Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

FREEDOM OF INFORMATION ACT PROGRAM

October 21, 2019

In reply refer to: FOIA #BPA-2019-00410-F

Nathan Sandvig
205 SE Spokane Street, Suite 300
Portland, OR 97202
Email: nathan.sandvig@nationalgrid.com

Dear Mr. Sandvig,

This communication is the Bonneville Power Administration's (BPA) final response to your request for agency records made under the Freedom of Information Act, 5 U.S.C. § 552 (FOIA). Your request was received on January 31, 2019, with an acknowledgement letter sent to you on February 12, 2019.

Request

"1. Construction Agreements and agreements regarding commercial transmission rights for such facilities for the AC Intertie facilities interconnecting the John Day Substation, the Grizzly Substation, the Summerlake Substation, and any other facilities needed to maintain the capability of the northern portion of AC Intertie between the Bonneville Power Administration, Portland General Electric, PacifiCorp and the Western Area Power Administration.
2. Any subsequent agreements amending or extending the agreements described in 1 above."

Clarification

On February 12, 2019, via letter to the agency, you clarified your request as follows:

"For the construction agreements and agreements regarding commercial transactions for the original Northern portion of the AC Intertie, we are only requesting active agreements and amendments to the agreements.

This request covers the original agreements surrounding construction and allocation of commercial rights on the northern portion of the Pacific Northwest-Pacific Southwest AC Intertie and any provisions still in effect. If all original provisions have been superseded, revised, or restated in the agreements regarding construction of the northern portion of the Third AC expansion of the Pacific Northwest-Pacific Southwest intertie, then [this request and item #7 from request BPA-2019-00412-F] would not differ. If not, then think of this request as addressing the original construction."

Response
BPA conducted a search of the electronic records of the following agency offices:

Customer Contracts Administration
Transmission Account Services
Customer Service Engineering Contract Administration

Those offices located 1,175 pages of records responsive to your request. BPA is herein releasing 1,147 pages in full, with no redactions applied. BPA notes that 28 pages of the 1,175 total pages are publicly available and can be found at the following Federal Energy Regulatory Commission web link:

https://elibrary.ferc.gov/idmws/File_list.asp?document_id=2138659

Fees
There are no fees associated with the response to your FOIA request.

Certification
Pursuant to 10 C.F.R. § 1004.7(b)(2), I am the individual responsible for the search, determination, and records release described above. Your FOIA request BPA-2019-00410-F is now closed with all available agency records provided.

Appeal
The adequacy of the search may be appealed within 90 calendar days from your receipt of this letter pursuant to 10 C.F.R. § 1004.8. Appeals should be addressed to:

Director, Office of Hearings and Appeals
HG-1, L'Enfant Plaza
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585-1615

The written appeal, including the envelope, must clearly indicate that a FOIA appeal is being made. You may also submit your appeal by e-mail to OHA.filings@hq.doe.gov, including the phrase "Freedom of Information Appeal" in the subject line. (The Office of Hearings and Appeals prefers to receive appeals by email.) The appeal must contain all the elements required by 10 C.F.R. § 1004.8, including a copy of the determination letter. Thereafter, judicial review will be available to you in the Federal District Court either (1) in the district where you reside, (2) where you have your principal place of business, (3) where DOE's records are situated, or (4) in the District of Columbia.

You may contact BPA's FOIA Public Liaison, Jason Taylor, at 503.230.3537, jetaylor@bpa.gov, or the address on this letter header for any further assistance and to discuss any aspect of your request. Additionally, you may contact the Office of Government Information Services (OGIS) at the National Archives and Records Administration to inquire about the FOIA mediation services they offer. The contact information for OGIS is as follows:

Office of Government Information Services
National Archives and Records Administration
8601 Adelphi Road-OGIS
College Park, Maryland 20740-6001
E-mail: ogis@nara.gov
Phone: 202-741-5770
Toll-free: 1-877-684-6448
Fax: 202-741-5769

Thank you for your interest in the Bonneville Power Administration.

Sincerely,

Candice D. Palen
Freedom of Information/Privacy Act Officer

Enclosure: responsive agency records

Via Facsimile

Wholesale Energy Services
825 NE Multnomah, Suite 600
Portland, Oregon 97232
FAX (503)813-6291

LOSS RETURN CONFIRMATION

Pac# 860934/860935/860936

PacifiCorp
825 NE Multnomah, Suite 600
Portland, OR 97232

Date: July 26, 2011

The following Loss Return Confirmation (hereafter "Confirmation") memorializes the terms of a transaction agreed to by Bonneville Power Administration (BPA) and PacifiCorp (PAC) (together the "Parties") in the Reconciliation Letter Agreement Contract No. 11TX-15452 (hereafter "Reconciliation Agreement"). Transactions hereunder are in accordance with reference contracts as follows: FPT Transmission Agreements Nos. 14-03-26811, DE-MS79-79BP90100, DE-MS79-94BP94280 and DE-MS79-94BP94333; PTP Transmission Agreements Nos. 02TX-10968, and 04TX-11722; AC Intertie Capacity Ownership Agreement Nos. DE-MS79-95BP94628, AC Intertie Transmission Agreement, DE-MS79-94BP94285, and the AC Intertie Agreement No. DE-MS79-94BP94332, (hereafter "the Contracts"). Unless otherwise stated, transactions hereunder are in accordance with Western System Power Pool (WSPP) Agreement, as amended.

This Confirmation is not a BPA purchase of energy from PAC. The sole purpose of this Confirmation is to facilitate PAC's delivery of losses returned under the Contracts as described in the Reconciliation Agreement. This delivery satisfies the return of losses for transmission services provided during the period July 1, 2001, through December 31, 2007 and the over delivery of losses during the period October 1, 2003 through March 31, 2009 under the Contracts, as discussed in the Reconciliation Agreement.

Trade Date:	July 26, 2011	
Seller:	PacifiCorp	Purchaser: Bonneville Power Administration
Seller Trader:	Jim Schroeder	Purchaser Trader: Mark Miller
Seller phone:	(503) 813-5380	Purchaser phone: (503) 230-4003
Product:	Loss return	

Schedule: flat – Monday through Sunday including NERC Holidays

Term: 10/01/2011 - 12/31/2011

Type of Service: WSPP Schedule C

Point of Delivery: A point where PAC-West System is interconnected with BPA's transmission system, excluding constrained paths. Parties further agree that when system to system deliveries cannot be made due to transmission constraints the Point of Delivery will be Mid-C.

Contract Price: N/A; this transaction returns previously unreturned transmission losses

Contract Quantity: 18,018 MWh

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Delivery Rate: Delivery Rate (MW/hr) shall be equal to:

10/01/2011 (HE 0100) through and including 12/24/2011 (HE 2400)= 8 MW/hr
12/25/2011 (HE 0100) through and including 12/31/2011 (HE 1400)= 10 MW/hr
12/31/2011 (HE 1500) through and including 12/31/2011 (HE 2400)= 11 MW/hr

PacifiCorp Contacts	Phone	Facsimile
Preschedule:	503-813-6972	503-813-6265
Real Time:	503-813-5389/5374	503-813-5512
Contracts/Confirms:	@ContractPhone503-813-5954	503-813-6291

BPA Contacts	Phone	Facsimile
Preschedule:	503-230-3813	866-861-6371
Real Time:	503-230-3341	866-861-6371
Contracts/Confirms:	503-230-4003	503-230-7463

Scheduling: Pursuant to the WSPP, this transaction shall be pre-scheduled. The Pre-Schedule Day is defined by the Western Electricity Coordinating Council's Pre-Schedule Calendar. Energy shall be pre-scheduled, identifying source and sink, by 1100 on the Pre-Schedule Day; provided, however, that the Parties may mutually agree to other arrangements. Real Time modifications will not be allowed except by mutual agreement or due to an uncontrollable force.

Liquidated Damages: Per Section 21.3 of the WSPP Agreement.

Please indicate your acceptance of the terms stated herein by returning an executed copy of this Confirmation Agreement by facsimile to **503-813-6291** within 5 business days.

