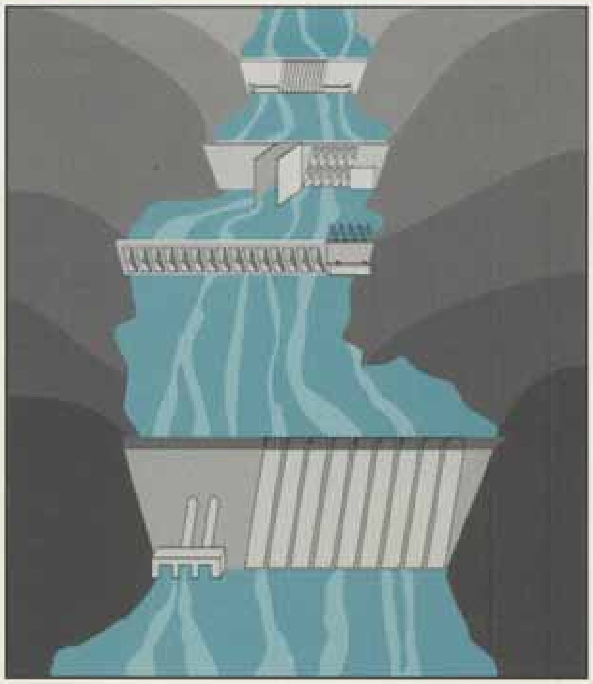

POWER SYSTEM COORDINATION

A GUIDE TO THE
PACIFIC NORTHWEST
COORDINATION AGREEMENT

POWER SYSTEM COORDINATION:
A GUIDE TO THE PACIFIC NORTHWEST COORDINATION AGREEMENT

U.S. DEPARTMENT OF ENERGY, BONNEVILLE POWER ADMINISTRATION

U.S. DEPARTMENT OF THE ARMY, CORPS OF ENGINEERS, NORTH PACIFIC DIVISION

U.S. DEPARTMENT OF THE INTERIOR, BUREAU OF RECLAMATION, PACIFIC NORTHWEST REGION

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Writing by Pat Logie with the assistance of agency staff.

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If you have any comments or questions, please contact:

Interagency Team
P.O. Box 2988
Portland, OR 97208-2988
Call: (503) 230-3478 (Portland) or 1-800-622-4519
To request documents, call: 1-800-622-4520.

The following SOR publications are also available:
- *Streamline*, a periodic newsletter that reports on the SOR;
- *The Columbia River: A System Under Stress*, a four-page introduction to the SOR;
- *The Columbia River System: The Inside Story*, an 85-page book that describes the Coordinated Columbia River System;
- *Screening Analysis: A Summary*, a 30-page book on the SOR alternatives screening process;
- *Screening Analysis*, a two-volume, 593-page report on screening;
- *Modeling the System: How Computers Are Used in Columbia River Planning*, a 43-page report on how computer models are used to help plan and regulate hydro operations in the Columbia River Basin.

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Introduction

The Pacific Northwest Coordination Agreement is a complex arrangement for the cooperative operation of the Northwest's major hydroelectric facilities. Through this arrangement, the region's major generating utilities gain many of the benefits they would realize if the Northwest's hydro system were a single utility managed by a single owner.

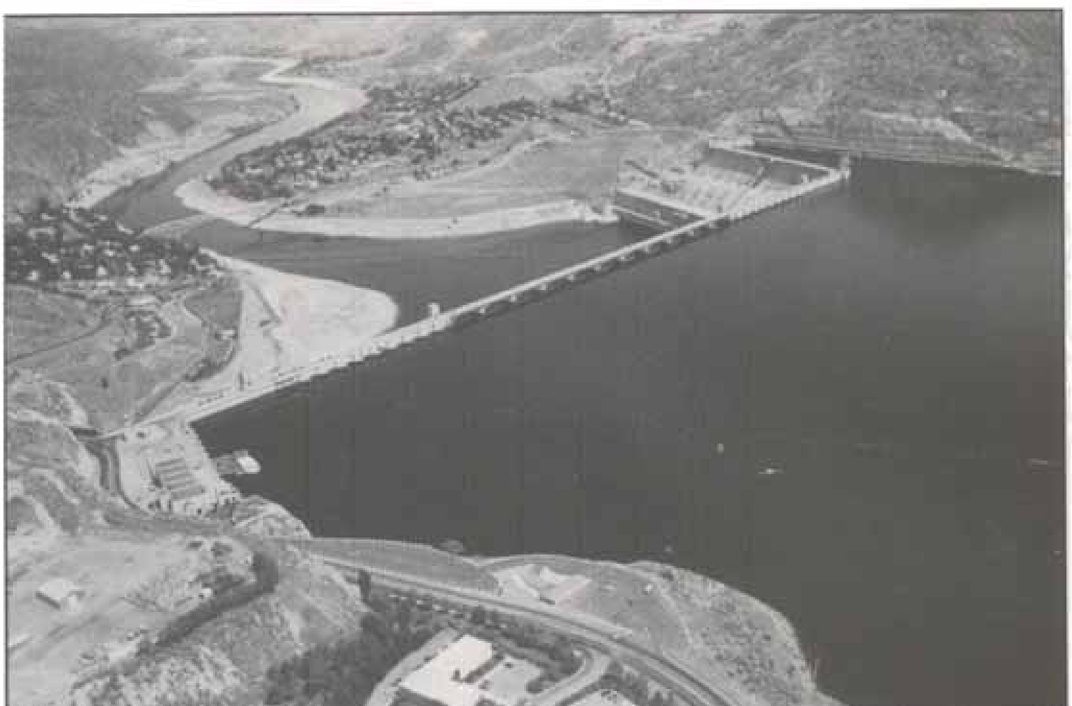
Power System Coordination is intended to provide an overview of the Northwest's power system and an introduction to current coordinated hydro operations. It begins by considering coordination itself and then takes a look at the Columbia River, the resource that gives substance to regional hydroelectric coordination. It next examines the elements that either spurred or impeded river development over several decades, culminating with the Columbia River Treaty, the framework for U.S.-Canadian development and management of the river. And, finally, it provides a detailed look at PNCA itself: its concepts, features, priorities, planning tools and operating procedures.

Why Coordinate?

Regional coordination of hydro resources did not begin with PNCA. Power managers have long recognized the benefits of joint planning and of inter-system power transfers, and the region has had its share of bilateral arrangements and voluntary efforts. But prior to PNCA, there was no *commitment* to coordinated storage operation and no mechanism for assuring the transfers of power needed to take advantage of diversities.

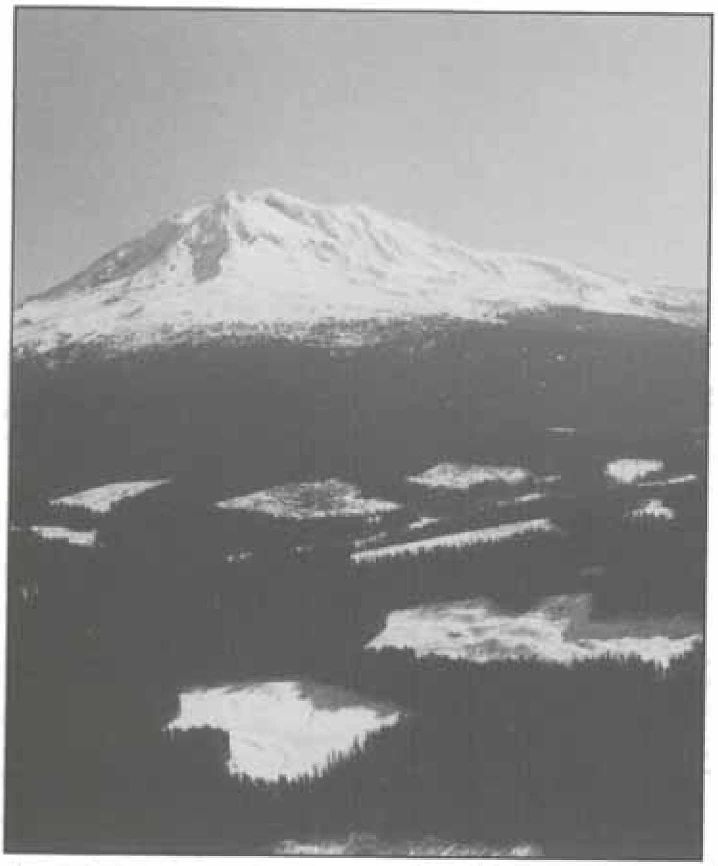
And it's diversities that make coordination advantageous. In fact, the benefits of coordination are directly proportional to the amount of diversity.

Why would anyone be interested in transferring power if local demand for electricity always matched local supply? How much power would be available for exchange if all regional streams were replenished to the same levels at exactly the same time? Fortunately for the Northwest, this region's climate, geography and population patterns combine to create remarkable diversity. West of the Cascades, stream flows peak early in the year, usually because of heavy rainfall. East of the Cascades, rainfall is sparse and stream flows, fed primarily from snowpacks, peak later. The west side has the most people; the east side, the biggest dams. The region's dams differ not only in size but in refill



Grand Coulee in north-central Washington, completed in 1941, is one of the earliest of the Northwest's many hydroelectric projects. Together, these diverse projects provide the foundation for hydrologically linking the region.

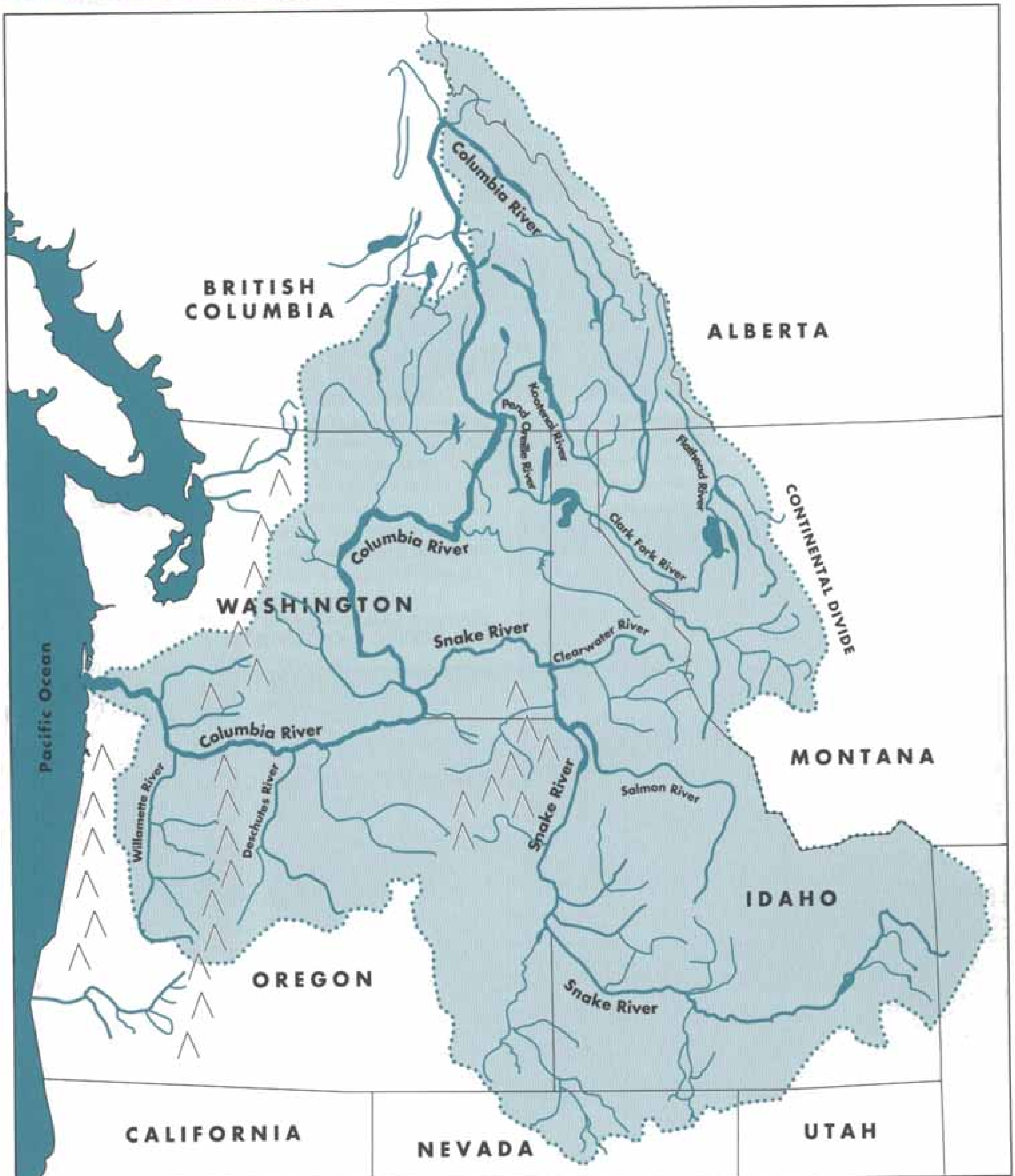
Libby Dam in northwest Montana was not completed until 1975. It is one of four storage projects made possible by the Columbia River Treaty and the drive for expanded river storage that directly stimulated regional coordination.



The Pacific Northwest is marked by extraordinary diversity in topography, climate, population, and demand for electricity. Moisture-laden clouds off the Pacific Ocean feed deep snowpacks that recycle this moisture each spring. A network of rivers, fed by spring rain and snowmelt, gives the region the nation's greatest hydroelectric potential.

The Pacific Northwest Coordination Agreement, PNCA, outlines water storage and power transfer rights and obligations — the keys to regional hydroelectric coordination.

The Columbia River Basin



The Columbia-Snake River system is the Northwest's premier natural resource. Stretching from the Rocky Mountains to the Pacific Ocean, it extends into six states and one Canadian province.

characteristics and type. Some run-of-river dams impound only a few acre feet of water while certain storage dams hold millions of acre feet. If a single owner controlled the Northwest's hydroelectric facilities, all regional uses might be viewed as a single load and all projects might be operated with this single load in mind. Coordination seeks to gain the efficiencies and economies of single ownership while retaining autonomy for each individual system. The problem has been to get agreement on a series of rights, obligations, and payments governing the participants' power production and supply.

The Columbia Basin's resources made it eminently worthwhile to coordinate some power operations. The power resources that came to be developed in the Northwest include a sophisticated regional transmission grid (14,779 miles (23.646.4 km) owned by the Bonneville Power Administration alone), 255 hydro projects, an average of 18,500 megawatts (aMW) of annual hydro generation, and 55.3 million acre-feet (MAF) (68.2 billion m^3) of reservoir storage on the Columbia and Snake Rivers. But even before these resources were developed, power managers were awed by the potential — and problems — inherent in the region's premier natural resource: the Columbia River.

Pacific Northwest streams and rivers combine to provide 18,500 average megawatts of energy annually, three-fourths of all electricity used in the region.

Chapter One: The Columbia River Cornucopia

The Columbia River is the answer to a power manager's dream — and nightmare. First, the dream. The Columbia River is a powerhouse. Among U.S. river systems, its natural runoff is second only to the larger Missouri-Mississippi system. Its source in the Canadian portion of the Columbia Basin helps to explain its enormous potential. There, lofty mountain ranges intercept moisture-laden clouds off the Pacific Ocean. The clouds give up their bountiful moisture, mainly as snowfall that accumulates in seasonal snowpacks. These snowpacks act as permanently renewable storage batteries, accumulating water in successive winters and releasing it every spring, summer, and fall. They feed lakes, streams and river systems, most prominently the Columbia River which originates at Columbia Lake, 200 miles (320 km) north of the U.S. border.

Throughout the Pacific Northwest, but particularly in the Columbia Basin, the marriage of topography and meteorology gives the Northwest region 40 percent of the nation's hydroelectric potential. Hydropower, which once furnished nearly all the electricity in the Northwest, still accounts for 75 percent on average. That's the power manager's dream.

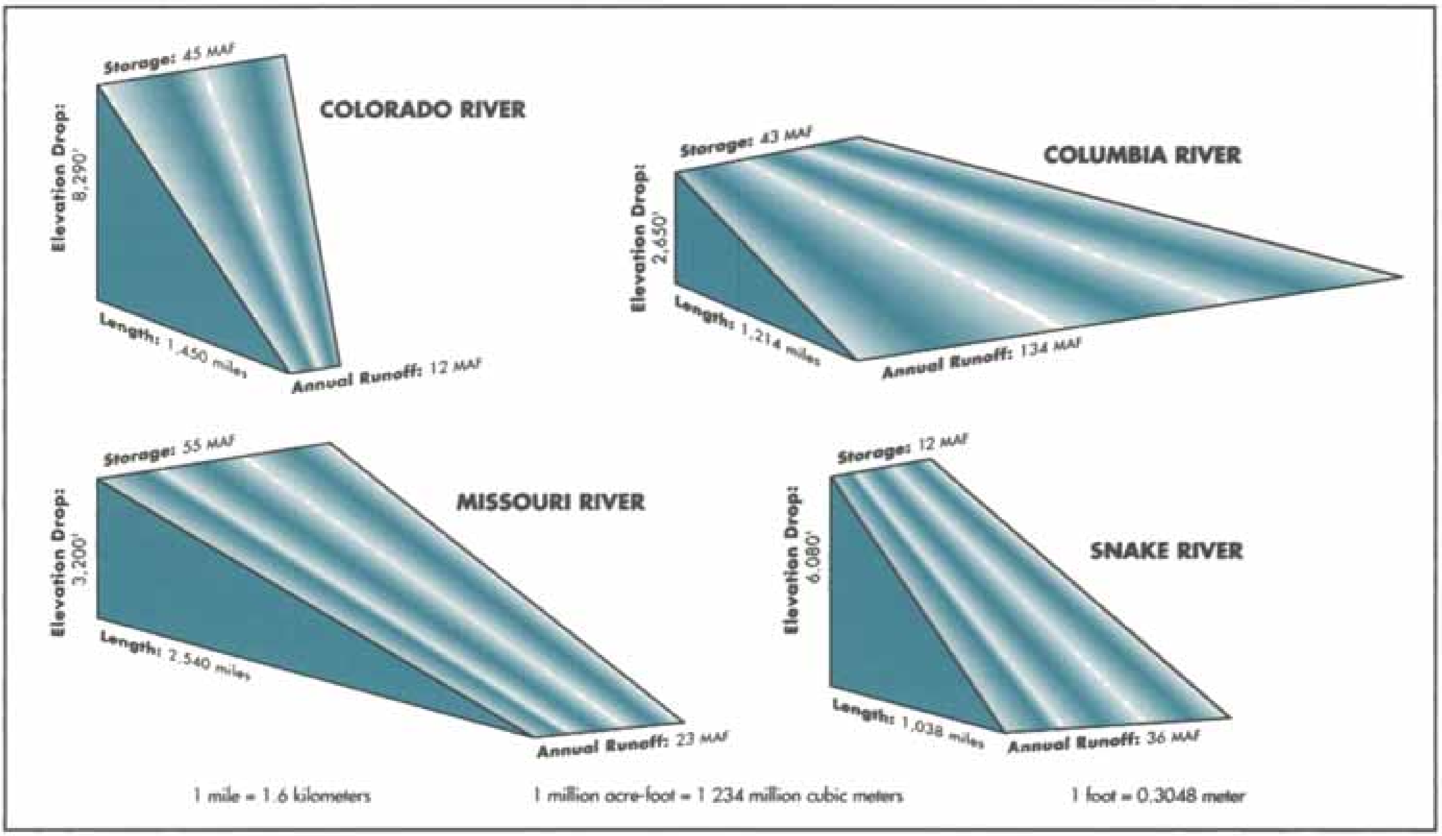
The Erratic River

On the other hand, there's the nightmare. The Columbia River's natural flows are extremely erratic, from year to year and season to season. At The Dalles, Oregon, record flows range from 1,240,000 cubic feet per second (cfs) (34 720 m^3 per second) at the peak of the June 1894 flood to a low of 36,000 cfs (1.008 m^3 per second) in December 1937: a ratio of 34 to 1. The natural flows at the U.S.-Canadian border are even more erratic, from 680,000 cfs (19 040 m^3 per second) in June 1894 to a winter low of 13,000 cfs (364 m^3 per second): a 52 to 1 ratio. Compare this

The many tributaries of the Columbia-Snake River system all end as one large body of water. At Astoria, Oregon, where the Columbia enters the Pacific Ocean, the river is 3½ miles (5.6 km) wide and has an average annual runoff of 198 million acre-feet (244 billion m³). Among U.S. rivers, it is second only to the Missouri-Mississippi system in runoff.

