Administrator's Record of Decision

BPA

Allocation of WNP-3 Settlement Agreement Costs and Benefits

U.S. Department of Energy
Bonneville Power Administration

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WNP-3 SETTLEMENT AGREEMENT
COSTS AND BENEFITS ALLOCATION METHODOLOGY
ADMINISTRATOR'S RECORD OF DECISION

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TABLE OF CONTENTS

Chapter		Page
1.	Introduction	1
	A. Development of the WNP-3 Settlement Agreement Allocation Methodology	1
	B. Scope of the Proceeding	2
	C. Organization of Record of Decision	2
	D. Procedural History of the Rate Proceeding	2
	E. Legal Requirements	3
	1. General Rate Guidelines	3
	2. Confirmation and Approval	4
2.	WNP-3 Settlement Agreement Costs and Benefits Allocation Methodology	4
	A. Introduction	4
	B. Allocation of Plant-Related Costs and Benefits	5
	C. Allocation of Exchange-Related Costs and Benefits	20
	D. Participant Comments	27

Appendices

Appendix A.	Party Abbreviations	A-1
Appendix B.	Party Witnesses and Representatives	B-1
Appendix C.	Participants Commenting	C-1

Chapter 1

INTRODUCTION

A. Development of the WNP-3 Settlement Agreement Allocation Methodology

In September of 1985, the Bonneville Power Administration (BPA) entered into agreements with four Pacific Northwest investor-owned utilities (IOUs) to settle litigation that arose from BPA's request of the Washington Public Power Supply System (Supply System) that construction on Nuclear Project No. 3 (WNP-3) be delayed. BPA is obligated to pay principal and interest on bonds sold by the Supply System to finance 70 percent of the WNP-3 project. The four Northwest IOUs, which collectively own the remaining 30 percent interest in WNP-3, opposed in litigation the construction delay.

The agreements entered into by BPA and the four Northwest IOUs are here referred to collectively as the WNP-3 Settlement Agreement. The Administrator's Record of Decision on the Exchange of Current BPA Surplus Power for Future Power From Certain Companies' Share of WNP-3 to Settle a Dispute Over Construction Delay (WNP-3 ROD), and associated exhibits published September 19, 1985, include the terms and resolution of all issues relating to the Settlement Agreement, as well as its background and supporting rationale. Statements here are intended only to provide a basic understanding of the foundation to this Record of Decision, which solely concerns the appropriate ratemaking treatment of the costs and benefits of the WNP-3 Settlement Agreement. Since this Record of Decision is premised on the acceptance of the WNP-3 Settlement Agreement, and takes all the determinations in the WNP-3 ROD as a given, readers interested in background detail are encouraged to read the WNP-3 ROD and associated documentation.

The WNP-3 Settlement Agreement is founded on an exchange of power in principle and in fact. The transactions that implement the exchange of power require payments and receipts of money between BPA and the IOUs under certain specifically defined conditions. BPA will incur certain costs and receive certain benefits at this time with respect to two aspects of this exchange: (1) BPA's option to acquire the IOUs' share of the output of WNP-3 involves plant-related costs specifically associated with preserving the IOUs' share of WNP-3, and plant-related costs and benefits arising from the IOUs' share of WNP-3 if the plant is decommissioned prior to completion; and (2) exchange-related costs and benefits arising from exchanging power with the IOUs under the WNP-3 Settlement Exchange Agreement. These plant-related and exchange-related costs and benefits are detailed in Chapter 2 of this Record of Decision.

In a letter to Snohomish County Public Utility District, set forth as Exhibit Q of the WNP-3 ROD, BPA indicated that it would conduct rate hearings under section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act (Pacific Northwest Power Act), 16 U.S.C. § 838(d), to establish a methodology for allocating the costs and benefits of the Settlement Agreement. In the letter, BPA stated the opinion that section 7(g) of the Pacific Northwest Power Act governs allocation of the costs and benefits.

B. Scope of the Proceeding

As previously indicated, the WNP-3 Settlement Agreement and all determinations made in the WNP-3 ROD are accepted here as given. The scope of issues discussed in this rate proceeding is limited solely to the appropriate allocation of costs and benefits arising from the WNP-3 Settlement Agreement. Quantification of the costs and benefits will occur in each BPA general rate proceeding. The purpose of this rate proceeding is to examine ratemaking principles and a general approach to allocating the costs and benefits of the Settlement Agreement, rather than to define the details necessary to implement the proposed methodology. Issues relating to future decisions concerning the completion or termination of WNP-3 are also beyond the scope of the hearing, as are any issues relating to the remaining 70 percent share of WNP-3.

C. Organization of Record of Decision

This Record of Decision contains two chapters. This Introduction is the first chapter; the second chapter discusses BPA's proposed methodology.

Specific issues raised by the parties are identified and evaluated in Chapter 2. The evaluation of each issue is in three sections. First, the parties' and BPA's positions on the issue are summarized, with citations to the record. Second, the positions are evaluated, noting the arguments on the record and presenting BPA's evaluation of the arguments. Third, the Administrator's decision on each issue is presented.

D. Procedural History of the Rate Proceeding

On April 1, 1986, BPA published in the FEDERAL REGISTER a notice of Proposed Allocation Methodologies for Certain Costs and Benefits of the WNP-3 Settlement Agreement, Public Hearings, and Opportunity for Public Review and Comment. 51 FR 11091. That notice initiated the section 7(i) rate proceeding on the WNP-3 Settlement Agreement costs and benefits allocation methodology.

In accordance with section 7(i) of the Pacific Northwest Power Act, an evidentiary hearing on the proposed allocation methodology was conducted by Judge Dean F. Ratzman, Hearing Officer. Interventions were filed by BPA's publicly owned and IOU customers, direct-service industrial (DSI) customers, customer groups, consumer groups, and California parties. A prehearing conference was held on April 14, 1986, at which time Judge Ratzman granted party status to intervenors and issued a procedural schedule.

BPA filed direct testimony on April 14, 1986. The parties filed direct testimony on April 30, 1986. Rebuttal testimony of all witnesses was filed on May 12, 1986. Cross-examination took place before Judge Ratzman on May 22-23, 1986. Opening briefs were filed on June 6, 1986. Oral argument was held on June 20, 1986. Reply briefs were filed on June 23, 1986.

This Record of Decision presents the Administrator's decisions on each of the issues appropriately raised in the proceeding, based on review of the testimony, initial briefs, oral argument, and reply briefs. Issues raised concerning the WNP-3 Settlement Agreement's appropriateness and legality are not dealt with here; neither are issues that were either determined in the WNP-3 ROD or later raised in the continuing litigation over the WNP-3 Settlement Agreement.

E. Legal Requirements

1. General Rate Guidelines

Section 7(a) of the Pacific Northwest Power Act requires BPA to set rates "in accordance with sound business principles" to produce revenues that recover the Administrator's costs and allow BPA to meet its obligations to the United States Treasury. Section 7(a) directs that these rates be set in accordance with sections 9 and 10 of the Federal Columbia River Transmission System Act (Transmission Act), 16 U.S.C. § 638; section 5 of the Flood Control Act of 1944; and the other provisions of the Pacific Northwest Power Act. Section 9 of the Transmission Act requires, inter alia, that rates be established "with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles," while having regard to recovery of costs and repayment of the U.S. Treasury. Substantially the same requirements are set forth in section 5 of the Flood Control Act.

The balance of section 7 of the Pacific Northwest Power Act generally outlines rate directives applicable to BPA's various customer classes. Section 7(b) provides for the establishment of rates for power sold to meet the general requirements of preference customers and Federal agencies, and for sales under section 5(c)(1) of the Act. The rates are to recover the costs of the Federal base system (FBS) resources needed to supply such loads until sales exceed the resources, at which time the rates are to recover the cost of additional power as needed to supply the loads. Section 7(c) provides for the establishment of rates to the DSIs before and after July 1, 1985. The rates are to be set in the first instance to recover the cost of resources necessary to serve the DSI load, plus the Administrator's net section 5(c) costs. After July 1, 1985, the DSIs' rates are to be "equitable" in relation to retail rates charged by BPA's public body and cooperative customers to their industrial consumers in the region. For rates for all other firm power sold by the Administrator in the region, section 7(f) provides that the rates shall be based upon the costs of the resources "which, in the determination of the Administrator, are applicable to such sales." 16 U.S.C. § 839e(f). Finally, section 7(k) provides that rates for the sale of nonfirm electric power within the United States, but outside the Pacific Northwest, shall be set in accordance with the Bonneville Project Act, the Flood Control Act of 1944, and the Transmission Act. 16 U.S.C. § 839e(k).

Section 7(g) provides for the allocation of costs and benefits not otherwise provided for under the Pacific Northwest Power Act or pre-existing law. Specifically, section 7(g) provides as follows:

> Except to the extent that the allocation of costs and benefits is governed by provisions of law in effect on the effective date of this Act, or by other provisions of this section, the Administrator shall equitably allocate to

power rates, in accordance with generally accepted ratemaking principles and the provisions of this Act, all costs and benefits not otherwise allocated under this section, including, but not limited to, conservation, fish and wildlife measures, uncontrollable events, reserves, the excess costs of experimental resources acquired under section 6, the cost of credits granted pursuant to section 6, operating services, and the sale of or inability to sell excess electric power.