PacifiCorp
Authorized Signature:

Name: Stacey Kusters

Title: Director, Origination

Date: July 26, 2011

Bonneville Power Administration
Authorized Signature:

Name: Mark E Miller

Title: Account Executive

Date: July 26, 2011

Bonneville File Path:
(W:\TMC\CT\PacifiCorp\Contracts (Final)\15452_ Losses Settlement Confirm.docx)

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AUG 02 2011

Contract No. 14-03-29224

4-4-73

CONSTRUCTION TRUST AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF THE INTERIOR

acting by and through the

BONNEVILLE POWER ADMINISTRATOR

and

PACIFIC POWER & LIGHT COMPANY

providing for design, construction and test of

Pacific's portion of the Malin Substation

Index to Sections

This CONSTRUCTION TRUST AGREEMENT, executed June 20, 1973, by the UNITED STATES OF AMERICA (Government), Department of the Interior, acting by and through the BONNEVILLE POWER ADMINISTRATOR (Administrator), and PACIFIC POWER & LIGHT COMPANY (Pacific), a corporation organized and existing under the laws of the State of Maine,

W I T N E S S E T H:

WHEREAS Pacific, Portland General Electric Company (Portland General), and the Government, acting by and through the Bureau of Reclamation and the Administrator, entered into an agreement (Contract No. 14-03-59840) which, among other things, provided for the construction of the Malin substation near Malin, Oregon, and outlines the ownership and responsibilities of the parties; and

WHEREAS the Malin substation is a part of the Pacific Northwest-Pacific Southwest Intertie program as recommended to Congress by the Secretary of the Interior and approved by Congress by making appropriations for the construction of the Government's portion thereof; and

WHEREAS the parties hereto executed Construction Trust Agreement, Contract No. 14-03-59835, which provided funds for the Administrator to design, furnish certain labor and material, construct and test Pacific's portion of the 500 kv switchyard (said switchyard is as defined in said Agreement No. 14-03-59840, and is hereinafter called the 500 kv Switchyard), at the Malin substation in conjunction with the design, construction, and test of the remainder of the 500 kv Switchyard; and

WHEREAS Portland General and the Administrator entered into a similar trust agreement (Contract No. 14-03-59834) which provided that the Administrator design, furnish certain labor and material, construct, and test Portland General's portion of the 500 kv Switchyard; and

WHEREAS the parties hereto desire to terminate said Contract No. 14-03-59835 and execute an agreement which provides for additional work, upon approval by

Pacific, to be performed by the Administrator when the Administrator determines that such performance is beneficial to the Government; and

WHEREAS Portland General and the Administrator expect to enter into a Construction Trust Agreement (Contract No. 14-03-29225) similar to this agreement which provides for additional work, upon approval by Portland General, to be performed by the Administrator; and

WHEREAS the Administrator is authorized pursuant to law to dispose of electric power and energy generated at various federal hydroelectric projects in the Pacific Northwest and to enter into related agreements;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. Termination of Agreement. Contract No. 14-03-59835 is hereby terminated as of the time this agreement takes effect but all liabilities accrued thereunder shall be and are hereby preserved.

2. Term of Agreement. This agreement will be effective on the date of execution of said Contract No. 14-03-29225 with Portland General or on the date of execution of this agreement, whichever is later, and shall continue in effect until terminated by either party upon written notice to the other party. All liabilities accrued as of the date of termination shall be and are hereby preserved.

3. Exhibits. Exhibits A and B are by this reference incorporated herein and made a part of this agreement. Pacific shall be the Contractor as that term is used in Exhibit A.

4. Trust Fund. Pacific hereby agrees to pay the Administrator an amount equal to its share of the total cost of performing the work as outlined in Exhibit B or any addition to Exhibit B, less any credit to Pacific for facilities furnished under section 6. Such amounts (trust fund) shall be held by the Administrator in trust for Pacific's share of the costs of performing the Administrator's duties pursuant to section 5(b). Pacific will make payments on account of such share of estimated cost in amounts requested by the Administrator. If at any time thereafter

the Administrator estimates that such amounts are insufficient to pay Pacific's share of the cost of completing performance of such duties, Pacific shall advance to the Administrator, when he so requests and in such installments as may be specified by him, such additional moneys as he estimates will be required for such completion.

The moneys so received by the Administrator, as aforesaid, together with all moneys, if any, advanced to him in trust under any other provisions of this agreement, will be placed in a trust account in the United States Treasury subject to withdrawal as provided in 31 U. S. C., sections 725r and 725s, for payment of the cost of performing the Administrator's duties pursuant to this agreement.

5. Duties of the Administrator.

(a) The Administrator shall submit to Pacific and Portland General all proposals for adding or modifying facilities at Malin substation, outlining the work to be performed and the costs to be borne by each party. Such work and pertinent data shall be described in Exhibit B, or additions to Exhibit B.

(b) The Administrator shall furnish all material and labor except that furnished by Pacific pursuant to section 6 and by Portland General pursuant to Contract No. 14-03-29225, and shall design, construct, and test the facilities to be installed at the Malin substation pursuant to Exhibit B.

(c) All work done at Pacific's expense hereunder will be performed in whole or in part by force account, by contract, or by both, in the same manner and subject to the same limitations as if all funds being expended therefor were Government funds.

6. Duties of Pacific. Pacific, at its sole expense, shall provide, for installation by the Administrator pursuant to section 5(b), any facilities which it agrees to supply.

7. Extension of Time. The completion date specified in Exhibit B shall be extended for a time equivalent to such delays, if any, as are caused by events which either party hereto could not reasonably avoid by the exercise of reasonable diligence and foresight.

8. Ownership of Facilities and Equipment.

(a) Each party's ownership of facilities constructed and installed pursuant to this agreement shall be as specified in said Agreement No. 14-03-59840.

(b) Title to all facilities constructed pursuant to section 5(b) that are furnished by the Administrator will remain in the Government until such facilities have been approved for the purposes of this agreement by the Administrator as being ready for operation. Notice of such approval shall be sent to Pacific. Title to and ownership of such facilities shall then pass to, and shall be vested in the parties in accordance with said Contract No. 14-03-59840.

9. Review by the Administrator. The Administrator shall review the design, construction, and test of the facilities installed hereunder with Pacific at regular intervals.

10. Additions to Exhibit B.

(a) The Administrator shall prepare, for execution by the parties hereto, an additional table to Exhibit B each time the parties hereto agree that facilities shall be added or modified at Malin substation. Such table shall specify the facilities to be installed, the work to be performed by each party and the estimated costs to be borne by Pacific. Such estimated costs less any credit for facilities furnished by Pacific shall constitute the amount of the trust fund, as specified in section 4, for each particular project.

(b) Upon execution by the parties hereto, new tables to Exhibit B shall be attached to and deemed to be a part of this agreement and shall be effective on the date specified therein.

11. Accounting.

(a) Within a reasonable time after completion of the work for which a deposit in trust has been made under the terms hereof, the Administrator shall make a full accounting to Pacific showing the receipts credited to, and the costs charged against, said trust fund. Such accounting shall be made in such manner so that Pacific can place the various units of property on its books in the manner prescribed in the Federal Power Commission Uniform System of Accounts for class A public utilities. The Administrator shall remit to Pacific any unexpended balance of said trust fund within a reasonable time after accounting is made as herein provided.

(b) If at any time the Administrator requests Pacific to advance additional moneys pursuant to section 4, the Administrator shall, within a reasonable time after Pacific so requests, make a full accounting to Pacific showing the receipts credited to, and the costs charged against, said trust fund. The Administrator shall, at the same time, submit a statement to Pacific showing in detail his estimate of the additional moneys required to pay its share of the cost of completing performance of his responsibilities specified in section 5(b).

(c) Pacific's share of the cost of performing the work and furnishing the materials mentioned in section 5(b) shall be proper charges against the trust fund, and shall be determined by charging the cost elements exclusive of interest in the same manner as if Government funds were being expended, including among other items, labor, leave obligations, contributions - employee benefits, equipment use, tool and stores expense, expense of transportation of any materials or equipment which is not included as stores expense, and overhead reasonably allocable thereto.

IN WITNESS WHEREOF, the parties hereto have executed this agreement in

several counterparts.

UNITED STATES OF AMERICA
Department of the Interior

(SEAL)

By ____________________
Acting Bonneville Power Administrator

PACIFIC POWER & LIGHT COMPANY

(SEAL)

By ____________________

Title Vice President

ATTEST:

By ____________________

Title Assistant Secretary

EXHIBIT A

(12-3-69)

PROVISIONS REQUIRED BY STATUTE OR EXECUTIVE ORDER

1. Contract Work Hours and Safety Standards.

This contract, to the extent that it is of a character specified in the Contract Work Hours and Safety Standards Act (Public Law 87-581, 76 Stat. 357-360, as amended) and is not covered by the Walsh-Healey Public Contracts Act (41 U. S. C. 35-45), is subject to the following provisions and to all other provisions and exceptions of said Contract Work Hours and Safety Standards Act.