Comparison of Major U.S. Rivers

Length, Storage, Annual Runoff and Elevation Drop



It is the large volume of water passing given points along the Columbia-Snake Rivers that is so valuable to river planners and users. Although the Columbia River total storage compares favorably with other large U.S. rivers, its runoff is significantly larger than its storage capacity as compared to the Colorado or Missouri which have annual flows less than storage capacity.

to the 2-to-1 natural ratio of a river like the St. Lawrence.

Seasonal variations, while not so extreme, are also pronounced. Seventy-three percent of the river's natural flow occurs in the six warmest months. This seasonally heavy flow is unfortunate for two reasons: (1) summer flows are a major cause of floods, and (2) the region's heaviest water runoff — and greatest natural hydroelectric potential — coincides with the period of lowest Northwest power use. Thus, the river's natural flow patterns make it difficult to control floods and to meet high power needs in the winter.

Most of the Columbia's natural flow occurs when hydroelectric power demand is the lowest.

Chapter Two: Toward Coordination

Why wasn't the river harnessed earlier? Regulating the river's flow — storing high runoff to avert floods and releasing it to meet winter's peak lighting and heating needs — would seem eminently logical. So would coordinated storage and operations. Yet, these approaches were not always self evident or viable.

When it came to developing the nation's rivers, political parties and administrations differed in their views about the appropriate roles of the Federal government, public agencies, and private investors. Moreover, in the case of the Columbia River, part of its potential development required joint U.S.-Canadian planning and agreement. Canada accounts fpr only 15 percent of the area of the Columbia Basin, but it is the source of 30 percent of the Columbia's average flow and 55 percent of its peak flood flow measured at The Dalles.

For a long time, low demand for electricity made large-scale hydroelectric development an academic question. Although small-scale power generation cropped up throughout the country in the 1880s and '90s, electricity was technologically unavailable, physically remote, or economically beyond the reach of most Americans well into this century. In cities and towns, power costs were many times current charges. In most rural areas, there was no electricity at any price.

When the region's first modern dams were built, Depression-era construction jobs seemed a more tangible benefit than electricity of doubtful marketability.

The 1930s: A Conservative Approach

In 1938, the Corps of Engineers completed the first phase of the Bonneville project — the first Federal dam on the mainstem of the Columbia. This phase consisted of two generators with a combined capacity of 86.4 megawatts (MW), about a sixth of this project's current rating but in the view of many, a wasteful excess. In an article titled "Dam of Doubt", a national magazine predicted all this Bonneville power "would never be used."

The region's population was small, per-capita energy use was modest, and industry was not widespread. There was very little data about energy resources and demand. It was believed that future needs could be met with low-head, run-of-river dams, like the Bonneville Project.

Federal agencies focused their attention on lower Columbia navigation. Storage dams didn't yet exist to alter flows, so floods were partially contained with local levees.

The 1940s: A Watershed Decade — a War, a Flood, Changing Views, and Changing Practices

During World War II, economic activity — and use of electricity — increased

Dust Bowl farmer-refugees were a hallmark of the nationwide depression of the 1930s. The depression also meant too little household income to buy electric appliances and too little capital to expand industries and power systems.

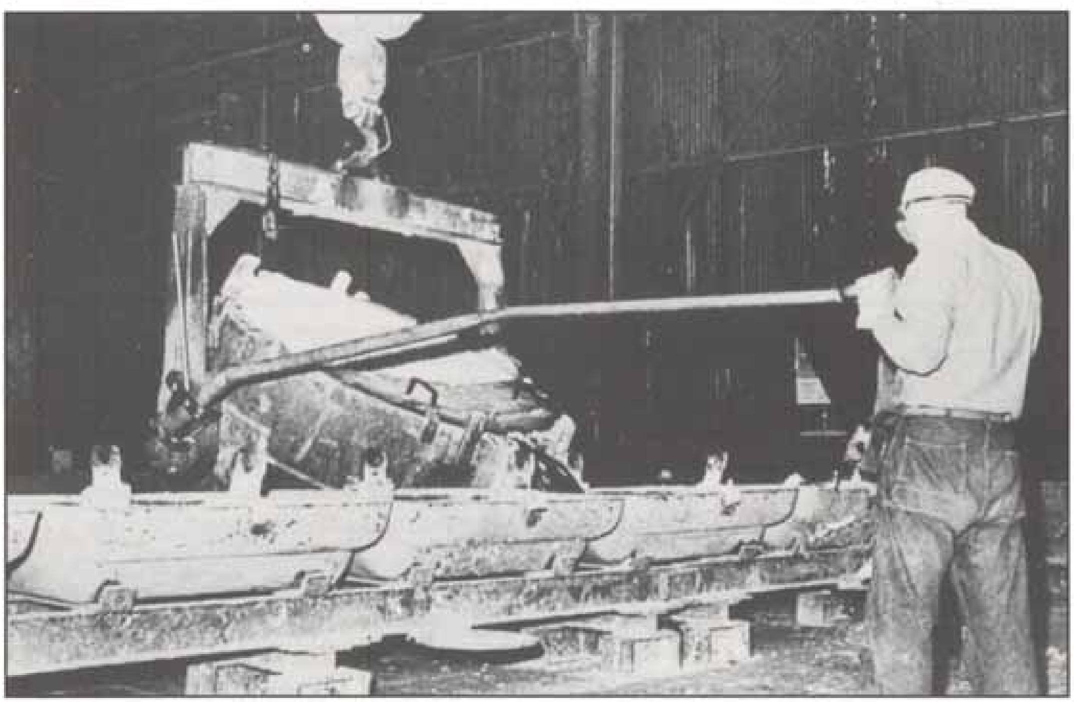
dramatically. In 1942, a Federal agency, the War Production Board, directed utilities across the country to cooperate, interconnect, and pool their operations to meet increased electric loads. One result was the Northwest Power Pool. After the war, the Pool continued as an informal, voluntary association to collect operational data and provide guidelines for power system operations and operations planning. But it could not ensure coordinated operation of independent utilities.

The physical means to coordinate and transfer power were becoming evident, though. The Bonneville Power Administration (BPA), the Federal agency created in 1937 to market power from Federal projects in the region, began work in the 1940s on an intricate regional transmission grid. Lines from the Bureau of Reclamation's Grand Coulee Project, the region's first major storage reservoir, crossed the Cascades, and BPA lines were interconnected with Idaho Power lines at La Grande, Oregon.

Data needed for coordinated planning of the region's hydro resources also became available: annual regional load forecasts and annual resource planning studies.

The International Joint Commission (IJC) considered how the U.S. and Canada could improve uses of the Columbia. And the Corps of Engineers, the Bureau of Reclamation, and BPA examined the possibility of building additional upstream dams — dams big enough to store, and selectively release, much of the seasonal runoff from snowmelt. The end of

Beginning in the 1920s and 30s, many utilities sold electric appliances. Household use of electricity increased dramatically throughout the region until per capita consumption leveled off in the 1980s.



World War II altered the Northwest economy. In the 1940s, the U.S. needed aluminum to build planes and ships, and aluminum required huge quantities of electricity. Thanks to abundant, low-cost electricity, the Northwest was a natural home for aluminum smelters.

Fifteen people lost their lives in a 1948 flood that leveled the city of Vanport, one of Oregon's largest cities at the time. The disaster spurred development of storage dams large enough to hold back potential floodwaters.

the decade dramatically underscored the need for such control.

Flooding Takes a Toll

Typically, the Northwest has two flood seasons — winter flooding caused principally by heavy rainfall west of the Cascades and spring/summer flooding caused by snowmelt in streams originating east of the Cascades. Until the 1960s, periodic flooding was a chronic regional problem, particularly in the lower Columbia.

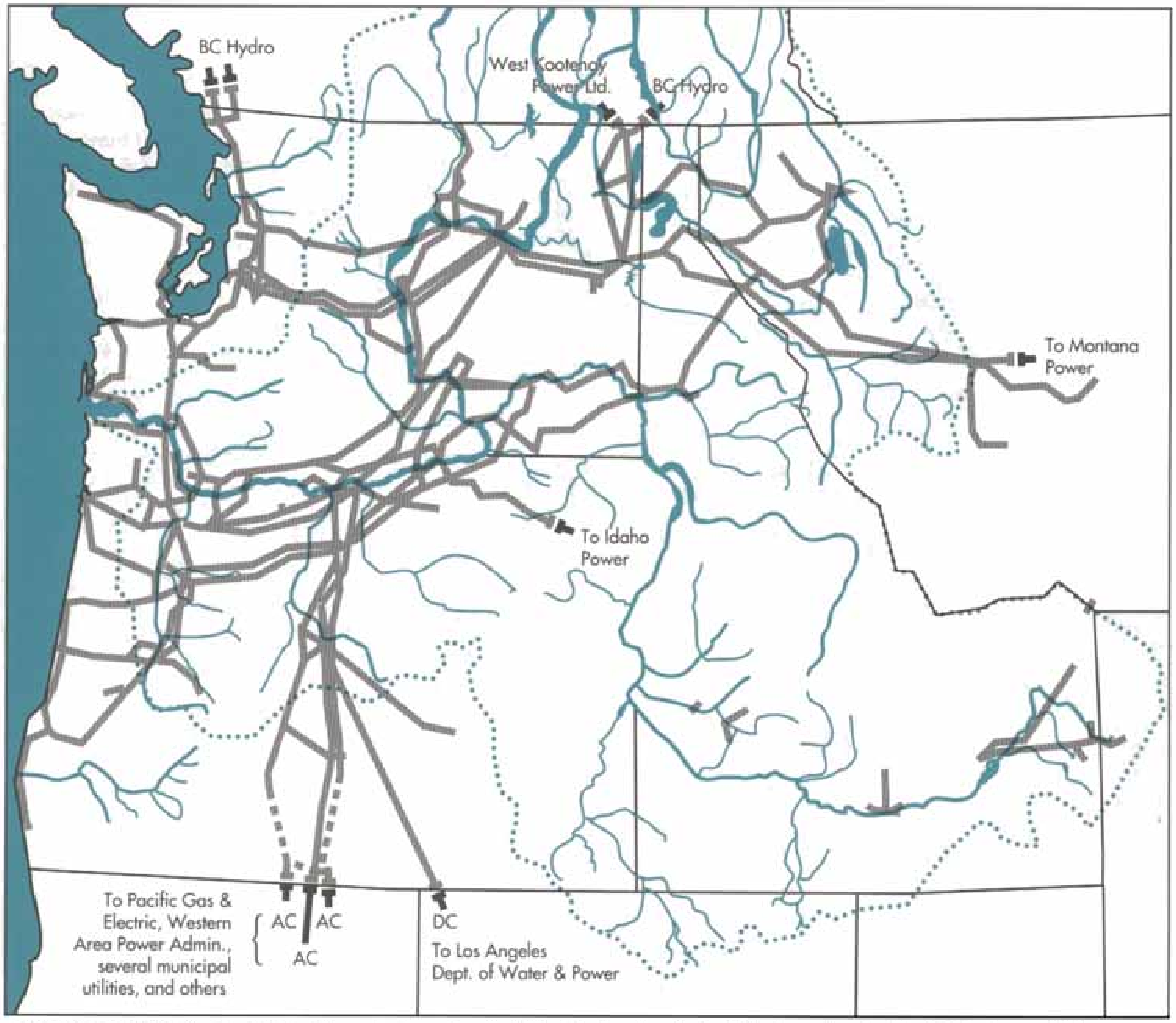
The problem was exacerbated whenever rains and snowmelt coincided — as they did on May 30, 1948. Before this Memorial Day flood, 18,000 people lived in Oregon's newest city — Vanport — located at the confluence of the Willamette and Columbia Rivers. That day, the Columbia reached a peak flow of 1,010,000 cfs (28 280 m^3 per second) at The Dalles. The flood wiped out Vanport, inundated 25,000 acres (101.2 km^2), and took 15 lives.

The flood motivated regional interests to request that the Corps of Engineers step up investigations of additional reservoir storage. That October, the Corps reported that upstream storage could halve the Columbia's peak flows and more than triple its low flows. In other words, the river's unregulated 34-to-1 flow could become a regulated 4-or-5-to-1 flow. In 1950 Libby Dam was authorized, contingent upon Canada granting approval, too, inasmuch as Libby's reservoir would extend 42 miles (67.2 km) into Canada.

The 1950s: Some Pieces Move into Place

Politically, the 1950s were a time of retrenchment in Federal power initiatives.

The Federal Transmission System



A 14,779-mile (23 646.4 km) Federal transmission system facilitates the transfer of electricity throughout the Pacific Northwest. Major transmission ties connect the region to California and provide access to the Southwest. The Northwest system also has major transmission interconnections with Canada, Idaho, and Montana.

The Truman Administration tried but failed to increase the region's upstream storage, and the Eisenhower administration focused on private development of major projects.

At the same time, the region's transmission grid grew, making widespread transfers of power possible throughout the region. Power transactions and operations became increasingly complex as non-Federal projects were licensed and built downstream from Federal projects. Three Washington public utility districts (PUDs) were planning to build four large new dams on the Columbia and sell much of the power to other regional utilities — utilities that would share in the rights and obligations of the PUD dam-builders.

Bilateral or trilateral arrangements demonstrated the potential benefits of regional coordination. A 1958 contract covered some aspects of coordinated operation for Washington

Hydroelectric Projects Owned by PNCA Parties

Federal Agencies

- Corps of Engineers
- Bureau of Reclamation
- Output part of U.S. Columbia River System

Public Agencies

- Chelan County PUD
- City of Seattle
- Douglas County PUD
- Snohomish County PUD
- Eugene Water and Electric Board
- Grant County PUD
- City of Tacoma
- Pend Oreille County PUD

Investor Owned

- Montana Power Company
- Pacific Power and Light Company
- Portland General Electric Company
- Puget Sound Power and Light Company
- Washington Water Power Company

PNCA studies include power generation from 120 hydroelectric projects owned and operated by PNCA parties.

Water Power, Pacific Power, and Idaho Power. And BPA and Montana Power entered into a contract regarding the draw-ing down of Flathead Lake.

Sustained progress was made toward U.S.-Canadian agreements for developing the Columbia in Canada. Canada undertook several engineering studies between 1956 and 1962. In December 1959, the IJC concluded 15 years of extensive studies into the feasibility of greater use of the Columbia River system with the publication of the IJC Principles, the basis for the upcoming Columbia River Treaty. Power principle No. 7 includes the expectation that "all participating power systems would retain their local autonomy but would necessarily operate their generation and transmission facilities under the terms of appropriate agreements with a view to maximizing mutual benefits."

The 1960s: When it All Came Together

At the beginning of the decade, the pieces were at hand for making a reality of the dream to tame the Columbia in the interest of flood control and enhanced power production. Four long-planned and interdependent developments converged: (1) the Columbia River Treaty between Canada and the U.S., (2) a network of storage reservoirs in the U.S. and Canada, (3) a Northwest-Southwest transmission intertie and (4) a long-term agreement for coordinating the operation of storage reservoirs for optimum power generation — the future PNCA.

A discussion of the North-South transmission interties is beyond the scope of this publication. Nonetheless, it should be noted that the Canadian share of downstream power benefits from their three projected storage dams was approximately 600 aMW, power that Canada and the Pacific Northwest would not need for many years. Thus, the capability to move power outside the region made it easier to gain approval for both the Treaty and the Coordination Agreement.

Neither will the region's hydroelectric projects be discussed here, but the map on page 12 (projects owned and operated by PNCA parties) gives an idea of the size and complexity of the resources being coordinated. Appendix B lists PNCA parties and the hydroelectric projects in which they have ownership rights or rights to purchase part of the output.

Under the Columbia River Treaty, power systems are able to retain local autonomy but handle generation and transmission for mutual benefit.

Chapter Three: The Treaty and Entitlement

Impediments to a Treaty

Although diplomatic negotiations began in February 1960, the generating utilities in the United States weren't ready to support a treaty. These non-Federal generators were expected to share in delivering power benefits to Canada, a commitment they wouldn't make without an assurance of coordinated operations of upstream storage projects. In general, the non-Federal generators wanted the certainty that each owner would be autonomous within a framework of defined rules, rights, and obligations. Specifically, they wanted to be sure that water would be released from the new upriver dams at the times and in the amounts needed to produce optimum firm power. When they received these assurances, they agreed to support the Treaty.

The non-Federal generators also recognized that their own dams — dams such as Montana Power's Kerr Project — produced benefits for downstream Federal projects and they wanted to be paid for these benefits. With storage dams, water need not pass through hydroelectric projects at the whim of the river. Instead, the same amount of water can be selectively released to pass through turbines at times when electric power is of greater value. The benefits of increased usable energy at downstream projects as a result of upstream storage are called headwater benefits.

In pre-PNCA days, the question of headwater benefits — who paid and how much — was a lingering problem. Under the Federal Water Power Act of 1920, Federal hydroelectric licensing was a responsibility of the Federal Power Commission (FPC), later the Federal Energy Regulatory Commission (FERC). One requirement of licensees was, and is, paying an annual charge for headwater benefits. The Federal government, however, was exempt from these charges because it was considered to own all waterpower that is subject to Federal jurisdiction.

Additionally, it was difficult to get agreement on the value of headwater benefits. In 1952, BPA asked the FPC to determine these charges for the Columbia, but the determination was difficult, and this issue was left for the Coordination Agreement. Resolution included Federal payments to non-Federal entities.

