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Power Sales to Electric Utilities

PURPA Qualifying Facility Development in Washington State

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Prepared by:

Resources and Policy Groups

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ABSTRACT

The Public Utilities Regulatory Policies Act (PURPA) of 1979 requires that electrical utilities interconnect with qualifying facilities and purchase electricity at a rate based upon their full avoided costs (i.e., costs of providing both capacity and energy). Qualifying facilities (QFs) include solar or geothermal electric units, hydropower, municipal solid waste or biomass-fired power plants, and cogeneration projects that satisfy maximum size, fuel use, ownership, location, and/or efficiency criteria.

In Washington State, neither standard power purchase prices based upon a proxy "avoided plant," standard contracts, or a standard offer process have been used. Instead, a variety of power purchase contracts have been negotiated by developers of qualifying facilities with investor-owned utilities, public utility districts, and municipally-owned and operated utilities. With a hydro-based system, benefits associated with resource acquisition are determined in large part by how compatible the resource is with a utility's existing generation mix. Power purchase rates are **negotiated** and vary according to firm energy production, seasonality of output, project ramping rate and load following capability; performance guarantees, ability to schedule maintenance or downtime, rights of refusal, power plant purchase options, project start date and length of contract; front-loading or levelization provisions; and the ability of the project to provide "demonstrated" capacity.

Legislation was also enacted which allows PURPA to work effectively. Initial laws established ownership rights and provided irrigation districts, PUDs, and municipalities with expanded enabling powers. Financial incentives for renewable resource and cogeneration projects were also created. Permitting processes were streamlined and, in some cases, simplified. Finally, laws were passed which are designed to ensure that development proceeds in an environmentally acceptable manner.

In retrospect, PURPA has worked well within Washington. During periods of forecasted generating resource need, avoided costs were high and served as an incentive to QF development. When Washington's utilities reran their avoided cost models to account for price-induced decreases in forecasted load growth, avoided costs declined as the need for new thermal resource development was deferred. The properly functioning avoided cost methodology served to establish an appropriate, effective, and reactive price signal to resource developers.

In the state of Washington, 20 small-scale hydroelectric projects with a combined generating capacity of 77 MW, 3 solid waste-to-energy facilities with 55 MW of electrical output, 4 cogeneration projects with 34.5 MW of generating capability, and 4 wastewater treatment facility digester gas-to-energy projects with 5 MW of electrical production have come on-line (or are in the final stages of construction) since the passage of PURPA. These numbers represent only a small portion of Washington's untapped and underutilized cogeneration and renewable resource generating potentials.

Finally, recent activities in both the electric and natural gas industries and regulatory change, at both the national and state levels, will affect the future rates of development for cogeneration and renewable resource projects. In particular, utility least-cost planning requirements, the imposition of competitive bidding based resource acquisition programs, and natural gas availability and pricing will impact both utility avoided cost projections and the rates of QF and independent power producer development.

ACRONYMS

AGA	American Gas Association
APCA	Air Pollution Control Authority
B&O	Business and Occupational (tax)
BC	British Columbia
BLM	Bureau of Land Management
BPA	Bonneville Power Administration
CDPW	County Department of Public Works
CHD	County Health Department
Corps	Corps of Engineers
Council	Northwest Power Planning Council
DGER	Division of Geology and Earth Resources
DNR	Department of Natural Resources
DSHS	Department of Social and Health Services
ECPA	Electric Consumers Protection Act P.L. 99-495
EFSEC	Energy Facility Site Evaluation Council
EIS	Environmental impact statement
FERC	Federal Energy Regulatory Commission
IOU	Investor-owned utility (private utility)
KGRA	Known geothermal resource area
kWh	kilowatt-hour
LAER	Lowest achievable emission rate
MSW	Municipal solid waste
MW	Megawatt (one million watts)
NPDES	National Pollutant Discharge Elimination System
NWP	Northwest Pipeline Corporation
NWPPC	Northwest Power Planning Council
PCU	Packaged cogeneration unit
PP&L	Pacific Power & Light Company
PSAPCA	Puget Sound Air Pollution Control Authority
PSP&L	Puget Sound Power & Light Company
PTPC	Port Townsend Paper Company
PUC	Public Utilities Commission
PUD	Public utility district
PURPA	Public Utilities Regulatory Policy Act P.L. 95-617
QF	Qualifying generating facility
RCW	Revised Code of Washington
RDF	Refuse derived fuel
SB, HB	Senate, House bill
SEPA	State Environmental Policy Act
SHB	Substitute House bill
tcf	thousand cubic feet
TPD	Tons per day
TRC	Thermal Reduction Company
UTC	Washington Utilities and Transportation Commission
VOC	Volatile organic compounds
WDOE	Washington Department of Ecology
WSEO	Washington State Energy Office
WWRC	Washington Water Research Center

TABLE OF CONTENTS

LIST OF TABLES

FIGURES

CHAPTER I: PURPA OVERVIEW

1.1 Background

Congress enacted the Public Utilities Regulatory Policies Act (PURPA) on November 9, 1979, as one of five component bills to the National Energy Act of 1978. PURPA was designed to lessen the country's dependence on foreign oil by requiring state utility commissions to consider rate structures that conserve energy and by encouraging the development of energy efficiency, cogeneration, biomass-fired powerplants, and renewable generating resources. Renewable resources include solar, wind, hydropower, and geothermal generating facilities.

Prior to the enactment of PURPA, a cogenerator or independent power producer seeking to sell electricity to a utility or directly to industry faced four major obstacles. First, utilities were not required to interconnect with the producer or to purchase that producer's electrical output. Second, even if a utility was willing to purchase electricity, the price offered by the utility might not reflect fair market value. Third, some utilities charged discriminatingly high rates for providing back-up services to cogenerators and small power producers that wanted to sell power to industries. Finally, a cogenerator or small power producer ran the risk of being considered an electrical utility and thus subject to extensive utility reporting requirements and to state and federal regulation.

PURPA amended the Federal Power Act to reduce or eliminate these obstacles to the development of cogeneration and small power projects. In effect, PURPA requires utilities to interconnect with qualifying cogenerators and small power producers (QFs) located in their service territories, to purchase power at a price based on the utility's full avoided cost for energy and capacity, and to provide non-discriminatory rates for back-up services. PURPA also exempts small power producers from portions of the Federal Power Act, the Public Utility Holding Company Act, and certain state utility regulations. PURPA does not, however, require a utility to interconnect with and purchase power from independent producers located outside of its service territory.

Of particular importance to independent power producers are the provisions of PURPA dealing with small power production. Specifically, under Title II Sections 201 and 210, the Federal Energy Regulatory Commission (FERC) amended its regulations to deal with such critical issues as size, ownership, and efficiency criteria for qualifying small power production and cogeneration facilities; electric utility obligations; rates for purchase and sales; interconnection cost reimbursements; and state implementation requirements regarding PURPA. (These changes are located in Title 18 of the Code of Federal Regulations, Chapter I, Part 292.)

1.2 Qualifying for PURPA Benefits

Two basic types of QFs exist: small power producers and cogenerators. Small power producers generate electricity from fuels other than oil and natural gas. A small power producer

(SPP) is automatically a QF under PURPA if it meets specified size, fuel use, and ownership criteria. Oil or gas-fired cogeneration projects must meet additional operating and efficiency standards to be considered QFs.

General QF criteria require that the total power production capacity of a SPP (together with the capacity of other facilities owned by the same person, using the same energy resource, and located at the same site) cannot exceed 80 MW. Cogenerating QFs have no size limitation. In addition, no more than 50 percent of the equity interest in the facility can be held by an electric utility or utilities, an electric utility holding company, or combination thereof. For multi-fuel fired facilities, at least 75 percent of the total energy input must be from biomass, wastes, renewable resources, geothermal resources, or any combination thereof. Conversely, during any calendar year, supplemental oil, natural gas, or coal use cannot exceed 25 percent of the total facility energy input.

Cogeneration technologies produce electricity and another form of energy (such as heat or steam) used for industrial processes, commercial applications, space heating, water heating, and/or cooling. Under PURPA, FERC established several criteria for topping cycle cogeneration facilities installed after 1980. Generally, these criteria require the facility's useful power output plus one-half of its thermal output to be no less than 42.5 percent of the total energy input from natural gas and oil. If the useful thermal output is less than 15 percent of the facility's total energy output, then this minimum is raised to 45 percent. Similar efficiency requirements exist for bottoming cycle units. A waiver process also is available for facilities that can produce "significant energy savings."

The Electric Consumers Protection Act of 1986 (ECPA, P.L. 99-495) imposed additional restrictions regarding QF status for hydroelectric facilities. Qualifying hydroelectric projects requiring new dams or diversions must not have significant adverse effects on the environment, including recreation and water quality; must not be located on a watercourse that is included in or designated for inclusion in a State or National Wild and Scenic Rivers system; must not be located on a river reach recognized by the state as possessing unique natural, recreational, cultural, or possess scenic attributes which would be adversely affected by development; and must conform with all terms and conditions imposed by federal and state fish and wildlife agencies.

1.3 Resource Development Under PURPA

Nationwide, PURPA has been extremely successful in stimulating the emergence of a multi-billion dollar independent power producing industry. In 1982, only 100 MW of California's power supply came from non-utility generation. By January 1985, independent producers had installed 1,659 MW of generating capacity, about the equivalent of two medium-sized coal-fired plants, and were constructing another 9,229 MW, enough to boost the output of independents to 25 percent of California's total generating capacity.

In the state of Washington, QFs totalling 171.5 MW of generating capacity have come on-line (or are in the final stages of construction) since the passage of PURPA. These projects include 20 small-scale hydroelectric projects with a combined generating capacity of 77 MW, 3 solid waste-to-energy facilities with 55 MW of combined capacity, 4 cogeneration projects with 34.5 MW of combined capacity, and 4 wastewater treatment projects with digester gas-to-energy facilities totalling 5 MW of capacity. A variety of power purchase contracts have been negotiated between developers of QFs and investor-owned utilities, public utility districts, and municipally-owned and operated utilities.

Although the majority of Washington's utilities buy their power from BPA, a growing number are involved in the generation of some of their own power, or the purchase of small power generation. The utility market structure in the state of Washington is made up of 60 utilities. The 60 utilities include 16 cooperative utilities, 20 municipal utilities, 21 public utility districts, and 3 investor-owned utilities. Utilities involved in the purchase of small power generation include:

- Puget Sound Power and Light
- Pacific Power and Light
- Washington Water Power
- Seattle City Light
- Tacoma City Light
- Mason County PUD No. 1
- Clark County PUD

1.4 Challenges to PURPA

PURPA and the FERC rulemakings implementing PURPA have been legally challenged on such issues as infringement on states rights, establishment of avoided costs, interconnection requirements, provision of back-up power, and the definition of a QF. These challenges have produced considerable uncertainty for utilities, project developers, and state utility commissions.

In the first challenge to PURPA, *FERC v. Mississippi*, a Mississippi District Court threw out Section 210 as an unconstitutional usurpation of state authority. The court also rejected all of Titles I and III, questioning PURPA's overall constitutionality. However, in June 1982, the U.S. Supreme Court found that PURPA was within the bounds of the Commerce Clause and 10th Amendment to the Constitution. In fact, the Supreme Court found that Congress had continued to honor the states' traditional role in utility regulation even in an area of interstate commerce that could be legally pre-empted by federal policy. The Supreme Court also found that requiring states to consider pricing provisions is a reasonable state involvement in federal energy policy and does not infringe on state's rights.

In the case of *American Electric Power Service Corporation v. FERC*, the electric utility industry shifted focus from the statutory framework of PURPA to FERC implementing rules (Orders 69 and 70). Specifically, the utilities contended that FERC's rules setting power purchase rates at full avoided cost were arbitrary, capricious, an abuse of discretion, and not in the public interest. (Full avoided cost is the cost the utility would incur by purchasing or developing an additional unit of energy and capacity.) The District of Columbia Court of Appeals agreed and suggested that FERC set purchase rates at a percentage of full avoided cost or adopt a "split the savings" approach.

In May 1983, the U.S. Supreme Court reversed this decision, again supporting FERC's position. While recognizing that a full avoided cost rule would not lower rates to consumers, the court ruled that FERC had correctly provided a significant incentive for cogeneration and small power producers. Ratepayers and the nation would benefit through decreased reliance on scarce fossil fuels and more efficient use of energy.

In *American Electric Power Service Corporation v. FERC*, the District of Columbia's Court of Appeals had also vacated FERC rules concerning interconnection. However, the Supreme Court reversed that ruling and found that requiring small power producers to undergo the same regulatory process as utilities would be time consuming, expensive, and nonproductive. The court, therefore, ruled that FERC had not exceeded its authority in waiving the requirements for evidentiary hearings established under the Federal Power Act.

In May 1983, a coalition of environmental groups requested a rehearing of FERC's "Order 70" which had established criteria and procedures for hydroelectric projects to attain QF status. In April 1985, these groups filed suit in the 9th U.S. Circuit Court of Appeals (*Sierra Club, et al., v. FERC*), claiming that FERC had violated the intent of Congress by not considering the environmental impact of awarding QF status to hydropower projects requiring new dams.

Although FERC denied the group's request for a rehearing in March 1986, Congress ultimately incorporated constraints on hydroelectric projects into the Electric Consumers Protection Act of 1986. (This action also made the suit before the 9th Circuit Court moot.) This Act imposed a moratorium on PURPA benefits to facilities requiring construction of a new dam which enter the FERC licensing process after October 16, 1986. The moratorium will probably last through late 1989. In the interim, FERC must prepare a report to Congress on the environmental impacts of allowing PURPA benefits for hydropower sites requiring new dams.

In addition to court rulings, FERC's internal rulings on administrative appeals have affected the rate and type of cogeneration and renewable resource development.

In its 1985 *Alcon (Puerto Rico) Inc.* decision, FERC determined that a utility is required to sell back-up power **only** to a QF and to the owners and operators of a QF. FERC's interpretation eliminated access to supplemental back-up, maintenance, or interruptible power for industries considering third-party financed cogeneration projects. Under a third-party leaseback (with option to buy) or leveraged leaseback agreement, an energy company would finance, install, and operate a cogeneration facility at an industrial site to qualify for available tax and depreciation credits. FERC's determination was later reversed so that an industry is eligible for supplementary and back-up power from the local utility when there is a "close nexus" between the QF facility and the industrial user.

Subsequent FERC decisions expanded the definition of "facilities" to include switchyards and dedicated transmission lines (*Kern River Cogeneration Co.* and *Clarion Power Co.*), addressed electrical sales or allocations to multiple parties (*PRI Energy Systems Inc.* and *Riverbay Corp.*) and clarified QF reporting requirements under the Federal Power Act (*Resources Recovery Inc.*).

More recently, in its 1988 *Orange and Rockland* decision, FERC invalidated New York's legislatively enacted 6¢/kWh avoided cost. FERC found that this minimum price for purchasing power, which had been passed to encourage QF development, was improperly established at a level higher than the purchasing utility's avoided cost.

1.5 The Future of PURPA

In March 1988, FERC issued three notices of proposed rulemaking. Under discussion by FERC, state regulators, and the electric utility industry for over a year, these proposed rules would try to create a competitive market for electric power generation. FERC solicited comments on the proposed rules during the summer of 1988 and will likely adopt final rules in 1989.

The first proposed rule addresses many of the problems experienced by the utility industry in determining an avoided cost. If this rule is adopted, state regulatory commissions could either use new procedures to calculate avoided costs or they could use competitive bidding to establish a market value for power purchased from independent producers. In any case, FERC would prohibit states from setting QF purchase rates above full avoided cost. Other FERC modifications in the proposed rule address fuel diversity of QFs, long-term contracts, multi-jurisdictional utilities, and the obligation of utilities to provide back-up power for QFs.

The second proposed rule details minimum requirements for a state competitive bidding program. However, FERC has stated that it only seeks to encourage development of state bidding programs and does not see unified bidding procedures altering state responsibility for regulation over a utility's need for capacity and over environmental or siting issues.

The third proposed rule addresses the regulatory burdens placed on certain non-QF independent power producers. These producers sell electricity in areas where they have no service franchise or otherwise lack significant market power. FERC hopes this rule will bring industrial generation into production and expand opportunities for utilities to also act as independent power producers, marketing excess capacity beyond their service territories.

These last two proposed rules could effectively deregulate electric power generation. Such a major change in the electric utility industry would raise many other questions, such as a utility's obligation to serve all customers in its service territory and the relationship between federal and state regulation. Although the proposed rules have not yet been adopted by FERC, their adoption will initiate a new round of legal challenges and will affect Washington State regulatory actions related to PURPA.

CHAPTER II: INSTITUTIONAL CHANGES AFFECTING RESOURCE ACQUISITIONS UNDER PURPA

2.1 Washington State Regulations Related to PURPA

Washington's Utilities and Transportation Commission (UTC) responded to PURPA by establishing regulations that address arrangements between electric utilities and qualifying cogeneration and small power production facilities. Following PURPA's lead, Chapter 480-105 of the Washington Administrative Code requires that investor-owned electric utilities purchase electrical energy at a rate based on their full avoided costs. Like FERC, the UTC defines avoided cost as "the incremental costs to an electrical utility of electrical energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, the utility would generate itself or purchase from another source."

The UTC requires that each electric utility put into effect standard rates for purchases from QFs with a design capacity of 100 kW or less. Developers of larger QFs have the option to sell energy at a price based on the purchasing utility's avoided energy costs calculated at the time of delivery or to provide both energy and capacity pursuant to a legally enforceable obligation over a specified term. Avoided costs for energy and capacity may be based on either the avoided costs calculated at the time of delivery or the avoided costs projected over the life of the obligation.

The UTC requires that utilities establish their avoided costs on a cents per kilowatt hour basis, during peak and off-peak periods, and that utilities submit these costs for the current calendar year and each of the next five years. Utilities must compute avoided costs for blocks of not more than 100 MW for systems with peak demands exceeding 1,000 MW or in blocks of not more than 10 percent of the peak demand for smaller systems.

Utilities and the UTC take the following factors into account when determining avoided costs:

- The utility's capacity expansion or energy purchase plans;
- The utility's ability to dispatch QF output;
- The expected or demonstrated reliability of the QF;
- The duration of the power purchase contract;
- Termination notice requirements and sanctions for non-compliance;
- The extent to which scheduled outages can be coordinated;
- The usefulness of the energy and capacity supplied during emergencies;
- The benefits associated with adding small, short lead time capacity increments to the utility's system; and
- The costs or savings associated with variations in line losses.

2.2 Least-Cost Planning: Overview

Least-cost planning is an integrated planning tool wherein utilities consider all potential resources, both demand-side and supply-side, to meet future electrical requirements. To determine the cost-effectiveness of a resource option, a utility first projects fixed and variable costs for its total system without the resource option. All characteristics of the new resource option are then placed in the resource planning model, and the utility again projects the total system costs. The resource option is cost-effective if adding the resource reduces the levelized cost for the total system or increases the total system's net present value .

Least-cost planning may affect PURPA resource development in several ways.

First, utilities must consider the cost of both supply-side and demand-side resources in developing their least-cost plans. But the inherent nature of conservation resources, which reduce demand and therefore utility sales, may lead utilities to favor supply side alternatives. Further, because utilities would have to finance conservation measures (just as they would for a new generating resource), their fixed costs would also increase. Thus, although a utility may identify conservation as its "least-cost" alternative, that utility may prefer to purchase power produced by a PURPA generating resource rather than reduce demand through investments in conservation. (However, the utility could also lose revenue if a PURPA cogenerator happens to be one of its major customers.)

Second, utility "self-dealing" and cross subsidization may be problems. For example, some investor-owned utilities in Washington State have unregulated subsidiaries involved in the development of non-utility generation. This situation could bias the resource acquisition process against public and private sector developers of generating and conservation options that may be of comparable or greater value.

Third, questions have arisen concerning resource reliability and longevity. A utility might enter into an agreement via a power purchase contract with a developer that does not have an "obligation to serve." Thus, the utility may not be fully assured that the resource will be available over the full term of the contract.

Fourth, the issue of least-cost to whom becomes important in the least-cost planning process. Least-cost to a utility may not be least-cost to its customers since switching to an another fuel may actually be the least-cost option for the customers. Similarly, resources that are least-cost for one utility's service area may not be least-cost from an overall state or regional perspective.

2.3 Least-Cost Planning by Investor-Owned Utilities

In Washington, the UTC requires investor-owned utilities (IOUs) to file least-cost plans every two years. (Puget Sound Power and Light is the first IOU to submit a formal plan.) These plans provide the UTC with the information necessary to develop comprehensive avoided cost and least-cost planning models for evaluating potential resource decisions. The UTC expects to utilize these models after each of the IOUs submits its least-cost plan. A flow chart for the UTC's least-cost planning model is given in Figure 2-1.

Least-cost plans required by the UTC must include both planning assumptions and scenario-specific resource plans. Financial parameters and underlying assumptions address future financial and economic conditions that may prevail under the utility's expected operating conditions. Important components of a least-cost plan prepared for the UTC include:

The General Rate of Inflation. The UTC requires utilities to use nominal dollars in their least-cost plans but also requires that they specify assumed rates of inflation. This requirement allows the UTC to compare the effects of varying assumptions about inflation used by different IOUs.

Tax Rates. These parameters include federal income tax, property tax, and other applicable tax rates.

The Cost of Capital and Capital Structure. The UTC requires utilities to submit both their projected cost of capital and the assumptions underlying that projection. These assumptions include the time value of money, opportunity costs, and the utility's proportion of debt (its debt/equity ratio). Further, the UTC requires the utility's mix of financial assumptions to be internally consistent. For example, the nominal cost of capital must be consistent with assumptions about the inflation rate.

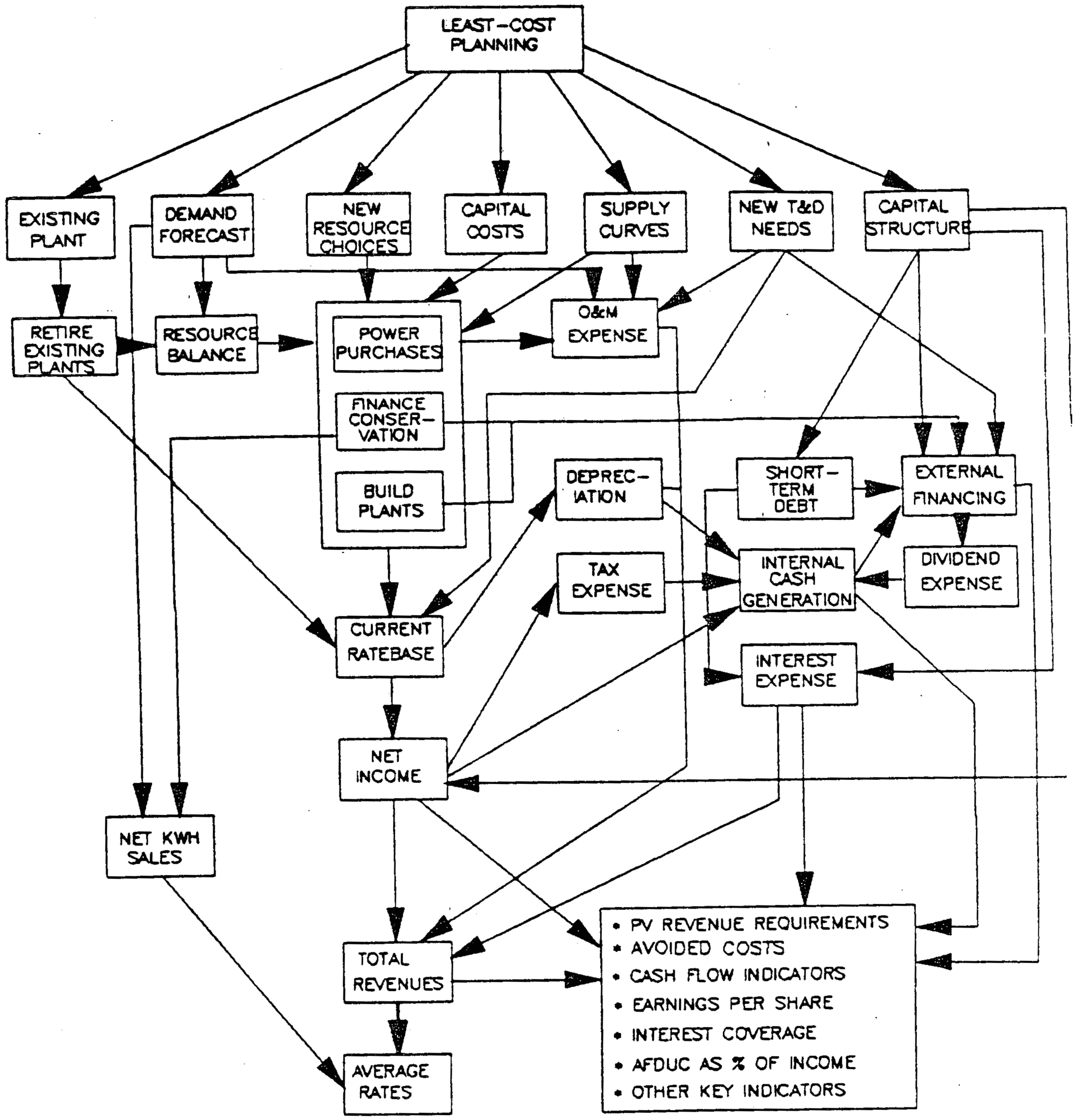
Existing Resources Forecast. This forecast describes resource availability, operation, and reliability. More specifically, this information includes an inventory and complete description of existing resources, any foreseeable problems that might affect resource availability over the planning horizon (usually 20 years), and variable operating costs associated with existing resources that may be considered dispatchable (i.e., inter-utility power exchanges).

Demand Forecasts and Load Growth Scenarios. The UTC leaves the methodology for forecasting demand to a utility's discretion but requires it to identify three demand scenarios—high, medium, and low—that encompass the full range of probable demand uncertainty. The UTC also requires utilities to describe the economic and technological factors that influence growth, as well as the relationships between price and demand (price elasticity).

New Resource Cost Estimates. These parameters include availability and cost estimates for all possible future resources. Typical resource categories include utility-owned generation, conservation, renewable energy resources, and inter-utility power transfers. Information on conservation and renewable resources may be presented as supply-curves, which specify available quantity as a function of price.

Figure 2-1

UTC Least Cost Planning Model



The optimal resource mix, like the demand forecast, depends on many quantitative and qualitative planning assumptions. Therefore, the UTC requires IOUs to estimate the general extent to which different resource categories will be relied on to meet estimated load growth. The utility must apportion resources over the planning period either annually or in five year blocks.

2.4 Least-Cost Planning by Public Utilities

No Washington State agency or regulatory body requires public utilities to develop a least-cost plan. However, if conservation or renewable resource opportunities increase and customers continue to press for low rates, public utilities may respond by developing least-cost plans. Just as the IOUs must satisfy UTC requirements, public utilities may find it advantageous to address the concerns of their commissioners, financial institutions, and ratepayers through least-cost plans.

Lewis County PUD is the first public utility in Washington to develop a least-cost plan. The PUD took this step because of its need to identify available electric power resources. Its plan contains two main sections: the first addresses resource planning, taking into account future demand, existing resource needs, financial assumptions, and levelized generating costs; the second section addresses potential resource options, including demand side, supply side, and future technological resources. A summary of the key topics in Lewis County PUD's least-cost plan follows:

Rate Forecasting. Many Washington state public utilities, including Lewis County PUD, purchase most of their power from BPA. Thus, a critical variable is the projected BPA wholesale rate.

Demand Forecasts and Load Growth Scenarios. Load forecasts depend on a wide range of variables, and many of these variables introduce uncertainty into the forecast. In addition to assumptions about future BPA rates, Lewis County's load forecasting model includes major assumptions about critical variables such as forecasts of economic and population growth, industrial load factors, adjustment for conservation programs, and weather. Using its model, the PUD developed the following four load growth scenarios:

- Low case—BPA rates decline;
- Medium low case—BPA rates decline modestly;
- Medium high case—BPA rates increase modestly; and
- High case—BPA is sold to a private group.

The low case is given a 10 percent chance of occurring, the medium low case a 40 percent chance, the medium high case a 40 percent chance, and the high case a 10 percent chance.

Existing Resources. Lewis County PUD describes existing resources by type and nameplate capacity. Since it purchases most of its power from BPA, the PUD treats BPA as a single existing resource.

Supply Surplus/Deficit Forecasts. Public utilities purchasing power from BPA have a strong incentive to realistically forecast future supply surpluses or deficits since a federal power sales contract obligates them to build new resources to satisfy any load growth above the terms of the contract. In fact, if such a utility does not meet requirements contained within its power sales contract, BPA can reduce power deliveries to that utility.

Financial Assumptions. The least-cost plan discusses general financial assumptions such as the rate of inflation, the real discount rate, and the nominal cost of capital. Other financial factors include the cost incurred for wheeling generated power, generation service charges, and efficiency improvements in generating plants.

Resource Options. This section of Lewis County PUD's plan describes available resources that could be used to meet future load requirements, including demand side management; conservation; acquisition or development of energy resources; power purchases from BPA, BC Hydro, or other utilities; and other options.

Levelized Cost Analysis. Lewis County PUD developed levelized costs for demand and supply-side resource options. Basically, levelized costs are calculated by amortizing the net present value of resource costs (excluding the effect of inflation) over the life of the resource and dividing the amortized cost by the annual energy output or conservation savings. The resource with the lowest levelized cost is the best option. The PUD considers those resource options with levelized costs below the expected value of BPA's wholesale power rate to be candidates for resource acquisition.

2.5 Competitive Bidding

In 1987, Martha Hesse, chairperson of the Federal Energy Regulatory Commission (FERC), proposed rules that would establish how state regulators allow independent power producers to competitively bid for the right to supply power to a utility. Although several states had established bidding programs prior to FERC's interest in the subject, FERC's proposed rules provided a catalyst for more states to become involved in competitive bidding. In theory, competitive bidding benefits consumers by establishing a market-based value for power and eliminating the risks to utilities associated with capacity expansion.

The process of competitive bidding begins when a utility identifies the need for new capacity. Well in advance of the date it begins to accept competitive bids, a utility typically publicizes the quantity and desirable attributes of its needed capacity, the terms of the offer to purchase capacity, participation criteria, and bid selection criteria.

More specifically, the typical elements of a competitive bidding process include:

Bidder Qualifications. Bidders establish their experience with projects of the same type and size as the proposed project. In general, utilities have to make bidder qualification requirements consistent with FERC's definition of a qualifying facility under PURPA. Bidders have to disclose both the percentage of utility ownership and the percentage of fossil fuel used by the proposed project.

Exemption of Potential Bidders. An exemption from bidder qualification requirements could be granted if a QF is deemed a small producer, or if a diverse resource mix is deemed desirable.

Bidding Criteria. These may include price criteria and non-price criteria such as preference to conservation or renewable resources, required in-service dates, and plant performance standards.

Security Requirements. These relate mainly to the technical and financial viability of a proposed QF project.

Flexible Selection of Bidders. This section gives the weight or relative importance of the criteria used to evaluate bids.

Post-award Negotiation and Contractual Obligations.

Competitive bidding may affect PURPA development in several ways. Competitive bidding would likely affect the price paid for PURPA resources and therefore the return a PURPA developer receives. For example, suppose a developer wishes to build a QF. If the utility were to pay the developer a rate based on an administratively-determined avoided cost, the development would receive a favorable return. However, if the rate were to be set through competitive bidding, the developer would earn a lower return. This type of situation would reduce incentives for developing PURPA resources. On the other hand, in a different situation, competitive bidding could increase the prices paid for non-utility generated power, thereby positively affecting the development of PURPA resources.

The actual influence of competitive bidding on price would depend heavily on how market forces replace administratively-set avoided costs and on what combination of least-cost resources are developed. For example, competitive bidding could lower a utility's marginal cost of electricity, resulting in higher profits. This improved profitability might lead the utility to purchase more power from PURPA resources, as long as the cost of those resources remains lower than the cost of utility-developed resources.

Competitive bidders will need transmission access to deliver their product, but, traditionally, utilities have only offered to "wheel" purchased power for other utilities during peak load periods. And, PURPA only requires that utilities give transmission access to QF developers **within** the utility's own service area. Thus, if provisions are not made for transmission and wheeling, the competitive bidding market could be severely limited since utilities might receive bids only from resources located within their own service areas. This would likely act to restrict development of PURPA resources.