(a) No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers or mechanics shall require or permit any laborer or mechanic in any workweek in which he is employed on such work, to work in excess of eight hours in any calendar day or in excess of forty hours in any workweek unless such laborer or mechanic receives compensation at a rate not less than one and one-half times his basic rate of pay for all hours worked in excess of eight hours in any calendar day or in excess of forty hours in such workweek, whichever is the greater number of overtime hours.

(b) In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible for such violation shall be liable to any affected employee for his unpaid wages. In addition, such Contractor or subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed, with respect to each individual laborer or mechanic employed in violation of the provisions of subsection (a), in the sum of $10 for each calendar day on which such employee was required or permitted to work in excess of eight hours or in excess of forty hours in a workweek without payment of the required overtime wages.

(c) The Administrator may withhold, or cause to be withheld, from any moneys payable on account of work performed by the Contractor or subcontractor, the full amount of wages required by this contract and such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for liquidated damages as provided in subsection (b).

(d) No contractor or subcontractor contracting for any part of the contract work shall require any laborer or mechanic employed in the performance of the contract to work in surroundings or under working conditions which are unsanitary, hazardous, or dangerous to his health or safety, as determined under construction safety and health standards promulgated by the Secretary of Labor by regulation based on proceedings pursuant to section 553 of title 5, United States Code, provided that such proceedings include a hearing of the nature authorized by said section.

(e) The Contractor shall require the foregoing subsections (a), (b), (c), (d) and this subsection (e) to be inserted in all subcontracts.

(f) The Contractor shall keep and maintain for a period of three (3) years from the completion of this contract the information required by 29 CFR § 516.2(a). Such material shall be made available for inspection by authorized representatives of the Government, upon their request, at reasonable times during the normal work day.

2. Convict Labor. The Contractor shall not employ any person undergoing sentence of imprisonment at hard labor.

3. Equal Opportunity. **Unless exempted pursuant to the provisions of Executive Order 11246 of September 24, 1965 and the rules, regulations and relevant orders of the Secretary of Labor thereunder, during the performance of this contract, the Contractor agrees as follows:**

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by the Administrator setting forth the provisions of this equal opportunity clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which he has a collective bargaining agreement or other contract or understanding, a notice, to be provided by the Administrator, advising the labor union or worker's representative of the Contractor's commitments under this equal opportunity clause and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and by the rules, regulations, and orders of the Secretary of Labor,

or pursuant thereto, and will permit access to his books, records, and accounts by the Administrator and the Secretary of Labor for purposes of investigations to ascertain compliance with such rules, regulations and orders.

(f) In the event of the Contractor's noncompliance with the equal opportunity clause of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(g) The Contractor will include the provisions of paragraphs (a) through (g) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as the Administrator may direct as a means of enforcing such provisions including sanctions for noncompliance; provided, however, that in the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by the Administrator, the Contractor may request the United States to enter into such litigation to protect the interests of the United States.

4. Interest of Member of Congress. No Member of or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this contract or to any benefit that may arise therefrom. Nothing, however, herein contained shall be construed to extend to such contract if made with a corporation for its general benefit.

EXHIBIT B
Table 1
Contract No. 14-03-29224

Modification of Facilities

Replacement of Out-of-Step Relaying

1. Amount of the trust fund: $3,750

   (Total estimated cost of replacement: $15,000)
   (Pacific's share of the cost: 25%)

2. Duties of the Administrator: The Administrator within 24 months after the date of execution shall furnish the necessary labor and material and

   (a) design, construct, and install a General Electric Company type SLL out-of-step relaying system;

   (b) perform test and energization of the facilities installed hereunder; and

   (c) remove the existing type HZM and KS out-of-step relaying systems after a successful trial period of the type SLL system mentioned in subsection (a) above.

3. Duties of Pacific: None.

Portland General Electric
121 S.W. Salmon Street
Portland, Oregon 97204

September 23, 1977
DRM-168-77-L

Mr. Robert W. Moench
Vice President
Pacific Power & Light Company
920 S.W. 6th Avenue
Portland, Oregon 97204

Dear Bob:

Subject: Proposed Parallel Operation of the PGE "Round Butte" and PP&L "Cove" 230-69 kV Transformers

We have reviewed your proposal of July 5, 1977, to operate our Round Butte transformer VAR-4 in parallel with your Cove transformer T-3517. We have no objection to this operating arrangement as long as the following conditions are met:

1) The portion of the PP&L load carried by the PGE transformer shall not exceed 20 MVA.

2) The line relaying shall be modified as specified in your letter of July 5, 1977.

3) The transformer protection shall be modified so that the loss of transformer T-3517 will trip OCB A-122. You may also want to trip OCB 3D100 for loss of transformer VAR-4.

4) Overtemperature tripping will be added to transformer VAR-4 by PGE to trip OCB A-122 when the transformer hotspot temperature reaches 110°C.

The cost to PGE to assist with the above modifications will be approximately $5,000. This cost includes PGE labor and material necessary for making the required modifications to PGE owned equipment. This cost assumes that PP&L will make the modifications associated with PP&L equipment. The above cost also assumes that PP&L will provide and install the additional line relays that are required. These relays will have to be installed on your relay panel 5R as no other space is readily available in our control building.

It is our understanding you wish to limit the load on transformer T-3517 to 48 MVA. With the two transformers operating in parallel, the portion of the PP&L load carried by PGE transformer VAR-4 will be 18 MVA, resulting in a total combined PP&L load of 66 MVA. We, therefore, suggest that the Round Butte interchange contract be modified to allow a maximum PP&L load of 70 MVA which includes a 4 MVA margin.

If you agree with the above conditions and agree to reimburse PGE for all labor and material required to implement this arrangement, please signify your approval by signing below and returning the original to me. PGE will then proceed to work out the details with your design group, make the appropriate design changes to PGE drawings, and arrange for a PGE construction crew to perform our portion of the work. We understand that these modifications are to be completed by October 1, 1978.

If you have any further questions, please let me know.

Sincerely,

D. R. Miller
Assistant Vice President

DRM/GHL/kb

Approved by ______________
R. C. Birkes
Pacific Power & Light Co.

Date: 10-4-77

Approved by ______________
R. W. Moench
Pacific Power & Light Co.

Date: 10-4-77

Attachment 2

TITLE PAGE

Filed in Compliance with an Order of the

Federal Energy Regulatory Commission

Docket No.________________ Entered the ____ Day of ________________

FILING UTILITY

Portland General Electric Company

UTILITY RENDERING SERVICE

Portland General Electric Company

UTILITY RECEIVING SERVICE

Pacific Power & Light Company

DESCRIPTION

Agreement between PGE and PP&L for modifications to PGE facilities to allow parallel operation of Round Butte and Cove transformers

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

K29225

AUG 2 3 1989

In reply refer to: PMTT

Mr. Tom Owens
Manager, Power & Fuel Contracts
Portland General Electric Company
121 SW. Salmon
Portland, OR 97204

Dear Mr. Owens:

To settle a number of remaining issues associated with Phase 2 and Phase 3 of the Stability Control Upgrade (SCU) Trust Tables, representatives from Portland General Electric Company (PGE) and Bonneville Power Administration (BPA) met on July 12, 1989. Discussion centered around the plan-of-service and cost estimates for the SCU projects at Malin and Fort Rock.

After reviewing the SCU proposal and cost information submitted by BPA's control engineers, PGE and BPA agreed that the project as proposed is the best plan-of-service. However, it was agreed that the following additional cost information and documentation was needed.

1. Update the Fort Rock cost estimate to reflect the change in scope from four transfer trip circuits to two transfer trip circuits.

2. Revise the cost estimate at Malin to reflect a reduction in Power Rate Relays from four to two.

3. Provide cost spreading formulas to be used for the Line Loss Logic Prototype and the Coordination, Project Management and Testing.

This cost information and documentation has been provided by Lloyd Hill, Chief, Control Systems Branch and is enclosed for your review and comments.