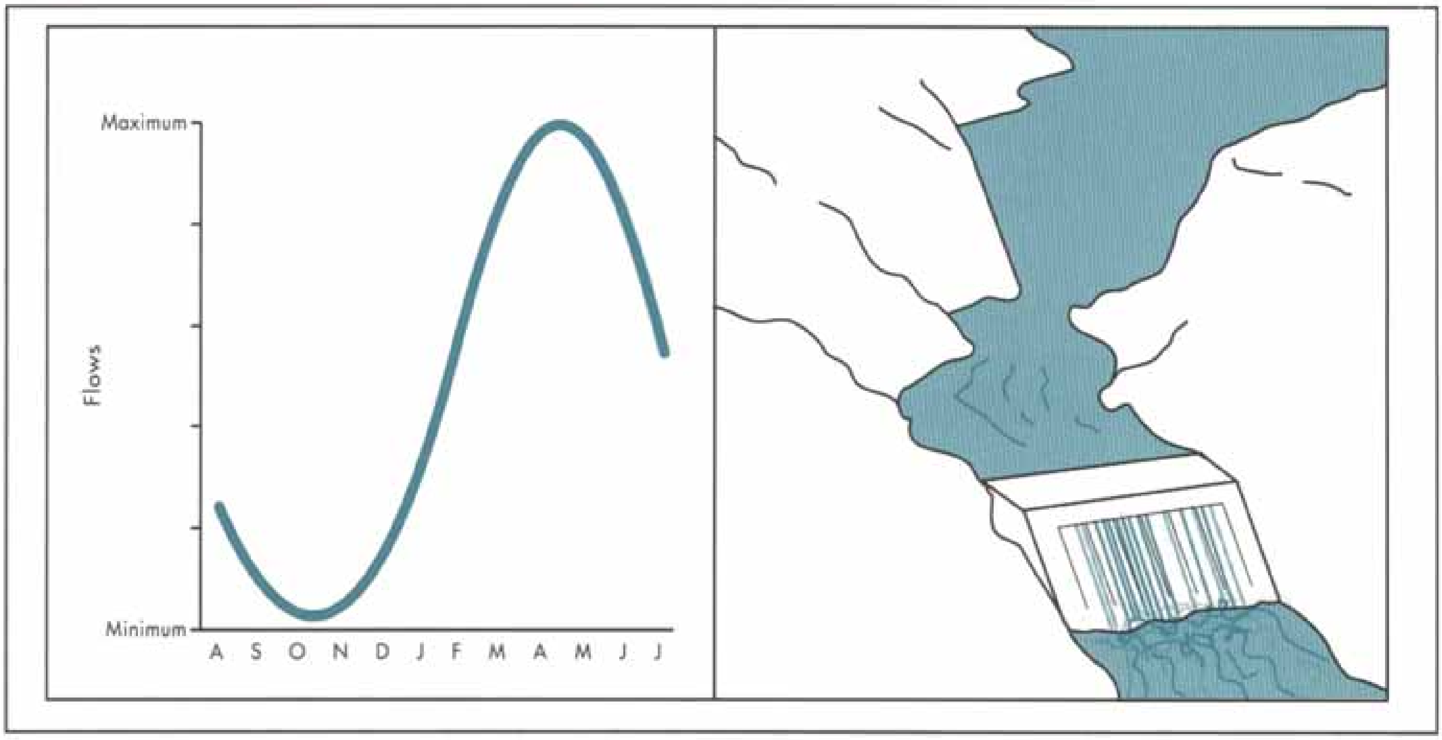
Treaty Provisions

The Columbia River Treaty, signed January 17, 1961 and ratified by the U.S. Congress in September 1964, provided a framework for bilateral development and management of the Columbia River to achieve two objectives: enhanced flood control and increased power production.

Prior to 1964, there were 90 hydroelectric projects of

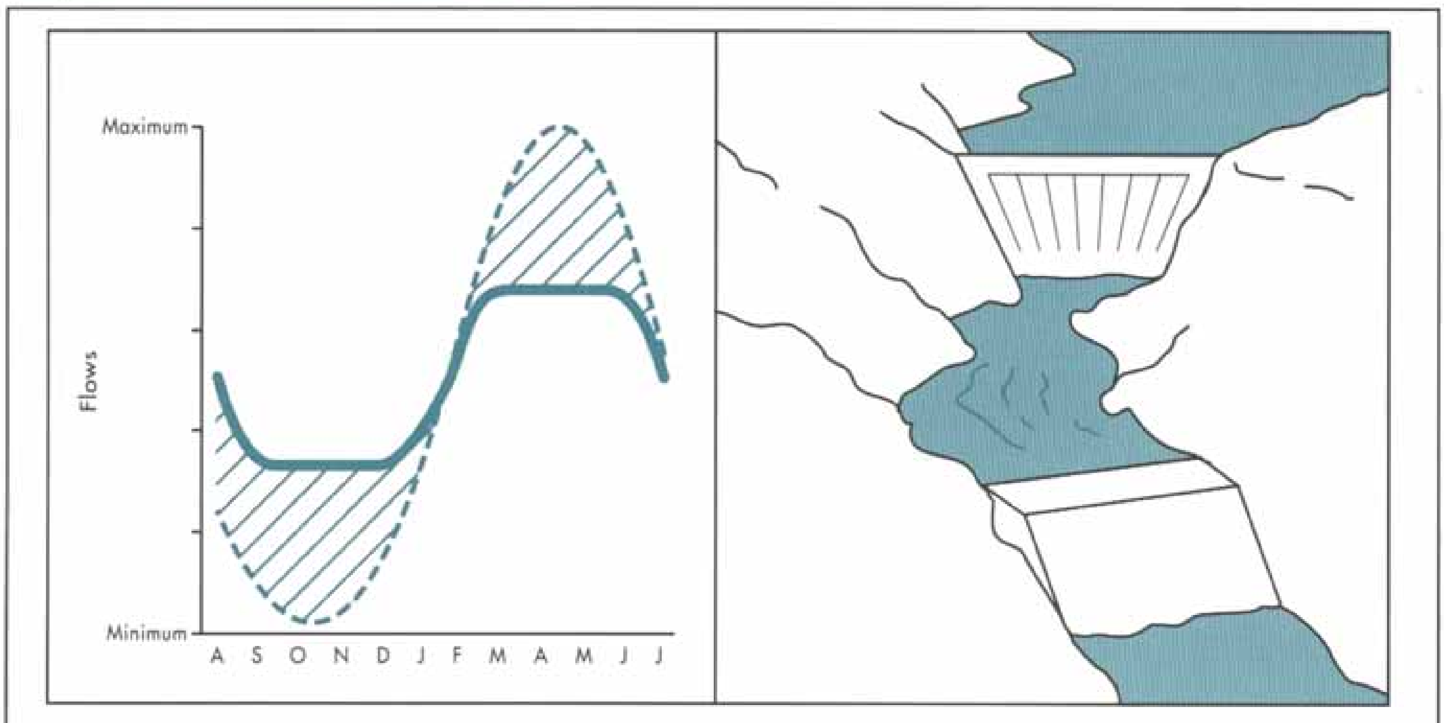
The Columbia River Treaty, signed in 1961, committed the U.S. and Canada to improved flood control and increased power production through bilateral river management.

Project without Upstream Storage



In the absence of an upstream storage project, uncontrolled flows vary widely throughout the year. In April and May, high flows from heavy snowmelt and spring rains, which typically exceed demand for electricity and generator capacity, must be spilled over the tops of dams.

Project with Upstream Storage

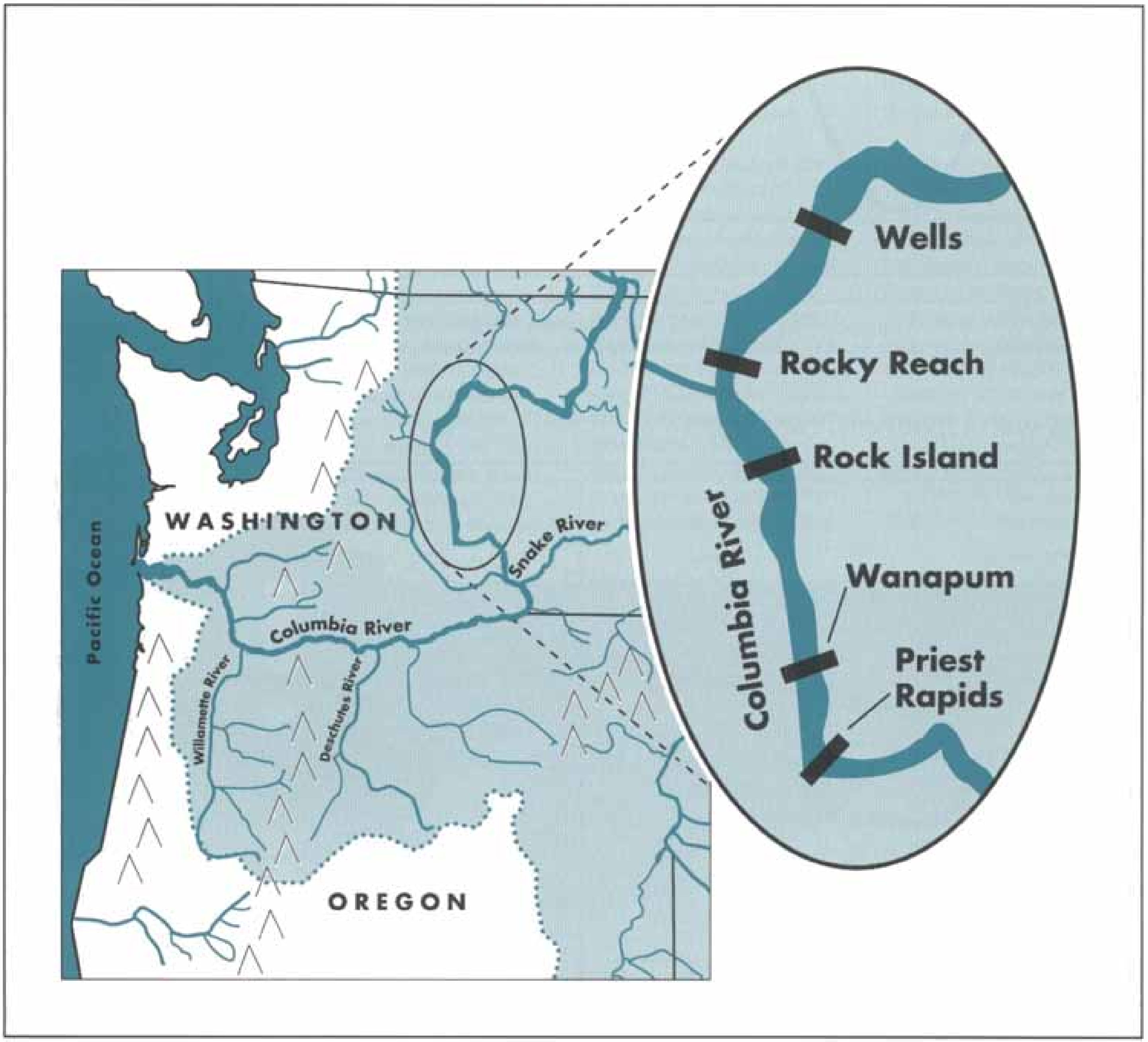


With upstream storage dams to contain heavy flows, the wide variations in natural flows can be moderated. Heavy spring flows can be saved for later in the year when demand for electricity is higher and available precipitation is lower. This operation, which provides benefit to downstream parties and compensation to the upstream utility, is called "headwater benefit."

more than 10 MW (including nine on the Columbia and 14 on the Snake) in the U.S. portion of the Columbia Basin. But the Columbia ran unharnessed for 500 miles (800 km) in Canada. The Treaty cleared the way for construction of four storage dams. Three of these — Mica, Duncan and Arrow (also called Keenleyside) — are in British Columbia. The fourth, Libby Dam in northwest Montana, impounds water into Canada.

The Treaty dams more than doubled the storage capacity of the Columbia hydroelectric system. The United States paid a one-time fee of $64 million for the estimated present worth of one half of the future flood control benefits attributable to Canadian storage and gained the right to purchase

The Non-Federal Mid-Columbia Projects



Increased Columbia River storage at new dams, constructed after the Columbia River Treaty was signed by the U.S. and Canada, greatly increased the ability to regulate flows which increased usable average generation at five mid-Columbia projects. These projects and the Federal mainstem projects are responsible for generating the Canadian and U.S. share of power benefits attributed to Treaty projects.

additional flood control storage in Canada, if needed. The U.S. also gained the full output of Libby Dam (230 aMW) and the U.S. half of the 1200 aMW attributed to improved streamflow regulation because of the Canadian dams (about 600 aMW). The other half (the Canadian Entitlement) is owed to Canada.

In addition to provisions for new construction, flood control, and power purchases, the Treaty requires representatives of BPA, the Corps, and B.C. Hydro to prepare two operating plans for Treaty storage: the Assured Operating Plan (AOP) which is designed to meet power and flood-control objectives beginning six years into the future, and the Detailed Operating Plan (DOP) which plots operations for the immediate 12-month period.

The Entitlement and CSPE

Under a separate contract, Canada sold its share of downstream power benefits (the Canadian Entitlement) for $254 million for a period of 30 years, tied to the scheduled completion date of each of the Treaty dams — Duncan in 1968, Arrow in 1972, and Mica in 1973. Thus, the first portion of the sale ends in 1998, and the sale is fully ended in June 2003. The Entitlement was purchased by the Columbia Storage Power Exchange (CSPE), a non-profit corporation of 11 Northwest utilities formed under the leadership of three of these utilities: Grant, Chelan and Douglas PUDs. CSPE issued revenue bonds to purchase the Entitlement and arranged contracts with 41 regional utilities to buy the power through a BPA exchange agreement. At the time, much of this power was not needed in the region; it was sold to Southwest utilities until needed in the Northwest.

Canadian Entitlement Allocation Agreements

The Canadian Entitlement Allocation Agreements are contracts between BPA and the three mid-Columbia PUDs that own the hydroelectric projects where CSPE power is generated. There are five contracts, one for each project: Wells, owned by Douglas County PUD; Rocky Reach and Rock Island, owned by Chelan County PUD; and Wanapum and Priest Rapids, owned by Grant County PUD. The contracts specify how much power is to be generated at each project from the increased Canadian flows. The three PUDs are responsible for power generation and delivery to BPA. As an agent, BPA is responsible for delivering the power to the 41 CSPE parties.

The Columbia River Treaty: A driving force for U.S. power coordination.

Chapter Four: Closing In

Coordination Principles

Attempts to coordinate during the 1950s gave the non-Federal parties a good idea of the fundamental principles that should form the basis for a coordination agreement. They sought and received these assurances in a document called the Secretary's Principles approved in March 1961 by Stewart Udall, Secretary of the Interior in the Kennedy administration. (See Appendix A for the Secretary's Principles.)

The Treaty as Catalyst

Ratification of the Treaty also helped clear the way for the Coordination Agreement. In the words of former BPA Administrator Charles Luce, the Treaty changed the status of coordination from "very desirable" to "imperative." The Treaty assumes coordination in language that specifies maintenance and operation of Columbia River hydro facilities in the U.S. "in a manner that makes the most effective use of the improvement in stream flow resulting from operation of the Canadian storage for hydroelectric power generation."

The Parties

Originally, there were 16 PNCA parties. One was the Federal government represented by the Corps of Engineers and the Bonneville Power Administration, which was then part of the Department of the Interior. Another was the U.S. (Treaty) Entity, acting through the Corps and BPA. Five were investor-owned utilities: Portland General Electric, Pacific Power & Light, Washington Water Power, Puget Sound Power & Light and Montana Power Company. Three were municipalities: Eugene, Seattle and Tacoma. Five were public utility districts: Grant, Chelan, Douglas, Cowlitz, and Pend Oreille. The sixteenth was Colockum Transmission Company, a subsidiary of Alcoa, an aluminum producer that purchases part of the output of the Rocky Reach project. In 1981, after BPA was transferred to the newly created Department of Energy, the Bureau of Reclamation was added as another Federal representative. In 1984, Snohomish County PUD became a party, bringing the total number to 17.

Idaho Power Company (IPC) did not sign because of disagreements over payment for headwater benefits of coordinated operation of IPC's Brownlee Dam. However, the license for the Hells Canyon Complex, which includes Brownlee, requires a certain amount of coordination with the Northwest Power Pool.

Charles Luce, Bonneville Power Administrator when the Pacific Northwest Coordination Agreement was signed, said PNCA's goal was "to achieve the same mode of operation for all of the dams on the Columbia River and its tributaries as if one entity owned them all."

Stewart Udall, Secretary of the Interior in the administration of President John F. Kennedy, signed a document called the Secretary's Principles, the basis for the Pacific Northwest Coordination Agreement.

Interim PNCAs

Between the Secretary's Principles in 1961 and the complex arrangements required before the execution of the Treaty in 1964, there were three Pacific Northwest Coordination Agreements, one each in the years 1961, '62 and '63. The first two agreements dealt only with energy, leaving peaking questions for later. Reservoir storage targets, energy capabilities, and headwater benefits were stipulated in exhibits to the agreements.

The third agreement was expanded to deal with peak loads and resources. Among other new features were annual operations planning, a method for computing needed reserves, and the use of forecasted runoff as a basis for drafting water below targeted reservoir elevations. Although it was a ten-year agreement, the parties expected that it would be superseded, as it was a year later, by a long-term PNCA after the signing of the Canadian Treaty.

The Beginning of PNCA

The PNCA was signed September 15, 1964 and became effective January 4, 1965. Its term extends until June 30, 2003. The ending date is the end of the last contract year encompassing the CSPE Sale.

Priorities Governing Hydro Operations

Signing the Agreement did not negate or diminish the parties' other obligations. With or without a coordination agreement, every hydroelectric project operates under its own guidelines and priorities. Frequently, these originate with Federal authorizing legislation. A certain amount of power may be earmarked for specified project purposes — running irrigation pumps, for example. Other state and Federal laws and licensing requirements may specify particular water levels and flows for nonpower purposes including navigation, flood control, domestic and industrial water supply, fishery needs, pollution control, and recreation.

For PNCA parties, nonpower requirements (NPRs) not part of licenses or legislation come next. These NPRs are developed by reservoir owners. They are often influenced by processes such as the Northwest Power Planning Council's fisheries program or regional consensus developed through hearings as a result of petitions for listings under the Endangered Species Protection Act. In other cases, project owners res to needs expressed by user groups. Some utilities develop NPRs under FERC guidelines and licensing requirements. Only after NPRs are accommodated can PNCA parties begin to optimize for power.

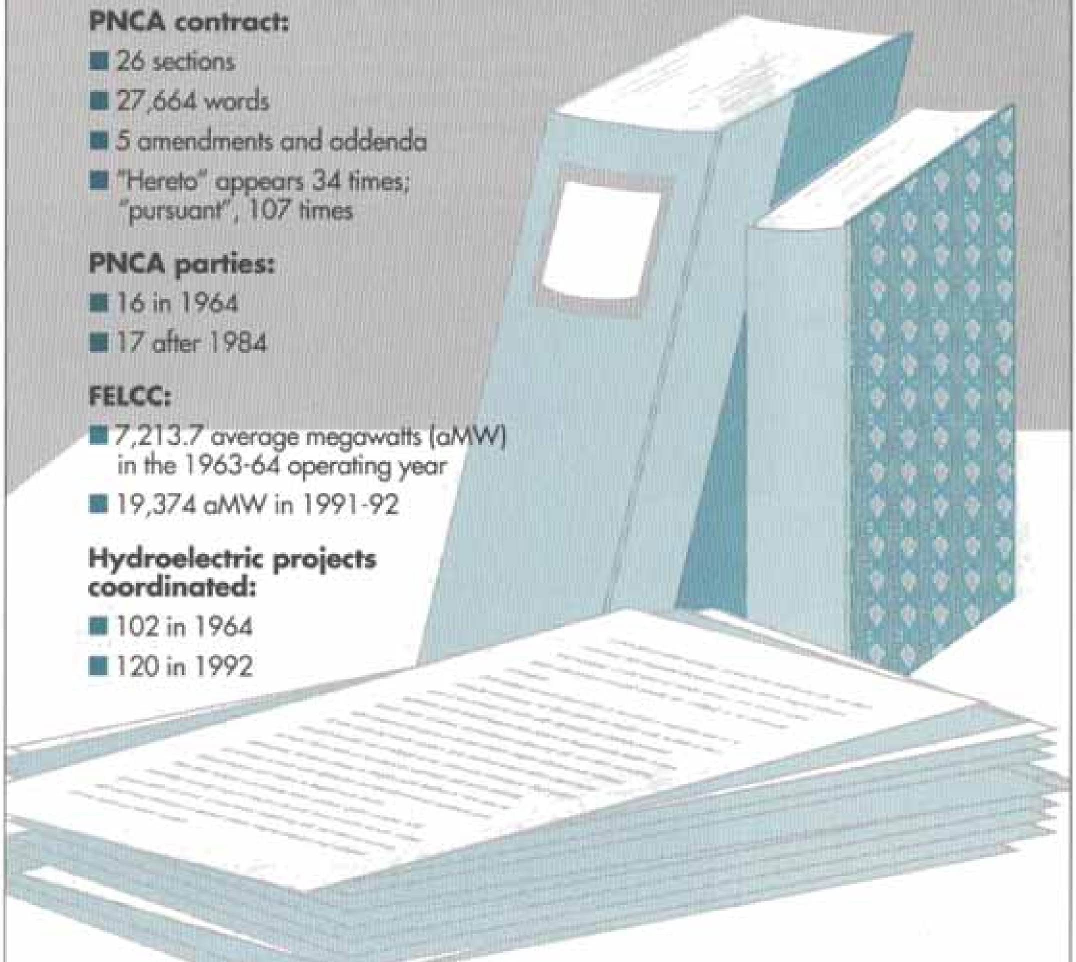
For PNCA parties, power-producing priorities take the following order:

- Producing firm energy, based on very low streamflows
- Refilling reservoirs
- Producing surplus energy with higher streamflows.

