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Implementing PURPA: Renewable Resource Development in the Pacific Northwest

Executive Summary

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Renewable Resource Development Overview

The Public Utilities Regulatory Policies Act (PURPA) of 1979 requires that electrical utilities interconnect with qualifying facilities (QFs) and purchase electricity at a rate based upon their full avoided cost of providing both capacity and energy. Facilities that qualify for PURPA benefits 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.

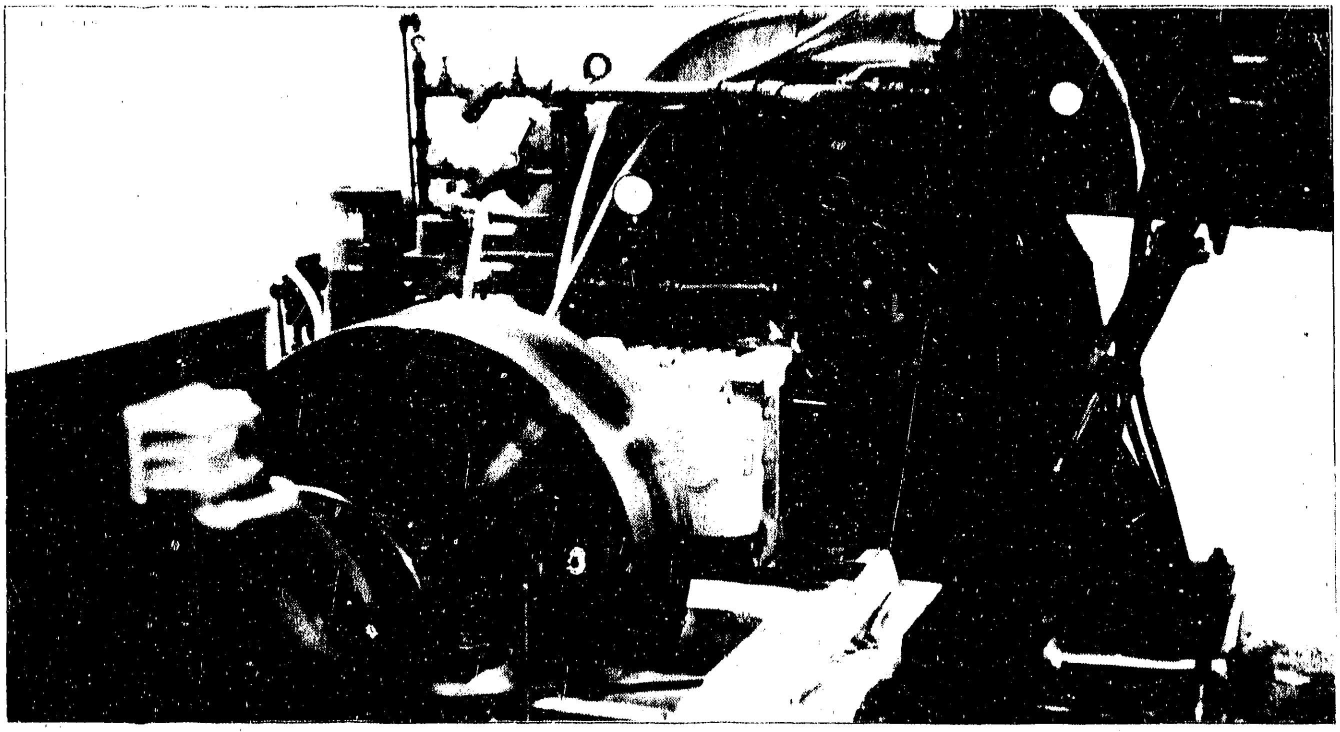
The mandate of PURPA, coupled with the electrical energy deficits projected to occur in the Pacific Northwest by the mid-1980s, led to a resurgence of interest in the development of small, decentralized, non-utility owned and operated generating stations. A variety of would-be developers conducted feasibility studies and initiated environmental permitting and power marketing discussions with appropriate authorities.

Initial avoided costs, based on the costs of owning and operating fossil-fired thermal plants, were high; a hydropower "gold rush" ensued as speculators filed dozens of permit applications to secure development rights on potentially attractive sites. This development climate persisted until the Bonneville Power Administration, Northwest Regional Power Planning Council, and Pacific Northwest Utilities Conference Committee released new forecasts in mid-1982. Predicted growth rates in electrical energy consumption were slashed by including programmatic and price-induced conservation in an econometric forecasting methodology. With the abandonment of traditional "straight line" forecasting techniques, electricity deficits were turned into surpluses. Almost overnight, the region shifted from planning to acquire new generating and conservation resources to disposing of electricity surpluses that were predicted to extend into the mid-1990s or beyond.