16 U.S.C. § 839e(g).

2. Confirmation and Approval

The Pacific Northwest Power Act specifies in sections 7(a)(2) and 7(i)(6) that rates become effective upon confirmation and approval by the Federal Energy Regulatory Commission (FERC). 16 U.S.C. § 839e(i). FERC must review the rates to determine that: (1) they are sufficient to assure repayment of the Federal investment in the Federal Columbia River Power System (FCRPS) over a reasonable number of years after first meeting BPA's other costs; (2) they are based on BPA's total system costs; and (3) transmission rates equitably allocate the costs of the Federal transmission system between Federal and non-Federal power using the system. Pursuant to section 7(i)(6) of the Pacific Northwest Power Act, FERC has promulgated rules found at 18 C.F.R. Part 300 establishing procedures for the approval of BPA rates.

BPA intends to file the record of the WNP-3 Settlement Agreement costs and benefits allocation methodology with FERC at the same time that the record of the next general rate proceeding is filed.

Chapter 2

WNP-3 SETTLEMENT AGREEMENT COSTS AND BENEFITS ALLOCATION METHODOLOGY

A. Introduction

BPA's proposed methodology for allocating the costs and benefits of the WNP-3 Settlement Agreement identifies and allocates two types of costs and benefits (receipts). The two categories are plant-related costs and benefits, and exchange-related costs and benefits.

The plant-related costs and benefits consist of: (1) payment of the costs of preserving the IOUs' 30 percent share of WNP-3 after February 1, 1985; (2) receipt of the proceeds, or payment of excess costs, under section 22(a) of the Ownership Agreement (dealing with receipts or disbursals related to decommissioning of WNP-3) of the 20 percent share of WNP-3 owned by PGE, Puget, and WWP if construction is terminated; and (3) receipt of a portion of the proceeds or payment of a portion of excess costs under section 22(a) of the Ownership Agreement for the 10 percent share of WNP-3 owned by PP&L if construction is terminated. The City of Tacoma stated that plant costs should include decommissioning costs as well as salvage and preservation costs.

Letter, TCL, May 7, 1986. The plant-related costs include any decommissioning costs incurred if the plant is terminated before construction is complete.

The settlement exchange-related costs and benefits consist of: (1) payments by BPA to the IOUs equal to the operation and maintenance costs of the combustion turbines or the fully distributed costs of less costly resources of the IOUs; (2) payments by BPA to other utilities equal to the cost of acquiring less costly resources to displace operation of the IOUs' combustion turbines; and (3) payments from the IOUs to BPA which equal the cost of operation and maintenance of four surrogate nuclear plants, or a calculated percentage of the operation and maintenance costs of WNP-3.

B. Allocation of Plant-Related Costs and Benefits

Issue #1

Does section 7(g) of the Pacific Northwest Power Act govern the allocation of costs and benefits arising from the WNP-3 Settlement Agreement?

Summary of Positions

BPA proposes to allocate the Settlement Agreement costs and benefits according to section 7(g) of the Pacific Northwest Power Act. Ratchye, BPA, E-BPA-01, 4. No party has taken issue with BPA's proposed allocation of exchange-related costs and benefits pursuant to section 7(g), so the only issue that need be addressed concerns the applicability of section 7(g) to plant-related costs and benefits. The plant-related costs and benefits are not associated with a specific resource pool; they are costs of an option to acquire a resource that BPA received in the course of settling litigation. Id. BPA previously decided in the WNP-3 ROD that it had authority to incur preservation costs, and that section 6(c) of the Pacific Northwest Power Act regarding resource acquisitions does not apply until BPA accepts the IOUs' irrevocable offers. WNP-3 ROD, 76-78.

WPAG argues that the plant-related costs are essentially preservation costs, and, as such, are resource costs that must be allocated to the New Resource Firm Power (NR) and Surplus Firm Power (SP) rates pursuant to sections 7(b) and 7(f) of the Pacific Northwest Power Act. WPAG, Opening Brief, B-WA-01, 2, 6-7. WPAG has withdrawn its initial position that the Pacific Northwest Power Act restricts BPA's ability to incur the preservation costs of the private utilities under the provisions of section 6 of the Pacific Northwest Power Act. Id., 6-7; June 25, 1986, Letter from Terrence L. Mundorf to Hearing Officer Dean Ratzman.

WWP and Puget support BPA's position that section 7(g) governs the allocation of WNP-3 costs and benefits. Opening Brief, WWP, B-WP-01; Opening Brief, Puget, B-PS-01, 2-5.

The Joint Customers state that any allocation methodology should not preclude the allocation of plant related costs to the customers that need the resource. Reply Brief, Joint Customers, R-JC-01, 1-2. The DSIs agree that section 7(g) applies to the allocation at issue here. Opening Brief, DSI, B-DS-01, 1.

Evaluation of Positions

(a) Introduction

This Evaluation first relates why WPAG believes the WNP-3 plant preservation costs should be allocated pursuant to section 7(f) of the Pacific Northwest Power Act, rather than section 7(g). The existence and rationale of resource pools is then explained. WPAG's arguments are then addressed, with the conclusion drawn that there is no factual and, hence, no legal basis for applying section 7(f) to plant preservation costs such that the costs might be included in the New Resource pool. Even if the costs were resource costs, the Administrator is unable to determine that the IOU's 30 percent share of WNP-3 should be assigned to one of the resource pools. As such, section 7(g) of the Pacific Northwest Power Act applies. Section 7(g) also applies because the costs are indeed option costs, and, as such, not governed by section 7(b), 7(c), or 7(f). The evaluation closes by relating why option costs, including the WNP-3 option cost, are by their very nature the type of costs to be allocated pursuant to section 7(g).

(b) WPAG's Arguments

In tracing WPAG's arguments, one needs to be careful to distinguish when WPAG speaks of allocating costs to a particular rate or rate pool, a class or classes, or a resource pool. The distinction is elemental, long-standing, and approved by the United States Court of Appeals for the Ninth Circuit in Central Lincoln Peoples' Utility District v. Johnson, 735 F.2d 1101, 1123 (9th Cir. 1984). As there noted, "In setting rates, BPA allocated costs of power resources among these three groups [preference, DSI and IOU] by the creation of three rate pools." Id. Unfortunately, WPAG is not clear as to the distinction between allocation of costs to a rate, to a resource pool, such as the FBS or New Resource pool, and to a rate pool. Care is therefore taken to quote the various terms used by WPAG lest further confusion result from relating their arguments.

WPAG recognizes that "BPA obtained an irrevocable option to acquire the private utilities [sic] 30% share of WNP-3" under the Settlement Agreement, and in return assumed the obligation to reimburse the IOUs for their share of WNP-3 preservation costs incurred since February 1, 1985. Opening Brief, WPAG, B-WA-01, 4 (emphasis added). Since BPA is not obligated to acquire the IOUs' share of WNP-3, WPAG argues that BPA is voluntarily and purposefully continuing to preserve WNP-3 and pay the costs thereof based on perceived load and resource needs. Id., 4. The preservation costs are "resource" costs, WPAG argues, because "[m]oney spent on an existing resource, whether to preserve it, or to construct it or to operate it, is a resource cost." Reply Brief, WPAG, R-WA-02, 5. Curiously, although WPAG states plant costs consist of both preservation costs and termination costs or revenues, it does not argue that termination costs should be treated as "resource" costs. Opening Brief, WPAG, B-WA-01, 4

Building on its premise that the plant-related costs are "resource" costs, WPAG goes on to argue that "[s]ection 7 of the Regional Power Act contains specific directives which govern the allocation of resource costs among Bonneville's rates." Opening Brief, WPAG, B-WA-01, 8 (emphasis added). In essence, WPAG argues that section 7 establishes a resource allocation scheme for the rates of BPA's industrial, public and private utility customers with certain resource costs identified with the various customer classes. Under section 7(b), according to WPAG, allocation of resource costs to the preference customer (PF) rate must proceed as follows:

> The resource costs which can be included in the PF rate are limited to Federal base system (FBS) resources until they are insufficient to [sic] the load. At that point, the costs of Exchange resources can be included in the rate as needed to serve load. When these resources are insufficient, other resource costs can be included in the PF Rate, but only to the extent they are needed to serve PF loads.

Opening Brief, WPAG, B-WA-01, 8 (emphasis added); Reply Brief, WPAG, B-WA-02, 3. Noting that similar resource allocation schemes are established for BPA's IOU and DSI customers, WPAG asserts that the rate for power sales to IOUs under section 7(f) "is based on the costs of excess FBS resources, exchange resources and the costs of resources acquired by the Administrator under the Regional Power Act." Opening Brief, WPAG, B-WA-01, 9 (emphasis added).

WPAG argues that by basing each rate on the costs of specific resources, Congress created a hierarchy of rates by which the 7(b) rate would be the lowest-cost rate, followed by the 7(c) rate, and then the highest-cost 7(f) rate for regional load growth and new industrial loads. Opening Brief, WPAG, B-WA-01, 9. Based on the foregoing, WPAG concludes as follows:

> Section 7 of the Regional Power Act dictates that no new resource costs can be allocated to the PF rate until they are needed to serve PF loads, and that the costs of new resources must be allocated to the 7(f) rate pool. Bonneville's proposal ignores these directives by allocating the costs of a new resource to the 7(b) pool before it is needed to serve load, and by failing to allocate these cost [sic] to the 7(f) pool.