The Goal

Charles Luce, administrator of BPA at the time of the agreement, said its goal was "to achieve the same mode of operation for all of the dams on the Columbia River and its tributaries as if one entity owned them all. Our premise was that by so operating such projects they would produce the maximum benefits for society. The tough negotiating problem was how to arrive at an equitable distribution of

PNCA at a Glance



PNCA contract:

- 26 sections
- 27,664 words
- 5 amendments and addenda
- "Hereto" appears 34 times; "pursuant", 107 times

PNCA parties:

- 16 in 1964
- 17 after 1984

FELCC:

- 7,213.7 average megawatts (aMW) in the 1963-64 operating year
- 19,374 aMW in 1991-92

Hydroelectric projects coordinated:

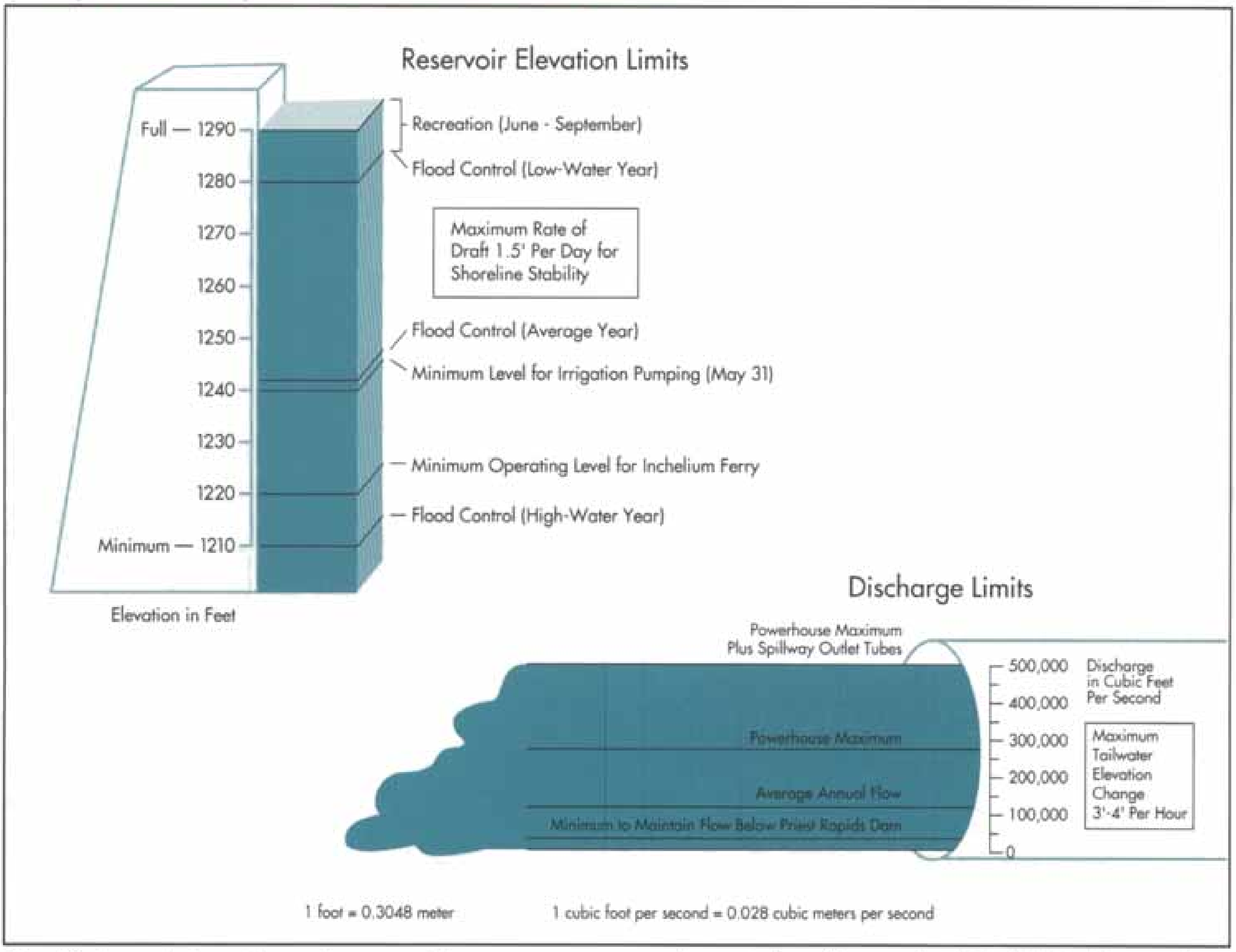
- 102 in 1964
- 120 in 1992

such benefits among the many entities which in fact owned the projects."

The Concept

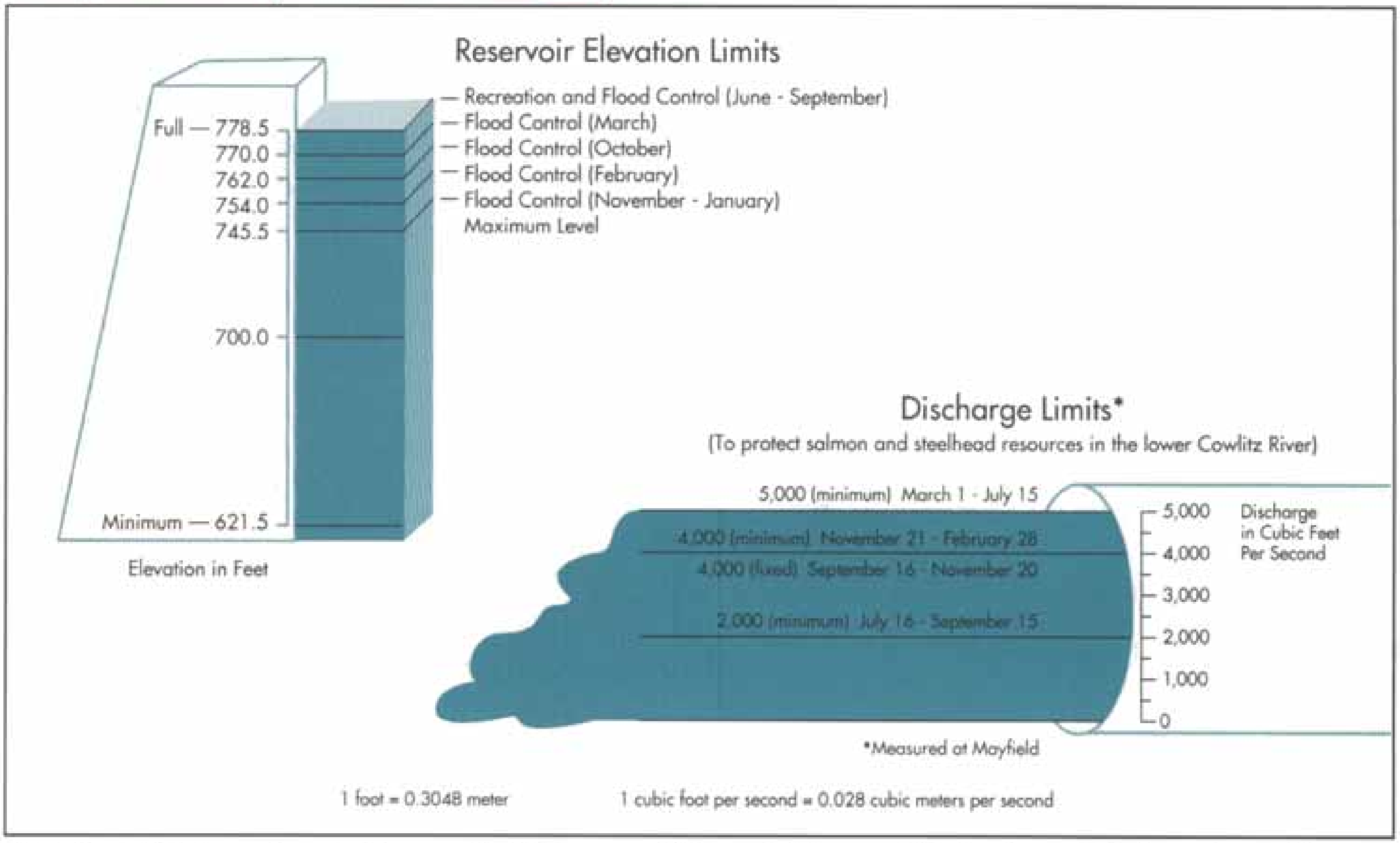
The agreement's basic concept is that all parties will jointly determine the aggregate firm load they can carry. They will then mutually support each other's operations to carry this load and to optimize their hydroelectric resources. One of PNCA's unique features is its provision for assured and coordinated storage operation. Except for Snohomish PUD, every PNCA party has generation downstream from storage owned and operated by others; thus, each is partially dependent upon others for its hydro resources and its operating economics. In other ways, too, PNCA provides what was missing from earlier region-wide coordination attempts: mechanisms for assuring power transfers needed to take advantage of diversities.

Nonpower Requirements at Grand Coulee

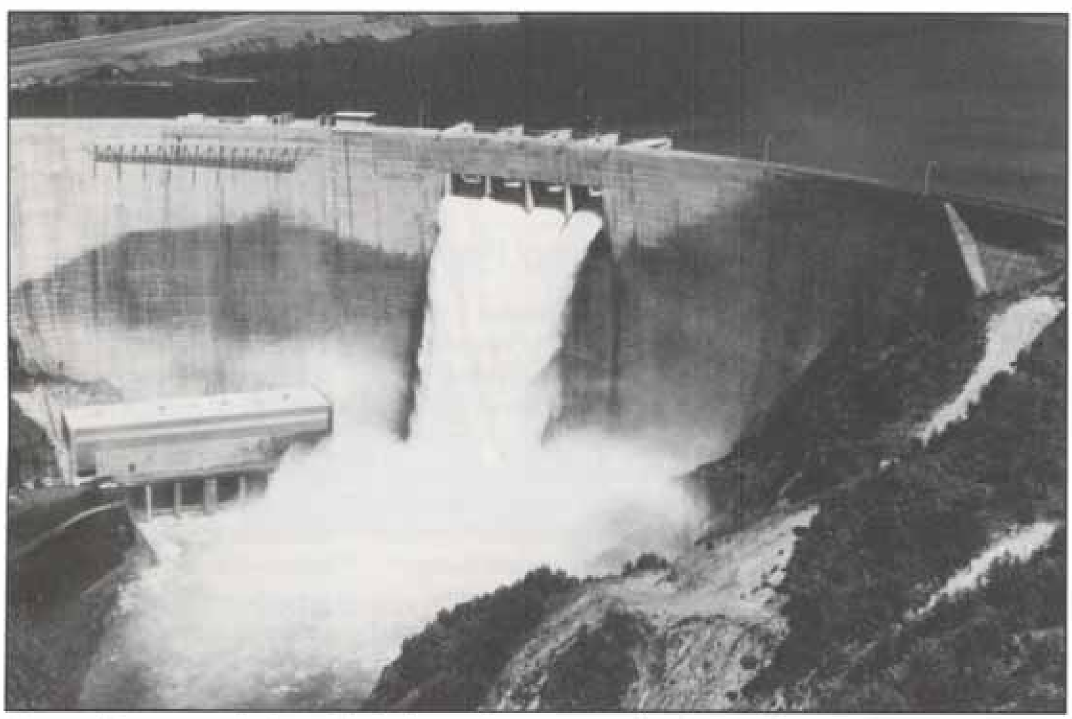


Grand Coulee project operators must accommodate numerous nonpower requirements. Some, like operation of the Inchelium Ferry can be met by maintaining a specified minimum level. Elevations needed for flood control, on the other hand, vary widely from year to year.

Nonpower Requirements at Mossyrock



As operator of the Mossyrock project, Tacoma City Light is responsible for maintaining specified elevations and discharges to meet fishery, flood control and recreation requirements. The flood control elevations shown are fixed for all years.



Mossyrock Project is a 348 MW hydroelectric plant constructed on the Cowlitz River by Tacoma City Light in 1968. The nonpower requirements for the project are shown above.

Chapter Five: The Coordination Agreement

The contractual agreement is extremely complicated and detailed. Apart from exhibits and amendments, the text itself is nearly 28,000 words long, more than 55 finely printed pages. Appendix C briefly summarizes the contents of each of the Agreement's 26 sections.

PNCA's planning and operations are guided by specific tools and procedures. Some were developed in the interim agreements and earlier cooperative arrangements; others are unique to the 1964 PNCA contract; still others were added in subsequent amendatory agreements and operating procedures.

The Critical Period

PNCA bases its planning and reliability criteria on the critical period, a projected recurrence of the lowest sequence of streamflows in the 50-year record used in PNCA studies. The amount of firm and reliable hydro capability of the region is determined by simulating operations of the hydroelectric system under recurrence of these low streamflows. In these simulations, reservoirs are drafted from full at the start of the period to empty by the end of each potential critical period. The period of adverse streamflows that would produce the lowest amount of firm energy is selected annually in the PNCA planning process. Currently, it is the 42-month period beginning in September 1928 and ending in February 1932.

Firm Load Carrying Capability

FLCC is the amount of energy and peak load (or demand) that can be served with the resources submitted by all parties after allowing for reserves and nonpower requirements. These resources, known as firm resources, include hydro that can be produced during the critical period plus thermal resources and purchase power contracts. FLCC is computed for both energy (FELCC) and peaking (FPLCC) for the coordinated system, as well as for each individual party. For the coordinated system, FLCC is what the system is **able** to supply; for a party, FLCC is what a party is **entitled to**. FLCC does not ensure that any system has the ability to meet its total load.

Forced Outage Reserves

The coordinated system plans on sufficient reserves so that the probability of loss of load due to generator-forced outages is equivalent to one day in 20 years, a fairly common industry standard. The method of allocating those outage reserves is designed to produce an equal probability of each system requiring assistance from others.

Operational Planning

Prior to August 1 each year, a series of studies compute the firm load carrying capability (FLCC) for each party and for the coordinated system during the critical period. Initially, these computations produce the maximum firm energy load carrying capability (FELCC) for the coordinated system while meeting nonpower requirements. Subsequently, each owner may make limited changes to the computed operation of its own reservoirs within the overall terms of the contract.

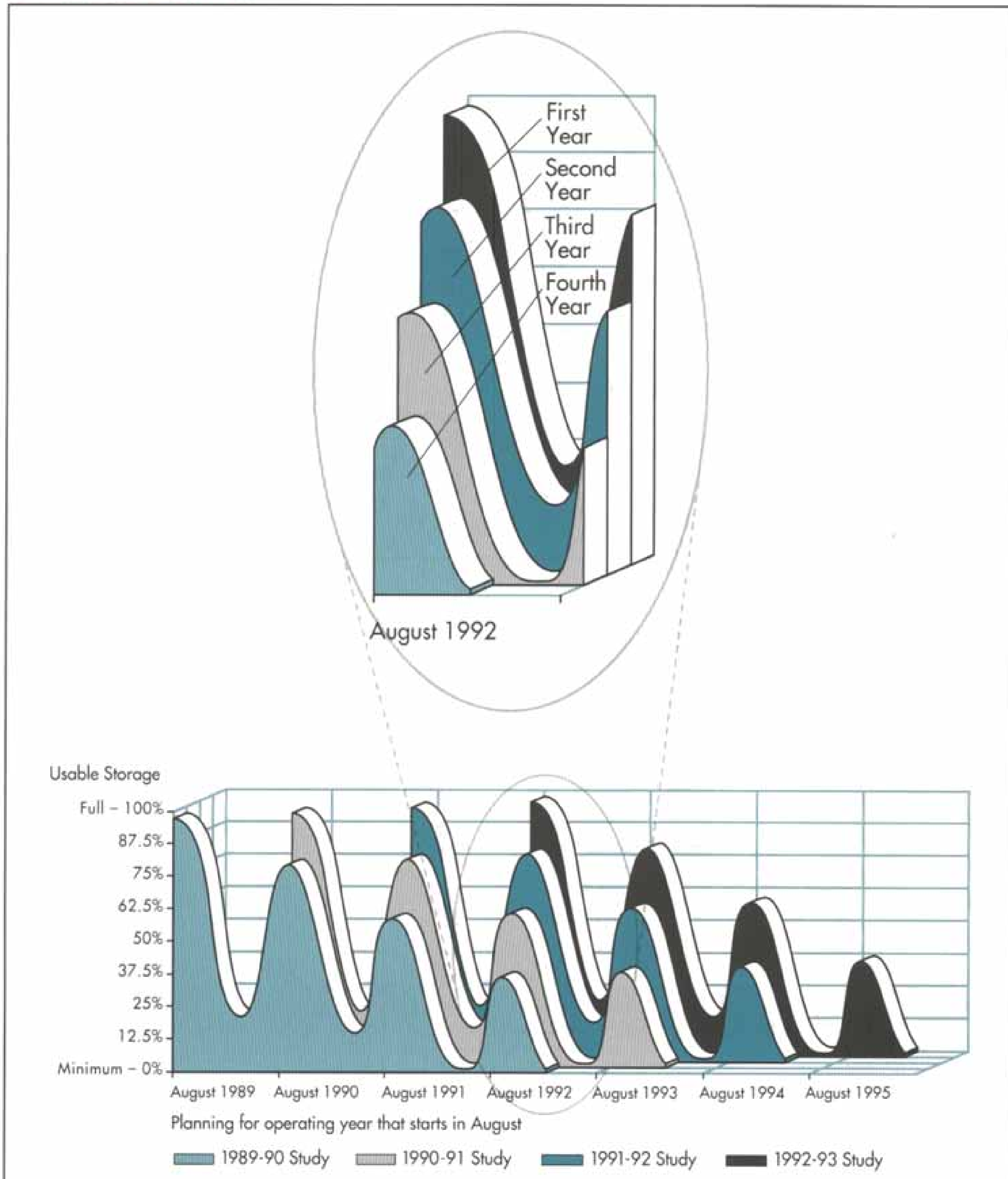
Guidelines to Reservoir Operation: Rule Curves

Before the August 1 beginning of each contract year, the Northwest Power Pool Coordinating Group and the reservoir owners construct numerous rule curves as guidelines to reservoir operations for the forthcoming operating year, August 1 - July 31. Each guideline, or rule curve, takes the form of end-of-the-month reservoir elevations which are used to calculate FELCC.

The **critical rule curve (CRC)** specifies elevations that must be maintained to ensure that FELCC can be met during the critical period. For multi-year critical periods, a critical rule curve is prepared for the upcoming year and for each of three successive years. Generally, each of these curves (the lst, 2nd, 3rd and 4th year critical rule curves) is progressively lower.

