27
12-27-79

United States Department of Energy

PNL-RAP-36 Vol. III
UC-11

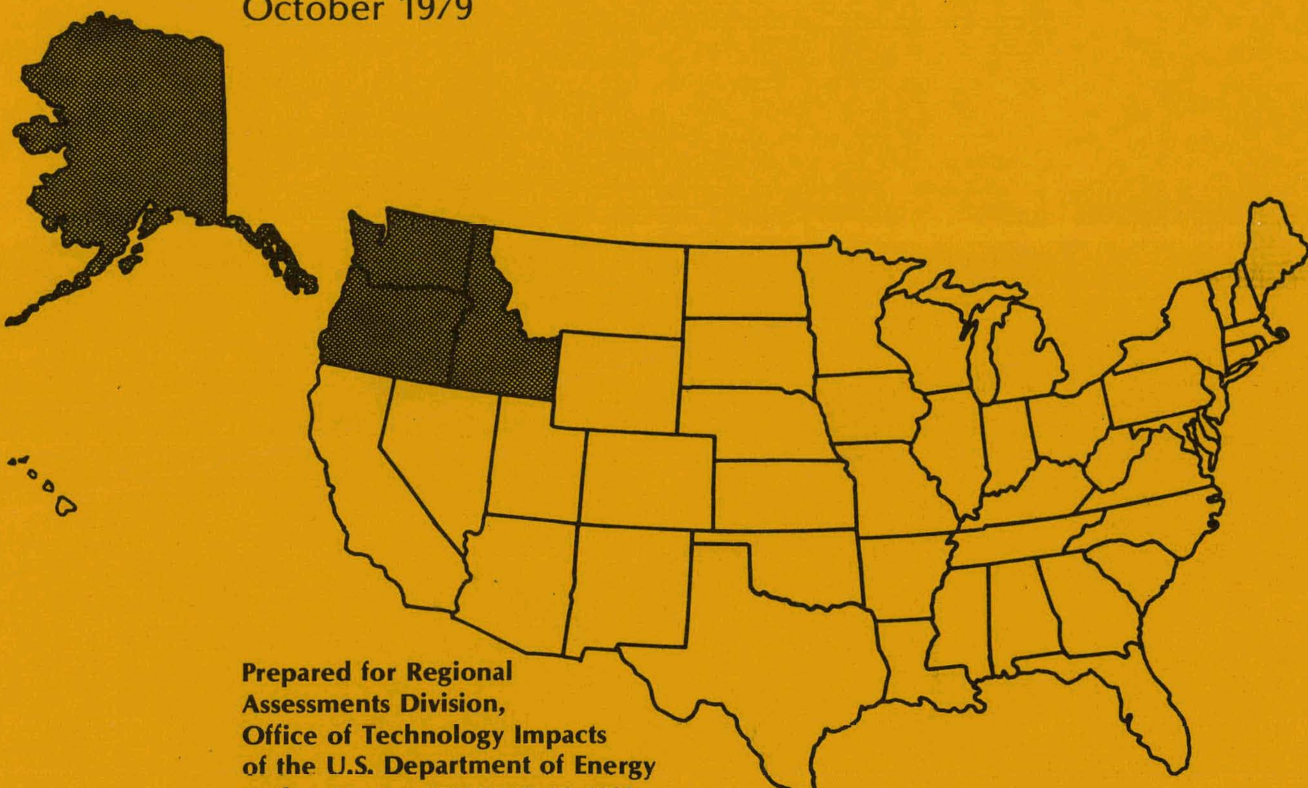
REGIONAL ASSESSMENT PROGRAM

Regional Issue Identification and Assessment (RIIA):

Volume III: Institutional Barriers to Developing Power Generation Facilities in the Pacific Northwest

MASTER

October 1979



Prepared for Regional Assessments Division, Office of Technology Impacts of the U.S. Department of Energy under Contract EY-76-C-06-1830

DOE Project Monitor: Arthur M. Katz

Pacific Northwest Laboratory
Operated for the U.S. Department of Energy
by Battelle Memorial Institute

Battelle Human Affairs Research Centers
Seattle, Washington 98105

Battelle

DISCLAIMER

PACIFIC NORTHWEST LABORATORY
operated by
BATTELLE
for the
UNITED STATES DEPARTMENT OF ENERGY
Under Contract EY-76-C-06-1830

Printed in the United States of America
Available from
National Technical Information Service
United States Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22151

Price: Printed Copy $_____*; Microfiche $3.00

*Pages	NTIS Selling Price
001-025	$4.00
026-050	$4.50
051-075	$5.25
076-100	$6.00
101-125	$6.50
126-150	$7.25
151-175	$8.00
176-200	$9.00
201-225	$9.25
226-250	$9.50
251-275	$10.75
276-300	$11.00

PNL-RAP-36

UC-11

REGIONAL ISSUE IDENTIFICATION AND ASSESSMENT (RIIA)

VOLUME III: INSTITUTIONAL BARRIERS TO DEVELOPING POWER GENERATION FACILITIES IN THE PACIFIC NORTHWEST

Prepared by:

F. A. Morris
C. H. Sawyer
J. H. Maxwell

October 1979

Prepared for Regional Assessments Division
Office of Technology Impacts
of the U.S. Department of Energy
Under Contract EY-76-C-06-1830

DOE Project Monitor: Arthur M. Katz

Battelle Human Affairs Research Centers
Seattle, Washington 98105

Pacific Northwest Laboratory
Richland, Washington 99352

<u>TABLE OF CONTENTS</u>

INSTITUTIONAL BARRIERS TO DEVELOPING POWER GENERATION FACILITIES IN THE PACIFIC NORTHWEST

INTRODUCTION

The Regional Assessments Division in the U.S. Department of Energy (DOE) has undertaken a program to assess the probable consequences of various national energy policies in regions of the United States and to evaluate the constraints on national energy policy imposed by conditions in these regions. The program is referred to as the Regional Issues Identification and Assessment (RIIA) Program.

Currently the RIIA Program is evaluating the Trendlong Mid-Mid scenario, a pattern of energy development for 1985 and 1990 derived from the Project Independence Evaluation System (PIES) model. This scenario assumes a medium annual growth rate in both the national demand for and national supply of energy. It has been disaggregated to specify the generating capacity to be supplied by each energy source in each state. The scenario does not represent a prediction. Rather, it provides a hypothetical baseline against which to evaluate the impacts and constraints associated with a particular pattern of energy development.

Pacific Northwest Laboratory (PNL) has the responsibility for evaluating the scenario for the Federal Region 10, consisting of Alaska, Idaho, Oregon, and Washington. PNL is identifying impacts and constraints associated with realizing the scenario in a variety of categories, including air and water quality impacts, health and safety effects, and socioeconomic impacts. This report summarizes the analysis of one such category: institutional constraints--defined to include legal, organizational, and political barriers to the achievement of the scenario in the Northwest.

This assignment has several inherent limitations. First, the scenario for the Northwest focuses primarily on electric power generation. Not only are the production and consumption of other energy sources important, but many of these sources compete directly with electricity in end use. For example, geothermal energy, natural gas, and oil are alternative sources of space and process heat. Second, the scenario projects capacity rather than energy. This emphasis may be misleading, especially in a region such as the Northwest that relies heavily on hydropower. Capacity refers to the maximum instantaneous power output of a generating facility. Energy refers to power output over time. While capacity determines the peak load that a facility or system can handle for a short duration, available energy determines the ability of a facility or system to handle loads over a longer period. Third, the scenario projections do not include several potentially important sources of electric energy: wind, biomass, solar. Fourth, the scenario disaggregates its projections to the state level. Because generating facilities in Idaho, Oregon, and Washington are interconnected through the transmission facilities of the Bonneville Power Administration, state-by-state analysis of the regional power system can be misleading. Fifth, the scenario projections for Alaska, which specify a 50% reduction in generating capacity, are highly unrealistic.

This report attempts to work within these limitations. First, it focuses on power generation. Second, it concentrates primarily on barriers to expanding electrical generating capacity. Third, it deals only tangentially with generation technologies other than those specified in the scenario. Fourth, it does attempt to provide some regional, as opposed to solely state, perspective by including an introductory chapter on regional power arrangements. Finally, this report does not deal with Alaska: while there are many important institutional issues in the energy field confronting that state, the unrealistic scenario figures provide a poor basis for discussing them. These limitations should be kept in mind in reading this report.

The report contains five chapters. Chapter One is an executive summary. Chapter two provides an overview and institutional analysis of regional power arrangements. Chapters three, four, and five identify institutional constraints to achievement of the scenario in Idaho, Oregon, and Washington respectively.

The authors wish to acknowldege the support and guidance provided for this study by the Regional Assessments Division in DOE.

CHAPTER ONE: EXECUTIVE SUMMARY

Table 1 presents the scenario's projections of electrical generation capacity in each northwestern state by energy source, together with current capacity. Table 2 summarizes the degree and nature of the institutional constraints to realization of each scenario element that involves a significant increase in capacity. With several exceptions, these constraints are relatively modest.

1.1 IDAHO

1.1.1 Hydroelectric

The scenario appears likely to be fully realized in Idaho. Most of the capacity there is to be hydroelectric. Current plans call for addition to hydroelectric capacity well beyond the level specified in the scenario. Although many of these plans are still preliminary, no particular opposition has developed; only about one third of this capacity need be built to realize the scenario.

1.1.2 Geothermal

As in the other states, realization of the geothermal portion of the scenario faces severe technical and economic problems. However, much of the moderate temperature power generation technology necessary to make geothermal power economically competitive is being developed in Idaho. The U. S. Department of Energy, the Idaho Water Resources Board, and various state utilities are participating. Therefore, if the technology proves commercially feasible, the institutional climate in Idaho appears relatively favorable.

1.2 OREGON

1.2.1 Nuclear

The institutional constraints to achievement of the scenario are perhaps most severe in Oregon. Political opposition to nuclear power in the state is significant, and opponents have some levers to delay the new

TABLE 1

Current Capacity and RIIA Scenario I for Electrical Power Generation
In the Pacific Northwest Region
(Capacity in Megawatts)

STATE	YEAR	GAS PEAKING	OIL PEAKING	NUCLEAR	COMBINED CYCLE	COAL STEAM	GAS STEAM	OIL STEAM	HYDRO	GEOTHERMAL	TOTAL
Alaska*											
Current capacity	1978	510	416		0	54	14	0	131		1,125
Scenario	1985	0	392		0	150	0	15	0		557
	1990	0	392		0	150	0	15	0		557
Idaho											
Current capacity	1978	50	5						1,631	0	1,686
Scenario	1985	50	0						2,182	0	2,232
	1990	0	50						2,182	200	2,432
Oregon											
Current capacity	1978		392	1,216	585	0	36	85	7,445	0	9,759
Scenario	1985		718	1,130	100	500	15	175	8,654	0	11,292
	1990		718	2,390	100	500	15	175	8,809	400	13,102
Washington											
Current capacity	1978		130	800	0	1,330		208	13,791	0	16,559
Scenario	1985		263	5,702	510	1,200		0	19,335	0	27,330
	1990		261	6,942	510	1,200		0	19,655	400	29,268
Total Region											
Current capacity	1978	626	730	2,016	585	1,384	50	293	22,990	0	29,129
Scenario	1985	50	1,373	6,832	610	1,850	15	190	30,191	0	41,411
	1990	0	1,421		610	1,850	15	190	30,941	1,000	45,359

*Presented here for reference only.

TABLE 2

Institutional Constraints to Realization of the Scenario

STATE	NUCLEAR	COAL STEAM	HYDROELECTRIC	GEOTHERMAL
Idaho			Low o Capacity planned well in excess of scenario.	Medium o Arrangements for transferring Raft River facility and resources undeveloped. o But state procedures established. o Utilities already involved.
Oregon	Medium o EFSC certification questionable and likely to be appealed. o Financial uncertainty created by prohibition or inclusion of CWIP in rate base.	Low o Construction in progress.	High o Planned capacity represents only 67% of scenario.	Medium o Federal procedures very sluggish. o But state procedures partially established. o Utilities partially involved.
Washington	Low o State siting permits granted. o NRC construction permits granted.		Low o 80% of capacity likely to be completed. o 20% of capacity still in early planning, facing some legal and political obstacles.	High o State laws unclear. o State procedures not established. o Federal procedures sluggish

nuclear facility embodied in the scenario. State site certification hearings have been reopened to consider the implications of the events at Three Mile Island. Whatever the decision of the siting council, it is likely to be appealed to the Oregon Supreme Court. Oregon voters have recently banned inclusion of "construction work in progress" in the rate base, creating financial uncertainties for the plant's builders. Moreover, NRC regulatory responses to the events at Three Mile Island could also delay construction.

1.2.2 Hydroelectric

The hydroelectric portion of the Oregon scenario may not be realized because currently planned additions to capacity do not include construction of pumped storage facilities. Lead times are sufficiently long that should more utilities begin planning the requisite capacity immediately, even modest political opposition could delay completion of the facilities within the time frame of the scenario.

1.2.3 Geothermal

In addition to problems of technical and economic feasibility, the development of geothermal electricity generation in Oregon must contend with exceptionally slow federal responses to applications for geothermal leases in the state. However, state procedures are reasonably well established and at least some utilities are actively pursuing the development of geothermal resources—at least to the stage of acquiring leases on private property. While technical considerations are likely to dominate, the institutional climate for geothermal is somewhat more favorable in Oregon than in Washington, though not so favorable as in Idaho.

1.2.4 Coal Steam

The coal steam plant at Boardman, Oregon, is midway through construction and is likely to be completed well before 1985.

1.3 WASHINGTON

1.3.1 Nuclear

In Washington, the nuclear facilities included in the scenario are under construction. State siting permits and NRC construction permits have been granted. Political opponents of these nuclear projects in the state such as the Crabshell Alliance have few legal channels left. Although cost escalation and charges of poor management may lead the Washington legislature to restructure the Washington Public Power Supply System, builder of the facilities, such a move is unlikely to delay completion of the facilities beyond 1990. Possible new NRC regulatory requirements imposed in the wake of the events at Three Mile Island could also slow completion, but probably not beyond 1990.

1.3.2 Hydroelectric

Most of the Washington additions to hydroelectric capacity in Washington are also sufficiently well advanced that they are likely to be in place by 1990. However, some 20% of the hydroelectric capacity required to meet the scenario is still in the very early planning stages. Of these, some federal projects may not receive necessary Congressional approval. Two projects proposed by Seattle City Light—the raising of High Ross Dam and the construction of a dam on Copper Creek--also face political and legal opposition that could block, or significantly delay them.

1.3.3 Geothermal

Technical and economic considerations tend to preclude the development of significant geothermal electrical generating capacity in Washington by 1990. Institutional considerations only compound the difficulties: the state has not developed statutory norms for leasing geothermal resources on state land; the state has not developed procedures for granting the required drilling permits on private or state land; and federal procedures for leasing federal land are at best expected to be slow.

THIS PAGE

WAS INTENTIONALLY

LEFT BLANK

CHAPTER TWO: INSTITUTIONAL ARRANGEMENTS FOR REGIONAL POWER GENERATION

Power generation in the Pacific Northwest is a regional undertaking. The Columbia River Basin drains major portions of Washington, Oregon, and Idaho. The Federal Columbia River Power System--the dams and generating facilities of the Army Corps of Engineers and the Bureau of Reclamation, and the transmission facilities and marketing authority of the Bonneville Power Administration (BPA)—accounts for 46% of the power produced in the three-state area.[1] The wheeling services of BPA's bulk transmission system also enable the public agencies and investor-owned utilities that produce the remainder of the region's power to buy and sell to each other through the Northwest Power Pool.

Physically, the regional power system is almost completely integrated. Institutionally, however, it is fragmented in important ways. Each state has autonomous institutions for siting and regulating power generation and transmission within that state's borders.[2] Each state contains a

---

[1] Comptroller General, Report to the Congress, Region at the Crossroads--The Pacific Northwest Searches for New Sources of Electric Energy (Washington, D.C.: General Accounting Office, EMD-78-76, August 10, 1978), p. 3.7. Investor-owned utilities account for 29% and publicly-owned utilities for 25% of the region's capacity.

[2] In Washington, the Energy Facility Site Evaluation Council must approve all nonfederal thermal power plants and power transmission facilities (RCW Ch. 80.50); the Washington Utilities and Transportation Commission regulates the rates of investor-owned utilities, (RCW Chs. 80.01, 80.04). In Idaho, the Public Utilities Commission issues certificates of convenience and necessity for the generating and transmission facilities of investor- owned utilities and regulates their rates (IC 61-101-61-714). In Oregon, the Energy Facilities Siting Council must approve all nonfederal power plants and power transmission facilities (ORS 469.300-469.580); the Public Utility Commission regulates the rates of investor-owned utilities (ORS 756.040).

different mix of public versus private utility ownership, and residential/rural versus commercial/industrial end-use.[3] The large number of regional power organizations and agreements, with their overlapping memberships and missions, complicates regional decisionmaking.[4] Until recently, the advantages of physical integration, coupled with the availability of inexpensive hydropower from the federal system, have overshadowed the potential difficulties posed by institutional fragmentation. As regional loads have begun to outstrip the supply of hydropower, however, the institutional issues have risen to the fore. Three are of central importance: (1) the allocation of existing, cheap hydropower; (2) the selection of alternative sources to serve future needs; and (3) the financing new power generation facilities. These issues raise both substantive and procedural questions. Substantively, who will receive federal hydropower and at what rates? What sources of energy will supply load growth? Who will provide the capital to finance these new sources? Procedurally, who will answer the substantive questions, according to what processes? What role will the state and federal governments, publicly owned and investor-owned utilities and various classes of consumers have in making substantive decisions? Resolution of these issues is likely to have far more impact on the course of power generation in the Northwest than the individual decisions of specific utilities in Idaho, Oregon, and Washington. At the same time, regional arrangements will importantly affect such decisions. This chapter provides a regional perspective that should be kept in

---

[3] Market shares are as follows: Washington, 77% publicly owned, 23% investor-owned; Oregon, 37% publicly owned, 63% investor-owned; Idaho, 14% publicly owned, 86% investor-owned. (U.S. Department of Energy, Office of the Regional Representative, "Regional Electric Power Planning Issues in the Pacific Northwest," Seattle, June 1978, p. 6.) End-use consumption is as follows: Washington, 31% residential, 3% irrigation, 66% commercial/industrial; Oregon 36% residential, 2% irrigation, 64% commercial/industrial; Idaho, 28% residential, 16% irrigation, 55% commercial/industrial. Computed from, Northwest Energy Policy Project, Energy Demand Modeling and Forecasting/Study Module II (Springfield, VA: National Technical Information Service, 1977), p. 109, "Energy Consumption 1974."

[4] Regional power organizations and agreements include: Northwest Power Pool, Pacific Northwest Coordination Agreement, Western Systems Coordinating Council, Mid-Columbia Hourly Coordination Agreements (investor-owned utilities, publicly owned utilities, and federal agencies); Pacific Northwest Utilities Conference Committee (investor-owned and publicly owned utilities); Columbia River Water Management Group (federal agencies); and Intercompany Pool (investor-owned utilities).

mind when reading the discussions on the institutional barriers to the specific facilities necessary for the achievement of the scenario.

