM

TAX RATES

FEDERAL	34.0%	FTAX
STATE	3.7%	STAX
INVESTMENT CREDIT	0.0%	ITC
INSURANCE	0.3%	INS
PROPERTY		
Public	0.0%	PTAX1
Private	0.0%	PTAX2
GROSS REVENUE		
Public	2.2%	GROSS1
Private	2.1%	GROSS2

FINANCIAL ASSUMPTIONS

PRICE LEVEL (year)	1990	BASEYR
FINANCIAL LIFE (years)	30	FINYRS
DEBT FRACTION		
Public	1.00	DEBTF1
Private	0.60	DEBTF2
NOMINAL DEBT INTEREST RATE		
Public	7.3%	DEBTR1
Private	9.7%	DEBTR2
NOMINAL RETURN ON EQUITY RATE		
Public	0.0%	EQR1
Private	12.5%	EQR2
REAL ESCALATION RATES		
Capital	1.2%	CAPESC
Fixed O & M	0.7%	FIXESC
Variable O & M	0.7%	VARESC
Fuel	1.0%	FUELESC
REAL DISCOUNT RATE	3.0%	DISC
INFLATION RATE	5.0%	INFL

SPONSORSHIP FRACTION			
Public		50.0%	SPONSOR1
Private		50.0%	SPONSOR2
PROJECT DATES			
Year Construction Begins		1998	YCB
Year-on-line		2000	YOL
PLANT CHARACTERISTICS			
Operating Life (years)		40	OPLIFE
Capacity (MW)	W/TRANS LOSS	20	CAP
Equivalent Availability	0.33	0.33	EA
Capacity Factor	0.33	0.33	CF
Heat Rate (BTU/kWh)		0	HR
COSTS			
Capital ($/kW)		923.00	CAPCST
Fixed O & M ($/kW/yr)		5.00	FIXCST
Variable O & M ($/kWh)		0.01030	VARCST
Fuel ($/Million BTU)		0.00	FUELCST

CONSTRUCTION PERIOD CASH FLOW DISTRIBUTION

Year	Direct Cost Distribution
1	10.00%
2	90.00%
3	0.00%
4	0.00%
5	0.00%
6	0.00%
7	0.00%
8	0.00%
9	0.00%
10	0.00%
Total	100.00%

OUTPUT SUMMARY

2000 Real Levelized Cost in 1990 mills/kWh	Public	Private	Combined
Capital	16.3	21.3	18.8
Fixed O & M	2.0	2.0	2.0
Variable O & M	11.7	11.6	11.6
Fuel	0.0	0.0	0.0
Total	29.9	34.9	32.4
Nominal	58.0	67.7	62.8
Ratebase ($1000)	$16,336	$17,373	$33,709
Annual Energy (MWh)	28,908	28,908	57,816
Real Fixed Charge Rate	0.045	0.059	0.052

RESOURCE:	MICROFIN Version 2.0MT	RUN TIME:
DTBAIN.XLS		08-Dec-91
Wind-2		5:21:05 PM

TAX RATES

FEDERAL	34.0%	FTAX
STATE	3.7%	STAX
INVESTMENT CREDIT	0.0%	ITC
INSURANCE	0.3%	INS
PROPERTY		
Public	0.0%	PTAX1
Private	0.0%	PTAX2
GROSS REVENUE		
Public	2.2%	GROSS1
Private	2.1%	GROSS2

FINANCIAL ASSUMPTIONS

PRICE LEVEL (year)	1990	BASEYR
FINANCIAL LIFE (years)	30	FINYRS
DEBT FRACTION		
Public	1.00	DEBTF1
Private	0.60	DEBTF2
NOMINAL DEBT INTEREST RATE		
Public	7.3%	DEBTR1
Private	9.7%	DEBTR2
NOMINAL RETURN ON EQUITY RATE		
Public	0.0%	EQR1
Private	12.5%	EQR2
REAL ESCALATION RATES		
Capital	1.2%	CAPESC
Fixed O & M	0.7%	FIXESC
Variable O & M	0.7%	VARESC
Fuel	1.0%	FUELESC
REAL DISCOUNT RATE	3.0%	DISC
INFLATION RATE	5.0%	INFL