2.6 Competitive Bidding in Washington

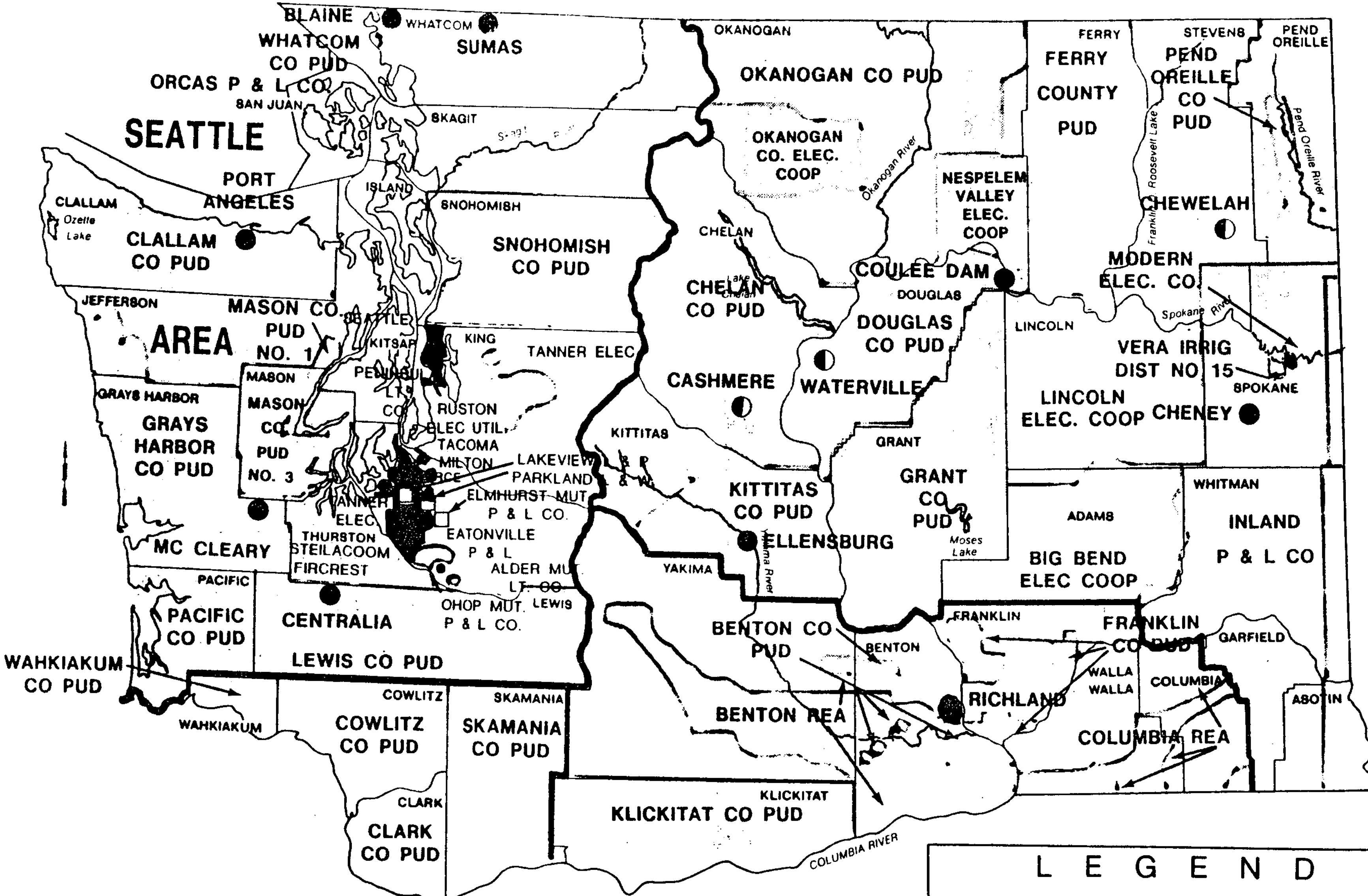
At the present time, competitive bidding in Washington is in the initial stages of development. The UTC, however, has identified several goals to guide the development of competitive bidding procedures for IOUs. Specifically, the UTC believes such a process should:

- Promote resource development that, subject to legal and reliability considerations, minimizes long-term costs to utilities and their ratepayers;
- Provide consistency and integration with the UTC least-cost planning process;
- Respond to the unique resource planning situations faced by each utility; and
- Preserve an appropriate degree of "management discretion" over utility planning decisions.

Many questions remain to be answered before competitive bidding could become a viable resource acquisition process in Washington. These include problems with utility self-dealing and cross subsidization, the importance of factors such as reliability, and the merits of all-source bidding versus bidding that is restricted to specific types of resources. Lack of transmission access is perhaps the biggest obstacle to competitive bidding in Washington. Service territories for public and investor-owned utilities are indicated in Figures 2-2 and 2-3, respectively. This complicated network of adjacent and overlapping service territories illustrates why readily available transmission access and wheeling services are necessary for PURPA transactions and competitive bidding to succeed in Washington.

Two utilities in Washington State currently have agreements to transmit and wheel electrical power from non-utility generators. Mason County PUD No.1 wheels power from Rocky Brook Hydroelectric project for the City of Seattle, and Clallam County PUD No. 1 wheels power from Morse Creek Hydroelectric Project for the City of Port Angeles. How agreements of this type would survive in a competitive bidding atmosphere is yet to be determined, but FERC and state regulators could handle this issue in much the same manner as the transport of natural gas, where a pipeline company sets tariffs for transporting gas sold independently from a producer to a consumer. These and other issues will be examined carefully by the UTC before it adopts any competitive bidding rules.

Until an actual bidding process is implemented, it will be difficult to assess the benefits and costs of competitive bidding on PURPA-related development in Washington. Nonetheless, government agencies, utilities, and QF developers have expressed strong interest in competitive



LEGEND

	MUNICIPALITY	COOP.	PUD	OTHER
OPERATING WITH BONNEVILLE POWER	●	■	□	□
OPERATING WITHOUT BONNEVILLE POWER	◐	□		

NOTE: PREPARED FROM BEST AVAILABLE INFORMATION AND NOT INTENDED TO REPRESENT LEGAL OR CLAIMED SERVICE BOUNDARIES. SOME OVERLAPPING SERVICE AREAS EXIST.

Figure 2-2
Service Areas—Operating Public Agencies and Cooperatives

STATE OF WASHINGTON

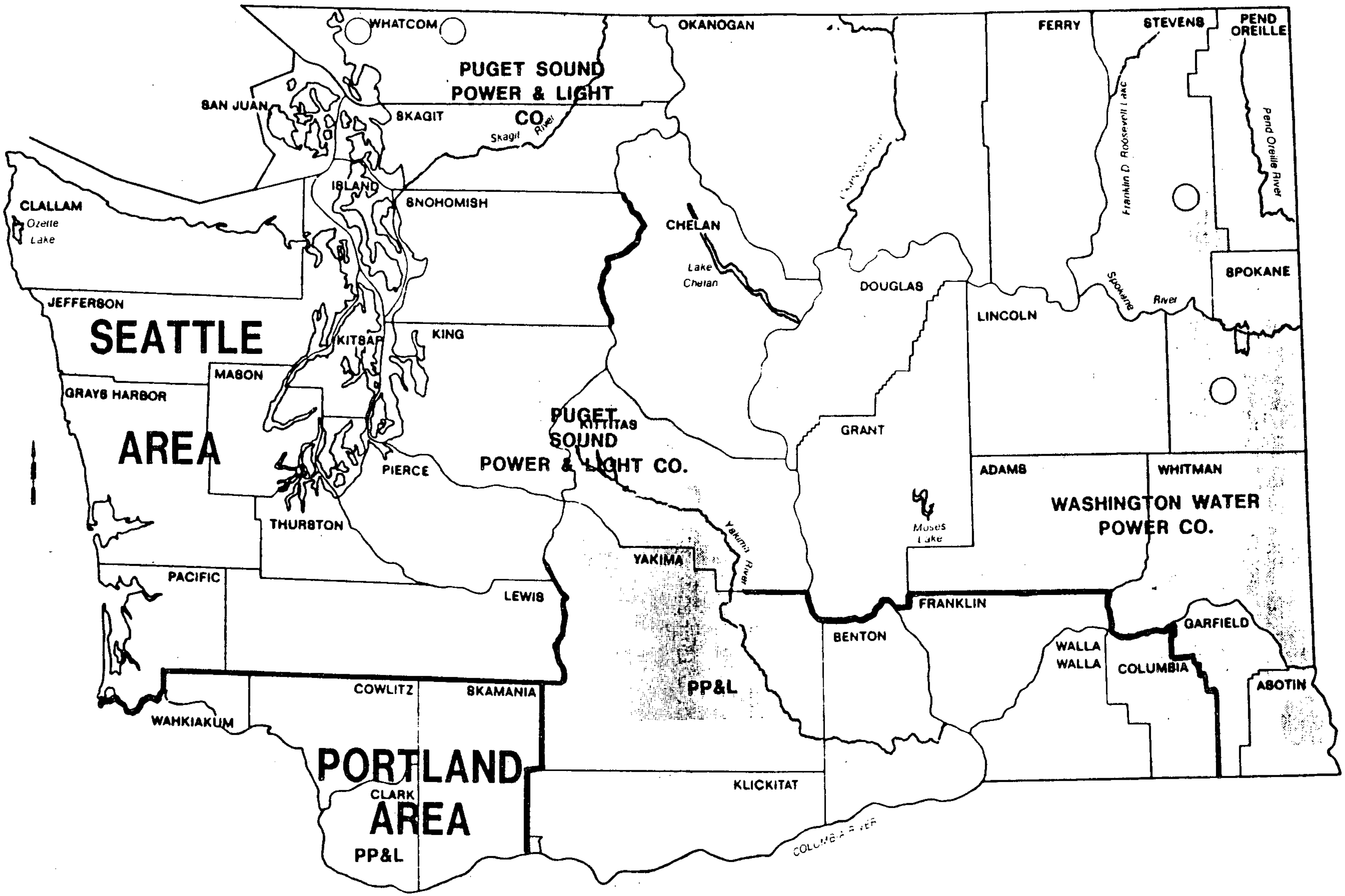


Figure 2-3

Service Areas—Investor-Owned Utilities

STATE OF WASHINGTON

bidding. As a result, the UTC issued a notice of inquiry to solicit comments on this issue. Overall, most developers caution against adopting competitive bidding, but most utilities favor the concept. A condensed version of comments submitted to the UTC follows.

2.6.1 Federal and State Agency Comments

Department of Energy, Bonneville Power Administration. "BPA recommends that the bidding procedures be designed to respond to resource needs listed in utilities least-cost plans....

To the extent that the bidding process lowers the price of QF produced power purchased under this program, there may be an impact on the quality of QF-produced power....Surplus utilities, which receive less benefit from the QF early in the QF's production life due to the utilities surplus condition, might be limited to offering a nominal price stream which is equivalent to the bid price over the term of the contract with the QF..."

Office of the Washington Attorney General. "The Public Council Section supports the concept of competitive bidding for new electric resources. If implemented properly, it can provide a mechanism for the acquisition of resources at less cost than the administratively determined "avoided cost" under section 210 of PURPA, without discriminating against Qualifying Facilities (QFs)... However, we think that if a bidding procedure is adopted, it should be integrated with the acquisition of all new long-term resources, and treat them all equally... within the context of the preference afforded to conservation by the Northwest Electric Power Planning and Conservation Act and by RCW 80.20.025."

Washington State Senate, Energy and Utilities Committee. "The idea of a market-based system for securing new resources is attractive. A bidding system could encourage development of more non-utility power sources and at better prices for consumers. It could free utilities from the concern that regulators will second-guess their decisions about whether to buy resources and how much to pay for them. It also would reduce the need for the commission to guess future avoided cost..."

Washington State Energy Office. "WSEO considers competitive bidding to be potentially important and a beneficial step towards achieving "least-cost" energy. We emphasize "potentially" because of our concern that an improperly structured competitive bidding process could impose greater risks on consumers due to non-price and external factors of electrical supply...

We feel it is also possible that, unless properly designed, a competitive bidding system could hinder regional cooperation between the Bonneville Power Administration (BPA) and Northwest utilities. A competitive bidding system might be used by some utilities as a means of avoiding reliance on BPA, or by encouraging industrial cogeneration that would adversely affect BPA's captive customers. Would the commission, therefore, automatically include offers from BPA when evaluating a utility's bids or evaluate bids against the cost of power from BPA? If not, the question of least-cost planning could be least-cost to whom?"

2.6.2 Utility Comments

Washington Water Power Company. "Water Power believes that a competitive bidding system for QF resources can better fit with the purposes and intent of the least-cost planning process than does the current method of QF acquisition. Water Power also believes that a bidding system which includes all non-utility resources in the acquisition process is appropriate to allow utilities to provide the lowest cost power to its customers."

Puget Sound Power and Light Company. "Puget generally agrees with the primary criteria to be used by the commission to evaluate alternative bidding procedures, as set forth at page five of the Notice of Inquiry. Competitive bidding for acquiring QF and conservation resources appears to be consistent with the goal of minimizing long-term costs to utilities and their ratepayers. Bidding may be preferable to current procedures insofar as it reduces or eliminates reliance on administratively determined estimates of avoided cost, and thus may lead to acquisition of resources at rates lower than such estimates."

Pacific Power and Light Company. "Turning to how the competitive-bidding concept might best be implemented to meet Northwest needs, Pacific first believes that having available such an option could reduce a utility's future revenue requirements, and could thereby produce a direct positive benefit for the utility's customers."

Public Power Council. "In order for any bidding procedure to help insure the least-cost provision of electricity, it is essential that all potential methods for meeting load are allowed to participate. This requires both the considerations of conservation measures and the opportunity for all utilities to bid..."

Seattle City Light. "We support the notion of least-cost planning and believe that a competitive bidding process for determining generation and conservation resource acquisitions would encourage or enhance such... Further, we consider competitive bidding to be consistent with the intent of the Public Utility Regulatory Policies Act (PURPA) in that a clearly delineated bidding procedure would tend to reduce administrative hurdles that could discourage the development of cost effective resources in the Pacific Northwest region."

2.6.3 Resource Developer Comments

Mission Energy Company.* "Any consideration of a bid system for the acquisition of power resource should consider the basic advantages and disadvantages of a generic bid system, then apply those to the specific acquisition program. As a rule bidding works well for simple items such as pencils, and progressively gets more complex and subject to problems as the complexity of the object of the bid becomes more complicated...

Some key advantages of bid systems are:

a. If a fair evaluation of all factors is performed then the object of the bid will be acquired at a competitive, market based price.

b. Bid systems will force the use of standard criteria, resulting in predictability for all involved.

c. Bid systems will acquire resources when the goal is to acquire resources.

Some key disadvantages of bid systems are:

a. Inflexible once the criteria are set.

b. Unable to capture short-lead opportunities.

c. Can be subject to manipulation in the evaluation.

d. May increase the risk of projects failures because of the tendency to drive down margins and contingencies."

*Note: Mission Energy is a wholly owned subsidiary of Southern California Edison.

Idaho Natural Energy, Inc. "At the current time, one IOU in particular, Puget Sound Power and Light Company, has not been purchasing power from QFs. Most of Puget's reasons center around the "Security Provisions" when used with a partial or full levelized cost. <u>The point here is that it does not matter what a QF thinks about competitive bidding if an IOU will not purchase power from the QF in the first place</u>. Unless the IOU's respond to the intent of PURPA as properly enforced by the UTC, not a single resource owned by a QF will be purchased. Therefore, for a QF, competitive bidding is a moot point at this time."

Pacific Hydro. "The concept of competitive bidding is probably feasible but doubtful that it is desirable. Competitive bidding is a highly complicated procedure that requires intricate detailing. Both standard contracts and a competitive bidding procedure do not provide the same degree of ferreting out the intangible characteristics of a QF that are very important in establishing minimum cost to the ratepayer...If, in fact, a competitive bidding process is developed, that becomes the least-cost planning method of developing resources that are needed."

Northwest Small Hydroelectric Association. "We believe that a properly developed competitive bidding process for new electric power resources in Washington State is both desirable and highly feasible, and would be, in the long term, in the best interest of those ratepayers served by this state's investor owned utilities, provided such a process truly recognizes all aspects of section 210 and 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA), including its very specific non-discriminating language."

Washington Hydro Associates. "WHA believes that a bidding procedure for projects under 10 megawatts of capacity is unworkable and unwarranted because:

(a) it will impose non-productive bid preparation and other costs on small projects unable to realize bid economies of scale available to larger projects,

(b) permit the institutional bias of utilities toward larger, thermal resources to distort the selection process (or worse, permit deliberate selection of uneconomic or infeasible projects),

(c) by periodically updating avoided cost and restricting the eligibility of small projects for power purchase contracts (establishing qualification criteria and deadlines on construction start up), the commission can prevent infeasible projects from cluttering the pipeline and confusing the supply picture, and

(d) it is in the best interest of the region to develop <u>all</u> licensable small renewable resources capable of being developed at the avoided cost..."

CHAPTER III. WASHINGTON STATE LEGISLATIVE RESPONSES TO PURPA

3.1 Washington State Energy Policy

Since the passage of PURPA in 1978, the Washington State Legislature has responded to issues ranging from incentives for resource development to regulation. Initially, the legislature removed barriers to the development of geothermal, cogeneration, and hydroelectric power resources and eventually passed laws offering financial incentives. Additional legislation simplified the permitting maze to expedite energy development. At the same time, the legislature enacted environmental protection laws that attempted to balance the concerns of power development and the environment.

Involvement of Washington's legislature in energy resource development did not begin with PURPA, however. In 1975, when the Washington State Energy Office was created, the legislature also articulated a clear state energy policy:

- The development and use of a diverse array of energy resources with emphasis on renewable energy resources shall be encouraged;
- The supply of energy shall be sufficient to ensure the health and economic welfare of its citizens;
- The development and use of energy resources shall be consistent with the statutory environmental policies of the state... (RCW 43.21F.015)

Additionally, the legislature charged WSEO with "...develop(ing) energy policy recommendations for consideration by the governor and the legislature (RCW 43.21F.045 (4))." Under this statutory directive, WSEO went on to initiate many of the laws discussed in this chapter.

3.2 Enabling Legislation Affecting Geothermal Resource Development

In 1979, the legislature recognized that exploration and development of geothermal resources was a relatively new endeavor and acknowledged that the property rights in these resources had not been clearly defined. Consequently, the legislature enacted SB 2191 (Ch.2, L.79, 1st ex.sess.). This law declared geothermal resources to be distinct and separate (*sui generis*) from mineral or water resources. Geothermal resources were also declared to be the private property of the party holding title to the surface above the resource.

In 1980 the legislature took an additional step to encourage geothermal development. Washington has five stratovolcanoes that indicate substantial geothermal resource potential, but these resources are located primarily on federal lands. In light of this situation, the legislature memorialized Congress (HJM 25) to enact comprehensive geothermal legislation which would assist the state in furthering geothermal development.

By 1981, interest in geothermal resources had increased. Federal land was being leased, explored, and assessed for its geothermal potential. Under provisions of the Geothermal Steam Act of 1970, a portion of the rents and royalties received for federal geothermal leases was to be returned to states. To take advantage of this situation, the legislature passed SHB 466 (Ch. 158 L.81), creating a geothermal account in the state general fund. Through SHB 466, the legislature also allocated funds in the geothermal account and placed the following limitations on how those funds could be used:

> Thirty percent to the Department of Natural Resources for geothermal exploration and assessment; thirty percent to the Washington State Energy Office or its statutory successor for the purpose of encouraging the development of geothermal energy; and forty percent to the county of origin for the mitigating impacts caused by geothermal energy exploration, assessment, and development (RCW 43.140.040).

3.3 Enabling Legislation Affecting District Heating and Cogeneration

Prior to 1983, Washington's legislature had been primarily interested in high temperature geothermal resources capable of producing electricity. In 1983, however, the legislature passed legislation that enabled and encouraged the creation of district heating systems, thereby recognizing the potential of lower temperature geothermal resources and other sources of heat. Actually, two laws were enacted: one enabled public entities to establish district heating systems (ESB 3224); the other encouraged private development of district heating by authorizing only limited regulation by the UTC (SHB 114).

ESB 3223 (Ch.216, L.83) specifically enabled municipalities (counties; cities; towns; irrigation districts that distribute electricity; and sewer, water, and port districts) to establish district heating systems using a variety of heat sources. These resources include (but are not limited to) geothermal, cogeneration, biomass, solar, and waste heat from industry. This legislation also authorized municipalities to finance, construct, operate, and regulate district heating systems (RCW 35.97.010-130).

Prior to enactment of SHB 114 (Ch.94, L.83), Washington law was silent as to whether district heating systems were subject to regulation by the UTC. Because of the uncertainty regarding rates created by this situation, potential developers had been reluctant to risk building these systems. Potential users of district heating systems were likewise cautious because of uncertainly about consumer protection. SHB 114 eliminated this uncertainty by granting limited permitting authority to the UTC. Specifically, the UTC can issue an operating permit to a heat supplier if the applicant is financially responsible, if the system is adequate for its intended purpose, and if consumer protection provisions are incorporated into the customer service contract (RCW 80.62.010-080).

To clarify some of the definitions spelled out in 1983, the legislature amended both district heating laws during its 1987 session (SHB 425, Ch.522,L.87). For example, the legislature explicitly included "Hydrothermal resources" as a potential heat source for district heating, thereby recognizing the growing use of water source heat pumps that capture heat from sources such as sewage effluent. The legislature also expanded the definition of "municipality" to include metropolitan corporations, such as King County METRO.

3.4 Enabling Legislation for Hydroelectric Resources

By 1979, several irrigation districts in the Columbia Basin were considering generating electricity from the water flowing through their irrigation systems. However, their authority to undertake such projects and their revenue bonding powers were unclear. In addition, it appeared that these districts might not be able to sell all the power they might generate.

In 1979, Washington's legislature changed state laws governing irrigation districts and clarified their authority to generate electricity. Specifically, the legislature set forth the following state policy, as stated in Section 1 of 2ESSB 3033:

> The legislature finds that a significant potential exists for the development of the hydroelectric generation capabilities of present and future irrigation systems serving irrigation districts. The legislature also finds that the development of such hydroelectric generation capabilities is beneficial to the present and future electrical needs of the citizens of Washington, furthers a state purpose and policy, and is in the public interest. The legislature further finds that it is necessary to revise and add to the authority of irrigation districts to obtain the most favorable interest rates possible in the financing of irrigation district projects which serve the agricultural community and hydroelectric facilities. It is the intent of the legislature to provide irrigation districts with the authority to develop these hydroelectric generation capabilities in connection with irrigation facilities.
>
> Further it is the intent of the legislature that the development of hydroelectric generation capabilities pursuant to this 1979 act not become the sole purpose or function of irrigation districts in existence on the effective date of this 1979 act, nor become a major function of irrigation districts created after that date. Nothing herein shall authorize an irrigation district to sell electric

power or energy to any municipal corporation not engaged in the distribution of electric power or energy (RCW 87.030.013).

Thus, with passage of 2ESSB 3033, the legislature clarified the authority of irrigation districts to develop hydropower projects inside and outside their boundaries and to sell any electricity produced by these projects. The legislature prohibited irrigation districts from distributing electricity and instead required that they sell that electricity to public utilities (PUD's or municipal utilities), which were already authorized to engage in distribution. (Irrigation district laws, generally, are found at RCW 87.030.005-900; their bonding authority is found at RCW 87.28.005-210.)

In 1981, the legislature further enabled irrigation districts to act jointly and cooperatively to develop hydroelectric projects. HB 188 (Ch. 62, L.81) included irrigation districts under provisions of the state's Interlocal Cooperation Act.

In 1983, the legislature passed HJM 4, encouraging Congress to streamline the permitting process for hydroelectric facilities. Specifically, this memorial asked the federal government to delegate all permitting authority for small scale hydroelectric projects (100 kW or less) to the states.

That year, the legislature gave further incentive to hydroelectric development by passing SSB 3511 (Ch. 47, L.83). This law enabled irrigation districts, municipalities, and public utility districts to jointly construct and operate hydroelectric facilities. (Prior to passage of SSB 3511, each entity could only develop hydropower resources jointly with other like entities. For example, municipalities could only join with other municipalities.) This new authority is found at RCW 87.030.825-837.

The uncertain situation faced by irrigation districts in the late 1970s eventually became apparent to other local governments and special districts in 1985. Cities, towns, water districts, and sewer districts were not expressly authorized to develop hydropower projects in connection with their sewer or water systems. Water systems, in particular, have significant hydroelectric potential. Further, installing generating equipment at existing water supply dams would disturb the environment much less than constructing new dams.

Consequently, the legislature passed SHB 846 (Ch. 444, L.85) in 1985, which authorized municipal water and sewer utilities to develop hydroelectric power, but only as an adjunct to their water or sewer systems. Further, these districts could only use the electricity within their own system or sell it to another entity authorized by law to distribute electricity. In fact, a city or town that does not have its own electric utility would have to obtain voter approval prior to issuing bonds to finance such a project, if its generating capacity was over 5 MW and the power would not be used within its sewer or water system. In addition, SHB 846 requires water and sewer utilities to furnish estimates of potential environmental and rate impacts to the Washington Department of Ecology. (The provisions of SHB 846 are found at RCW 35.92.010, 35.92.070, 56.08.010, 57.08.010 and 90.54.170.)

In 1987, the legislature responded to Congress' passage of the Electric Consumer's Protection Act of 1986 and the Northwest Power Planning Council's proposal for "protected areas." Specifically, the legislature authorized a task force to study the feasibility of developing a comprehensive state hydroelectric development and resource protection plan. In its 1988 report, the task force recommended that the state should prepare such a plan. A policy bill directing development of the plan and a budget proposal will be pending before the 1989 legislature.

3.5 Legislation Enabling Solar Resource Development

During its 1977 session, the Washington State Legislature took its first action in the area of solar energy by exempting systems installed as improvements to real property from property taxes. Under 2SHB 388 (Ch. 364, L. 77, 1st ex. sess.), these exemptions were for seven years after a claim was filed with the county assessor. These exemptions could not be renewed, and after December 31, 1981 no new claims could be filed. Thus, 2SHB 388 only opened a four year window for these exemptions.

However, in 1980, the legislature repealed the solar tax exemption and, in its place, passed ESB 3181 (Ch. 155, L. 80) requiring that buildings with unconventional heating, cooling, domestic water heating, or electrical systems should not be assessed at a higher value than similar buildings with conventional systems. The 1987 legislature allowed this provision to sunset on December 31, 1987, when assessors testified that the provisions of the 1980 law were now common practice.

SHB 912A (Ch. 170, L. 79, 1st ex. sess.), passed in 1979, established a more enduring approach to solar resource development. Once again, the legislature focused on defining property rights and protecting solar access. Specifically, this law authorized city and county planning commissions to investigate the potential for solar energy development and encouraged them to include solar issues in their local comprehensive plans. (These plans are the basis for zoning ordinances which can be used to protect solar access.) Additionally, SHB 912A authorized private parties to negotiate solar easements and spelled out what these easements must contain. Solar easements would be real property interests, subject to the same conveyancing and recording requirements as other easements. (Protection of solar access through local planning procedures is found at RCW 35.63.015, 35.63.060, 35.63.090, 35A.63.015, 35A.63.062, 35A.63.100, 36.70.025, 36.70.350, and 36.70.560. The solar easement requirements are found at RCW 64.04.140-170.)

3.6 Financial Incentives

In the first few years following enactment of PURPA, Washington's legislature considered a variety of financial incentives for energy resource development. For example, owners of certain power projects are allowed to pay a reduced business and occupational tax, and are exempt from property taxation for seven years. Other legislation offers investor owned natural gas and electric utilities credits against the state utility tax and increases in the rates of return allowed on an investment in the small power production business.

The passage of SHB 1013 in 1979 (Ch. 191, L. 79) established financial incentives for developing electric power, mechanical power, or useful heat energy from cogeneration. Under this law, a developer could credit 50 percent of his capital investment at a rate of 2 percent per year. In any one year, the credit could not exceed 50 percent of the developer's total B&O tax liability. This legislation also specified that the Department of Revenue could only authorize tax credits on $100 million of these cogeneration facilities.

In 1982, the legislature increased the B&O tax credit rate to 3 percent per year and limited eligibility for the tax credit to $10 million per applicant. (SB 3394, Ch. 2, L. 82). The increased cogeneration tax credits were authorized only for facilities built and operating by December 31, 1984. After that date, no new tax credits were authorized. (The cogeneration tax credit laws are found at RCW 82.35.010-080.)

With the passage of SHB 1013 in 1979, the legislature also granted a seven-year exemption from property taxes, starting when the cogeneration facility became operational (RCW 84.36.485). An additional provision of SHB 1013 directly addressed new power producers expected to enter the market under PURPA. That provision exempted entities, not normally in the business of power generation, from statutes and rules regulating electric generating facilities. Specifically, the law provides:

> The generation of power by a nonpolluting, renewable energy source by an individual natural person not otherwise engaged in the business of power generation is declared to be exempt from all statutes and rules otherwise regulating the generation of power. PROVIDED, That such an individual is hereby authorized to provide such power to the utility servicing the property on which the power is generated and the servicing utility is hereby authorized to accept such power under such terms and conditions as may be agreed upon between the parties (RCW 80.58.010).

In 1980, the legislature passed SHB 1419 (Ch. 149 L. 80), which establishes two financial incentives encouraging electric and gas utilities to invest in renewable resources and conservation.

The first incentive applies to IOUs and directs the UTC to allow a 2 percent higher rate of return on the "common equity" portion of a qualifying investment. Qualifying investments include measures to improve end use efficiency (conservation programs); cogeneration facilities; and facilities that produce energy from renewable resources. The increased rate of return is allowed for up to 30 years (RCW 80.28.025).

The second incentive applies to both IOUs and public utilities. SHB 1419 allows a public utility tax deduction for production costs of energy derived from cogeneration, improved efficiency, or renewable resources. The deduction is from gross income that is subject to the public utilities tax, and the amount is equal to the cost of producing the power or savings. (The public utility tax deduction provisions are found at RCW 82.16.055.)

To be eligible for either incentive, developers had to begin construction after June 12, 1980, but before January 1, 1990. During the 1989 session, the legislature will review both incentive programs to determine whether they should be eliminated, extended, or modified.

3.7 Government as an Example

To establish state government as a model in energy efficient design and construction, Washington's life cycle costing laws were amended in 1982. The original law, passed in 1975, required all public agencies to analyze the life cycle cost of alternative designs for new publicly owned or leased facilities and major renovations (25,000 square feet or more). (There is, however, no requirement that the minimum life-cycle cost alternative be chosen by the agency.)

SB 3156 (Ch. 159, L. 82) amended the life cycle cost procedures to encourage the use of renewable resources in new public buildings or facilities undergoing major renovations. The legislature directed state agencies, schools, and local governments to evaluate the life cycle cost for three energy systems, one of which must be renewable, before deciding which system to install. (The state's life-cycle cost analysis provisions are found at RCW 39.35.010-040.)

The legislature also expanded the bonding authority of school districts in 1980 to cover energy efficiency improvements. HB 1597 (Ch. 170, L. 80) allows school districts to borrow money or issue bonds for improving the energy efficiency of school district buildings or installing renewable energy systems. This authority can be found at RCW 28A.51.010.

3.8 Permitting Issues

Problems associated with licensing and permitting smaller energy projects became apparent in Washington with the first influx of new power projects (primarily hydro) in the early 1980s. (Although Washington has had an Energy Facility Site Evaluation Council (EFSEC) since 1970, that agency's jurisdiction remains limited to major energy facilities with at least 250 MW of generating capacity. Further, EFSEC had no jurisdiction over hydro projects (RCW 80.50.010-800)).

In response, the legislature encouraged a "one-stop" permitting process that supports energy resource development. The passage of HB 859 (Ch. 179 L. 82) amended the state's existing Environmental Coordination Procedures Act (RCW 90.62.010-130) to require the state agencies to follow certain time frames in the permitting process. For example, once the state Department of Ecology, which administers this law, has been notified of the location, type, and size of the proposed energy facility, it must determine whether a public hearing is required and then notify all state agencies with permitting authority. If a hearing is required, agencies must grant or deny their respective permits within 120 days of the hearing; if no hearing is required, agencies have 150 days from the date of notification to make their permitting decision. Failure to adhere to the timelines constitutes unconditional approval by that agency of the application.