This chapter is presented in three parts. The first sketches the background of these issues. The second states the currently proposed alternatives for their resolution. The third provides some analysis of possible outcomes.

2.1 BACKGROUND

The unique institutional arrangements for power generation in Idaho, Oregon, and Washington date from the construction of the Grand Coulee and Bonneville Dams by the Bureau of Reclamation and the Army Corps of Engineers in the 1930s. At that time, the Bonneville Project Act created the Bonneville Power Administration to market the federally generated power at wholesale prices and provide the requisite bulk transmission services.[5] To encourage the formation of publicly owned utilities, the Act gave public agencies first claim to BPA's hydropower in the form of the "preference clause." As a consequence, publicly owned utilities have prospered, especially in Washington.[6] Indeed, many have relied exclusively on BPA for power, as have direct industrial users (chiefly aluminum plants that sprang up before and during World War II). In addition, both investor-owned and publicly owned utilities have supplemented self-generated power with that purchased from BPA. BPA's role broadened further when it was authorized by Congress to transmit nonfederal as well as federal power. This action made possible a truly regional system in which a given facility might buy federal and nonfederal power and sell self-generated power, federal power, and power supplied by other utilities—all through Bonneville's high-voltage transmis-

[5] 16 U.S.C. 832-832d.

[6] The varying success of publicly owned utilities in Idaho, Oregon, and Washington probably stems from differing state laws. Idaho law does not authorize the formation of PUDs at all: publicly owned utilities are confined to municipalities and rural electric cooperatives. Oregon law requires one election to establish a PUD and a second election to fund it (ORS Ch. 261). In Washington, voters can establish and fund a public utility district (PUD) in a single election (RCW Tit. 54). <u>Region At the Crossroads</u>, pp. 3.6-3.9.

sion lines, which now constitute about 80% of the region's total high voltage system.[7]

To date, these arrangements have worked remarkably well. Until recently, there was enough inexpensive federally supplied hydropower to satisfy the demands of publicly owned utilities, investor-owned utilities, and direct industrial uses alike—at extraordinarily reasonable rates compared to those paid by customers in other parts of the United States. However, by the 1960s, few environmentally and economically acceptable dam sites for large-scale facilities remained. In 1973, BPA stopped selling investor-owned utilities firm (guaranteed) wholesale power.[8] In 1976, Bonneville put the region's publicly owned utilities on notice that after 1983 they would no longer be able to satisfy projected needs from available BPA power.[9] At the same time, BPA announced that the direct service industries' contracts for power would not be renewed when they expired in the 1980s.[10] Bonneville's wholesale customers have responded in differing ways to the prospect of insufficient supplies. Both publicly owned and investor-owned utilities have begun to build their own generation facilities, largely thermal. For the investor-owned utilities, this step has meant obtaining capital from the private market and passing the costs along to retail customers. The publicly owned utilities have adopted a more complicated course. Either separately, or jointly through the mechanism of the Washington Public Poweer Supply System (WPPSS, comprised of publicly owned utilities in Washington), they have built thermal power plants and arranged to sell the output to BPA. This power is then blended with federally generated hydropower and the combination sold to Bonneville's customers at rates that average the two power sources. (This procedure, known as net billing, is described in more detail below.) The direct service industries have responded primarily by engaging in public relations and lobbying

---

[7] Region At the Crossroads, pp. 3.2-3.3.

[8] Institute of Environmental studies, University of Washington, Background Paper 5, "The History of Hydroelectric Power in the Pacific Northwest," n.d.

[9] "History of Hydroelectric Power."

[10] "History of Hydroelectric Power.

efforts aimed at changing federal law to secure their continued access to low-cost federal hydropower. All three sets of Bonneville' customers face the same problem—the inability of federal hydropower supplies to meet regional power demands. This generates the issues addressed here.

The first substantive issue concerns allocation of the now clearly finite supply of federal hydropower: that is, who is to receive the power, and at what rates. Under current arrangements, all of this power could easily go to publicly owned utilities, which are preference customers under the Bonneville Project Act. Although obviously satisfactory to the publicly owned utilities, this result is plainly unacceptable to the investor-owned utilities and the direct service industries. Nor is it a matter of merely corporate concern. Cut off from inexpensive federal hydropower, the investor-owned utilities would have to rely ever more heavily on thermal power generation costing some 10 times as much.[11] Their ratepayers, both residential and industrial, are unlikely to quietly endure the widening discrepancy in rates that would result. These ratepayers could be a potent political force in themselves. While in Washington investor-owned utilities serve about 23 percent of the market, in Oregon investor-owned utilities account for 63% and in Idaho, 86%.[12] Similarly, if the aluminum industry and other industrial users were forced to rely solely on expensive thermal power, their continued concentration in the region seems problem-

[11] The weighted average production cost in 1976 was 1.8 mills per kilowatt hour for hydroelectric power, and 17.2 mills per kilowatt for coal. Comparable figures for the Trojan nuclear facility in Oregon were 20 mills per kilowatt hour; for the Hanford N-Reactor, 10 mills per kilowatt hour. Region At the Crossroads, pp. IV-10-IV-11.

[12] U.S. Department of Energy, Office of the Regional Representative, "Regional Electric Power Planning Issues in the Pacific Northwest," p. 6.

atic.[13] Given these forces, the publicly owned utilities' unique status may give way to some form of sharing with the investor-owned utilities, and possibly the industrial users as well.

The second substantive issue is how to make up the shortfall between existing hydro and thermal power generating capacity and projected demands for the 1990s. The basic options are conservation; reliance on "soft path" technologies such as solar, biomass, and wind; substitution of natural gas and geothermal for electricity as a source of space heat; and construction of new thermal power plants. Few doubt that conservation and renewable resource technologies can make a contribution. Reduced reliance on electricity doubtless has some role to play as well. Disagreement centers on the necessity of adding more thermal power plants beyond those already under construction or planned. For example the Natural Resources Defense Council study of Terry Lash and Roger Beers argue that additional thermal capacity is unnecessary.[14] However, such conclusions differ sharply from the projections of utility planners. For example, for the year 1995 the "alternative scenario" for the West Group Area developed by the National Resources Defense Council projects energy demand which is 42% less than that projected by the Pacific Northwest Utilities Conference Committee.[15] Absent very strong political pressures to the contrary, the ultimate decisions will rest with utility planners. They seem most likely to trust their own demand projections, and to meet the demand with conventional sources. Thus, the

---

[13] As Professor Kai Lee of the University of Washington Institute of Environmental Studies has argued, the role of the direct industrial users in the region's power system is more complicated than the standard image of industries consuming a great deal of power and supplying few jobs. Because at least half of these users are willing to purchase power that is more interruptible than is likely to be acceptable to other categories of users, their presence provides a form of peaking power: power than can be diverted in times of short supply and strong demand. If the merits of this role can be sustained in the heat of political debates, the direct users may remain an important part of the regional energy system.

[14] Roger Beers and Terry R. Lash, Choosing an Electrical Energy Future for the Pacific Northwest: an Alternative Scenario (Washington, D.C.: Energy Research and Development Administration, January 31, 1977), p. 3.

[15] Beers and Lash, p. 29.

region's utilities seem likely to rely at least partially on new thermal power plants to meet the projected demand for electricity in the 1990s.

The third substantive issue is how to finance new thermal power. One mechanism is "net billing." Under net billing, BPA promises to "buy" a utility's share of the electricity generated by a thermal power plant in whose construction the utility participates. BPA then blends this more expensive thermal power with its cheaper hydropower and sells the combination to all its customers, including the utility from which it bought the thermal power, at an averaged rate. The accounting for such transactions is slightly more complicated than this summary would suggest. Rather than actually purchasing the thermal power, BPA credits the utility's account in an equivalent amount. Bonneville then subtracts this sum from the utility's bill for the power it receives. Hence, "net billing." By acting as guarantor, BPA eases the utility's access to investors who may be reluctant to invest in otherwise risky power plant construction ventures. In effect, "net billing...shifts financial risks associated with thermal plants from the different customers to the federal government through BPA. This occurs because BPA agrees to pay for its preference customers' share of plant capability, even if the plant never produces electricity."[16] The cost of the guarantee is borne by BPA's customers. When introduced to finance portions of WPPSS 1, 2, and 3 and the Trojan nuclear facility, net billing was quickly perceived as inequitable by investor-owned utilities and many of their customers since BPA's mandate prohibits use of the arrangement for financing privately owned power plants. Investor-owned utilities would have to pay increased costs for power purchased from BPA to help cover the costs of plants constructed by publicly owned utilities. In addition, realizing that their access to low cost power from BPA would be increasingly limited in the next few years, they were having to proceed to construct their own generating facilities without benefit of the BPA guarantee enjoyed by the region's publicly owned utilities.

In fact, the arrangement is hardly proving to be a bonanza for any of BPA's customers. As a result of recent cost escalation in the construction

---

[16] Region At the Crossroads, p. 3.13.

of WPPSS' net billed facilities, Bonneville has announced a wholesale rate increase of 40% for November, 1979. Additional projected increases are 28% in 1981, 24% in 1983, and 15% in 1985. Previously, Bonneville has raised rates only twice in its 40 year history, for a total of 31%.[17] Of course, Bonneville's growing reliance on thermal power makes some rate increases inevitable. Thermal power is inherently more costly than power from the existing hydro facilities. However, the contractual arrangements for the net billed plants may not have created adequate incentives for WPPSS to keep costs to the minimum, since BPA agrees to pay for the debt service on WPPSS' bonds "whether or not the Project is completed, operable, or operating."[18]

Currently, the potential contribution of net billing to the financing of new thermal power plants is limited in three ways. First, a utility's credit for supplying thermal power to BPA cannot exceed 85% of Bonneville's bill to the utility. Second, as previously mentioned, net billing is unavailable to investor-owned utilities, which are most dependent on self-generated power. Third, under a Treasury Regulation of August, 1972, if a publicly owned utility sells more than 25% of its interest in a facility's output to BPA, the bonds used to finance the facility will lose their tax-exempt status.[19]

In light of the reluctance of investors to finance thermal power plants under current arrangements, some form of federal or state guarantee, possibly a form of net billing, seems likely to emerge.

---

[17] "3 Nuclear Plants Will Hike BPA's Rates by 152 Percent," Seattle Post-Intelligencer, February 20, 1979, p. A1.

[18] "State Power System May Triple Rates to Build Nuke Plants," The University Daily, February 7, 1979, p. 1.

[19] 26 U.S.C. 103; Treas. Reg. §1.103-7(b)(5).

2.2 ALTERNATIVE PROPOSALS

Numerous groups have proposed policies for dealing with the three substantive issues and with the procedural question of where decisionmaking authority should reside. Some, but not all, would involve federal legislation to replace current arrangements under the Bonneville Project Act. Four primary proposals, and several less comprehensive approaches, are outlined below.

2.2.1 The Weaver Bill

Congressman Jim Weaver of Oregon introduced his proposal for dealing with these issues in March 1977.[20] This legislation would replace BPA with a federally chartered Columbia Basin Energy Corporation, (CBEC), consisting of five members. Two members would be appointed by the President, and one each elected by the people of Idaho, Montana, Oregon, and Washington together.[21] CBEC would purchase nonfederal power and pool it with federal power.[22] The Corporation would also be authorized to construct new generating facilities of all types.[23]

The Weaver Bill would address the allocation question by eliminating the Preference Clause. CBEC would purchase the power generated by cooperating publicly owned and investor-owned utilities, meld it with federally generated power, and resell the power to the utilities and direct service industrial customers through three rate pools.[24] Rate I power would consist of a "conservation percentage" of present residential consumption, sold by CBEC to publicly owned and investor-owned utilities at a cost equal to that of the lowest cost hydro power, for resale to residential customers at prices including utility operating costs, and in the case of investor-

---

[20] H.R. 5862, 95th Cong., 1st Sess. (1977).

[21] H.R. 5862 §4.16v
[22] H.R. 5862 §6.16v
[23] H.R. 5862 §7.16v
[24] H.R. 5862 §§19, 20.

owned utilities, a reasonable allowance for profit. Rate II power would consist of all remaining energy available from facilities constructed and operable before CBEC's establishment. Rate II power would be sold at cost of production and transmission, in the following priority: first, to meet remaining residential demand; second, to meet demand of nonresidential utility customers; third, to direct industrial customers of CBEC. Rate III power would consist of energy generated from facilities coming on line after CBEC's establishment. It would be sold at cost of production to meet all remaining demand.

The Weaver bill would address the question of meeting future load growth by relying heavily on conservation. CBEC could construct new generating facilities only after determining that the technology chosen would constitute the most economical means of balancing energy supply and demand. Similarly, CBEC could agree to purchase power from utility-owned facilities built after CBEC's establishment only after approving the construction on a similar basis.[25] Through power sales contracts, CBEC would impose stringent insulation, weatherization, and conservation requirements on all structures. CBEC would fund these conservation activities through direct grants.[26]

The Weaver bill would address the question of financing new thermal power facilities, if necessary, by authorizing CBEC to construct the facilities itself.[27] CBEC could obtain the necessary funds through Congressional appropriation or issuance of its own bonds.[28] CBEC could also ease the access of utilities to capital by agreeing to purchase the output of new facilities. The Weaver Bill, however, contains no provision that would allow publicly owned utilities to retain the tax exempt status of their bonds if they took this course.

---

[25] H.R. 5862 §7.

[26] H.R. 5862 §18.

[27] H.R. 5862 §6.

[28] H.R. 5862 §§22, 24.

2.2.2. The PNUCC Bill

The Pacific Northwest Utilities Conference Committee (PNUCC), a group of publicly owned and investor-owned utilities, drafted legislation introduced in Congress in September of 1977.[29] This legislation would rely heavily on an expanded role for BPA, which would acquire new powers. The bill would also establish the Pacific Northwest Planning and Conservation Organization (PNEPCO), a Washington corporation, whose members would consist of all publicly owned and investor-owned utilities in the region desiring to join.[30] PNEPCO would prepare load and resource forecasts, promote power conservation, study alternative energy sources, review utilities' long-range planning, provide oversight services specified in BPA power purchase contracts, and participate in plant siting studies.[31]

The PNUCC Bill would address the allocation issue by modifying the Preference Clause to allow investor-owned utilities and direct industrial users to share in cheap hydropower. Bonneville would allocate power through three rate pools. Rate Pool A would consist of about 2/3 of existing federal hydropower and net billed thermal power, to be purchased by publicly owned utilities at low cost. Before 1985, Rate Pool B would consist of the remaining federal hydropower and net billed thermal power, plus 4,000 MWe of mostly thermal power owned by the investor-owned utilities. Until 1985 investor-owned utilities and direct service industries would share Rate Pool B power at medium rates. After 1985, Rate Pool B power would include increasing amounts of new thermal power, with rates increasing commensurately. After 1985, Rate Pool B power would meet half of the publicly owned utilities' load growth, half of the investor-owned utilities' load growth, and half of the maximum 1% annual load growth of the direct service industries. Remaining load growth after 1985 would be met by Rate Pool C, consisting of new thermal power not allocated to Rate Pool B, at full cost of production.[32] In short, publicly owned utilities would retain

[29] H.R. 9020, 95th Cong., 1st Sess. (1977).

[30] H.R. 9020 §17.

[31] H.R. 9020 §2.

[32] H.R. 9020 §§7, 8, 10.

rights to about two-thirds of the federal hydropower and would thus be able to continue to sell power at rates below those of the investor-owned utilities. Nonetheless, the publicly owned utilities would be paying higher wholesale rates than under existing arrangements. Investor-owned utilities would pay less for power than if they were forced to rely solely on thermal power. Direct service industries would obviously pay far more than they do presently, but still less than the cost of relying entirely on thermal power.

The PNUCC proposal addresses the question of meeting new load growth by encouraging conservation, although to a lesser extent than the Weaver Bill. PNEPCO and BPA would manage a program of conservation standards to be adopted by the states, or if they failed to do so, by BPA. A state's failure to adopt standards would result in a surcharge on power sold to BPA customers within that state. BPA would be authorized to make grants and loans for conservation purposes. The standards would be designed to encourage conservation as an alternative to new thermal power.[33] However, the utilities would still have substantial freedom to meet new load growth with new generation facilities instead of conservation measures.

The PNUCC Bill would address the issue of financing new power plants by giving BPA the authority to buy the output of any new thermal power plant, whether constructed by a publicly owned or investor-owned utility.[34] It would also amend Internal Revenue Code Section 103 to allow publicly owned utilities to assign power to BPA while retaining the tax-exempt status of their bonds.[35] The PNUCC proposal would thus restore and expand net billing.

2.2.3 The Jackson Bill

Partly in response to opposition to the PNUCC proposal by some publicly owned utilities (especially Snohomish County Public Utility District and

---

[33] H.R. 9020 §4.

[34] H.R. 9020 §5.

[35] H.R. 9020 §20.

Seattle City Light), Senator Henry Jackson, chairman of the Senate Energy Committee, introduced his Northwest regional power bill in August, 1978.[36] The Jackson Bill would also expand BPA's role in regional power supply and planning. It would direct Bonneville to prepare a regional power planning and conservation program in consultation with the governors of Idaho, Montana, Oregon, and Washington and with two newly created groups, the Bonneville Consumers' Council and the Bonneville Utilities' Council.[37]

The Jackson Bill would address the allocation issue by allocating the federal power now received by direct service industries to the residential customers of the investor-owned utilities. This policy would be phased in gradually over a five-year period. Essentially, BPA would sell a pool of power at averaged rates to meet the general requirements (residential and existing industrial) of publicly owned utilities and the residential requirements of investor-owned utilities. This pool would consist of existing federal power, existing net billed power, and as needed, "exchange power" purchased from utilities and power from new resources otherwise acquired by Bonneville. Direct service industries would purchase from Bonneville at rates comparable to those charged industrial customers by utilities.[38] Presumably, BPA would sell power to publicly owned utilities for use by new industrial customers and to investor-owned utilities for use by all industrial customers at rates similar to those charged the direct service industries.

The Jackson Bill would address the question of meeting load growth by emphasizing conservation and renewable resource power generation. BPA would be required to meet power obligations through feasible, cost effective conservation measures such as financing residential construction, increased system efficiency, and waste energy recovery. Bonneville would also provide technical and financial assistance to others to promote conservation. If

---

[36]S. 3418, 95th Cong., 2d Sess. (1978). The identical bill has been reintroduced as S. 885, 96th Cong., 1st Sess. (1979).

[37]S. 3418 §4.

[38]S. 3418 §§5, 7.

BPA found conservation measures insufficient to meet power obligations, it would be authorized to acquire additional resources from federal or nonfederal entities, according to the following priority: waste heat, cogeneration, or renewable resources; high energy resources, such as combined cycle or magnetohydrodynamic; and others. Bonneville would itself be authorized to construct nonhydro generating facilities using renewable resources, as well as facilities using other resources if necessary to assure transmission system reliability.[39]

The Jackson Bill would address the issue of financing new thermal generating capacity by restoring and expanding a form of net billing to include publicly owned and investor-owned utilities alike.[40] As with the PNUCC proposal, the Internal Revenue Code would be amended to permit the bonds of publicly owned utilities used to finance net-billed facilities to remain tax-exempt. BPA itself would have expanded authority to finance its own construction projects through the sale of revenue bonds.[41]

2.2.4 WPPSS Proposal

As a back-up approach in the event no federal power bill is approved, the Washington Public Power Supply System (WPPSS) has recently proposed a more limited regional electricity generation plan that it claims would require no new legislation. WPPSS, a joint operating agency composed of publicly owned utilities in Washington, builds and operates power plants for its member utilities. (See the discussion beginning on page 80.) Under the WPPSS plan, publicly owned utilities would create a power pool and assign to it their allocation of federal hydropower and any other power to which they have rights, such as that generated by their own thermal power plants or power plants in which they have a share, to the extent these shares are not assigned to BPA. The power pool would then sell the electricity back to the utilities and to industrial users at an averaged rate. Investor-owned

---

[39] S. 3418 §6.