PROJECT DESCRIPTION

SPONSORSHIP FRACTION			
Public		50.0%	SPONSOR1
Private		50.0%	SPONSOR2
PROJECT DATES			
Year Construction Begins		1998	YCB
Year-on-line		2000	YOL
PLANT CHARACTERISTICS			
Operating Life (years)		40	OPLIFE
Capacity (MW)	W/TRANS LOSS	30	CAP
Equivalent Availability	0.3	0.30	EA
Capacity Factor	0.3	0.30	CF
Heat Rate (BTU/kWh)		0	HR
COSTS			
Capital ($/kW)		1247.00	CAPCST
Fixed O & M ($/kW/yr)		5.00	FIXCST
Variable O & M ($/kWh)		0.01050	VARCST
Fuel ($/Million BTU)		0.00	FUELCST

CONSTRUCTION PERIOD CASH FLOW DISTRIBUTION

Year	Direct Cost Distribution
1	10.00%
2	90.00%
3	0.00%
4	0.00%
5	0.00%
6	0.00%
7	0.00%
8	0.00%
9	0.00%
10	0.00%
Total	100.00%

OUTPUT SUMMARY

2000 Real Levelized Cost in 1990 mills/kWh	Public	Private	Combined
Capital	24.2	31.7	27.9
Fixed O & M	2.2	2.2	2.2
Variable O & M	11.9	11.9	11.9
Fuel	0.0	0.0	0.0
Total	38.2	45.7	41.9
Nominal	74.1	88.6	81.4
Ratebase ($1000)	$33,106	$35,207	$68,313
Annual Energy (MWh)	39,420	39,420	78,840
Real Fixed Charge Rate	0.045	0.059	0.052

RESOURCE:	MICROFIN Version 2.0MT	RUN TIME:
DTBAIN.XLS Wind-3		08-Dec-91 5:21:52 PM

TAX RATES

FEDERAL	34.0%	FTAX
STATE	3.7%	STAX
INVESTMENT CREDIT	0.0%	ITC
INSURANCE	0.3%	INS
PROPERTY		
Public	0.0%	PTAX1
Private	0.0%	PTAX2
GROSS REVENUE		
Public	2.2%	GROSS1
Private	2.1%	GROSS2

FINANCIAL ASSUMPTIONS

PRICE LEVEL (year)	1990	BASEYR
FINANCIAL LIFE (years)	30	FINYRS
DEBT FRACTION		
Public	1.00	DEBTF1
Private	0.60	DEBTF2
NOMINAL DEBT INTEREST RATE		
Public	7.3%	DEBTR1
Private	9.7%	DEBTR2
NOMINAL RETURN ON EQUITY RATE		
Public	0.0%	EQR1
Private	12.5%	EQR2
REAL ESCALATION RATES		
Capital	1.2%	CAPESC
Fixed O & M	0.7%	FIXESC
Variable O & M	0.7%	VARESC
Fuel	1.0%	FUELESC
REAL DISCOUNT RATE	3.0%	DISC
INFLATION RATE	5.0%	INFL

SPONSORSHIP FRACTION			
Public		50.0%	SPONSOR1
Private		50.0%	SPONSOR2
PROJECT DATES			
Year Construction Begins		1998	YCB
Year-on-line		2000	YOL
PLANT CHARACTERISTICS			
Operating Life (years)		40	OPLIFE
Capacity (MW)	W/TRANS LOSS	30	CAP
Equivalent Availability	0.22	0.22	EA
Capacity Factor	0.22	0.22	CF
Heat Rate (BTU/kWh)		0	HR
COSTS			
Capital ($/kW)		1036.00	CAPCST
Fixed O & M ($/kW/yr)		5.00	FIXCST
Variable O & M ($/kWh)		0.01020	VARCST
Fuel ($/Million BTU)		0.00	FUELCST

CONSTRUCTION PERIOD CASH FLOW DISTRIBUTION

Year	Direct Cost Distribution
1	10.00%
2	90.00%
3	0.00%
4	0.00%
5	0.00%
6	0.00%
7	0.00%
8	0.00%
9	0.00%
10	0.00%
Total	100.00%

OUTPUT SUMMARY

2000 Real Levelized Cost in 1990 mills/kWh	Public	Private	Combined
Capital	27.4	35.9	31.6
Fixed O & M	2.9	2.9	2.9
Variable O & M	11.5	11.5	11.5
Fuel	0.0	0.0	0.0
Total	41.9	50.3	46.1
Nominal	81.2	97.7	89.4
Ratebase ($1000)	$27,504	$29,250	$56,754
Annual Energy (MWh)	28,908	28,908	57,816
Real Fixed Charge Rate	0.045	0.059	0.052