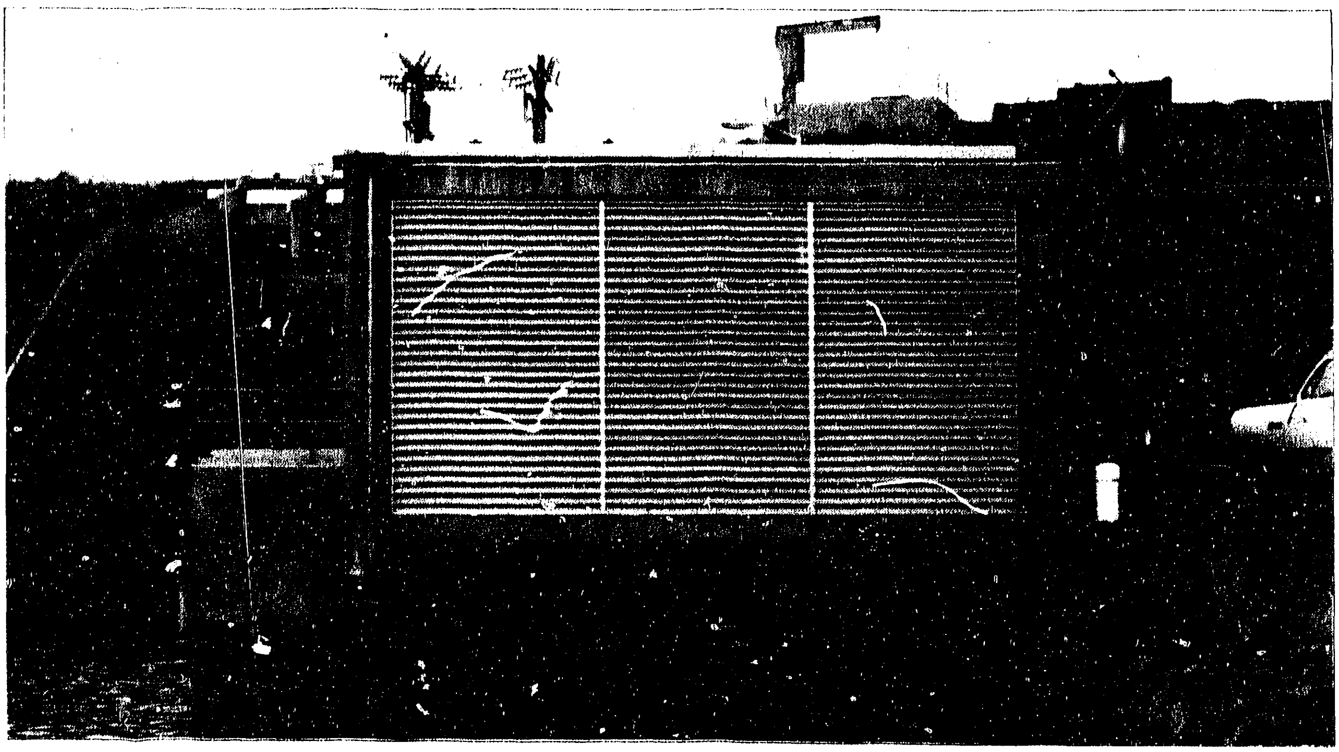
While many proposed PURPA projects fell by the wayside, others were successfully brought on-line. A variety of public and private sector developers, including cities, counties, irrigation districts, utilities, ranchers, timber companies, and food processing plants, successfully negotiated PURPA-based, or "share-the-savings" power purchase contracts. Other developers "run their meter backwards" or provide energy to their local utilities at the same rate that would otherwise be paid to Bonneville.

One hundred and twelve small-scale hydroelectric projects with an aggregate of 320 MW of nameplate generating capability, 21 cogeneration plants with 178.7 MW of capacity, and 8 municipal solid waste, waste coal, or wind-powered plants providing 147.3 MW of output were built during the 1980s in

One-hundred and twelve small-scale hydroelectric projects with 320 MW of nameplate generating capacity came on-line in the Northwest region during the 1980's. The projects are situated at existing dams, water supply pipelines, irrigation drop structures, or operate in a run-of-the-river mode.



Turbine/generator set from the 650 kW Woods Creek Hydropower Plant



Powerhouse for the 6.2 MW PEC 22.7 project in Washington State

the Pacific Northwest. Summaries of developed capacity by generating technology and state are given in Table 1.

PURPA underwent a maturation process during the decade of the 1980s. Initially, there was resistance from the utilities, eagerness to build from proponents of renewable resource power plants, and uncertainty with respect to new ways of planning and doing business. Legislation and regulations were put in place to allow PURPA to work effectively. Initial laws established ownership rights and expanded the enabling powers of public authorities. Financial incentives for renewable resource and cogeneration projects were created. Permitting procedures were streamlined and, in some cases, simplified.

As regulatory agencies obtained experience with both the site-specific and cumulative impacts of development, and as the need for new generating resources diminished, laws and regulations were passed that were designed to ensure that development would proceed in an environmentally acceptable manner. For example, the Northwest Power Planning Council implemented its "Protected Areas" program, which designates stream segments as off-limits to hydropower development in order to protect and preserve anadromous and resident fishery values and wildlife habitat.