[40] S. 3418 §5.

[41] S. 3418 §8.

utilities would be left out of the plan entirely. Thus, the WPPSS plan would address the issue of allocating federal hydropower by channeling it to publicly owned utilities and industrial users, to the exclusion of investor-owned utilities. The WPPSS plan does not directly address the question of how to meet future load growth. The plan does envision construction of new thermal power plants by WPPSS or individually or cooperatively by publicly owned utilities. The proposal leaves conservation to others, such as individual utilities or BPA. The WPPSS approach addresses the problem of financing new thermal power plants by reinstituting a form of "net billing" for publicly owned utilities, albeit with the regional power pool rather than BPA as the net biller. The plan does not address the question of financing new thermal power plants for investor-owned utilities.[42]

2.2.5 Other Proposals

Various groups have made other, less comprehensive proposals. Portland Utilities Commissioner Ivancie has proposed changing the Preference Clause to favor end-use allocation of federal hydropower to residential customers. Through 1977 legislation, the Oregon legislature has attempted to qualify the entire state of Oregon as a BPA preference customer, to be known as the Oregon Domestic and Rural Power Authority (DRPA). This "paper utility" would channel federal hydropower to existing Oregon publicly owned and investor-owned utilities.[43] By the terms of the enabling legislation, DRPA's powers were to commence March 1, 1979, if the U.S. Congress had failed to enact a regional power bill satisfactory to the Oregon governor. Although Governor Atiyeh has instructed the Public Utilities Commission to begin hearings required to set up DRPA, he has also indicated he wishes to await the outcome of regional energy legislation in Congress. A bill to delay implementation of DRPA for one year has been introduced in the Oregon legislature. (Telephone conversation with Michael Grainey, Staff Attorney,

[42] "New plan: reallocate electricity without Congress' help," The Seattle Times, December 15, 1978, p. B10.

[43] 1977 Or. Laws Ch. 888.

Oregon Department of Energy, April 30, 1979.) Finally, as indicated above, a Natural Resources Defense Council (NRDC) study has proposed an "alternative scenario" for meeting the region's electrical needs without constructing any additional nuclear or coal-fired power plants in the next twenty years beyond those already approved or under construction—that is, primarily through conservation.[44] The NRDC proposal addresses the allocation issue by assuming BPA would continue to supply power to direct service industries only so long as their plants are less than 35 years old. In other words, publicly owned utilities would gradually consume all federal hydropower.[45] This scenario obviously does not reach the issue of financing new thermal power plants.

2.3 PROSPECTS

The inadequacy of present arrangements is creating strong and increasing pressures on the region's publicly owned utilities, investor-owned utilities, and direct service industries alike. Obviously, none of the principal proposals is equally satisfying to all. With respect to the critical allocation issue, the choice between alternatives clearly represents a "fixed sum game:" that is, publicly owned utilities, investor-owned utilities, and industrial users are competing for a limited resource. Similarly, end-users in the state of Washington are competing with end-users in the states of Oregon and Idaho. The Weaver Bill favors investor-owned utilities and residential and rural end-users at the expense of publicly owned utilities and direct industrial users. The PNUCC Bill does more for investor-owned utilities, direct industrial users, and Washington end-users than it does for publicly owned utilities and end-users in Oregon and Idaho. The Jackson Bill tries to satisfy publicly owned utilities, investor-owned utilities, and end-users in all states largely at the expense of direct service industries, which will nonetheless retain their access to power, albeit at higher rates. Not surprisingly, the Jackson Bill has received the support

---

[44] Beers and Lash, p. 3.

[45] Beers and Lash, pp. 78-79. According to the authors, the scenario could also accommodate a complete phase-out of direct service customers or full continued service, if the Bonneville Project Act were appropriately amended.

of the region's publicly owned and investor-owned utilities, and perhaps as the least of several evils, the aluminum companies.

The timing and character of the outcome is likely to depend heavily on Congressional politics.[46] In the Senate, support for the Jackson Bill is relatively strong. In addition to Jackson, who is, Chairman of the Energy and Natural Resources Committee, the recently reintroduced bill's cosponsors include Senators Frank Church of Idaho, James McClure of Idaho, Robert Packwood of Oregon (all members of the Energy and Natural Resources Committee as well), and Senator Mark Hatfield of Oregon. The bill's future in the House of Representatives is more problematic. An important House backer of the bill in the last Congress, Representative Lloyd Meeds of Washington, Chairman of the House Interior Subcommittee on Water and Power, has retired. This session, the only Northwest member of the committee is Representative Weaver of Oregon, sponsor of a competing approach.[47] Don Bonker of Olympia is also skeptical of the Jackson Bill, as is Representative John Dingell of Michigan, Chairman of the House Commerce Energy and Power Subcommittee. Both are concerned about the precedent of eliminating publicly owned utilities' preferential access to federal power and about federal underwriting of thermal power plant construction.[48] Of special concern is the unusually high cost escalation of the WPPSS nuclear facilities, costs which will be borne by all consumers whose utilities purchase wholesale power from BPA. Representative Weaver and others believe restoration of this practice for the construction of thermal generating facilities by publicly owned utilities, and its extension to investor-owned utilities as well, could result in unacceptably high power rates because of inadequate incentives for the builders of net billed plants to

[46] "Senators Ask Jackson to Go Slow on NW Power Bill," Seattle Post-Intelligencer, March 15, 1979, p. A7.

[47] "Senators Ask Jackson."

[48] "Jackson ready for Round 3 on energy bill," The Seattle Times, March 2, 1979, p. A10; "'Zilch' Outlook for NW Power Measure," The Seattle Post-Intelligencer, March 2, 1979.

hold down costs.[49] In this connection, the results of a GAO audit of BPA's net billing contracts with WPPSS, ordered by Representative Dingell, could be critical to the future of the Jackson Bill.[50] As a consequence, Congressional action may come slowly, or not at all if compromise eludes legislators. In the meantime, the uncertainties and pressures may affect the siting and construction of individual generating facilities discussed in the remainder of this report.

---

[49] "3 Nuclear Plants Will Hike BPA's Rates by 152 Percent." Seattle Post-Intelligencer, February 20, 1979, p. A1.

[50] "Congress To Audit N-Contracts In State," Seattle Post-Intelligencer, February 7, 1979, p. A1.

CHAPTER THREE: IDAHO

For Idaho, the scenario specifies an expansion in generating capacity from 1,686 MWe in 1978 to 2,432 MWe in 1990. The bulk of this increase is to come from new hydroelectric capacity, with a smaller amount coming from geothermal power. No serious institutional constraints stand in the way of realizing the hydroelectric portion of the scenario: sufficient facilities are under construction or in advanced planning that the scenario figure is likely to be met. The addition of the geothermal capacity is unlikely to be justified by technical and economic considerations. However, these factors as well as the institutional climate are more supportive of geothermal power in Idaho than in other northwestern states. The prospects for some commercial-scale geothermal power generation coming on line by 1990 appear relatively favorable.

3.1 HYDROELECTRIC

The scenario envisions the addition of 551 MWe of hydroelectric generating capacity in the state of Idaho by 1985, and no further addition between 1985 and 1990. As Table 3 indicates, a number of hydroelectric projects are planned for the state, representing about 1,164 MWe of additional generating capacity. However, the addition of a fifth generating unit to the Brownlee Dam is the only one of these projects yet under construction. All others are in various stages of planning. None of the federal projects has received funding for construction, and only one of the projects proposed by the Idaho Board of Water Resources has received authorization to issue bonds for construction financing. Thus, only the 225 MWe of capacity represented by the Brownlee Dam can be said with some certainty to be in operation by either 1985 or 1990. However, only about a third of the other 939 MWe being planned need be completed by 1990 to realize the hydro component of the scenario. As there are no severe institutional constraints, the scenario figures will probably be met.

This section lays out the institutional context for the construction of hydroelectric power generation facilities in Idaho and then discusses the

TABLE 3

ADDITIONAL HYDROELECTRIC CAPACITY PLANNED FOR IDAHO

PLANT/AGENCY/LOCATION	SCHEDULED COMPLETION	CAPACITY (MEGAWATTS)	CURRENT STATUS
Brownlee Dam/Idaho Power Co./Snake River, Washington County	1979	225	Under construction.
Palisades Dam/Bureau of Reclamation and Idaho Department of Water Resources/Snake River, southeast Idaho, Bonneville County	1985?	90	Authorization from Congress and state legislature.
Wiley Dike/Idaho Board of Water Resources and Idaho Power Co./southern Idaho, SW of Bliss, ID	1985-86	86	Permits stage.
Payette River Dams--South Fork (Grimes Pass, Black Bear, Big Falls, and Pine Flat dams)/Idaho Board of Water Resources and Idaho Power Co./South Fork, Payette River, SW Idaho, north of Boise, Boise County	1985-86	85	Under study.
Payette Rivers Dams-North Fork (Cascade, Ferncroft, and Banks dams)/Idaho Power Co./North Fork, Payette River, western edge of Valley County	1985-87	270	Under study.
Dworshak Dam/ U.S. Army Corps of Engineers/ North Fork of the Clearwater River, Clearwater County	?	220	Design memo.
Lucky Peak Dam/Corps of Engineers	?	75	Survey report.
Swan Falls-Guffy Dams/Idaho Board of Water Resources and Idaho Power Co./Snake River, Owyhee County	?	113	DEIS, FERC license application.

current status of projects now planned and the institutional constraints to their completion by 1985 or 1990.

3.1.1 Institutional Context

Virtually all of the electricity now generated in Idaho is hydroelectric power. In contrast to Washington, Idaho is served primarily by regulated, investor-owned utilities. Indeed, these privately owned utilities service about 86% of the state. The remainder is served by municipal utilities or rural electric cooperatives.[1] However, Idaho's investor-owned utilities do not build and operate all the generating capacity upon which they rely for power. In some instances, they purchase power from facilities built in whole or part by the Idaho Board of Water Resources. In still other cases, they rely on power marketed by BPA from facilities built and operated by the Army Corps of Engineers or the Bureau of Reclamation. Thus, there are three ways of bringing generating capacity on line in the state of Idaho, even if most of it is eventually sold to end-users by the state's investor-owned utilities: privately built facilities, Board of Water Resources facilities, and federally built facilities.

3.1.1.1 Privately-Built Facilities

Construction of a privately owned hydroelectric generating facility in Idaho requires the approval of several state agencies. The central role is played by the Idaho Public Utilities Commission, from which the utility must obtain a certificate of convenience and necessity before construction can begin.[2] Unlike Washington, Idaho has neither a "mini-NEPA" requiring an EIS for state actions significantly affecting the environment nor a comprehensive energy facility siting process. While in principle the Idaho Public Utilities Commission could incorporate broad-gauged environmental and siting considerations in determining whether to issue a certificate of

---

[1] U.S. Department of Energy, Office of the Regional Representative, "Regional Electric Power Planning Issues in the Pacific Northwest," p. 6.
[2] IC 61-503.

convenience and necessity, it has not typically done so. Two factors appear to account for this posture. First, like other public utilities regulators, the Commission can be expected to view its mission as economic regulation: assessing the validity of a utility's load growth projections, its ability to obtain financing, and the appropriateness of its rate structure are familiar tasks. Factoring in environmental considerations is relatively alien. Second, the Commission must finance any environmental and siting studies out of its own funds.[3] As a result, environmental considerations are brought to bear separately through the requirements of other state agencies. The utility must obtain a separate water permit from the Department of Water Resources, the state office charged with adopting a comprehensive program for the conservation, development, and use of all unappropriated water resources.[4] And the utility must see that its proposed facility complies with local land use requirements. A proposed thermal or geothermal facility would also have to obtain an air quality permit from the Air Quality Bureau. Finally, the utility would have to obtain a license from the Federal Energy Regulatory Commission under the Federal Power Act.[5]

3.1.1.2 Board of Water Resources Facilities

An entirely different set of procedures is invoked for generating facilities proposed for construction by the Idaho Board of Water Resources within the Department of Water Resources. The Board's mandate, written in the state's constitution, includes the development of hydroelectric resources in the state.[6] While the Board may exercise this mandate through the construction of dams and associated generating facilities, it is not authorized to function as a utility. Therefore the Board must market power from its facilities to the investor-owned utilities or rural cooper-

---

[3] Northwest Energy Policy Project, Institutional Constraints and Opportunities, Study Module V, Tasks 4-7 (Springfield, VA: National Technical Information Service, 1977) ("NEPP V/4-7"), pp. 165-166.

[4] IC 42-701--42-1759.

[5] 16 U.S.C. 797.

[6] Idaho Constitution art. 15 §7.

atives that serve the state in much the same way as BPA markets power, usually through long-term purchase agreements.

Specific arrangements can vary widely. For instance, the Board has entered into agreements with a utility whereby the Board finances and constructs a dam and the utility finances and constructs the generating units to be used in conjunction with the dam. In this situation, the Board essentially sells the utility the water necessary to turn its turbines. In other cases, the Board constructs and operates the entire facility, selling power to the utilities.

The Board must receive legislative authorization to proceed with the construction of any project, including a hydroelectric facility. Generally, the Board conducts economic, engineering, and environmental studies and negotiates preliminary agreements with the utilities before approaching the legislature for construction authorization. The legislative hearings on the Board's requests for authorization afford potential opponents of a project an opportunity to achieve highly visible input at an important decision point in the process. If the dam would affect a body of water over which Congress has jurisdiction or the powerhouse would utilize surplus water from an existing government dam (in practice, nearly always), the Idaho Water Board would also have to obtain a license from the Federal Energy Regulatory Commission (FERC).[7]

Once the project is authorized by the legislature, the Board then issues bonds to finance project construction. The security and tax-exempt status of these state-issued bonds can result in considerable savings when compared to the financing costs which would be incurred by an investor-owned utility. Ultimately, these savings should be reflected in the cost of electricity to Idaho consumers. (Telephone conversation with Ken Dunn, Idaho Board of Water Resources, January 17, 1979.)

---

[7] 16 U.S.C. 797.

3.1.1.3 Federally Constructed and Operated Facilities

The procedures for bringing a federally constructed hydroelectric facility on line in the Pacific Northwest are described in somewhat greater detail in Section 5.2 dealing with hydroelectric power in Washington. Such facilities would be built by either the Bureau of Reclamation or the Army Corps of Engineers. Detailed project planning would require congressional authorization and, upon completion of detailed planning studies, circulation of draft environmental impact statements required by NEPA. Were the decision made to proceed, additional congressional authorization and appropriation of funds would be required. Upon completion of the project, the power generated would be marketed by the Bonneville Power Administration. Because of the Preference Clause, most or all of the power would go to publicly owned utilities unless new federal legislation reallocates BPA's hydropower. Since most power in Idaho is retailed by investor-owned utilities, this would mean exporting most of the power out of Idaho. Therefore, additional federal hydroelectric projects are not apt to be very popular in the state.

3.1.2 Hydroelectric Projects and Institutional Constraints

3.1.2.1 Idaho Power Company

The Idaho Power Company, an investor-owned utility serving most of southern Idaho, is currently proceeding with the construction of a fifth generating unit to add 225 MWe of capacity to the company's Brownlee Dam about 100 miles northwest of Boise on the Snake River. This project is under construction and is scheduled for completion by November 1979.

Idaho Power is also proposing three projects on the North Fork of the Payette River. The Cascade project would involve the addition of 128 MWe of generating capacity to an existing Army Corps of Engineers Dam at which Idaho Power currently has a small (300 KW) generating facility. This project is in the planning stage. The company has applied for a water rights permit and submitted a preliminary FERC application. Idaho Power is also planning to construct two additional dams on the North Fork of the Payette River: Ferncroft Dam, with a planned capacity of 165 MWe, and Banks

Dam, with a planned capacity of 93 MWe. These projects are also in the planning stage. Presently, only water rights permits have been applied for, and the company expects to apply for preliminary FERC permits by the end of 1979.

For each of these projects, Idaho Power expects the licensing process to take at least two to three years, and construction an additional two or three years. Thus, the company currently expects that, at the earliest, the Cascade project could be completed by 1985 or 1986, and the Ferncroft and Banks projects could be completed in 1986 or 1987. (Personal correspondence from Gower Condit, Vice President, Idaho Power Company, February 2, 1979; telephone conversation with Glenn Brewer, Idaho Power Company, February 2, 1979.) Delays in the licensing progress can be expected to cause corresponding delays in project completion.

The company is also planning to participate in several joint projects with the Idaho Board of Water Resources, as described below.

3.1.2.2 Idaho Board of Water Resources

The Board is planning a number of hydroelectric projects. Among these, the most intriguing is the Board's proposal to add two new generating units (for a total of 90 MWe of capacity) to the Palisades Dam in southeast Idaho. This dam has been constructed and operated by the U.S. Bureau of Reclamation. The Board is proposing that the state finance the construction of the new units, and that the Bureau oversee construction, and when completed, assume responsibility for their operation. The Board would then serve as marketing agent for the power generated. Apparently, this would be the first arrangement of its kind. Members of the state's congressional delegation are expected to propose legislation in this session of Congress to authorize the Bureau of Reclamation to negotiate such an agreement with the Board.

This proposal is primarily motivated by the desire to ensure Idaho consumers continued access to relatively inexpensive hydro power. Under normal arrangements, the Bureau of Reclamation would construct this Palisades project as it has others, and BPA would market the power. Because BPA must provide preferential access to federal hydro power to publicly owned utilities and since Idaho is served primarily by investor-owned utilities, much of the low-cost hydro power generated in Idaho must be sold to publicly owned utilities in Washington. The Board's proposal would provide Idaho customers continued access to low-cost hydro power by financing the construction and marketing of power from two new generating units in a federal dam.

As noted in Chapter Two, a number of important issues revolve around the future role of BPA in the region, and a number of proposed solutions have been submitted to Congress. Within this context, the Board's proposed Palisades project will be viewed as representing one of a number of competing proposals to resolve these issues. Since construction by either the IBWR or the Bureau of Reclamation seems unlikely to proceed until the broader issues are resolved, the time frame for the Palisades project is uncertain. However, these issues are of sufficient importance in the region to warrant relatively quick resolution. Since construction of the project itself will take only a few years, its completion over the time frame of the scenario remains possible if not probable.

The IBWR is also currently proposing the Wiley Dam project, involving the construction of a new dam on the Snake River just southwest of Bliss, Idaho. This dam would include three generating units with a capacity of 86 MWe. The Board is now negotiating the terms of a joint venture agreement on this project with the Idaho Power Company. Idaho Power has completed a feasibility study and has applied for water rights permits with the Department of Water Resources, a certificate of convenience and necessity from the Idaho Public Utilities Commission, and a license from FERC. In addition, the Board has applied to this session of the state legislature for project authorization. While some environmental objections to the project are expected, the Board does not anticipate these will represent a serious obstacle to project construction, primarily because the river is not free-flowing and there are no anadromous fish at the proposed site. Thus, the IBWR expects the Wiley project to be complete by 1985. (Personal correspondence from Gower Condit, February 2, 1979; telephone conversation with Glenn Brewer, February 2, 1979.)