The **flood control rule curve (FCRC)** is one of many nonpower requirements not specifically mentioned in the Agreement. The Corps of Engineers develops these curves. Since flood control takes priority over power production, in practice the other guidelines to reservoir elevation are defined and adjusted to assure this precedence. FCRCs specify reservoir elevations that must not be exceeded to provide sufficient space for holding back excessive rainfall and snowmelt. FCRCs

Critical Rule Curves



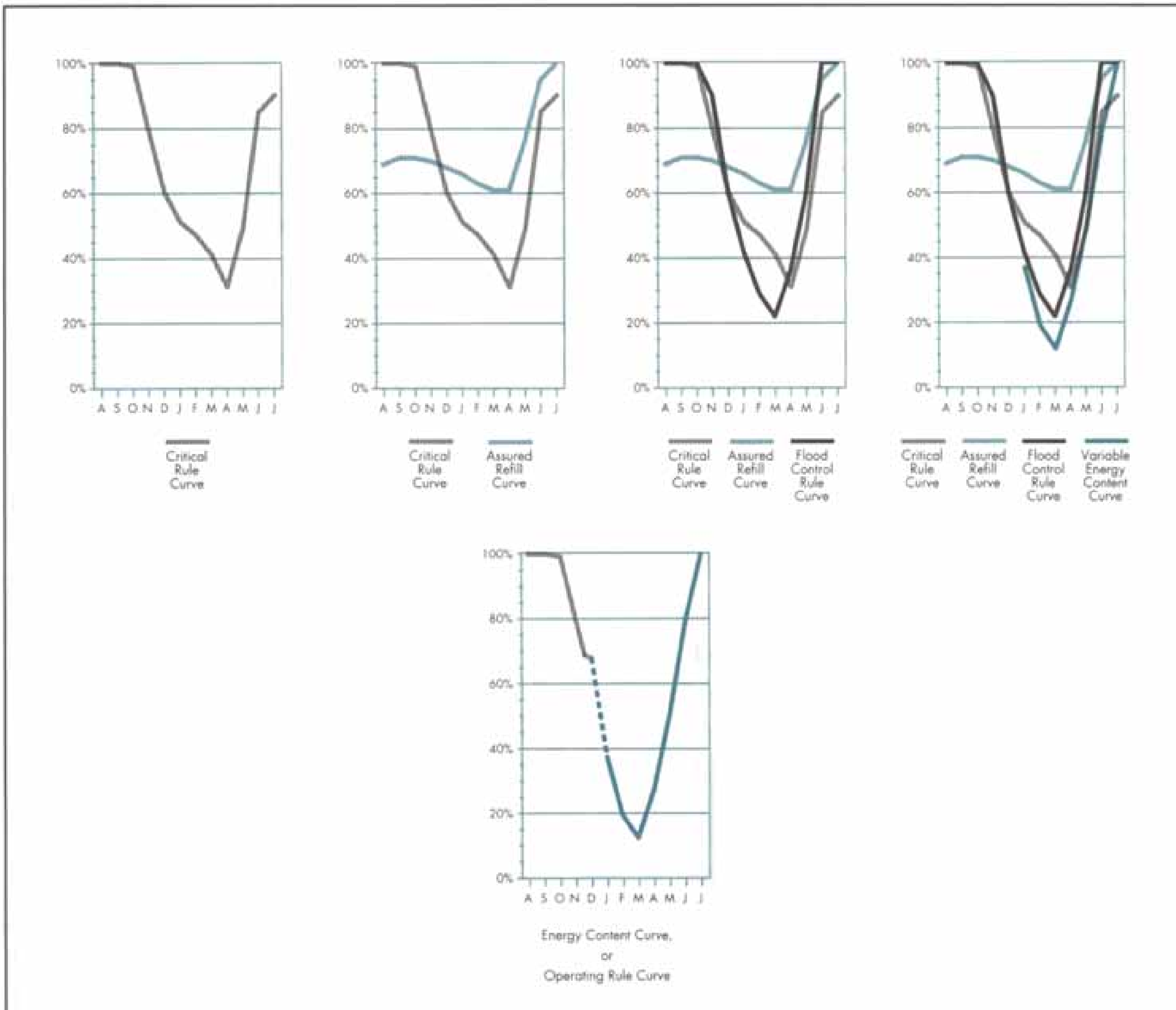
To ensure that the region's firm electric load can be met, PNCA studies use a 4-year planning horizon and a series of rule curves. This series of rule curves is part of what is used to determine where the system is allowed to operate during the year.

are often referred to as upper rule curves.

The **assured refill curve (ARC)** represents the lowest drawdown level from which a reservoir could refill given a repetition of the third-lowest runoff year (1931) in the 50-year water record. The assured refill curve is not specifically named in the Agreement.

The **energy content curve (ECC),** also known as the operating rule curve, is the higher of two curves, the critical rule curve and the assured refill curve; it must be at or below the flood control curve. It defines the level of drawdown available for producing nonfirm energy. After January, the ECC can be lowered, based on runoff forecasts that predict inflow. If it is lowered, it is known as the **variable energy content curve (VECC).** The VECC shows how much

The Energy Content Curve and its Relationship to Other Rule Curves



Each storage reservoir has its own ***energy content curve (ECC)****, or operating rule curve, that limits its reservoir draft and guides its operations. The ECC is constructed from the appropriate segments of the other rule curves. In the illustration above, the ECC is initially the critical rule curve and then, briefly, the assured refill curve. After refill projections in January, the variable energy content curve becomes the ECC. Had the flood control curve been below the VECC, that lower segment of the FCRC would have temporarily become the ECC.*

water must remain in each reservoir to create a 95 percent probability of refill by July 31.

Proportional Drafting

Whenever drafting to the ECC would not produce FELCC or meet certain flow requirements, proportional drafting may be used. Then, operations are guided by the 1st, 2nd, 3rd and 4th year critical rule curves that were developed during the previous years' planning. The 1st year CRC was developed during the current year's planning; the 2nd year CRC during the previous year's planning, and so forth. Each reservoir is operated the same distance proportionally (expressed in feet of elevation) between the guiding critical rule curves. These points, called proportional draft points (PDPs), become the ECCs.

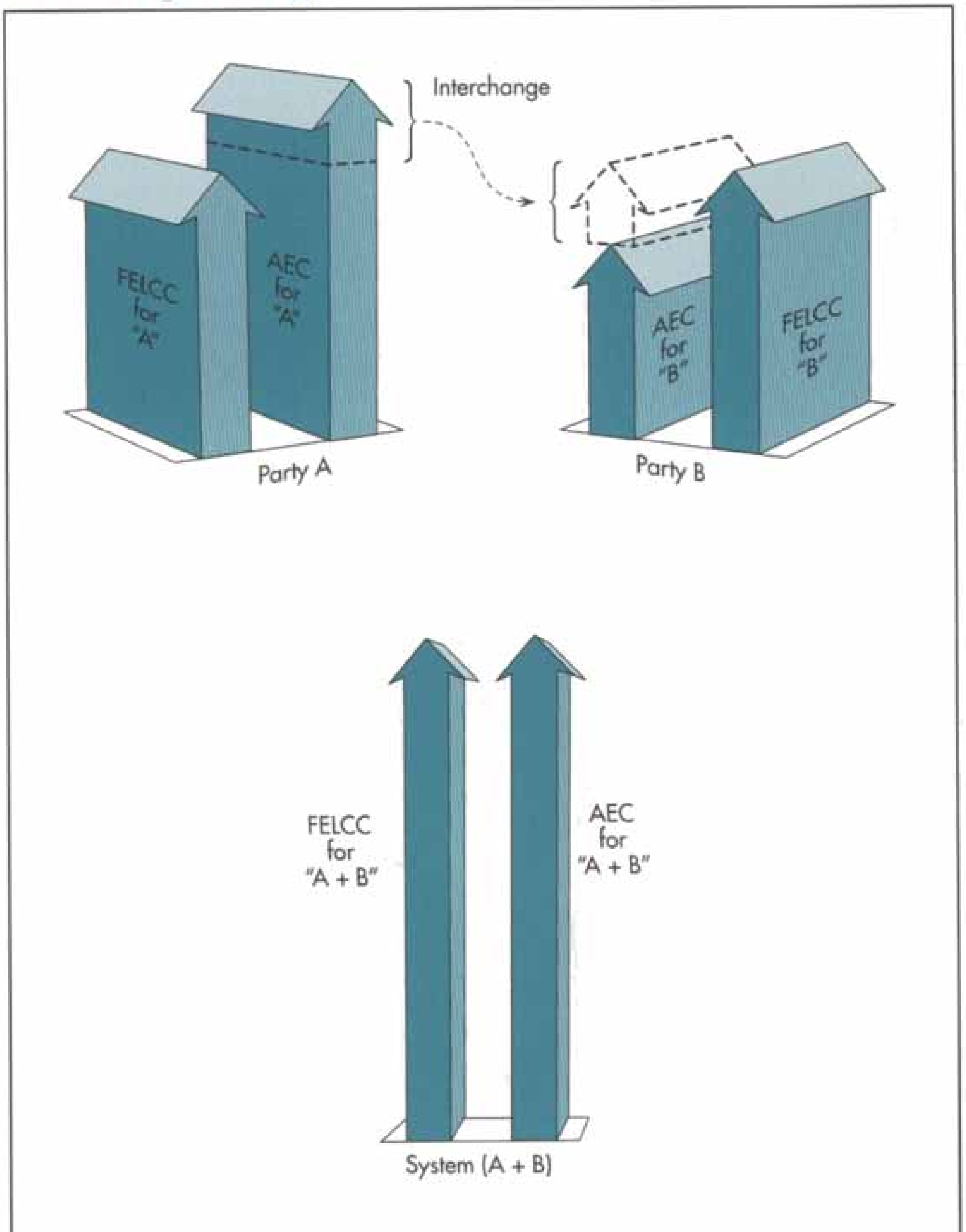
PNCA Transactions

Several kinds of energy transactions permit parties to realize many of the benefits of diversity.

Interchange energy. Interchange energy assures each party the ability to maintain its FELCC. Each party is expected to use its own resources to supply its own FELCC over the critical period. At any given time, however, a party may not be able to produce enough energy to meet its FELCC. Then, it may request the deficiency from other parties with resource capabilities exceeding their FELCCs. Since the total system is operated to meet system FELCC, one or more parties would have excess capability, and they are obligated to supply all or part of that excess to parties needing it. Energy so transferred is interchange energy.

In-lieu energy. When a party stores water in its reservoir above the ECC or PDP, downstream parties have a right to request release of the stored water. The reservoir party has the option to deliver the energy

Interchange Energy



In this example, the actual energy capability (AEC) of the coordinated system equals the system's firm energy load carrying capability (FELCC). Party A's AEC exceeds its FELCC while party B's AEC is less than its FELCC. Through coordination, party B has a right to request interchange energy from party A. If B makes this request, party A is obligated to deliver the energy.

equivalent of the water in lieu of an actual water release. Downstream parties receiving in-lieu energy must return it as the storage reservoir returns to ECC.

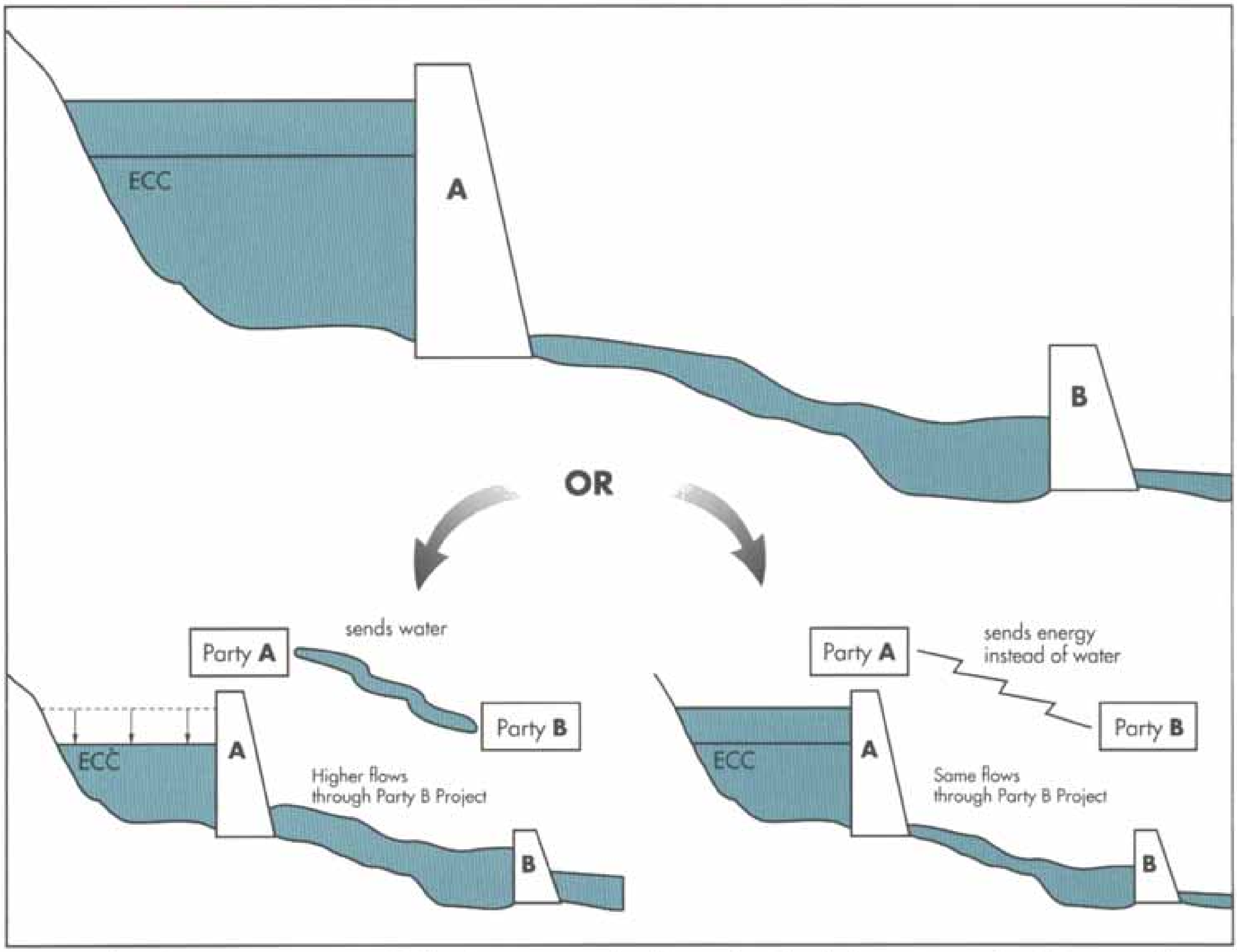
Storage energy. Any party with available reservoir space is obligated to accept energy deliveries from another party for storage and subsequent return. Both obligations are limited by storage ability as well as generation and transmission facilities surplus to the receiving party's needs.

Provisional energy is energy produced by drafting below the ECC or PDP, usually to obtain a higher short-term value for energy. To draft provisionally, owners must show how they can replace the energy. BPA typically drafts below the ECC to serve Direct Service Industries (DSIs).

Holding interchange energy replaces a party's need to draft its reservoir in early autumn to meet its FELCC even though the system's operating plan would not call for draft that early. To delay the draft, a reservoir receives energy (holding interchange energy) from other parties during September and/or October. The delivering parties also pay the reservoir party a "holding" or storage fee. The reservoir party returns the energy between November and March.

Flexibility adjustments permit parties to borrow up

In-Lieu Energy



Any water above the energy content curve (ECC) is the reservoir party's, subject to the rights of other parties to call on in-lieu energy. If water is stored above ECC, a downstream party may ask for its release. The upstream party may release the water or deliver the energy equivalent in lieu of the water.

to 5 percent of their future FELCC. Any such advances must be paid back by the end of the operating year (July 31). Typically, flexibility adjustments are allowed and needed to temporarily produce more than the planned amount of hydro power for higher than expected loads or the underperformance of thermal generation. When a party requests a flexibility adjustment the system's FELCC is increased by the amount of the party's request and the reservoirs are proportionally drafted to meet the adjusted FELCC. Later in the year the party's FELCC must be reduced and the reservoir system produces less FELCC in order to pay back the amount borrowed through flexibility.

Mica Dam is one of three Canadian storage projects built as a result of the Columbia River Treaty. Canadian hydroelectric operations are among the activities not covered in the Pacific Northwest Coordination Agreement.

The Role of Thermal

Although PNCA focuses primarily on hydroelectric operations, thermal resources figure into PNCA planning

What PNCA Does Not Cover

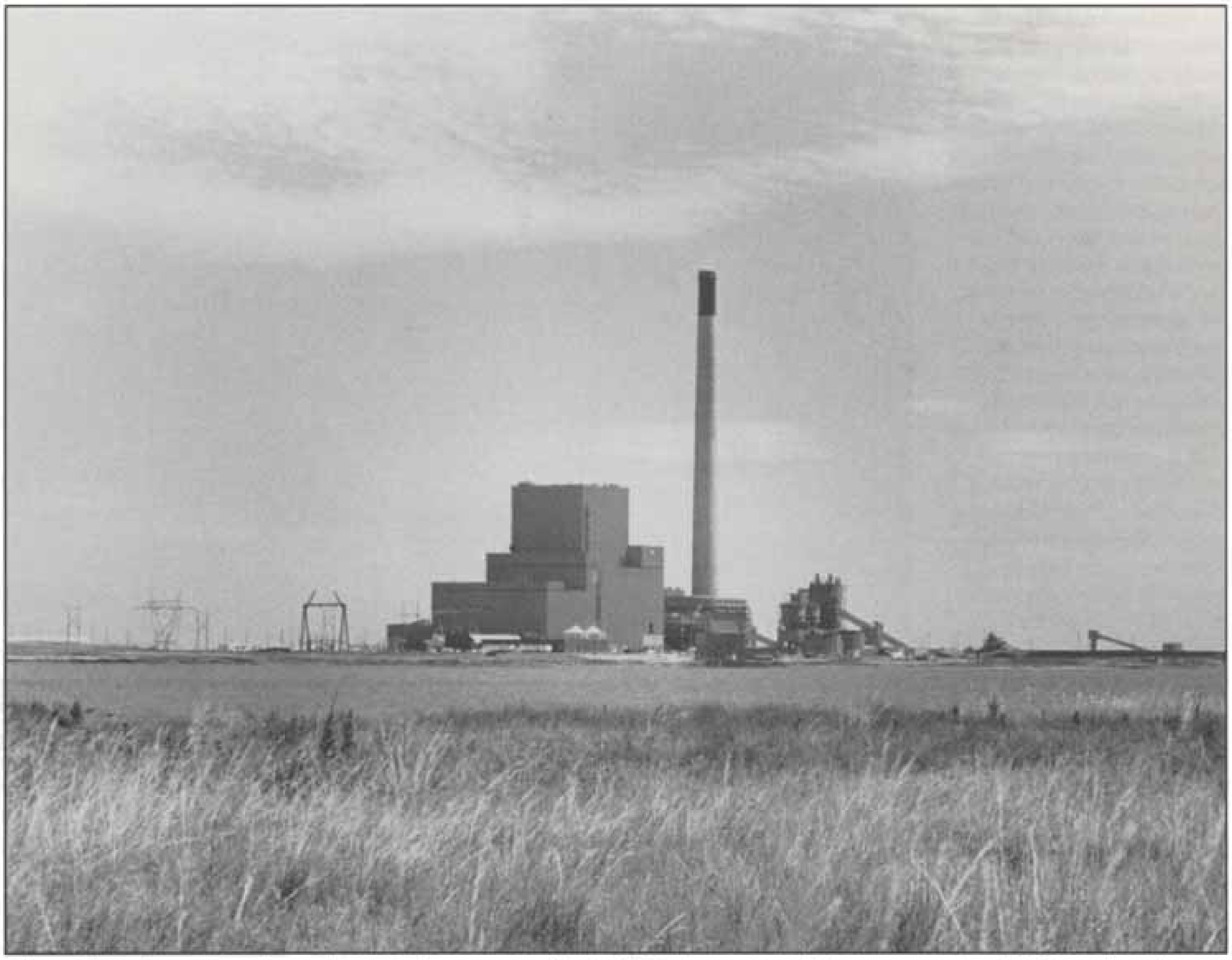
PNCA was not intended to and does not cover certain activities of importance to hydro planning and operations. These include the following.