If PGE concurs with the enclosure please let us know so that the Trust Tables for Malin and Fort Rock can be updated to reflect the most recent cost estimates. We would prefer not to include the spreading formulas in the Trust Tables but to use this information as a supplement to the contract actions.

Please advise your staff to contact Dennis L. Loraas (230-4017) of my staff or Allen Aplass (522-6223) of the Snake River Area Power Management staff concerning your response to the enclosure and any aspects of the Trust Tables.

Sincerely,

Allen L. Burns
Chief, Transmission Branch

Enclosure

cc:
M. Mikolaitis/J. Eden - PGE
w/enclosure

DLoraas:kls:4017 (VS6-PMTT-3793d)

cc:
D. Rubin/J. Yocom - DSA
R. Ellingwood/R. Hanford - EBB
M. Johnson/M. Westfahl - EEBA
L. Hill/P. Schaad - EEP
D. Winchester/R. Edwards - EEPC
M. Nelson - PMTI
D. Loraas/D. Ross - PMTT
S. Lee/A. Aplass - WCA
Official File - PMT

CONSTRUCTION TRUST AGREEMENT

executed by the

UNITED STATES OF AMERICA

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W I T N E S S E T H:

WHEREAS Portland General, Pacific Power & Light Company (Pacific), and the Government, acting by and through the Bureau of Reclamation and the Administrator, entered into an agreement (Contract No. 14-03-59840) which, among other things, provided for the construction of the Malin substation near Malin, Oregon, and outlines the ownership and responsibilities of the parties; and

WHEREAS the Malin substation is a part of the Pacific Northwest-Pacific Southwest Intertie program as recommended to Congress by the Secretary of the Interior and approved by Congress by making appropriations for the construction of the Government's portion thereof; and

WHEREAS the parties hereto executed Construction Trust Agreement, Contract No. 14-03-59834, which provided funds for the Administrator to design, furnish certain labor and material, construct and test Portland General's portion of the 500 kv switchyard (said switchyard is as defined in said Agreement No. 14-03-59840, and is hereinafter called the 500 kv Switchyard), at the Malin substation in conjunction with the design, construction, and test of the remainder of the 500 kv Switchyard; and

WHEREAS Pacific and the Administrator entered into a similar trust agreement (Contract No. 14-03-59835) which provided that the Administrator design, furnish certain labor and material, construct, and test Pacific's portion of the 500 kv Switchyard; and

WHEREAS the parties hereto desire to terminate said Contract No. 14-03-59834 and execute an agreement which provides for additional work, upon approval by

Portland General, to be performed by the Administrator when the Administrator determines that such performance is beneficial to the Government; and

WHEREAS Pacific and the Administrator expect to enter into a Construction Trust Agreement (Contract No. 14-03-29224) similar to this agreement which provides for additional work, upon approval by Pacific, to be performed by the Administrator; and

WHEREAS the Administrator is authorized pursuant to law to dispose of electric power and energy generated at various federal hydroelectric projects in the Pacific Northwest and to enter into related agreements;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. Termination of Agreement. Contract No. 14-03-59834 is hereby terminated as of the time this agreement takes effect but all liabilities accrued thereunder shall be and are hereby preserved.

2. Term of Agreement. This agreement will be effective on the date of execution of said Contract No. 14-03-29224 with Pacific or on the date of execution of this agreement, whichever is later, and shall continue in effect until terminated by either party upon written notice to the other party. All liabilities accrued as of the date of termination shall be and are hereby preserved.

3. Exhibits. Exhibits A and B are by this reference incorporated herein and made a part of this agreement. Portland General shall be the Contractor as that term is used in Exhibit A.

4. Trust Fund. Portland General hereby agrees to pay the Administrator an amount equal to its share of the total cost of performing the work as outlined in Exhibit B or any addition to Exhibit B, less any credit to Portland General for facilities furnished under section 6. Such amounts (trust fund) shall be held by the Administrator in trust for Portland General's share of the costs of performing the Administrator's duties pursuant to section 5(b). Portland General will make payments on account of such share of estimated cost in amounts requested

by the Administrator. If at any time thereafter the Administrator estimates that such amounts are insufficient to pay Portland General's share of the cost of completing performance of such duties, Portland General shall advance to the Administrator, when he so requests and in such installments as may be specified by him, such additional moneys as he estimates will be required for such completion.

The moneys so received by the Administrator, as aforesaid, together with all moneys, if any, advanced to him in trust under any other provisions of this agreement, will be placed in a trust account in the United States Treasury subject to withdrawal as provided in 31 U. S. C., sections 725r and 725s, for payment of the cost of performing the Administrator's duties pursuant to this agreement.

5. Duties of the Administrator.

(a) The Administrator shall submit to Pacific and Portland General all proposals for adding or modifying facilities at Malin substation, specifying the work to be performed and the costs to be borne by each party. Such work and pertinent data shall be described in Exhibit B, or additions to Exhibit B.

(b) The Administrator shall furnish all material and labor except that furnished by Portland General pursuant to section 6 and by Pacific pursuant to Contract No. 14-03-29224, and shall design, construct, and test the facilities to be installed at the Malin substation pursuant to Exhibit B.

(c) All work done at Portland General's expense hereunder will be performed in whole or in part by force account, by contract, or by both, in the same manner and subject to the same limitations as if all funds being expended therefor were Government funds.

6. Duties of Portland General. Portland General, at its expense, shall provide, for installation by the Administrator pursuant to section 5(b), any facilities which it agrees to supply.

7. Extension of Time. The completion date specified in Exhibit B shall be extended for a time equivalent to such delays, if any, as are caused by events which either party hereto could not reasonably avoid by the exercise of reasonable diligence and foresight.

8. Ownership of Facilities and Equipment.

(a) Each party's ownership of facilities constructed and installed pursuant to this agreement shall be as specified in said Agreement No. 14-03-59840.

(b) Title to all facilities constructed pursuant to section 5(b) that are furnished by the Administrator will remain in the Government until such facilities have been approved for the purposes of this agreement by the Administrator as being ready for operation. Notice of such approval shall be sent to Portland General. Title to and ownership of such facilities shall then pass to, and shall be vested in the parties in accordance with said Contract No. 14-03-59840.

9. Review by the Administrator. The Administrator shall review the design, construction, and test of the facilities installed hereunder with Portland General at regular intervals.

10. Additions to Exhibit B.

(a) The Administrator shall prepare, for execution by the parties hereto, an additional table to Exhibit B each time the parties hereto agree that facilities shall be added or modified at Malin substation. Such table shall specify the facilities to be installed, the work to be performed by each party and the estimated costs to be borne by Portland General. Such estimated costs less any credit for facilities furnished by Portland General shall constitute the amount of the trust fund, as specified in section 4, for each particular project.

(b) Upon execution by the parties hereto, new tables to Exhibit B shall be attached to and deemed to be a part of this agreement and shall be effective on the date specified therein.

11. Accounting.

(a) Within a reasonable time after completion of the work for which a deposit in trust has been made under the terms hereof, the Administrator shall make a full accounting to Portland General showing the receipts credited to, and the costs charged against, said trust fund. Such accounting shall be made in such manner so that Portland General can place the various units of property on its books in the manner prescribed in the Federal Power Commission Uniform System of Accounts for class A public utilities. The Administrator shall remit to Portland General any unexpended balance of said trust fund within a reasonable time after accounting is made as herein provided.

(b) If at any time the Administrator requests Portland General to advance additional moneys pursuant to section 4, the Administrator shall, within a reasonable time after Portland General so requests, make a full accounting to Portland General showing the receipts credited to, and the costs charged against, said trust fund. The Administrator shall, at the same time, submit a statement to Portland General showing in detail his estimate of the additional moneys required to pay its share of the cost of completing performance of his responsibilities specified in section 5(b).

(c) Portland General's share of the cost of performing the work and furnishing the materials mentioned in section 5(b) shall be proper charges against the trust fund, and shall be determined by charging the cost elements exclusive of interest in the same manner as if Government funds were being expended, including among other items, labor, leave obligations, contributions - employee benefits, equipment use, tool and stores expense, expense of transportation of any materials or equipment which is not included as stores expense, and overhead reasonably allocable thereto.

IN WITNESS WHEREOF, the parties hereto have executed this agreement in

several counterparts.