3.9 Environmental Protection

Since 1970, the state of Washington has been increasingly concerned about environmental quality and the balance between energy production and environmental protection. Examples of general laws (merely cited here) that embody Washington's commitment to environmental protection include the State Environmental Policy Act (RCW 43.21C), laws creating the Energy Facility Site Evaluation Council (RCW 80.50), and the Environmental Coordination Procedures Act (RCW 90.62). Also, numerous state laws deal with air quality (RCW 70.94), water quality (RCW 90.48), hazardous waste (RCW 70.105), and solid waste (RCW 70.95).

Management of municipal solid waste has been the most recent energy/environmental challenge to the state. Washington's solid waste management laws established the following management priorities: 1) waste reduction; 2) recycling; 3) treatment; 4) energy recovery or incineration; 5) solidification/stabilization; and 6) landfill.

Incineration has become a leading option for solid waste disposal for many cities and counties in Washington. Several jurisdictions are seriously considering incinerators, and a few (Tacoma, Skagit County, and Bellingham) are currently building facilities. However, disposal of incinerator ash poses a special problem. Both the bottom ash and fly ash, depending on chemical content, could be considered either dangerous or hazardous waste under the state's laws. As such, the increased cost of disposal could effect the feasibility of various incineration projects. In response to this situation, the legislature enacted SSB 5570 (Ch. 528, L. 87) which established a regulatory framework for incinerator ash residues from solid waste incinerators. These provisions are contained in RCW 70.138.

CHAPTER IV. AVOIDED COSTS AND UTILITY POWER PURCHASE CONTRACT NEGOTIATIONS

4.1 Avoided Costs and PURPA

The introduction of PURPA and the avoided cost concept changed utilities plans for capacity expansion and resource acquisition. New practices, procedures, and interpretations had to be designed to translate the concept of "full avoided cost" into a quantitative pricing structure.

Simply put, "avoided cost" is the cost to an electric utility of purchasing, financing, building, and operating an additional unit of electrical generating capacity or, if capacity expansions are not required, the incremental cost of running the most expensive resource(s) in the utility's generating mix.

Theoretically, avoided costs should not be difficult to compute. But, the avoided cost issue becomes extremely complex when taking into account such factors as the cost of money, licensing and construction lead times, interest during construction, costs of the next unit installed, fuel costs and escalation rates, labor and maintenance requirements and costs, costs of environmental protection and mitigation, how the added resource would be dispatched or fit into a utility's merit order, and other supply and demand factors. Non-price factors, such as reliability, transmission and distribution losses, fuel diversity, and security, may also be included in the avoided cost computation.

4.2 Avoided Cost Methodologies

To calculate avoided cost, the incremental cost of purchased or generated power must be predicted for a number of years into the future. Each utility has a specific expected value for the incremental costs of owning and running generating resources, which can be expressed as a stream of levelized or time-varying avoided costs.

Due to uncertainties in both supply and demand, such predictions constitute a formidable task. Uncertainties in supply and demand are further magnified by other uncertain factors such as economic growth; changes in fuel prices; variations in electrical production, transmission, generation, and end use efficiencies; and new technological developments.

The avoided cost for non-generating public utilities that purchase their power exclusively from BPA is embedded in the appropriate BPA wholesale rate. (Since BPA supplies the majority of the power throughout the Northwest, its new resources rate predicts the long-term marginal cost of power. The BPA rate setting process thus establishes the avoided cost standard for utilities which purchase their power solely from the BPA.) When these "full-requirement" utilities purchase power from cogenerators or other small power producers, a straightforward method known as the "administrative ease" method is used to determine avoided costs.

For utilities with a mixed electrical power supply (those that either generate power themselves or buy it from other sources), calculations of avoided cost become more complex.

One avoided cost method frequently used by IOUs considers two cost streams. The **long term cost stream** assumes that the long run marginal resource is a coal-fired electrical generating facility. Because such facilities have recently been built, basic data is available for determining construction and operating costs. Additional calculations are required to determine changes in capital costs and the variable cost escalation over the life of the facility. Uncertainties often increase the avoided cost of this type of long term resource, making other short lead-time, small increments of capacity more attractive.

The **short term cost stream** (short-term avoided cost) depends on whether a utility has a power surplus or deficit. With a surplus, the avoided cost equals the price those utilities can get for selling power on the secondary market minus transmission and distribution losses. If there is a deficit, the avoided cost is the BPA new resource rate as a proxy for the true value of power. Combining the long term and short term cost streams reflects the utility's need for energy and eventual need for more capacity. Thus, an estimate of the full avoided cost is obtained.

Although there are many ways to establish an avoided cost, no one method considers all possible elements that are involved in supplying the Northwest with electricity. Other avoided cost methodologies which may be used under varying circumstances include:

The Peaker Method. The avoided cost of capacity is determined by the installed cost of a new combustion turbine or combined cycle peaking unit.

The Fuel Offset Method. With this approach, the capacity portion of avoided cost is based on the capital cost of a baseload plant minus the fuel savings compared to operating a peaking unit of equivalent capacity.

The Revenue Requirements Method. Here, the avoided cost is the difference between the cost of a utility system with and without QFs.

The Opportunity Purchase Method. The avoided cost is equal to power available for purchase. This method is used when a utility's opportunities for purchasing power are more economical than its generating options.

The Opportunity Sales Method. The opportunity for off system sales of QF generated power is weighed and factored into the avoided cost determination.

The Competitive Bid Method. Avoided cost is equal to the lowest bid a utility obtains for energy and/or capacity.

The Retail Price or "Run the Meter Backwards" Method. The avoided cost is established by pricing in parallel with retail electric rates.

Typically, an avoided cost model's planning assumptions include inflation, tax rates, capital costs and structure, existing resources forecast, load-growth scenarios, resource costs, escalation rates, and supply curves. Other factors that are evaluated include the resource mix owned by the utility, its conservation programs, its PURPA-related resource acquisitions, and its planned contracts for purchasing power.

In Washington State, the UTC and both pubic and private utilities have determined their avoided costs. The UTC's comprehensive avoided cost model, used in conjunction with a specific private utility's least-cost plan, produces both an expected range of avoided costs and levelized values for energy purchased given various resource lifetimes and on-line dates. Thus, the UTC's avoided cost model is similar to those used by utilities, except that it examines multiple supply and demand scenarios.

The UTC's avoided cost model is structured around six functionally-defined blocks, as shown in Figure 4-1. The determination of avoided cost proceeds as follows: calculate the resource balance for each time period; calculate levelized variable and fixed costs; schedule resources on the basis of the company's scenario-specific generating mix; determine incremental costs based on the resources selected to meet projected resource deficits; and generate present value cost streams and levelize these streams for different resource lifetimes.

Regional and utility-specific least-cost planning can assist utilities in determining their avoided costs since least-cost planning considers every possible mix of generating and conservation resources, planning assumptions, and demand projections.

Investor-owned and public utility actions additionally should be consistent with the Northwest Power Planning Council's 20 year Regional Power Plan and with its Fish and Wildlife Program. The Council has prepared two power plans, the first in 1983 and the second, more complete plan in 1986. In 1988, the Council updated its 1986 power plan. These regional power plans account for utility cooperation, cost effectiveness, availability, and the seasonality of different energy conservation or generating resource alternatives. By considering all energy resource options available to the region, the Council can direct the acquisition of resources that will best serve the region as a whole. The Council's priorities for electricity resources are: conservation, renewable resources, cogeneration, conventional thermal sources such as coal-fired plants, and nuclear.

The Council's priority on conservation highlights why this resource is a major part of the avoided cost picture. In many cases, conservation technologies represent the least-cost resource alternative and are a lower cost alternative to a generating resource acquisition.

4.3 Power Purchase Contract Provisions

Public and private utilities' power purchase contracts represent a vital link between the independent power producer and the electric utility market. Power purchase contracts are legal documents protecting both purchaser and seller. Two types of contracts have been historically offered: a short duration, non-firm power purchase agreement (typically offered to owners of micro-scale generating facilities); and a long duration, variable and/or fixed-price, firm power agreement. Both begin by setting the term of the contract and the date for commencement of the agreement.

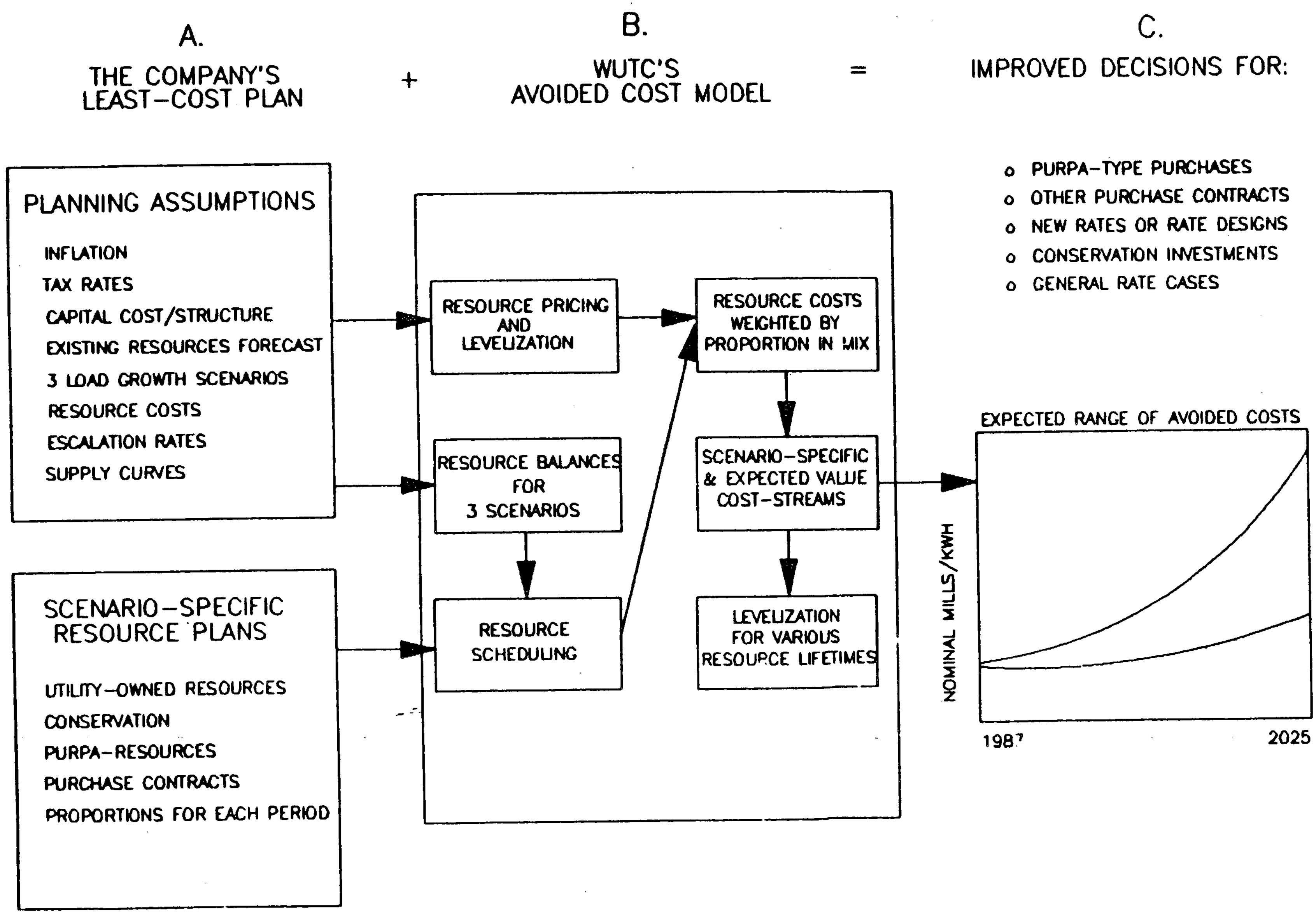


Figure 4-1

Least-Cost Planning and UTC's Avoided Cost Model

In addition, sellers are typically offered the choice of signing a levelized or "front-loaded" contract or of accepting the actual utility avoided cost at a given point in time. Levelized or constant price contracts are advantageous to the seller because they produce higher revenues during the early years of project operation, allowing the developer to secure a profit while meeting debt service, operating, and maintenance costs. (In fact, levelized contracts are often necessary for developers to demonstrate project feasibility and obtain construction financing from a lending institution.)

But levelized contracts also entail risks. For example, the levelized cost offer is based on assumptions made during a "snapshot in time" that cover load growth, equipment and construction costs, fuel prices, taxation, and maintenance costs. Since these predictions are most often wrong, the contract potentially could benefit either the developer or the utility. The developer benefits when expected load growth does not materialize or technological advances lower the price of power and, hence, utility avoided costs. The utility benefits when fossil fuel prices, the rate of load growth, or the cost of alternative generating and conservation resources increases. In this situation, avoided costs increase but the developer is "locked" into a fixed price sales contract.

A second type of risk occurs with levelized power purchase contracts. Under these contracts, the developer is paid more than the market value of electricity in the near term and less during the latter years of project operation. Utilities fear that developers may take the "overpayment" at the front-end but abandon the project when it no longer returns a profit. To protect themselves, some utilities insert termination penalty provisions into their power purchase contracts. Others require the posting of insurance or a security bond. (Bonding requirements impose a considerable burden on small-scale generating project developers as bonds may not be available or may be so costly as to preclude development.)

Overall power purchase contracts differ in complexity, in utility-specific interconnection and metering requirements, in insurance and security provisions, in defining termination and interruption situations, and in the magnitude of avoided capacity and energy payments. Typical contract provisions and required exhibits are summarized in Table 4-1 and in the following descriptions.

Table 4-1

Power Purchase Contracts: Highlights and Exhibits

Contract Terms

- Term of Agreement
- Purchase and Sale of Energy
- Service to Seller
- Metering
- Interconnections
- Wheeling
- Interruptions (seller & buyer)
- Project Transferability
- Termination
- Insurance

Typical Exhibits

- Point of delivery and electrical one-line diagram
- Length of contract spreadsheet, showing year; summer and winter payments in mills/kWh
- Interconnection cost estimate
- Sample calculations of termination amount (for levelized contracts only).

Purchase and Sale of Energy. The main body of a power purchase contract states who will deliver and sell the power and identifies the party who will purchase and receive it. The purchase price is defined, along with the payment provisions and the amount of electricity (energy and capacity) to be delivered.

In cases where the parties agree on a "front-loaded" contract with levelized payments, both contract duration and purchase price are shown over the length of the contract. Provisions are generally included to protect the purchaser from losing front-loaded overpayments in the event of a project termination.

Construction and Operation of the Project. This section is one of the most detailed parts of the contract and includes the construction schedule, permitting and licensing issues, project performance criteria, interconnection issues, wheeling contract concerns, responsibilities of the seller, outage provisions, metering installations, interruptions by the buyer, and numerous other legal issues, mainly pertaining to liability.

Inspection, Access, and Information. This section deals with three very important aspects of business communication. The first is inspection. With advance notice, the utility may be present during construction; during performance of maintenance procedures; and during all testing of the facility. The section also spells out access rights to the facility. Finally, the section contains provisions making any and all information that may relate to project operation available for utility review.

Transferability. Restrictions pertaining to transferability of a project may be added to the contract language. For example, the seller may not permit the transfer of all or any part of a project, the output of the project, or any legal agreement associated with the project. On the other hand, the utility may desire to hold an option to purchase a project if offered for sale, either in part or in whole.

Termination. This sections states that contract termination may result if the seller or buyer breach or default under the agreement. Termination provisions first require that the seller or buyer be given written notice of the breach or default. After an agreed upon time, the contract may then be terminated. Other conditions related to termination may include insolvency of either party, general assignment of the majority of project assets for the benefit of creditors, or seeking relief under insolvency laws. Termination may also occur if wheeling contracts are terminated or expire during the life of an agreement.

Miscellaneous. The last section of a power purchase contract may include such items as a requirement that the sellers warrant the project has received QF Status. The contract may stipulate that the agreement should not be misconstrued to mean that a QF/utility partnership exists. This section may also address miscellaneous legal issues such as insurance requirements and liability limitations; releases from claims, losses, and harms; options to purchase after the contract period; and specifications of authority.

4.4 Summaries of Power Purchase Contracts in Washington

Various power purchase contracts, which are in effect in the state of Washington, are summarized below.

Port Townsend Paper Corporation and Puget Sound Power and Light Company. The Port Townsend Paper Corporation (PTPC) operates a 375 kW hydropower project on an industrial water supply pipeline. PTPC signed a two year purchase agreement with Puget Sound Power and Light (PSP&L) in November of 1987. Under this short term agreement, PSP&L will pay a purchase price for energy delivered to the company of:

	Electricity Purchase Price, mills/kWh	
	Summer	Winter
Year 1	14.6	16.6
Year 2	15.1	17.4

South Fork II Inc. & Puget Sound Power and Light Company. In this October 1984 contract, PSP&L agreed to purchase electrical output from the 5 MW Weeks Falls hydroelectric project at a levelized rate of 75 mills/kWh. The duration of the contract is 35 years. In an interesting clause, the contract requires that the amount of energy delivered to PSP&L during the first half of the operating period shall not be more than that delivered over the remainder of the period. PSP&L has the option of extending the operating period until delivery balance obligations are met. The developer benefits in the near term from this front-loaded contract while PSP&L ratepayers are ensured of long term benefits.

Thermal Reduction Company and Puget Sound Power and Light Company. Thermal Reduction Company (TRC) of Bellingham and PSP&L signed a five-year power purchase contract on August, 1986. Energy from a 2 MW solid waste-fired electricity generating plant is sold to PSP&L at the following rates:

Operating Year	Price (mills/kWh)
1	28.3
2	30.6
3	31.9
4	33.3
5	34.8

One section of this contract establishes an option by PSP&L to purchase all of the project interests on terms "not less advantageous" to PSP&L than those which TRC is willing to accept from a proposed transferee. PSP&L is thus protected from the loss of generation which it has acquired and is counting on to meet load growth.

Skagit County and Puget Sound Power & Light Company. Skagit County and PSP&L entered into an arrangement in January of 1987 whereby the utility purchases delivered energy from an 1,800 kW waste-to-energy facility at a levelized price of 49 mills/kWh for a 20-year period. This contract includes a termination payment clause designed to protect PSP&L's front-loaded investment in the event that the County abandons the plant or ceases operations. The termination penalty is based upon the difference between the levelized payment to the County less the utility's variable rate plus interest charges.

City of Spokane and Puget Sound Power & Light Company. Spokane and PSP&L signed an agreement in January 1988, under which PSP&L will accept wheeled energy produced by the city's proposed 800 ton-per-day waste-to-energy facility. Energy is purchased from the 22.9 MW resource recovery plant in accordance with the following escalating, seasonally differentiated schedule.

Energy Purchase Price for Spokane Waste-to-Energy Project

Year	Winter Period Sept. - March mills/kWh	Summer Period April - August mills/kWh
1	11.4	8.3
2	18.5	12.4
3	24.1	19.4
4	24.8	20.0
5	25.5	20.4
6	26.0	20.8
7	27.1	21.6
8	29.6	23.7
9	33.7	27.1
10	35.0	28.0
11	96.4	52.8
12	96.4	52.8
13	96.4	52.8
14	96.4	52.8
15	96.4	52.8
16	96.4	52.8
17	96.4	52.8
18	96.4	52.8
19	96.4	52.8
20	96.4	52.8
21	96.4	52.8

Woods Creek, Inc. and Snohomish County PUD #1. In December 1982, Woods Creek Inc. entered into an agreement with Snohomish County PUD regarding purchase of energy produced from a 650 kW hydroelectric project. The seller is paid 1.02 times the current Bonneville Power Administration Priority Firm Power Rate for all energy delivered. Effective October 1, 1982, the melded priority firm rate was 20.9 mills/kWh for the months of December through May and 15.7 mills/kWh between June and November.

The majority of the 60 electric utilities in Washington are non-generating Public Utility Districts, Cooperatives, and Municipal Utilities. The avoided cost for non-generating full-requirements Bonneville Power Administration customers is generally equal to the priority firm wholesale rate for purchased electrical energy and capacity.

Pacific Cogeneration Inc. and Public Utility District No. 1 of Clark County. Pacific Cogeneration Inc. (PACCO), a subsidiary of Penwest Company, signed a 12 year agreement with Clark PUD in July of 1982 under which Clark PUD agreed to purchase the electric generation of PACCO's Vancouver cogeneration facility. The facility is a natural gas fired turbine/generator which produces electric energy and process heat which is sold to the Great Western Malting Company for the purpose of malting grain.

Energy is purchased from the 20.1 MW facility under the terms of the power purchase agreement which specifies that Clark PUD will reimburse PACCO for all of the project's fixed and variable costs. The majority of this cost is related to the purchase of natural gas. As such, the project's future generating cost is dependent on the price of natural gas.

Clark PUD and PACCO negotiated the agreement under the shadow of a utility avoided cost based on the now terminated WNP 4 & 5 projected costs. These costs were estimated to be in excess of 80 mills per kWh. The results of the negotiations provided PACCO with a low cost heat source and the PUD with an electrical energy resource at a price much lower than projected avoided costs.

City of Walla Walla and Pacific Power and Light Company. In July 1984, the city of Walla Walla and Pacific Power and Light (PP&L) entered into an agreement for the purchase of energy and capacity from a 2,000 kW hydropower project on the city's Mill Creek water supply transmission pipeline. Terms of the 24 year contract call for firm payments for both energy and capacity. Pacific will pay the seller a fixed price of \$5.90/kW for "demonstrated" capacity, which is the lesser of (1) kWh of net metered output per 12 months / 8,760 x 0.70; (2) the average rate of delivery (kW) during the highest consecutive 24-hour period of kWh deliveries of net metered output in such 12-month period; or (3)2,200 kW. Pacific will also pay an escalating rate for firm energy as follows:

PP&L Purchase Price for Firm Energy from the Walla Walla Hydropower Project

Contract Year	Energy Price Mills/kWh
1988	21.0
1989	23.0
1990	25.0
1991	27.0
1992	29.5
1993	31.0
1994	90.4
1995	92.2
1996	94.1
1997	96.1
1998	98.2
1999	100.5
2000	102.9
2001	105.4
2002	108.1
2003	110.9
2004	114.0
2005	117.2
2006	120.6
2997	124.2
2008	128.0
2009	132.0
2010	136.3
2011	140.8
2012	145.7

In the Walla Walla contract, the utility points out that "time is of the essence." Therefore, the contract is terminated if deliveries of electrical output do not commence by January 1, 1990, or if the seller does not obtain all required governmental authorizations and permits necessary to construct, operate, and maintain the facility by July 1, 1989. The seller is also required to supply an annual minimum quantity of energy.

Yakima-Tieton Irrigation District and Pacific Power and Light Company. In June 1985, the Yakima-Tieton Irrigation District negotiated an agreement with PP&L to sell and purchase output from the 1,500 kW Cowich Hydroelectric Station and the 1,450 kW Orchard Avenue project. Similar to Walla Walla, the District's contract calls for payments for "demonstrated" capacity of $5.30/kW/month, provided that the projects produce at least 215,000 kWh during the billing period, and for firm energy. Prices paid for each kWh of net metered output from the summer producing facilities are as follows:

PP&L Purchase Price for Firm Energy from the Yakima-Tieton Irrigation District Hydroelectric Projects

Contract Year	Energy Price Mills/kWh
1986	18.5
1987	19.5
1988	21.0
1989	23.0
1990	25.0
1991	27.0
1992	29.5
1993	31.0
1994	84.3
1995	86.1
1996	88.0
1997	90.0
1998	92.1
1999	94.4
2000	96.8
2001	99.3
2002	102.0
2003	104.8
2004	107.9
2005	111.1

David Cereghino and the Washington Water Power Company. In June 1986, David Cereghino negotiated a 35 year power purchase contract under which the Washington Water Power Company (WWP) agreed to accept energy from the 900 kW John Day Creek hydroelectric project in Idaho County, Idaho. WWP has a complicated procedure under which benchmark streamflows, benchmark project output, an availability factor, and operational ability are used to estimate and refine annual average and critical period generation. Levelized, seasonally varying utility fixed costs and periodically updated variable costs are computed and paid for the project output. Like PSP&L, WWP includes a liquidated damages clause which goes into effect given a reduction in a project's benchmark ability or project termination. WWP's fixed and variable costs for firm energy are given below. The variable costs may be adjusted from time-to-time and are equal to the variable operation, maintenance, and fixed fuel cost of WWP's share of the Colstrip plant.

WWP Purchase Rate for Output from the John Day Hydropower Project

Term of Agreement In Full Years	Seasonal Payment Mills/kWh July-Oct.	Nov.-Feb.	Mar.-June
5	9	17	8
10	15	28	13
15	20	37	18
20	23	43	21
25	26	47	23
30	27	51	25
*35	29	54	26

Firm Energy Variable Costs

	July-Oct.	Nov.-Feb.	Mar.-June
Firm Energy Variable Costs	12	17	8

Sheep Creek Hydro and the Washington Water Power Company. In October 1984, WWP signed an agreement to purchase energy from the 1,456 kW Big Sheep Creek hydropower station located near Northport, Washington. During negotiations, WWP and the developer came to an agreement that the purchase rate would be based upon rates that WWP had filed with the Idaho PUC. Subsequently, the UTC rejected a levelized contract (the proposed Potlatch contract) which had a level of payment consistent with the Idaho PUC approved rates. WWP reacted by proposing a "prepayment of power" mechanism which was "just and reasonable" to both ratepayers and the developer. Under this mechanism, WWP would prepay the developer for fixed, firm power expenses over the first five years of the agreement and recover the prepayment, with interest, for ratepayers during years 6-20. This prepayment scheme provides the developer with a revenue stream which is adequate for meeting debt service and maintenance costs in the initial years of project operations, yet does not impose capacity charges to the ratepayer until such time that additional capacity is actually required.

Gordon Foster and the Washington Water Power Company. In July 1984, WWP signed a ten year agreement with Gordon Foster to purchase energy from a 400 kW hydroelectric project located near Northport, Washington. Under the agreement, WWP pays the seller 27 mills for each kWh of electrical energy delivered. On the fifth anniversary of the effective date of agreement, seller has the option, upon supplying 60 days written notice, of accepting a monthly payment equivalent to WWP's actual non-firm energy cost for the corresponding month. If seller does not exercise this option, the 27 mill/kWh rate remains in effect for the duration of the agreement.

East, Quincy, and South Columbia Basin Irrigation Districts and Seattle and Tacoma City Light. In the middle and late 1970s, the East, Quincy, and South Columbia Basin Irrigation Districts decided to proceed with the development of six hydroelectric sites with approximately 132 MW of generating capacity. The projects are located at drop structures on the Columbia Basin Project irrigation system. Rather than use the avoided cost concept, the districts entered into "share the savings" agreements with the cities of Seattle and Tacoma for the sale of all power and energy from the six sites.

Under a negotiated "zero risk to the districts" power purchase and sales agreement, the cities are obligated to pay all of the operating and maintenance expenses of the six projects, including any charges imposed by the Federal Energy Regulatory Commission; all of the debt service on the districts' bonds issued to finance the six projects; and an incentive factor consisting of the greater of 1.65 mills per net kWh of electricity generated by the six projects or one-half of the difference between the cities' average cost of energy and the average cost of energy from the six projects.

City of Spokane and the Washington Water Power Company. In March 1983, the City of Spokane and WWP entered into an "exchange" agreement for the disposition of electrical output from a 13.8 MW capacity expansion at the city's Upriver Dam. Under this agreement, the utility agrees to purchase firm energy and capacity in excess of the city's municipal water supply pumping loads at the avoided cost on file with the UTC. In essence, the city uses project output to first meet pumping requirements (billable under Rate Schedule 31) with surplus power sold to the utility. Under this contract, the city is obligated to schedule all routine maintenance outages with WWP in accordance with prudent utility practice. The city also agrees to reimburse WWP for costs incurred for construction of a distribution line, substation, and necessary metering and telemetry equipment.

4.5 Negotiated Power Purchase Rates

PURPA requires that utilities interconnect with qualifying facilities and purchase electrical energy at a rate based on their full avoided costs (i.e., costs of providing both capacity and energy). It is important to note, however, that the actual purchase price is often negotiated and may vary for different generating technologies (i.e., baseload versus peaking).

In fact, **negotiation** of power purchase prices at a rate based upon utility avoided costs is the norm within the state of Washington. And, in order to negotiate effectively, developers usually retain consultants that are intimately familiar with a given utility's generating system and mode of operation. Power purchase contracts in Washington are thus tailored to specific project characteristics (except for micro-scale projects with less than 100 kW of installed generating capacity). For example, different power purchase rates may be specified for firm/non-firm power, for energy produced during different seasons, and for different project ramping rates and load following capabilities.

Negotiated power purchase rates may also reflect performance guarantees, the ability to schedule maintenance or downtime, rights of refusal, power plant purchase options, the project start date, length of contract, front-loading or levelization provisions, and the ability of the project to provide "demonstrated" capacity.

4.6 PURPA in Washington: A History and Evaluation

Initially, predictions of an electrical supply deficit led to high PURPA-based avoided cost projections in Washington. A hydropower "gold rush" ensued. By mid-1982, developers had initiated the federal permit process for approximately 250 hydroelectric projects. Frequently, multiple applications were filed for a single site with vigorous competition between private individuals, public and private utilities, irrigation districts, cities, towns, and "hybrid" public/private associations. Speculators filed dozens of permit applications to secure development rights on potentially attractive sites.

When the predicted electricity deficit failed to materialize and was, in fact, transformed into a 2,000 average megawatt surplus, avoided costs tumbled and interest in hydropower development waned. As the avoided plant (i.e., the plant on which avoided installed capacity, fuel and maintenance costs are based) was pushed further into the future, avoided costs declined even further, reflecting the effects of discounting. Thus, the implementation of avoided cost pricing in Washington generated effective, reactive price signals. As the need for new generation approaches, avoided costs should increase and serve as a stimulus for development.

In retrospect, PURPA worked well in Washington. During periods when a need for generating resources was forecast, avoided costs were high and served as an incentive to QF development. When Washington's' utilities reran their avoided cost models to account for price-induced decreases in forecasted load growth, avoided costs declined and interest in renewable resource and cogeneration project development waned.

Washington entirely avoided the disastrous consequences that befell California due to the establishment of a "standard offer" for the purchase of PURPA project energy and capacity. Under that system of implementing PURPA, California utilities were forced to sign contracts with unexpected and unprecedented numbers of QFs. Terms of these contracts were predetermined and set by the California PUC. Due to lags in regulatory response, many of the offers were based on extremely high baseline and escalation rates for oil and natural gas. California utilities now pay much more for QF electricity than it costs them to generate at their own existing thermal plants.

In contrast, avoided costs in Washington were attached to an increment of additional energy and/or capacity. Thus, published avoided costs held only for an increment of generating capacity, typically 100 MW or 10 percent of a utility's load. New avoided costs would have to be determined for capacity expansions beyond the stated increment.

The different approaches taken in the Northwest and California reflect differences in generating resources, peak seasons, quantities of reserves, rates of load growth, and reliability of project output. Resource acquisitions in California typically offset the need to burn oil or natural gas in existing thermal generating stations. Avoided costs were thus driven by projected fuel cost savings which did not materialize due to the subsequent decline in oil prices.

In the hydro-based Northwest, benefits associated with acquiring a resource were determined in large part by how compatible the resource would be with a utility's existing hydropower facilities. Intermittency, seasonality, peaking ability, and firm energy output affect the avoided cost or value of a resource. Therefore, Northwest avoided cost computations were and continue to be more complex and utility specific than avoided cost calculations in California. Further, specific negotiations establish the rates paid for electricity from specific projects. Thus, the rate paid for electricity from a powerplant at an irrigation drop structure, which produces only in the summer and early fall, would incorporate that powerplant's particular seasonality.

Avoided cost submittals for Puget Sound Power and Light Company (PSP&L) for 1980, 1983 and 1988 illustrate this type of situation (Tables 4-2, 4-3, and 4-4). PSP&L determines avoided costs for both winter and summer periods given favorable, average, and adverse streamflow conditions. The value to PSP&L of acquiring a particular resource is strongly dependent upon the seasonal and firm energy characteristics of that resource.