Under a three-phase contract with the Bonneville Power Administration, the Washington State Energy Office, in consultation with the energy agencies of the other Northwest States, examined the effectiveness of the PURPA acquisition

Table 1

Renewable Resource Development In the Pacific Northwest During the 1980s (Number of Projects/Megawatts) Generating Technology

	Hydroelectric	Cogeneration	Municipal Solid Waste	Wind	Waste Wood or Coal	Total by State
Washington	21/84.2	8/39.8	3/50.5	—	1/42.5	33/217.0
Oregon	17/86.7	7/65.0	1/11.3	1/1.2	—	26/164.2
Idaho	62/134.2	6/73.9	—	—	—	68/208.1
Montana	12/15.0	—	—	1/0.3	1/41.5	14/56.8
Totals:	112/320.1	21/178.7	4/61.8	2/1.5	2/84.0	

Grand Total: 141 projects with 646.1 MW of generating capacity approach within each state. Generating resource potentials were estimated while emerging activities such as least-cost planning and competitive bidding were examined. In addition, this research summarized relevant information concerning enabling authorities, financial incentives, and required environmental protection measures. Also considered were resource development activities as well as power purchase prices and contractual provisions.

A separate PURPA acquisitions report is now available for each state. Available reports include the following:

- *Power Sales to Electric Utilities: PURPA Qualifying Facility Development in Washington State*
- *Development Framework for PURPA Resources in Oregon*
- *Development of PURPA Qualifying Facilities in Idaho*
- *Regional Generating Resources Assessment: Montana Report*

Executive summaries of the four state reports follow. BPA also funded the state energy agencies to conduct case studies of the resource development process. A case study document, *PURPA Resource Development in the Pacific Northwest: Case Studies of Ten Electricity Generating Powerplants*, describes the development process for a variety of generating technologies, details developer interactions with regulatory agencies and power purchasers, and summarizes lessons learned.

Case studies were completed for 10 facilities with an installed cost of $205 million and a cumulative nameplate capacity of 111.5 MW. The case studies contain equipment, installation, and maintenance costs, outline power marketing considerations, identify potential environmental impacts, and summarize mitigation approaches and summarize practices used.

The third phase of the "PURPA" project consists of an examination of competitive bidding resource acquisition procedures used outside of the Northwest. An issue paper, *Meeting the Northwest's Energy Needs through Competitive Bidding*, examines resource acquisition goals and objectives, illustrates competitive bidding program issues and choices, and makes recommendations regarding the structuring of a Northwest competitive resource acquisition program.

Summary of Renewable Resource Development Activity by State

Washington

The Washington Utilities and Transportation Commission (WUTC) responded to PURPA by establishing regulations that address relationships between investor-owned electric utilities and small power production facilities. Following PURPA's lead, Chapter 480-105 of the Washington Administrative Code requires that electrical energy be purchased at a rate based upon full avoided costs defined as "the incremental cost 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 WUTC requires that utilities establish their avoided costs on a cents per kilowatt hour basis during peak and off-peak periods, and that these costs be determined for the current year and each of the next 5 years. Avoided costs are computed for blocks of not more than 100 MW for utilities with peak demands exceeding 1,000 MW, and in blocks of not more than 10 percent of the peak demand for smaller systems. Standard rates for purchases were put into effect for purchases from QFs with a design capacity of 100 kW or less.

Early state PURPA-related legislative activity involved the creation of an enabling authority, removal of barriers to resource development, the establishment of financial incentives for project construction, and simplification of the permitting process. At the same time, the legislature enacted environmental protection laws that attempted to balance the concerns of resource developers and environmental activists.

In 1979, the legislature declared that geothermal resources were distinct and separate from mineral or water resources and were the private property of the party holding title to the surface lands above the resource. Laws governing irrigation districts were clarified to authorize the incorporation of hydropower facilities into water projects and allow the issuance of revenue bonds. The legislature also focused on protecting solar access through comprehensive planning and solar easements, and established business and occupation tax credits and property tax exemption financial incentives for the development of cogeneration projects.

During 1980, two financial incentives were enacted to encourage electric and gas utilities to invest in renewable resources and conservation. The first incentive directs the WUTC to allow a 2 percent higher rate of return on the common equity portion of investor-owned utility investments in conservation, cogeneration, and renewables projects. The second incentive, applying to both investor-owned and public utilities, allows a deduction from gross income, subject to the states' public utilities tax.

By 1981, interest in geothermal development had increased, and the legislature directed that a portion of federal lease rentals and royalties returned to the state be used to encourage geothermal development. The cogeneration tax credit rate was increased in 1982, and a "one-stop" permitting process that supports resource development was encouraged. In 1983, municipalities and special districts obtained the authority to establish district heating systems using a variety of heat sources and private sector developers, including investor-owned utilities involved in district heating, were deregulated. Subsequently, municipal water and sewer utilities were authorized, subject to some restrictions, to develop hydroelectric power on their systems.

Management of municipal solid waste has been the most recent energy/environmental challenge to the state. In 1987, the legislature provided a regulatory framework for dealing with ash residues from solid waste incinerators.