UNITED STATES OF AMERICA
Department of the Interior

(SEAL)

By J. N. O'Neal
Acting Bonneville Power Administrator

PORTLAND GENERAL ELECTRIC COMPANY

(SEAL)

HHP By A J Porter
Title **Senior Vice President**

ATTEST:

By H H Phillips
Title Secy

PROVISIONS REQUIRED BY STATUTE OR EXECUTIVE ORDER

1. Contract Work Hours and Safety Standards.

This contract, to the extent that it is of a character specified in the Contract Work Hours and Safety Standards Act (Public Law 87-581, 76 Stat. 357-360, as amended) and is not covered by the Walsh-Healey Public Contracts Act (41 U. S. C. 35-45), is subject to the following provisions and to all other provisions and exceptions of said Contract Work Hours and Safety Standards Act.

(a) No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers or mechanics shall require or permit any laborer or mechanic in any workweek in which he is employed on such work, to work in excess of eight hours in any calendar day or in excess of forty hours in any workweek unless such laborer or mechanic receives compensation at a rate not less than one and one-half times his basic rate of pay for all hours worked in excess of eight hours in any calendar day or in excess of forty hours in such workweek, whichever is the greater number of overtime hours.

(b) In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible for such violation shall be liable to any affected employee for his unpaid wages. In addition, such Contractor or subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed, with respect to each individual laborer or mechanic employed in violation of the provisions of subsection (a), in the sum of $10 for each calendar day on which such employee was required or permitted to work in excess of eight hours or in excess of forty hours in a workweek without payment of the required overtime wages.

(c) The Administrator may withhold, or cause to be withheld, from any moneys payable on account of work performed by the Contractor or subcontractor, the full amount of wages required by this contract and such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for liquidated damages as provided in subsection (b).

(d) No contractor or subcontractor contracting for any part of the contract work shall require any laborer or mechanic employed in the performance of the contract to work in surroundings or under working conditions which are unsanitary, hazardous, or dangerous to his health or safety, as determined under construction safety and health standards promulgated by the Secretary of Labor by regulation based on proceedings pursuant to section 553 of title 5, United States Code, provided that such proceedings include a hearing of the nature authorized by said section.

(e) The Contractor shall require the foregoing subsections (a), (b), (c), (d) and this subsection (e) to be inserted in all subcontracts.

(f) The Contractor shall keep and maintain for a period of three (3) years from the completion of this contract the information required by 29 CFR § 516.2(a). Such material shall be made available for inspection by authorized representatives of the Government, upon their request, at reasonable times during the normal work day.

2. <u>Convict Labor</u>. The Contractor shall not employ any person undergoing sentence of imprisonment at hard labor.

3. <u>Equal Opportunity</u>. **Unless exempted pursuant to the provisions of Executive Order 11246 of September 24, 1965 and the rules, regulations and relevant orders of the Secretary of Labor thereunder, during the performance of this contract, the Contractor agrees as follows:**

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by the Administrator setting forth the provisions of this equal opportunity clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which he has a collective bargaining agreement or other contract or understanding, a notice, to be provided by the Administrator, advising the labor union or worker's representative of the Contractor's commitments under this equal opportunity clause and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and by the rules, regulations, and orders of the Secretary of Labor,

or pursuant thereto, and will permit access to his books, records, and accounts by the Administrator and the Secretary of Labor for purposes of investigations to ascertain compliance with such rules, regulations and orders.

(f) In the event of the Contractor's noncompliance with the equal opportunity clause of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(g) The Contractor will include the provisions of paragraphs (a) through (g) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as the Administrator may direct as a means of enforcing such provisions including sanctions for noncompliance; provided, however, that in the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by the Administrator, the Contractor may request the United States to enter into such litigation to protect the interests of the United States.

4. Interest of Member of Congress. No Member of or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this contract or to any benefit that may arise therefrom. Nothing, however, herein contained shall be construed to extend to such contract if made with a corporation for its general benefit.

EXHIBIT B
Table 1
Contract No. 14-03-29225

Modification of Facilities

Replacement of Out-of-Step Relaying

1. Amount of the trust fund: $3,750

   (Total estimated cost of replacement: $15,000)
   (Portland General's share of the cost: 25%)

2. Duties of the Administrator: The Administrator within 24 months after the date of execution shall furnish the necessary labor and material and

   (a) design, construct, and install a General Electric Company type SLL out-of-step relaying system;

   (b) perform test and energization of the facilities installed hereunder; and

   (c) remove the existing type HZM and KS out-of-step relaying systems after a successful trial period of the type SLL system mentioned in subsection (a) above.

3. Duties of Portland General: None.

United States Department of the Interior

BONNEVILLE POWER ADMINISTRATION
P.O. BOX 3621, PORTLAND, OREGON 97208

OFFICE OF
THE ADMINISTRATOR

In reply refer to: PCH

JUL 14 1976

Amendatory Agreement No. 1 to
Contract No. 14-03-37013

Mr. R. B. Lisbakken
Vice President, Power Resources
Pacific Power & Light Company
920 S.W. Sixth Avenue
Portland, Oregon 97204

Dear Mr. Lisbakken:

By letter of March 19, 1975, Pacific requested that Bonneville design and construct, at Company expense, the tap facilities necessary to connect Pacific's proposed Pleasant Hill substation and tap line to the Government's Lookout Point-Alvey 115 kv No. 1 line (Lookout Point-Alvey Line).

Bonneville and Pacific subsequently determined that Bonneville's construction of such a connection would be mutually beneficial. I therefore propose that the connection (Pleasant Hill Tap) be made under the Bonneville-Pacific General Trust Agreement (Contract No. 14-03-37013 as amended and hereinafter referred to as "Primary Agreement").

To make Primary Agreement financial procedures consistent with requirements made necessary by Bonneville's "Self Financing" legislation (Public Law 93-454 of October 18, 1974), terminology and procedures of that agreement relating to moneys deposited by Pacific to defray Bonneville's costs thereunder are hereby amended as follows:

1. The title to section 3 is changed from "Trust Fund" to "Trust Account", and the term "trust fund" as used in section 3 and elsewhere in the Primary Agreement is deleted and the term "Trust Account" substituted therefor.

2. The last paragraph of section 3 is deleted and the following substituted therefor:

"The moneys so received by the Administrator together with all moneys, if any, advanced to him in trust under any other

Letter to R. B. Lisbakken, Pacific Power & Light Company, Subject: Amendatory Agreement No. 1 to Contract No. 14-03-37013

provisions of this agreement, shall be placed in a trust account in the Bonneville Power Administration Fund in the United States Treasury subject to withdrawal for payment of his cost of performing his duties pursuant to this agreement."

Construction of Pleasant Hill Tap would be as provided for in Table 9 of Exhibit B which is attached hereto.

I further propose that Bonneville's maintenance of the Pleasant Hill Tap facilities installed hereunder be provided for at Company expense under Revision No. 1 of Exhibit A to the Bonneville-Pacific Operation and Maintenance Agreement (Contract No. 14-03-19304). Revision No. 1 is enclosed for execution.

If this Amendatory Agreement No. 1, which includes attached Table 9 of Exhibit B to Contract No. 14-03-37013, and Revision No. 1 of Exhibit A to Contract No. 14-03-19304 are acceptable to Pacific, please indicate your approval by signing one copy of each and returning them to me. Amendatory Agreement No. 1 and Revision No. 1 of Exhibit A will be effective on the date Bonneville receives the signed copy of each together with Pacific's check for the remainder of the Trust Account.

Sincerely yours,

Donald Paul Hodel

(SEAL)

Administrator

Effective Date: July 27, 1976

APPROVED:

PACIFIC POWER & LIGHT COMPANY

By R. B. Lisbakken

Title Vice President

1. Trust Account. A $27,000 Trust Account has been designated. Of this amount, $4,000 was deposited by the Company on December 22, 1975, to defray the Administrator's cost of designing Pleasant Hill Tap.

2. Duties of the Administrator. The Administrator, at Company expense, shall:

   (a) by two months after the effective date of this amendatory agreement

      (1) review the manufacturer's drawings furnished by the Company pursuant to section 3(a); and

      (2) prepare the necessary design drawings and specifications for construction of Pleasant Hill Tap to include a three-pole steel tap structure and two sectionalizing switches; the Lookout Point-side sectionalizing switch shall be of the load-break type;

   (b) by five months after the effective date of this amendatory agreement provide all necessary labor, equipment, and material, and

      (1) remove Lookout Point-Alvey Line structure 10/1;

      (2) construct Pleasant Hill Tap in accordance with the design drawings and specifications prepared under subsection (a)(2) above; in so doing, install the tap structure and sectionalizing switches provided by the Company under section 3(b); and

      (3) make Pleasant Hill Tap final line connections, and with the Company conduct joint test and energization of the tap facilities.