Resource planning. PNCA does **not** deal with planning and construction of new resources. Overall regional resource planning is the responsibility of the Northwest Power Planning Council. Carrying out this overall plan for the Federal system is the responsibility of BPA's Resource Program. Individual utilities are responsible for planning to meet their own loads — for example, through construction, acquisition, purchase, and conservation. However, many parties will use the FLCC developed in PNCA studies to estimate their need for additional resources.

Short-term operations. Although transactions such as storage and in lieu are arranged daily and may apply for periods as short as an hour, most PNCA studies are of longer duration. PNCA studies deal primarily with monthly energy transactions. During April and August, the months of greatest flow differences, these "monthly" studies are performed for half-month intervals. The Actual Energy Regulation (AER) is run routinely twice a month and as often as weekly to determine ending elevations and interchange rights and obligations. FPLCC studies are made annually but are not currently influencing transactions.

Canadian operations. Canadian project operations are guided by the Assured Operating Plan (AOP and Detailed Operating Plan (DOP) specified by the Treaty. However, the DOP and PNCA planning are mutually consistent.

Determination and implementation of nonpower requirements. NPRs are submitted by parties. PNCA planning and operating studies must accept them. Individual parties adapt their operations to NPRs, and PNCA studies optimize system FELCC within these requirements.



Although thermal resources submitted by parties become part of their FELCC, the operation of these resources is not PNCA-coordinated.

and operations. A party with thermal projects may include them in the firm resources that comprise its FLCC. As part of FLCC, these resources will help determine that party's PNCA rights and obligations. In PNCA planning, however, a party's thermal energy capability is not guaranteed or backed up by the hydro system. Parties have a fixed amount of hydro energy in the critical period and will attempt to meld that hydro capability with their thermal capability in planning by scheduling thermal generation and maintenance when streamflows are expected to be respectively low or high.

In actual operations, thermal resources are backed up by the hydro system in a limited way. For example, if thermal resources do not perform as planned, PNCA flexibility adjustments are permitted as long as repayment occurs by the end of the operating year. However, major unplanned outages will require the thermal project owner to seek other than coordinated firm hydro backup as the hydro must be repaid.

Nonpower Requirements

The single sentence in the agreement dealing with nonpower requirements (NPRs) assures priority to NPRs over power needs. Whenever an NPR can be implemented by a single reservoir owner, that owner includes the NPR in the data submittal to the annual planning process. The process begins in February. But if coordination between two or more owners is needed, the affected owners make appropriate arrangements.

Most NPRs are project specific. For example, minimum flow requirements at Libby or reservoir elevation limits at Mid-Columbia projects can be met by the project owners in the absence of PNCA operations. Some NPRs, however, cannot be met without coordinated upstream storage. The Vernita Bar Agreement, for example, requires cooperative efforts of Grant County PUD, BPA, the Bureau of Reclamation, and others to deliver flows needed for fall chinook salmon to spawn downstream of Priest Rapids Dam.

Typically, owners include NPRs in PNCA planning and operations to facilitate system coordination. The question for PNCA parties as a whole is **how**, not **whether**, to meet NPRs. PNCA studies and operations meet the requirements defined by the owners submitting the NPRs. Sometimes an owner chooses to leave an NPR out of PNCA. Then, the owner meets the NPR in actual operations, but these operations do not affect PNCA transactions.

Management of PNCA Operations

Each party is responsible for submitting data about its own load and resources (hydro, thermal, purchases and exchanges) as well as the maintenance schedule for its generating resources. The staff of the Northwest Power Pool collects the data and prepares the studies that guide operations.

Under PNCA, nonpower requirements (NPRs) take precedence over power requirements. An important nonpower requirement is the Water Budget, a specified volume of water that must be provided during a two-month period each spring to help move young salmon downstream.

Chapter Six: How The PNCA Has Changed

Over nearly three decades, the basic PNCA principles have remained intact, but numerous changes have been made. One new representative and one new party have been added (the Bureau of Reclamation in 1981 and Snohomish County PUD in 1984), and charges for services have been modified.

Others changes reflect operating experience or adaptations to new requirements. The more significant changes and interpretations appear in amendatory agreements or in documents called operating procedures which annually clarify and fill in gaps in the contract. Three particularly important changes are the Actual Energy Regulation (AER), the composite reservoir, and modelling for the Water Budget.

Actual Energy Regulation

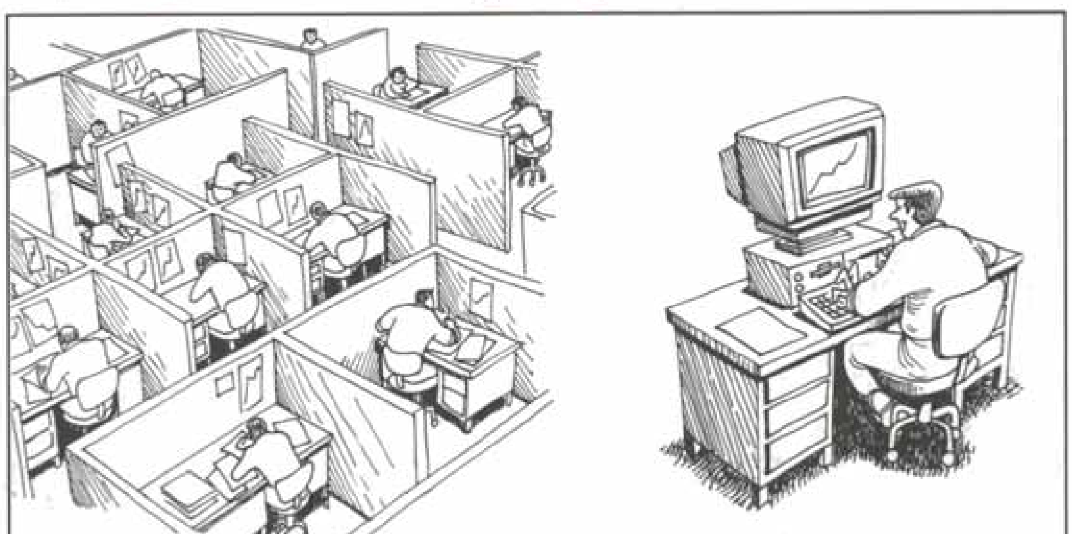
The PNCA contract requires the development of **Actual Energy Capability** (AEC) to guide short-term operations and serve as a basis for rights and obligations. Initially, each party prepared its own AEC. Beginning in 1977, this procedure was superseded by a unified PNCA procedure, the AER. The AER, a continuous simulation of the hydro system using actual and forecasted streamflows for past and future periods for the current operating year, is distributed at least twice a month and now serves as the basis for determining actual rights and obligations. For each reservoir, the AER determines the required storage operation or energy content and specifies the hydroelectric component of each party's AEC.

Composite Reservoir

The **composite reservoir** concept was introduced to simplify in-lieu energy transactions among the five mid-Columbia projects and the upstream Federal and Canadian storage projects. These transactions were complicated, in part, because each mid-Columbia project had multiple participants (based on ownership or contractual right to shares of the output), and each participant typically had rights in more than one project. This meant they all had rights to in-lieu energy, based on their proportional shares. And each had specific needs and limitations when it came to scheduling water releases or in-lieu energy. Furthermore, each upstream reservoir had its own peculiarities to be considered in determining how and when water releases reached a downstream project or, alternatively, how much in-lieu energy was owed.

The composite reservoir simplifies things by treating the Federal upstream reservoirs as one reservoir located at Grand Coulee. All mid-Columbia plants are assumed to have the same flow time with respect to a given upstream reservoir. And numerous additional provisions clarify

Preparing the Actual Energy Regulation



Prior to 1977, each party prepared its own actual energy capability (AEC). Now, the Northwest Power Pool simulates the hydro system and prepares the actual energy regulation (AER) that determines storage and energy content for each coordinated reservoir as well as interchange energy rights and obligations.

scheduling, accounting, and other relevant issues. With composite reservoirs, utilities that ask for release of water receive equivalent energy in every situation.

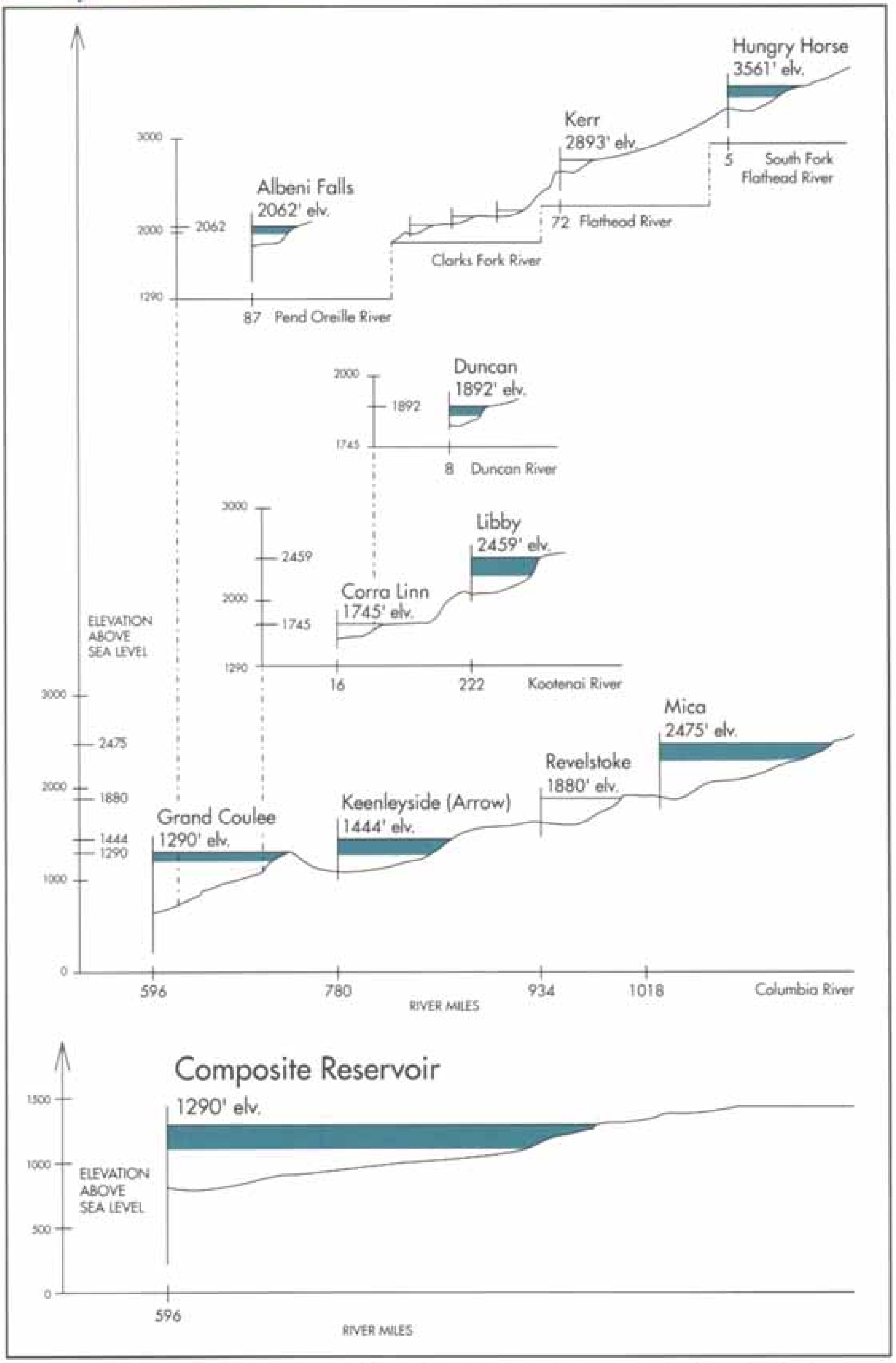
Modeling the Water Budget

The **Water Budget**, which originated with the Northwest Power Planning Council plan for rebuilding salmon stocks, is a specified volume of water to be released between April 15 and June 15 to help move juvenile salmon between reservoirs as they travel downriver. These releases simulate the effects of the spring freshets, the heavy streamflows from spring snowmelt that moved fish downstream before dams were built. The Water Budget is intended to reduce mortality from predators and other hazards of migration.

It requires releases of up to 4.64 million acre-feet (5 726 million m^3) during the two specified months, 3.45 million acre-feet (4 257 million m^3) on the Columbia and 1.19 million acre-feet (1 468 million m^3) on the Snake. The monitoring points are Priest Rapids and Lower Granite Dams. Since these dams have no storage, the Water Budget comes primarily from upriver dams.

A PNCA operating procedure outlines the principles for **modeling the Water Budget** and the priorities and procedures to be used. The main procedures include proportional draft of all projects, sequential drafts of specified projects to specified levels, and proportionally filling all reservoirs whose outflow does not pass through the McNary Project.

Composite Reservoir



The concept of a composite reservoir simplifies in-lieu energy transactions among the mid-Columbia projects and the upstream storage projects. The concept assumes that all Federal and Canadian Treaty projects at and upstream of Grand Coulee are one project with Grand Coulee's location. It includes the total storage capability of each reservoir (represented by the shaded area) summed together.

Chapter Seven: Frequently Asked Questions About PNCA

Q. What is the Pacific Northwest Coordination Agreement?

A. An agreement that establishes rights and obligations for receiving and delivering energy needed to meet the parties' firm load carrying capability (FLCC).

Q. What is PNCA's purpose?

A. To define the optimum power system capability by taking advantage of the flexibility that remains in the Columbia River system after nonpower requirements are met.

Q. Who are the 17 parties?

A. Fourteen of the Northwest's major hydro generating utilities plus the Federal government, the U.S. Entity (the U.S. representative in Columbia River Treaty matters), and a subsidiary of an industry served directly by the Bonneville Power Administration.

Q. How is the Columbia River Treaty handled?

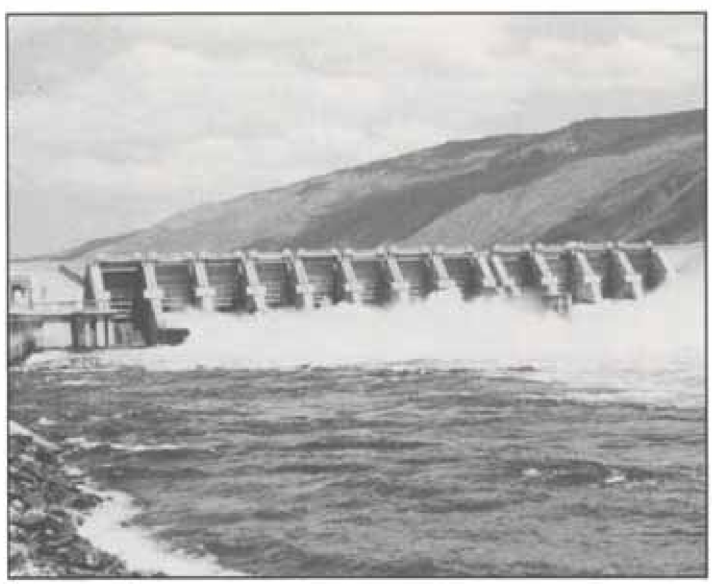
A. Operating plans for the Treaty projects are agreed to by the U.S. Entity and the Canadian Entity. These plans are incorporated into PNCA planning.

Q. What is the term of the Agreement?

A. The Agreement (executed September 15, 1964) became effective January 4, 1965 and extends until June 30, 2003.

Q. How does PNCA affect the power planning of individual PNCA parties?

A. PNCA can be the foundation but is not expected to be the totality of an individual power plan. Other local planning decisions involve adding and retiring resources, incorporating non-hydro resources and purchases, negotiating nonfirm sales, and operating individual projects within other guidelines.



When water is spilled, it bypasses turbines and produces no electricity. Spilling is minimized through coordinated planning and operation of the region's major hydroelectric projects.

Q. How does PNCA affect a party's power operations?

A. PNCA does not specify day-by-day operations. PNCA establishes monthly operating guidelines and targets for each project's storage. PNCA also defines rights and obligations for receiving and delivering firm energy through bilateral transactions. Although the requirements are **expressed** in operational terms, parties may choose to **meet** these requirements in a variety of ways — storage, discharge, energy delivery or payments.

Q. How are nonpower requirements handled by PNCA?

A. Since NPRs have priority over power production, the question is not whether but how to meet NPRs. For project-specific NPRs, the project owner lets PNCA representatives know how the NPR will be accommodated. For NPRs affecting multiple projects, the affected owners make arrangements to meet the NPR. For systemwide NPRs, the PNCA contract committee determines the best way to meet the obligation.

Q. What are PNCA's priorities?

A. In order, PNCA's priorities are nonpower requirements, ensuring that parties can produce their firm capabilities, refilling the region's reservoirs, and producing nonfirm energy. (In addition, individual parties may have other legislative and licensing commitments.)

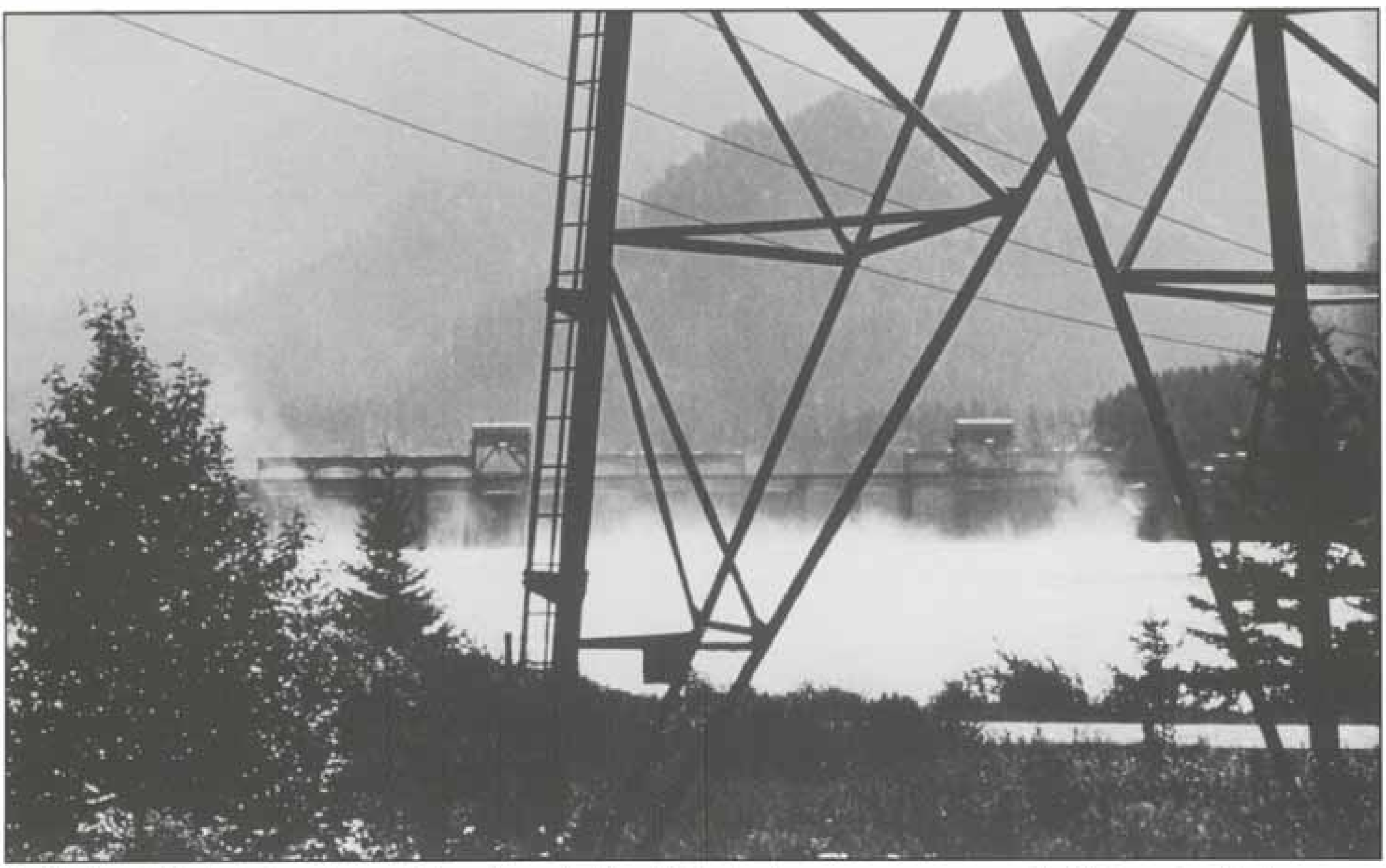
Q. What is the relationship between PNCA and the Canadian Entitlement?