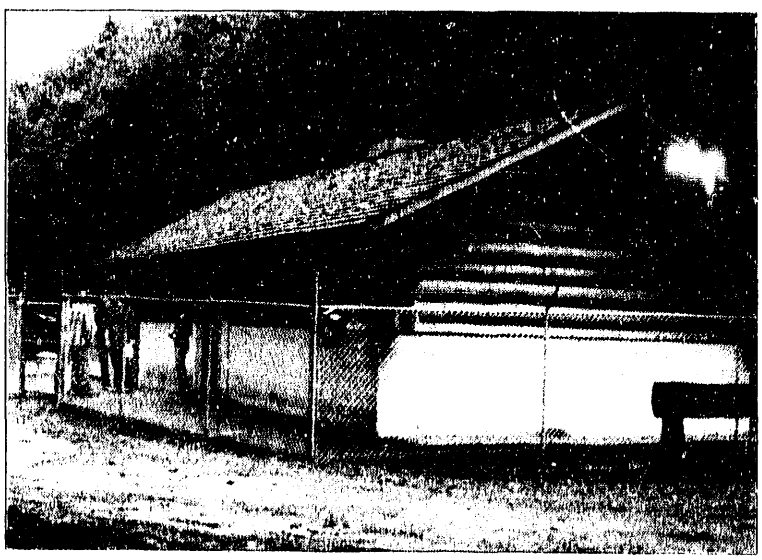
In the early 1980s forecasts of an electrical supply deficit led to high avoided cost estimates by Washington's investor-owned utilities. A hydropower "gold rush" ensued, with speculative activity and vigorous competition leading to the filing over 250 federal preliminary permit applications by 1982. When the predicted electricity deficit failed to materialize and was, in fact, transformed into a 2,000 aMW (average MW) regional surplus, avoided costs tumbled and interest in hydropower development waned.

In Washington State, neither standard power purchase prices based upon a proxy "avoided plant," standard contracts, nor a standard offer process were used. Instead, a variety of power purchase contracts with investor-owned utilities, public utility districts, and municipally owned and operated utilities have been negotiated by developers of qualifying facilities. With a hydropower-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. Terms and conditions from 14 power sales contracts are summarized in *Power Sales to Electric Utilities: PURPA Qualifying Facility Development in Washington State.*

In the state of Washington, 21 small-scale hydroelectric projects with a combined generating capacity of 84 MW, 3 solid waste-to-energy facilities with 50 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.

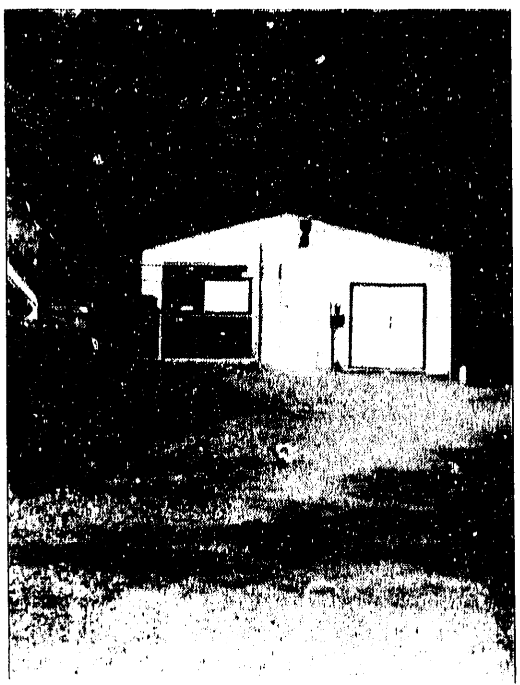
Diversion structure for the 1.5 MW Lilliwaup project

Hydroelectric Projects. Typically a low weir or dam diverts water through fish screens into a pressurized pipeline or penstock. The penstock conveys this water to a powerhouse containing water turbines, generators, control equipment, and electrical switchgear.



Powerhouse for the 1.0 MW Hutchinson Creek facility

Penstock for the 1.5 MW Lilliwaup project



1.8 MW Rocky Brook Creek powerhouse

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 a price-induced decrease 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 late 1980s, the WUTC required investor-owned utilities to prepare and submit least cost plans on a biennial basis. Use of this comprehensive capacity expansion planning tool forces utilities to consider all potential opportunities, both demand and supply-side, to meet future electrical requirements. Least cost planning, however, does not dovetail well with a PURPA-based acquisitions approach, where a utility is obligated to acquire all qualifying resources offered to them.

The WUTC issued a notice of inquiry regarding competitive bidding as a resource acquisition mechanism and followed in April 1989 with Chapter 480-107 WAC, a set of regulations governing the purchases of energy by investor-owned utilities from QFs, independent power producers, and conservation suppliers. The WUTC process requires the utility to determine and file a schedule of avoided costs with future avoided costs adjusted to reflect the most recent bidding solicitation.

The investor-owned utilities are required to solicit bids for energy and power savings with a competitive ranking procedure, at least every 2 years, using price and non-price factors to determine the group of bidders with which the utility will finalize long-run purchase contracts.

In response to the WUTC order, Puget Power issued a *Request for Proposals for Long-Term Purchase of Resources from Commercial and Industrial Conservation and Generating Facilities* in June of 1989. The solicitation was for a 100 aMW block of energy. Puget Power required respondents, in addition to stating their bid price, to submit information describing the project, its output characteristics, and the likelihood of successful completion. The developer had to provide information on positive and adverse environmental effects and permit and license requirements; estimate construction and operating costs; provide a financing plan and a fuel supply and availability statement; and indicate how security would be provided for front-loaded payments.