The Board is also proposing the Swan Falls-Guffy Dam project. This would involve raising the existing Swan Falls Dam and constructing Guffy Dam to regulate the river flow, for an additional 113 MWe of capacity. A joint venture agreement between the IBWR and the Idaho Power Company was reached on this project in the early 1970s. The Board also received legislative authorization at that time. However, the proposal raised a number of legal issues related to bonding. They were not resolved by the courts until 1975. Since that time, the project has been delayed by environmental issues. Currently, Idaho Power is completing a draft environmental impact statement and is in the process of applying for a FERC license. Conditions have changed so much since the original agreement between the Board and Idaho Power was reached that the parties are also expected to negotiate a new agreement. State officials expect this project to be completed by 1985. (Personal correspondence from Gower Condit, February 2, 1979; telephone conversation with Glenn Brewer, February 2, 1979; telephone conversation with Wayne Hart, Idaho State Office of Energy, January 17, 1979.) However, it seems reasonable to suppose some uncertainty exists with regards to the length of time needed to resolve project related environmental issues and contractual arrangements.

Finally, the Board and Idaho Power are studying the possibility of entering into yet another joint venture to construct four medium-head dams on the south fork of the Payette River. These dams would have a combined generating capacity of 85 MWe. Idaho Power has obtained preliminary permits for this project from FERC, and has applied for a water rights permit. Idaho PUC hearings on this proposal were scheduled for March 1979. Although this proposal is still in the study phase, state officials expect it to be completed by 1985. (Telephone conversation with Wayne Hart, January 17, 1979; telephone conversation with Ken Dunn, January 17, 1979.) This expectation is based on the assumption that no significant delays will occur in licensing and permitting or legislative authorization proceedings, an assumption that may be optimistic.

3.1.2.3 The U.S. Army Corps of Engineers

The Army Corps of Engineers is currently proposing two hydro projects in Idaho. The Corps is requesting Congress to fund an additional 220 MWe of generating capacity at Dworshak Dam on the north fork of the Clearwater River. At present, the dam has space for three additional units of 220 MWe each. Once funding is obtained, the units can be installed within a period of one to two years. Thus, if no significant opposition to the project is encountered in congressional hearings, the project could be completed before 1985.

The Corps is also preparing a Summary Report on a project to install a 75 MWe power house at Lucky Peak Dam on the Boise River near Boise. The dam is now used only for flood control purposes. A draft EIS is currently circulating for review. (Telephone conversation with Frank Parsons, U. S. Army Corps of Engineers, Walla Walla District Office, January 19, 1979.) Based on the Summary Report, Congress may choose to authorize construction, or may require a more detailed "Phase I Report." Thus, although the project could easily be completed by 1990, opposition during the congressional appropriations hearings or other congressional priorities could delay construction beyond the time frame of the scenario.

3.2 GEOTHERMAL

The scenario specifies 200 MWe in geothermally generated electric power for the state of Idaho by 1990. A combination of technical, economic, and institutional considerations render this estimate highly optimistic. However, the prospects for generating electric power with geothermal resources within the time frame of the scenario are brighter for Idaho than for either Oregon or Washington.

Although the extent of Idaho reservoirs are not fully known, three known geothermal resource areas in the state seem likely to have sufficient moderate temperature hot water resources to generate electric power in commercial quantities. They are: Raft River, Weiser-Crane Creek, and

Bruneau-Grandview.[8] The technology for generating electric power from moderate temperature hot water resources has not yet been perfected. Significantly, however, the R&D for this technology is being performed by DOE at Raft River, at the urging of a local rural electric cooperative and with the participation of other regional utilities. Two 5 MWe pilot generating facilities are now planned. The first is to become operational by 1980, and the second some time in the mid-1980s. This situation has several favorable implications. First, the two pilot plants themselves could make a small contribution—10 MWe--to Idaho's electrical generating capacity. Second, if the usable reservoir at Raft River proves to have the currently estimated potential of 50 MWe and if certain institutional barriers can be overcome, Raft River could contribute up to 50 MWe to the state's power supplies by 1990. Third, the early involvement of local utilities, federal agencies, and state regulators could ease the transfer of the technology to developers and users of the resources at Weiser-Crane Creek and Bruneau-Grandview over the next decade or so. Although the extent of usable resources at these two locations is not fully known, some estimates place the aggregate as high as 6,000 MWe.[9] Nonetheless, any optimism as to the extent and pace of commercialization in Idaho should be tempered by certain realities. The most important is economic. A recent DOE analysis places the levelized busbar cost of electricity from binary system power production (the currently planned mode) at about 47 mills per kilowatt hour for a plant coming on line in 1988, taking into account R&D advances,

---

[8] Northwest Energy Policy Project, Energy Supply and Environmental Impacts--Unconventional Sources, Study Module III-B (Springfield, VA: National Technical Information Service, 1977) ("NEPP III-B":), p. 59.

[9] NEPP III-B, p. 59.

expensing of intangible drilling costs, and a 22% depletion allowance.[10] This figure is roughly twice the currently expected cost of electricity from nuclear sources coming on line at the same date. However, project personnel at Raft River are convinced that R&D advances over the next decade or so will make electricity generated by moderate temperature hot water competitive with that generated by thermal power plants. (Telephone conversation with Clay Nichols, DOE Raft River Program Office, Idaho Falls, Idaho, January 26, 1979.) In addition, there do remain institutional constraints. A best guess is that while geothermally generated electricity will be available in <u>some</u> commercial quantities by 1990, the amount will not reach the 200 MWe specified in the scenario.

This section uses the Raft River project as a window on the larger institutional issues of geothermal power development in Idaho. It is presented in three parts. The first sketches the institutional context for geothermal power development in Idaho. The second outlines the history and current status of the Raft River project. The third analyzes the institutional constraints to commercial development at Raft River, and touches upon the implications for geothermal power generation elsewhere in the state.

3.2.1 Institutional Context

As detailed in Section 5.3 concerning geothermal power generation in Washington State, the procedures for geothermal resource deveopment depend on whether the land under which the resources are located is federal, state, or private. A developer must obtain a lease from the Bureau of Land Management (BLM) pursuant to the Geothermal Steam Act of 1970,[11] and the National Environmental Policy Act of 1969 (NEPA).[12] The federal agency

---

[10] R. Trehan <u>et al</u>., <u>Site Specific Analysis of Geothermal Development--Data Files of Prospective Sites, Volume II</u> (Washington, D.C.: U.S. Department of Energy, 1978), pp. XVII-10--XVII-14.

[11] 30 U.S.C. 1001-1025.

[12] 42 U.S.C. 4321-4361.

managing the land in question does the requisite environmental analysis. To engage in exploratory drilling, the developer must receive approval from the U.S. Geological Service (USGS), which also conducts an environmental analysis. The federal agency with managerial responsibility for the land in question, such as BLM or the U.S. Forest Service, monitors compliance with the plan. If the resources prove substantial enough to justify production, the operator must obtain additional approval from BLM, this time probably requiring a full environmental impact statement. Finally, construction of the power generating facility itself and associated transmission facilities requires compliance with applicable state and federal energy facility siting laws. The laws as they apply in Idaho are discussed in connection with the construction of hydroelectric facilities in Idaho. The necessary approvals include those of the Idaho Public Utilities Commission, the Idaho Water Resources Department, local land use authorities, and for geothermal power generation, the Air Quality Control Bureau in the Division of Environment, Department of Health and Welfare. Transmission facilities also require the approval of the Idaho Public Utilities Commission, perhaps the Federal Energy Regulatory Commission, and of those authorities having jurisdiction over the lands through which the transmission lines would run.

The procedures for geothermal resource development on state and private lands in Idaho are analogous to those discussed in connection with geothermal resource development in Washington, with two main differences. First, the process is more fully developed in Idaho. Second, as with other energy development activities in Idaho, the process is more fragmented than that likely to be established in Washington. If the geothermal resource were on state land, the developer would first have to obtain a lease from the Idaho Board of Land Commissioners.[13] Because Idaho has no mini-NEPA, the Board has neither the statutory obligation nor the funds to conduct a environmental analysis, and has not elected to do so on its own. (Telephone conversation with Art Zierold, Idaho Board of Land Commissioners, February 2, 1979.) Whether the land were owned by the state or privately, in order to begin exploration the developer would have to obtain two permits from the

[13] IC 47-1601—47-1611.

Idaho Department of Water Resources. These are the drilling permit required by the Idaho Geothermal Resources Act,[14] and the water use permit required by the Department for any use of unappropriated water resources in the state.[15] Again, no comprehensive environmental analysis is required by statute. However, the Department of Water Resources makes a practice of consulting with all other state agencies whose interests could be affected by issuing the permits. (Telephone conversation with John Mitchell, Idaho Department of Water Resources, January 26, 1979.) This would include local land use authorities when relevant. If the developer decided to go into production, drilling and water use permits from the Department of Water Resources would be required for drilling the production wells. Construction of power generating facilities and transmission facilities would be subject to the requirements outlined in the preceding paragraph on development of federally owned lands.

Broadly speaking, the institutional setting for geothermal power development appears favorable in Idaho. The technology has the strong and effective support of Senator Frank Church, chairman of the Senate Energy and Natural Resources Subcommittee on Energy R&D. The Idaho Department of Water Resources, a key participant, has a keen interest in geothermal development and has been involved in the Raft River project on a cooperative basis. And geothermal power could have buyers in the form of Idaho's rural electric cooperatives, whose access to low cost federal hydro power is threatened and whose needs and resources may make construction of large thermal or hydroelectric facilities impractical.

3.2.2 The Raft River Project

The Raft River project began in 1973. In that year Raft River Electric, a rural electrical cooperative, hired a geologist to investigate the near-boiling water found through a variety of 200 to 500 foot irrigation wells drilled in the area. Based on this work, the Co-op approached DOE's Idaho National Engineering Laboratory (INEL) and sought its involvement. Apparently through the support of Senator Frank Church, DOE decided to pro-

---

[14] IC Ch. 42.40.

[15] IC 42-1701—42-759.

ceed with the project, which received funding at the end of 1973. During 1974, USGS personnel and scientists from INEL performed extensive geophysical exploration. In January of 1975, DOE's prime contractor, Aerojet General, began deep drilling for geothermal water. Predicted maximum reservoir temperatures were between 140° and 150° C.[16] This is at the low end of the range considered feasible for geothermal power generation. As a result, the thrust of the DOE project has become the performance of R&D to develop moderate temperature geothermal power generation capabilities—that is, to determine whether or not geothermal power generation is economically feasible with hot water at these temperatures. Now under advanced development are a 60 KW binary test power plant and a 500 KW direct contact pilot plant. Two major pilot generating facilities at the near commercial scale (5 MWe each) are planned. The first is a binary shell and tube plant, scheduled for operation in 1980. The technology for the second plant is now being selected. DOE's goal is to choose a technology with a demonstration purpose beyond that of the first facility. Program personnel are optimistic that when this second generation of technology emerges in the late 1980s, moderate temperature geothermal power production will be proved economically competitive with thermal power generation. If these estimates prove correct, Raft River itself could be generating 10 MWe of economically competitive power by the late 1980s. If current estimates of reservoir size are correct, the area might contribute another 40 MWe more by 1990 or shortly thereafter. (Telephone conversation with Clay Nichols, DOE Raft River Program Office, Idaho Falls, Idaho, January 26, 1979.) In addition, this technology could be transferred to geothermal resources areas in Idaho with characteristics similar to those of Raft River, but with potentially much larger reservoirs: Grandview-Bruneau and Weiser-Crane Creek.

3.2.3 Institutional Constraints

It is worth repeating that the fundamental prerequisites to generating power at Raft River and other locations in Idaho on a commercial scale are

---

[16] Robert N. Chappell *et al.*, "The Multi-Purpose Geothermal Test and Experimental Activities at Raft River, Idaho," *Geothermal Resources Council Transactions*, July 1978, pp. 83-84.

technical and economic. Moderate temperature geothermal power generation must be developed to a level that it becomes at least roughly competitive with thermal power. However, technical and economic feasibility is a necessary but not sufficient condition for commercial development. The institutional problems remain. In short, they are: how to transform and expand an R&D effort conducted by the federal government on federal land into a workable commercial enterprise conducted by utilities on federal, state and private lands. The result will depend on the success of interactions between federal agencies, state agencies, and the utilities.

At the federal level, the institutional issues arise from the necessity of transferring both the pilot generating facilities and the geothermal resources to utilities for commercial use. (The factual information in this paragraph is based on a telephone conversation with Sky Bradley, DOE General Counsel's Office, Idaho Falls, Idaho, January 26, 1979.) At the end of the project, DOE will own the pilot facilities. Its ability and willingness to relinquish control are not in question. DOE regards the Raft River project as basically an R&D enterprise. DOE's position is that once the experiment is complete--that is, when test results from the second 5 MWe facility are in, sometime in the late 1980s--DOE's interest would cease, and the facilities would become surplus government property, to be sold by the General Services Administration to the highest bidder. Transfer of the geothermal resources, however, complicates the problem of transition. These resources lie partly under private and partly under federal land. All but one of the current wells is on federal land, under the jurisdiction of Bureau of Land Management. Currently, DOE is operating the project under a relatively informal cooperative agreement with BLM, by which DOE has the right to develop geothermal resources on the land and construct pilot power plants. The more normal procedure in such instances involves negotiating an agreement for "withdrawal from the public domain" for a specified period of time. DOE may soon negotiate sucha formal withdrawal with BLM, in which case the term will probably run for about 10 years from the time at which the withdrawal is granted—that is, through 1989. Whether governed by the current cooperative agreement or a formal withdrawal, the land will revert to BLM when DOE's R&D purposes are complete. The land would then become subject to lease under standard BLM procedures. The problem is coordinating the activites of GSA and BLM so that the pilot plants and the resources are disposed of in a way that enables the owner of the plant to make use of the resources. The preferred mechanism would be to transfer both the resource and the plant to BLM, which could then solicit competitive bids from parties designed to lease both the resource and the facility. However, this would be a novel procedure for the organization, and BLM might be reluctant to adopt this course. Specific congressional legislation might be necessary. Coordinating these arrangements appears to pose the largest institutional constraint to the operation of Raft River on a commercial basis.

The state level institutional constraints appear relatively less severe. The Supremacy Clause of the U.S. Constitution exempts federal activities on federal lands from the state police power. Therefore, DOE did not have to obtain state permission for its activities in connection with the Raft River project. However, DOE has avoided explicitly raising this politically sensitive issue by negotiating a cooperative agreement with the Idaho Department of Water Resources for the development of Raft River. The Department has even contributed some money to the project. Thus, DOE was able to drill its wells without obtaining drilling or water permits from the Department without either agency having to raise the issue. Nonetheless, DOE has proceeded to apply to the state for water permits in connection with the consumptive use of geothermal resources and their later injection. (Telephone conversation with Sue Spencer, E.G.&.G., May 2, 1979.) The application contains a comity provision saying in effect that while the federal government need not apply for the permits, it desires to cooperate. (Telephone conversation with Sky Bradley, January 26, 1979.) This relationship could have a number of beneficial effects. First, it gives the Department of Water Resources a stake in success. Second, it familiarizes Department personnel with the specifics of the Raft River project. Third, it enables the Department to develop necessary procedures. It is likely that when entities clearly subject to the Department's jurisdiction take over Raft River or develop other areas, the Department will have developed the understanding and the repertoire to make the processing of these applications more routine than they would otherwise be. Of course, some state regulators are not presently involved. These include the Idaho Public Utilities Commission and the Air Quality Bureau. Both would become involved in licensing future commercial facilities, at least those constructed by investor-owned utilities. It would be desirable to include them in the current efforts at Raft River, in order to develop their substantive understanding and speed the development of permit procedures. This involvement could hasten the licensing of future facilities.

Institutional barriers relating to the willingness and ability of the utilities to develop and operate geothermal power facilities also appear relatively low, at least in comparison to the situation in other states. As noted, the Raft River Electrical Co-op has been involved with the Raft River project from the beginning. Indeed, the Co-op acted as entrepreneur. (Telephone conversation with Clay Nichols, DOE Raft River Program Office, Idaho Falls, Idaho, January 26, 1979.) As sponsor and observer of the project, the Raft River Co-op will have an understanding and commitment to geothermal energy not shared by many other utilities in the country. And the Co-op may be able to absorb the power. Currently it buys its electricity from Bonneville. As noted repeatedly in this report, the availability of low- cost power from BPA is diminishing. The other suppliers of power in the area--Idaho Power Company and and Utah Power and Light--recently had trouble meeting the area's growing demand for power. Idaho Power was cutting off industrial customers in the area during a recent harsh winter. (Telephone conversation with Clay Nichols, DOE Raft River Program Office, Idaho Falls, Idaho, January 26, 1979.) In addition to the potential willingness to absorb the geothermal power, the Raft River Co-op will likely have the ability to do so. The power from the two pilot plants will go directly into the Co-op's grid. And the Co-op will have had a role in operating the facilities. The Co-op is a member of the Geothermal Power Development Group, which has been formed to operate and maintain the pilot plants at the Raft River project. Other members of the group include WPPSS, BPA, Portland General Electric Company, Idaho Power Company, and the Snake River Power

Association.[17] The involvement of these organizations could also serve to spur their interest in managing other geothermal facilities, whether at Raft River or at the other two main locations in Idaho.

In short, the early involvement of the utilities and the Idaho Department of Water Resources in the Raft River geothermal project bode well for geothermal power development in the state. The main institutional difficulties are likely to stem from the mechanics of transferring the Raft River facilities and resources to the utilities, and possibly the length of time for state agencies not presently involved to develop requisite understanding and procedures.

[17] Walter Youngquist, "Pacific Northwest Geothermal 1977 Review--1978 Outlook," Geothermal Energy Magazine, June 1978, p. 41.

THIS PAGE

WAS INTENTIONALLY

LEFT BLANK

CHAPTER FOUR: OREGON

In Oregon, the scenario specifies an increase of generating capacity of 3,343 MWe—from 9,759 MWe in 1978 to 13,102 MWe in 1990. Most of the increment represents new hydroelectric and nuclear power. However, coal steam and geothermal are also assigned significant portions of the increase. Institutional constraints to realization of the scenario in Oregon are relatively important. Much of the expansion in hydroelectric capacity has not progressed beyond preliminary planning, the Pebble Springs nuclear facility faces the prospect of opposition and legal challenge, and a fairly slow federal leasing program compounds the technical and economic barriers to geothermal power development. Only the coal steam capacity and a portion of the hydroelectric capacity seem relatively secure.