Opening Brief, WPAG, B-WA-01, 10.

(c) The resource pool concept

Before addressing WPAG's arguments, it is necessary to first discuss the rate pool and resource pool concepts that have been embodied in BPA's ratemaking practices since the passage of the Pacific Northwest Power Act. In the 1981 rate case, the Administrator "conclude[d] that the express words of the Regional Act contemplate the creation of three rate pools." Administrator's Record of Decision, 1981 Transmission Rate Proposal and 1981

Wholesale Power Rate Proposal, II-8 (hereinafter 1981 ROD). In making this determination, the Administrator quoted and emphasized language of sections 7(b), 7(c) and 7(f) to the effect that the rates should be set in part with reference to the costs of resources needed to supply, required to serve, or applicable to the load. Id. The Administrator described the rate pool and associated resource pool concepts as follows:

> The primary concern raised with respect to BPA's interpretation of Sections 7(b), 7(c), and 7(f) of the Regional Act revolves around the issue of the allocation of the cost of the three resource pools to rate pools. The three resource pools are distinguished as (1) Federal base system resources; (2) resources acquired through the Section 5(c) residential exchange; and (3) any additional new resources acquired by the Administrator. The rate pools are also defined in the Regional Act. Section 7(b) directs the Administrator to set a rate applicable to the preference customer loads exclusive of new large single loads and to Section 5(c) residential/rural exchange loads. Section 7(c) provides for the rate or rates applicable to the DSI's, and the rates provided for in 7(f) will be applicable to new large single loads of the preference customers and the power supply needs (deficit plus load growth) of the IOU's. These are the three essential sections of the Regional Act defining the three rate pools. They also provide the principal basis for the identification of three resource pools.
>
> In the COSA [cost of service analysis], a sufficient amount of Federal base system resources were assigned to the 7(b) rate pool to serve the entire 7(b) load. The proportionate cost of these resources was the basis for determining the proposed PF-1 rate. A small amount of Federal base system was not required to serve 7(b) loads. The costs of the remaining portion of Federal base system resources, and all the costs of resources acquired through the residential exchange were assigned to be recovered from the 7(c) loads. These costs were the basis for determining the proposed IP-1/MP-1 rate. The 7(f) loads were assigned the costs of all remaining resources which constituted additional new resources. These costs formed the basis for the proposed NR-1 rate.
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> Before July 1, 1985, the Regional Act clearly identifies three rate pools all based on costs. . . .
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> After July 1, 1985 there are fundamentally the two rate pools advocated by the investor-owned utilities, the 7(b) rate pool and the 7(f) rate pool. The section 7(c) rate is determined independently of cost. The costs of the

> three resource pools move between the two rate pools <u>in proportion to the amounts needed</u> to satisfy the load size in each rate pool and in accordance with the priorities established in Section 7(b). The 7(b) rate pool is satisfied first with Federal base system, then, as needed, with exchange, and finally with the new resources.

Id. at VI-9 through VI-11 (emphasis added). It is with this in mind that we turn to WPAG's arguments concerning cost allocation according to sections 7(b) and 7(f).

(d) Sections 7(b) and 7(f) do not govern allocation of the preservation costs

The philosophical underpinning of WPAG's 7(b)/7(f) allocation argument is that "[t]he underlying theme to the resource cost allocation provisions of Section 7 of the Regional Power Act, . . . is that costs should be allocated to the customers who need the resources." Reply Brief, WPAG, B-WA-02, 13. In actuality, while need (i.e., load) may determine from which resource pool(s) a customer class is served and, hence, what the applicable section 7(b) or 7(c) or 7(f) rate is, nevertheless costs are first assigned to resource pools. Though need may play an important role in the assignment of a resource to a particular resource pool, the assignment is not based on need alone. For instance, a resource might be designated by statute as an FBS resource, or a resource might be designated by the Administrator as an FBS replacement resource. Also, one must be careful to recognize that class load is not necessarily determinative of the allocation of a particular resource's costs. For instance, one might envision a situation where the preference customers' load is growing such that the growing load calls upon the exchange resource pool otherwise used in the rate allocation process to serve the IOU load, with the consequence that an addition to the new resource pool must be made to meet the existing IOU load. Under existing practice, the cost of the new resource pool is the melded cost of all resources in the pool. Under the situation just posed, the growing preference customer load would be allocated no cost from the new resource pool, whereas the stable IOU load served by the new resource pool would be allocated the melded cost of the new resource pool.

If it is WPAG's purpose that BPA should either abandon or carve exceptions to the resource pool concept that has served as the foundation for BPA's rates, its proposal should be made explicitly. A multitude of questions would then have to be thoroughly addressed for the issue to be resolved. The present arguments of WPAG afford no reasoned basis for either abandoning the resource pool concept or drafting any exceptions to it.

WPAG's vision of "need" is contradictory and unacceptably one-sided. Boiled down, WPAG's argument is essentially that the preservation costs are costs of a resource not needed by the 7(b) rate class, and that the costs must hence be allocated to the section 7(f) rate class. In so arguing, WPAG contravenes its philosophical argument, just discussed, that the theme of the Northwest Power Act is to allocate costs to the customers who need the resources. Reply Brief, WPAG, B-WA-02, 13. Just as section 7(b) speaks in terms of recovering "the cost of additional electric power as needed to supply such loads, first from the electric power acquired by the Administrator under section 5(c) and then from other resources", section 7(f) encompasses the allocation of resource costs "which, in the determination of the Administrator, are applicable to such sales." 16 U.S.C. § 839(f). The statutory directives do not establish the 7(f) rate pool as a dumping ground for resource costs not recovered pursuant to sections 7(b) and 7(c). If the plant-related preservation costs are resource costs, it must first be determined which, if any, resource pool the costs should be assigned to. Then, the resource's cost melded with other costs in the resource pool would be allocated pursuant to sections 7(b) or 7(f) of the Pacific Northwest Power Act upon a determination of the necessary factual predicate (need or applicability).

Even if it were assumed arguendo that the WNP-3 preservation costs are resource costs, no determination has been, or can be, made at this time that the 30 percent share of WNP-3 associated with the preservation costs at issue here should be assigned to a particular resource pool and, hence, allocated to a rate pool or pools. For instance, the 30 percent share of WNP-3 could be assigned as an FBS replacement. Opening Brief, Puget, B-PS-01, 4-5. In addition, as is discussed in Issue #2 infra, even if one were to accept WPAG's customer class allocation argument, no determination has been, or can be, made at this time that the 30 percent share of WNP-3 associated with the preservation costs here should be assigned to a particular customer class. WPAG errs when it argues that BPA will have no better information before it when and if it acquires the resource. Reply Brief, WPAG, B-WA-02, 6. The act of acquiring a resource signifies the existence of a determined need for the resource, now lacking, such as will justify going forward with acquisition and construction of the resource. As detailed subsequently, an option exists and remains an option until sufficient need is established to justify acquiring the resource. Reliance on load forecasts in gross as a barometer of need for the purpose of maintaining an option in the face of an uncertain future is far different than relying on those same forecasts to establish a need such as would justify a resource acquisition. With this, we now turn to section 7(g) of the Pacific Northwest Power Act.

(e) Section 7(g) governs allocation of the plant preservation costs

Section 7(g) governs costs not otherwise allocated under section 7:

> Except to the extent that the allocation of costs and benefits is governed by provisions of law in effect on the effective date of this Act, or by other provisions of this section, the Administrator shall equitably allocate to power rates, in accordance with generally accepted ratemaking principles and the provisions of this Act, all costs and benefits not otherwise allocated under this section, including, but not limited to, conservation, fish and wildlife measures, uncontrollable events, reserves, the excess costs of experimental resources acquired under section 6, the cost of credits granted pursuant to section 6, operating services, and the sale of or inability to sell excess electric power.

As has been BPA's position in past rate cases, and as continues to be BPA's position in this proceeding, section 7(g) covers the allocation of option costs because their allocation is not "governed by provisions of law in effect on the effective date of this [Pacific Northwest Power] Act, or by other provisions of this section [7] . . ." 16 U.S.C. § 839e(g). WPAG admits that section 7(g) applies when a cost is not allocated by other provisions of section 7. Opening Brief, WPAG, B-WA-01, 11. Preservation costs are option costs, and therefore section 7(g) governs their allocation. Even if the preservation costs are regarded as resource costs, they are to be allocated under section 7(g) since, as we have seen, they are not governed by the allocation provisions of section 7(b) or 7(f) due to the absence of the necessary factual predicate.

Apart from the fact that sections 7(b) and 7(f) cover the allocation of some "resource" costs, not option costs, such that section 7(g) applies to option costs, the general applicability of section 7(g) to options is also made apparent by examining what options are and why they are of value to BPA. The following discussion briefly provides this examination. It also sets the framework for understanding why the preservation costs are option costs, not resource costs.