   Removal of line structure 10/1 and construction of Pleasant Hill Tap shall not begin until representatives of the parties hereto have mutually agreed on a construction schedule for all construction hereunder.

3. Duties of the Company. The Company, at its expense, shall:

   (a) as soon as reasonably practicable after the effective date of this amendatory agreement furnish the Administrator three copies of the manufacturer's drawings of the tap structure and the two line sectionalizing switches it shall provide him pursuant to subsection (b) below;

(b) by three months after the effective date of this amendatory agreement provide the Administrator the three-pole steel tap structure and the two sectionalizing switches required for his construction of Pleasant Hill Tap pursuant to section 2(b)(2); and

(c) by five months after the effective date of this amendatory agreement

(1) complete the Company's Pleasant Hill substation (Pleasant Hill) and tap line;

(2) design and install Pleasant Hill revenue metering to standards prepared by the Administrator for similar Government-owned metering; and

(3) conduct joint test and energization of Pleasant Hill Tap facilities with the Administrator.

All work performed by the Company under this agreement shall conform to generally accepted utility practice.

4. Ownership. Title to and ownership of the Pleasant Hill Tap facilities installed by the Administrator hereunder shall be and remain in the Company, except those parts of such facilities which cannot be removed without damage to Government property. Title to and ownership of such nonsalvable parts shall be and remain in the Government.

5. Removal of Facilities and Payment Therefor. When Pleasant Hill Tap is no longer required by the parties, the Administrator, at the Company's expense, shall remove the Company's salvable facilities described in section 4 and return them to the Company at Pleasant Hill.

After such removal, the Administrator may, at the Company's expense, return the Government's facilities altered hereunder to the configuration (1) existing before this amendatory agreement became effective, or (2) as agreed by the parties.

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208

OFFICE OF THE ADMINISTRATOR

In reply refer to: PCH

JAN 27 1978

Amendatory Agreement No. 2 to
Contract No. 14-03-37013

Mr. R. B. Lisbakken
Vice President, Power Resources
Pacific Power & Light Company
920 SW. Sixth Avenue
Portland, Oregon 97204

Dear Mr. Lisbakken:

Following its installation of a second transformer at its Tucker substation (Tucker), the Company requested that Bonneville modify the present bus differential relay protective scheme at the Government's Hood River substation (Hood River) for the purpose of protecting Tucker transformer high side circuit switchers.

The desired protection is to be obtained by excluding the Tucker transformers from the Hood River bus differential scheme, while permitting Tucker transformer faults in excess of circuit switcher interrupting capacities to be cleared by Hood River power circuit breakers instead of the circuit switchers.

Bonneville and the Company have determined that the requested modifications would be mutually beneficial. I therefore propose that Bonneville make such modifications at Pacific's expense under the Bonneville-Pacific General Trust Agreement (Contract No. 14-03-37013 as amended and hereinafter referred to as "Primary Agreement"), and as provided in Table 12 which is attached hereto.

I further propose that sections 3 and 9 of the Primary Agreement be deleted and replaced by the following:

"3. Trust Deposit. The Company hereby agrees to pay the Administrator an amount equal to the total cost to the Government of performing the work specified in Exhibit B, or any table to be added to Exhibit B. Such amount shall be held by the Administrator in trust to defray the cost to the Government of performing the duties pursuant to section 4 and specified in any such table. The Company will make payments of the estimated cost as provided in the appropriate table to Exhibit B in amounts and at times requested by the Administrator. If at any time thereafter the Administrator estimates that such amounts are insufficient to pay the Company's share of the cost of completing performance of such duties, the Company will advance to the Administrator, when he so requests and in such installments as may be specified by him, such additional moneys as he estimates will be required for such completion.

"At any time before completion of the duties specified in any table to Exhibit B the Company may elect to have the salvable equipment installed pursuant to such table removed and returned to the owner. In this event, the Administrator will cease all work pursuant to such table and proceed with such removal of the work completed. The Company will advance to the Administrator when he so requests and in such installments as he may specify any additional moneys he estimates will be required for such work; provided, however, that any uncommitted funds remaining in the Trust Deposit on the effective date of the Company's election to remove and salvage, shall be applied to the Administrator's cost of such removal.

"The moneys so received by the Administrator, as aforesaid, together with all moneys, if any, advanced to him in trust under any other provisions of this agreement (Trust Deposit), shall be placed in a trust account in the Bonneville Power Administration Fund in the United States Treasury subject to withdrawal for payment of his cost of performing his duties pursuant to this agreement."

"9. Accounting.

"(a) Within a reasonable time after completion of the work specified in a table of Exhibit B for which a deposit in trust has been made under the terms hereof, the Administrator shall make a full accounting in regard to such work to the Company showing the receipts credited to, appropriate salvage values credited to, and the costs charged against, said Trust Deposit. Such accounting shall be made in the manner prescribed by the agency designated by the Secretary of the Department of Energy to supervise the Federal uniform system of accounts for class A public utilities. The Administrator shall remit to the Company any unexpended balance of the Trust Deposit within a reasonable time after accounting is made as herein provided.

"(b) If at any time the Administrator requests the Company to advance additional moneys pursuant to section 3 for work specified in a table of Exhibit B, the Administrator shall, within a

Ltr to R. B. Lisbakken, PP&L Company, Subj: Modification of Bus Differential Relay Protective Scheme at the Government's Hood River Substation

reasonable time after the Company so requests, make a full accounting to the Company showing the receipts credited to, appropriate salvage values credited to, and the costs charged against, said Trust Deposit. The Administrator shall, at the same time, submit a statement to the Company showing in detail his estimate of the additional moneys required to pay the cost of completing performance of his responsibilities specified in section 4.

"(c) The cost of performing the work and furnishing the materials mentioned in section 4 as such work and material relate to a table of Exhibit B shall be proper charges against the Trust Deposit, and shall be determined by charging the cost elements exclusive of interest in the same manner as if Government funds were being expended, including among other items, labor, leave obligations, contributions - employee benefits, equipment use, tool and stores expense, expense of transportation of any materials or equipment which is not included as stores expense, and overhead reasonably allocable thereto."

If this Amendatory Agreement No. 2, which includes attached Table 12 of Exhibit B to the Primary Agreement, is acceptable to the Company, please indicate your approval by signing one copy and returning it to me. Amendatory Agreement No. 2 will be effective on the date Bonneville receives the signed copy together with the Company's check for the Trust Deposit.

Sincerely,

Sterling Munro

Administrator

Effective Date: 2/13/78 ~~1/27/78~~

APPROVED:

PACIFIC POWER & LIGHT COMPANY

By R. B. Lisbakken

Title Vice President

RHS

1. Trust Deposit. $11,000.

2. Duties of the Administrator. The Administrator, at the Company's expense, shall:

   (a) by two months after the effective date of this amendatory agreement, prepare necessary design drawings (Design Drawings) for modification of the Hood River bus differential relay protective scheme to operate with the Tucker fault selector scheme to limit Tucker circuit switcher operations to those Tucker transformer faults within the interrupting ratings of the circuit switchers, and submit such drawings to the Company for review; and

   (b) by four months after the effective date of this amendatory agreement or two months after the Company's review of the Design Drawings, whichever is later, at Hood River:

      (1) provide one type AR auxiliary relay, control cable, conduit, and other items specified in the Design Drawings; and

      (2) provide all necessary labor, equipment, and material, and

         (i) modify panel wiring of the bus differential relay installation to include Tucker transformer high side current transformers;

         (ii) install conduit and control cable from the Hood River control house to the Tucker control house as stipulated in the Design Drawings;

         (iii) wire in one contact of the WL auxiliary relay to trip the Tucker 69-kV power circuit breakers;

         (iv) wire in the AR auxiliary relay to allow the Tucker fault selector scheme to trip the Hood River power circuit breakers and block their reclosure; and

         (v) test and energize the modified bus differential and fault selector installation jointly with the Company.