4.1 HYDROELECTRIC

The scenario envisions the addition of 1,359 MWe of hydroelectric capacity in Oregon from 1978 to 1985, and no additional capacity from 1985 to 1990. However, as noted in Table 4, projects currently planned to expand hydro generating capacity in Oregon amount to slightly over 800 MWe. This is only about 67% of the capacity projected in the scenario. Moreover, of the projects listed on Table 4, the only one which is almost certain to be completed by 1990 is the addition to the Bonneville Dam, which is currently under construction. With only minor delays, the Cougar-Strube and Illinois projects could be completed in the late 1980s, but major slow-downs could push completion of these past 1990. Finally, the McNary Dam project could also be completed within the time frame of the scenario. Since the Administration must propose the project, and Congress must authorize and fund construction, its completion by 1990 depends upon political priorities and decisions at the federal level. However, timely completion of the smaller (600 MWe) of the alternative proposals for McNary, when combined with the additional capacity of the Bonneville project, would allow this element of the scenario to be substantially realized.

TABLE 4

ADDITIONAL HYDROELECTRIC CAPACITY PLANNED FOR OREGON

PLANT/AGENCY/LOCATION	SCHEDULED DATE OF COMPLETION	CAPACITY (MEGAWATTS)	CURRENT STATUS
Bonneville Dam, Second Powerhouse U.S. Army Corps of Engineers Columbia River, Multnomah County	1985	530	Under construction.
McNary Dam, Second Powerhouse U.S. Army Corps of Engineers Columbia River, Umatilla, Oregon	1988?	600-1,000	Phase I study.
Cougar-Strube Dams U.S. Army Corps of Engineers 45 miles east of Eugene on the McKenzie River	—	40	Under study.
Illinois River Dams Coos-Curry Electric Cooperative, Inc. Illinois River, Curry County	—	200	Planning stage.
Owhyee Dam Bureau of Reclamation Owhyee River, Malheur County	—	30-50	Under study.

Other potential projects not currently under active consideration could possibly be completed by 1990. However, given necessary planning, regulatory, and construction lead times, planning on these would have to begin almost immediately.

This section outlines the institutional context in which hydroelectric facilities are developed in Oregon and then reviews the current status and likely prospects of hydroelectric projects in the state in light of institutional constraints.

4.1.1 Institutional Context

In reliance on publicly owned versus investor-owned utilities, Oregon occupies a position between Idaho's investor-owned and Washington's public orientation: investor-owned utilities service 63% of Oregon's load; publicly owned utilities and co-ops service the remainder. Oregon's investor-owned and publicly owned utilities alike rely heavily on hydroelectric power. The utilities purchase the bulk of their hydropower at wholesale from BPA supplies, which are generated at federal projects on the Columbia River and its tributaries in Washington and Idaho as well as Oregon. The utilities obtain some power from nonfederal dams in Oregon, built by the utilities themselves.

The procedures for construction of federal hydroelectric projects are detailed in Sections 3.1 and 5.2 on hydroelectric power in Washington and Idaho and need not be repeated here. Like Washington and unlike Idaho, Oregon lacks a state agency that develops its own hydroelectric power projects. Therefore, there is but one alternative to federal construction of hydroelectric facilities: construction by the utilities themselves. Whether the developer is a peoples' utility district, a municipal utility, a rural electric cooperative, or an investor-owned utility, any nonfederal project is governed by ORS 469.300-469.570. This statute requires developers of energy facilities—including hydroelectric generating plants with a nominal capacity of more than 25,000 kilowatts—to obtain a site certificate from the Oregon Energy Facility Siting Council. The Council consists of seven public members appointed by the governor. It receives applications for site certification; sends copies to specified state agencies and affected cities and counties; studies the site application independently or with outside assistance; holds public hearings, and approves, conditionally approves, or rejects the site application. For applications to add generating capacity to an existing dam the Council must act within six months after the application is filed; for applications to build new hydroelectric facilities, within twelve months. Approval or rejection is subject to judicial review by the Oregon Supreme Court. Once the certificate of approval becomes final, it binds the state and all its political subdivisions as to the approval of the site and the construction and operation of the facilities. Affected state agencies and political subdivisions must issue the appropriate permits, licenses, and certificates necessary for construction and operation of an approved facility.[1] As a consequence, ORS Ch. 543, which requires the developer of any hydroelectric project to obtain a preliminary permit and a license from the Oregon Department of Water Resources, becomes essentially a formality.

4.1.2 Current Status of the Projects and Institutional Constraints

4.1.2.1 U.S. Army Corps of Engineers

The Army Corps of Engineers has begun construction of a second powerhouse at the existing Bonneville Dam. Upon completion, scheduled for 1982, this powerhouse will add an additional eight turbines with a combined capacity of 530 MWe.

The Corps is also preparing a Phase I study on a project to add a second powerhouse to McNary Dam on the Columbia River near Umatilla, Oregon. The Corps is considering the addition of from 6 to 10 new generating units to provide additional generating capacity of from 600 to 1,000 MWe at McNary. The Phase I report is scheduled for completion in October, 1979, when it and a draft EIS will be circulated for review. This report will probably be submitted to Congress in 1980. If Congress authorizes the project and provides the funds to proceed, the Corps expects to have a Phase II study, including detailed engineering and design work and a final EIS,

[1] ORS 469.400.

completed by FY 1982. At that point, the Administration must request authorization and funding from Congress for the Corps to proceed with construction. Should Congress do so immediately, the Corps would expect to have the project completed by 1988. (Telephone conversation with Frank Parsons, U.S. Army Corps of Engineers, Walla Walla Branch, January 19, 1979.) However, opposition to the project, or conflicting budgetary priorities on the part of the Administration or Congress, could lead to delays in authorization or funding, and corresponding delays in project completion. It is currently difficult to predict either the length or the likelihood of such delays.

The Corps is also involved in a detailed study of a project to add an additional 35 MWe generating unit to the existing Cougar Dam, and to construct the Strube Dam, a 36 foot high earthen structure downstream from the Cougar on the McKenzie River. Primarily proposed to regulate river flow, the Strube Dam is expected to have one or two small generating units with an additional capacity of about 5 MWe. The overall project received congressional authorization in 1962, and funding for a joint Phase I-Phase II study was appropriated by Congress in 1977. Currently, a draft of this report is circulating for review within the Corps, and among other governmental agencies, public interest groups, and individuals. In the public hearings held as part of this review, the project drew some opposition on environmental grounds. The Corps' congressional appropriations hearings will be held in February 1979. However, the project has not been included in the President's proposed budget, and it seems unlikely Congress will appropriate funds for construction of the project this year. (Telephone conversation with Ken Cooper, U.S. Army Corps of Engineers, Portland Office, January 26, 1979.)

If the Cougar-Strube project receives funding within the next few years, it could be completed by 1990. Whether or not it does receive funding depends upon the priorities of the Administration and Congress and the amount of state and local support or opposition the project receives in congressional hearings or other forums.

4.1.2.2 U.S. Bureau of Reclamation

The Bureau is conduction a preliminary or appraisal level study of adding power generating units to the existing Owhyee Dam. This dam, on the Owhyee River in eastern Oregon, is now used for providing water for irrigation purposes. As currently envisioned, the project would add between 30 and 50 MWe of generating capacity. The appraisal level study was authorized during FY 1979, and is expected to take two years. A feasibility study, if authorized and funded by Congress, would probably take another two or three years. Construction of the project would require an additional five to six years. (Telephone conversation with Perry Harrison, U.S. Bureau of Reclamation, Boise Office, January 19, 1979.) Thus, the very earliest the project could be completed would be 1989 or 1990. However, this time frame assumes that Congress would immediately authorize and fund construction once the feasibility study is complete, and that the project would encounter no additional delays. Even modest opposition or slippage for other reasons would preclude completion by 1990.

4.1.2.3 Coos-Curry Electric Cooperative, Inc.

The Coos-Curry Electric Co-op, Inc., a rural cooperative, has proposed construction of two hydroelectric dams on the Illinois River in southwest Oregon. This project would involve the construction of a 590 foot generating dam and a small reregulating dam downstream. The capacity of the two generating units would be about 200 MWe. The Cooperative has applied to FERC for a preliminary permit which would allow site testing and analysis to proceed during the planning process. Although no firm schedule has been set for completion of the facility, it could be completed by 1990 if no lengthy delays in licensing or construction are encountered. (Telephone conversation with W. A. Cook, Manager, Coos-Curry Electric Cooperative, Inc., January 25, 1979.) At this point, it is difficult to estimate the potential magnitude of opposition to the plant, and therefore the likelihood of its completion by 1990.

4.2 NUCLEAR

The nuclear component of the scenario envisions the addition of a total of 1,174 MWe of generating capacity in Oregon between 1985 and 1990. This figure approximately corresponds to the power expected to be generated by one unit of the two unit 2,250 MWe Pebble Springs nuclear power plant being planned by Portland General Electric (PGE) and other utilities. Although PGE expects to have both units completed by 1989, there are a number of legal issues which may either delay licensing or complicate financing of the project to the extent that completion of one or both units is delayed beyond 1990.

This section summarizes the institutional context for nuclear power development in Oregon, describes the current status of the proposed Pebble Springs plant, and identifies several institutional constraints to its timely completion.

4.2.1 Institutional Context

In broad outline, the procedures for bringing a nuclear power plant on line in Oregon are similar to those applicable in Washington. As in Washington, the developer must win site certification approval from the state siting authority, which in Oregon is the Energy Facility Siting Council (EFSC) created by ORS 469.300-469.570. As in Washington, the Council's procedures constitute a one-stop licensing process that overrides the individual authority of the state's agencies and political subdivisions. Unlike Washington's Council, however, the Oregon EFSC is composed of public members appointed by the governor, each serving for four years at the governor's pleasure, rather than members representing the state agencies affected.[2] The EFSC procedures are outlined in Section 4.1 on hydroelectric power and need not be repeated here, except to note two differences in the procedures applicable to nuclear as opposed to hydroelectric facilities. First, at least 120 days before filing an application for site certification the developer must file a "notice of intent" to file an application for

[2] ORS 469.450.

nuclear site certification identifying and describing the site.[3] Second, the Council has 24 months after the application is filed to approve or disapprove the site.[4] In addition, of course, the developer must obtain a construction permit and operating license from NRC. Intervention in the EFSC and NRC hearings, and appeals of the orders certifying the site and granting the construction permit, afford interested groups several opportunities to raise issues of concern and possibly to delay construction. In principle, opponents could also apply pressure on the Governor to remove members of the EFSC, but this would likely be a politically difficult course during the middle of a site certification proceeding.

4.2.2 Current Status of the Plant

The Pebble Springs nuclear power plant would be built and operated by Portland General Electric, Pacific Power and Light, Puget Sound Power and Light, and the Pacific Northwest Generating Company, the latter a consortium of rural electrical cooperatives in Washington and Oregon. The facility is to be located on the Columbia River in Gilliam County, Oregon. It would consist of two generating units of 1,260 MWe each.

In 1972, PGE filed its notice of intent to construct the project with the Oregon Nuclear Energy Council, the predecessor of EFSC. In 1974 the Council held public hearings and in 1975 recommended that the Governor approve the facility, as provided under then-existing law. However, the Council's decision was appealed to the Oregon Court of Appeals by two intervenors. The primary basis for this appeal was that the "council failed to establish the standards required by ORS 469.470 before it reached its decision to recommend a site certificate for the Pebble Springs project."[5] In March 1977, the Oregon Supreme Court reversed the Court of Appeals and held in favor of the intervenors, remanding the case to EFSC. The Council immediately began rulemaking proceedings to develop general standards that

[3] ORS 469.320, 469.350.

[4] ORS 469.370.

[5] Application of Portland General Electric Co., 561 P.2d 154, 162 (Or. 1977).

applicants for site certification must meet. In July 1977 and January 1978 the Council promulgated such standards as rules.

In the meantime, the Council reopened hearings on PGE's application for site certification of the Pebble Springs plant. These hearings were apparently concluded in December of 1978. (Telephone conversation with Don Goddard, Oregon Department of Energy, February 6, 1979.) More recently two sets of events have led EFSC to plan reopening hearings yet again. First, NRC has withdrawn its support of certain portions of the Rasmussen Report on reactor safety.[6] Second, the events at Three Mile Island may have implications for the Pebble Springs facility, which also would utilize pressurized water reactors supplied by Babcock and Wilcox, though of a different design than the nuclear steam supply system at Three Mile Island.[7] Before these events PGE expected to receive both EFSC site certification and the NRC construction permit during 1979, and planned to commence construction in early 1980. Unit 1 was scheduled for completion in 1987, and Unit 2 was scheduled for completion in 1989. (Telephone conversation with Dave Eagon, Public Relations Department PGE, January 25, 1979, and Don Goddard, Oregon Department of Energy, February 6, 1979.)

4.2.3 Institutional Issues

Several legal constraints may delay PGE's planned schedule. First, NRC approval of the facility's construction permit is likely to take longer than initially expected. The events at Three Mile Island will almost certainly result in new NRC safety regulations with respect to design and operation of civilian power reactors.[8] These regulations, which themselves may

---

[6] Nuclear Regulatory Commission, Reactor Safety Study (WASH-1400, August, 1974). "Nuclear Regulatory Commission Issues Policy Statement on Reactor Safety Study and Review by Lewis Panel," Nuclear Regulatory Commission News Release, January 19, 1979.

[7] "Panel to probe safety of Pebble Springs Plant," The Oregonian, March 30, 1979.

[8] Nucleonics Week, April 19, 1979, pp. 5-6.

require a year or more to promulgate, could have particular impact on Pebble Springs reactor, which like Three Mile Island is to be supplied by Babcock and Wilcox.

Second, EFSC will also reopen its hearings as a result of the events at Three Mile Island. EFSC had already planned to reopen hearings in response to withdrawal of NRC support for some portions of the Rasmussen Report. PGE did not expect the issues raised by this action to represent a serious obstruction to site certification. (Telephone conversation with Dave Eagon, op. cit.) Three Mile Island may pose more serious issues. EFSC's new site certification standards expressly address the adequacy of the emergency core cooling system and the level of residual risk to the public arising from operation of the facility.[9] Governor Vic Atiyeh, who has said he would be "very comfortable if they [the siting council] said no" and reject the facility on this basis.[10] At the very least, new safety issues will likely require considerable time to explore. Their resolution by EFSC will probably await the outcome of NRC actions.

Newly posed safety issues aside, if EFSC disapproves the facility, PGE could appeal the decision to the Oregon Supreme Court. If EFSC does grant approval, intervenors will almost certainly appeal. (Telephone conversation with Don Goddard, Oregon Department of Energy, January 10, 1979.) In addition to raising the safety issues, the intervenors are likely to challenge the need for the power and the methods used by the utilities to forecast energy demand, as well as the relative economy of the Pebble Springs plant in providing electrical power to the region, even the need is shown. Since the original appeal of the Council's recommended certification of the Pebble Springs plant in 1975, the Oregon legislature has made a number of changes in the state's energy facilities siting legislation to reduce potential delays in the certification and appeals process. Under previous versions of the statute the Council was only able to recommend that the Governor approve a site certification application. Before consideration by the Governor, the

---

[9] O.A.R. §§345-76-030, 345-76-032.

[10] "Panel to probe safety of Pebble Springs Plant," The Oregonian, March 30, 1979.

recommendation could be appealed—first to the Oregon Court of Appeals then to the Oregon Supreme Court. To streamline this process, the legislature authorized the Council itself to grant or deny site certification, removing the Governor from the process, provided that appeals proceed directly to the Supreme Court, and directed the Supreme Court to give such cases priority.[11] Thus, once the Council's decision on site certification is appealed, this process would likely take less than the two years required for the previous appeal.

A third issue which could delay the project is the possible difficulty in obtaining the additional financing that will be required as a result of the passage of Ballot Measure 9 by Oregon voters in November 1978. This measure prohibits utilities from directly including charges for "construction work in progress" (CWIP) in their rate base. Opposition to inclusion of CWIP charges in the rate base has two main sources. First, consumer advocates argue the inequity of charging the current generation of power users for capacity that will serve a future generation. Second, opponents of nuclear power see exclusion of CWIP from the rate base as one more barrier to erect in the fight against construction of nuclear facilities. And even a losing fight for excluding CWIP could provide a forum for raising nuclear power issues.

The successful campaign in Oregon resulting in the passage of Ballot Measure 9 raises a number of uncertainties. In a rate order issued on January 25, 1979, Oregon's Public Utilities Commissioner Davis included an interpretation of several critical aspects of Ballot Measure 9.[12] Most important, he ruled that PGE be allowed a "fully compensatory AFDC rate." A "fully compensatory Allowance for Funds Used During Construction (AFDC) rate" simply means that the full amount of the interest paid during construction can be capitalized once the project is completed and subsequently recovered through amortization. Before the passage of Ballot

[11] ORS 469.370, ORS 469.400.

[12] Public Utility Commission of Oregon, Order No. 79-055 (1979).

Measure 9, a utility could issue bonds to pay for a large construction project, and include the payments made to retire these bonds as part of the rate base while construction was in progress. However, passage of the measure prohibits this practice. In order to pay the interest on the money borrowed for construction, the utility must now borrow additional money during construction. Previously, since ratepayers were absorbing some of the interest during construction, interest payments could be only partially capitalized.

However, the Commission rejected PGE's arguments that passage of the measure increases the risks to those who loan money to a utility for the construction of a power plant. As a result, the Commission will not allow PGE to pay higher interest rates on the utility's bonds to reflect increased risk. Apparently, the basis for this judgment was a further interpretation allowing a utility to amortize (and thus include in the rate base) the cost of any plant which for safety, environmental, or other reasons never reaches completion or goes into operation. In other words, with this guarantee of repayment, lenders face no additional risk and thus should not require a premium.

The Public Utilities Commission does not believe the measure will impair the ability of utilities to finance large energy facilities. However, the Commission does concede that the measure will raise the ultimate costs to the customers of a utility undertaking such a project. This is because the ratepayers must ultimately pay back both the money borrowed to construct the facility <u>and</u> the money borrowed to make interest payments on loans during the construction period. The Commission points out that since the rate of interest paid on loans to the utility is generally higher than the rate of interest generally available to the utility's customers, the ultimate cost to the utility's customers will be greater.[13]

Although the Public Utilities Commission maintains the measure will not hinder the future development of large energy facilities, (Telephone conversation with Leroy Hemmingway, Deputy Commissioner, Public Utility Commission

---

[13]Public Utility Commissioner of Oregon, Additional Staff Testimony, Portland General Electric UF3443, November, 1978.

of Oregon, January 26, 1979), considerable uncertainty as to the measure's ultimate impact remains among utilities and others. Moreover, if the experience of the state of Missouri is indicative, a rapid resolution of this uncertainty may not be forthcoming. Apparently, the construction of plants in the state has been halted since 1976 when CWIP was disallowed from the rate base of utilities in Missouri. (Telephone conversation with Dave Eagon, Public Relations Department, Portland General Electric, January 25, 1979.)

4.3 GEOTHERMAL

The scenario calls for 400 MWe in geothermal electric generating capacity in the state of Oregon by 1990. Although some capacity may then be in, 400 MWe appears much too high a figure. Oregon may have substantial geothermal resources appropriate for moderate temperature power generation. Three KGRAs in the southeastern corner of the state--Alvord Desert, Crump Geyser, and Summer Lake--all appear to have potential for development. The main barriers to development of these and other geothermal resources for power development in Oregon stem for uncertain technical and economic feasibility (problems now being addressed at the Raft River Project), uncertainty about the nature and extent of the resources, and several institutional factors. This section highlights some of the institutional barriers at each of the critical stages in bringing geothermal generating capacity on line: leasing, exploration, development of power plants and production fields, and transmission.