Puget Power completed its project ranking by the end of February 1990. It had received 41 proposals representing over

Falls and powerhouse for the 270 kW Deep Creek project

1,200 aMW of potential resources. Key criteria that were used to make the final selection included:

- The sponsor's ability to bring the proposed project to commercial operation
- The ability of the proposed project to operate throughout the proposed term at the bid prices
- The bid price relative to the avoided cost ceiling and other proposals
- The level of economic risk placed upon the utility

The preliminary award group consists of 5 conservation bidders supplying a total of 9.6 aMW and 3 supply-side projects with 127 aMW of output. Winning bidders are the following:

Conservation:

Abacus	4.0 aMW
Northwest Cogeneration	1.2 aMW
Puget Energy Services	3.2 aMW
Sycom Corporation	0.7 aMW
Washington State Energy Office	0.5 aMW

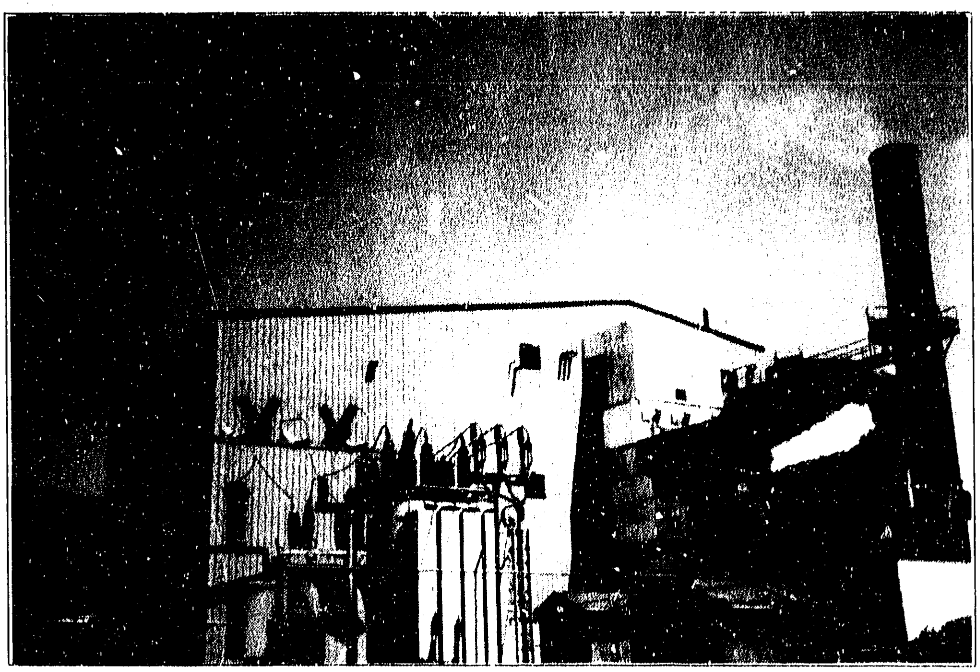
Generation:

Enserch Dev. Corp.	(Natural-gas-fired cogeneration at Georgia-Pacific Mill, Bellingham, WA)	100 aMW
Trans-Pac Geothermal	(Surprise Valley, CA)	10 aMW
Wheelabrator Pierce	(Pierce County municipal solid waste-to-energy, Tacoma, WA)	17 aMW

Oregon

The evolution of PURPA in Oregon is complex. On the whole, Oregon embraced an attitude of activism and support for renewable energy resources and conservation. The Oregon legislature and the Public Utilities Commission (PUC) took steps to make it clear that Oregon, unlike some states, welcomed the concepts embodied in the PURPA statutes. However, utilities were reluctant partners to QF transactions as no earnings accrue from purchased power.