Table 4-2

Puget Sound Power & Light Company
Avoided Energy Cost Submittal - 1980-81
(Mills/kWh)

	SUMMER (April-September) Streamflow Conditions		
	Favorable (1959-60)	Avg.	Adverse (1928-29)
1981	3.0	19.9	37.7
1982	3.6	20.7	37.2
1983	7.4	40.8	54.6
1984	12.2	47.7	59.3
1985	13.6	46.9	58.6

	WINTER (October-March) Streamflow Conditions		
	Favorable (1959-60)	Avg.	Adverse (1928-29)
1980-81	3.8	27.5	56.7
1981-82	5.1	39.6	70.4
1982-83	5.4	43.4	71.1
1983-84	35.5	61.4	79.0
1984-85	31.3	65.5	84.1
1985-86	30.1	71.8	89.3

The figures displayed above represent Puget's estimated avoided energy costs for the first 100 MW of system demand for seasonal peak (winter) and off-peak (summer) seasons. As the majority of Puget's resources are hydroelectric, variability in streamflow has a significant impact upon expected generation levels. Hence, to give an indication of the range of variability, estimated avoided costs have been developed under each of three historical streamflow conditions: a favorable streamflow year (1959-60), an adverse streamflow year (1928-29), and the average of costs for each of the streamflow years 1928-29 through 1967-68. Further, it should be noted that the costs reported above are seasonal averages and that monthly avoided costs will exhibit even greater variability.

Table 4-3

Puget Sound Power & Light Company
Avoided Energy Cost Submittal - 1983
(Mills/kWh)

	SUMMER (April - September) Streamflow Conditions		
	Favorable (1959-60	Avg.	Adverse (1928-29)
1983	2.6	7.9	24.6
1984	10.6	13.9	39.4
1985	13.1	17.2	44.2
1986	15.3	20.5	59.7
1987	15.8	23.2	68.7

	WINTER (October - March) Streamflow Conditions		
	Favorable (1959-60)	Avg.	Adverse (1928-29)
1983-4	9.2	21.8	45.0
1984-5	15.8	32.0	60.2
1985-6	16.1	25.1	61.7
1986-7	17.3	25.0	52.3
1987-8	16.4	41.0	87.5

It should be noted that these avoided costs are slightly lower than those filed previously. These reductions in avoided costs have been attributed to two factors. First, the forecast deficits have been reduced through Puget's signing of a Power Sales Contract with BPA and contracting to purchase from BPA certain amounts of power over the next seven years. This BPA purchase significantly reduces Puget's exposure to the need to run oil and gas-fired generators to meet customer load. Secondly, Puget recently acquired Grays Harbor's 4 percent share of the Centralia Coal Plant. This causes a reduction in the avoided costs because the incremental rate of this plant is lower than more expensive peaking resources.

4.7 Power Purchase Contracting Issues

In spite of the overall success of PURPA in Washington, a number of contracting issues continue to affect the development of PURPA resources. The following discussion summarizes the most important issues.

The Potlatch Decision. In November 1983, the UTC refused to allow WWP to pass the capacity portion of its avoided costs on to its customers in the form of a levelized power purchase contract until the utility was, in fact, deficient in generating capacity.

The UTC held that, in a time of surplus capacity, levelized payments should be determined by using a two-step levelization procedure. Because the value of capacity during a time of surplus is zero, the UTC held that only energy costs could be levelized until such time as capacity is needed. After that time, the levelized payment could include both a capacity and an energy component.

The Potlatch decision is a disincentive to project development because it discourages utilities from offering levelized contracts with a fixed price that is higher than actual avoided costs in the early years of project life in order to defray the sizable debt service associated with capital intensive renewable resource projects.

Table 4-4

Puget Sound Power & Light Company
25 Year Forecast of Avoided Costs, May 1988

Year	Fixed Firm Avoided Costs Energy (Mills/kWh) Winter Sep-Mar	Summer Apr-Aug	Capacity ($/kW-mo) Jan-Dec	Nonfirm or Secondary Avoided Costs (Mills/kWh) Annual Avg.
1988	5.5	3.1	3.00	12.5
1989	6.3	3.7	3.00	13.9
1990	7.2	4.3	3.00	13.9
1991	12.9	7.8	3.69	15.3
1992	18.1	13.3	4.53	15.7
1993	18.6	13.7	4.72	18.4
1994	19.0	13.9	4.89	20.0
1995	19.2	14.0	5.05	22.2
1996	20.0	14.5	5.31	23.4
1997	21.9	15.9	5.75	24.6
1998	25.1	18.4	6.40	25.8
1999	25.9	19.0	6.69	27.3
2000	84.0	40.5	9.02	28.9
2001	84.0	40.5	9.02	30.8
2002	84.0	40.5	9.02	32.3
2003	84.0	40.5	9.02	33.9
2004	84.0	40.5	9.02	35.6
2005	84.0	40.5	9.02	37.4
2006	84.0	40.5	9.02	39.3
2007	84.0	40.5	9.02	41.2
2008	84.0	40.5	9.02	43.2
2009	84.0	40.5	9.02	45.4
2010	84.0	40.5	9.02	47.7
2011	84.0	40.5	9.02	50.1
2012	84.0	40.5	9.02	52.6

Variable Firm Avoided Costs

1988 7.7 (mills/kWh)

For projects with an installed capacity over 100 kW, Puget is willing to enter into negotiations for long-term purchase of power. Rates under such long-term contracts will consist of two components: a fixed portion based upon the fixed costs avoided by the PURPA contract and a variable portion based upon Puget's avoidable variable operating costs. The rate paid for each contract year will be the sum of the fixed firm avoided costs, determined at the time the contract is executed, and the variable firm avoided costs, determined at the beginning of each contract year by taking the previous year's variable cost and escalating it to reflect inflation. For hydroelectric projects, secondary or nonfirm energy production will be evaluated at nonfirm costs.

Liability Insurance Requirements. All utilities require that the project owner obtain and maintain general liability insurance with an initial limit not less than $1,000,000 for each occurrence. For projects greater than 5 MW in capacity, one utility—WWP—requires $5,000,000 worth of insurance. For developers, such insurance can be costly and may be offered by few companies, if at all. These liability insurance requirements particularly affect the cost effectiveness and feasibility of micro-scale generating facilities.

Security Requirements. Utilities seek to impose security requirements when a levelized contract is negotiated. Security, in the form of project failure insurance, a letter of credit, payment bond, or performance bond, places a financial burden on the project developer. Small project developers are particularly affected. Also at issue is the amount of security to be posted and the establishment of an interest rate to be used in determining overpayment obligations. Utilities generally propose that overpayments be compounded at an interest rate equivalent to their rates of return.

Developers, on the other hand, argue that a lien on the project should be adequate to satisfy utility concerns. Utilities counter by pointing out that lending institutions would hold similar liens and they could not ensure recovery of ratepayer "investments."

Transmission Access and Wheeling Charges. While utilities in need of resources must interconnect with and purchase energy from QFs within their own service territory, they are not required to purchase from potential sellers located outside of their service area. Even if a utility is willing to purchase at an attractive rate, neighboring utilities are not obligated to provide wheeling services. In short, the **potential** exists for a willing seller to be unable to supply needed energy to a willing buyer.

If transmission access issues are not resolved, non-utility independent power producers may be restricted to a single customer—the utility in whose service territory they are located. Similarly, utilities will be served by a geographically limited number of energy producers. Market-based least-cost plans, such as FERC's envisioned competitive bidding process, are inefficient or unworkable without the price competition allowable under open transmission access.

Thus far, transmission access has not proven to be an unsurmountable barrier. The City of Spokane is anticipating the wheeling of energy produced in the eastern part of the state to PSP&L's service territory. The City of Seattle and Mason County PUD #1 negotiated a transmission and meter reading agreement whereby Mason PUD provides firm transmission capacity for the privately developed 1,850 kW Rocky Brook Creek hydropower project to a point of connection with BPA's transmission substation. Similarly, the City of Port Angeles and Clallam County PUD #1 signed an agreement to provide transmission services for output from the city's 465 kW Morse Creek hydroelectric project. A second agreement was required between BPA, the city, and the

PUD. Wheeling payments may be based upon capacity, energy transferred, or may cover all or a portion of the annual maintenance costs for the transmission facilities involved in the wheeling process.

Utility Development and Ownership of QF Projects. Utilities have the opportunity to become minority partners in the development of renewable or cogeneration projects, or to establish an unregulated subsidiary to actively engage in QF development. Under PURPA, utilities can hold a minority interest (i.e., up to 49 percent) in a qualifying facility. In the state of Washington, PSP&L and McMaster and Shroder were awarded a FERC license to construct, operate, and maintain the 12 MW Koma Kulshan hydropower project. To date, electric utility-owned subsidiaries that develop generating resources have not been active within Washington. They have, however, played a major role in California.

QF developers are generally mistrustful of a utility's dealings with its own subsidiary. The potential exists for cross-subsidization of a portion of a project's costs through the offering of design services or of higher avoided costs than might be awarded to a private developer.

A third developer/utility interaction involves utility purchase or lease of a licensed site or constructed project at a negotiated or previously agreed upon price. (For instance, Lewis County PUD purchased the 600 kW Mill Creek hydropower project from a private developer.) Early developer/utility discussion is required under this option so that the plant can be built to utility specifications and standards.

UTC Approval of Power Purchase Contracts. Investor-owned utilities generally include a clause in a power purchase agreement which states that the negotiated agreement is not effective unless and until approved by the UTC. Because QF developers generally need a signed and approved power purchase agreement prior to obtaining financing, an expedient review and approval process is essential.

CHAPTER V. DEVELOPMENT OF QUALIFYING FACILITIES AND ESTIMATES OF RESOURCE POTENTIAL IN WASHINGTON

5.1 Hydropower

5.1.1 Development of Hydropower Projects Following Passage of PURPA

Twenty small-scale (less than 30 MW) hydropower projects came on-line in Washington between January 1980 and June 1988 (see Table 5-1) with a total installed generating capacity of 77.7 MW. The projects were of several distinct types: seven were built on irrigation facilities; six were run-of-river projects requiring new dam construction; four were built at existing dams; and three were added to municipal or industrial water supply lines.

Project developers included 10 independent producers and 9 public entities. The capacity of the publicly sponsored projects was five times larger than those of the independent power producers (64.5 vs. 12.7 MW). No projects developed by IOUs came on line during this time period, although IOU's are purchasing power from eight of these new hydropower plants.

5.1.2 Washington's Remaining Hydropower Potential

Washington has more developed hydroelectric capacity than any other state in the nation. Its remaining potential ranks third, behind only Alaska and Oregon.

Efforts to calculate Washington's developable potential go back at least as far as 1910. Several studies have been completed in recent years, but their estimates of total hydropower potential vary significantly. None of these studies focus exclusively on small scale hydro projects, and, in some instances, the studies include large impoundments that would be virtually impossible to site and license. In addition, a number of the studies ignore projects less than 1 MW in size, although this group comprises one-third of the new sites shown in Table 5-1.

Due to a lack of site-specific information, most of the studies have estimated theoretical generating potential after subjecting the hydropower sites to relatively crude technical, economic, environmental, and transmission line screening criteria.

Several of these hydropower assessments are summarized below.

> ***Seattle City Light: 1977.*** A hydropower site inventory was compiled in 1977 by R.W. Beck and Associates for Seattle City Light. All previously-identified sites in Washington State were inventoried, including new and incremental projects. After excluding those sites with an average capacity of less than 10 MW and those sites located in National Parks, Wilderness Areas, and Wild and Scenic Rivers, 134 sites remained for further evaluation. The capacity of these projects totaled 9,178 MW with an "average energy output" of 4,614 MW. The sites were then screened on the basis of power costs and site availability to Seattle City Light. Only 18 of the sites showed promise of developing

Table 5-1

Small-Scale Hydroelectric Projects in Washington
- On-Line After 1980 -

Project Name/ Developer		Creek Name	On-Line Date	Installed Cost	Head,Ft.	Capacity, kW	County	Purchasing Utility	Type
1.	Russell D. Smith/ SCBID	PEC 22.7	8/81	$7(+6)	54	6,200	Franklin	SCL/TCL	I
2.	Port Townsend Mill	Water Supply Line (Big Quilcene R.)	8/82	$300,000	265	375	Jefferson	PSP&L	WS
3.	Woods Creek (Woods CK. Inc.)	Woods CK.	12/82	$1.26(+6)	72	650	Snohomish	SNOH. PUD	ED
4.	Smith CK. Project Robert Shipp	Smith CK.	12/82	$64,800	207	120	Whatcom	PSP&L	ROR
5.	Mill CK. Lewis Co. PUD	Mill CK.	3/83	$1.31(+6)	105	600	Lewis	LEWIS CO. PUD	ROR
6.	Eltopia Branch Canal/SCBID	EBC 4.6	5/83	$3.8(+6)	127	2,200	Franklin	SCL/TCL	I
7.	P.E.C. 66/ SCBID	PEC 66.0	9/83	$3.0(+6)	325	2,400	Franklin	SCL/TCL	I
8.	Upriver Dam/ City of Spokane	Spokane River	5/84	$23.3(+6)	35	13,800	Spokane	WWP	ED
9.	Deep Creek/ Gordon Foster	Deep Creek	4/84	$300,000	39	270	Stevens	WWP	ED
10.	Quincey Chute/ Grant Co. PUD	QCBID	9/84	$20.2(+6)	---	9,400	Grant	GRANT CO. PUD	I
11.	Hutchinson CK./ Robert Shipp	Bellingham Water Line/ M.F. Nooksack R.	3/85	$400,000	277	1,000	Whatcom	PSP&L	WS

Table 5-1 (cont)

	Project Name/ Developer	Creek Name	On-Line Date	Installed Cost	Head,Ft.	Capacity, kW	County	Purchasing Utility	Project Type
12.	Lilliwaup R./ John Kraft	Lilliwaup R.	6/85	---	285	1,505	Mason	MASON CO. PUD NO. 1	ED
13.	Rocky Brook CK./ Weatherly Assoc.	Rocky Brook CK.	3/86	---	440	1,850	Jefferson	SCL	ROR
14.	Cowiche Yakima-Tieton I.D.		5/86	---	---	1,400	Yakima	---	I
15.	Orchard Ave. Yakima Tieton I.D.		5/86	---	---	1,600	Yakima	---	I
16.	Big Sheep CK. Glenn Phillips	Big Sheep CK.	6/86			1,500	Stevens	WWP	ROR
17.	Main Canal Headworks SCBID	Main Canal	7/86	---	---	27,000	Grant	SCL/TCL	I
18.	Sygitowitz CK. Kingdom Energy	Sygitowitz CK.	12/86			400	Whatcom	PSP&L	ROR
19.	Morse CK. Port Angeles City Light	Morse CK.	3/87	$965,000	427	465	Clallam	PORT ANGELES CITY LIGHT	ED,WS
20.	Weeks Falls S. Fork II Associates	S.F. Snoqualmie R.		$8.5(+6)	85	5,000	King	PSP&L	ROR
		Total Installed Generating Capacity				77,735			

Project Type Key:

I = Irrigation
WS = Water Supply Pipeline
ED = Existing Dam
ROR = Run-of-the-River Diversion Project

power at a cost of 25 mills or less (in 1975 dollars). Only nine sites survived a further screening for "licensability'' based on social, environmental, and political feasibility. These nine sites have a total potential for 294.5 MW of average power production.

U.S. Army Corps of Engineers: 1976. The Water Resource Development Act of 1976 authorized the U.S. Army Corps of Engineers to conduct a National Hydropower Study. The *National Hydroelectric Power Resources Study,* completed in 1981, develops an inventory of hydropower potential at existing dams and undeveloped sites, identifies institutional issues affecting hydropower development, and makes policy recommendations to Congress for the best use of the nation's hydropower resources.

The inventory phase of the study progressed through several screening steps. Of 1,001 potential hydro sites originally identified in Washington, 449 have a potential capacity of one megawatt or more. Of these, 213 were found to have energy costs of 70 mills/kWh or less. Based on a preliminary evaluation, 103 of the 213 appeared to have no unacceptable environmental, social, or institutional impacts. Finally, the Corps identified 92 sites comprising 2,730 MW of installed capacity with an annual electrical generation of 1,085 average MW as suitable for further study. The Corps considers these projects to be economically feasible with no identified constraints to development. It should be noted that most of the projects on the Corps' list are large projects (greater than 25 MW in generating capacity) and often involve substantial new reservoir storage.

Water and Power Resources Service: 1980. The Water and Power Resources Service (now U.S. Bureau of Reclamation) commissioned the Tudor Engineering Company of San Francisco to assemble an inventory of potentially developable low head hydroelectric resources. The *Western States: Inventory of Low-Head Hydroelectric Sites* study, completed in 1980, focuses on sites with potential generating capacities greater than 1,000 kW and with less than 20 meters (or 66 feet) of available head. The Tudor study contains information on 415 sites in Washington, with 7,566 MW of potential installed capacity and an expected average annual electrical output of 2,964 MW. The identified sites also were subjected to an environmental assessment which identified land use, critical habitat, fish and wildlife, and historic and cultural constraints to development.

U.S. Department of Energy—Region X: 1981. In 1981 the U.S. Department of Energy contracted with the Center 4 Engineering Company of Redmond, Oregon to conduct the *Pacific Northwest Small Scale Hydroelectric Resource and Site Ranking Information* study. Center 4 Engineering considered 2,046 sites in the four Northwest states. The study excluded known sites located within Wilderness areas, in National Parks or Monuments, or on designated Wild and Scenic Rivers. In an attempt to rank sites, Center 4 Engineering assigned high, medium, and low development priorities. Seventy-nine of the high development priority sites, with 474 MW of potential installed capacity, are located within the state of Washington.

Washington Water Research Center: 1979, 1981. The Washington Water Research Center (WWRC) at Pullman has published *An Assessment of Potential Hydroelectric Power and Energy for the State of Washington.* The two-phase study, funded by the U.S. Department of Energy, was part of an overall effort to determine the hydro potential in the entire Pacific Northwest.

In Phase I, WWRC divided all streams in the state with an average flow of 35 cubic feet per second or more into reaches. WWRC then investigated Washington's 1,431 qualifying reaches to determine their theoretical power potential at various streamflow exceedance levels. The study assumed that all available head would be used at 100 percent efficiency, that all water up to the powerhouse design capacity would be used to generate power (i.e., no minimum instream flows), and that projects would be run-of-the-river (i.e., no significant reservoir storage).

Assuming power facilities were designed for flow rates equal to the median (50% exceedance) flow, the study concluded that Washington's remaining theoretical hydropower potential exceeded 8,800 MW. The study also concluded that only 1,950 MW of this theoretical potential could actually be developed. Reaches were screened out if they had land use restrictions; if they exhibited more than one feasibility constraint among utility displacement, building displacement, or special fish problems; or if they were more than 10 miles from a high voltage transmission line and lacked a local market for power.

Phase II of the WWRC study evaluated the hydropower potential at existing dams without generating facilities. In addition, the study examined previously identified hydro sites and proposed power sites located within irrigation systems. The study found 57 MW of potential for small (less than 25 MW) hydro projects at existing, non-generating dams in Washington. An additional 170 MW of generation capability was found within irrigation systems.

Northwest Power Planning Council: 1983, 1986. In 1983, the Northwest Power Planning Council issued it's first *Northwest Conservation and Electric Power Plan.* The Council reviewed studies performed by CH_2M-Hill and by the Pacific Northwest Utilities Conference Committee's Hydropower Subcommittee. These studies contained estimates of developable potential ranging from 450 to 2,337 average megawatts. The Council ultimately included 920 average megawatts of cost-effective, firm hydroelectric energy in its 1983 plan.

In 1985, the U.S. Fish and Wildlife Service, the National Marine Fisheries Service, state fish and wildlife agencies, and tribes made an interim attempt to rank the environmental acceptability of these hydropower sites. Hydropower sites were categorized based upon their projected fish and wildlife impacts. That effort helped spur a Council/BPA sponsored resource assessment of the regions rivers. As a result, the Council lowered its estimate in 1986 to 200 megawatts of firm energy potentially available at existing water control structures. The Council plans to revise this estimate pending completion of studies overseen by its Hydropower Assessment Steering Committee.

5.1.3 The Council's Hydropower Site Data Base and Hydropower Assessment Study

Previous studies of Washington's hydropower potential used sites identified in the FERC permit, exemption, and licensing processes, along with judgment, to develop "realistic" estimates of project output and bus-bar generating costs. The major limits to improving the accuracy of these forecasts were: 1) the lack of detailed, site-specific hydrological and physical information necessary to determine project capacity, expected annual energy production, and installed costs; and 2) an absence of information on constraining environmental factors such as use by resident and anadromous fish, the presence of threatened and endangered species, highly valued wildlife habitat, and socio-cultural factors.

To obtain better information regarding potential hydropower sites, the Northwest Power Planning Council, jointly with BPA and the Corps of Engineers, developed the Pacific Northwest Hydropower Site Data Base. This data base contains location, cost, and performance information for all proposals before FERC and for sites identified in the Corps of Engineers National Hydropower Survey. Computer algorithms were designed to estimate project capacity, instream flow requirements, energy output, and installed cost for projects where estimates were not available from interested developers.

To better understand the qualities of streams potentially affected by hydropower development, the Council and BPA, assisted by federal agencies, states, and the tribes, also undertook a comprehensive assessment of regional river resources. This Pacific Northwest Rivers Study evaluates the relative value of river segments based on resident fish, wildlife, natural features, culture features, and recreation. For each environmental resource, the study ranked a given stream segment as having either outstanding, substantial, moderate, or limited value. (The Council considered anadromous fish and tribal cultural and archaeological resources under separate contracts.)

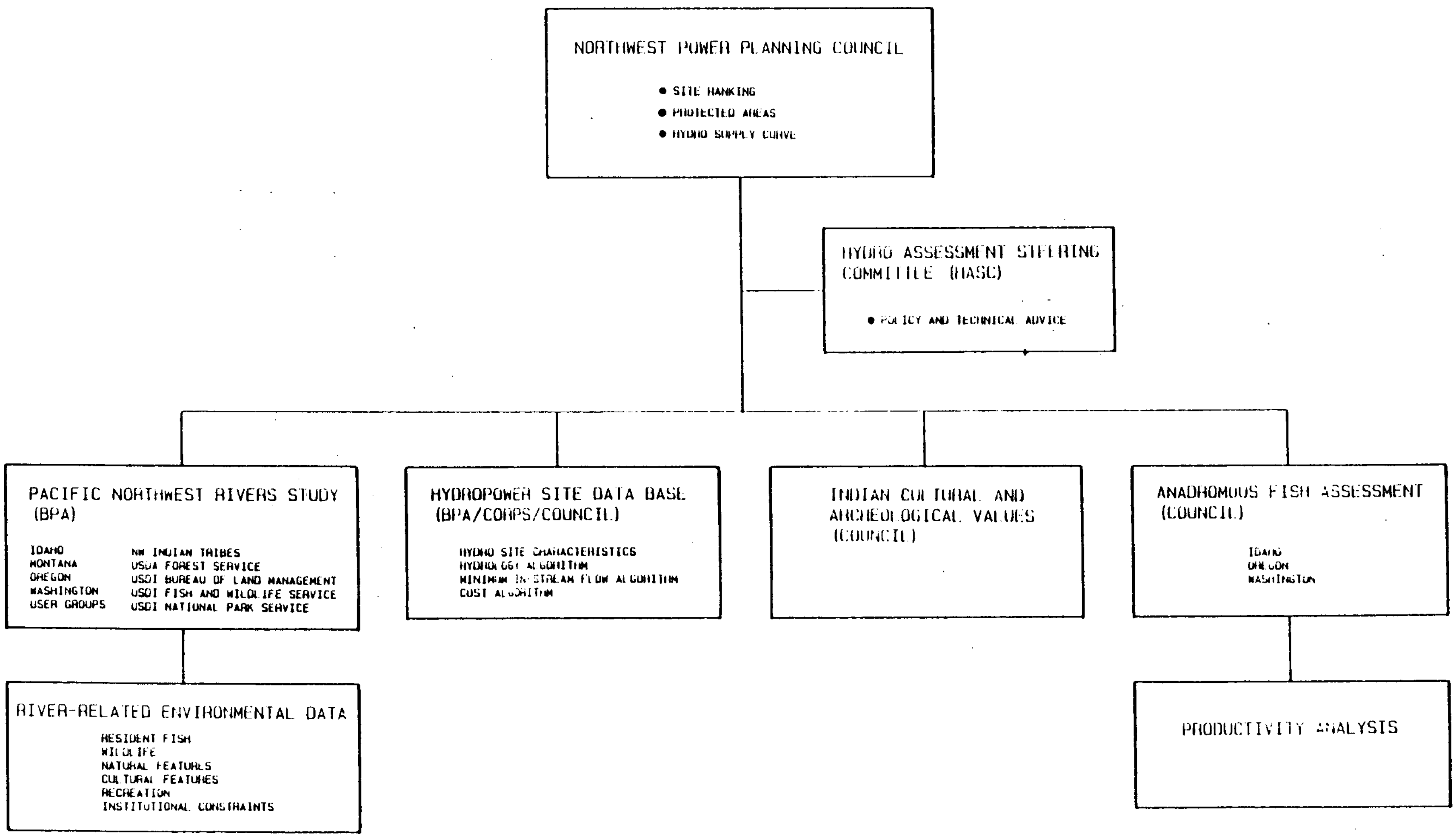
The Council integrated the Hydropower Site Data Base, the Pacific Northwest Rivers Study, the Anadromous Fish Assessment, and the Study of Tribal Cultural and Archaeological Resources into a comprehensive assessment of the Northwest hydropower potential that could realistically be developed. The organization of the Council's overall Hydro Assessment Study is depicted in Figure 5-1.

Overall, the Hydro Assessment Study surveyed approximately 134,000 stream miles, representing approximately 40 percent of the region's total stream miles. (In Washington State, 1,415 reaches containing 7,500 stream miles were considered.) The Hydro Assessment Study did not include streams under federal protection (in wilderness areas, National Parks, and National Wild and Scenic Rivers) or small headwater streams.

Figure 5-1

HYDRO ASSESSMENT STUDY

ORGANIZATION CHART



Assessment corridors extended 1,000 feet on each side of the stream centerline. Each stream was classified according to the presence or absence of anadromous (migratory) fish, and ranked for each of the environmental resources. The information is maintained by BPA, the Council, and the states on a computerized data base. (In Washington, the data base is referred to as the Energy/Environmental Resource Digital Database.)

Based on the Hydro Assessment Study, the Council prepared a list of river reaches where hydropower development would entail unacceptable risk of harm to critical fish or wildlife, their spawning grounds, or habitat. By establishing 44,000 river miles of "protected areas" in an August 1988 rulemaking (12,400 river miles are within the state of Washington), the Council is working toward the goals of:

- Protecting remaining critical fish and wildlife habitat;
- Avoiding disputes over hydropower development in sensitive fish and wildlife areas;
- Reducing uncertainties in the region's ability to meet its power needs at least-cost;
- Ensuring that ratepayer investments in fish and wildlife enhancement are not undermined;
- Sending clear signals to hydropower developers on the importance of fish and wildlife values so that they can focus their attention on less sensitive areas for development; and
- Providing information to FERC so that hydropower licensing decisions will reflect the region's interest in environmental protection.

The latest hydropower potential estimate by the Council is contained within the *Draft—1988 Supplement to the 1986 Northwest Power Plan* released in November 1988. Using BPA's Hydropower Supply Assessment Process (Figure 5-2) and factoring in its own protected area rule, the Council estimates that 500 average megawatts of firm energy are available in the region from new hydropower development. This resource is available at a cost of 5.8 cents per kilowatthour or less (in levelized real 1988 dollars).

In Washington, the Council's protected areas ruling affects about one third of the state's potential sites or 44 percent of the 948 MW active in FERC's permit or licensing processes as of September 1988 (Figure 5-3). Except for the 96 MW Asotin and 70 MW Cowlitz Falls projects, these active sites each had less than 35 MW of capacity. (Sites are assumed to fall into protected status if half or more of the stream reach containing the site is protected.)

Figure 5-2

HYDROPOWER SUPPLY ASSESSMENT PROCESS

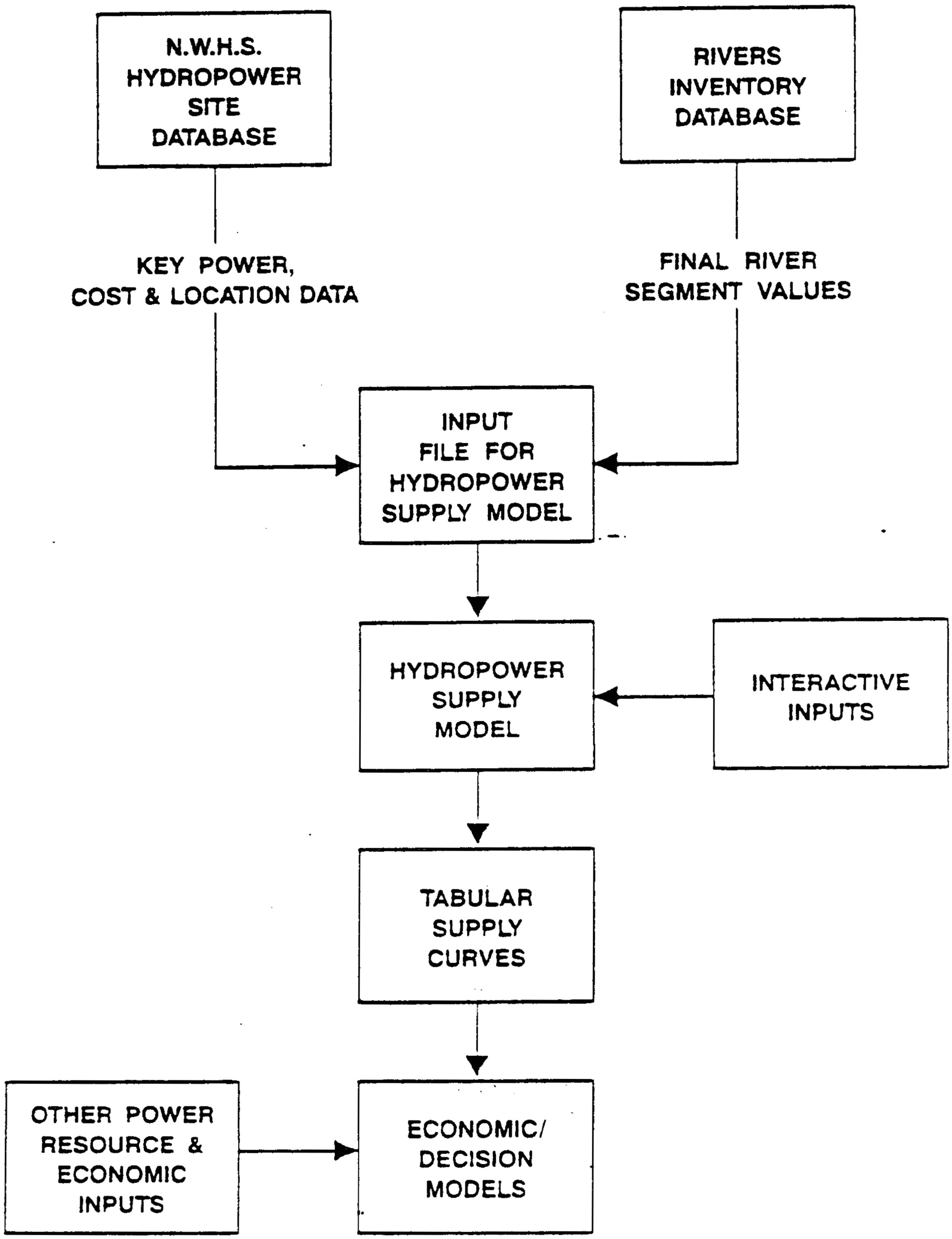


Figure 5-3

Washington State
Small Hydropower Sites
All FERC Sites Not On-Line

	UNPROTECTED	PROTECTED
IN-ACTIVE	697 MW 181 SITES	514 MW 78 SITES
ACTIVE	**529 MW 121 SITES**	419 MW 64 SITES

Independent small power producers are far and away the largest class of active developers in Washington, holding preliminary permits, exemptions, or licenses for about 80 percent of the state's capacity in "active" sites outside protected areas. Holders of and applicants for FERC permits, exemptions, and licenses are summarized by developer class for both protected and unprotected areas in Figure 5-4.

The 302 projects (121 active projects totalling 529 MW and 181 inactive sites totalling 697 MW) located outside the Council's protected areas have not undergone further environmental or economic screening. The bulk of the active projects (66%) fall into the "preliminary permit granted" licensing category.

The licensing status for Washington's active projects is summarized in Figure 5-5. Because many of the preliminary permits are speculative and are held by single individuals, these numbers do not reflect the technical or environmental feasibility, or the potential cost-effectiveness of Washington's untapped hydropower resources.