<u>(f) The plant preservation costs are option costs, not resource costs</u>

BPA is authorized to obtain and pay for an option consistent with BPA's utility responsibility and sound business principles to further the Pacific Northwest Power Act's purpose of assuring the Pacific Northwest of an adequate, efficient, economic, and reliable power supply. <u>E.g.</u>, Bonneville Project Act, 16 U.S.C. § § 832a(b), (c), (f), 832d(a); Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § § 839(2), 839c(b)(1), 839d(a)(2), 839d(f), 839f(a). No party to this proceeding disputes BPA's legal authority to obtain and pay for an option. Although WPAG did initially argue that BPA could not allocate the plant preservation costs because BPA had not complied with the requirements of Pacific Northwest Power Act section 6(c) applicable to resource acquisitions, WPAG now agrees that the question of whether there has been an acquisition of a resource is outside the scope of this proceeding. WPAG, Letter to Hearing Officer Dean Ratzman, June 25, 1986. BPA previously decided that the provisions of the Settlement Agreements under which BPA incurs preservation costs do not violate the Pacific Northwest Power Act, particularly section 6(c); challenges to that decision are not the appropriate focus of this rate allocation proceeding, which assumes the validity of prior WNP-3 Settlement decisions.

In its general legal sense, an "option" constitutes a continuing, irrevocable offer or contract by which the owner of property grants to another person, for consideration, the right to buy property within an agreed period and at an established price. <u>Black's Law Dictionary</u>, at 1245 (Rev. 4th Ed. 1968). BPA's description of an option for the purpose of its Hydro Power Options Program is similar:

> "Option," in the context of this NOPI, means a contract between a resource sponsor and BPA, wherein BPA reimburses the resource sponsor for certain costs incurred during the

development of the project in exchange for the right to purchase the energy from the resource, when developed, and the right to control the timing of the start of project construction during the term of the option contract.

Notice of Program Interest, No. DE-NP79-85BP21039, Hydro Power Options Program, at page 10. See also 1986 Northwest Conservation and Electric Power Plan, Vol. 1, Glossary-3, Pacific Northwest Power Planning Council (hereinafter 1986 Power Plan). The WNP-3 option comports with these general definitions, and is unquestionably an option. Although BPA obtained the right to acquire the IOUs' share of Project 3 generating capability in the future, BPA has no present right to the IOUs' share such as would occur upon an acquisition of the share.

An option is distinguishable from a contract to sell in that a contract to sell grants the purchaser the right and obligation to purchase, whereas in an option, the seller alone is obligated, and the option taker may buy at his own discretion. E.g., Rottkamp v. Eger, 346 N.Y.S.2d 120, 126 (1973); 30 Words & Phrases, "Option" ("Contract of sale, and agreement to sell distinguished") (1972 & Supp. 1986). By referring to an "option to acquire," section 6(f)(3) of the Pacific Northwest Power Act evidences Congress' recognition that an option to acquire differs from an acquisition, just as an option to purchase differs from a purchase. 16 U.S.C. § 839d(f)(3).

The distinction between an option to acquire and an acquisition is fraught with legal and practical consequences, and sheds light on the general applicability of Pacific Northwest Power Act section 7(g) to option costs. In the WNP-3 ROD, which was accepted by the Pacific Northwest Power Planning Council, BPA determined that the provisions of section 6(c) of the Pacific Northwest Power Act governing certain resource acquisitions do not apply to agreements to settle lawsuits, to exchanges of power, or to irrevocable offers (i.e., options). 16 U.S.C. § 839d(c)(1). An option was determined to merely provide an opportunity to acquire later what the statute does permit, that is, the acquisition of the capability of the project. WNP-3 ROD, 76-77. By avoiding the section 6(c) acquisition process, BPA is not forced to make premature decisions on the need for and cost effectiveness of resources based on partial information. An option affords BPA the opportunity to economically capture what otherwise might be a lost opportunity; at the same time, BPA can wait until the facts are sufficiently ascertainable and well-known so that "the project could be scheduled, placed on hold, constructed or terminated, depending on the demand for electricity." 1986 Power Plan, 3-2. By moving acquisition and construction decisions as close as possible to the time power is projected to be needed, the options process reduces "the likelihood of beginning construction on a project that is not needed." Id., 3-3. As stated in the 1986 Power Plan, "By having a licensed or readily licensable resource effectively 'on hold,' the period over which electricity needs must be forecast could be reduced to the resource construction period, which may be as little as half of the total time that is now needed." Id., 3-2. Flexibility, efficiency, economy, and environmental protection are all characteristic of the options process. See Id. So, too, is an uncertain determination of need, as just shown; if need were or could be sufficiently established to justify an acquisition, an acquisition would take place.

When posed against the following backdrop provided by WPAG counsel during oral argument, it can readily be seen that the determination of the prudence and economy of a decision to secure an option is a far different determination than must be made in connection with any decision to acquire the IOUs' share of WNP-3:

> Unfortunately, it [the option to acquire] comes to you at a time when you are massively surplus and when utilities which are projecting deficits in the future aren't placing load on you in any significant sense <u>and you don't have any real strong way of finding out whether they will place those loads on you</u>.

WPAG, TR 206 (emphasis added). The flexibility associated with the WNP-3 option allows BPA to economically and timely determine whether there is a need for the resource. This was recognized by the Northwest Power Planning Council's recommendation that "[p]reservation planning should not be based on a fixed restart date, but instead should employ a floating restart concept, where the plants would be restarted <u>only when need was established</u>." 1986 Power Plan, 7-20. BPA's 1986 Resource Strategy adopted the flotation restart concept, commenting as follows:

> In developing the resource strategy, WNP-1 and -3 were treated as secured resource options. Their completion dates were assumed to be a function of future need for power. Since load growth is treated as an uncertain variable, the on-line dates for WNP-1 and -3 are also uncertain.

<u>1986 Resource Strategy</u>, Volume 1, 27, (Bonneville Power Administration, April 1986).

At one point during oral argument, WPAG counsel attempted to differentiate the WNP-3 option from a "pure option" on the basis in part that the WNP-3 plant is "out there, it's real, you can feel it and you're spending money on it." WPAG, TR 283. By this, WPAG's counsel apparently intended to equate a resource with what it would perhaps term an impure option. BPA does not share WPAG's view that such a distinction is warranted.

The reason BPA disagrees with WPAG follows from the fact that a "resource" is defined by the Pacific Northwest Power Act in relevant part as "electric power, including the actual or planned electric power capability of generating facilities, . . ." 16 U.S.C. § 839a(19)(A). Under this definition, no distinction can be drawn between a pure option and an impure option for the purpose of determining if something is a resource. The relevant consideration as to whether a resource and therefore a resource cost exists for rate assignment and allocation purposes is whether an acquisition has taken place. The fact of acquisition is implicit in the definition of a resource. It is at the point of acquisition that BPA has the right to the capability, and has assumably identified a need or purpose for the capability such as justified the acquisition. It is at that point that it makes sense to assign the cost to a resource pool and, through that action, to trigger the allocation of the costs through the rate pool/resource pool match-up allocation process. Until then, different considerations, such as may be allowed under the determination of what is "equitable" under section 7(g), should be allowed to be taken into consideration.

The WNP-3 option does not fit the criteria expressed in section 7(b), 7(c) or 7(f) for the direct allocation of resource costs through those sections. The inherent and demonstrated characteristics of the WNP-3 option do qualify it for allocation pursuant to section 7(g) of the Pacific Northwest Power Act. The allocation methodology established for the plant-related costs and benefits will be thus consistent with the allocation of options costs in general. Ratchye, BPA, E-BPA-01, 4. An initial, uniform allocation pursuant to section 7(g) does not disturb the low-to-high cost hierarchy of rates argued for by WPAG, but maintains the relative positions of the rates. As is discussed in the evaluation of the next issue, an allocation of costs under section 7(g) may involve numerous additional considerations than are allowed and applied for purposes of a direct allocation under sections 7(b), 7(c) and 7(f). Under section 7(g), a cost may be allocated to a class, a rate pool, or a resource pool.

BPA will hold a public involvement process to decide whether to acquire the 30 percent share of WNP-3 as a resource. Part of the process will include a determination of the need or purpose for the resource. Ratchye, BPA, E-BPA-01, 4-5; TR 103. At that point, provisions of section 7 other than 7(g) will apply to allocation of future costs.

Decision

Section 7(g) of the Pacific Northwest Power Act applies to the allocation of the WNP-3 Settlement Agreement costs and benefits.

Issue #2

How should plant-related costs be allocated?

Summary of Positions

BPA considers the plant-related costs and benefits as options costs that should be allocated across all firm loads. These costs and benefits are also included in the calculation of the Nonfirm Energy rate, subject to certain limitations. Ratchye, BPA, E-BPA-01, 4-5. Puget and WWP support BPA's proposed allocation of plant-related costs. Puget, Opening Brief, B-PS-01, 1, WWP; Opening Brief, B-WP-01, 1.

WPAG argues that even if section 7(g) governs allocation of the costs, the plant-related costs should be allocated on a cost causation basis. WPAG states that the plant-related costs are incurred only to meet load growth. Hutchison et al., WPAG, E-WA-01, 5-8. WPAG maintains that WNP-3 is not needed to serve load growth of preference customers and is only needed to meet the load growth of IOUs. Hutchison et al., WPAG, E-WA-01, 10-11; Opening Brief, WPAG, B-WA-01, 14-15. Therefore, based on its view of cost causation, WPAG proposes that the plant-related costs be assigned directly to the SP and NR rates. Hutchison et al., WPAG, E-WA-01, 12. WPAG also states that an allocation of all currently projected plant-related costs to the SP and NR rates would cause these rates to increase by only 0.7 mills/kWh. Hutchison et al., WPAG, E-WA-01, 13.