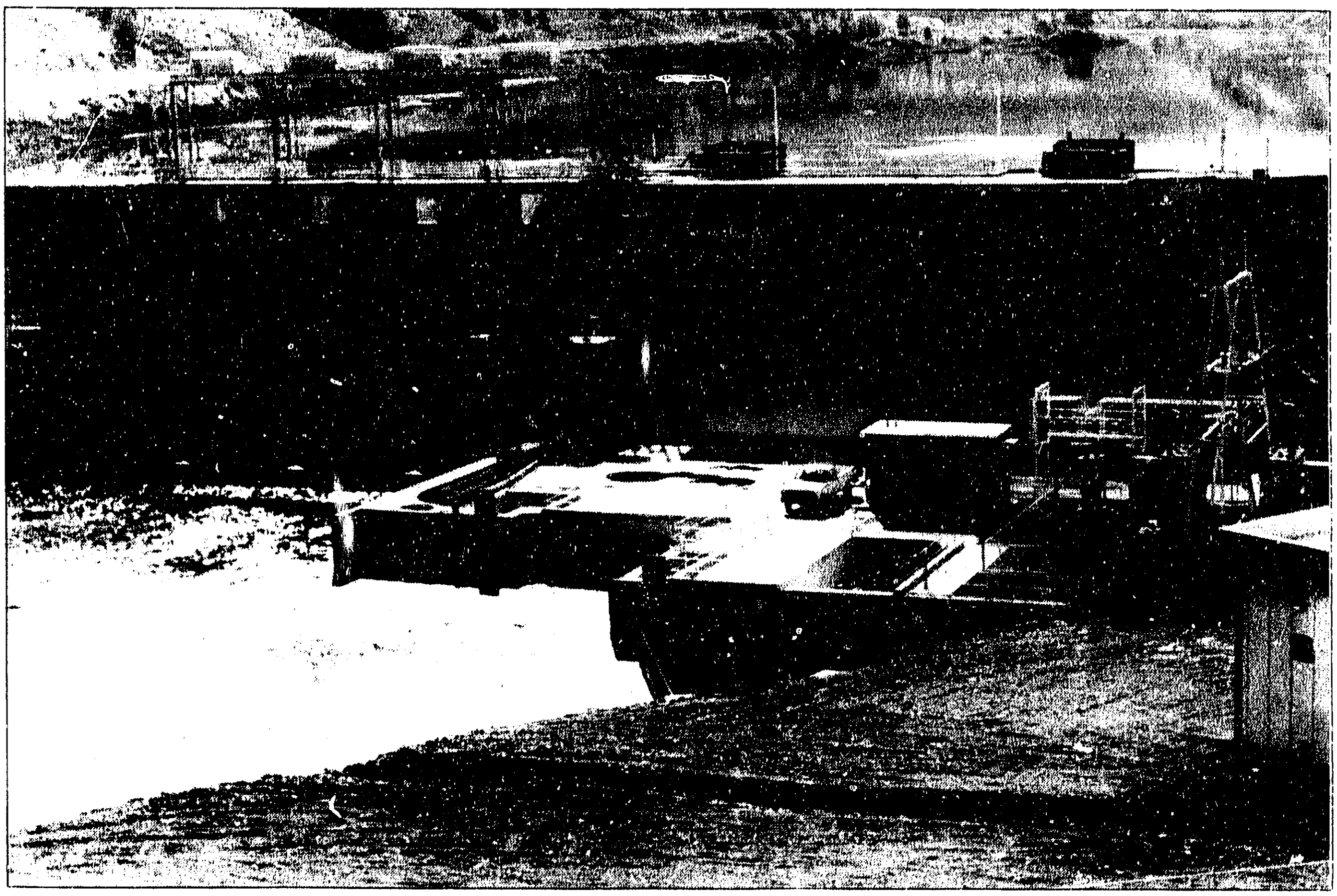
In 1979, Oregon's mini-PURPA statute was enacted "to encourage cogeneration and small power production." The Oregon Department of Energy's Small-Scale Energy Loan Program (SELP) was also started, under which municipal corporations and small businesses could obtain long-term loans for solar, wind, geothermal, biomass, or water resources energy projects. The Alternative Energy Development Commission prepared a comprehensive plan to develop Oregon's renewable resources. Domestic water supply, drainage, water improvement, and irrigation districts were authorized to sell revenue bonds for hydropower projects. Finally, a 35 percent business income tax credit was established for capital costs of wood, municipal solid waste, and solar, wind, water, and geothermal energy facilities.



Seven cogeneration projects with 65 MW of generating capacity recently came on-line in Oregon. Pictured is the 7.5-MW Prairie Wood Products project. Electricity produced from this facility is sold to the Oregon Trail Rural Electric Cooperative.

Support for renewables generation continued through 1983. In 1981, a number of legislative refinements were enacted that allowed development to proceed smoothly. PURPA provisions being challenged in federal court were incorporated into state statutes to insulate local developers against national uncertainties. SELP was revised to include authorized tribal organizations under the definition of "municipal corporation." New dams greater than 25 feet in height with an annual flow exceeding 2 cubic feet per second had to be designed such that hydroelectric generation could be added in the future. Requirements and contents of easements to protect access to wind energy were created. Marion County was given waste management authority allowing a proposed waste-to-energy project to proceed.

In 1981, and again in 1983, Oregon's mini-PURPA statutes were amended to address wheeling. All utilities had "to make a good faith effort" to wheel for qualifying facilities. Utilities were required to pay the greater of their own avoided cost or an index rate equal to the lowest PUC-approved avoided cost for similar electric deliveries to a PUC-regulated utility. This



The Warm Springs Indian Tribes used SELP to finance half of this $31 million, 19.6-MW hydroelectric plant on the Deschutes River.

rate was defined as the cost of generation from the highest-cost base load plant serving Oregon customers and owned and operated by an Oregon utility.

By 1984, it was apparent that the region was entering a period of energy surplus. Utility avoided costs began to tumble; complaints about the environmental impacts of hydroelectric development reached a high level; and attitudes favoring renewable resource development hardened. In 1985, bills were introduced to ban all hydropower development no new dams would be allowed. While these bills failed, six bills containing many restrictive statutes did pass.

PURPA became a prime target of those opposed to hydropower development if the market for power was eliminated, new projects could not be built. The business tax credit was revised to exclude hydropower and geothermal projects exceeding 1 MW in capacity. Some river reaches were declared off limits; water districts' authority to develop hydroelectric projects was reduced; and developers had to pay fees into a fund to pay state agencies' costs for fish and wildlife protection. New groups were formed to oversee water issues and the "one fish rule" was adoptedno hydro project could harm a single anadromous fish. To obtain pe mits, resource developers had to fully restore, enhance, or improve the anadromous fishery and cause no net loss of resident fish or recreational opportunities.

By 1987, electrical utilities nationwide were pushing for changes in PURPA. Common themes were that the utilities wanted PURPA benefits for themselves and that the rates paid QFs are too high. Some eastern utilities were attempting to capture economic benefits by using competitive acquisition approaches. A late 1986 rate increase request by CP National of 34.3 percent, due to cogeneration contract costs, spawned controversy: bills attempting to terminate or undo QF contract obligations, and PUC proceedings. Ultimately, CP National's Oregon territory was sold to the Oregon Trail Electric Consumers Cooperative.