A. The Treaty assumed some form of coordination to realize the benefits of operating the Canadian storage. The PNCA provides that particular coordination for the hydro system.

Q. What is critical water, and why does PNCA use it instead of average water as the basis for PNCA planning?

A. Critical water is a term describing the region's most adverse streamflows during the 50-year historical record. Average water refers to average streamflows during this same 50-year period. In planning, PNCA uses critical water to provide a high degree of certainty of being able to meet FELCC. Average water planning, in theory, would leave the region short of water needed to meet firm load one out of every two years, on average.

Critical water assures a high degree of hydroelectric reliability throughout the region.



The Northwest's highly developed transmission system makes it possible to transfer power among areas with widely varying climatic conditions, electric loads and energy resources.

Chapter Eight: What's Ahead for PNCA

Since mid-1990, a comprehensive review of the multiple uses of the Columbia River has been underway. The System Operations Review (SOR) will culminate in a draft environmental impact statement (DEIS) scheduled for 1993 and, after public meetings and comments, a final environmental impact statement (EIS) in 1994. The review is being conducted by the U.S. Army Corps of Engineers, the U.S. Bureau of Reclamation, and the Bonneville Power Administration.

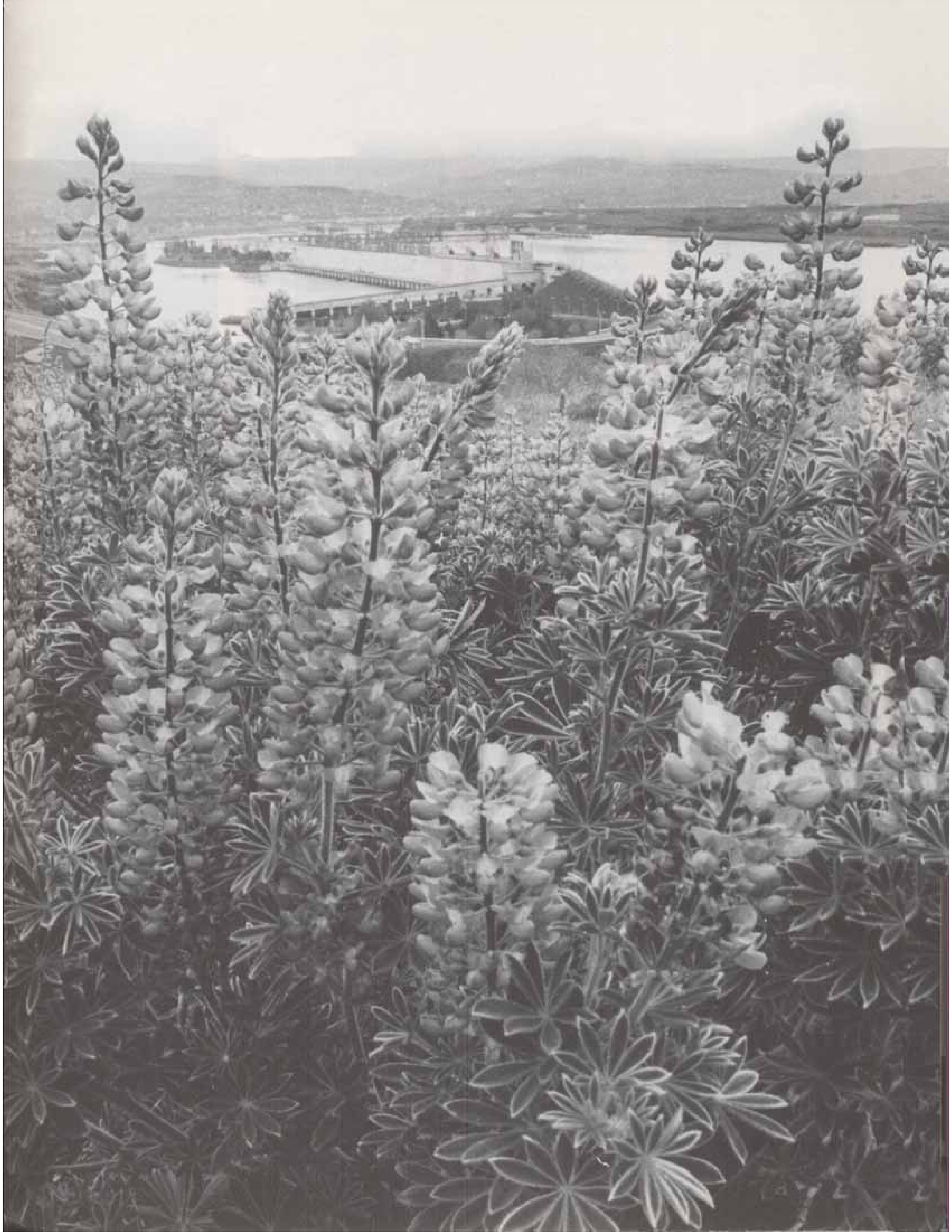
Multiple-use decisions are increasingly complicated as more river users compete for a limited resource. At issue are four major decisions: (1) a system operating strategy, or SOS, (2) a method for reviewing and updating the SOS, (3) renewal of the PNCA, and (4) renewal of the Canadian Entitlement Allocation Agreements (CEAA).

PNCA's expiration, in 2003, was intentionally set to incorporate the transactions reflecting the 30-year purchase of the Canadian Entitlement (Canada's half of the Treaty benefits) by the Canadian Storage Power Exchange (CSPE) and the power generation required by the CEAA. PNCA renewal needs to be considered well in advance of its expiration date, in view of its four-year planning horizon and its connection to the allocation of obligations to partially return the Canadian Entitlement starting in 1998. By 2003, the U.S. obligation to return Canadian entitlement is fully required. The parties are currently working on defining new entitlement agreements that specify the non-Federal share of the return. This new CEAA will appear in PNCA studies that begin in 1995-96 and will include, as part of the 4-year critical period, the 1998-99 operating year.

How to Remain Informed

An SOR work group, the PNCA Alternatives Analysis Group, began meeting in February 1992 to identify potential alternatives for analysis and to develop analytical methods for comparing the alternatives. In 1990, parties to PNCA also began holding open meetings to consider potential changes to the agreement as preparation for contract renewal. A decision by Federal parties to renew or revise this agreement requires compliance with the National Environmental Policy Act (NEPA). To find out about the status of these activities or to receive information about SOR publications, call the SOR Interagency Team. Telephone numbers are listed at the beginning of this document.

Many Northwesterners are taking part in a comprehensive review of the multiple uses of the Columbia River. Among major decisions to be made are those involving renewal or modification of the Pacific Northwest Coordination Agreement.



Summing It Up

The Pacific Northwest Coordination Agreement is a commitment by the region's major hydroelectric generating utilities and affected Federal agencies to optimize power benefits by treating the Columbia River as a single-owner system.

In annual planning sessions, the parties jointly and cooperatively determine the system's aggregate firm capability. They then mutually support each other's operations to meet nonpower requirements, to carry firm load, to use their hydroelectric resources most economically and effectively, and to enhance the production of nonfirm energy. Load carrying capability is assured through rights and obligations related to bilateral transfers of energy, including delivery, replacement, and payment obligations.

PNCA develops guidelines for storage reservoirs that determine how much load can be carried under the most adverse streamflow conditions. These guidelines take the form of permitted reservoir storage elevations. Obligations may be met in various ways — storing or discharging water, delivering energy, making payments, and demonstrating refill capability if drafting below targets.

Few places in the world can equal the hydroelectric potential found in the Pacific Northwest's clouds, snowpacks, and streams. Optimizing the power benefits from this natural potential is a major objective of the Pacific Northwest Coordination Agreement.

Appendix A: The Secretary's Principles

In paraphrased form, these are the principles that form the basis for the Pacific Northwest Coordination Agreement. They were announced by Interior Secretary Stewart Udall in March 1961.

1. No party shall be required to operate its facilities in a manner inconsistent with nonpower uses.
2. The combined power facilities of the parties shall be operated to produce optimum firm load-carrying ability.
3. Upon demand by a downstream entity a storage owner shall release all water not needed for subsequent firm loads or shall provide energy in lieu thereof.
4. Each party shall be entitled to a firm load carrying capability equal to its capability in the critical streamflow period with full upstream storage release, except for reimbursement of Canadian Treaty benefits and restoration of capability to parties that suffer loss in critical period capability as a result of the Treaty.
5. Firm load carrying capabilities shall be sustained by exchange of energy between parties.
6. Each party shall accept energy that is surplus to other parties' needs for storage in available reservoir space.
7. The obligation to reimburse Treaty power to Canada shall be shared by the projects that benefit from Treaty storage in proportion to their benefits.
8. Equitable compensation shall be made for the benefits from reservoir storage, including compensation by the United States to the extent consistent with applicable law.
9. Interconnecting transmission facilities shall be made available for coordination use subject to the owner's prior requirements.
10. Each party shall consult with the others in developing detailed plans for operation of its facilities.
11. Equitable charges shall be made for capacity, energy, transmission, storage and other services.
12. Bonneville Power Administration shall sell to the nonfederal parties the capacity they require for delivery of capacity benefits to Canada.

Appendix B: Hydroelectric Projects Coordinated By PNCA

Federal agencies

Corps of Engineers
- Albeni Falls
- Big Cliff
- Bonneville
- Chief Joseph
- Cougar
- Detroit
- Dexter
- Dworshak
- Foster
- Green Peter
- Hills Creek
- Ice Harbor
- John Day
- Libby
- Little Goose
- Lower Granite
- Lookout Point
- Lost Creek
- Lower Monumental
- McNary
- The Dalles

Bureau of Reclamation
- Anderson Ranch
- Black Canyon
- Boise Diversion
- Chandler
- Grand Coulee
- Hungry Horse
- Minidoka
- Packwood
- Palisades
- Roza

Project Output part of Federal Columbia River System
- Cowlitz Falls (owner, Lewis County PUD)
- Packwood (owner, Washington Public Power Supply System [WPPSS])
- Priest Rapids[1]
- Wanapum[1]
- Wells[1]

Public agencies

Chelan County PUD
- Lake Chelan[2]
- Rock Island[2]
- Rocky Reach[2]

Colockum Transmission Co., Inc.
- Rocky Reach[3]

Cowlitz County PUD
- Swift #1[3]
- Swift #2[3]
- Priest Rapids[3]
- Wanapum[3]

Douglas County PUD
- Rocky Reach[3]
- Wells[2]

Eugene Water and Electric Board
- Carmen
- Leaburg
- Priest Rapids[3]
- Trail Bridge
- Walterville
- Wanapum[3]

Grant County PUD
- Priest Rapids[2]
- Wanapum[2]

Pend Oreille County PUD
- Box Canyon
- Sullivan Lake

Seattle, City of
- Boundary
- Cedar Falls
- Diablo
- Gorge
- Newhalem
- Priest Rapids[3]
- Ross

Snohomish County PUD
- Henry M. Jackson

Tacoma, City of
- Alder
- Cushman #1
- Cushman #2
- La Grande
- Mayfield
- Mossyrock
- Priest Rapids[3]

Investor owned

Montana Power Company
- Kerr
- Thompson Falls

Pacific Power and Light Company
- Albany
- Bend
- Big Fork
- Clearwater #1
- Clearwater #2
- Cline Falls
- Condit
- Copco #1
- Copco #2
- Eagle Point
- Falls Creek
- Fish Creek
- Iron Gate
- John Boyle
- Klamath Lake
- Lebanon
- Lemolo #1
- Lemolo #2
- Merwin
- Naches
- Naches Drop
- Pelton Reregulating[4]
- Powerdale
- Priest Rapids[3]
- Prospect #1
- Prospect #2
- Prospect #3
- Prospect #4
- Rocky Reach[3]
- Slide Creek
- Soda Springs
- Stayton
- Swift #1[2]
- Swift #2[2]
- Toketee Falls
- Wallowa Falls
- Wanapum[3]
- Wells[3]
- Yale

Portland General Electric Company
- Bull Run
- Faraday
- North Fork
- Oak Grove
- Pelton
- Pelton Reregulating[5]
- Priest Rapids[3]
- River Mill
- Rocky Reach[3]
- Round Butte
- Sullivan
- Timothy
- Wanapum[3]
- Wells[3]

Puget Sound Power and Light Company
- Electron
- Lower Baker
- Nooksack
- Priest Rapids[3]
- Rock Island[3]
- Rocky Reach[3]
- Snoqualmie Falls #1
- Snoqualmie Falls #2
- Upper Baker

Wanapum[3]
Wells[3]
White River
Washington Water
Power Company
Cabinet Gorge
Lake Chelan[3]
Little Falls
Long Lake
Meyers Falls
Monroe Street
Nine Mile
Noxon Rapids
Post Falls
Priest Lake Storage
Priest Rapids[3]
Rocky Reach[3]
Upper Falls

Wanapum[3]
Wells[3]

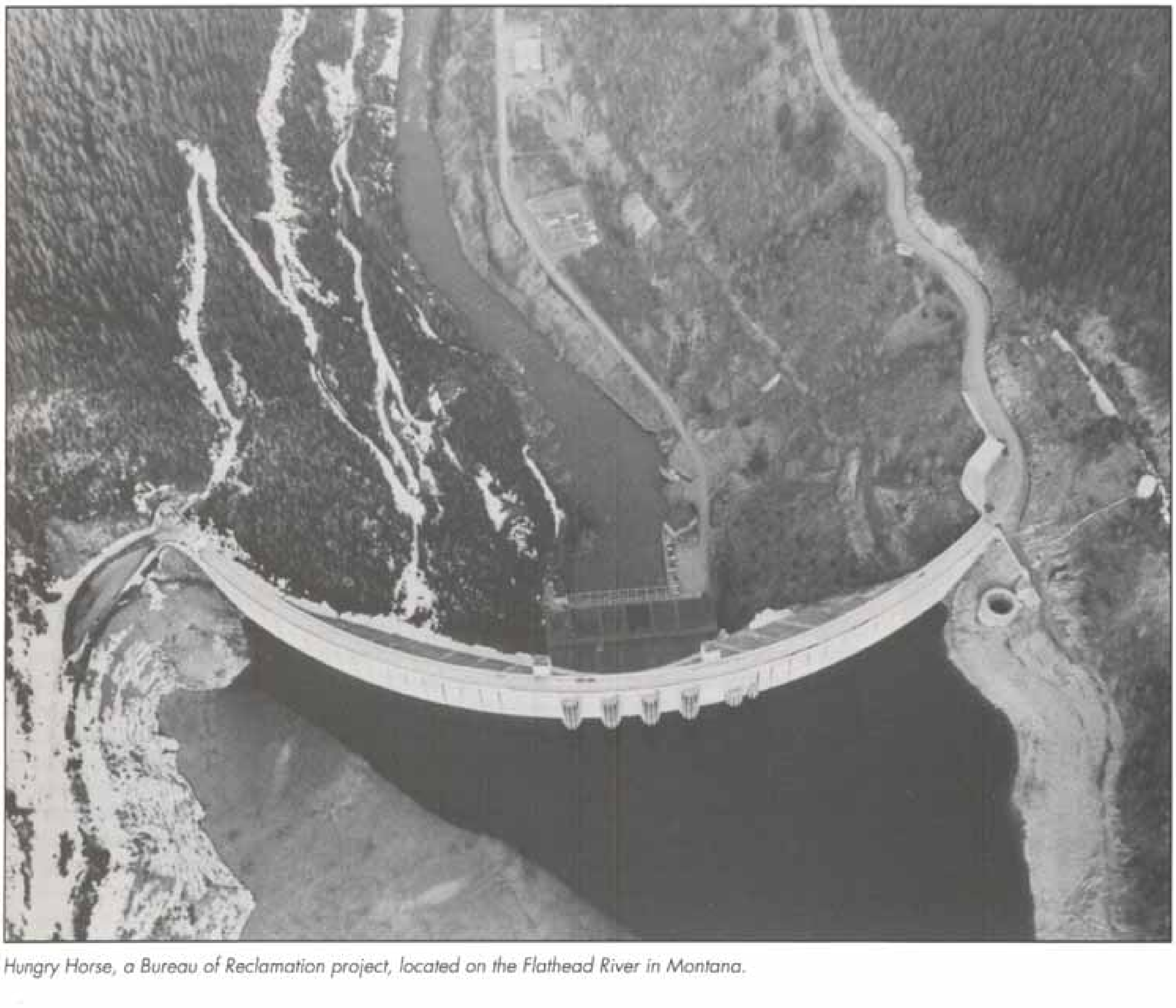
[1]Part of project output is purchased by Forest Grove, McMinnville, and Milton-Freewater and received through BPA.

[2]Project is operated by utility; part owner of project output.

[3]Part of project output is purchased by utility.

[4]Full project output is purchased by utility.

[5]Project is operated by utility, but has no share of project output.



Hungry Horse, a Bureau of Reclamation project, located on the Flathead River in Montana.

Appendix C: PNCA: Section By Section

This summary is intended only as an overview, not as a substitute or interpretation for the agreement itself. In the interest of space and readability, the contract language has been paraphrased and greatly compressed. As a further aid to readability, technical terms that are capitalized in the contract are not capitalized here. Operating procedures, typical practices and comments are bracketed to distinguish them from contract specifications. It is totally inappropriate to consider Appendix C as an official interpretation of the contract by any party.

Part I. Introductory Provisions

Section 1. Term of agreement. This section lists the beginning and ending dates, refers to survival rights and obligations, and terminates the [then] existing agreement.

Section 2. Definitions of terms. The meanings of 36 terms are explained. [The most important of these terms are discussed in the text and defined in the glossary of this publication.]

Section 3. Exhibits. The following exhibits are attached to the agreement: (1) system firm resources, (2) hydroelectric projects existing or under construction on January 17, 1961, (3) limits of rights to restoration, (4) reserves, (5) computation of payments under subsection 13(a), (6) provisions relating to work hours, (7) provisions relating to discrimination.

Section 4. Agreement to coordinate. The parties agree to coordinate the operation of their systems to produce optimum FLCC and usable nonfirm energy.