The Joint Customers state that the allocation methodology should not preclude the direct allocation of plant-related costs to the customer group that needs the power from the 30 percent share of WNP-3. Drummond et al., Joint Customers, E-JC-01, 9; Opening Brief, Joint Customers, B-JC-01, 15-16.

PP&L recommends that WNP-3 be terminated. Boucher, PP&L, E-PL-01R, 3. PP&L supports an allocation of plant-related costs across all loads. Boucher, PP&L, E-PL-01R, 2. PP&L argues that if the 30 percent share of WNP-3 were acquired and assigned to the NR pool, PP&L would probably not buy power from that pool. Boucher, PP&L, E-PL-01R, 3.

SCE and PG&E argue that plant-related costs should not be allocated to Nonfirm Energy rates. Opening Brief, SCE, B-CE-01, 2-4; Letter, PG&E, June 16, 1986.

The DSIs state that section 7(c) precludes direct assignment of WNP-3 costs to the DSI's. Opening Brief, DSI, B-DS-01, 2.

Evaluation of Positions

WPAG argues that even if section 7(g) does apply, it does not require costs to be allocated across all loads. It states section 7(g) provides three guidelines for cost allocation: "First, the costs must be allocated to one or more of the Bonneville's rates, as appropriate. Second, the allocation must be equitable. And third, the allocation must be based on generally accepted ratemaking principles." Opening Brief, WPAG, B-WA-01, 12. BPA agrees that section 7(g) does not require an allocation of costs across all loads. Possible equitable allocation schemes include: 1) allocation across all loads; 2) direct assignment of costs to a particular customer class; and 3) assignment of the costs to loads served by a resource pool. An equitable allocation under section 7(g) depends on the totality of circumstances under consideration. Ratchye, BPA, TR 96, 132; Opening Brief, WPAG, B-WA-01, 13.

WPAG argues that under generally accepted ratemaking principles, the principle of cost causation must be used to determine the equitable allocation of resource-related costs. By this, it means that costs must be allocated to the customer class causing the costs to be incurred, i.e., to the customer group needing the resource. WPAG, Opening Brief, B-WA 01, 13. By WPAG's view of cost causation, the 7(b) rate pool should not be allocated any of the preservation costs because, according to it, its load growth can adequately be served by other resources. WPAG further argues that if there is any need for preserving WNP-3, the need can only be attributed to the marginal load growth of the 7(f) rate pool. As such, according to WPAG, the 7(f) rate pool must be allocated the entire plant preservation costs. WPAG asserts this is fair, consistent with economic theory, and consistent with generally accepted ratemaking principles. Opening Brief, WPAG, B-WA-01, 13.

BPA disagrees with WPAG's assumption that cost causation principles require an assignment of preservation costs to marginal loads. WPAG's argument is predicated on its view of marginal cost pricing. Under cross-examination, WPAG admitted that there is "still a debate going on throughout the United States as to the desirability of using marginal costs in ratesetting versus using average or embedded costs," and that "both methodologies may be considered in accord with generally accepted ratemaking principles." Saleba, WPAG, TR 183-184; see also Ratchye, BPA, TR 131. For instance, in Snohomish's case, a utility using embedded cost pricing, costs from adding facilities or resources to meet utility load have characteristically been melded into base rates. Hutchison, WPAG, TR 185-86. However, under either embedded cost pricing or marginal cost pricing, economic theory does not support allocation of new resource costs to marginal loads in the manner envisioned by WPAG.

Alfred Kahn, an authority on marginal cost pricing, describes the economic theory that all loads are responsible for the need to acquire new resources. A customer class that maintains its load is just as responsible for the need to acquire new resources as another customer class that is growing. From a cost causation standpoint, economic theory supports the allocation of new resource costs in direct proportion to each customer class's load. Ratchye, BPA, E-BPA-02R, 8. WPAG cited no authority stating cost causation requires the assignment of new resource costs to marginal loads. It is in accord with generally accepted ratemaking principles to allocate the plant preservation costs across all loads at this time.

Furthermore, WPAG assumes that the marginal load requiring a purchase of a new resource can be clearly identified. WPAG argues that it is IOU load growth that is causing BPA to acquire new resources. However, this is not the case because of how BPA performs its resource planning. Loads are forecast separately for each customer class, then an aggregate load forecast is compared to available resources to determine the need for new resources. New resources are acquired to meet total system loads, not individual class loads. Ratchye, BPA, E-BPA-02R; TR 109.

WPAG states that BPA's resource planning is not germane to determining the resource cost allocation because the "statute" requires cost allocations to be based on "customer groups and resource types." Opening Brief, B-WA-01, 16. It also argues that BPA would not be spending money on a new resource unless the load of some customer group required it. Opening Brief, B-WA-01, 16. However, the part of the "statute" that is controlling in this instance is section 7(g). Section 7(g) applies in part because an option is involved. The option exists not because of any one class's particular load growth, but because it is viewed as an economic element of BPA's resource planning. Hence, to rule out any consideration of BPA's resource planning practices would be most inequitable.

The reasoning used by BPA to establish an allocation of short-term purchased power costs in the 1981 rate proceeding is relevant here. BPA determined in that proceeding that allocating purchased power costs to both Federal base system and NR-1 customers "appropriately reflects the requirement that the Administrator acquire resources sufficient to meet all of his contractual firm obligations." 1981 ROD, VI-13. BPA determined in that proceeding that short-term purchases were being made to meet BPA's contractual firm obligations including deficits which would have been present on the Federal system as well as deficits on the IOU systems that would be served at the NR rate. It was concluded that BPA's system is operated to meet total load at the lowest costs and that power purchases could not be identified with a particular rate pool load. BPA soundly rejected reasoning by the preference customers that FBS resources were more than adequate to meet 7(b) loads and therefore deficit power purchases should not be allocated to 7(b) loads. Id., VI-13-14. Instead it was declared that there is no evidence that the Pacific Northwest Power Act removes the responsibility of preference customers for sharing the costs of meeting BPA's firm contracts. BPA, 1981 ROD, VI-13-14. This reasoning applies under this situation where an option is being preserved to meet BPA's total system load.

WPAG states that the evidence clearly demonstrates that the only portion of total loads that is forecast to need thermal generation is that of IOU load growth. Hutchison et al., WPAG, E-WA-10, 10-11; Reply Brief, WPAG, B-WA-02, 11. It states that BPA has sufficient resources to meet public utility load growth through the turn of the century. When IOU load growth is placed on BPA the probability of needing WNP-1 or WNP-3 increases to one in two by the year 2000 from a one in four probability without IOU load on BPA's system. Hutchison et al., E-WA-01, 11.

On cross-examination however, WPAG could not state what the probability of needing WNP-3 would be based solely on IOU load growth. McGary, WPAG, TR 107-108. Puget points out that WPAG did not perform an analysis of the probability of needing resources based solely on IOU loads on BPA. Opening Brief, Puget, B-PS-01, 4. Puget also cited the uncertainty in growth rates for public agency customers. Puget notes a significant difference between load forecasts for Snohomish PUD in the 1986 Northwest Regional Forecast and BPA's 1985 Pacific Northwest Loads and Resources. Opening Brief, Puget, B-PS-01, 3. Also, WPAG fails to recognize that all customer loads are growing during the time the plant would be operating if completed. A nuclear plant has a 40-year life. During the time the plant is operating, current forecasts indicate preference customer loads will also need new sources of power. IOU load growth may need the power first, but the plant would not be completed solely to meet IOUs' load under current forecasts. Ratchye, BPA, E-BPA-02R, 7. Under the circumstances, especially when dealing with an option that is predicated on economies of planning and an absence of need such as would justify an acquisition, it is equitable to allocate the option costs uniformly across all loads.

WWP identifies several reasons why cost allocations should not be based on long-term load forecasts as WPAG implies. First, load forecasts vary from year to year and thus do not consistently predict costs placed on BPA in the future. Second, basing cost allocation to customer classes on long-term load forecasts would make the forecasts unduly contentious. Third, there is no direct correlation between load forecasts and contractual obligations. Opening Brief, WWP, B-WP-1, 4-5. It is clear that cost allocations under section 7(g) should not be based entirely upon a forecast of load growth because load forecasts are uncertain. Furthermore, because there is no guarantee that particular loads will be placed on BPA in the future, cost recovery remains uncertain. For example, PP&L states that BPA should not preserve the plant to meet their load growth. Boucher, PP&L, E-PL-01R, 3.