The 1987 session concluded with a legislative resolution SJR 27 which noted that QF contracts threatened the ratepayers of investor-owned utilities; the resolution directed the PUC to hold hearings and conduct a study. An incentive rates bill was also passed, under which utilities were empowered to offer special discounted rates to large industrial users to prevent the installation of on-site cogeneration.

In addition to the legislature, Oregon's PUC exerted a major influence on the renewable resource development process. Throughout the 1980s, the PUC reflected the legislature's mandates and was instrumental in establishing policies and practices that affected the development of renewable resource projects. Early PUC orders required utilities to pay full avoided costs for QF output and allowed levelized payments to begin upon delivery of electricity. An interim standard rate, based on retail rates, was enacted for QFs with less than 100 kW of generating capacity.

In 1983, the PUC required the removal of "regulatory out" or reopener clauses from power purchase contracts and defined the time at which the obligation to purchase power from a QF is incurred. As avoided costs were declining, utility delays in the signing of a power purchase contract meant significant losses in revenues to project developers. The PUC interpretation was later modified by a court decision to be that time when the QF tenders a valid offer that obligates it to provide power.

Ultimately, 26 projects, with an aggregate installed capacity of 164 MW, were brought on-line in Oregon. Because unregulated, consumer-owned utilities (COUs) base their avoided costs on Bonneville wholesale rates, all independent power was purchased by investor-owned utilities. The majority of the power purchase contracts were signed in 1982 and 1983, when avoided costs were several times the COU rate, depending on resource expansion plans. Few new contracts have been signed since 1985. The average cost of QF output was 5.91 cents/kWh in 1986, adding 0.08 cents/kWh to average retail rates.

The availability of SELP financing was instrumental in fostering renewable resource project development within Oregon. Funding in the amount of $116 million was provided for 15 projects with a combined nameplate generating capacity of 94 MW. These projects are expected to produce 43.9 aMW of electrical energy.

In 1986, the PUC declared that it would not approve utility "incentive rate" contracts to deter cogeneration or transport gas contracts with cogenerators without first conducting a cost-effectiveness review. The PUC reserved the right to restrict cogeneration because of concerns involving the welfare of captive customers when fuel switching or self-generation is involved. As of 1988, ten rate discounts were in effect to shut down, delay, or prevent the installation of approximately 133 to 150 aMW of on-site generation.

Oregon's PUC is currently examining competitive bidding as a preferred resources acquisition approach. A staff issue paper on this topic should be completed by mid-1990.

Idaho

Prior to the passage of PURPA in 1978, cogeneration and small power production, in which energy is sold to a utility, were extremely uncommon in Idaho. Idaho Power's standard offer for purchase of power from others was less than 2 mills/kWh. Consequently, the only small power development activity involved very small, non-utility interconnected projects that produced energy for on-site use.

In Idaho, PURPA did not bring about a rash of activity at the state level to implement the new law. No "mini-PURPA" laws were introduced or believed to be required. Existing laws, and in some cases the absence of law, were sufficient to enable the development of renewable resource and cogeneration projects to proceed. In fact, most new legislation in Idaho was regulatory in nature with the intent of placing restrictions on new development, rather than encouraging it. Such legislation was in response to the effects of PURPA, rather than to PURPA itself.

As for energy policy, the first Idaho State Energy Plan was completed in 1982. (It hasn't been updated since.) The plan places a high priority on conservation, renewable resources, and generating resources with high fuel conversion efficiencies. Much state legislation already existed or was implemented after PURPA to enable, guide, or restrict development of electrical generating resources. Cities and other political subdivisions were given the authority to issue revenue bonds, acquire and dispose of excess energy, and exercise the power of eminent domain. Geothermal leasing policies were put into place and resource assessment was authorized; a state hydropower siting process was designed for projects with less than 15 MW of capacity; and cities were allowed to create and operate district heating systems.

The key player with respect to implementing PURPA in Idaho was clearly the Idaho Public Utilities Commission (IPUC). The IPUC early on stated an objective, which has remained consistent, to "do all in our power as a regulatory agency to remove institutional barriers and to encourage development of cogeneration and alternative energy sources." Actions taken by the IPUC to encourage QF development include:

- Requiring that utilities pay full avoided costs for energy purchased
- Adopting a clearly understood "surrogate avoided resource method" to determine avoided costs
- Allowing seasonalized rates and ruling that all capacity with long-term contracts, no matter how small, has value and should receive capacity payments
- Insisting on allowing simultaneous purchase and sales
- Encouraging long-term contracts

- Adopting levelized power purchase contracts, even during periods of surplus
- Encouraging utilities to finance up to 50 percent of project costs
- Encouraging gas companies to become involved in cogeneration facilities that use gas as a fuel
- Rejecting conservation as a reliable and securable proxy avoidable resource
- Amortizing the payment to utilities by QFs for interconnection and metering costs
- Front-end loading of payments by utilities to better meet the debt service schedules of small power producers.