Figure 5-4

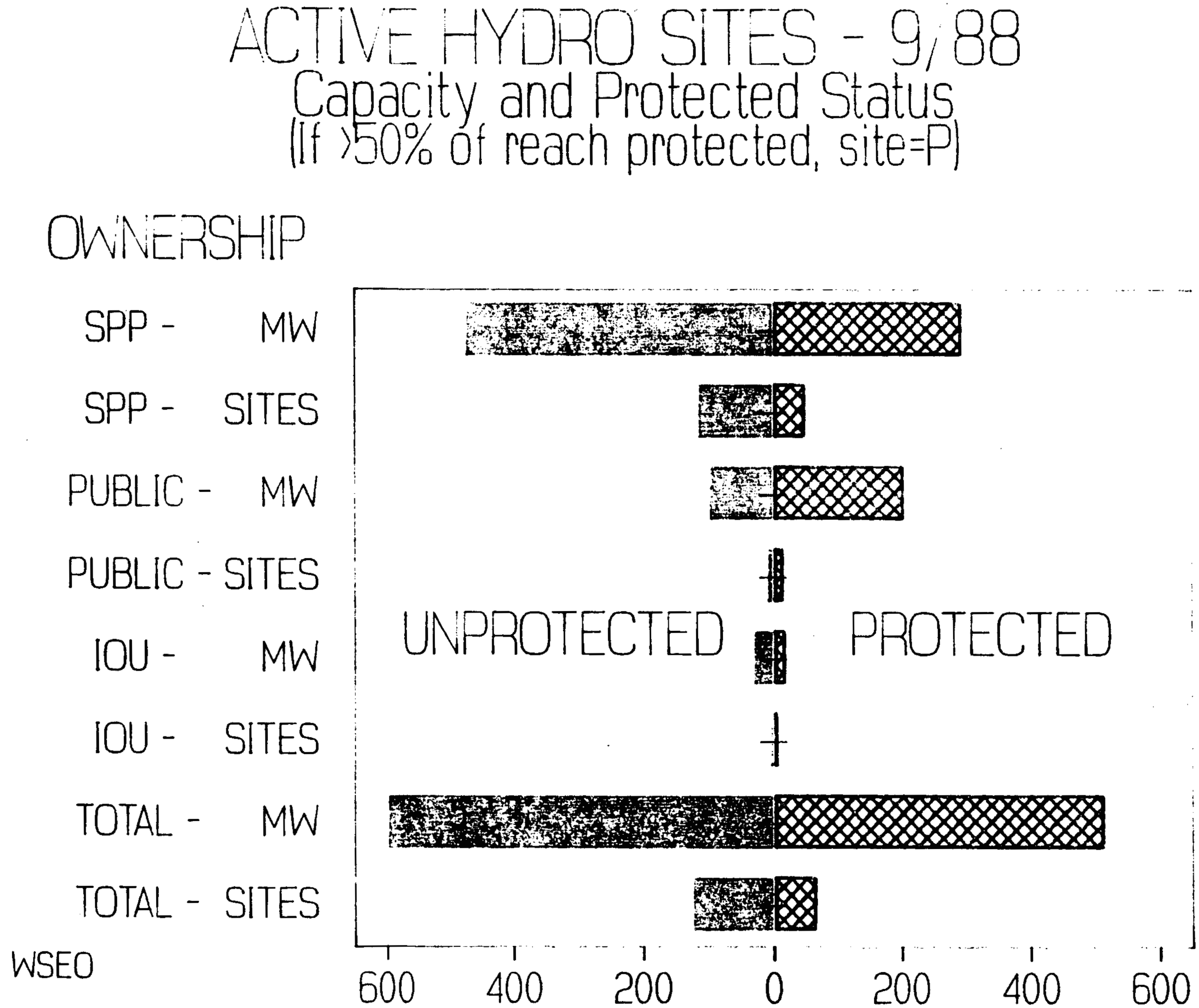
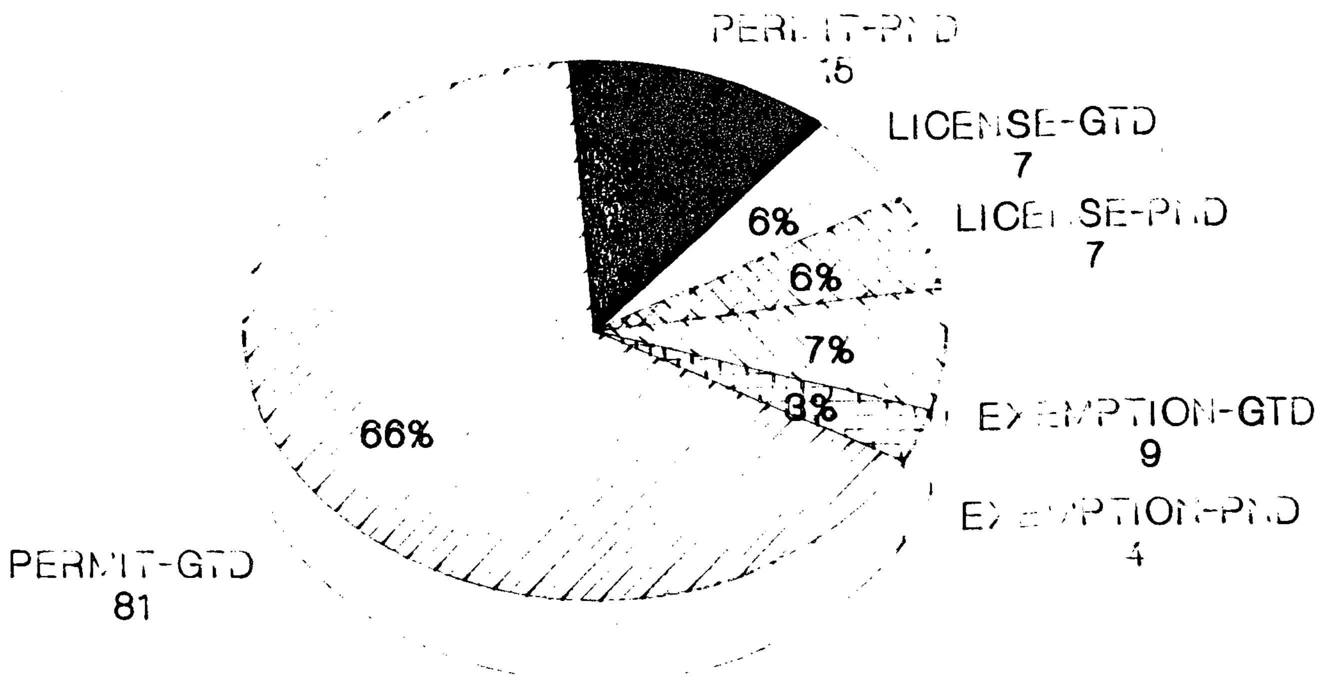

ACTIVE HYDRO SITES - 9/88
Capacity and Protected Status
(If >50% of reach protected, site=P)
OWNERSHIP
SPP - MW
SPP - SITES
PUBLIC - MW
PUBLIC - SITES
IOU - MW
IOU - SITES
TOTAL - MW
TOTAL - SITES
UNPROTECTED
PROTECTED
WSEO
600
400
200
0
200
400
600

Figure 5-5

SMALL HYDROPOWER PROJECT
Active Project Status



WSEO

5.2 Municipal Solid Waste-to-Energy Projects and Resource Potential

5.2.1 Resource Potential

Overall, Washington has 21 counties with refuse streams capable of supporting an energy recovery facility with an installed capacity exceeding 1 MW. If implemented, the total capacity represented by these 21 counties is approximately 185 MW. Given a capacity factor of 80 percent, approximately 1,228,457 MWh of electric energy could be generated annually by these projects (Table 5-2).

Waste-to-energy planning activity is underway in the four largest counties in Washington State. These counties contain approximately 70 percent of the available generating potential from municipal solid waste (MSW) incineration. If completed, the projects would add up to 130 MW of capacity to the region.

The likelihood of capturing all or part of the MSW energy resource is uncertain. Up until last year, both the social and political momentum behind waste management seemed to favor energy recovery. Recent trends, however, appear to be shifting away from incineration, as public opposition strengthens and calls for waste reduction and recycling increase.

While incineration loses momentum, the concept of shipping municipal waste to eastern Washington and Oregon is gaining interest. Waste Management Inc. of Oregon is in the process of constructing a massive landfill near the town of Arlington to handle municipal waste from the Portland metropolitan area. The City of Seattle, as well as other west side governments, has expressed interest in rail shipment of MSW as an economic and political solution to their MSW problems.

5.2.2 Current Waste-to-Energy Project Activities

The current status of waste-to-energy projects in Washington State is described below and summarized in Table 5-3 and Figure 5-6.

> ***Bellingham.*** This plant is a 100 ton per day (TPD) incineration project built by Thermal Reduction Company (TRC) of Bellingham. The 2 MW project came on-line in December 1986 following a 6 month construction schedule and a 9 month permitting and licensing period.

Table 5-2

Energy Recovery Potential in Washington State
(Counties With Waste Streams Greater Than 40 TPD)

County	Waste (TPD)	Installed Capacity (MW)	Annual(1) Generation (MWh)	Status
King	3,560	71.2	467,784	P
Pierce	1,500	30.	197,100	C
Spokane	760	15.2	99,864	D
Snohomish	640	12.8	84,096	P
Kitsap	500	11.0	65,700	P
Clark	475	9.5	62,415	I
Yakima	328	6.2	43,099	N
Thurston	225	4.2	29,565	I
Benton	196	3.2	25,754	N
Cowlitz/Wahkiakum	150	2.8	19,710	N
Skagit	150	2.8	19,710	O
Whatcom	150	2.8	19,710	O
Walla Walla	110	2.1	14,454	N
Clallam	100	1.9	13,140	N
Grays Harbor	100	1.9	13,140	P
Lewis	100	1.9	13,140	I
Grant	96	1.8	12,614	N
Whitman	58	1.1	7,621	N
Island	55	1.0	7,227	I
Chelan/Douglas	53	1.0	6,964	N
Franklin	43	0.8	5,650	N
Total	9,349	185.7	1,228,457	

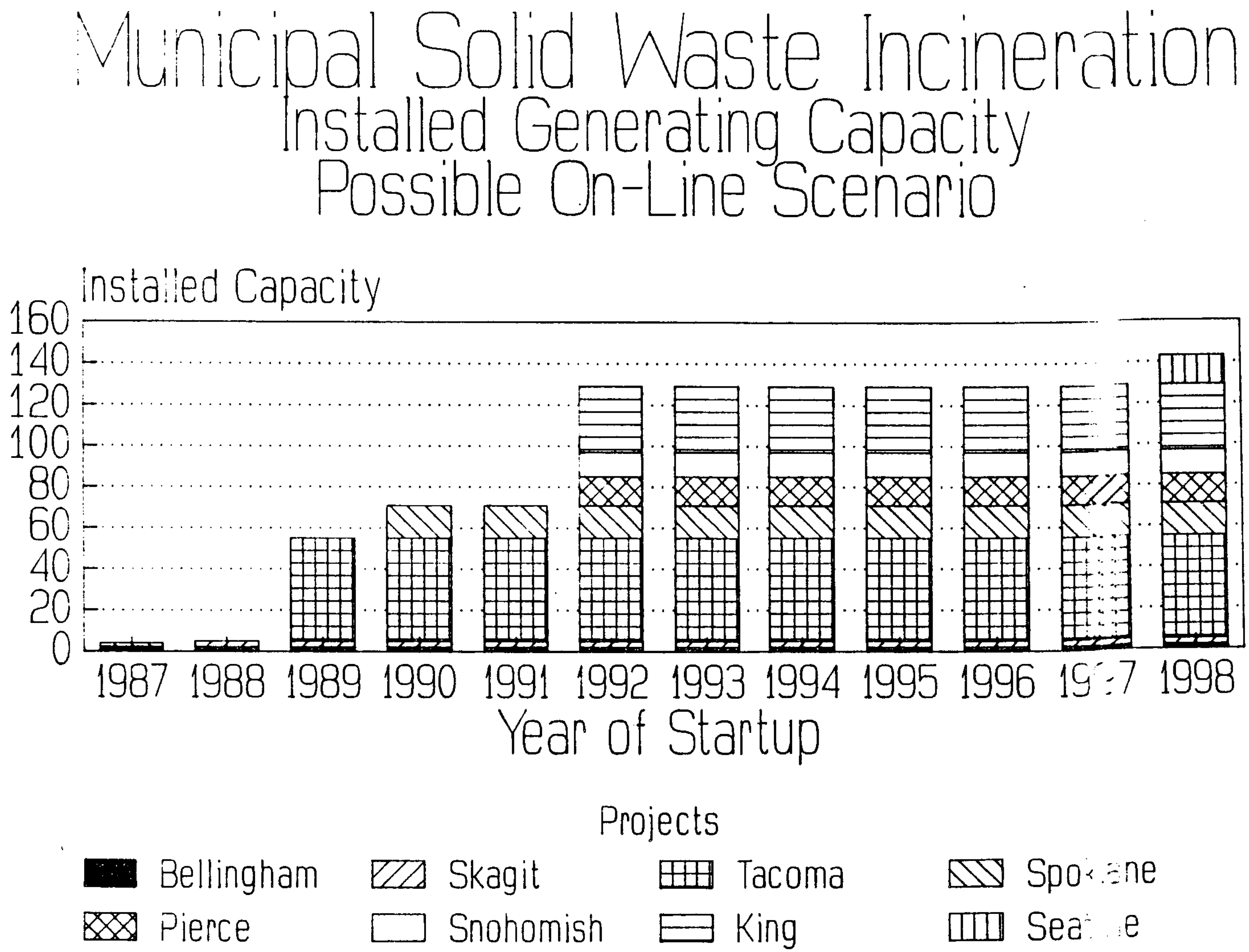
P = Planning, C = Construction, D = Design, I = Idea, N = No Activity, O = Operational
(1) Assumes an 80 percent capacity factor with 450 kWh per ton of waste processed.

Table 5-3

Status of Municipal Solid Waste Incineration Projects in Washington

Location	Capacity	Status/Online	Technology	Output	Cost (million)
Bellingham	2x50 TPD	operating 12/86	Consumat modular	Electric 2 MW	$2
Skagit Co.	2x89 TPD	operating 7/88	Technitalia rotary	Electric 3 MW	$14
Tacoma	2x500 TPD	construction 12/88	EPI fluidized bed	Electric 50 MW	$32
Fort Lewis	3x60 TPD	construction 12/88	Dravo modular	Steam heat	N/A
Spokane	2x400 TPD	permitting 1990	Wheelabrator Von Roll	Electric 16 MW	$80
Pierce	700 TPD	planned 1992	Wheelabrator	Electric 14 MW	$100
Snohomish	600 TPD	planned 1992	Ogden/Martin	Electric 12 MW	N/A
King Co.	1600 TPD	EIS 6/92	mass burn	Electric 32 MW	N/A
Seattle	700-1600	EIS 6/96	unknown	Electric 14-32 MW	N/A
Tulalip	3000 TPD	planned (assumes regional control of waste stream-Snohomish, King Counties)	Ogden/Martin	Electric 90 MW	N/A

Figure 5-6


Municipal Solid Waste Incineration
Installed Generating Capacity
Possible On-Line Scenario
Installed Capacity
160
140
120
100
80
60
40
20
0
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1998
Year of Startup
Projects
Bellingham
Skagit
Tacoma
Pierce
Snohomish
King

The project includes two 50 ton per day (TPD) Consumat CS-2000 refractory type, mass burn, modular incinerators. Together, the two units are capable of handling 100 TPD; however, the average plant throughput is estimated at 70 to 80 TPD. The system utilizes a field erected boiler which produces 400 to 450 psig steam at approximately 5000 lbs of steam per ton of throughput. The steam passes through a 4.6 MW condensing turbine.

Project output is sold to Puget Sound Power and Light in accordance with Schedule 91 of its Electrical Tariff. The purchase price is expected to increase from 28.3 to 34.8 mills/kWh over the 5 year contract period.

The project is owned and operated by TRC. Project capital costs are proprietary; however, an estimated cost of $2 million was provided, $1.5 million of which was secured by industrial revenue bonds. The market value of the plant is estimated at $5 to $6 million.

Skagit. Incineration was first identified as the preferred disposal alternative for Skagit County in its 1981 Solid Waste Management Plan. The county conducted additional detailed studies, including an EIS, from 1983 to 1986. In June 1986, the county put out an RFQ and RFP for a 150 TPD plant. By November 1986, a contractor (Wright Schuchart Harbor Co. of Seattle) was selected, and by January 31, 1987, preliminary design work had begun. Construction of the project started in July 1987. The project came on-line in July 1988.

The project consists of two 90 TPD, rotary kiln incinerators manufactured by Technitalia; 2 waste heat boilers manufactured by Zurn Industries; a 2.6 MW Coppus Murray turbine generator; and an acid gas scrubber and fabric filter baghouse provided by Research Cottrell. The project is designed to process up to 160 TPD of waste and will generate approximately 13.2 million kWh per year. Project output will be sold to the Puget Sound Power and Light Company. The power sales contract is for 20 years at a levelized rate of 49 mills per kWh.

The cost of constructing the Skagit project was approximately $13 million. Fifty percent of this cost was obtained through a WDOE Referendum 39 Grant. The remainder will be paid by the county through revenues from the sale of limited general obligation bonds. The county owns the incineration plant but has contracted with Energy Resource Recovery, Inc. of Mount Vernon for plant operation.

City of Tacoma. Tacoma received a $15 million grant from state Referendum 39 funds. The bulk of the grant, $11 million, was awarded to Tacoma City Light for restoration of a mothballed steam plant on the Tacoma tideflats. The renovation will include new superheaters and economizers, state-of-the-art pollution control equipment, and two fluidized bed combustion units. The plant's primary fuel will be coal and wood chips (50 and 35 percent, respectively) with the remaining 15 percent supplied by refuse derived fuel (RDF). The RDF will be supplied at no charge to Tacoma City Light. Of Tacoma's 500 TPD waste stream, 425 TPD will go to the RDF facility where 300 TPD will actually be processed into RDF.

The plant is expected to come on-line in 1988. The facility will have a total installed generating capacity of 50 MW with an annual electrical production of 344,417 MWh if steam is not recovered for sale. The estimated capital cost of the project is $31,670,000. This does not include an expected $3.5 million cost for renovating Tacoma's existing RDF facility.

Pierce County. Pierce County faces the mandatory closure of its only landfill by the end of 1992. In May, 1988 the County Council selected Wheelabrator Environmental Systems to build, own, and operate a resource recovery project. The project is estimated to cost approximately $100 million and be capable of incinerating up to 700 TPD of county waste. The installed generating capacity of the plant is estimated at 14 MW.

The county believes a privately owned and operated facility will come on-line faster because it believes that private corporations can select and seek approval for only one site under state law while public entities must examine environmental impacts for all potential sites within its jurisdiction.

Spokane. In 1984, Spokane County updated its Solid Waste Management Plan and identified the need for an incineration plant. From 1984 through 1985 the county proceeded with a general scoping of an incineration project and selected HDR Techserv to prepare an EIS. In March 1986, Spokane County completed its EIS and received agency comments by June 1986. During this time, the county was awarded a 50 percent matching grant of $60 million from state Referendum 39 funds for project construction.

From 1986 through 1987, both the county and city of Spokane responded to public and agency comments. During this period, Spokane completed site selection, final design, and changes in local zoning codes that were necessary to allow project construction. Although public involvement was ongoing throughout this process, litigation opposing the project was initiated by local citizen groups. Currently, the project has entered the permit phase and most of the litigation has been resolved.

The project, as it currently stands, will be capable of handling up to 800 TPD of municipal waste and will have an installed generating capacity of 16 MW. Wheelabrator has been selected as the project contractor, and the expected on-line date is 1990. Electricity produced by the project will be sold to Puget Sound Power and Light. The purchase contract offers approximately 2 cents per kWh of electricity in 1990, rising to over 9 cents per kWh by the end of the 20 year contract.

Seattle. The City of Seattle has been researching the need for a waste incineration plant since the early 1970's. In May 1988, the city completed a Draft EIS for various disposal options, two of which included waste to energy facilities. Concurrent with its EIS process, the city embarked on an ambitious waste reduction and recycling campaign. The success of this effort, coupled with strong public opposition to waste incineration, has convinced the city administration to withdraw from the King County system and to pursue a recycling goal of 60 percent, with the remaining 800 TPD of city waste shipped by rail to Eastern Oregon or Washington. If the recycling goal is not achieved by 1996, the city will begin development of an incineration plant.

King County. In October 1980, King County and the City of Seattle completed a joint study which concluded that market conditions could support an energy recovery project. In early 1983, the county began a Phase II study to determine the feasibility of an energy recovery project. The study, completed in late 1986, recommends construction of a mass burn facility with electricity, which appeared to be the only stable energy market, as the project's primary energy product.

King County proposed constructing a 1,500 TPD plant with the option to either expand the plant or locate multiple facilities, depending on the waste stream served. A site selection process was initiated in 1987 with the goal of selecting a final site by the end of 1988 and beginning commercial operation by July 1992. However, this time line has slipped as opposition to incineration has grown. Currently, the county is closely watching the City of Seattle's recycling efforts as well as the possibility of shipping its MSW by rail to rural eastern Washington and Oregon landfills.

Snohomish County. Snohomish County has completed a feasibility study for a 12 MW waste to energy project and is currently in the procurement process to select a site for an incinerator. The county has selected Ogden/Martin as the design contractor.

5.3 Cogeneration

5.3.1 Cogeneration Technologies

Cogeneration is defined as the **sequential** production of two forms of useful output energy (typically, electricity and heat) from the same energy input. As a result, the overall energy conversion efficiency of cogeneration facilities is high (usually in the 60-80 percent range on an annual basis.)

In a cogeneration system, some or all of the steam exits from the turbine at a pressure of 15-150 psi and is used to meet process heat, space heating, and domestic hot water (DHW) heating requirements. For many industrial plants, the availability of combustible wastes as a "free fuel" makes cogeneration a logical solution to three needs: electricity (or other forms of shaft power); steam for process needs; and waste disposal. For example, the lumber and paper industries often use wood waste as a boiler fuel.

As the previous example illustrates, cogeneration is more a rediscovered concept than a new technology. Historically, large industrial plants and large institutional facilities (such as universities and hospitals) that had a need for both electricity and heat during all seasons were prime candidates for the installation of cogeneration systems. Typically, these cogeneration installations were similar to utility power plants, producing steam in boilers to power turbine-generator units, and included large (5,000 to 50,000 kW or more) generating units.

Facilities that are technically best suited for cogeneration projects have: (1) significant thermal loads, (2) small load fluctuations, (3) high capacity factors (i.e., operating hours per day and year), and (4) adequate space for extra equipment.

In recent years the potential market for cogeneration has increased due to the development and widespread marketing of Packaged Cogeneration Units (PCUs). These PCUs utilize either reciprocating engines or combustion turbines as prime movers. They are available with electrical outputs ranging from 20 kW to about 5,000 kW. Because they are compact, they can be completely assembled and tested prior to shipping and can be integrated into a broad range of host facilities.

Reduced size, simplicity of installation, and competitive pricing have all contributed to the marketability of these small cogeneration systems. This market expansion would not have occurred without rising energy prices and various economic incentives provided in federal government regulations such as those developed under PURPA.

The installed cost per kW of generating capacity for a PCU is typically one-third to one-half the cost per kW of large cogeneration systems. For example, the cost per kW for custom designed systems increases dramatically in unit sizes below 10,000 kW, while the cost per kW for PCUs shows only a modest increase as unit size decreases from 5,000 kW to 20 kW.

Compact cogeneration systems that are not factory assembled are not considered PCUs. However, compact systems using reciprocating engines are available in the 2,000-20,000 kW range. Systems using combustion turbines are available up to about 150,000 kW. The installed cost of these systems is also less than that of cogeneration units using steam boiler-turbine systems.

5.3.2 Cogeneration Resource Development

While the amount of electricity produced by cogeneration systems in the United States has increased significantly over the last several years, most of the activity has taken place in states where electricity rates are high or where fuel costs are relatively low. In particular, cogeneration has flourished in the states of Texas and California. For example, investor-owned California utilities have signed contracts with 388 cogeneration projects with a total capacity of 6,861 MW, while an additional 170 projects (2,868 MW) are in the planning stages.

In the Pacific Northwest, the economic climate for cogeneration has been poor. Electricity costs have been low compared to other parts of the nation. Further, the Northwest's electricity surplus all but eliminated any market for excess electricity generated on-site.

Table 5-4 indicates the existing cogeneration capacity in the state of Washington. There are 18 projects in the state, with an installed capacity exceeding 218 MW. The actual average output from these facilities is not known, but is believed to be much lower.

Most of the cogeneration capacity in the state is in the forest products industries. Cogeneration systems are economical in these industries because of the availability of large quantities of wood waste products (biomass) which serve as low cost fuels for such systems. Only five of the cogeneration projects, totalling 38.2 MW of generating capacity, were constructed after 1980 and have entered into PURPA-based contracts with purchasing utilities.

Table 5-4

Existing Cogeneration Capacity in Washington

Facility/City	Fuel	Capacity(MW)	Average Output(MW)
Crown Zellerbach/Camas	Biomass	12.0	8.3
Port Townsend Paper	Biomass	13.5	6.2
Crown Zellerbach/Omak	Biomass	7.2	-
Longview Fibre/Longview	Biomass	45.0	35.9
Weyerhaeuser/Longview	Biomass	35.0	-
Weyerhaeuser/Cosmopolis	Biomass	15.0	6.5
Weyerhaeuser/Everett	Biomass	12.5	10.0
Weyerhaeuser/Snoqualmie Falls	Biomass	7.0	-
SDS Lumber Co/Bingen	Biomass	3.8	-
*Vaagen Brothers/Colville	Biomass	4.0	2.0
University of Washington/Seattle	Coal	5.0	-
Washington State Univ./Pullman	Coal	2.5	-
*Boeing Company/Auburn	Natural Gas	9.0	-
*Pacific Cogeneration/Vancouver	Natural Gas	20.0	-
*METRO/Seattle	Biogas	3.9	2.0
ITT-Rayonier/Hoquiam	Biomass	10.0	-
ITT-Rayonier/Port Angeles	Biomass	12.0	-
*Texaco Refinery/Anacortes	Offgas	1.3	-
	Total	218.7	

*Project came on-line after 1980.

5.3.3 Electrical Generating Potential.

The amount of cost-effective cogeneration is strongly dependent on fuel and electricity prices and escalation rates, electricity sell-back prices, "hurdle rates" or internal rates of return required by a potential developer, the developer's cost of capital, the mode of project operation, and the type of cogeneration technology deployed.

Washington has an estimated cogeneration potential of anywhere from 690 to 2,045 MW, depending on the types of systems installed. Different cogeneration technologies have varying capabilities in terms of efficiency of electrical conversion, thermal output, and the types of thermal end-uses that can be satisfied. The relative amount of electricity produced by a cogeneration system for a given thermal output is referred to as the electricity-to-steam or E/S ratio. E/S ratios vary from approximately 50 for a steam turbine to over 200 for a gas turbine system, and may exceed 400 kWh/MBtu for a diesel reciprocating engine/generator set.

Approximately 112 MW of cogeneration capacity could be developed in the commercial sector while from 578-1,933 MW could be developed in the industrial sector. Much of the industrial potential resides in the wood and paper products industries. Other industries that might consider natural gas-fired cogeneration include food and kindred products (47-156 MW); chemicals and allied products (45-150 MW); primary metals (35-115 MW); petroleum and coal products (36-120 MW); and transportation equipment (9-30 MW).

5.3.4 Industrial Sector Cogeneration Potential

Estimates of potential power generation within Washington for each of the key 2-digit SIC industries were examined by WSEO in its 1987 *Lost Opportunities for Electrical Generation* report. These estimates are summarized in Table 5-5. They represent the low to high MW scenarios for each industry, based on a variety of possible cogeneration technologies. The net totals for the seven industries range from approximately 580 MW to over 1,900 MW.

Table 5-5

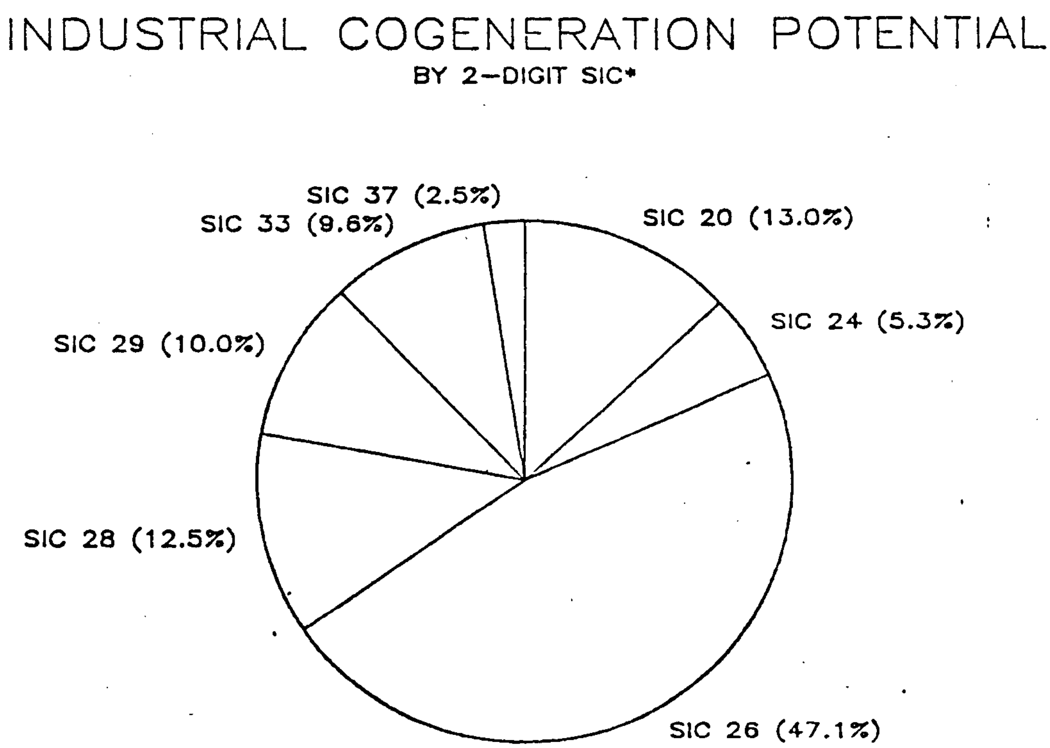
Industrial Sector Cogeneration Potential, MW*

Technology Mix	SIC20	SIC24	SIC 26	SIC 28	SIC 29	SIC 33	SIC 37	Total
90% steam turbine, 10% gas turbine	46.7	41.0	366.4	44.8	36.0	34.4	8.9	578.2
67% steam turbine, 33% gas turbine	78.1	68.7	613.3	74.9	60.3	57.6	14.9	967.8
50% steam turbine, 50% gas turbine	101.3	89.1	795.7	97.1	78.1	74.4	19.4	1,255.1
33% steam turbine, 67% gas turbine	124.6	109.6	978.3	119.4	96.1	91.8	23.9	1,543.7
10% steam turbine, 90% gas turbine	156.0	137.2	1,225.1	149.6	120.3	114.9	29.8	1,932.9

* The estimates for SIC 20, 24, 26, and 37 take into consideration the existing cogeneration capacity in the state; see Table 5-4. SIC 20 = Food and kindred products, SIC 24 = Lumber and wood products, SIC 26 = Paper and allied products, SIC 28 = Chemicals and allied products, SIC 29 = Petroleum and coal products; SIC 33 = Primary metal industries, and SIC 37 = Transportation equipment.

The percentage of the total cogeneration potential accounted for by each of the industrial categories is indicated in Figure 5-7. Even when it is assumed that almost all of their thermal demands will be met by steam turbine systems, the forest products industries (SICs 24 and 26) still represent over 50 percent of the total theoretical potential.

Figure 5-7



* In SICs 20,28,29,33, and 37, it is assumed that 50% of the steam loads will be met by steam turbines, and 50% by gas turbines. In SICs 24 and 26, it is assumed that 90% of the steam loads will be met by steam turbines, and 10% by gas turbines.

For a cogeneration project of a given capacity, electrical production is highly dependent upon operational characteristics. A facility may be operated in a thermal load following mode, may be used to meet plant electrical needs (electrical dispatch), or may be operated in a continuous or base-loaded manner. Selection of an optimum mode of operation is dictated by specific commercial or industrial facility needs and projected operating revenues. The most desirable mode of operation is thus strongly affected by a utility's avoided cost offer or negotiated electricity sell-back rate. Higher electricity purchase prices lead to the availability of increased quantities of cogeneration.