   Construction and installation to be performed hereunder shall not begin until the parties have agreed upon and prepared a schedule for all such work.

3. Duties of the Company. The Company, at its expense, shall:

   (a) as soon as reasonably practicable after receipt of the Design Drawings, review and approve such drawings if they are acceptable; and

(b) by four months after the effective date of this amendatory agreement or two months after the Company review of the Design Drawings, whichever is later, at Tucker:

  (1) install transformer protective and fault selector schemes on each transformer bank;

  (2) install two hot bus checking relays to supervise reclosing of the 69-kV power circuit breakers; and

  (3) test and energize the modified Hood River bus differential and fault selector installation jointly with the Administrator.

All work performed by the Company hereunder shall conform to generally accepted utility practice.

4. Ownership of Facilities.

(a) Title to and ownership of the equipment and facilities constructed and installed hereunder shall be and remain in the party constructing or installing such equipment and facilities.

(b) The Administrator shall identify the Government's equipment installed hereunder by permanently affixing thereto suitable markers plainly stating that the property so identified is owned by the Government.

5. Operation and Maintenance of Facilities. Each party will operate and maintain its equipment constructed or installed hereunder and shall provide all replacement parts therefor at its expense. Before either party performs maintenance or does testing on either the fault selector relay installation or the bus differential relay installation hereunder, the party desiring to perform such maintenance or testing shall notify the other party and shall make arrangements for joint participation by both parties where required.

AUTHENTICATED COPY

AMENDATORY AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFICORP

This AMENDATORY AGREEMENT, executed August 10, 1989, by the UNITED STATES OF AMERICA (Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and PACIFICORP, doing business as Pacific Power & Light Company and Utah Power & Light Company (Company).

W I T N E S S E T H :

WHEREAS Bonneville offered a General Trust Agreement to the Company on April 3, 1973, and the parties have executed such General Trust Agreement (Contract No. 14-03-37013, which as amended is hereinafter referred to as "General Trust Agreement") providing for the design, construction and test of the Company's facilities on the Federal Columbia River Power System; and

WHEREAS the parties hereto have agreed that Exhibit B, Table 6 should be deleted from the General Trust Agreement;

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power and energy generated at various Federal hydroelectric projects in the Pacific Northwest, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW THEREFORE, the parties hereto mutually agree as follows:

1. Effective Date of Agreement. This Amendatory Agreement shall be effective on the date of execution.

2. Amendment of General Trust Agreement. The General Trust Agreement is hereby amended as follows:

Table 6 of Exhibit B is deleted.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement in several counterparts.

PACIFICORP, doing business as
Pacific Power & Light Company and
Utah Power & Light Company

By /s/ Thomas A. Lockhart
Thomas A. Lockhart
Title Vice President

Date August 3, 1989

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By /s/ Jack Robertson

Title Acting Administrator

Effective Date August 10, 1989

ATTEST:

By /s/ Sally A. Nofziger
Sally Nofziger
Title Corporate Secretary

Date August 3, 1989

(VS12-UCA-3468c)

Contract No. 14-03-37013

4-3-73

GENERAL TRUST AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF THE INTERIOR

acting by and through the

BONNEVILLE POWER ADMINISTRATOR

and

PACIFIC POWER & LIGHT COMPANY

providing for design, construction and test of the Company's facilities on the Federal Columbia River Power System

Index to Sections

This GENERAL TRU_ AGREEMENT, executed May 6, 1973, by the UNITED STATES OF AMERICA (Government), Department of the Interior, acting by and through the BONNEVILLE POWER ADMINISTRATOR (Administrator), and PACIFIC POWER & LIGHT COMPANY (Company), a corporation organized and existing under the laws of the State of Maine,

W I T N E S S E T H:

WHEREAS the Company from time to time requests the Administrator to design and construct facilities of the Company on the Federal Columbia River Power System; and

WHEREAS the parties hereto desire to provide for such design and construction upon the approval of the Administrator when he determines that such design and construction is beneficial to the Government; and

WHEREAS the Administrator is authorized pursuant to law to dispose of electric power and energy generated at various federal hydroelectric projects in the Pacific Northwest and to enter into related agreements;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. Term of Agreement. This agreement will be effective on the date of execution and shall continue in effect until terminated by either party upon written notice to the other party. All liabilities accrued as of the date of termination shall be and are hereby preserved.

2. Exhibits. Exhibits A and B (including Tables 1 and 2) are by this reference incorporated herein and made a part of this agreement. The Company shall be the Contractor as that term is used in Exhibit A.

3. Trust Fund. The Company hereby agrees to pay the Administrator an amount equal to the total cost to the Government of performing the work as specified in Exhibit B, or any addition to Exhibit B pursuant to section 8. Such amount (trust fund) shall be held by the Administrator in trust to defray the cost to the Government of performing the duties specified in section 4.

The Company will make payments of the estimated cost in amounts requested by the Administrator. If at any time thereafter the Administrator estimates that such amounts are insufficient to pay the Company's share of the cost of completing performance of such duties, the Company will advance to the Administrator, when he so requests and in such installments as may be specified by him, such additional moneys as he estimates will be required for such completion.

At any time before completion of the duties specified in any Table to Exhibit B the Company may elect to have the salvable equipment installed pursuant to such Table removed and returned to the owner. In this event, the Administrator will cease all work pursuant to such Table and proceed with such removal of the work completed. The Company will advance to the Administrator when he so requests and in such installments as he may specify any additional moneys he estimates will be required for such work; provided, however, that any uncommitted funds remaining in the trust fund deposited pursuant to such Table, on the effective date of the Company's election to remove and salvage shall be applied to the Administrator's cost of such removal.

The moneys so received by the Administrator, together with all moneys, if any, advanced to him in trust under any other provisions of this agreement, will be placed in a trust account in the United States Treasury subject to withdrawal as provided in 31 U. S. C., sections 725r and 725s, for payment of the cost of performing the duties of the Government as specified by this agreement.

4. Duties of the Administrator.

(a) The Administrator shall perform the duties specified in Exhibit B.

(b) All work done at the Company's expense hereunder will be performed in whole or in part by force account, by contract, or by both, in the same manner and subject to the same limitations as if all funds being expended therefor were Government funds.

5. Duties of the Company.

(a) The Company shall perform the duties specified in Exhibit B.

(b) The Company may perform such duties in whole or in part, by force account, by contract, or by both.

6. Extension of Time. Completion dates specified in Exhibit B shall be extended for a time equivalent to such delays, if any, as are caused by events which either party hereto could not reasonably avoid by the exercise of reasonable diligence and foresight.

7. Ownership of Facilities and Equipment.

(a) Ownership of facilities and equipment shall be specified in Exhibit B.

(b) The Company shall identify its equipment installed hereunder by permanently affixing thereto suitable markers plainly stating that the property so identified is owned by the Company.

8. Additions to Exhibit B.

(a) The Administrator shall prepare, for execution by the parties hereto, an additional table to Exhibit B each time the parties hereto agree that work is to be performed hereunder. Such table shall specify the facilities to be installed, the work to be performed by each party, ownership of facilities and equipment and the amount of the trust fund.

(b) Upon execution by the parties hereto, new tables to Exhibit B shall be attached to and deemed to be a part of this agreement and shall be effective on the date specified therein.

9. Accounting.

(a) Within a reasonable time after completion of the work for which a deposit in trust has been made under the terms hereof, the Administrator shall make a full accounting to the Company showing the receipts credited to, and the costs charged against, said trust fund. Such accounting shall be made in the manner prescribed in the Federal Power Commission Uniform System of Accounts for class A public utilities. The Administrator shall remit to the Company any unexpended balance of said trust fund within a reasonable time after accounting is made as herein provided.

(b) If at any time the Administrator requests the Company to advance additional moneys pursuant to section 3, the Administrator shall, within a reasonable time after the Company so requests, make a full accounting to the Company showing the receipts credited to, and the costs charged against, said trust fund. The Administrator shall, at the same time, submit a statement to the Company showing in detail his estimate of the additional moneys required to pay the cost of completing performance of his responsibilities specified in section 4.

(c) The cost of performing the work and furnishing the materials mentioned in section 4 shall be proper charges against the trust fund, and shall be determined by charging the cost elements exclusive of interest in the same manner as if Government funds were being expended, including among other items, labor, leave obligations, contributions - employee benefits, equipment use, tool and stores expense, expense of transportation of any materials or equipment which is not included as stores expense, and overhead reasonably allocable thereto.