Section 5. The coordination contract committee. Each PNCA party has one representative on this committee. The committee's duties are making studies and plans required for coordinated operation.

Part II. Planning

Section 6. Determination of FLCC.

- **Section 6a. Load and resource data.** By February 1 each year, each party provides data to guide planning for the contract year beginning August 1. This information includes the party's (1) estimated firm load, (2) hydro and thermal resources, including nonpower requirements, (3) firm contracts for buying or selling power outside the system, (4) scheduled maintenance outages, (5) schedule of new or additional resources, and (6) resources to be retired. This is commonly called the "February data submittal".
- **Section 6b. Preliminary regulation.** By March 15, a preliminary regulation is made, using the February 1 data as input. It estimates each party's FELCC and distributes it during the critical period. The regulation assumes each reservoir begins the critical period full and, by the end of the critical period, is drafted to its normal bottom elevation. This is the parties' first estimate of their FLCC.
- **Section 6c. Modified regulation.** By April 1, each party may make changes to its February 1 data submittal in regard to thermal resources, contracts, outages, and loads. It must revise loads so that (1) average loads during critical periods equal the party's critical period capability from the preliminary regulation adjusted for restoration and (2) peak load in any period does not exceed its capability expected in the modified regulation. After April 1, a modified regulation shapes the system's FELCC to its estimated adjusted load and adjusts loads for "nonusable" or unshapable FELCC during the critical period. It also determines each system's FLCC.
- **Section 6d. Changes in modified regulation.** By May 15, each party may fine-tune the regulation of its reservoirs as set forth in the modified regulation. [This procedure occurs during the "6(d) meeting".] Such changes must fall within established limits — e.g., no increase in the system's total spill during the critical period, no change in the April 1 reservoir elevations in the modified regulation. Following these adjustments, any party may reregulate its reservoirs to increase peaking if it is peak deficient or to increase its energy capability, subject to limitations and rights of downstream parties. If desired adjustments to eliminate imports are precluded by these contract limitations, importing or exporting parties may designate the transfers as holding interchange energy to assure delivery and minimize cost.
- **Section 6e. Final regulation.** By July 1, a final

regulation is made, incorporating all changes in the preliminary and modified regulations, decisions made at the 6(d) meeting and adjustments for restoration.

- **Section 6f. Determination of restoration**. This section affirms the right of each party to carry at least the same firm energy load with as without Canadian storage. [Some parties found that they had reduced critical period capabilities with the addition of Canadian storage.] Parties with reduced critical period capabilities are entitled to restoration from parties with increased abilities. A formula for computing gains or losses is provided.
- **Section 6g. General limitations on estimated adjusted loads**. This section states that a party's FELCC (adjusted load) must not exceed its critical period capability.
- **Section 6h. Rankings for critical rule curves from current and previous years' critical period studies**. This section identifies and establishes rule curves to be used for the contract year.
- **Section 6i. Establishment of firm load carrying capability**. By August 1, FELCC is established, from the final regulation, for each party for the new contract year. However, if the coordinated system's reservoirs failed to reach 98 percent of refill on July 31, the actual composite system content is compared, in order, to critical rule curves 2, 3, and 4 and to "empty" from the previous year's final regulation studies. The study with the rule curve closest to the actual energy content is adopted as FELCC. [Note: In recent years, the actual energy regulation, or AER, elevation is used for the actual elevation.)
- **Section 6j. Adjustments in planned firm load carrying capability**. By August 15, if FELCC adjustments have been required because the system failed to reach 98 percent refill, other adjustments are permitted — e.g., adding or retiring firm resources, making extra-system purchases, and considering new nonpower uses. Changes in a party's FELCC reflect the adjustments.

Section 7. Determination of energy content curves. ECCs are intended to provide (1) enough storage for the system to generate FELCC during periods of adverse streamflow and (2) assurances of refill. They are expressed as elevations in feet at each end-of-month for the 12-month period beginning August 1. ECCs are the higher of the lst year critical rule curve (CRC) or assured refill curve (ARC). From January through July when runoff projections are used to predict refill, the variable energy content curve (VECC), if lower than CRC and ARC, becomes the ECC. The ECC is also limited by flood control and minimum flows for power and nonpower requirements. Proportional drafts below ECC or nonpower requirements may also become the ECC. [These clarifications are specified in an operating procedure.] Each reservoir party may draft to the ECC at any time to produce nonfirm energy. Drafting below ECC is permitted only for proportional draft to support coordinated system FELCC or to generate provisional energy. Downstream parties have the right to request draft to the ECC. A reservoir party has the right to release the water or to deliver energy in lieu of the water that would have been released.

- **Section 7a. Critical period one year or less.** [This has not been used for more than 20 years.]
- **Section 7b. Critical period longer than one year**. For multi-year critical periods, the ECC for each reservoir at the end of each period is the higher of the 1st year critical rule curve or the assured refill curve. [Note: As the historical streamflow data base grew, this was subsequently changed to the third lowest streamflow to maintain the same probability.]
- **Section 7c. Variable energy content curves**. VECCs provide for drafts below the ECC from January through July by the amount that forecasted inflows exceed refill requirements. VECCs are developed to allow secondary energy to be produced without jeopardizing refill. To reduce refill failure caused by producing nonfirm energy, a refill test is made using the historical streamflow record to determine the number of years that energy exceeded FELCC (in January-July) and system reservoirs failed to reach 98 percent full by July 31. If this happened more than 5 percent of the years in the historical period, VECCs and ARCs

are raised to reduce nonfirm energy production or eliminate the refill failure.

Section 8. Maintenance and reserves. This section deals with outages for scheduled maintenance and reserves needed to cover maintenance outages as well as forced outages.

Part III. Operations

Section 9. Operating procedures, obligations and entitlements.

- **Section 9a. Use of FLCC and of energy and capacity in excess of FLCC.** Each party may use its FLCC for any purpose. It may similarly use its energy or capacity in excess of FLCC to the extent that coordinated system capability exceeds that needed to carry load. A party's excess is the difference between its AEC and its FELCC, adjusted for other parties' rights and obligations.
- **Section 9b. Actual Energy Capability.** This section outlines the method for parties to determine their AEC — energy generated by their systems and received from firm arrangements outside their systems — and for adjusting AEC to reflect PNCA obligations. [Note: Following changes in the PNCA operating procedures, the AEC is produced for all parties by the Northwest Power Pool staff from the actual energy regulation, a continuous simulation of actual observed streamflows and forecasted current and future flows for the current contract year.]
- **Sections 9c,d,e. Interchange energy and interchange capacity.** Each party is entitled to its FLCC at all times. But, at any given time, some parties will have more generation than their FELCC and some will have less. Those with less can meet their FELCC by scheduling deliveries from those with excess. Arrangements for returning the energy are complicated. In any case, return is required when the receiver's own AEC once again exceeds its FELCC. If returns do not equal deliveries by the end of the contract year (July 31), imbalance payments are made.
- **Sections 9f and g. Priorities on deliveries of thermal interchange energy.**
- **Section 9h. Operation of reservoirs below ECCs and CRCs (proportional draft).** [Note: Parts of this section have been revised by operating procedures.]
- **Section 9i. Priorities on use of facilities.** This section ensures that PNCA requirements do not exceed a party's capabilities, considering its obligations to supply its own FLCC and meet its own transmission contracts. In order, the first five (of 12) priorities are: (1) supplying a party's own FLCC from its own firm hydro and using its transmission capacity for its own FLCC and to fulfill transmission contracts, (2) supplying its own FLCC from its other firm resources, (3) delivering interchange capacity, (4) delivering and returning in-lieu energy, and (5) returning stored energy needed for another's FELCC.
- **Section 9j. Storage of energy in reservoirs.** A party with excess energy may store it with any reservoir party having available space. The reservoir party decides how to use its storage space, which energy to displace and which requests for storage or return can be met. If spills are required, the reservoir party decides which energy is spilled, notifies the affected party and tries to conserve the energy that will be displaced.
- **Section 9k. Release of water from storage and in-lieu energy deliveries.** If a downstream party requests a release of water that is above the ECC of an upstream storage reservoir, the reservoir party has the option to release the water or supply the downstream party with energy equivalent to what the downstream party could have generated if the release had been made. When the reservoir returns to its ECC, the downstream party must return the energy.
- **Section 9m. Adjustments in FELCC [aka flexibility adjustments].** A party may borrow and return future FELCC, but these transactions must zero out at the end of the contract year. A party's borrowing may not exceed 5 percent of its FELCC remaining in the contract year.
- **Section 9n. Provisional energy.** A reservoir party may draft below its ECC if it can demonstrate that it can return to ECC (i.e., that the energy generated from the draft can be recovered from the purchaser or from firm resources not committed

to the party's FLCC under the PNCA agreement). A downstream party may either retain the energy from the release or deliver it to the reservoir party during the release period. In the latter case, the reservoir party owes the downstream party replacement energy.

- **Section 9o. Adjustment of ECCs.** From January through July (the variable drawdown period), each party notifies other parties of forecasted ECC elevations through the end of the contract year for all reservoirs for which a variable ECC has been determined plus the data needed to determine inflow to such reservoir(s). When reservoirs operate below ECC because of nonpower requirements or above ECC because of natural restrictions, then the actual elevation becomes the ECC.
- **Sections 9p,q,r. Adjustments for changes in schedules of resource availability, transfers due to forced outages, operating data and deviations.** Section 9(r) requires cooperative preparation of hourly schedules for power and energy transfers.

Section 10. Transmission rights, obligations, and scheduling.

Section 11. Flow of reactive power. Flow of reactive power due to coordinated operations is not to adversely affect the system or interconnected systems.

Section 12. Loads in excess of capabilities. An individual party is responsible for meeting its loads that could exceed its FLCC and the secondary energy it is entitled to under Section 9. [Note: This section recognizes the limitations of the Northwest hydro system.]

Section 13. Payments for coordinated storage releases from reservoirs in the U.S. This section outlines the method for computing payments owed by owners of downstream projects for coordinated releases from upstream projects. [Note: These payments are also known as headwater payment benefits.]

Section 14. Charges for exchanges, transfers and services. [Note: These charges have been updated twice.]

Section 15. Nonpower uses. This section affirms the priority of nonpower uses. [Note: NPRs are sometimes called "Section 15 requirements".]

Sections 16 - 21. General provisions. These provisions include preference rights of public agencies and cooperatives, contract rights and obligations, and water rights.

Section 22. Canadian storage.

Section 23. Federal reclamation projects.

Section 24. Re-negotiation, modification and withdrawal from PNCA.

Section 25. Notices.

Section 26. Additional parties.

Glossary

Acre-foot: The volume of water that will cover an acre to a depth of one foot. It equals 1,233.5 m^3.

Actual Energy Capability (AEC): Each PNCA party's generating capability based on operating the coordinated system's reservoirs to the energy content curve or to proportional draft points.

Actual Energy Regulation (AER): Hydro regulation study used to determine each party's Actual Energy Capability.

Assured refill curve (ARC): A representation of the lowest drawdown level from which a reservoir could refill given a repetition of the third-lowest runoff year of record.

Average megawatt (aMW): The average amount of energy (in megawatts) supplied or demanded over a specified period of time; equivalent to the energy produced by the continuous operation of one megawatt of capacity over the specified period.

Canadian Entitlement: Canada's share of hydropower generated at downstream projects by the use of the Columbia River Treaty projects.

Canadian Entitlement Allocation Agreements: Contracts that specify how much power is to be provided by five mid-Columbia projects as a result of increased flows made possible by the Columbia River Treaty projects.

Capacity: The maximum sustainable amount of power that can be produced by a generating resource at specified times under specified conditions or carried by a transmission facility; also, the maximum rate at which power can be saved by a nongenerating resource.

Columbia River Treaty: U.S.-Canadian agreement for bilateral development and management of the Columbia River to achieve flood control and increased power production.

Columbia Storage Power Exchange (CSPE): A non-profit corporation of 11 Northwest utilities that issued revenue bonds to purchase the Canadian Entitlement and sell it to 41 Northwest utilities through a Bonneville Power Administration exchange agreement.

Composite Reservoir: A PNCA operational procedure that simplifies in-lieu energy transactions by treating federal upstream reservoirs as one reservoir located at Grand Coulee and assuming the same flow time between these upstream reservoirs and the mid-Columbia projects.

Coordinated operation: The operation of interconnected electrical systems to achieve greater reliability and economy; as applied to hydro resources, the operation of a group of hydro plants to obtain optimal power benefits.

Critical period: That portion of the historical 50-year streamflow record which, when combined with the drafting of all storage reservoirs from full to empty, would produce the least amount of energy shaped to seasonal load patterns.

Critical rule curves (CRC): Graphic or tabular representations of reservoir storage water levels under critical streamflow conditions at various times of the year during all years of a critical period.

Critical water: Streamflows which occurred during the critical period.

Cubic feet per second (cfs): A measurement of water flow representing one cubic foot of water moving past a given point in one second. One cfs is equal to 7.48 gallons per second and 0.028 m^3 per second.

Demand: The rate at which electric energy is delivered to or by a system; usually expressed in kilowatts or megawatts over a designated period of time.

Draft: Release of water from a storage reservoir, usually measured in feet of reservoir elevation.

Drawdown: The distance the water surface of a reservoir is lowered from a given elevation as a result of withdrawing water.

Energy: Average power production over a stated interval of time, expressed in kilowatt-hours, megawatt-hours, average kilowatts, or average megawatts.

Energy content curve (ECC): Graphic or tabular representation of the month-end elevations at each storage reservoir which defines certain rights and obligations under the Agreement.

Firm energy load carrying capability (FELCC): The amount of firm energy that the region's hydroelectric system, an individual system or project can be called on to produce during actual operations from all firm resources.

Firm energy: Energy that is guaranteed to be available given a recurrence of the region's worst historical streamflows.

Flood control rule curve (FCRC): A curve, or group of curves, indicating reservoir elevation or drawdown required to control floods.

Flow: The volume of water passing a given point in a given period of time.

Forced outage: An unforeseen outage that results from emergency conditions.

Forced outage reserves: Peak generating capability planned to be available to serve peak loads during forced outages of generating units.

Generation: Production of electric energy from other forms of energy; also refers to amount of electric energy produced.

Headwater benefits: Gains in usable downstream energy as a result of upstream storage.

Historical streamflow record: The unregulated streamflow data base of the 50 years beginning in July 1928; data are modified to adjust for factors such as irrigation depletions and evaporations for the particular operating year being studied.

Hydroelectric: The kind of electric power produced by the force of falling water.

In-lieu energy: Energy provided by a reservoir owner instead of water to which a downstream party is entitled.

Interchange energy: Electric energy received by one utility from another, usually in exchange for energy to be delivered to the other system at another time or place.

Load: The amount of electric power delivered or required at a given point on a system.

Megawatt-hour (MWh): A unit of electrical energy equal to one megawatt of power applied for one hour.

Mainstem: A principal river or channel, as opposed to its tributaries.

Megawatt (MW): A unit of electric power equal to one million watts, or one thousand kilowatts.

Mid-Columbia: The Columbia River from the Canadian border to its junction with the Snake River.

Nonfirm energy: Energy that is not guaranteed; energy that is available when water conditions are better than those in the critical period and not required for refill.

Nonpower requirements: Operating requirements at hydroelectric projects that pertain to navigation, flood control, recreation, irrigation and other nonpower uses of the river.

Operating requirements: Guidelines and limits that must be followed in operating a reservoir or generating project; they may originate in legislation, physical limitations, agreements and other sources.

Operating rule curve: A curve, or group of curves, indicating how a reservoir is to be operated under specific conditions and for specific purposes.

Operating procedure: Alternative method substituted for a provision in the PNCA contract by agreement of parties, clarification of the contract, or method for carrying out a procedure.

Operating year: The 12-month period from August 1 through July 31.

Outage: In a power system, the state of a component (such as a generating unit, transmission line, etc.) when it is not available to perform its function due to some event directly associated with the component.

Outflow: The volume of water per unit of time discharged at a hydroelectric project.

Pacific Northwest Coordination Agreement (PNCA): An agreement among owners of hydro generating plants that coordinates the release of stored water and other procedures for obtaining optimum usable energy.

Peak load: The maximum electrical demand in a stated period of time.

Proportional draft: Drafting all reservoirs in the same proportion to meet firm loads.

Proportional draft point (PDP): Reservoir elevation that guides operations whenever drafting to the ECC will not produce FELCC; all reservoirs' PDPs are the same proportional distance between the critical rule curves unless restricted by NPRs.

Provisional energy: Energy produced by drafting below the ECC or PDP and delivered under contracts which provide for the return of the energy to the delivering utility under certain conditions. Provisional energy is called Advance Energy in contracts between BPA and its direct service industrial customers.

Refill: The annual process of filling a reservoir; also the point at which the hydro system is considered full from the seasonal snowmelt runoff.

Reliability: Generally, the ability of an item to perform a required function under stated conditions for a stated period of time.

Mathematically, the probability that a device will function without failure over a specified time period or amount of use.

In a power system, reliability is a measure of the ability of the system to continue operation while some lines or generators are out of service. Reliability deals with the performance of a system under stress.

For a relay or a relay system, reliability is a measure of the degree of certainty that the relay or relay system will perform correctly. Note that reliability denotes certainty of correct operation together with assurance against incorrect operation from all extraneous causes.

Reregulation: Storing erratic discharges of water from an upstream hydroelectric plant and releasing them uniformly from a downstream storage plant.

Reregulating reservoir: A reservoir located downstream from a hydroelectric peaking plant having sufficient pondage to store the widely fluctuating discharges from the peaking plant and release them in a relatively uniform manner downstream.

Reservoir elevation: The level of water stored behind a dam.

Reservoir storage: The volume of water in a reservoir.

Restoration: Adjustments that permit all PNCA projects to carry the same firm energy load with as with-out Canadian Treaty storage; projects losing load-carrying capability are restored by projects gaining capability.

Rule curves: Graphic representations of water levels; used to guide reservoir operations.

Run-of-river dams: Hydroelectric projects that use available streamflow and a relatively small amount of short-term storage as opposed to storage projects, which have sufficient storage space to carry water from one season to another.

Secondary energy: Another term for nonfirm energy.

Secretary's Principles: The framework of rights and obligations that forms the basis of PNCA.

Shaping: In planning, moving surplus or deficit FELCC from one period to another period within the year.

Shifting: In planning, moving surplus or deficit FELCC from one year of the critical period to another to increase the FELCC's value.

Spill: Water that passes over a spillway without going through turbines to produce electricity.

Storage energy: The energy equivalent of water stored in a reservoir above normal bottom elevation.

Storage reservoirs: Reservoirs with space to retain water from the annual high-water season to the following low-water season.

Streamflow: The rate at which water passes a given point in a stream, usually expressed as cubic feet per second (cfs).

Surplus: Another term for nonfirm energy.

Thermal Resource: Electrical generating means that rely on conventional fuels such as coal, oil, and gas.

Transmission: Transporting electric energy in bulk from one point to another in the power system rather than to individual customers.

Transmission grid: An inter-connected system of electric transmission lines and asso-ciated equipment for transferring electric energy in bulk.

Variable energy content curve (VECC): The January through July portion of the energy content curve; the VECC is based on the expected spring runoff.

Water Budget: A volume of water to be reserved and released in the spring if needed to assist in the downstream migration of juvenile salmon and steelhead.

Watt: A unit of electrical power or rate of doing work. The rate of energy transfer equivalent to one ampere flowing under a pressure of one volt at unity power factor. It is analogous to horsepower or footpounds per minute of mechanical power. One horsepower is equivalent to approximately 746 watts. A kilowatt equals 1,000 watts, a megawatt equals 1,000,000 watts.

Wheeling: Using transmission facilities of one system to transmit power of and for another system.