In its 1987 *Assessment of Commercial and Industrial Cogeneration Potential in the Pacific Northwest*, BPA determined that the **theoretical** cogeneration potential within the state of Washington exceeds 23,400 average megawatts. The sensitivity of the developable portion of this resource to such parameters as electricity sell-back rates, hurdle rates, and forecasted load growth scenarios is examined in Table 5-6. Under the base or mid-range load growth scenario, with a 5¢/kWh sell-back rate, the cost-effective or developable cogeneration potential is estimated at 870 to 1,350 average megawatts.

Table 5-6

Sensitivity of Washington's Cost-Effective Cogeneration Potential to Hurdle Rate and Load Growth Scenario, Average MW

	Hurdle Rate, %	
	25	35
Base (mid-range) Load Growth Scenario	1,350	877
High Load Growth Scenario	9,700	1,217

5.3.5 Commercial and Institutional Sector Cogeneration Potential

The types of commercial and institutional facilities with the greatest cogeneration potential are hospitals, nursing homes, hotels/motels, commercial laundries, recreational facilities (with pools), colleges (four-year with dormitories), airports, and prisons. Almost all of these facilities are continuously occupied and have thermal demands at all times. The exceptions are commercial laundries and recreational facilities, which are generally occupied only 10 to 16 hours per day; however, when these facilities are open, their thermal loads are significant.

Other commercial building types believed to have limited cogeneration potential include office buildings, restaurants, retail stores, grocery stores, apartment complexes, and shopping centers. These facilities are, however, typically occupied only 10 to 12 hours per day and have significant load fluctuations during that time. While apartment complexes, restaurants, and grocery stores may be open 24 hours per day, they typically have small thermal loads and present little potential for electrical generation.

Potential power generation estimates for the key commercial sectors in the state are listed in Table 5-7. The total **theoretical** potential for all key sectors is estimated at 112 MW. Figure 5-8 illustrates the relative distribution of the potential between sectors. Hospitals represent nearly 45 percent of the total—over two and one-half times the potential of any other sector.

5.3.6 Natural Gas Availability and Cost

Historically, Washington has had an abundance of low-cost electricity, primarily from large-scale hydroelectric resources. As a result, cogeneration fueled by natural gas has simply not been cost-effective. However, as the cost of producing (or acquiring) electricity increases, natural gas cogeneration should become increasingly viable.

In recent years, some cogenerators in Washington have turned to natural gas as the fuel of choice for their facilities. Natural gas is offered at an attractive price, is abundant, and projected to be available over the long term. For example, while Washington currently has approximately 218 megawatts of installed cogeneration capacity, most frequently using wood waste as fuel, two operations—Boeing in Auburn and Pacific Cogeneration in Vancouver—use natural gas. (However, due to low avoided cost offers, it is likely that neither company would have cogeneration systems if state tax incentives had not been available to help subsidize installation.)

Although a moderate amount of gas exploration has occurred in the last few years, natural gas is not currently being produced in Washington. All natural gas is supplied by the Northwest Pipeline Corporation (NWP), an interstate pipeline company, which imports the gas from the southwest United States and Canada. Canadian imports now make up approximately 40 percent of all supplies. NWP's pipeline system and the service areas of the utilities that distribute the natural gas are shown in Figure 5-9.

Table 5-7

Potential Cogeneration Production in the Commercial Sector

Facility Type	# of Facilities Identified in the State*	Potential Power Output per Facility(kW)	Total Theoretical Potential (MW)
• Hospitals			
large (greater than 300 beds)	15	1200[a]	18.0
medium (100-299 beds)	40	800[a]	32.0
• Nursing Homes (greater than 150 beds)	41	100[b]	4.1
• Hotels/Motels (greater than 150 beds)	41	170[c]	7.0
• Prisons			
large	4	1500[d]	6.0
medium	8	300[d]	2.4
• Laundries	20	300[d]	6.0
• Recreational Facilities (with pools)	35	60[d]	2.1
• Colleges (4 yr, w/dorms)	12	500[d]	6.0
• Airports			
SeaTac Intl.	1	9200[d]	9.2
King Co. Intl.	1	500[a]	0.5
• Misc. Institutions			
Fircrest School	1	4400[a]	4.4
Rainier School	1	5700[a]	5.7
Western St. Hosp.	1	9000[a]	9.0
TOTALS	221		112.4

a Estimated from actual steam capacities at facilities in the Puget Sound Air Pollution Control Authority (PSAPCA) service area; see Appendix C2.

b From San Diego Gas & Electric "Cogen 3 Simulations," 1986.

c Estimate based on the average power output of hotels/motels with cogeneration in the San Diego Gas & Electric (SDG&E) service area.

d Estimate based on data from Seton, Johnson, Odell (1984) and/or quarterly reports on cogeneration and small power production from the major California utilities.

Figure 5-8

COMMERCIAL COGENERATION POTENTIAL

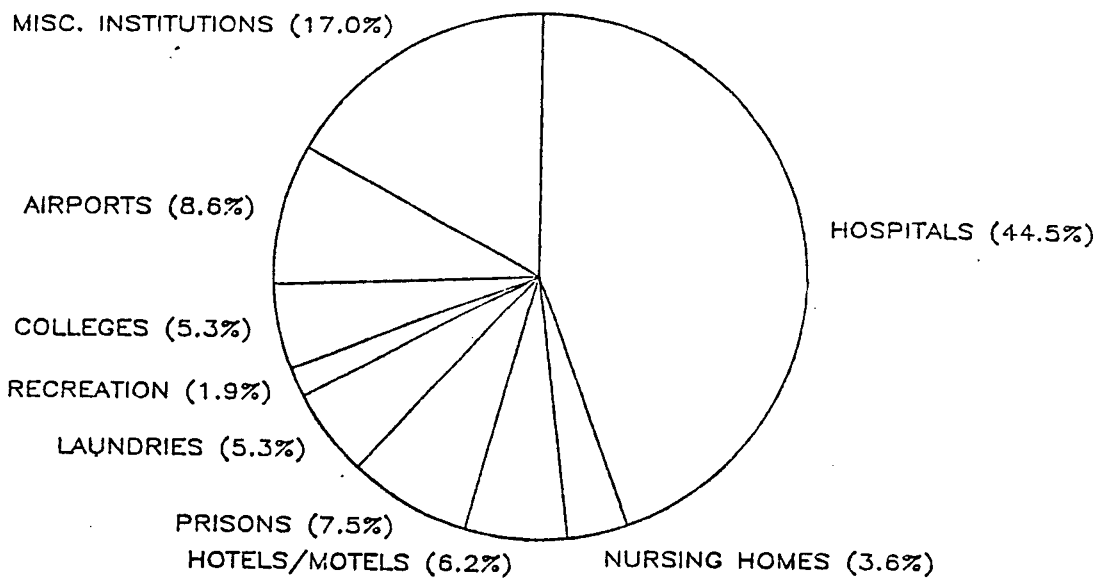
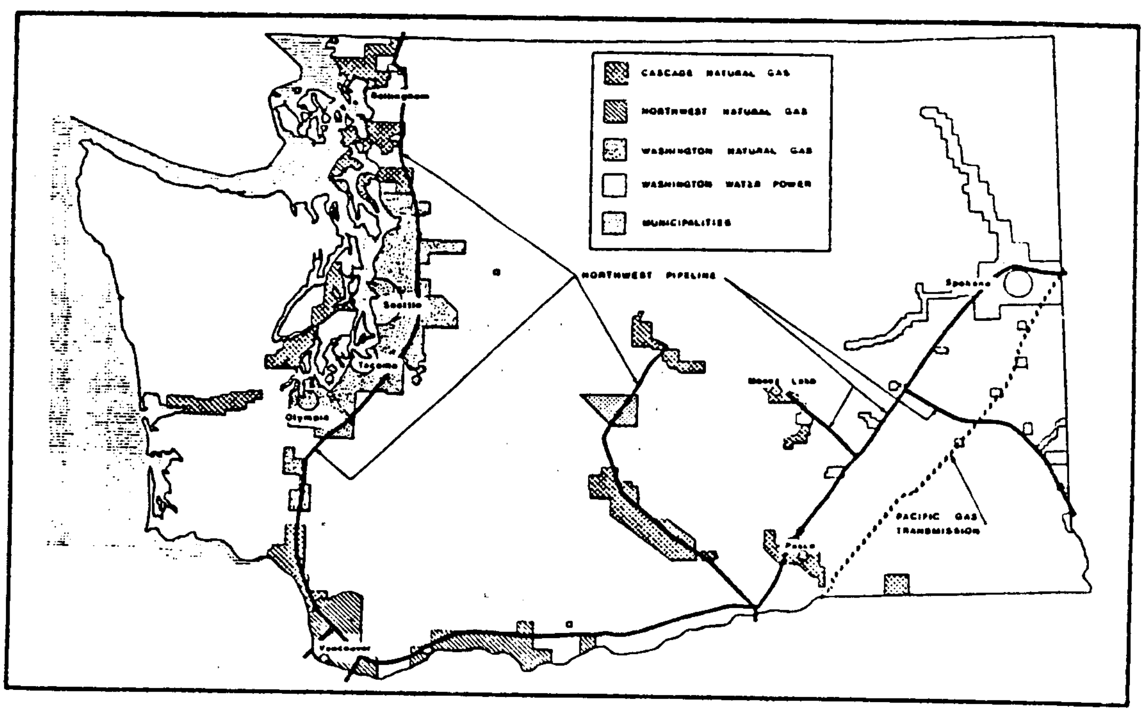


Figure 5-9
Natural Gas Pipelines and Service Areas in Washington



The price of natural gas in Washington declined substantially during 1986 and 1987 as a result of deregulation, competitive Canadian pricing policies, and reduced world crude oil prices. Natural gas prices from January 1985 to January 1987, estimated for typical 1 and 20 MW gas turbine systems and based on Washington Natural Gas Company's declining block rate schedules 85 and 87, are shown in Table 5-8.

Table 5-8

Natural Gas Prices for Typical 1 and 20 MW Gas Turbine Systems

Effective Date of Rate Schedule	Schedule 85[a] Price ($/MBtu) 1 MW[c]	Schedule 85[a] Price ($/MBtu) 20 MW[d]	Schedule 87[b] Price ($/MBtu) 1 MW[c]	Schedule 87[b] Price ($/MBtu) 20 MW[d]
January 4, 1985	5.24	5.20	4.99	4.95
April 1, 1985	5.25	5.21	5.00	4.96
June 17, 1985	5.24	5.20	4.99	4.95
August 3, 1985	5.01	4.97	4.76	4.72
October 1, 1985	4.89	4.86	4.64	4.61
February 13, 1986	4.75	4.71	4.50	4.46
August 2, 1986	3.94	3.90	3.32	2.59
November 6, 1986[e]	3.86	3.77	3.23	2.55

a Interruptible gas service.
b Non-exclusive interruptible service.
c Assumes a monthly gas usage of 91,800 therms, given a heat rate of 15,000 Btu/kWh and an 85 percent capacity factor. Demand charges are included.
d Assumes a monthly gas usage of 1,407,600 therms, given a heat rate of 11,500 Btu/kWh and an 85 percent capacity factor. Demand charges are included.
e Prices still in effect as of March 1, 1987.

Natural gas is an abundant resource in both the U.S. and Canada. In 1987, proven reserves in the U.S. and Canada were about 193 trillion cubic feet and 90 trillion cubic feet, respectively, or about 15 years of supply for both countries at the current level of demand. Undiscovered reserves in both countries are estimated to be from two to four times the amount of proven reserves.

The proximity of Canada's natural gas fields also bodes well for a continued supply of natural gas for Washington. Approximately 98 percent of Canada's gas supplies are located in British Columbia and Alberta. The Pacific Northwest is the closest U.S. market for those fields and currently the only viable export market for British Columbia suppliers.

Producers in both the U.S. and Canada currently have a surplus of deliverable natural gas. This surplus resulted from exploration undertaken after natural gas price deregulation. This surplus of natural gas places a downward pressure on its price. Average industrial prices for natural gas in Washington state have dropped from $4.12 per thousand cubic feet in 1983 to a low of $3.17 per tcf in 1987. The American Gas Association predicts the surplus will end around 1990, but new discoveries could easily extend the surplus. The AGA predicts that natural gas prices will stay about the same until the surplus dwindles and then prices will increase moderately.

Canadian producers are also anxious to regain the market share they lost during the mid-1980s, when Canadian price controls resulted in high gas prices to U.S. customers. The competition between producers in both countries may place continued downward pressure on natural gas prices, which would keep the cost of natural gas for PURPA cogeneration competitive.

This competition in the gas industry would not exist, except for changes brought about by the Federal Energy Regulatory Commission. In the past, industrial customers purchased natural gas from local distributing companies. Distribution companies purchased the gas from an interstate pipeline, which in turn purchased the gas from producers (or from their own fields). Access to gas transportation services was controlled by the pipeline company.

FERC removed price controls at the wellhead, theoretically allowing industrial customers to solicit competitive bids directly from producers, but because access to transportation was still controlled by pipeline companies, deregulating wellhead prices did not fully introduce competition in natural gas markets. On October 31, 1985, FERC addressed this situation by issuing Order 436 (replaced eventually with Order 500). This order sets forth a voluntary open access transportation program for interstate pipelines. Under the new FERC ruling, interstate pipeline companies that chose to offer transportation services are required to make the service available on an indiscriminate basis.

At the time of the ruling, NWP had contracts to purchase much more gas than it could sell. Furthermore, NWP was not interested in transporting gas for utilities or industries when their independent gas purchases would help reduce their take-or-pay obligations to NWP. As a result, NWP filed a transportation tariff request with FERC, asking that past take-or-pay obligations be passed on to consumers as a condition of accepting open access transportation. On January 19, 1988, FERC granted NWP a certificate under Order 500 to implement open access transportation with certain restrictions for passing through take-or-pay obligations. NWP rejected the offer, declaring that the conditions of the certificate would force unmanageable take-or-pay liabilities on the company.

During the ensuing negotiating period, NWP offered transportation services to industries and utilities on a temporary basis. Northwest gas utilities paid NWP to transport low-cost spot market purchases, so utility customers could have access to low-cost gas. This worked well in the interim and all customers benefited from the spot market purchases. On June 10, 1988, NWP finally accepted a certificate under Order 500 and offered open access transportation through its system. The signing ended two and a half years of negotiations between FERC and NWP over the conditions of the certificate.

Now that interstate transportation services are permanently available, local gas utilities are able to offer transportation services to large industrial customers. However, these utilities argue that local transportation rates are too high to encourage gas transportation. The UTC, which regulates local gas utilities, recently granted one local utility—Washington Water Power - a reduction in its transportation tariff. Reductions for other utilities can be expected.

Thus, industrial customers who want to develop cogeneration no longer need to purchase natural gas from a utility or pipeline. Instead, the customer can go straight to producers and negotiate separate contracts with the pipeline and local utility for transportation. For example, an industrial customer could purchase gas from a producer on a long-term contract with fixed prices over the length of the contract. Alternatively, an industrial customer could operate its own gas fields and pay pipeline companies for transportation. Either scenario reduces the risk of fueling a cogeneration facility with natural gas and allows an industrial customer to estimate life-cycle cogeneration costs with a greater level of confidence.

These recent changes in gas markets will not necessarily ensure that the price of gas remains comparatively low over the long term. Since the price of gas is closely linked to the price of oil, an increase in oil prices could also increase the price of natural gas. Thus, it is uncertain at this time how changes in the natural gas market will affect the future development of PURPA cogeneration facilities in Washington.

5.3.7 Coal Availability and Cost

In 1984, approximately 4.9 million short tons of coal were consumed in Washington. Of this total, only 428,000 tons were used in the residential, commercial, and industrial sectors; the remainder went to facilities operated by electric utilities.

About 90 percent of the coal consumed in Washington comes from in-state mines. The additional 10 percent comes from a variety of sources, including mines in Utah, Wyoming, Montana, and British Columbia.

Average coal costs from 1984 to 1986 for both electric utilities and manufacturing plants are listed in Table 5-9. The actual delivered costs depend on the heating value, sulfur content, and ash content of the coal; the mode of transportation; and the distance to the plant site. Approximately two-thirds of the cost of coal from Utah, for example, consists of rail transportation costs.

There should be no shortage of coal in the state in the foreseeable future because abundant supplies exist in the Northwest. Coal reserves in Washington alone exceed 6 billion tons, although only 1.6 billion tons are considered to be economically recoverable.

Table 5-9

Average Quarterly Coal Prices in Washington State

Year/Quarter		Electric Utilities $/short ton	Electric Utilities $/MBtu*	Manufacturing Plants $/short ton	Manufacturing Plants $/MBtu*
1984	I	28.93	1.45	45.60	2.28
	II	28.95	1.45	49.97	2.50
	III	28.33	1.42	57.26	2.86
	IV	25.60	1.28	48.13	2.41
1985	I	28.75	1.44	47.50	2.38
	II	27.21	1.36	52.06	2.60
	III	25.80	1.29	51.44	2.57
	IV	25.92	1.30	47.82	2.39
1986	I	25.66	1.28	47.30	2.37
	II	27.20	1.36	46.97	2.35
	III	27.48	1.37	51.85	2.59

* assumes 10,000 Btu/lb

5.3.8 Mill and Logging Residues: Availability and Cost

Both wood and bark residues are produced in large quantities by sawmills, veneer and plywood mills, and shake and shingle mills in the state. Mill residue production and use in Washington is summarized in Table 5-10. Total production from the 309 mills operating in 1984 was over 5.4 million dry tons, 77 percent of which came from the western portion of the state.

In 1984, the mill residues were used primarily by the pulp industry (41%) and as boiler fuel (43%). The "other" uses, which account for 13 percent of the total, include animal bedding, landscaping, gardening, and mulch. Only 2 percent, or 114,446 dry tons, went unused. Thus, utilization of mill residues increased considerably since 1974 when 564,000 tons or 10 percent of total production were unused.

Table 5-10

1984 Production and Use of Mill Residues in Washington

Economic Area	Total Residues Produced (dry tons)	Wood Residues Unused (dry tons)	Bark Residues Unused (dry tons)
Puget Sound	1,552,084	47,760	15,669
Olympic Peninsula	1,499,609	31,932	11,355
Lower Columbia	1,127,232	------	163
Central Washington	698,262	3,655	2,833
Inland Empire	546,977	637	392
Total	5,424,164	83,984	30,462

Current mill residue costs are difficult to obtain. A 1983 WSEO survey of 27 sawmills and pulp mills in the state found that residue **selling** prices ranged from $3.18 to $25.80 per dry ton, with a weighted average of $10.60 per dry ton for the 380,000 tons reported. When a heating value of 8,600 Btu per pound of dry wood is assumed, the average selling price was approximately $0.62/MBtu.

The residue **purchase** prices, which include the costs of transportation, varied from $18.18 to $25.98 per dry ton with the weighted average being $25.21 per dry ton, or approximately $1.47/MBtu.

Various mill operators indicate that these costs are still representative, although they may be somewhat high due to the depressed forest products industry. Nonetheless, because over 98 percent of the state's wood and bark mill residue is beneficially used at the present time, this fuel source is expected to play a minor role in the development and operation of new cogeneration resources.

Logging residue remains a little utilized cogeneration fuel. This material, the woody material at least three inches in diameter and one foot long existing on an area after timber harvest, can include small and rotted logs, limbs, tops, cull logs, and bark. Logging residue also includes any piled and yarded material that cannot be sold.

Delivered logging residue costs in Washington are estimated to range from $2.60 to $4.95/MBtu, depending on the location and quantity of residues delivered. These costs should be compared to the mill residue costs mentioned above, which ranged from $1.06 to $1.51/MBtu, delivered. Clearly, in areas where both resources are available, mill residues are economically more attractive.

5.4. Geothermal Resources

5.4.1 Geothermal Potential

In Washington, geothermal resources occur in three distinct geographic areas: the Olympic Peninsula, the Columbia Basin, and the Cascade Range. The Olympic Peninsula has little or no known **developable** geothermal potential; all known thermal sources in that area are found in the Olympic National Park and are protected from exploitation by the Geothermal Steam Act of 1970.

Large areas in the Columbia Basin have above normal groundwater temperatures and geothermal gradients. Groundwater temperatures of 18°C (65°F) to 40°C (104°F) are common, as are geothermal gradients above 50°C (122°F) per kilometer. These widespread resources are available at a moderate depth, less than 610 meters (2,000 feet). (Many irrigation and municipal wells in the Columbia Basin deliver water at temperatures between 18°C (65°F) and 40°C (104°F).) Although these resources may not be hot enough to be used directly for industrial processing or space heating, they can be economically utilized with heat pumps.

Of the three areas, the Cascade Range Geothermal Province most likely holds the greatest potential, as evidenced from the number of thermal and mineral springs, significant amounts of hydrothermal alteration, and from the area's five major stratovolcanoes with fumarole activity. Recent volcanic activity associated with Mt. Saint Helens illustrates that geothermal potential exists beneath Washington volcanoes. Deep drilling in the Cascades of Oregon and British Columbia has also uncovered geothermal resources in excess of 250°C. Researchers estimate the undiscovered resource base in the Cascade Mountains of Washington, Oregon, and northern California could be as high as 90,000 MW.

Although no large, high temperature hydrothermal systems (needed for geothermal power production) have been identified in Washington's Cascade Mountains, the abundance of young volcanic rocks and the isolated occurrences of hot water along the range suggest that a large resource may exist. Additional work must be completed before the systems can be identified and the resource base estimated.

Overall, the Cascade Range Geothermal Province has received a great deal of attention from potential developers. Geothermal lease applications have been filed on over 700,000 acres of United States Forest Service lands in Washington since 1974. The filing of lease applications has continued with new submittals being made yearly. There are currently over 40,000 acres in Washington with lease applications pending.

However, many geothermal sites may be located in areas where leasing for geothermal development is not permitted. The Geothermal Steam Act of 1970 states that leasing is not permitted in National Parks, National Monuments, National Recreation Areas, fish hatcheries, identified wildlife areas, and lands selected by the Secretary of the Interior. Wilderness Areas are also restricted from geothermal development.

5.4.2 Resource Assessment Activities

Washington State's geothermal resource assessment program is managed by the Department of Natural Resources, Division of Geology and Earth Resources (DGER). The program has been active since the mid-1970s. The program, funded primarily by the United States Department of Energy, is limited to geologic mapping, thermal and mineral spring sampling, and thermal gradient well drilling (500' to 1,500'). The southern Cascade Range has received the greatest share of the resource assessment and leasing activity.

Resource assessment by the private sector has been limited in Washington due to current surpluses of electricity and natural gas and the resulting lack of interest expressed by northwest utilities. Without a perceived market for energy, developers of geothermal power have concentrated their efforts in areas where market conditions are more favorable. For example, development has occurred in California and in other areas where there is either inter-tie access to California markets or a local demand for power.

5.4.3 Geothermal Development

The first commercial geothermal power plant in the United States was commissioned in 1960 at The Geysers, California. The Geysers now produces approximately 1,900 MW or 87 percent of all the geothermal power generated in the United States.

Geothermal electrical power development has occurred solely in the western United States; however, no geothermal power plants have come on-line or are currently proposed for development within the state of Washington.

CHAPTER VI. LICENSING AND PERMITTING ISSUES AFFECTING PURPA QUALIFYING FACILITIES

6.1 Hydropower Projects

6.1.1 Environmental Impacts of Hydropower Development

Hydropower has a number of advantages over other generating resources since it avoids or minimizes emissions affecting air quality, thermal pollution, production of solid or hazardous wastes, pollutants affecting water quality (for run-of-river projects), and heavy vehicular traffic associated with projects with high maintenance requirements.

Hydropower development is not, however, environmentally benign. Impacts on fish and wildlife can be severe if facilities are not properly designed, installed, and operated. Project components that potentially impact the environment include diversion and intake structures; impoundments; penstocks and powerhouses; access road; and transmission lines. Impacts are likely to arise from the construction of these facilities as well as from their operation and maintenance. Moreover, hydropower projects can degrade both the project site and downstream areas.

The actual environmental impacts from hydropower development are highly site and design-specific A design that is optimal for one site from an environmental standpoint may be destructive at another site. Thus, it is difficult to rank the environmental acceptability of hydropower projects in general terms. Nonetheless, resource agencies generally agree that projects involving an existing dam (or, for small projects, no dam at all) will have fewer adverse impacts than projects requiring construction of a new dam and impoundment. Similarly, run-of-river and diversion projects, assuming maintenance of adequate instream flows, will generally be more environmentally acceptable than projects requiring a storage reservoir. In fact, few large reservoir projects have been proposed for non-federal development in recent years.

Key environmental and design concerns evaluated by potential hydropower developers include:

> ***Bedload Transport.*** Any structure built within a stream channel has the potential to impede movement of fish, aquatic organisms, spawning gravels, and sediment. Large quantities of material can accumulate in the pool formed by a diversion structure. Occasional cleaning by dredging or sluicing may be necessary. These activities can affect water quality and must be scheduled to minimize adverse affects on resident and anadromous fish, which rely on stream habitat for spawning, incubation, and rearing.
>
> ***Intake and Tailrace Screening.*** An intake structure can kill fish if high water approach velocities trap fish at the intake screen. (If no screen existed, the fish would go through the water turbines and might still be subject to high mortality rates.) Poorly designed intake structures may also cause vortexing and entrainment of air, resulting in high

dissolved nitrogen levels in the water released from the powerhouse. To minimize these problems, resource agencies specify approach velocities, screen mesh size, and cleaning requirements. Resource agencies also specify tailrace screening requirements and discharge velocity limitations to avoid establishing false attraction sites for fish migrating upstream.

Sedimentation Plans. Pipeline, canal, or penstock leakage can destabilize slopes and lead to pipeline failure, land slides, and other slope failures. These situations can affect public safety, necessitating contingency plans. The resulting erosion can drastically affect stream productivity. Most projects must, therefore, incorporate leak detection and automatic shut-off mechanisms.

Erosion and bed load (sediment) may also increase due to stream bank clearing, blasting underlying bedrock, and construction of dams or diversion structures within the stream channel. Standards for water quality must be met during all phases of construction. Harmful impacts to fish and wildlife can be minimized by working within the stream channels only during low flow periods. Resource agencies require that sedimentation plans be prepared and approved.

Instream Flow Requirements. Insufficient instream flows through a bypass reach can affect the quantity and quality of fish and wildlife habitat, water quality, recreation, scenic and aesthetic values, navigation, and other environmental values. In some cases, barriers can become impassible to migrating fish during periods of low flow. When carried out too rapidly, project start-up can dewater a bypass reach, stranding fish and creating a surge of water below the powerhouse. This surge can, in turn, cause erosion, sediment transfer, and fish and wildlife habitat damage. A sudden shutdown could also cause a surge of water through the bypass reach and dewater the reach below the powerhouse.

The Department of Ecology, in conjunction with the Departments of Fisheries and Wildlife, establishes instream flow requirements and ramping rate (rate of change in flow) limitations to avoid these adverse impacts. In the Water Resources Act of 1971 (Chapter 90.54 RCW), the Washington State Legislature declared that "perennial rivers and streams of the state shall be retained with base flows necessary to provide for preservation of wildlife, fish, scenic, aesthetic, and other environmental values," and gave the Department of Ecology exclusive authority to set instream flows (see also RCW 90.22.010 and 90.03.247). Under the department's Instream Resource Protection Program, minimum instream flows are being established for all major streams in western Washington.

Fish Passage. In an effort to reduce the adverse impacts of dams on fish populations, the State of Washington has enacted laws and regulations which require: 1) the construction and maintenance of approved fish guards or screens at the intake of ditches, channels, canals, or water pipes to prevent the passage of fish into such structures (RCW 75.20.040 and 77.16.220); and 2) the construction and maintenance of an effective fishway or ladder over every dam or obstruction in any stream (RCW 75.20.060 and 77.16.210). If the Department of Fisheries finds that a fishway is impractical, the project developer is required to erect and fund a fish hatchery or make annual payments to operate a nearby hatchery (RCW 75.20.090).

6.1.2 Land Use Constraints to Hydropower Development

Development of any hydropower project requires the developer to secure ownership, leases, easements, rights-of-way, or other approval to occupy and use the land and water. There are many areas in Washington where construction of a hydropower project is prohibited by law or severely regulated.

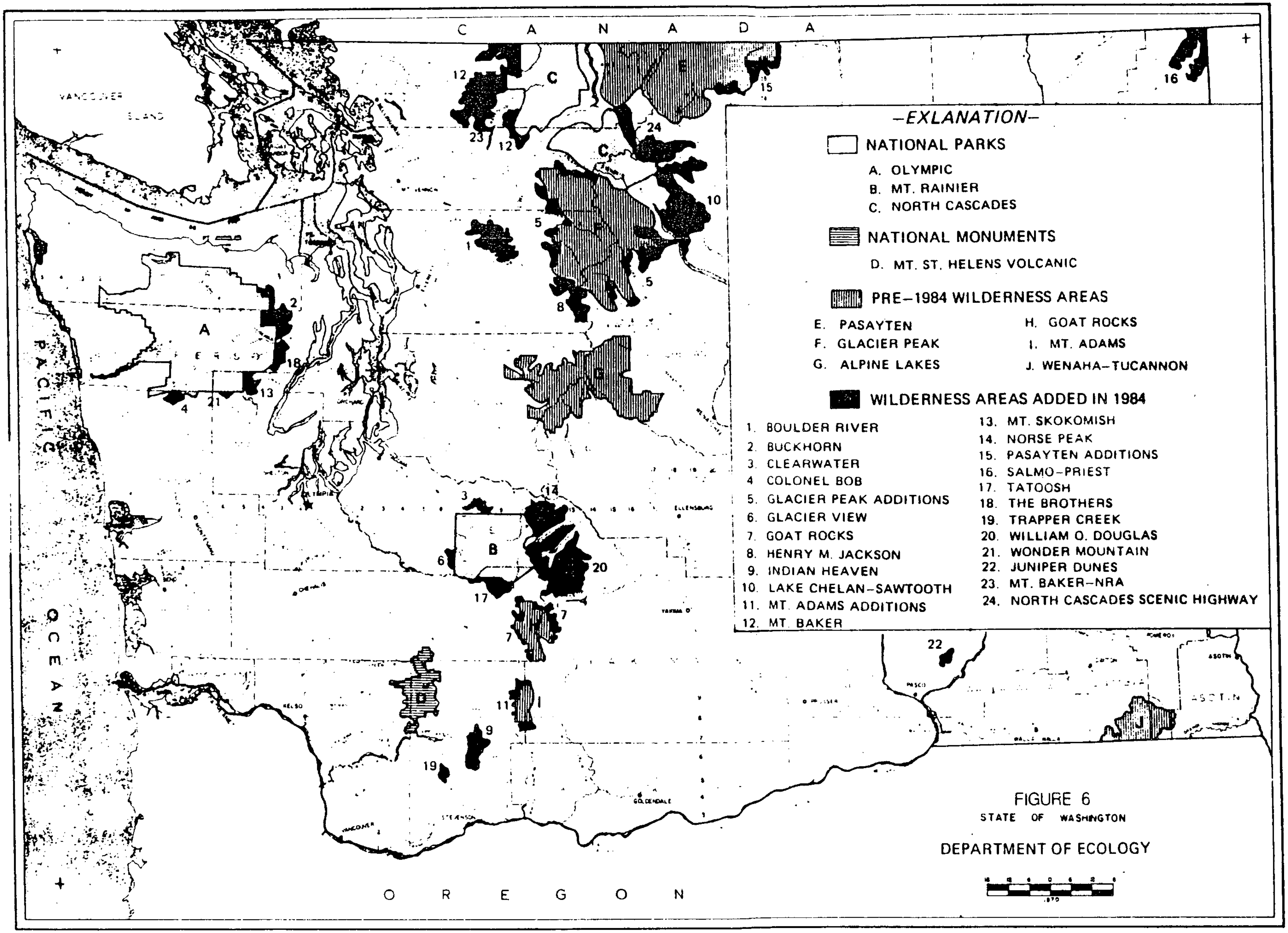
Federally designated areas where hydro development is restricted include Wilderness Areas, National Parks, and National Monuments. Recent passage of the Washington State Wilderness Bill, S. 837, added one million acres to the National Wilderness Preservation System. This brings the total to 2.6 million acres of designated wilderness in Washington State. In 1982, the Mount St. Helens National Monument Area was established for the protection of geologic, ecologic, and cultural resources in the Mount St. Helens Area. Wilderness areas, National Parks, and National Monuments in Washington State are indicated in Figure 6-1.