Perhaps to establish that their proposal is equitable, WPAG argues that assigning plant-related costs directly to SP and NR rates would not affect the marketability of power at those rates. WPAG uses data from the 1985 rate case to support the assertion that the SP and NR rates would increase by only 0.7 mill/kWh if all plant-related costs were assigned to these rates. Hutchison, WPAG, E-WA-01, 13. WPAG argues this is the "best available calculation." Reply Brief, WPAG, B-WA-02, 9. However, as Puget points out, the data used by WPAG for projecting SP sales is not supported by current experience. Opening Brief, Puget, B-PS-01, 5. In addition to not making SP sales of the magnitude cited by WPAG, BPA is finding it difficult to market SP power at its fully allocated cost. Ratchye, BPA, E-BPA-01R, 8-9. Current experience is the best evidence available. In addition, PP&L indicates the need to have "stable, predictable, and economical" NR rates. Boucher, PP&L, E-PL-01R, 3. The NR and SP rates are market-sensitive to a greater degree than BPA's other rates. Based on all the facts, and as a matter of equitable allocation, it is appropriate that only a pro rata share of WNP-3 Settlement Agreement plant-related costs be allocated to these rates. Ratchye, BPA, E-BPA-02R, 8-9.

The foregoing analysis generally focuses on the immediate situation and on generally accepted ratemaking principles. It reflects the fact that the parties have devoted little or no attention to the question of how, if at all, an equitable allocation of the Settlement Agreement costs and benefits ought to recognize or take into account the possibility of BPA either acquiring the IOU share of WNP-3 as a resource through a section 6(c) process, or determining with certainty at some point that WNP-3 is being preserved for a particular resource or rate pool. The immediacy and polarity of the parties' positions have masked an unspoken assumption that once option costs have been uniformly allocated, that would be the end of the matter until an acquisition takes place, in which case future costs would likely be directly allocated through one of the resource pools. However, confining the determination of what is equitable to the immediate future may produce long-range inequity and divisiveness. A creative view of the entire horizon, short- to long-term, should be taken to determine what is encompassed by an equitable allocation of the preservation costs. BPA will undertake here a discussion of a longer-term view, subject to further discussion and consideration if and when the need arises.

Section 7(g) speaks in terms of equitably allocating costs "in accordance with generally accepted ratemaking principles and the provisions of this Act . . ." 16 U.S.C. § 839e(g). Insofar as concerns "the provisions of this Act" involving rate directives, it is apparent from the structure and wording of section 7 that Congress envisioned a hierarchy of resources paired with rate pools. Set against this hierarchy is the need Congress evidenced throughout the Pacific Northwest Power Act for a regional approach to resource planning and development. Clearly, some tension may exist between the individual needs of customer groups and the regional need for coordination. There also exists some tension between generally accepted ratemaking principles and the ratemaking provisions of the Pacific Northwest Power Act. As previously demonstrated, allocating costs on the basis of existing load has long been held as a fundamental precept of generally accepted ratemaking principles; on the other hand, the somewhat contrary principle of assigning resources to a specific resource pool, and then allocating costs to rate pools, is evident in sections 7(b) and 7(f) of the Pacific Northwest Power Act.

BPA's present purpose is to approach the problem as follows. The record firmly establishes that IOU load growth is not the only reason BPA is preserving the option to complete WNP-3. Reliance on current load growth estimates cannot at this time justify directly or indirectly allocating all plant-related costs to the SP and NR rates. The record has also established that BPA is unable to assign the plant-related costs to a resource pool at this time. As previously indicated, the IOUs' share of WNP-3 may be needed as an FBS resource replacement or as a new resource. Under present circumstances, it is appropriate and equitable that the plant-related costs be allocated uniformly across all customer class loads. Such a sharing recognizes the economy of options, which are predicated in part on an absence of demonstrated and definite need, and the regional or class-wide approach to power planning. If the plant is terminated, a circumstance that would indicate no reasonable and sufficient need for the plant by any customer class or classes, then no customer class would be disadvantaged because it alone paid the price of adequate, efficient, economic, and reliable power planning.

On the other hand, if it can be reliably and conclusively determined which resource pool the IOU share of WNP-3 will be assigned to, or if BPA acquires the IOU share of WNP-3, then it is arguable that the costs of the resource should be equitably allocated to reflect this. Although it may not be the only equitable solution, and although BPA will consider the issue afresh when and if appropriate, it would appear that an equitable solution under the changed circumstances would be to (a) calculate the amount of preservation costs previously allocated; (b) allocate those costs to the identified resource pool; (c) amortize those costs over a reasonable number of years; and (d) in tandem with the amortization, credit excess revenues from the collection of amortized costs back to the rate pools that paid the preservation costs earlier. The effect of the methodology on the costs of the resource to the resource pool would be similar to a situation where no costs are included in the revenue requirement until the resource comes on line. Considerable detail would need to be developed to implement such a methodology.

SCE and PG&E argue that none of the costs at issue in this proceeding should be allocated to NF rates pursuant to section 7(g). However, their argument that no Settlement Agreement costs should be included in the NF rate ignores the initial decision of Judge Miller on BPA's NF-1 and NF-2 rates (Docket No. EF81-2011-003 and EF82-2011-003). In line with Judge Miller's decision, it is equitable and appropriate to include the plant-related costs of the Settlement Agreement in the determination of the NF rate, up to the capacity cost limitation. Ratchye, BPA, E-BPA-01, 5-6. Characterizing the costs as "variable" or "fixed" is not determinant; focus must be had on whether the costs do or may contribute to the availability of nonfirm energy. U.S. Department of Energy, Bonneville Power Administration, 20 FERC ¶ 63,039 at 65,085, 65,089-094 (1984).

Also, contrary to the "legislative history" cited by SCE for the proposition that section 7(g) applies only to firm loads, the language of section 7(g) clearly applies to all "power rates." 16 U.S.C. § 839e(g). SCE, without providing any citation of authority, states that "under traditional ratemaking terminology, 'power' refers to energy delivered on a firm, not nonfirm, basis." Reply Brief, SCE, R-CE-01, 3. It also posits that Congress would have referred to "electric power" rates had it intended to include nonfirm rates within the coverage of section 7(g). Id., 4. However, when Congress meant to refer to firm power, it used the term "firm power." E.g., 16 U.S.C. §§ 839c(b)(1) (sales to meet "firm power" loads), 839c(e)(1) and (2), 839e(b)(2) (amounts "to be charged for firm power"), 839e(f) ("Rates for all other firm power"), and 839e(k) ("nonfirm electric power"). Elsewhere, such as in the definition of a BPA "customer" and in the requirement that "power sales" be subject to the preference and priority provisions of the Bonneville Project Act, it is clear that the term "power" is intended to encompass firm and nonfirm power. See 16 U.S.C. §§ 839a(7), 839c(a), 839e(a)(1). The language of section 7(g) is controlling; costs may be allocated under section 7(g) to rates for both firm and nonfirm power. Judge Miller's decision also recognizes that costs may be allocated to nonfirm rates pursuant to section 7(g). U.S. Department of Energy, Bonneville Power Administration, 20 FERC ¶ 63,039 at 65,095 (1984).

Insofar as concerns an equitable allocation of WNP-3 Settlement Agreement costs, it has been determined that the costs and benefits should be allocated before the determination of the DSI rate according to section 7(c)(2). Ratchye, BPA, E-BPA-01, 7-8. No party took issue with BPA's testimony that this is equitable.

Decision

Allocating costs according to section 7(g) does not require costs to be uniformly allocated across all loads. Instead it provides for establishing equitable cost allocation methodologies that are consistent with generally accepted ratemaking principles and with other provisions of the Pacific Northwest Power Act. Three cost allocation methodologies were considered: 1) allocation to all loads; 2) assignment to a specific customer class or classes; and 3) assignment to loads served by a resource pool. The determination of an equitable allocation methodology depends on all the circumstances under consideration. Given the circumstances at this time, plant-related costs will be allocated uniformly across all firm loads and, consistent with Judge Miller's opinion, included in the development of the NF rate. The allocation to all loads will be performed before the 7(c)(2) calculation of the DSI rate.

C. Allocation of Exchange-Related Costs and Benefits

Issue #1

Should the opportunity cost of power used to displace combustion turbine operation be identified and included in the calculation of exchange-related costs?

Summary of Positions

BPA does not assign a cost to, or forecast revenue from, the surplus firm power and nonfirm energy used to displace IOU combustion turbine operation in the exchange process. The effect of BPA's methodology is potentially to decrease the amount of excess revenues credited in the rate design process. Ratchye, BPA, E-BPA-01, 7. BPA maintains that this allocation method does not harm preference customers. Ratchye, BPA, E-BPA-02R, 2-3.

The Joint Customers argue that BPA should determine the opportunity cost of power used to displace the combustion turbines. They maintain that one of the principles of the Settlement Agreement is not to adversely impact other customer classes. Drummond et al., Joint Customers, E-JC-01, 6. The Joint Customers claim that they would be harmed by BPA's methodology because the percentage allocation of the excess revenue credit to the preference customer class is different from the implied cost allocation in BPA's proposed methodology. Drummond et al., Joint Customers, E-JC-01, 7-9. Reply Brief, Joint Customers, R-JC-01, 2-3.

WPAG supports the Joint Customers' position. Hutchison et al., WPAG, E-WA-01, 3.

WWP, Puget, and PGE agree with BPA that the opportunity cost of power used to displace combustion turbines should not be calculated. Opening Brief, WWP, B-WP-01, 3; Opening Brief, Puget, B-PS-01, 6-7; Reply Brief, PGE, R-GE-1, 2-3; Reply Brief, Puget, R-PS-01, 2-3.