The IPUC has also become involved with security provisions and the posting of liquidated damages to protect utilities against the event of developers walking away from projects that were overpaid due to front-loaded contracts. Every power project is liable for the full level of overpayment in the event of default. While wheeling has not been a major issue, with only one agreement negotiated between a utility and a QF, it could become a major issue in the future as developers examine the feasibility of using Idaho energy resources to meet the needs of out-of-state customers.

In Idaho, mostly wood-waste and hydropower projects were developed. Sixty-two small-scale hydroelectric projects producing a total of 134 MW and 6 wood-fired cogeneration facilities producing approximately 74 MW have been developed. Whether a specific project was developed or not depended mostly on its cost effectiveness, not on state tax credits or financial incentive programs.

Montana

Montana's *Regional Generating Resources Assessment* report examines generating resource development within Montana during the 1970s and '80s. The first section of the report discusses issues and controversies that have arisen concerning the development of PURPA-based small power production facilities. The second section relates Montana's experiences with resource development and resource developers. The final section addresses lessons learned and identifies special concerns that may arise as the need for additional resource development approaches.

One the whole, Montana's experience with PURPA parallels that of other states. Initially there was resistance from the utilities and eagerness from enthusiasts for small renewable energy systems, coupled with uncertainty among developers, regulators, and utilities as they began to develop new methods of planning and doing business.

The utility industry in Montana is dominated by Montana Power, which is responsible for roughly 60 percent of total electricity sales and virtually all of the QF purchases in Montana. Rural electric cooperatives, which are not regulated by the Montana Public Service Commission, argue that their avoided cost is simply their wholesale rate roughly 22 mills/kWh for western Montana cooperatives purchasing from BPA, and even less for eastern cooperatives purchasing from the Western Area Power Administration.

The Montana PSC initially selected a methodology for setting avoided costs that established a rate considerably in excess of the value of QF power to the utility. A hydropower "gold rush" ensued and enthusiasts began promoting wind farm development. In 1985, when the PSC decided to revise its avoided cost methodology, a flood of proposed contracts appearedresource developers wanted to secure high purchase prices while a window of opportunity was open. Since 1985, avoided costs have decreased about 38 percent in nominal terms.

Montana Power ultimately signed power purchase contracts with 42 small power producers offering 113 MW of generating capacity. As of early 1990, only 13 small-scale projects providing 15 MW were operational. An additional 41.5-MW project is under construction. Facilities that were counted on to produce over 70 MW of power were never built or had ceased to operate.

Significant lessons learned include the following:

- It is important to use the correct methodology to set avoided cost rates. QF development will not occur at the appropriate time or rate if an incorrect price signal is given.
- Security requirements for levelized contracts can be extremely burdensome and damage a project's cash flow. Care must be taken to protect the utility without eliminating the ability of the developer to finance and maintain the project.
- Inexperienced developers will have problems bringing projects on-line. Many projects were poorly conceived and badly managed. Typical problems include developers being overly optimistic regarding their projects and their own capabilities, faulty or uncritical feasibility analyses, inadequate engineering and maintenance, unreliable equipment, poor site selection, and inability to obtain financing or post required financial security.

Phantom PURPA resources projects for which contracts have been signed but on which little or no progress is made towards completion or delivery of power can create an additional element of uncertainty in the utility's planning process. First, avoided costs are suppressed as the need for additional power appears further off in the future than is actually the case. Second, conservation programs or other cost-effective acquisitions may be deferred because of this apparent abundance of resource.

Additional lessons learned are that it is important to not treat power contracts for conceptual projects as firm resources, to specify the conditions under which schedules may be stopped by either party, and to create penalties associated with not meeting contractual deadlines or development mileposts.

Montana believes that its coal reserves, wind, biomass, and small hydro potential will be attractive to future resource developers. However, Montana's DNRC points out that the Montana transmission grid was designed to serve Montana's loads and is unlikely to have substantial excess capacity available for conveying large blocks of power to the Northwest. Transmission is likely to become a major issue if substantial resource development requires the construction of additional power lines. Few feasible east-west corridors exist through the Rocky Mountains, and all are environmentally sensitive. In terms of lead times, environmental requirements, and permitting costs, transmission lines may be comparable in difficulty to the development of a major energy resource.

Finally, Montana's experiences with phantom resources and poorly constructed projects causes it to be cautious regarding reliance or dependence upon a competitive acquisition process to meet regional energy needs. Bidding is perceived as experimental until experience indicates that it is an effective way to acquire firm resources without exposing the purchaser to excessive or undue risks. Montana points out that the value of a resource depends on many characteristics other than price, including the timing of power deliveries relative to the buyer's load curve, degree of dispatchability, arrival date, firmness of the power being supplied, fuel supply certainty, reliability of the technology, project location, external societal costs, and the need for new transmission lines.

Montana is also concerned that regional acquisitions be in accordance with least-cost planning principles and that the acquisition procedure mesh with state siting and regulatory requirements in a timely manner. Finally, the DNRC points out that the future is unknown and unknowable. A plant that looks like a good bet under today's assumptions may be a disaster tomorrow. Loads may prove volatile, environmental mitigation may be more burdensome than expected, and interest rates can skyrocket. Risks can only be minimized through early recognition and flexibility in planning, financing, project design, contractual arrangements, and power plant operation.

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