Under the Wild and Scenic Rivers Act of 1968, the Federal Energy Regulatory Commission (FERC) is barred from licensing projects on or directly affecting any component of the National Wild and Scenic River System. This includes not only "designated" wild and scenic rivers, but also "study" rivers identified by Congress under section 5(a) of the Act. In addition, a federal agency cannot make a loan or provide assistance for a project on these rivers without assurance that the project will not adversely affect the river's special values.

In addition to Congressionally designated rivers, rivers may be administratively listed as "potential" wild and scenic rivers under section 5(d) of the Wild and Scenic Rivers Act. Twenty-seven rivers or segments of rivers in Washington have been identified as having potential wild or scenic status (Figure 6-2 and Table 6-1). "Potential" scenic river status does not automatically preclude hydro development, but requires the prospective developer to evaluate the river for wild, scenic, and recreational values and to report these findings to FERC as part of the license application. Further, all federal actions (i.e., FERC licensing) having an adverse impact on these rivers must be coordinated with the National Park Service.

Similarly, Washington's Scenic River Act of 1977 (Chapter 79.72 RCW) does not expressly forbid dams or hydro projects on rivers within its system; however, the state is required to consider the impact of development on these rivers and must work to enhance their natural environments. The Skykomish River and several of its tributaries are included in the State Scenic River System (Figure 6-2). During the 1989 legislative session, 18 more streams will be nominated for inclusion into the state scenic river system.

Figure 6-1



WILDERNESS AREAS, NATIONAL PARKS AND NATIONAL MONUMENTS.

Figure 6-2

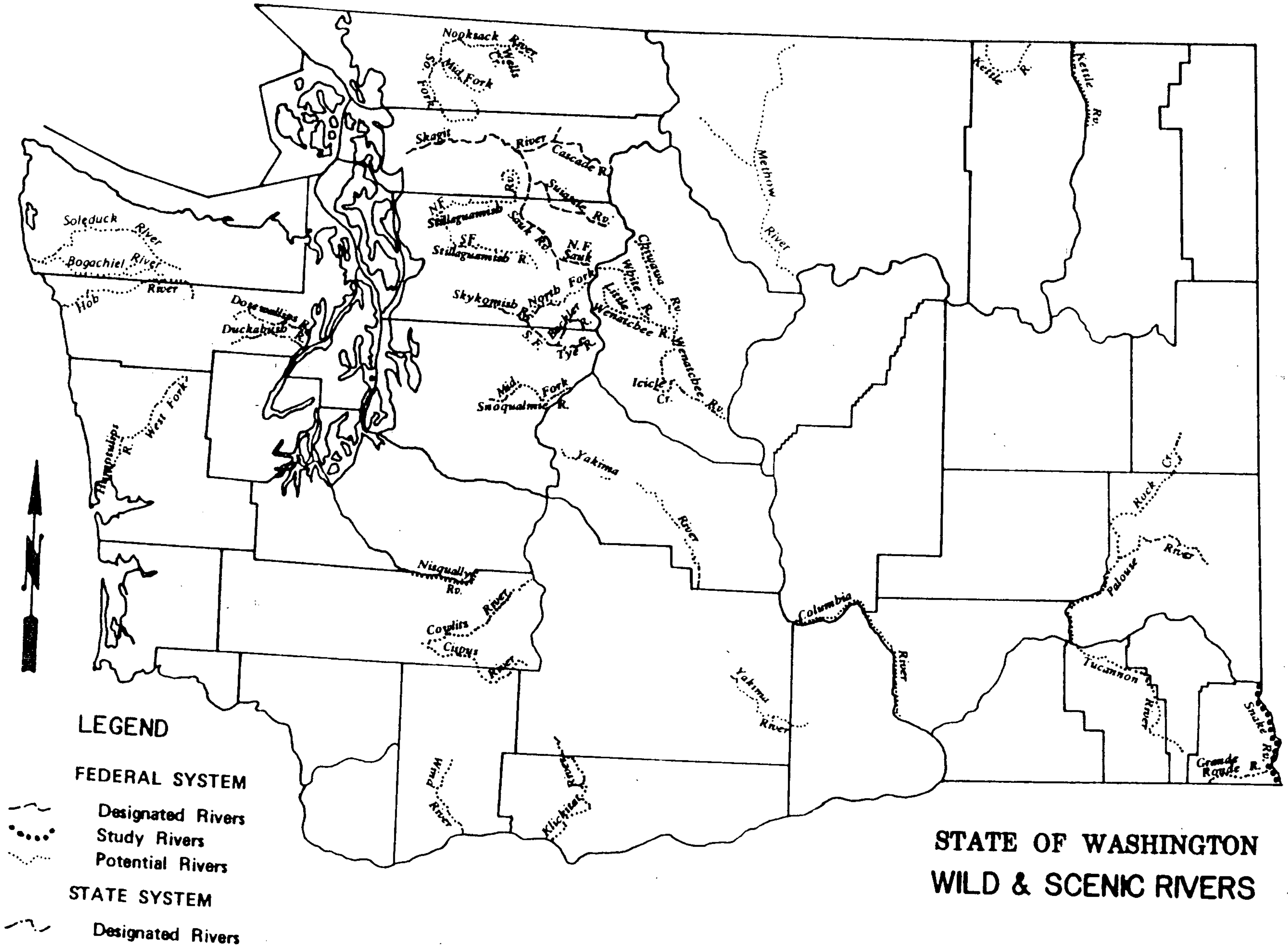

STATE OF WASHINGTON
WILD & SCENIC RIVERS
LEGEND
FEDERAL SYSTEM
Designated Rivers
Study Rivers
Potential Rivers
STATE SYSTEM
Designated Rivers
Nooksack River
Skagit River
Cascade R.
Suiattle Rv.
Sauk Rv.
N.F. Stillaguamish
S.F. Stillaguamish R.
N.F. Sauk
Skykomish
North Fork
Beckler R.
Tye R.
Mid Fork Snoqualmie R.
Chiwawa Rv.
White R.
Little Wenatchee R.
Wenatchee Rv.
Icicle Cr.
Methow River
Kettle R.
Kettle Rv.
Soleduck River
Bogachiel River
Hoh River
Dosewallips R.
Duckabush R.
Humptulips R.
West Fork
Yakima River
Nisqually Rv.
Cowlitz River
Cispus River
Columbia River
Yakima River
Rock Cr.
Palouse River
Tucannon River
Snake Rv.
Grande Ronde R.
Wind River
Klickitat River

Table 6-1

WILD AND SCENIC RIVERS IN WASHINGTON STATE

Federal Wild and Scenic Rivers in Washington State

RIVER	REACH
Designated Rivers	
1. Skagit River	
Main Stem:	From the pipeline crossing at Sedro Woolley upstream to and including the mouth of Bacon Creek.
Cascade R:	From its mouth to the junction of its north and south forks.
S. Fork Cascade R:	From its mouth to the boundary of the Glacier Peak Wilderness Area
Suiattle R:	From its mouth to the boundary of the Glacier Peak Wilderness Area at Mill Creek.
Sauk R:	From its mouth to its juncture with Elliot Creek.
N. Fork Sauk R:	From its juncture with the S. Fork Sauk to the boundary of the Glacier Peak Wilderness Area.
Study Rivers	
1. Snake River	33-mile reach downstream from the northern boundary of the Wallowa-Whitman National Forest to the Town of Asotin.
Potential Wild Rivers	
1. Bogachiel and North Fork	Entire mainstem and North Fork from source to confluence with the Soleduck River, 51 miles.
2. Cispus River	Entire length, 52 miles
3. Columbia River	From Priest Rapids Dam downstream to slack water at McNary Pool, 55 miles.
4. Cowlitz River	From its source downstream to the confluence with the Cispus River, 42 miles
5. Dosewallips River	Entire length, 28 miles.
6. Duckabush River	Entire length, 25 miles
7. Grande Ronde River	From the confluence of the Wallowa River downstream to the confluence with the Snake River, 78 miles.
8. Hoh River	Entire length, 55 miles
9. Humptulips River and West Fork	Entire mainstem and West Fork, 61 miles.
10. Icicle Creek	From Eightmile Campground downstream to diversion below Snow Creek confluence, 5 miles.
11. Kettle River	Entire portion in Washington State, 54 miles.
12. Methow River	Entire mainstem from source to mouth and the major tributary, Chewack River, 121 miles.
13. Nisqually River	From Nisqually glacier downstream to slack water Alder Reservoir, 23 miles.

Federal Wild and Scenic Rivers in Washington State

RIVER	REACH
14. Nooksack River, South Fork, Middle Fork, and Wells Creek	1) The upper mainstream from its source downstream to its confluence with the South Fork; and 2) the entire South fork; 3) the entire Middle Fork; and 4) Wells Creek 35, 37, 20; 7 miles.
15. Palouse River	From Colfax downstream to the confluence with the Snake River, 72 miles.
16. Rock Creek	Entire length, 52 miles.
17. Skykomish River	The entire North Fork, South Fork, and mainstem including major tributaries, 108 miles.
18. Snoqualmie River, Middle Fork	From its source downstream to a point approximately four miles upstream from the confluence with the South Fork, 31 miles.
19. Soleduck River	Entire length, 65 miles.
20. Stillaguamish River North and South Forks	Entire North and South Forks, 123 miles.
21. Tucannon River	Entire length, 57 miles.
22. Wenatchee River	Entire river including Lake Wenatchee and its tributaries, White River, and Chiwawa River, 118 miles.
23. Wind River	Entire length, 29 miles.
24. Yakima River	1) From Crystal Springs to Lake Easton; 2) R.M. 190 to confluence with Cle Elum River; 3) from Teanaway, WA, to Hwy. I-90 at Ellensburg; 4) R.M. 146 to slack water behind Roza Dam; 5) and from Zillah to Prosser, 9, 6, 28, 15; 44 miles.

Source: HCRS Nationwide Rivers Inventory, 1980.

Washington State Scenic River System

Designated River	
1. Skykomish River	
Main Stem:	From junction of North and South forks downstream to its junction with the Sultan River, 14 miles.
South Fork:	From junction of North and South forks upstream on the South fork to the junction of the Tye and Foss Rivers, 20 miles.
North Fork:	From junction of North and South forks upstream on the North Fork to its junction with Bear Creek, 11 miles.
Beckler River:	From its junction with the South Fork Skykomish upstream.
Tye River:	From its junction with the South Fork Skykomish upstream to Tye Lake, 14 miles.

Source: Chapter 79.72 RCW.

Washington state law also prohibits dams greater than 25 feet high within the migration range of anadromous fish on all streams and rivers tributary to the Columbia River downstream from McNary Dam. First established in 1949 (RCW 75.20.010), the Columbia River Fish Sanctuary was reenacted in the form of an initiative to the Legislature in 1961 (RCW 75.20.110) for the purpose of "preservation and development of the food and game fish resources of (the) river system." The law also prohibits any water diversion, other than those used for fisheries, that will reduce the streamflow in any sanctuary steam below the average annual flow. In addition, the Columbia River Gorge National Scenic Area Act of 1986 designates the Lower White Salmon and Klickitat Rivers as national recreational rivers.

Finally, the Northwest Power Planning Council has designated 3,723 river reaches comprising 12,401 stream miles within Washington State as "protected areas." These areas are "off-limits" to new hydropower development due to the presence of anadromous fish; threatened or endangered species (including bald eagles, peregrine falcons, white-tailed deer, spotted owls, or grizzly bears); or highly valued habitat areas such as deer or elk-winter range, old growth, spotted owl management areas, bald eagle or peregrine falcon nesting habitat, and grizzly, moose, or caribou habitat. Reaches that are protected because of their value to anadromous fish are indicated in Figure 6-3. Complete lists of protected areas can be obtained from the Washington State Energy Office or the Department of Wildlife.

Projects affecting historic or archaeological sites on federally owned or controlled lands must be approved by the Secretary of the Interior, through the National Park Service. During licensing, FERC must evaluate the effect of a hydropower project on these sites and negotiate mitigation agreements with the Executive Director of the Advisory Council on Historic Preservation and with the State Historic Preservation Officer.

6.1.3 Federal, State, and Local Hydropower Permit Requirements

Numerous federal, state, and local laws have resulted in a large number of permit requirements which must be satisfied before a hydro project can be built. A detailed explanation of licensing and permit requirements is contained in the WSEO document *Developing Hydropower in Washington State: A Guide to Permits, Licenses and Incentives*. This section summarizes these permit requirements.

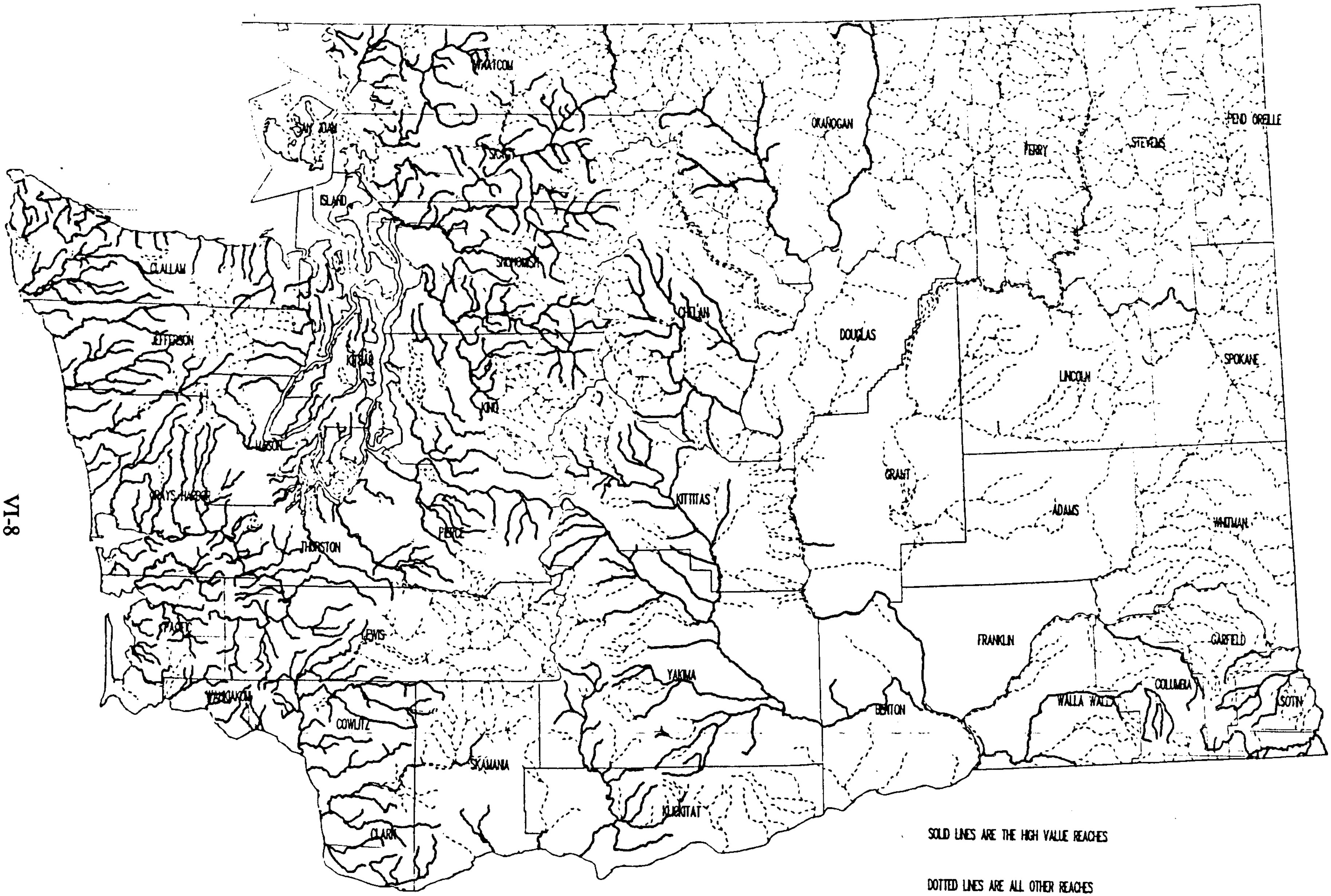


Figure 6-3

REACHES WITH HIGH ANADROMOUS FISH VALUES

Federal laws affecting hydroelectric project development include:

National Environmental Policy Act	42 USC 4321
Fish and Wildlife Coordination Act	42 USC 661
Historic Preservation Act	16 USC 470A
Wilderness Act	16 USC 1131
Clean Water Act	33 USC 1251
Wild and Scenic Rivers Act	16 USC 1271
Endangered Species Act	16 USC 1531
Coastal Zone Management Act	16 USC 1451
Federal Land Policy and Management Act	43 USC 1701
Public Utilities Regulatory Policies Act	P.L. 95-619
Pacific NW Electric Power Planning & Conservation Act	P.L. 96-501
Electric Consumers Protection Act	P.L. 99-495

At the federal level, FERC oversees hydroelectric development. A hydropower developer must obtain a license or an exemption from licensing from FERC if the project will be located on a navigable waterway; affect interstate commerce (a project will affect interstate commerce if it is connected to the regional transmission grid); utilize federal land; or use surplus water or water power from a federal dam. Obviously, few projects do not require FERC involvement since most small projects affect navigable waterways, interstate commerce, or are tied into the utility distribution system.

Federal fish and wildlife mitigation requirements are included as conditions of the FERC license or exemption. Under FERC rules, potential hydro developers must consult with state fish and wildlife departments and with the U.S. Fish and Wildlife Service and National Marine Fisheries Service to determine requirements for mitigation. Past court decisions, such as *Phase 2 of the U.S. vs. Washington*, indicate that anadromous fisheries subject to Indian treaty rights create special environmental obligations upon federal, state, and local governments.

At the Washington State level, the first step in the permitting process is completion of an environmental checklist under the State Environmental Policy Act, or SEPA (Chapter 43.21C RCW) and submittal of that checklist to the lead agency for review. The lead agency then determines whether the proposed development will have a "probable significant adverse impact on the environment." If the lead agency determines that the project will not have such an impact, it then issues a **Determination of Nonsignificance**. If, however, the proposed project poses some risk to the environment, the lead agency will prepare an Environmental Impact Statement (EIS).

To ensure that a hydro facility will not present a danger to life, property, or environmental quality, engineers from the Washington Departments of Ecology, Fisheries, and Game, through Dam Safety Approval and Hydraulic Project Approval permits, may examine project specifications for structural characteristics and design, potential erosion and sedimentation, materials strength, structural geology of the diversion site, and penstock bedding and anchoring. A Dam Safety Approval and a Reservoir Operating Permit are required for dams that impound water to a depth of 10 feet or more or that retain at least 10 acre-feet of storage.

Not every hydroelectric project will require every state permit. Generally, large developments will require up to 20 permits, while a micro-scale project may only need to file a Water Rights Application and a Hydraulic Project Approval. Processing time requirements vary, depending on the complexity of the project and the amount of controversy attracted. If several public hearings or court actions are necessary for any one permit, the length of time for approval will increase substantially.

Local permits necessary for developing a hydroelectric project vary in number, type, processing sequence, application, location, and cost. The most common permits are summarized in Table 6-2.

6.1.4 Water Resource Management Issues

Cumulative Impacts of Hydroelectric Project Development. In February 1983, the National Marine Fisheries Service and the Tulalip Tribes filed a petition with FERC requesting a coordinated proceeding in the Snohomish Basin and for the development of comprehensive data on all of the active sites (about 60) within the Basin. In response, FERC developed a Cluster Impact Assessment Procedure (CIAP) to identify cumulative impacts of such development. Use of the CIAP process resulted in a decision in 1985 to develop an environmental impact statement (EIS) for seven proposed projects. The final EIS, issued in June 1987, concluded that five of the proposed projects would cause significant and unavoidable adverse environmental impacts. While the remaining two projects could be constructed and operated without significant impacts to environmental resources, the prospective developer of one project concluded that mitigation measures recommended by FERC staff would make that project uneconomical.

FERC's EIS was not well received by agencies, tribes, or hydropower developers. The CIAP process is lengthy (taking 15 to 17 months to complete), cumbersome, inflexible, and expensive. Adding the time requirements of the CIAP assessment to the time already needed to complete other federal, state, and local permitting requirements results in an almost insurmountable regulatory burden on the hydropower development community.

Instream Flow and Water Allocation Program Review. In 1986, the Water Resources Program of the Washington Department of Ecology initiated a comprehensive review of its surface water resources planning program. WDOE, in conjunction with an advisory committee, identified policy alternatives for instream flow standards, maximum net benefits tests, interpretation of statutory language, and water resource allocation. The Department of Ecology prepared a programmatic EIS that identified environmental impacts and Ecology's preferred alternatives.

In March 1988, the Washington State Legislature created a Joint Select Committee on Water Resources Policy (2SSB 6724). Formation of the committee was spurred by concerns generated over WDOE's Preferred Alternative, which would set "optimum for fishery" instream flow requirements. The legislation also created the position of an Independent Fact Finder to gather information, solicit opinions, and assist the committee in its review. The Final Report by the Fact Finder was issued in July 1988. The Water Resources Policy Committee is expected to issue a draft report in December 1988, containing recommendations to the full legislature regarding water resource policies for the state of Washington.

State Comprehensive Hydropower Plan. During the 1987 Session, the Washington State Legislature provided an appropriation to the Washington State Institute for Public Policy to complete a study of the need for and feasibility of a comprehensive state hydroelectric and resource development plan. In their December 1987 Final Report, a Hydroelectric Development/Resource Protection Task Force recommended that:

- The state should adopt a set of goals to direct future development of hydropower and river-related resources;
- The state should take steps to enhance the existing state hydropower permit review process; and
- The state, in concert with appropriate interests, should prepare a state comprehensive hydropower plan.

At a minimum, the proposed plan would identify sensitive areas, where hydropower development is likely to conflict with significant environmental values, and less sensitive areas, where development will not conflict with or may enhance environmental values. The task force recommended the following goals for this planning effort:

- Creation of opportunities for balanced development of cost-effective and environmentally sound hydropower projects by a range of development interests;
- Protection of significant values associated with the state's rivers;
- Protection of the interests of the citizens of the state regarding river-related economic development, supply of electric energy, recreational opportunities, and environmental integrity; and
- Full utilization of the state's authority in the federal hydropower licensing process.

Governor's request or committee-introduced legislation will likely be presented during the 1989 legislative session.

Table 6-2

Local Permits for Hydropower Projects

Name	Agency	Conditions	Time
Shoreline Substantial Development Permit	County Planning Department	Required if any part of project is $\leq$200 ft. of applicable shoreline.	4 mos.
Zoning Conditional Use Permit	County Planning Department	Required if project is not in conformance with zoning in master plan.	3 mos.
Surface Water Drainage Approval	County D.P.W.	Drainage plan must be approved before other plan pending permits are issued.	1 mo.
Commercial Building Permit	County Bldg. and Plumbing Department	Applies to construction of a powerhouse.	2 wks.
Temporary Road Closure Permit	County D.P.W.	Needed for construction that would completely close a road to traffic.	1 wk.
Utility Permits	County D.P.W.	Needed for transmission lines and/or intertie.	2 wks.
Sewage Holding Tank Variance	County Health Department	For sewage facilities installed as part of the project on a permanent basis.	2 mo.
Grading Permit	County D.P.W.	For all excavation or filling activities, with exceptions.	1 mo.
Plumbing Permit	County Bldg. and Plumbing Department	Must approve plumbing plans.	1 day
Inter-local Agreement for Construction on County Roads	County D.P.W.	Short-term agreement applies to upgrading and performing maintenance work. Review on county roads used by every overweight cont. equipment.	3 mos. month.

6.2 Municipal Solid Waste-to-Energy, Biomass, and Cogeneration Projects

6.2.1 State Environmental Policy Act (SEPA) Compliance

As for hydropower projects, the Washington State Environmental Policy Act (Chapter 43.21C RCW) requires state and local agencies to evaluate the environmental impacts from proposed waste-to-energy, biomass, or cogeneration projects before issuing any permits or other approvals. Figure 6-4 highlights the key steps in the SEPA process.

When the lead agency receives the completed environmental checklist, it makes a **Threshold Determination** to determine whether an EIS is needed. If the lead agency determines the project will not have a probable significant adverse impact on the environment, it issues a **Determination of Nonsignificance** and sends it to affected agencies and agencies with permits or approvals to issue, to affected Indian tribes, and to interested persons.

Whenever the lead agency determines that there may be a probable significant adverse environmental impact, it must prepare an EIS. The lead agency uses a scoping process to narrow the contents of the EIS. During scoping, the lead agency consults with other agencies and the public. The draft EIS then focuses on any significant adverse impacts that may result from the project, on project alternatives, and on measures to mitigate or eliminate adverse impacts. After considering all comments on the draft EIS, the lead agency prepares a final EIS.

6.2.2 Air Pollution Control Requirements

All biomass-fired, municipal solid waste, oil, or natural gas-fueled cogeneration projects are closely regulated from an air pollution control standpoint.

A New Source Construction Approval is required for construction, installation, or establishment of a new stationary source or modification of an old stationary source of air emissions. The approval must be obtained from the local Air Pollution Control Authority (APCA) or the Department of Ecology. Boundaries of regional air pollution control agencies are shown in Figure 6-5. The New Source Construction application process is summarized in Figure 6-6.

Facilities sited in an urban environment or that could impact off-site sensitive areas (National Parks and Wilderness Areas) are subject to more stringent air quality standards. For example, some urban areas in Washington are designated as non-attainment areas because they do not meet U.S. EPA air quality standards for designated pollutant(s). In these non-attainment areas, the developer of a new source or major modification to a source of carbon monoxide (CO) or volatile organic compounds (VOC) must evaluate alternative locations, plant sizes, processes, and control techniques. The benefits derived from the controlled source must significantly outweigh the environmental and social costs of the other alternatives.

If the proposed facility or major modification would be a "major source" in a non-attainment area, the local APCA or Regional DOE office will require that "Lowest Achievable Emission Rate" (LAER) technologies be employed. If the facility is not a major source then the "Best Available Control Technology" will be required.

Figure 6-4

THE SEPA PROCESS

See SEPA Rules, Chapter 197-11 (April 4, 1984)
for more detailed information

Numbers Refer to Sections of the SEPA Rules

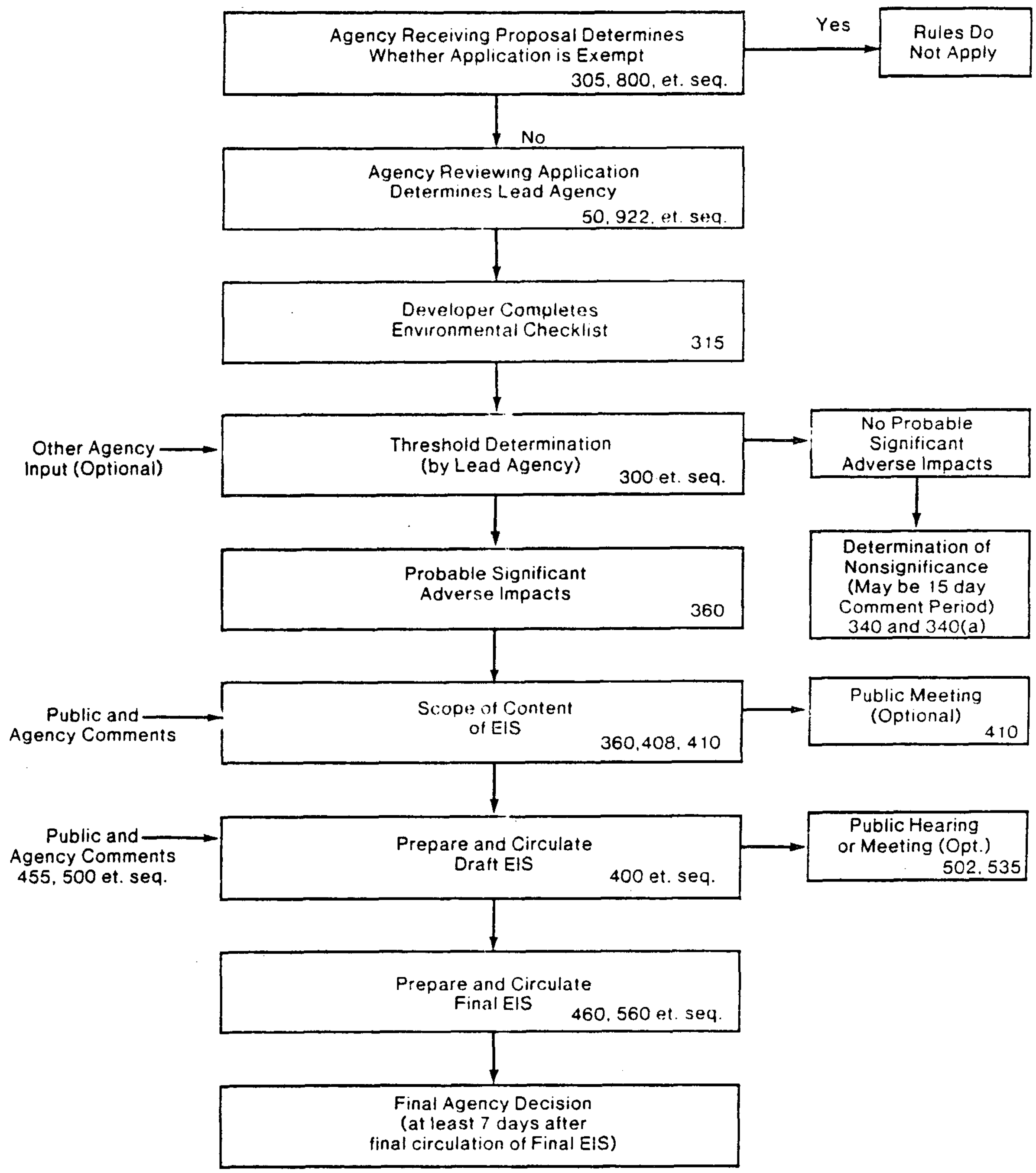
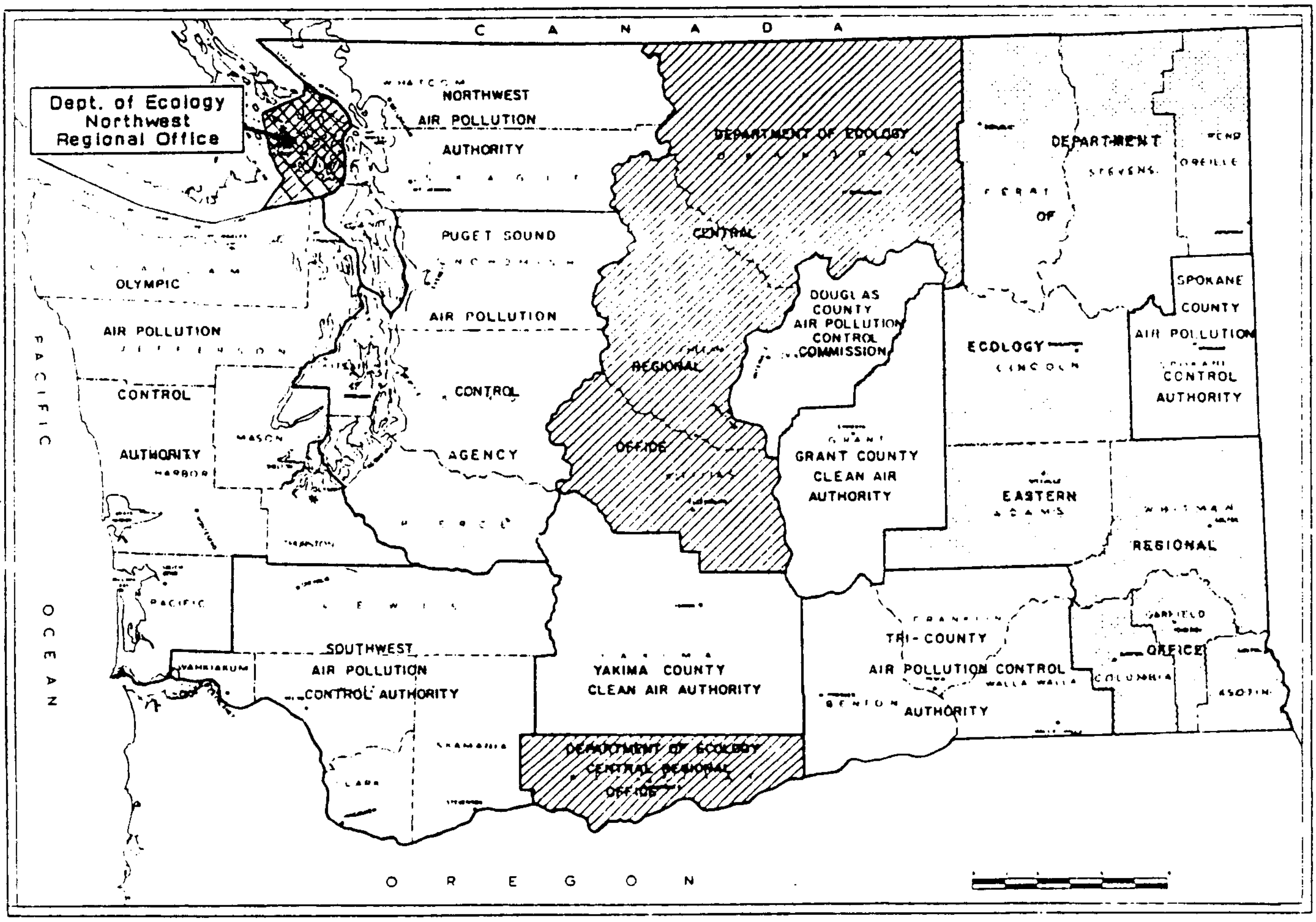