Evaluation of Positions

The Joint Customers argue that the cost allocation methodology adopted in this proceeding must not adversely impact other customers, citing a Statement of Principles that BPA developed for use in negotiations on the Settlement Agreement. The principle states that other customer classes must not be adversely impacted. Drummond et al., Joint Customers, E-JC-01, 6. The Joint Customers state that the Administrator committed to proceed with a section 7(i) hearing to establish a method for allocating the costs and benefits of the Settlement in a manner consistent with the principle that BPA's customers not be adversely impacted. Opening Brief, Joint Customers, B-JC-01, 5.

It is not true that the Administrator, when agreeing to hold a section 7(i) rate hearing, committed to establish a rate methodology that followed the Statement of Principles BPA supported in negotiating the Settlement. See Exhibit Q, WNP-3 ROD. BPA agrees with PGE and Puget that it is not appropriate to use the pre-settlement principles to evaluate an isolated cost or benefit element in the methodology. Reply Brief, PGE, R-GE-01, 2; Reply Brief, Puget, R-PS-01, 2. The Statement of Principles applied simply to the determination whether to enter the Settlement Agreement. BPA demonstrated in the WNP-3 ROD that BPA ratepayers are not harmed or adversely impacted by the Agreement. Ratchye, BPA, E-BPA-02R, 2-3. As such, BPA carried through on the settlement principles.

In this proceeding, BPA has taken the Settlement Agreement as a fact, and has developed a cost allocation methodology that could be integrated into BPA's overall rate development process. Ratchye, BPA, E-BPA-01, 1. Under section 7(g) of the Pacific Northwest Power Act, it is necessary and appropriate to consider equitable allocation as an issue on its own merits. BPA considers the question of adverse impacts to be within the purview of equitable allocation, not as a matter that must be addressed and given preeminence because it is identified as a negotiation principle. The issues to be addressed in this hearing include ratemaking principles and a general approach to an equitable allocation of the Settlement Agreement costs and benefits. Ratchye, BPA, E-BPA-01, 2.

The Joint Customers argue that preference customers are harmed by BPA's proposed cost and benefit allocation methodology because the value of nonfirm energy used to displace combustion turbines is not explicitly recognized. Opening Brief, Joint Customers, B-JC-01, 12. The Settlement Agreement costs and benefits are proposed to be allocated uniformly to all loads. If excess revenues were allocated uniformly to all loads, this issue would be moot. The issue exists because currently the FBS receives a predominant share of the excess revenues from sales made at NF rates. Ratchye, BPA, E-BPA-02R, 2-3. However, BPA does not agree that the proposed methodology will significantly affect preference customer rates. As explained in rebuttal testimony, the Joint Customer proposal would at most allocate 12 percent more excess revenue credit to loads served by FBS resources. Ratchye, BPA, E-BPA-02R, 2. The results of the rate analysis prepared for the WNP-3 ROD used a cost allocation methodology that is the same as BPA's proposed methodology, and it demonstrated no significant impact on preference customer rates. Ratchye, BPA, TR 134.

Puget, WWP, and PGE raise questions regarding the equitability of the Joint Customers' proposal. Opening Brief, Puget, B-PS-01, 6; Opening Brief, WWP, B-WP-01, 2; Reply Brief, PGE, B-GE-01, 2-3; Reply Brief, Puget, R-PS-01, 2-3. The Joint Customers provided a more detailed explanation of their proposed methodology in their reply brief. Reply Brief, Joint Customers, R-JC-01, 2-3. However, the Joint Customers did not directly address Puget's concern that the Joint Customer's proposal will not operate even-handedly as the relative costs and benefits fluctuate over time.

The Joint Customers propose that BPA determine the revenues from nonfirm energy and surplus firm power as if the Settlement Agreement does not exist. Reply Brief, Joint Customers, R-JC-01, 2-3. The assumptions required to create this hypothetical situation would make the rate process more contentious and complicated. The calculation of opportunity costs is not straightforward. For example, there was considerable controversy regarding the proper calculation of opportunity costs in BPA's Variable Rate proceeding. Ratchye, BPA, E-BPA-02R, 3. Puget and WWP agree with BPA and argue that the Joint Customer's proposal is unworkable, impractical, and would unnecessarily complicate the rate proceedings. Opening Brief, Puget, B-PS-01; 6. Opening Brief, WWP, B-WP-01, 3.

The Joint Customers are concerned that even if the impact on preference customer rates is minimal, BPA's methodology, by not recognizing the opportunity cost of nonfirm energy, could set a dangerous precedent for future arrangements for firming up nonfirm energy with thermal resources. Opening Brief, Joint Customers, B-JC-01, 11-12; Reply Brief, Joint Customers, R-JC-01, 3. BPA understands the Joint Customers' concern; however, the hypothetical they cite is different from the Settlement Agreement. If BPA made a power sale based on nonfirm energy firmed up with thermal resources, a rate would be developed and revenues would be gained from the transaction. This is a different situation from the Settlement Agreement, where an exchange of power was developed and incidental monetary payments not directly related to the cost of the power were designed to equalize the value of the power exchanged.

Decision

BPA agrees in principle that a transaction intended to benefit all customers, such as the Settlement Agreement, should not in itself cause one customer class to suffer or to enjoy a disproportionate rate impact in relation to existing ratemaking practices. A full quantification of the costs and benefits of the Settlement Agreement would require the calculation of the opportunity cost of power used to displace combustion turbines. However, opportunity cost calculations are generally complex and contentious. Based on the analyses in the WNP-3 ROD, it appears that preference customer rates will not be disproportionately impacted by the proposed methodology. As such, and on balance, calculating the opportunity cost is not warranted. BPA may include an opportunity cost analysis for the surplus firm power and nonfirm energy used to displace combustion turbines under the Settlement Agreement in a general rate proceeding if it is demonstrated by a customer class that it is disproportionately impacted by BPA not performing an opportunity cost analysis. This methodology does not set a precedent for the ratemaking treatment of displacing BPA resources with nonfirm energy.

Issue #2

Should exchange-related costs be allocated to the Nonfirm energy rate?

Summary of Positions

BPA excludes exchange-related costs from the calculation of the NF rate. BPA calculates the NF rate to conform with Judge Miller's initial decision regarding BPA's NF-1 and NF-2 rates. Ratchye, BPA, E-BPA-01, 5. Because the exchange does not contribute to the availability of nonfirm energy, Judge Miller's decision does not require that the exchange-related costs and benefits be allocated to the NF rate. Additionally, the calculations required to incorporate the WNP-3 exchange-related costs in the NF rate would be inordinately complex. Ratchye, BPA, E-BPA-01, 8-9; E-BPA-02R, 5-6.

SCE agrees with BPA that exchange-related costs and benefits should not be allocated to the NF rate. Opening Brief, SCE, B-CE-01, 2. PG&E on the other hand, argues that the nonfirm rate is inappropriately affected by the exchange transaction because the exchange loads are not included in the calculation of the target NF rate. Letter, PG&E, June 16, 1986.

The Joint Customers maintain that Judge Miller's decision requires the exchange-related costs and benefits to be allocated to the NF rate. They state that Judge Miller declared that all BPA system costs are properly allocated to extraregional rates. Therefore, because the exchange-related costs are system costs, they should be included in the determination of the NF rate. Drummond et al., Joint Customers, E-JC-01, 3. Opening Brief, Joint Customers, B-JC-01, 89. They also state that the calculations would not be too complex because the iteration required should converge quickly. Drummond et al., Joint Customers, E-JC-01, 3-5; Opatrny, Joint Customers, TR 72-75.

WPAG and WWP support the position of the Joint Customers. Hutchison et al., WPAG, E-WA-01, 3; Opening Brief, WWP, B-WP-01, 1-2.

Evaluation of Positions

The Joint Customers argue that the exchange-related costs and benefits are system costs that should be allocated to NF rates. They state that all costs that BPA incurs are system costs that relate to BPA's role as a power marketing agency. Opening Brief, Joint Customers, B-JC-01, 8-9; Opatrny, Joint Customers, TR 74. BPA agrees that these are system costs, as are all of BPA's costs. Even so, system costs not associated with nonfirm energy need not be allocated to nonfirm rates. For example, Judge Miller ruled that only the thermal capacity costs up to the generation capacity equivalent to secondary energy available under average water conditions could properly be allocated to the nonfirm energy rates. United States Department of Energy, Bonneville Power Administration, 29 FERC ¶ 63,079, at 65,078 (1984). Costs in excess of the capacity cost limitation are still BPA system costs; however, since Judge Miller found that they do not contribute to the availability of nonfirm energy, they are excluded from the nonfirm energy rate. The exchange-related costs are significantly different from other costs that Judge Miller decided should be allocated to the NF rate. These costs evolve from an exchange of power and do not contribute to the availability of nonfirm energy. Ratchye, BPA, E-BPA-01, 8; E-BPA-02R, 5.

The Joint Customers argue that the exchange does contribute to the availability of nonfirm power because access to the combustion turbines and other resources could enhance BPA's operating flexibility. On the other hand, the Joint Customers acknowledge that serving the WNP-3 exchange load would diminish the amount of power available for export. Opening Brief, Joint Customers, B-JC-01, 9-10. Although operating flexibility may be enhanced; nevertheless, the net impact is that this transaction does not contribute to the availability of nonfirm energy.