4.3.1 Leasing

The procedures for leasing geothermal resource rights on federal lands is described in Section 5.3 on geothermal power generation in Washington. The procedures for leasing geothermal resources located on Oregon state lands are well developed. They involve routine application and review by the Division of State Lands.[14] Owners of private land own the geo-

---

[14]ORS 273.780.

thermal resources lying underneath.[15] Therefore, the leasing of such resources is subject to individual negotiation and contractual arrangements.

The geothermal resources of many federal, state, and private acres in Oregon are now under lease for the purpose of geothermal resource exploration. For example, 67,000 of the 177,000 acres at the Alvord Desert KGRA are now under lease; at least 14,500 of the 85,500 acres of the Crump Geyser KGRA have been leased; and at least 7,875 acres of the 13,600 acres of the Summer Lake KGRA have been leased. (Telephone conversation with Robert Koeppen, Geoheat Utilization Center, Klamath Falls, Oregon, January 26, 1979.) Significant acreage elsewhere in the state, often outside KGRAs, is also under lease, much of it from private owners. (Telephone conversation with Deborah Justus, Oregon Department of Energy, February 6, 1979.) Caution at the federal level has hindered the leasing process at all levels. BLM and the U.S. Forest Service have been very slow in issuing leases. Partly this delay seems to stem from limited resources to do the necessary analysis before leases can be issued. Sometimes, the appropriate level of analysis may be determined by others. For example, the High Desert Study group and the Sierra Club have sued BLM seeking preparation of a full environmental impact statement in connection with geothermal leasing in the Alvord area. In January 1978, the U. S. District Judge denied a preliminary injunction and allowed leasing to continue, but BLM seems to be proceeding cautiously pending outcome of the case on the merits. (Telephone conversation with Deborah Justus, Oregon Department of Energy, February 6, 1979.) In addition, both BLM and the U.S. Forest Service are in the process of preparing generic analyses of their land management practices, which are also slowing the process. (Telephone conversation with Deborah Justus, Oregon Department of Energy, February 6, 1979.)

Delay at the federal level also impinges on leasing from state and private owners. Since the pattern of land ownership in Oregon is often of a patchwork variety, a prospective developer must assemble a collection of federal, state, and private leases in order to develop a given area. Developers are reluctant to drill on state or private land adjacent to federal

---

[15] ORS 522.035.

land before obtaining federal leases because if they make a discovery, the federal land is likely to be declared a KGRA and leases thereon subject to competitive bidding. (Telephone conversation with Herbert Hunt, Eugene Water and Electric Board, February 5, 1979.) BLM has recently announced a tentative schedule for the sale of leases on federal lands which if followed would break this bottleneck in FYs 1979 and 1980.[16]

4.3.2 Exploration

The procedures for exploration on federal lands are outlined in Section 5.3 on geothermal development in Washington. Basically, the process involves application for a drilling permit from the USGS, environmental analysis by the Service, and issuance of a permit containing conditions. Oregon has its own legal requirements for geothermal resource development.[17] Although by implication Oregon law purports to apply to drilling on federal lands, the Supremacy Clause of the U.S. Constitution as well as federal preemption under the Geothermal Steam Act of 1970 probably insulate developers of geothermal resources on federal lands from state regulation. However, developers of federally owned resources may find it prudent to comply with state law in any case.

Obviously, developers of geothermal resources on state or private lands must comply with state procedures. The procedures depend upon whether the application is for a "prospect well" or a "geothermal well." Basically, a prospect well is a well of less than 500 feet in depth drilled in prospecting for geothermal resources.[18] A geothermal well is any excavation 500 feet deep or more made either for discovery or for production of geothermal resources. A permit for a prospect well requires submission of a $200 application and a $5,000 bond or security deposit to the State Geologist, limited review by affected agencies, and issuance of the permit by the State Geologist. Application for a geothermal well permit requires

---

[16] 1 CCH Federal Energy Management ¶9422.

[17] ORS Ch. 522.

[18] ORS 522.005.

submission of a $100 application fee and a $10,000 bond or security deposit for each well to be drilled or a total $25,000 bond or security deposit for three or more wells. The State Geologist circulates the application to affected state agencies, which may suggest conditions to be imposed on the applicant. Before issuing the permit, the State Geologist must determine that issuing the permit would be consistent with Oregon laws concerning air quality, water quality, and the appropriation of ground water. If necessary, he must impose conditions in the permit to insure compliance with the purposes of these laws, as well as any conditions proposed by the Department of Environmental Quality (with respect to air and water quality) and the Water Resources Director (with respect to appropriation of ground water) necessary to carry out the statutory purposes.[19] In addition, successful applicants must separately obtain air and water pollution control permits from the Department of Environmental Quality.

Both federal and state procedures appear to be reasonably well worked out. Extensive exploration has been conducted and is continuing in areas throughout the state.[20]

4.3.3 Selling and Utilizing the Resources

As indicated in the discussion of geothermal resource development in Washington, once a developer has demonstrated the geothermal resource potential of a particular site, it must sell the resource to a user. Economic and technical considerations aside, potential users may be somewhat reluctant to embrace geothermal resources as a source of electrical capacity, simply because of the novelty. In the case of Idaho, utilities are already sufficiently involved that this barrier may not be insuperable. In Oregon, some utilities have expressed interest in geothermal resource development. For example, the Eugene Water and Electric Board has adopted a 3-year strategy for geothermal resource development, which involves monitori all leasing activities on the west side of the Cascades from Mt. Hood to Eugene. The

---

[19] ORS 522.135.

[20] See Walter Youngquist, Pacific Northwest Geothermal 1977 Review, "1978 Outlook," Geothermal Energy Magazine, June, 1978.

utility has invited all resource companies to exchange information. Further, the utility has been negotiating with utilities in the Southwest to jointly develop a small pilot project in Nevada. Participation of the utility in a project in Nevada is currently prohibited by state law, but the utility has been instrumental in introducing a bill in the current session of the legislature which would allow such participation. (Telephone conversation with Kenneth Rinard, Eugene Water and Electric Board, April 30, 1979.) Thus if significant discoveries are made, the Eugene Water and Electric Board appears ready to move. Other utilities in the state have taken a similar approach. (Telephone conversation with Herbert Hunt, Eugene Water and Electric Board, February 5, 1979.)

4.3.4 Construction of Production Facilities

The procedures for developing production wells and constructing generating capacity on federal lands are outlined in the section on geothermal resource development in Washington. For state and private, and possibly federal, lands, Oregon imposes its own requirements. Production wells fall under the definition of geothermal wells in ORS Ch. 522 and thus require a drilling permit obtained through the procedures just described. Geothermal power generation is also subject to the Oregon energy facility siting laws.[21] As with hydroelectric and nuclear facilities, a person desiring to utilize geothermal resources for producing electric power must obtain site certification from the Oregon energy facilities siting council. The procedures are as described in connection with site certification for hydroelectric facilities, except that the Council must act on an application within nine months of filing. Because no one has yet applied for a geothermal facility site certification, the Council might find this schedule difficult to follow. The Council has not promulgated general standards for geothermal siting, nor has it developed the specific procedures that an applicant would have to follow. Therefore, the siting of the first several geothermal power facilities may be expected to go slowly. (Telephone

---

[21] ORS 469.300-469.570.

conversation with Deborah Justus, Oregon Department of Energy, February 6, 1979.)

4.3.5 Transmission

Because of the relatively small size of geothermal power generating facilities and the typical isolation of geothermal resources from major load centers, the availability of existing transmission facilities may be an important determinant of geothermal feasibility. In Oregon, the situation appears relatively favorable. The Alvord, Summer Lake, and Crump Springs KGRAs are all within 20 miles or so of existing significant transmission lines, in the case of Crump Springs and Summer Lakes major 800 KV BPA lines. (Telephone conversation with Deborah Justus, Oregon Department of Energy, February 6, 1979.) On the west side of the Cascades, most geothermal resources are near existing power grids. (Telephone conversation with Herbert Hunt, Eugene Water and Electric Board, February 5, 1979.) The relatively short distances involved in construction of the necessary tie lines should limit the economic and political costs of constructing the requisite transmission capabilities.

4.4 COAL STEAM

The scenario envisions the addition of 500 MWe of coal generating electrical capacity in the state of Oregon by 1985, with no additional capacity from 1985 to 1990. This is equivalent to the planned capacity of the Boardman coal-fired plant currently under construction in Morrow County. The Boardman plant is being built by Portland General Electric, Idaho Power, and the Pacific Northwest Generating Company, a consortium of rural electric cooperatives. The plant obtained site certification from Oregon's EFSC in 1974 or 1975 and construction began in 1976. As of January 1979, the plant was from 40% to 50% complete and was expected to be operational by mid-1980. (Telephone conversation with Dave Eagon, Public Relations Department, Portland General Electric, January 25, 1979.) At this point, institutional issues sufficient to significantly delay completion seem unlikely to arise.

CHAPTER FIVE:
WASHINGTON

According to the scenario, electrical generating capacity in Washington is to increase from 16,559 MWe to 29,268 MWe between the years 1978 and 1990. The increase is to come primarily from three sources: nuclear, hydroelectric, and geothermal.* With several important exceptions, institutional constraints are unlikely to prevent construction of the requisite facilities. The additional nuclear capacity and most of the hydroelectric capacity are likely to be in place by 1990. Legal and political concerns may, however, prevent Seattle City Light from undertaking the Ross Dam and Copper Creek projects that are part of the scenario. The geothermal generating capacity, which represents 400 MWe, is unlikely to be available. In this instance, institutional constraints only reinforce the central technical and economic constraints.

5.1 NUCLEAR

The nuclear component of the scenario for Washington consists of five nuclear power plants currently under construction by the Washington Public Power Supply System. Three of these plants are to be located at Richland and two at Satsop. All five are sufficiently far along that barring extraordinary circumstances, neither technical nor institutional considerations are likely to stand in the way of their completion by the dates specified in the scenario.

Not included in the scenario is the capacity represented by a two-unit, 2,660 MWe nuclear power plant planned by Puget Sound Power and Light for Skagit County. Puget Power applied to NRC in 1972-73 for a construction permit. The two units were originally scheduled for operation in 1981 and 1984. However, numerous parties have intervened in the hearing process and raised a number of issues. Early in 1978, intervenors raised serious safety questions regarding potential seismic activity in the area. These questions have led NRC to require further geological studies in the region. As of

*The scenario also specifies an addition of 131 MWe of oil peaking capacity and 510 MWe of combined cycle capacity. This report does not discuss these scenario elements.

April, 1979, these issues remained unresolved. In April, 1979, Valentine Deale, Chairman of NRC's Atomic Safety and Licensing Board, identified areas in which further information would be needed before the Board could make a decision on Puget Power's application for a limited work authorization. First, he indicated further information was needed on the geological and seismological conditions at the proposed site. Deale also indicated the review of alternative sites in the EIS was inadequate, and requested additional testimony before the Board to compare such alternatives. The Board also wishes to consider the need to analyze a possible reactor melt-down at the site, as well as the possible impacts of a failure of Seattle City Light's proposed Copper Creek Dam upstream from the site on the Skagit River.[1] Currently, Puget Power still formally plans to have units 1 and 2 in operation by 1986 and 1987-88, respectively. However, given the past history of the hearings proceedings and the nature of the unresolved issues, there remains some doubt as to whether this schedule will be met. Therefore, their exclusion from the scenario appears reasonable.

This section sketches the institutional context in which the construction of the nuclear facilities is taking place, describes the current status of these facilities, and identifies several institutional constraints that could delay their completion.

5.1.1 Institutional Context

5.1.1.1 Financial Aspects

The builder of all five nuclear plants represented by the scenario is the Washington Public Power Supply System (WPPSS). WPPSS was established in 1957 as a municipal corporation and joint operating agency of the State of Washington. Its members consist of 19 public utility districts and three

---

[1] "Board Wants New Information on Puget Power N-Plants," Seattle Times, April 23, 1979, p. A 11.

municipal utilities in the State of Washington.[2] Essentially, WPPSS is a vehicle for the joint construction and operation of thermal power plants by its member utilities, which are thereby able to aggregate their capability to issue low-interest municipal bonds.

In 1967, WPPSS and its member utilities joined with other utilities in the region and with BPA to form the Joint Power Planning Council (JPPC). In 1968, the Council adopted a set of regional power goals and planning strategies constituting the Hydro-Thermal Power Program. The fundamental principle embodied in the program was to meet the region's increasing base load with power generated by new thermal sources, and the region's peak demands with power generated by existing and expanded hydroelectric sources.[3] WPPSS and the region's utilities soon embarked upon what was to become known as Phase I of the program, which envisioned the construction of seven thermal power plants in the region by 1981, including the five nuclear power plants considered here, WPPSS Units 1-5.

The new thermal plants were to be financed through net billing, as described in Chapter Two. Congress approved the net billing arrangement for WPPSS units 1, 2, and 3, and the Trojan nuclear plant in Oregon in 1969 and 1970. Under these arrangements WPPSS has assigned BPA the entire output of units 1 and 2, and 70% of the output of unit 3. Because of Treasury regulations described in Chapter Two, WPPSS was forced to rely on agreements with the utilities themselves to purchase the power in order to finance units 4 and 5.

5.1.1.2 <u>State Licensing Procedures</u>

In constructing the facilities, WPPSS is subject to the state and federal licensing procedures. The state licensing process centers on the approval of the Energy Facility Site Evaluation Council (formerly the Thermal Power Plant Site Evaluation Council), created by RCW Ch. 80.50. Represented on the Council are the state agencies and political subdivisions

---

[2] WPPSS, <u>Quarterly Report</u>, September 30, 1978.

[3] Northwest Energy Policy Project, <u>Institutional Constraints and Opportunities, Study Module V, Tasks 1-3</u> (Springfield, VA: National Technical Information Service, 1977) ("NEPP V/1-3"), Ch. 6.

whose approval would otherwise have to be individually obtained for siting of the facility. Instead of approving the facility separately, however, the Council's members review the application for compliance with relevant state laws, hold hearings, and collectively pass on the application. If the Council's decision is favorable, it recommends certification (subject to any conditions) by the Governor, with whom the final decision rests. Among other things, EFSEC is responsible for ensuring the equivalent of compliance with the Washington State Environmental Policy Act (RCW Ch. 43.21C) through environmental analysis by an independent consultant.[4] EFSEC's authority supersedes the authority of all state agencies and political subdivisions that might otherwise impose requirements on the construction of the facility.

Apparently, EFSEC's authority even overrides city, county, or regional zoning codes. The Council is required to hold hearings on compliance of the facility with land use plans or zoning ordinances. The enabling statute provides that "if it is determined that the proposed site does conform with existing land use plans for zoning ordinances in effect as of the date of the application, the county or regional planning authority shall not thereafter change such land use plans or zoning ordinances so as to affect the proposed site."[5] This language might seem to imply that if the facility does not comply with applicable land use law as of the date of the application, EFSEC cannot approve the site. However, a recent Attorney General's opinion states that the Council may approve sites even though their use is inconsistent with local land use laws. The opinion cites the preemption language in the statute, RCW 80.50.110(2).[6] This issue is now being litigated and will be resolved either by the Washington Supreme Court or by legislation. State legislators have recently introduced several bills that would require compliance with local zoning as of the date of application to

---

[4] RCW 80.50.071.

[5] RCW 80.50.090.

[6] AGO 1977 No. 1.

EFSEC.[7] Governor Ray has indicated her opposition to such legislation.[8]

5.1.1.3 Federal Licensing Procedures

Under the Atomic Energy Act of 1954, the Energy Reorganization Act of 1974, and the National Environmental Policy Act of 1969, the Nuclear Regulatory Commission (NRC) is responsible for issuing the requisite construction permit and operating license required to operate a civilian nuclear power plant. The procedures are relatively straightforward. Early in the planning stage, the utility approaches NRC, submitting data on the reactor's proposed site and design along with preliminary safety and environmental reports. These submissions are reviewed simultaneously by two NRC bodies: the licensing staff and a subcommittee of the Advisory Committee on Reactor Safeguards (ACRS), an independent committee of fifteen members from a diversity of fields appointed part-time to four-year terms by the Commission. The ACRS issues brief reports and the licensing staff more detailed statements assessing the proposed reactor's safety and environmental impact, plus details on the applicant's financial status and any antitrust complications. To conduct the mandatory construction permit hearing, the Commission appoints a three-member Atomic Safety and Licensing Board (ASLB), chosen from a panel of qualified lawyers, scientists, and engineers from business and academia. NRC gives at least 30 days notice before the hearing, at which interested parties may speak or formally intervene. The ASLB then issues an initial decision stating its findings of fact and law, including the adequacy of the Commission's final environmental statement. If the regulatory staff, the applicant, or an intervenor files an exception, a three-member Atomic Safety Licensing and Appeal Board (ASLAB) performs the necessary review for the Commission. A party who is dissatisfied with the ASLAB's decision may appeal to the Commission or to a United States Court Appeals. The procedures for issuing an operating license are basically similar, though a hearing is not mandatory at this stage.

---

[7] For example, S. B. No. 3129.

[8] "Ray Opposes Energy Restrictions," Seattle Times, January 17, 1979.

5.1.2 Current Status of WPPSS Plants, 1-5

5.1.2.1 WPPSS Units 3 and 5, Satsop, Washington

WPPSS is undertaking construction of two 1,240 MWe nuclear power plants at Satsop, Washington. WPPSS obtained the necessary site certification permit from the Washington State EFSEC in 1977, and construction permits from NRC in April 1978. As of the end of the first quarter of 1979, construction was 11.2% complete on Units 3 and 1.8% complete on Unit 5, with about one year's slippage from schedule since 1978. Planned commercial operation dates for Units 3 and 5 are December 1984 and June 1986, respectively, which will be ahead of the schedule envisioned in the scenario.[9] Since 1973, estimated costs of completion have escalated from $756 million to $1.5 billion for WPPSS-3 and from $1.2 billion to $2.1 billion for WPPSS-5.[10]

5.1.2.2 WPPSS Units 1, 2, and 4, Richland Washington

WPPSS is constructing three nuclear power plants at Richland. Site certification and construction permits have been obtained for all units and construction is well underway. Plant size and date of scheduled commercial operation of the three units are: Unit 1—1,250 MWe, December 1983; Unit 2—1,100 MWe, September 1981; Unit 4—1,250 MWe, June 1985. As of the end of the first quarter of 1979, the percentages of construction completed were: Unit 1--22.0%, Unit 2--66.8%, Unit 4--7.6%.[11] This represents about one year's slippage from schedule since 1978. Since 1973, estimated costs of completion have escalated from $633 million to $1.6 billion for WPPSS-1 and from $394 million to $1.4 billion for WPPSS-2 and from $1 billion to $1.9 billion for WPPSS-4.[12]

---

[9] WPPSS, Quarterly Report, March 31, 1979.

[10] Nucleonics Week, November 2, 1978, p. 14.

[11] WPPSS, op. cit.

[12] Nucleonics Week, op. cit.

5.1.3 Institutional Constraints

Several categories of institutional factors could delay construction of the WPPSS nuclear facilities. However, none of these factors appears decisive enough to prevent any of the facilities from coming on line by 1990, as envisioned in the scenario.