Figure 6-5

Air Quality Areas of Jurisdiction
Regional Air pollution Control Agencies and Department of Ecology



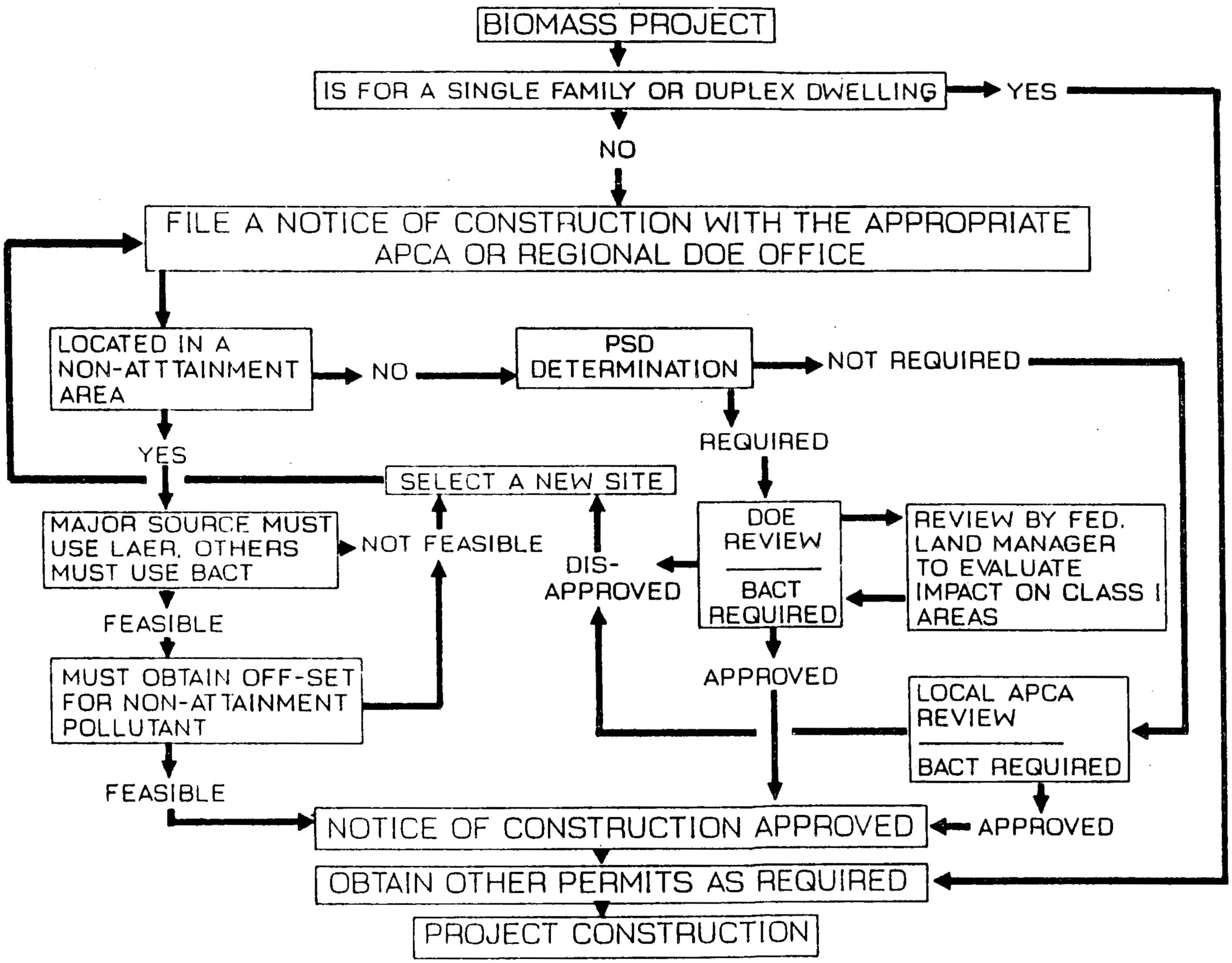


Figure 6-6

Notice of Construction Application Process

In addition, the developer must obtain "off-sets" for any pollutant which is not in compliance under the Federal Clean Air Act. Only then can the project be considered. The total emission from all sources existing at the time of the application for Notice of Construction plus the proposed allowable emissions for the new source must be no greater than the original emissions from existing sources. The local APCA or DOE may require that new total emissions be reduced to less than exiting total emissions in order to achieve the air quality attainment goals of a state implementation plan. Non-attainment areas within Washington State are indicated in Figure 6-7.

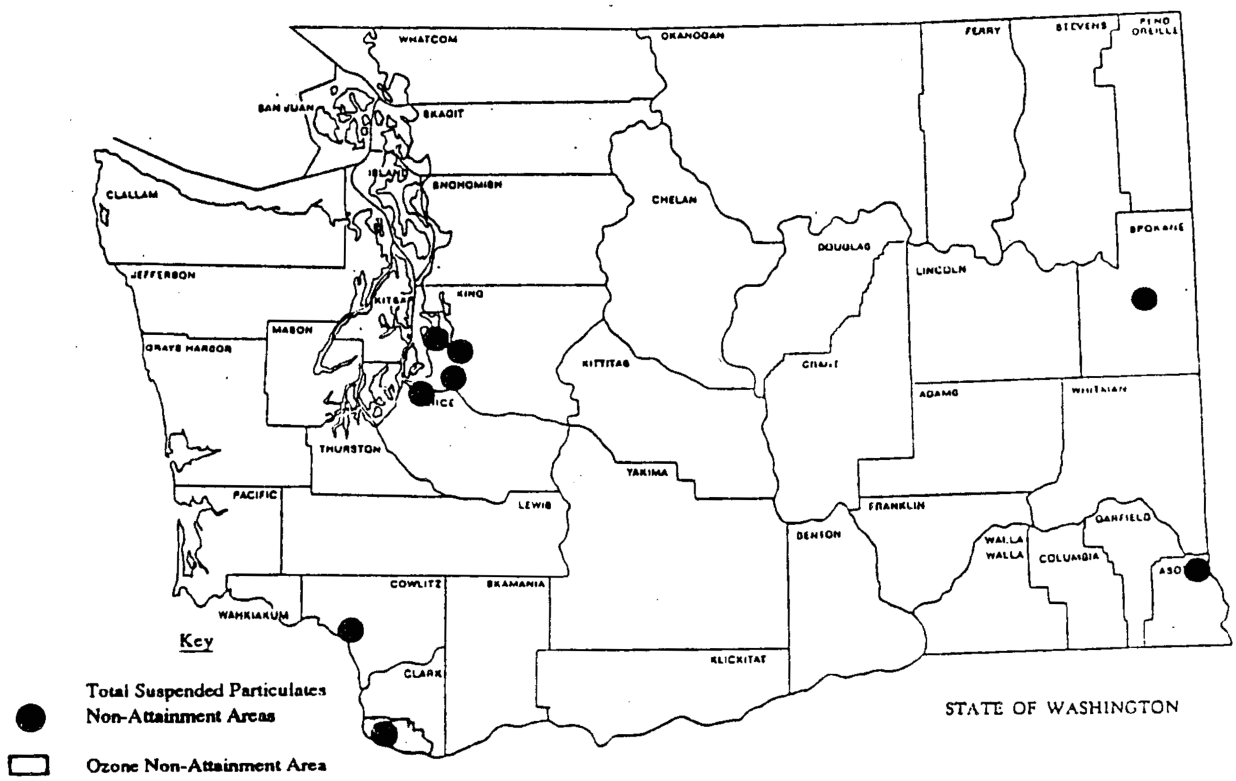
If a proposed project or major modification is in an area that meets EPA standards (attainment area), then a "prevention of significant deterioration" determination is made by local or state air quality control authorities. Projects with emission rates exceeding the values given in Table 6-3 also are generally reviewed at the state level.

Table 6-3

Significant Emission Rates

Pollutant	Significant Emission Rate Tons/Yr.	Lbs./Day	Lbs./Hr.
Carbon Monoxide (CO)	100		
Nitrogen Oxides (NO_x)	40		
Total Suspended Particulate Matter (TSP)	25	500	50
Sulfur Dioxide (SO_2)	40	800	80
Volatile Organic Compounds (VOC)	40		
Lead	0.6		
Mercury	0.1		
Beryllium	0.0004		
Asbestos	0.007		
Vinyl Chloride	1		
Fluorides	3		
Sulfuric Acid Mist	7		
Hydrogen Sulfide (H_2S)	10		
Total Reduced Sulfur (including H_2S)	10		
Reduced Sulfur Compounds (including H_2S)	10		

Figure 6-7
Non-Attainment and Class I Areas in Washington



Non-Attainment Areas For Total Suspended Particulates

- Northern Duwamish Valley
- South Duwamish Valley
- Kent
- Renton
- Tacoma Tideflats
- Industrial Area of Longview
- Port Area of Vancouver
- Clarkston
- Spokane

Non-Attainment Areas For Carbon Monoxide

- Seattle-CBD
- Seattle-Univ. Dist.
- Bellevue-CBD
- Spokane-CBD and Indust. Area
- Vancouver-CBD and Indust. Area

Stations That Have Shown Violation Of The PM 10 Standard**

- Northern Duwamish Valley
- South Duwamish Valley
- Kent
- Tacoma Tideflats
- Lacey
- Yakima
- Wallula
- Clarkston
- Spokane

Class I Areas Of Washington State

- Mount Rainier National Park
- North Cascade National Park
- Olympic National Park
- Alpine Lakes Wilderness Area
- Glacier Peak Wilderness Area
- Goat Rocks Wilderness Area
- Mount Adams Wilderness Area
- Pasayten Wilderness Area

*Source: Department of Ecology
**PM 10 Standard-Consems a limit on particulates less than 10 microns

All projects within attainment areas must comply with the "New Source Performance Standards" (Table 6-4) and are required to use the "Best Available Control Technology." The Air Quality group at DOE determines compliance for projects that must "prevent significant deterioration;" the local APCA or Regional DOE office determines compliance for projects in attainment areas that do not fall into that category.

Table 6-4

New Source Performance Standards

Category	Relevant Emission Limitation
Combination wood- and fossil-fuel-fired and fossil-fuel-fired steam generators	Particulate - 0.10 lb. per million Btu/hr. heat input
	Opacity of 20 percent maximum
	Nitrogen Oxides (NO_2) - 0.70 lb. per million Btu/hr. heat input for wood
Sludge burning portion of sewage treatment plants	Particulates - 1.3 lbs/ton of dry sludge input
	Opacity of less than 20 percent
Electric utility steam generating units	Particulate - .030 lb/million Btu heat input, or
	1.00 percent of potential combustion when burning solid fuel
	Opacity of 20 percent maximum except for one 15 minute period within any 8 hour period
	Nitrogen Oxides - 1.0 micrograms per cubic meter
Stationary gas turbines	Nitrogen Oxides - See 40 CFR 60.332 for this complicated formula
Incinerators (wood)	Particulate - .02 grains/dry standard cubic foot (DSCF) of exhaust gas corrected to 7 percent O_2

6.2.3 Other Permit Requirements

Municipal solid waste-to-energy, biomass, and cogeneration projects are subject to a broad array of other federal, state, and local permitting requirements. Various processes and procedures may apply depending on the size of the proposed facility, characteristics of the fuel used, the combustion and electrical generation technologies employed, and the location of the project. Generic combustion plant permit requirements are given in Table 6-5. Detailed requirements for biomass-fired projects are contained in WSEO's *Guide to Washington's Permits for Biomass Energy Projects.*

Table 6-5

Permits Required for Biomass Combustion Projects

Permit Name/Issuing Agency

Environmental Permit Information Center (DOE)

State Environmental Policy Act (DOE)

New Source Construction Approval (DOE or APCA)

State Waste Discharge Permit (DOE)

Permit to Appropriate Public Waters (Water Right) (DOE)

Burning Permit (Air Quality) (DOE or APCA)

Hazardous Waste Permit (DOE)

On-Site Sewage Disposal Permit
(Flows greater than 14,500 gals/day) (DOE)
(Flows between 3,500 and 14,500 gals/day) (DSHS)
(Flows less than 3,500 gals/day) (CHD)

Special Incinerator Ash Disposal Permit (DOE)
National Pollutant Discharge Elimination System (NPDES) Permit (DOE)

Mill Waste and Forest Debris Dumping Permit (DNR)

Surface Water Drainage Plan Approval (CDPW)

Sewage Holding Tank Variance (CHD)

Noise Control (CHD)

Waste Permit (CHD)

Washington's Environmental Coordination Procedures Act was adopted by the state legislature in 1973. Permits and approvals which must be coordinated under the Act are listed in Table 6-6. To fulfill the mandate of the Act, the Department of Ecology established an Environmental Permit Information Center. Project facilitators inform developers about state environmental permits, public notice requirements, appeal procedures, and required federal and local permits. The permit coordinator can consult with agencies and assemble a preliminary list of required permits, estimated processing times, and potential issues. The permit coordinator can also arrange preapplication meetings with the agencies for consultation and information.

Table 6-6

Environmental Coordination Procedures Act (1973)
Coordinated Permits

Permit	DOE	DOW	FIS	DSHS	DNR	AGR	Regional APCA	County Gov.	City Gov.
Shoreline management substantial development								x	x
Septic tanks	x			x				x	
Flood control zones	x							x	
Miscellaneous permits								x	x
Weather modification	x						x		
New source construction	x						x		
Burning -commercial	x						x		
-agricultural	x						x		
-for seed	x						x		
-forest material	x				x				
-household								x	x
Dams - 10 acre-feet or larger	x								
Reservoirs - 10 acre-feet or larger	x								
Water right (surface or ground)									
-appropriation	x								
-change	x								
Waste treatment facilities	x								
Waste discharge - groundwater	x								
NPDES - waste discharge from point source	x								
Water quality certification	x								
Hydraulics projects		x	x						
Forest practices					x				
Dumping of mill or forest waste					x				
Operating power machinery in dead or down timber					x				
Rendering plant operations						x			
Surface mine reclamation					x				
Removal of floating or beach logs					x				
Oil and gas drilling					x				
Mechanical clam harvest		x							
Public water supplies			x						

Legend:

DOE	Wash. Dept. of Ecology	APCA	Air Pollution Control Authority
DOW	Wash. Dept. of Wildlife	AGR	Wash. Dept. of Agriculture
FIS	Wash. Dept. of Fisheries	DNR	Wash. Dept. of Natural Resources
DSHS	Wash. Dept. of Social & Health Services		

Municipal solid waste (MSW) incinerator ash disposal requires a Special Incinerator Ash Disposal Permit. DOE is currently developing rules and regulations that should be in place by late 1988. Additionally, the fly and bottom ash from wood and coal boilers could potentially be classified as hazardous waste. Thus, an analysis of the fuel must be completed to determine if a waste permit is required. Finally, the installation of all boilers requires a local building permit. The type and location of the project will determine specific permit and zoning needs.

Energy facilities with greater than 250 MW of electrical generation capacity, oil pipelines with an inside diameter larger than 6 inches and longer than 15 miles, and natural gas pipelines with an inside diameter larger than 14 inches and longer than 15 miles also require Energy Facility Site Evaluation Council (EFSEC) review for certification. However, almost all biomass-fired or cogeneration projects are expected to produce less than 250 MW of electrical output.

6.3 Geothermal Power Plants

6.3.1 Environmental Effects and Mitigation Practices for Geothermal Development

Although geothermal resources often are considered a relatively clean energy source which is environmentally benign, adverse environmental effects have occurred in various parts of the world. The degree to which geothermal development affects the environment is, in most cases, proportional to the scale and type of development.

The main environmental factors to consider during geothermal exploration and/or development include the release of airborne effluents; water pollution; earth subsidence; induced seismicity; noise; water supply; solid waste; land use; vegetation and wildlife; and economic, social, and cultural factors. Table 6-7 summarizes these effects for the major steps during exploration and development.

Although it is impossible to predict the type of system(s) which will be encountered in the Cascade or Basin and Range Provinces of the Pacific Northwest, these tables do give an indication of the major differences between vapor dominated and hot water systems.

Airborne Releases. Local air quality impacts due to geothermal development may be significant because of site-specific factors or the cumulative effects of emissions from several facilities in one geographic area. The geochemistry of geothermal resources is complex and is exemplified by variations in concentrations of noncondensible gases from field to field, as well as variations from wells tapping the same aquifer. The major constituent of the noncondensible fraction is typically carbon dioxide, with lesser amounts of ammonia, methane, hydrogen sulfide, mercury, radon, boron, and trace metals. Noncondensible gases escape from the system by condenser gas ejection, cooling tower exhaust, power plant by-passing during shut down, and well venting.

Hydrogen sulfide (H_2S) usually is the most troublesome of the gases because of its objectionable odor even at low concentrations.

Table 6-7

Environmental Matrix for Geothermal Development

	Exploration	Production Drilling & Testing	Parallel Field Development Operations	Plant Construction	Full-Scale Operations
	• Mapping/field studies • Drilling pad construction • Test drilling (shallow and small diameter) • Temporary roads/ traffic • Equipment operation	• Well drilling and construction (production and reinjection) • Well stimulation • Accidental blowouts • Well testing/venting, ponding/reinjection	• Land clearing and roads/vehicular traffic • Gathering systems • Equipment activities • Service living quarters • Water, sewage temporary electricity and other supporting services	• Structures and im--provements • Vehicular traffic/ equipment • Activities • Special construction activities (e.g., blasting) • Electric transmission systems • Supporting services (e.g., water, electricity)	• Cooling towers • Venting (during short-term outages • Well head bleeding • Reinjection • Recharge, stimulation, and re-drilling • Corrosion and scale control • Gaseous, liquid, and solid wastes • Work force movement • Abandonment
Air Quality	H	L/H	L	L	L/H
Water Resources	L	L/H	L/M	L	L/H
Wildlife & Vegetation	L	L/M	L/M	L/M	L
Geology & Soils	L	L/M	L/M	L/M	L
Noise	H	M/H	M	M	L/M
Social, Economic, & Cultural	L	L/M	L/H	L/H	L/H
Health & Safety	L	M	L	L	L/H
Land Use	L	L	L/H	L/H	L

H= High potential impacts; long-term and/or great intensity

M= Moderate potential impacts; major short-term and/or overshadowed

L= Low/negligible potential impacts; minor and/or short-term

Available mitigation measures include equipping the drilling rig with blowout preventers or a scrubber and installing alarms that indicate when H_2S levels reach a hazardous level so that personnel may don emergency breathing equipment. Treatment technologies developed to control H_2S emissions from geothermal facilities include the Cycloform scrubber, Coury heat exchanger process, EIC Corporation's copper sulfate ($CuSO_4$) process, Stretford process, Dow Oxygenator procedure, iron catalyst method, and electron beam induced H_2S removal.

Boron has been found to be a cause of stress and serious damage to certain native trees and shrubs near geothermal power plants at The Geysers. Power plant cooling water at The Geysers is derived from condensed steam, and some boric acid from this condensate escapes from the cooling towers in drift droplets. The boric acid problem at The Geysers could be mitigated by use of other sources of water for cooling or through steam cleaning.

The emission of radon at The Geysers power plant has been studied in detail and while it was concluded that effects from radon emissions are not discernible in the general environment of the power plant, or in downwind communities, recent concerns over the health risks which may accrue from radon exposure make adoption of stringent controls likely.

Although mercury and arsenic are almost always found in trace amounts in geothermal fluids, they appear to be marginal contaminants and no control mechanisms have been required.

In addition to the more common and better understood noncondensible gas constituents mentioned above, detailed source-term measurements at sites of hydrothermal use are needed to determine the levels of other trace elements which may be released. In particular, information on hydrogen fluorides, mercaptans, and volatile hydrides must be obtained.

Water Pollution. Water pollution can occur during geothermal field exploration and testing, production well drilling, construction, or power plant operation.

Muds used for drilling frequently contain petroleum-based additives which can jeopardize the environment if they are allowed to enter either surface waters or groundwater aquifers. To prevent contamination, these substances, together with rock dust and the water used in the drilling operation, must be isolated from surface as well as groundwaters. Blowout protection should be provided and wells should be cased through potable groundwater horizons to prevent mixing of drilling fluids with groundwater. Sumps with an impermeable lining or steel tanks should be used to store drill cuttings and drilling fluids to ensure that these materials do not contaminate surface water.

The most serious water pollution problems, however, usually are associated with power production and the management of spent hydrothermal fluids. Spent geothermal fluids from a hot water flash system are likely to contain large amounts of silica and/or calcium carbonate, together with potentially toxic amounts of NH_3, H_2S, Hg, B, and As.

Of the various methods for wastewater disposal, injection to the geothermal reservoir is considered to be the most advantageous because with a properly constructed and cased injection well, no pollutants in the water will come into contact with surface or shallow groundwater. In addition, injection may also help to maintain the long-term production of the geothermal resource and lessen subsidence. Problems with injection can, however, occur from unusually high amounts of silica and/or calcium carbonate which may cause well-bore plugging by precipitation.

All subsurface disposal of geothermal waters is regulated by the EPA's Underground Injection Control (UIC) regulation and by state drinking water programs developed pursuant to the Safe Drinking Water Act.

Induced Seismicity. Many hydrothermal reservoirs are located in regions with a high frequency of naturally occurring seismic events. A significant environmental issue is whether the withdrawal and/or injection of geothermal fluids may enhance the rate of microseismic events, or even trigger a major earth movement. Experience with fluid injection in a number of nongeothermal situations has demonstrated that induced seismicity can be minimized or prevented by regulating injection pressures.

Land Subsidence. The removal of large quantities of geothermal fluid from a geologic formation may result in land surface subsidence. Permanent and non-recoverable subsidence results from slow and long-term removal of fluids and from the compression of aquitards—such as clay, silty materials, or shale—above or below a reservoir. Subsidence problems can often be mitigated through the injection of spent geothermal fluids which serve to maintain the pressures within a reservoir. However, localized sinking around withdrawal wells and uplifting around injection wells may occur despite an injection program.

Water Supply. Geothermal power production may require the use of large amounts of water for cooling purposes. In a binary system, the geothermal fluid is injected directly to the geothermal reservoir once it has passed through a heat exchanger. Thus, 100 percent of the spent fluid is available for injection, but nothing is available for cooling the chlorofluorocarbon or isobutane used to drive the turbine and an external source of water is required. The development of Hot Dry Rock geothermal projects which require large volumes of water for circulation through the system and for cooling could require even greater amounts of water.

Preliminary designs for a 10 MWe demonstration binary power plant with an evaporative cooling tower indicate that about 346 gal/min of make up water is required for cooling. This amount is substantially greater than that needed by alternative power generation systems and is a result of the low thermal efficiency of a geothermal plant. The availability of such large volumes of water may be a major problem in many arid areas where scarce water resources are needed for other purposes or where all available water has already been appropriated.

The use of dry cooling towers which require very little water may provide a potential solution to the problem of water availability for cooling.

Solid Waste. Solid waste accumulations include drilling muds and rock cuttings from drilling operations; precipitated solids (primarily silica and heavy metal sulfides) from spent geothermal fluids; removed scale from heat exchangers, flash tanks and piping; and sludge from the H_2S abatement process. Composition of waste products will vary according to the physical and geochemical characteristics of the geothermal fluid, type of energy conversion process, type of cooling, and method of H_2S abatement.

Solid wastes which contain hazardous substances should be contained and isolated from possible leaching to ground or surface water, or the leachate may be treated in order to remove hazardous elements and materials. Most wastes will have to be dewatered before they are removed to an approved disposal area.

Noise. A number of significant noise sources are associated with the development and utilization of geothermal resources. These sources include the sound generated by heavy earthmoving and construction machinery, stationary diesel-powered engines and compressors used during well drilling, compressed air releases, turbines, gas ejection, and cooling towers at the power plant; and unmuffled venting of geothermal steam to the atmosphere.

If sensitive receptors such as homes, schools, hospitals, or outdoor recreation areas are located within one-half to three miles of a geothermal development, site noise may lead to public annoyance and complaints. Noise shielding by terrain, forests, equipment, or the lip of the drilling pad can be used to reduce noise levels. The full use of demonstrated noise control technology can reduce most source noise levels to levels acceptable to most quiet rural communities.

Land Use. Land use in the vicinity of high temperature geothermal developments will most likely be changed by the construction of roads, ponds, drill sites, wells, above ground pipelines, powerlines, power plants, and by-product facilities associated with industrial development. Such changes in land use can be most critical if they result in the loss of wildlife habitat.

Land use changes resulting from high temperature geothermal development have a minimum effect upon agricultural and forest production as normally less than 20 percent of a typical lease hold is actually taken out of production by exploration and development activities.

Mitigating measures to reduce adverse impacts on land use from geothermal developments include actions such as land use planning, environmental evaluation, the use of buffers around critical habitats, a sound engineering and construction process, and the restriction of certain activities to noncritical periods.

Vegetation and Wildlife. The effects of geothermal energy development on biological resources can involve direct loss of habitat, disruption of fish spawning and nursery habitats, fisheries danger from water contamination, vegetation damage from airborne pollutants, and habitat disturbances from noise and human intrusion.

Geothermal facilities should, wherever possible, be sited to avoid disturbance of important wildlife habitats such as state and federal refuges, wetlands, or desert areas with rare or endangered species.

6.3.2 Utility Easements

The culmination of any successful geothermal exploration and development project is to deliver the energy to the user. However, the ability to deliver energy to market, either in the form of hot water or electricity is dependent upon both the economics of constructing pipelines or power lines, and also upon the developer's ability to obtain easements across federal, state, local, and/or private lands for the construction of pipelines or electric transmission lines. The lack of existing power lines or lines with available capacity is one of the major economic barriers to geothermal development in the BPA service area.

The ability to obtain easements to cross both public and private lands is simplified if such easements are for "public use" with the public use requirement satisfied by most definitions of a "public utility."

Public utilities are entities (individuals, corporations, associations, etc.) that supply services considered indispensable to the public, and are thus "affected with a public interest." Washington Revised Code § 80.04.010 defines public service companies to include gas, electric, and water companies, among others. Thus, under most utility statutes, both electrical generating and district-sized direct use projects would be considered to be public utilities entitled to apply for easements across state and federal lands for the construction of needed pipelines and electric transmission lines.

Applications for easements are made through the appropriate office of the responsible land management agency. Applications require the preparation of environmental reviews and, if there is a finding of significant environmental impact, an environmental impact statement is required and must be prepared under provisions of the appropriate state or national environmental protection act. If the easement is granted, the applicant will be required to annually pay the fair market value for the interest in the land being acquired.

Easements are also required to cross city or county properties, and may be granted as a public use by the city or town councils, boards, or county commissioners.

If pipelines, transmission lines, or other facilities for developing or using a geothermal resource must cross privately owned lands, the geothermal developer must negotiate with the landowner(s) for the necessary easements, and, if that fails, seek to acquire easements through the right of "eminent domain." Eminent domain is the right of the state or other entities operating in the public interest to take private property for "public use."

In order to use eminent domain, the developer must file a complaint in court describing the proposed public use, the source of the right to such use, the property interest sought, and the present ownership(s). The court must determine whether the proposed use is an authorized public use, and establish the amount of property to be taken. The court may also determine the appropriate compensation to be paid by the petitioner.

6.3.3 Federal Permits

Permits for exploration, drilling, and production on available federal lands are issued by the Department of the Interior and Bureau of Land Management (BLM), pursuant to the Geothermal Resource Operational Orders (United States Geological Survey, 1979).

The permits needed to conduct surface exploration and the drilling of temperature gradient holes to a depth of 150M (500 feet) are issued to an applicant after a finding of no significant environmental impact by the BLM. The applications for such permits are entitled "Notice of Intent and Permit to Conduct Exploration Operations." Notice may be filed for projects on federally managed lands, including lands in KGRAs*, and on lands which are under lease application by another developer. Federal permits that allow drilling of exploratory holes to a depth of 900M (3,000 feet) are also granted to lease holders and to non-lease holders.

All post-lease exploration activities on federal lands are carried out under a Plan of Operation approved by the BLM and the applicable surface management agency. Permit applications for these activities require completion of an environmental review by the responsible surface management agency.

Geothermal production activity on federal lands is regulated by a Plan of Production approved by the BLM. Before this plan can be approved, the applicant must gather environmental baseline data for one year and complete an environmental review. A finding of significant environmental impact during the review process will require the preparation of an Environmental Impact Statement (EIS), pursuant to the National Environmental Protection Act. The EIS is prepared by the BLM and must be approved by all other responsible land management agencies.

*KGRA is defined as "an area in which the geology, nearby discoveries, competitive interest, or other indications would, in the opinion of the Secretary of the Interior, engender a belief in men who are experienced in the subject matter that the prospects for extracting of geothermal steam or associated geothermal resources are good enough to warrant expenditures of money for that purpose." (United State Geological Survey, 1979.)

6.3.4 State Permit Requirements

Detailed information on the geothermal project permit and license processes is given in the WSEO publication *Geothermal Energy Development in Washington: A Guide to the Federal, State, and Local Regulatory Processes*. All pre- and post-lease exploration activities on state and private lands are under the jurisdiction of the Washington Department of Natural Resources or the Department of Ecology.

The state of Washington regulates drilling on all state and private lands, but claims no authority to issue permits related to exploration, drilling, or production on federal lands. However, production permits are issued by the state of Washington for all lands where the state claims ownership of geothermal resources. Thus, the state may require permits for lands of mixed ownership, if it believes those permits are necessary for the conservation of state natural resources.

6.3.5 Local Permit Requirements

Permits at the local level, which may be applicable to geothermal development, are related to project construction. For example, some local jurisdictions are developing regulations to encourage geothermal development. These regulations may include:

- Zoning ordinances which would create a more favorable heat load density for geothermal district heating, and
- A density bonus incentive allowing a greater number of homes per acre for developments using renewable resources.

6.4 Permits for Wind Energy Conversion Facilities

Permits that are necessary for windpower development primarily address land use issues. The Washington Department of Ecology's Environmental Permit Information Center should be contacted to ascertain which permits are necessary for development at a specific site. Permits that may be required, reasons and conditions associated with permit issuance, and approximate time parameters involved in the development of a windpower project are summarized in Table 6-8.

Table 6-8

Permits Required for Wind Energy Conversion Systems

Permit Name	Conditions	Issuance Time
Shoreline Substantial Development Permit	Required if any part of project is ≤200 ft. of applicable shoreline.	4 mos.
Zoning Conditional Use Permit	Required if project is not in conformance with zoning in master plan.	3 mos.
Commercial Building Permit	Applies to construction of a powerhouse.	2 wks.
Temporary Road Closure Permit	Needed for construction that would completely close a road to traffic.	1 wk.
Utility Permits	Needed for transmission lines and/or intertie.	2 wks.
Grading Permit	For all excavation or filling activities, with exceptions.	1 mo.
Plumbing Permit	Must approve plumbing and plumbing plans.	1 day

Special Concerns

Federal Communications Commission Permit (FCC)
Determination of No Hazard (FAA)
Special Permit for Oversize Movements (DOT)
Electrical Work Permit (L&I or CBD)
Noise Control (CHD)
New Source Construction Approval (APCA or DOE)

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