The Joint Customers state that BPA did not offer any evidence that the net impact of the transaction does not contribute to the availability of nonfirm energy. Reply Brief, Joint Customers, R-JC-01, 4. BPA relied on evidence offered in the WNP-3 ROD to make the determination that the exchange transaction doesn't contribute to the availability of nonfirm. The power associated with the exchange-related costs consists of three components: (1) BPA's right to request firm energy from the companies' combustion turbines; (2) surplus capacity on BPA's system used to shape the energy deliveries; and (3) nonfirm energy available to displace the combustion turbines. WNP-3 ROD, 17. The WNP-3 ROD states that the exchange reduces the amount of energy that BPA would make available for export at prices the market will usually bear. WNP-3 ROD, 74. The Joint Customers did not quantify the effect of the increased operating flexibility that they claim could occur. As such, the discussion presented in the WNP-3 ROD fully supports BPA's position that the exchange does not contribute to the availability of nonfirm.

The Joint Customers also argue that, like the residential exchange subsidy, this exchange should be included in the NF rate. Opening Brief, Joint Customers, B-JC-01, 10. However, the settlement exchange is a different transaction from the Residential Purchase and Sale Agreement. Instead of being a subsidy as is the residential exchange, and thus possibly being viewed as a cost of BPA's other operations, this exchange is demonstrated in the WNP-3 ROD to result in a net cash flow to BPA. WNP-3 ROD, 20-21. Also, the settlement exchange does directly benefit the Pacific Northwest customers. Ratchye, BPA, E-BPA-01, 8. The Joint Customers dispute the conclusion that the settlement exchange results in a net cash flow arguing that cash flow varies depending on a number of uncontrollable factors. Reply Brief, Joint Customers, R-JC-01, 4-5. The study performed for the WNP-3 ROD is based on the most reasonable assumptions given the data available when the study was performed. Although the Joint Customers question the assumptions used in the analysis, they did not present any evidence to lead BPA to conclude that the net cash flow is negative.

PG&E argues that if BPA's witness is correct that the exchange-related costs and benefits are not a cost of providing nonfirm energy, then

> the non-firm rate should not be affected by the exchange transaction. However, BPA's proposal causes the unit costs of non-firm energy to increase since the exchange loads are removed from the sales portion of the rate formula. Thus, exchange-related costs are included in the non-firm rate.

Letter, PG&E, June 16, 1986. PG&E's comment speaks about an issue regarding implementation of the rate methodology. Resolution of this issue will occur in the next general rate proceeding when the WNP-3 allocation methodology will be implemented.

Finally, the calculations required to implement the Joint Customers' proposal would likely be unreasonably complex. The Joint Customers' proposal would require BPA to develop a NF rate that is partially dependent on the opportunity cost of nonfirm energy. This is not a straightforward calculation and could require several iterations for a stable NF rate to appear. Ratchye, BPA, E-BPA-01, 9; E-BPA-02R, 5-6. Even if an opportunity cost analysis were performed, it would still be inordinately difficult to incorporate the opportunity cost into the determination of the NF rate.

Decision

The exchange-related costs and benefits will not be included in the development of the NF rate. Inasmuch as the exchange does not contribute to the availability of nonfirm energy, Judge Miller's decision does not require that exchange-related costs be included in the NF rate. Additionally, it would be unreasonably difficult and impractical to include the exchange-related costs in the NF rate.

Issue #3

Should BPA allocate the exchange-related costs and benefits uniformly across all firm loads?

Summary and Evaluation of Positions

BPA stated that the exchange related costs and benefits would be allocated across all firm loads. Ratchye, BPA, E-BPA-01, 7.

The Joint Customers point out that BPA's testimony does not state that exchange-related costs would be allocated uniformly across all firm loads. Drummond et al., Joint Customers, E-JC-01, 10.

BPA stated in rebuttal testimony that the word "uniformly" was inadvertently omitted from the description of the allocation methodology. BPA does intend to allocate plant-related and exchange-related costs uniformly across all firm loads. Ratchye, BPA, E-BPA-02R, 6.

The DSIs requested that BPA clarify that the costs would be uniformly allocated to both demand and energy components of the rates. Oral Argument, DSI, TR 194. BPA stated in testimony and cross-examination that the Settlement Agreement costs and benefits would be classified to demand and energy using the uniform classification percentages developed in each general rate proceeding. Ratchye, BPA, E-BPA-01, 10; TR 190. BPA also stated that the costs and benefits would be seasonally differentiated according to the seasonal splits developed in each general rate proceeding. Ratchye, BPA, E-BPA-01, 10.

Decision

Exchange-related costs and benefits will be classified, seasonally differentiated, and allocated uniformly across all firm loads.

D. Participant Comments

In comments dated April 30, 1986, Lane Electric Cooperative, Inc. filed a document with BPA, asking that it be "made part of the record in the settlement hearing process and that all parties investigate and otherwise explore the issues raised to ensure that any settlement reached is legally valid and recognizes the rights of all parties involved." The document then lists and discusses a number of issues bearing on the wisdom and legality of the WNP-3 Settlement Agreement. These issues will not be addressed here for the reasons stated in the Introduction to this Record of Decision related to the scope of the proceeding.

Based on the foregoing, I hereby adopt the proposed allocation methodology for the WNP-3 Settlement Agreement costs and benefits.

Issued at Portland, Oregon, this 18th day of July 1986.

Peter T. Johnson

Peter T. Johnson
Administrator

Appendices

Appendix A

LIST OF PARTIES AND ABBREVIATIONS

Parties	Abbreviations
Bonneville Power Administration	BPA
Chelan County PUD No. 1	CC
City of Port Angeles	PA
City of Seattle, City Light Department	SCL
Columbia Falls Aluminum Company	CF
Direct Service Industries	DSIs
Eugene Water and Electric Board	EWEB
Joint Customers (PPC and DSIs)	
Pacific Power and Light Company	PP&L
Portland General Electric Company	PGE
Public Power Council	PPC
Puget Sound Power & Light Company	Puget
Rural Electric Company of Rupert, Idaho et al	Rural
Southern California Edison	SCE
Utility Reform Project	URP
The Washington Water Power Company	WWP
Western Montana Electric Generation and Transmission Cooperative	WMEGT
Western Public Agencies Group	WPAG

Appendix B

LIST OF PARTIES' WITNESSES AND REPRESENTATIVES

Name	Party Name
Alcantar, Michael P.	Columbia Falls Aluminum Company
Anderson, Wilbur	Western Montana Electric Generation Transmission Cooperative, Inc.
Austin, R. Michael	Bonneville Power Administration
Baxendale, James C. L.	Portland General Electric Company
Bearzi, Judith A.	Public Power Council
Boucher, Rodney M.	Pacific Power and Light Company
Crisson, Mark	Direct Service Industries
Dahlke, Gary A.	Washington Water Power Company
Dorsey, David J.	Chelan County PUD No. 1
Drummond, William	Public Power Council
Early, Michael B.	Direct Service Industries
Frazee, Mark	Southern California Edison
Galloway, George M.	Pacific Power and Light Company
Grant, Harry E.	Rural Electric Company of Rupert, Idaho et al.
Herndon, Steven L.	Western Montana Electric Generation Transmission Cooperative, Inc.
Hutchison, Coe	Western Public Agencies Group
Kari, Donald G.	Puget Sound Power & Light Company
Kaufman, Paul	Public Power Council
Knutson, Craig	City of Port Angeles
Kunkel, Garry	Eugene Water and Electric Board
Larsen, Alan S.	Eugene Water and Electric Board
Lubking, Eugene W.	Chelan County PUD No. 1
McCullough, Robert	Portland General Electric Company
McGary, Patrick	Western Public Agencies Group
McGrane, John D.	Southern California Edison
Miller, Max M.	Association of Public Agency Customers
Mundorf, Terence L.	Western Public Agencies Group
Murphy, Paul M.	Direct Service Industries
Myers, Robert V.	Puget Sound Power & Light Company
Opatrny, Carol C.	Joint Customers
Prekeges, Gregory P.	Washington Water Power Company
Ratchye, Leslie K.	Bonneville Power Adminstration
Rhoads, Robert R.	Columbia Falls Aluminum Company
Roach, Randy	Bonneville Power Administration
Saleba, Gary	Western Public Agencies Group
Spettel, Scott C.	Joint Customers
Wertz, Darren	Western Public Agencies Group
Williams, Linda K.	Utility Reform Project
Williams, Walter L.	City of Seattle, City Light Department
Young, Robert	Joint Customers

Appendix C

PARTICIPANTS COMMENTS ON BPA'S ALLOCATION METHODOLOGY FOR WNP-3 SETTLEMENT AGREEMENT COSTS AND BENEFITS

Comments Made by Letters

Commenter	Representing/Affiliation
Coates, E. E.	Tacoma City Light
Fadeley, Charles N.	Lane Electric Cooperative
Fairchild, Peter G.	California Public Utilities Commission
Maudlin, Gene	Oregon Public Utility Commission
Oglesby, Douglas A.	Pacific Gas and Electric Co.
Runyan, Paul C.	Clark County PUD
Zahn, E.	Self

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**Allocation of WNP-3
Settlement Agreement
Costs and Benefits**

DOE/BP-686
July 1986
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