The first of these factors stems from political opposition to nuclear power in general and the WPPSS facilities in particular. The Crabshell Alliance has targeted the Satsop facilities, conducting demonstrations there and hoping to turn state and local authorities against completion of the facilities. Crabshell is now suing WPPSS to prevent completion of the facility. A Portland-based group called the Hanford Conversion Project aims to stop construction of the WPPSS facilities at Hanford. Neither of these groups appears to have the levers to achieve these immediate ends. Because all the facilities have state site approvals and NRC construction permits, with the exception of the two units at Satsop, they await only NRC operating licenses to begin operation. WPPSS has requested the Washington EFSEC to reopen hearings on the state's certification of the Satsop site in order to increase allowable wastewater discharges of hot water, copper and heavy metals. Considerable opposition to these proposals has been expressed at the EFSEC hearings, which opened on March 27, 1979. Opposition to the proposal is primarily based upon the negative impacts of increased effluent discharges on salmon and steelhead runs in the Chehalis River. The Washington State Departments of Ecology and Fish and Game and a number of private environmental groups are opposing the proposed changes.[13] The situation is complicated by the fact that design of the plants has proceeded not according to existing permits but on the basis of expectations that these effluent limitations will be relaxed.[14] The Council is not

---

[13] "Fish Peril Seen in N-Plant Bid," Seattle Post Intelligencer, March 27, 1979, p. A5.

[14] "Design Won't Match Permit, Council Told," Seattle Times, March 29, 1979, p. C4.

expected to make a final decision on discharge standards until early July.[15]

For the most part, however, the opportunities to political opponents to engage in delaying litigation--for example, challenges to the adequacy of environmental assessments--have largely passed. Absent the discovery of major safety problems at the plants or promulgation of new NRC regulations requiring major redesign, the facilities are likely to receive their operating licenses in timely fashion. Theoretically, political opponents could also achieve their aims through Washington State legislative action directing WPPSS to modify or cancel the facilities, but this course seems unlikely in the extreme--especially in light of the large costs already invested in the facilities.

A second factor concerns management of the construction process generally. Strikes have caused some delays of construction of the units at Hanford. A recent study performed for BPA by Theodore Barry and Associates notes the cost escalations mentioned earlier and attributes them in part to inadequacies in the management of WPPSS. In addition, the study concludes that WPPSS lacks effective checks and balances from either external or internal sources.[16] If this characterization is accurate and WPPSS' management inadequacies continue in the future, additional cost escalation and schedule slippage may be expected; Barry consultants predict the cost of completing the five plants will escalate to about $10 billion.[17] On the other hand, the recent unfavorable publicity should serve to create pressures on WPPSS to do a better job of managing the construction process. For example, the Barry report recommends a strengthened role for the BPA in overseeing construction of the WPPSS facilities. If it turns out that management problems at WPPSS are severe, the Legislature may act to recon-

---

[15] "Testimony Opposes Waste-Rule Changes for Satsop N-Plants," Seattle Times, April 13, 1979, p. A10.

[16] Management Study of the Roles and Relationships of Bonneville Power Administration and Washington Public Power Supply System (Los Angeles: Theodore Barry and Associates, 1979), p. II-3; Seattle Times, January 5, 1979, p. A-14.

[17] "State N-plants Could be the Most Expensive in the U.S.," Seattle Times, January 6, 1979.

struct its managment in a fashion that forces it to be more responsive. Senator Ted Bottiger, chairman of the Senate Energy and Utilities Committee in the Washington legislature, has proposed creation of a joint legislative committee to monitor the projects on a continuing basis.[18] A similar measure has also been proposed in the state's House of Representatives.[19] Such a shakeup could be highly disruptive of facility construction in the near term. However, this course might ultimately speed the construction process, and at least is not likely to have a decisively negative effect in the long run.

A third factor involves continuation of the net billing practice. In principle, reconstitution of BPA's role could alter or eliminate the net billing arrangement negotiated between WPPSS and BPA to finance the construction of Units 1-3. Given the extraordinarily adverse impact this outcome would have, this result seems unlikely in the extreme.

A fourth factor stems from NRC's response to the events at Three Mile Island. In light of the accident, NRC (and possibly Congress) appears likely to impose new design and operating requirements on civilian power reactors.[20] The time needed to develop and implement such regulations plus the time necessary to incorporate them in the designs of reactors now under construction could slow completion of the WPPSS units by a year or more.

Absent a very protracted regulatory snarl at the federal level in the wake of Three Mile Island, WPPSS facilities appear likely to be completed within the time frame contemplated by the scenario.

---

[18] "N-plant Builders to Get Chance to Answer Critics," Seattle Times, January 21, 1979.

[19] "Committee to Watchdog N-Plant Is Urged," Seattle Times, February 6, 1979, p. A6.

[20] Nucleonics Week, April 19, 1979, pp. 5-6.

5.2 HYDROELECTRIC

The scenario specifies the addition of 5,864 MWe of hydroelectric generating capacity in Washington by 1985, and no additional hydro capacity added between 1985 and 1990. Currently, there are a number of projects under construction to expand the capacity of existing hydroelectric projects by adding additional generating units. (See Table 5.) The additional generating capacity of these projects will be 4,523 MWe, 90% of which will represent additions to the Federal Columbia River Power System by the Army Corps of Engineers or the Bureau of Reclamation. In addition, Seattle City Light is proceeding with plans either to raise Ross Dam in the northern Cascades to add an additional 251 MWe of generating capacity to the city's system. Alternatively, City Light may negotiate an agreement with the provincial government of British Columbia to purchase an equivalent amount of power, presumably at a price equivalent to the cost of raising the dam. With the exception of Ross Dam, these projects are all near completion. Potential delays seem unlikely to push completion dates for the federal projects past 1985. The Ross Dam project, however, faces considerable uncertainty and delay because of an existing lawsuit, as well as the negotiations with British Columbia.

Thus, projects identified as likely to reach completion over the time frame of this scenario are expected to add an additional 5,186 MWe of generating capacity in the State of Washington, or only about 88% of the additional capacity envisioned by the scenario. Completion of other projects sufficient to add the additional 678 MWe of power specified by the scenario for 1990 appears unlikely. A number of additional hydro projects are under consideration by the Bureau of Reclamation, the Corps of Engineers, and publicly owned utilities within the state. However, these are only in the preliminary planning stages and, as noted by the Pacific Northwest Utilities Conference Committee (PNUCC), significant further

TABLE 5

Additional Hydroelectric Capacity
Planned for Washington

PLANT/AGENCY/LOCATION	Initial Operation	Date of Completion	Nameplate Rating	Current Status
Chief Joseph, U.S. Army Corps of Engineers, Douglas County.	Feb. 78	May 79	760	Under const.
Grand Coulee, U.S. Bureau of Reclamation, Grant County.	Feb. 78	Feb. 79	2,100	Under const.
Grand Coulee, pump generators, U.S. Bureau of Reclamation, Grant County.	Dec. 80	Dec. 81	200	Under const.
Rock Island, Chelan County PUD, Chelan County.	June 78	Sept. 79	408	Under const.
Lower Granite, U.S. Army Corps of Engineers, Whitman County.	Jan. 78	May 78	405	Under const.
Little Goose, Corps of Engineers, Columbia County.	Feb. 78	June 78	405	Under const.
Lower Monumental, Corps of Engineers, Walla Walla County.	Feb. 79	April 79	405	Under const.
Mayfield, Tacoma City Light, Lewis County.	—	May 82	40	Pre-const.
Ross Dam, Seattle City Light, Whatcom County	—	Before 1990	251	In negotiation, litigation
Sultan, Snohomish County; PUD, Snohomish County	1985	—	112	Planning
Columbia Basin Irrigation Dams, Seattle City Light and Tacoma City Light, South Columbias Irrigation District	—	Before 1990	100	Planning

additions to the state's generating capacity are unlikely to be completed by 1990.[21]

This section outlines the institutional context in which the development of hydroelectric facilities in Washington takes place, reviews the status of ongoing and potential hydroelectric projects, and identifies institutional constraints to their implementation.

5.2.1 Institutional Context

As is evident from Table 5, all current projects to expand hydroelectric generation in the state are the responsibility of public agencies: the U.S. Bureau of Reclamation (Bureau), the U.S. Army Corps of Engineers (Corps), Seattle City Light, Tacoma City Light, Chelan County P.U.D., and Snohomish County P.U.D. This section presents a general and somewhat simplified overview of the steps these agencies must take in developing additional generating facilities. This overview highlights those stages in the process which provide access for interested groups attempting to exert political or legal pressure to delay, modify, or halt a project.

Generally, the project development process may be divided into four major phases: planning, permits applications, design, and construction. The first two of these are of the greatest interest here.

5.2.1.1 The Planning Phase

The planning phase is usually broken into two steps, the first consisting of preliminary and the second detailed planning efforts. The preliminary planning step usually involves a rough assessment of the economic feasibility and environmental impacts of the project. Ideally, this preliminary step represents one element of an ongoing planning process that evaluates mixes of new generating capacity. When this step is part of such a broader planning process, as in the case of Seattle City Light's Energy 1990 study, it can provide a forum for disseminating technical information, identifying technical problems, and discussing different points of view on social and environmental considerations. It may also lead to the establish-

---

[21] Pacific Northwest Utilities Conference Committee, West Group Forecast of Power Loads and Resources (March 1, 1978) ("PNUCC, 1978").

ment of a consensus of opinion regarding the direction of future planning efforts. This type of process may lead to fewer conflicts at more advanced stages in the planning and development of particular projects. Of course, institutional considerations play a major role in an agency's ability to conduct a comprehensive planning program. Seattle City Light, with a broad responsibility in the area of energy, may be in a better position to conduct a wide-ranging planning program than are the U.S. Bureau of Reclamation or Army Corps of Engineers, whose energy-related missions are directed primarily at the development of hydroelectric generating facilities.

The results of the preliminary planning stage help determine whether to embark upon a second, more detailed, planning study. The decision to proceed with formal project planning is usually legislative. For example, after conducting hearings on future electricity demand and supply alternatives, the Seattle City Council may ask City Light for a detailed study on a particular project. (Telephone conversation with Rebecca Wiess, Office of Environmental Affairs, Seattle City Light, January 12, 1979.) Likewise, Congress must authorize the Bureau or Corps to go forward with detailed project planning, and annually appropriate the money for them to do so. The public hearings usually held as part of this decision process provide a second forum for citizens and interest groups to make their views known. Opposition at this stage is likely to have an impact on the direction and requirements of the further, more detailed, planning efforts.

Generally, the detailed planning stage is directed towards determining whether the costs and benefits of a project, broadly defined, justify project construction. As such, this step usually involves a formal cost-benefit analysis as well as the preparation of an environmental report to meet state and federal requirements. Studies needed to comply with other federal, state, or local licensing or land use requirements are likely to be conducted during this stage.

5.2.1.2 The Permits Phase

Detailed planning efforts are often devoted to meeting various statutory and regulatory requirements. Thus, the completion of detailed planning studies usually signals the beginning of applications for necessary permits and the circulation of draft environmental impact statements (EIS) required by the National Environmental Policy Act (NEPA),[22], or the Washington State Environmental Policy Act (SEPA).[23] The permitting and EIS processes provide yet another forum within which outside interests may exert some form of pressure to have their concerns addressed. Municipal or local utilities must conform to the requirements of the state EIS process as outlined in SEPA. Other necessary state permits for new dams or additional generating units include: water discharge, dam safety, water impoundment, and flood control permits from the state Department of Ecology; hydraulic permits from the Department of Fisheries; and permits to excavate from the state Department of Archaeology. The municipal or local public utility districts must also apply to the Federal Economic Regulatory Commission (FERC) for a license under the Federal Power Act.[24] This licensing procedure, in turn, involves an EIS process at the federal level under NEPA. In addition, these agencies must often apply for local building and land use permits and, under the Shoreline Management Act,[25] shoreline substantial development permits. The extent to which federal agencies must comply with state and local permit or licensing requirements is not always clear. However, hydroelectric facilities will generally require state water use permits.

The granting or denial of necessary permits or licenses may almost always be appealed to the courts, and this appeal process represents yet another mechanism through which outside interests can attempt to require the developing agency to address their objections to a project.

---

[22]42 U.S.C. 4321-4361.

[23]RCW Ch. 43.21C.

[24]16 U.S.C. 791-828c.

[25]RCW Ch. 90.58.

5.2.1.3 Engineering Phase

This phase involves the development of detailed engineering plans for the construction of a project. For the public agencies of concern here, this phase also usually requires some form of authorization and perhaps funding by the appropriate legislative body (e.g., city council, Congress). Such legislative action again usually provides a forum for other interested parties to make their views on the project known, and to exert public and political pressure to have their views addressed.

5.2.1.4 Construction Phase

Finally, in order to proceed with construction, the operating agency must again usually turn to the appropriate legislative body for authorization and funding. This legislative process provides yet another opportunity for the expression of views and the application of pressure by other interests. Since Congress makes annual appropriations for construction projects, projects by the Bureau of Reclamation and Corps of Engineers may be much less insulated from intensive public opposition than other projects during the construction phase itself.

5.2.2 Current and Potential Projects and Institutional Constraints

5.2.2.1 Federal Agencies

The Bureau of Reclamation currently is constructing a number of new generating units at Grand Coulee Dam. Taken together, these represent the largest project currently under construction or consideration in the state. This project is expected to add 2,300 MWe of generating capacity.

The Army Corps of Engineers is currently constructing four projects in Washington. These include additions to the Chief Joseph (760 MWe), Lower Granite (405 MWe), Little Goose (405 MWe), and Lower Monumental (405 MWe) dams.[26]

---

[26] PNUCC, 1978.

These federal hydroelectric projects are all well under construction. The licenses and permits necessary for constructing the facilities have all been obtained. The annual congressional appropriations necessary for completion of the projects represent the only major institutional hurdle facing the developing agencies. However, at this late stage, it seems unlikely that the projects will be blocked or delayed at the congressional level.

Other federal projects are under study. The Bureau is conducting a feasibility study (detailed planning) for a third power plant extension at Grand Coulee. This project could potentially involve the installation of two generators and two pumps to pump water back into the reservoir. In other words, it could become a pumped storage project. Preliminary estimates call for the addition of 200 MWe of peaking capacity. The project is not expected to be completed before 1990-1995. The Bureau is also conducting appraisal level (preliminary planning) studies of potential projects at dams in other Pacific Northwest states. (Telephone conversation with Perry Harrison, U.S. Bureau of Reclamation, January 10, 1979.) The Corps is also conducting a detailed planning study of a project to add an additional six units to McNary Dam in Washington. This would add an estimated 350 MWe of capacity and could possibly be completed by 1990. Given the time necessary for completion of studies and for obtaining necessry licenses and permits as well as congressional authorization and funding, it seems unlikely any of these projects will reach completion by 1990.

5.2.2.2 Seattle City Light

Seattle City Light was issued a license by FERC in July 1977 for its project to raise the height of Ross Dam to add an additional 251 MWe of generating capacity. One major impact of raising the dam would be to flood over 5,000 acres of the Skagit Valley in Canada, a major recreation area in British Columbia. Issuance of the license is currently being appealed in U.S. District Court by three groups representing Indian tribes and American and Canadian environmental groups. The trial is expected to last from 18 to 24 months, delaying construction to at least the end of that period. In addition, the provincial government of British Columbia, which opposes the raising of the dam, is attempting to negotiate an agreement with City Light to exchange power generated in British Columbia for a commitment not to raise the dam. If such an agreement is consumated, it could require expansion of the existing intertie to accommodate the exchange power from B.C. In light of these complications, the likelihood that Seattle City Light will have the power from High Ross or its equivalent by 1990 appears modest.

Seattle City Light is also completing a detailed study on building a dam on Copper Creek in Whatcom County. This proposal must yet proceed through City Council hearings which will review the costs, benefits, and impacts of this project, as well as City Light's forecasts of power supply and demand. These forecasts provide a context for evaluating the need for this project as opposed to other generating alternatives and measures to reduce demand. In addition, the project faces numerous licensing and permit proceedings. The potential environmental consequences of this project have already stimulated considerable opposition from groups representing environmentalists, Native Americans, and fishermen.[27] It seems unlikely this project will be operational before 1990.

In addition, both Seattle and Tacoma City Light have contracted for a study of the feasibility of constructing six small-scale generating facilities on irrigation canals in three Columbia Basin irrigation districts. Depending on the technical and environmental problems, these facilities, which would have a total capacity of 100 MWe, could possibly be constructed before 1990. (Telephone conversation with Rebecca Weiss, Seattle City Light, January 12, 1979.)

5.2.2.3 Tacoma City Light

Tacoma City Light is proceeding with plans to add 40 MWe of generating capacity at the Mayfield Dam in Lewis County. The utility recently received

---

[27] "Dam Foes Voice Fears for Bald Eagles, Fish Runs," Seattle Times, March 9, 1979.

FERC licensing on the project and is in the process of issuing bonds to finance construction. Construction is expected to start in mid-1979. (Telephone conversation with Mark Grisson, Tacoma City Light, January 12, 1979.) Tacoma City Light is preparing to commence construction on its project to add generating capacity to Mayfield Dam. Since all necessary permits and licenses have been obtained, it seems likely the project will be completed close to its scheduled date of May, 1982.

5.2.2.4 Chelan County Public Utility District

Chelan County Public Utility District is currently adding 408 MWe of generating capacity to its Rock Island Dam.[28] The project is nearing completion. No significant institutional hurdles remain, and the project is expected to be operational by late 1979.

5.2.2.5 Snohomish County Public Utility District

Currently, Snohomish County P.U.D. is preparing an amendment to its licensing application to FERC for a proposal to raise the height of the Sultan Dam by 60 to 70 feet and add an additional five generating units capable of generating 112 MWe. The utility expects amendments to the original application to be filed with FERC by May 1, 1979. On February 15, 1979, it plans to release a draft EIS for circulation and public comment under provisions of Washington State's SEPA. The final state EIS is expected to be filed with the state Department of Ecology by April, 1979. The P.U.D. expects FERC approval of its application by July, 1981, and plan to begin construction by the spring of 1982. At this time, the project is expected to be operational in 1985. (Telephone conversation with Russell McQuigg, Sultan Project Manager, Snohomish County Public Utility District, January 15, 1979.) The extent of potential opposition to this project is unclear as of this writing.

---

[28] PNUCC, 1978.

5.3 GEOTHERMAL

The scenario specifies 400 MWe of geothermal generating capacity in Washington by the year 1990. There are several reasons to believe this figure unrealistic, independent of institutional considerations. First, knowledge about the location and characteristics of geothermal resources in Washington is incomplete. Second, geothermal resources suitable for electricity generation (i.e., with temperatures in excess of 150° C) presently appear to be scarce in the Northwest. The region's abundant known geothermal resources are better suited for use in direct heat applications. One estimate places the total maximum resource available for electric power production at approximately 500 MWe for the states of Washington, Oregon, and Idaho combined.[29] Third, present knowledge places the bulk of these resources in the states of Idaho and Oregon rather than Washington. There are only three known geothermal resource areas (KGRAs) in Washington: Kennedy Hot Springs, Mount St. Helens, and Indian Heaven,[30] although Mount Baker may soon receive that designation as the result of several new steam vents exhibited in the past several years.[31] Some federal leases are pending for the purpose of geothermal exploration at Mount St. Helens, Mount Baker, and the Glacier Peak area of Mount Rainer. In addition, the State Department of Natural Resources has received a grant from the U.S. Department of Energy to drill exploratory heat flow wells in the Camas, Steamboat Rocks and White Pass areas, and sample mineral and hot springs throughout the state. (Conversations with Donald Ford, Geologist, Washington State Department of Natural Resources.) No firm has yet announced plans to develop any geothermal resources in the state of Washington. These factors alone suggest that the projected 400 MWe

---

[29] Comptroller General, Report to Congress, Region At the Crossroads--The Pacific Northwest Searches for New Sources of Electric Energy (Washington, D.C.: General Accounting Office, EMD-78-76, August 10, 1978), p. 4.11.

[30] Northwest Energy Policy Project, Energy Supply and Environmental Impacts--Unconventional Sources, Study Module III-B (Springfield, VA: National Technical Information Service, 1977) ("NEPP III-B"), p. 59.

[31] Walter Youngquist, "Pacific Northwest Geothermal 1977 Review--1978 Outlook," Geothermal Energy Magazine, June 1978, p. 42.

geothermal capacity is unlikely to be on line in the state of Washington by 1990.

Even if the current estimates of suitable geothermal resources for the state turn out to err substantially on the low side, the necessary development is unlikely to take place by the year 1990. The requisite exploratory drilling has not begun, although tax incentives under the Energy Tax Act of 1978 (a 22% depletion allowance, optional expensing of intangible drilling costs) may spur exploration.[32] While geothermal electrical generation technology is relatively less demanding than say, nuclear power generation, which involves lead times of roughly 12 years, recent experience shows that it takes about nine years to get even quite standard fossil fired generating facilities on line. In the case of geothermal, the times are initially likely to be greater, while the utilities, regulators, and other participants evolve the procedures necessary to comply with federal, state, and local laws. In short, even if a major geothermal discovery were made tomorrow, the likelihood that it would be producing electricity by 1990 appears relatively low.

For completeness, this section outlines here some of the principal legal, organizational, and political constraints likely to face developers of geothermal resources in the state of Washington at each stage of the development process: leasing, exploration, bringing power plants and production fields on line, and transmission.[33]

5.3.1 Leasing

Before a developer can begin exploring an area for geothermal resources, he must first obtain a lease on the rights to the geothermal

---

[32] Pub. L. No. 95-618.

[33] This segmentation of the development process follows C. R. Schuller et al., Legal, Institutional and Political Problems in Producing Electric Power from Geothermal Resources in California (Seattle: Battelle Human Affairs Research Centers, 1976).

resources in question. The procedures required depend on the ownership of the resources in the first instance: federal, state, or private. In each case, the owner of land is the owner of the geothermal resources lying underneath.

Presently, most geothermal resource areas in Washington lie on land owned by the federal government, principally in U.S. Forests. The procedures for leasing geothermal resources located on federally-owned land are established by the Geothermal Steam Act of 1970,[34] and the National Environmental Policy Act of 1969, (NEPA),[35] and the regulations promulgated thereunder.[36] The leases themselves are issued by the Bureau of Land Management (BLM). The federal agency that manages the land in question is required to prepare an Environmental Analysis Report (EAR), and in some instances, a full scale Environmental Impact Statement (EIS). In the case of most federally owned lands in Washington, this agency would be the U.S. Forest Service. In other states, this process has been relatively slow. Operating on the assumption once a lease is granted, it could be developed to full capacity, the Forest Service must assure itself before any lease is granted that such development will not overly disrupt the management of surface resources. Thus, the Forest Service undertakes detailed environmental analysis of the consequences of geothermal development before it can be determined whether any geothermal potential exists.[37] In addition, leasing of many federal areas may be slowed pending completion of the Forest Service's Roadless Area Review and Evaluation (RARE II), now nearing completion, and BLM's analagous wilderness review program, just getting underway.[38] Both agencies' designations of wilderness areas are controversial and may prompt intense Congressional activity.

---

[34] 30 U.S.C 1001-1025

[35] 42 U.S.C. 4321-4361

[36] The Federal Geothermal Resources Leasing Regulations are at 43 CFR Part 3200.

[37] Schuller, p. 59.

[38] John McComb, "The BLM Begins Its Wilderness Review," Sierra, January/February 1979, p. 46.

Procedures for the lease of geothermal resources owned by the state of Washington have not yet been worked out. By providing that geothermal resources are <u>sui generis</u>--neither mineral resources nor water resources--Washington's Geothermal Resources Act renders inapplicable existing state law on the leasing of state property, including mineral resources.[39]

The Washington legislature has recently clarified the status of geothermal resources lying under private land: they are the property of the landowner.[40] Therefore the landowner controls the development rights, subject to state environmental and drilling requirements.

For both federal and state resources, the leasing process is likely to be time-consuming until it becomes relatively routine. The leasing phase also affords political opponents of geothermal development an opportunity to intervene in the process under NEPA or, once Washington authorizes state leases, the Washington State Environmental Policy Act (SEPA).[41] These opponents are likely to be groups or individuals opposed to geothermal development on the particular land in question because of conflicts with alternative uses, such as recreation, agriculture, or silviculture. However, since the danger is relatively remote at the leasing phase, most of the opposition is likely to be postponed until later in the development process.

5.3.2 Exploration

The allocation of governmental roles in the exploration process depends on whether exploratory drilling is to take place on federally owned lands or on state or private lands. For federal lands, the developer must submit an exploration plan to the U.S. Geological Service (USGS) for approval. The USGS prepares a site-specific environmental analysis (EA), and if the EA indicates that the project would be a major action affecting the quality of the human environment, prepares an EIS. As with the leasing phase, environmental analyses must address the full range of impacts associated with geothermal development--not just the limited impacts of drilling test wells.

---

[39] RCW 79.76.040.

[40] 1979 Wash. Laws Ch. 2.

[41] RCW Ch. 43.21C.

The USGS then approves or disapproves the developer's application, perhaps with special conditions governing operations at the particular site. The federal agency having managerial responsibility for the land in question (for example BLM or in the case of most relevant land in Washington, the U.S. Forest Service) then acts as observer to assure compliance with approval conditions, although the USGS retains ultimate authority for enforcement.[42]

Washington State laws which would apply to the developers of geothermal resources located on state owned or private lands are analogous to federal law. The Geothermal Resources Act,[43] gives the Washington Department of Natural Resources responsibilities essentially similar to those of the USGS and the federal managing agency under federal law. A prospective developer of geothermal resources must apply to the department for a drilling permit, which requires submission of a fee, a public hearing on the application, determination by the Department that the area in question is suitable for the activities applied for, and the granting of a permit by the Department, subject to whatever conditions the Department deems necessary. SEPA would require the Department to conduct an environmental analysis of the proposed activity to determine whether it would significantly affect the environment. The Department would then either issue a declaration of no significant impact or prepare a full-scale state environmental impact statement. While the Geothermal Resources Act generally preempts local regulation of the drilling and operation of wells for geothermal resources, it does not preempt local land use law.[44] Therefore the drilling of any geothermal resource well on state or privately owned land would require compliance with local zoning regulations. If the land in question were not zoned to allow geothermal resource development, the applicant would have to convince the local zoning authority to rezone the land in question, or more likely, obtain a conditional use permit. Drillers on federally owned lands

---

[42] Schuller, pp. 89-91.

[43] RCW Ch. 79.76.

[44] RCW 79.76.060.

are probably not required to comply with state and local requirements. However, they may nonetheless find it politically useful to do so.

Political opposition to particular geothermal projects may begin to gel at this stage. Exploratory drilling itself can have a number of unfavorable environmental impacts. These include: noise (from the drilling rig itself and from the steam released), odor (for example, of hydrogen sulfide), sump failures, blowouts, brine disposal (where applicable), air pollution, subsidence, erosion, landslides, and destruction of wildlife habitats.[45] In addition, since progress from the leasing phase to the exploratory development phase increases the probability that the area will ultimately be developed for geothermal power production, opposition based on conflicts between geothermal development and other uses for the land in question are likely to become more intense. Forums for this opposition could include the state and federal environmental assessment process, the public hearings required under the Geothermal Resources Act and state zoning law, and a variety of other channels involving direct intervention by federal, state, or local officials.

5.3.3 Selling and Utilizing the Resource

Once a developer demonstrates the geothermal resource potential of a particular site, it must sell the resource to a user (if the developer is not itself a user). As previously indicated, most Washington resources are likely to go to direct heat users. Candidates for use of geothermal resources to generate electricity include utilities, specially organized electric wholesalers, or industrial concerns that could use the electricity directly. The institutional constraints here relate to the willingness of the prospective user to buy the resource for construction of a generation facility, and its ability to obtain financing. Because individual geothermal facilities are relatively small (10 - 100 MWe), they are unlikely to justify construction of significant new transmission lines unless colocated with other facilities (e.g., as part of a geyser field). Therefore, potential buyers may be limited to those utilities serving load centers rela-

[45] Schuller, p. 127.

tively close to the proposed facility unless it is located near one of BPA's bulk transmission lines.

Once these conditions are met, the prospective buyer must still be convinced that the investment is a sound one. At a minimum, this means that the facility must be capable of generating enough power for a cost comparable to other generating facilities available to the utility. As discussed in somewhat greater detail in the section on geothermal power generation in Idaho, the technology for moderate temperature geothermal power generation has not yet progressed to the point of parity with thermal power. Accounting for R&D advances, one DOE study places the levelized busbar energy cost of generating electricity on a commercial scale at Mount Baker Hot Springs at 76 mills per kilowatt hour. Expensing intangible drilling cost and a 22% depletion allowance, both available under the Energy Tax Act of 1978 (Pub. L. No. 95-618) would further reduce the cost to 52.7 mills per kilowatt--still well above the comparable figure of 27 mills per kilowatt hour for nuclear power under assumptions of high escalation rates for nuclear fuel.[46] And whatever the cost, such a proposal must overcome natural resistance to unfamiliar sources of power on the part of the utility's management.

Finally, the utility must obtain financing. Although the absolute sums required for construction of a geothermal electrical generating facility are not large compared to other forms of electrical generation (mainly because of the smaller plants involved), investors may regard such unconventional technologies as geothermal as unduly risky, even given the 75% federal loan guarantees available under the Geothermal Energy Research, Development, and Demonstration Act of 1974.[47] This is especially likely to be the case in a state such as Washington, where the uncertainties are especially large and likely to remain so for some time. These include uncertainties about

---

[46] R. Trehan et al., Site Specific Analysis of Geothermal Development--Data Files of Prospective Sites, Volume II (Washington, D.C.: U. S. Department of Energy, 1978), p. XIV-7.

[47] 30 U.S.C. 1101-1164.

the extent of reservoirs (once located), uncertainty about the feasibility of hot water geothermal electricity generation (the likely form in Washington and as yet not fully developed), and uncertainty about the regulatory apparatus that will emerge in the state.

5.3.4 Construction of Production Facilities

As with exploration, the procedures required for constructing a geothermal generating facility depend on the ownership of the site. The Federal procedures are set out in regulations promulgated under the Geothermal Steam Act at 30 CFR Part 270. Because a commercial production facility has not yet been constructed on federal land, how these procedures will function in practice remains unclear. In general, the power plant operator is subject to the conditions imposed on the geothermal resource lessee.[48] "In addition, the producer will probably have to apply to BLM for a Special Land Use Permit."[49] Almost certainly, such an action would also be determined to significantly affect the quality of the human environment and thus require a full environmental impact statement under the National Environmental Policy Act.

For facilities to be located on land owned by the state of Washington or privately, a number of statutes would be invoked. First, the power plant operator would have to apply for permits for production drilling under the Geothermal Resources Act. (Ten to fifteen wells would be required for a 110 MWe facility.) This would involve hearings, and the issuance of a permit subject to conditions. Second, an environmental impact statement would almost certainly be required under SEPA. Third, the operator would have to comply with the applicable local zoning ordinance. Operators of geothermal electrical generating facilities would <u>not</u> have to comply with two sorts of laws in Washington that they might have to comply with in other states: public utility regulations and energy facility siting regulations. Washington law does not require builders of power plants to obtain certificates of convenience and necessity from the Washington Public Utilities Commission.

---

[48] 30 CFR 270.31.

[49] Schuller, p. 127.

Nor does the Energy Facility Siting Act,[50] apply to geothermal generating facilities.

Political opposition would likely reach a peak at this phase. The likely focus would be the hearings of the federal and state agencies involved, and lawsuits challenging the resulting decisions, if favorable to the applicants.

5.3.5 Transmission

As mentioned above, transmission of geothermal power may present special problems because of the distance of geothermal resources from load centers, and the small size of the typical geothermal facility. Unless the utility that owns the facility happens to serve a load center located nearby, long-distance, high-voltage transmission services will be required. If the geothermal facility is located near BPA's bulk transmission grid, as are Mount Baker and Mount Rainier, this may pose no great problem. Otherwise, the utility will have to carefully consider the worth of constructing its own long-distance facilities. And in any event, some low-voltage feeder lines will doubtless be required. The creation of even low-voltage transmission facilities running through federal or state lands could be controversial and arouse political opposition, especially if these areas were pristine wilderness. Such transmission facilities would require the approval of the federal land managers or the Washington Commissioner of Public Lands as applicable, and would also likely require federal or state environmental impact statements. These statements could be the focus of political opposition by groups concerned with preserving alternative land uses, essentially analogous to those groups opposed to the development of geothermal resources generally in wilderness areas.

5.3.6 Conclusion

In sum, neither the legal procedures, nor the organizational capabilities, nor the political opposition involved in geothermal development are unique. However, since geothermal power generation is so novel, especially in Washington State, it can be expected that the development process will be

[50] RCW 80.50.

slow. Procedures will have to be worked out, organizational capabilities of utilities and regulators will have to be developed, and political battles may have to be fought. Institutional factors do not appear to be a binding constraint to geothermal power generation in Washington, but they do appear to further reduce the possibility that geothermal resources will be developed for this purpose to any great extent within the next decade or so.

DISTRIBUTION

No. of
Copies

OFFSITE

A. A. Churm
DOE Chicago Patent Group
9800 South Cass Avenue
Argonne, IL 60439

Mrs. Ruth Clusen
DOE Assistant Secretary
for Environment
Washington, DC 20545

J. A. Coleman
DOE Office of Technology
Impacts
Washington, DC 20545

Dr. Joan Hock
DOE Office of Technology
Impacts
Washington, DC 20545

Dr. Peter W. House
DOE Office of Technology
Impacts
Washington, DC 20545

45 Dr. Arthur Katz
DOE Regional Assessments
Division (Mail Stop E-201)
Office of Technology Impacts
Washington, DC 20545

Dario M. Monti
DOE Office of Technology
Impacts
Washington, DC 20545

No. of
Copies

Dr. Roger D. Shull
DOE Office of Technology
Impacts
Washington, DC 20545

Edward R. Willlams
DOE Office of Technology
Impacts
Washington, DC 20545

27 DOE Technical Information
Center

3 Dr. Steve Ballou
Argonne National Laboratory
9700 South Cass Avenue
Argonne, IL 60439

Dr. L. J. Hoover
Argonne National Laboratory
9700 South Cass Avenue
Argonne, IL 60439

3 Dr. Peter M. Meier
Building 475
Brookhaven National Laboratory
Upton, NY 11973

3 Dr. William Siri
University of California
Lawrence Berkeley Laboratory
Berkeley, CA 94720

Dr. D. Layton
University of California
Lawrence Livermore Laboratory
P. O. Box 808
Livermore, CA 94550

No. of
Copies

Dr. Ron K. Lohrding
Los Alamos Scientific
Laboratory
P.O. Box 1663
Los Alamos, NM 87545

3 Dr. Don Morris
Los Alamos Scientific
Laboratory
University of California
P. O. Box 1663
Los Alamos, NM 87545

3 Dr. Richard M. Davis
Oak Ridge National Laboratory
P.O. Box X
Oak Ridge, TN 37830

Dr. W. Fulkerson
Oak Ridge National Laboratory
P.O. Box X
Oak Ridge, TN 37830

ALASKA

Greg Edblom
Dept. of Commerce & Economic
Development, State of Alaska
MacKay Building
338 Denali Street
Anchorage, AK 99501

Clarissa Quinlan
Dept. of Commerce & Economic
Development, State of Alaska
MacKay Building
338 Denali Street
Anchorage, AK 99501

David C. Sturdevant
Dept. of Environmental
Conservation, State of Alaska
Division of Planning & Program
Coordination
Pouch O
Juneau, AK 99811

No. of
Copies

IDAHO

L. K. Hall
Idaho Energy Office
State House
Boise, ID 83720

Jim Wilson
Idaho Department of Health
& Welfare
700 West State Street
Boise, ID 83720

OHIO

Robert Cobb
Battelle Columbus Laboratory
505 King Avenue
Columbus, OH 43201

James Lawson
Battelle Columbus Laboratory
505 King Avenue
Columbus, OH 43201

Ann Rudolph
Battelle Memorial Institute
505 King Avenue
Columbus, OH 43201

OREGON

Michael Grainey
Oregon Department of Energy
Salem, OR 97301

Peter O. Hengesteg
Corps of Engineers
P.O. Box 2870
Portland, OR 97208

Nan Nalder
Thermal Power Section
Branch of Power Resources
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208

No. of
Copies

Robert J. Tallman
Head, Thermal Power Section
Branch of Power Resources
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208

William H. Young
Oregon Department of
Environmental
Quality
1234 S.W. Oregon Street
Portland, OR 97201

WASHINGTON

Fred S. Adair
Washington State Department of
Commerce & Economic
Development
Olympia, WA 98504

Wilbur T. Hallauer
Washington Department of Ecology
Abbot Raphael Hall
Saint Martin's College
Olympia, WA 98504

William H. Ostenson
Economic Development Council of
Puget Sound
1900 Seattle Tower,
1218 - 3rd Avenue
Seattle, WA 98101

Don Provost
Department of Ecology
Mail Stop PU-11
Olympia, WA 98504

J. B. Robertson
DOE, Federal Region X
Federal Building, Room 1992
915 Second Ave.
Seattle, WA 98174

No. of
Copies

Alexandra Smith
Chief, Environmental Evaluation
Environmental Protection Agency
1200 - 6th Avenue
Seattle, WA 98178

ONSITE

DOE Richland Operations Office

P. W. Gottschalk
H. E. Ransom

Pacific Northwest Laboratory

W. J. Bair
M. A. Beckwith
C. H. Bloomster
J. B. Brown
S. M. Brown
J. S. Burlison
D. B. Cearlock
D. C. Christensen
C. E. Cowan
J. W. Currie
D. E. Deonigi
A. E. Davis
D. W. Dragnich
D. R. Drewes
W. J. Eadie
D. L. Hessel (10)
G. R. Keizur
S. Marks
H. E. McCartney
P. J. Mellinger
A. R. Olsen
W. F. Sandusky
W. H. Swift
M. L. Warner
G. L. Wilfert (25)
L. D. Williams

Economics Library (5)
Publishing Coordination (2)
Technical Information Files (5)

No. of
Copies

Human Affairs Research Center

C. Cluett
R. Cole
M. R. Greene
J. A. Hebert
F. A. Morris
S. M. Nealey
C. H. Sawyer