IN WITNESS WHEREOF, the parties hereto have executed this agreement in

several counterparts.

UNITED STATES OF AMERICA
Department of the Interior

(SEAL)

By Bernard Goldhammer
Acting Bonneville Power Administrator

PACIFIC POWER & LIGHT COMPANY

(SEAL)

By

Title Vice President

ATTEST:

By

Title Assistant Secretary

EXHIBIT A

(12-3-69)

PROVISIONS REQUIRED BY STATUTE OR EXECUTIVE ORDER

1. Contract Work Hours and Safety Standards.

This contract, to the extent that it is of a character specified in the Contract Work Hours and Safety Standards Act (Public Law 87-581, 76 Stat. 357-360, as amended) and is not covered by the Walsh-Healey Public Contracts Act (41 U. S. C. 35-45), is subject to the following provisions and to all other provisions and exceptions of said Contract Work Hours and Safety Standards Act.

(a) No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers or mechanics shall require or permit any laborer or mechanic in any workweek in which he is employed on such work, to work in excess of eight hours in any calendar day or in excess of forty hours in any workweek unless such laborer or mechanic receives compensation at a rate not less than one and one-half times his basic rate of pay for all hours worked in excess of eight hours in any calendar day or in excess of forty hours in such workweek, whichever is the greater number of overtime hours.

(b) In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible for such violation shall be liable to any affected employee for his unpaid wages. In addition, such Contractor or subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed, with respect to each individual laborer or mechanic employed in violation of the provisions of subsection (a), in the sum of $10 for each calendar day on which such employee was required or permitted to work in excess of eight hours or in excess of forty hours in a workweek without payment of the required overtime wages.

(c) The Administrator may withhold, or cause to be withheld, from any moneys payable on account of work performed by the Contractor or subcontractor, the full amount of wages required by this contract and such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for liquidated damages as provided in subsection (b).

(d) No contractor or subcontractor contracting for any part of the contract work shall require any laborer or mechanic employed in the performance of the contract to work in surroundings or under working conditions which are unsanitary, hazardous, or dangerous to his health or safety, as determined under construction safety and health standards promulgated by the Secretary of Labor by regulation based on proceedings pursuant to section 553 of title 5, United States Code, provided that such proceedings include a hearing of the nature authorized by said section.

(e) The Contractor shall require the foregoing subsections (a), (b), (c), (d) and this subsection (e) to be inserted in all subcontracts.

(f) The Contractor shall keep and maintain for a period of three (3) years from the completion of this contract the information required by 29 CFR § 516.2(a). Such material shall be made available for inspection by authorized representatives of the Government, upon their request, at reasonable times during the normal work day.

2. <u>Convict Labor</u>. The Contractor shall not employ any person undergoing sentence of imprisonment at hard labor.

3. <u>Equal Opportunity</u>. Unless exempted pursuant to the provisions of Executive Order 11246 of September 24, 1965 and the rules, regulations and relevant orders of the Secretary of Labor thereunder, during the performance of this contract, the Contractor agrees as follows:

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by the Administrator setting forth the provisions of this equal opportunity clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which he has a collective bargaining agreement or other contract or understanding, a notice, to be provided by the Administrator, advising the labor union or worker's representative of the Contractor's commitments under this equal opportunity clause and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and by the rules, regulations, and orders of the Secretary of Labor,

or pursuant thereto, and will permit access to his books, records, and accounts by the Administrator and the Secretary of Labor for purposes of investigations to ascertain compliance with such rules, regulations and orders.

(f) In the event of the Contractor's noncompliance with the equal opportunity clause of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(g) The Contractor will include the provisions of paragraphs (a) through (g) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as the Administrator may direct as a means of enforcing such provisions including sanctions for noncompliance; provided, however, that in the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by the Administrator, the Contractor may request the United States to enter into such litigation to protect the interests of the United States.

4. Interest of Member of Congress. No Member of or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this contract or to any benefit that may arise therefrom. Nothing, however, herein contained shall be construed to extend to such contract if made with a corporation for its general benefit.

EXHIBIT B
Table 1
Contract No. 14-03-37013

Installation of Facilities

Replacement of existing two terminal carrier current transfer trip scheme with three terminal scheme on the Company's 230 kv Walla Walla terminal at McNary substation.

1. Amount of the trust fund: $8,400

2. Duties of the Administrator: The Administrator, at Company expense, within two months after the date of execution hereof shall furnish all necessary labor and material, and

   (a) review and approve the Company's design for power system control modifications of the Company's Walla Walla 230 kv terminal position at McNary substation and make necessary modifications to existing design drawings for McNary substation;

   (b) provide and install test panel, and install power system control facilities furnished by the Company; and

   (c) perform test and energization of the power system control facilities installed hereunder.

3. Duties of the Company: The Company, at its expense, within one month after the date of execution hereof shall,

   (a) design and submit for the Administrator's approval the power system control modifications of the Company's Walla Walla 230 kv terminal position at McNary substation;

   (b) provide carrier equipment and all other relaying equipment necessary to complete the power system control modifications.

4. Ownership. Title to and ownership of the equipment and facilities installed hereunder shall be and remain in the Company except parts of such equipment which cannot be removed without damage to Government property. Title to and ownership of said parts shall be and remain in the Government.

EXHIBIT B
Table 2
Contract No. 14-03-37013

Installation of Facilities

Installation of a 34.5 kv terminal position in the Government's Flathead substation.

1. Amount of the trust fund: $66,400

2. Duties of the Administrator: The Administrator, at Company expense, within 18 months after the date of execution of this Table 2 shall furnish the necessary labor and material and

   (a) design, construct, and install a complete 34.5 kv terminal position using the power circuit breaker furnished by the Company; and

   (b) perform test and energization of the facilities installed herein.

3. Duties of the Company: The Company, at its expense, within 12 months after the date of execution of this Table 2 shall provide the Administrator at Flathead an 600 ampere, 500 mva 34.5 kv power circuit breaker.

4. Ownership: Title to and ownership of the equipment and facilities installed hereunder shall be and remain in the Company except parts of such equipment which cannot be removed without damage to Government property. Title to and ownership of said parts shall be and remain in the Government.

AMENDATORY AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF THE INTERIOR

acting by and through the

BONNEVILLE POWER ADMINISTRATOR

and

PORTLAND GENERAL ELECTRIC COMPANY

This AMENDATORY AGREEMENT, executed October 13, 1967, by the UNITED STATES OF AMERICA (hereinafter called "the Government"), Department of the Interior, acting by and through the BONNEVILLE POWER ADMINISTRATOR (hereinafter called "the Administrator"), and PORTLAND GENERAL ELECTRIC COMPANY (hereinafter called "the Company"), a corporation organized and existing under the laws of the State of Oregon,

W I T N E S S E T H:

WHEREAS the parties hereto, on January 3, 1966, executed a trust agreement (designated as Contract No. 14-03-56747) which provides for the design, construction and test by the Administrator of the Company's portion of the Grizzly substation; and

WHEREAS each party is constructing similar capacitor facilities at Fort Rock, Sand Spring and Sycan capacitor stations; and

WHEREAS the parties hereto desire to amend said Contract No. 14-03-56747 to provide for installation under said trust agreement of certain control facilities within Grizzly substation by the Administrator, and for his installation of supervisory control equipment for each parties capacitor facilities at Fort Rock, Sand Spring and Sycan capacitor stations; and

WHEREAS the Administrator is authorized to dispose of electric energy generated at various federal hydroelectric projects in the Northwest and to enter into related agreements in accordance with the Bonneville Project Act, approved August 20, 1937, as amended, and pursuant to the following orders of the Secretary of the Interior: No. 2563 dated May 2, 1950, and No. 2860 dated January 19, 1962, as amended;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. Effective Date of Agreement. This amendatory agreement shall take effect at 12 p.m. on the date of execution.

2. Amendment of Contract No. 14-03-56747. Said Contract No. 14-03-56747 is hereby amended as follows:

(a) Section 2 is hereby deleted and the following substituted therefor:

"2. Trust Fund. The Company hereby agrees to pay the Administrator an amount equal to forty percent (40%) of the expense and cost of performing the duties imposed upon him by sections 3(a)(1) and 3(a)(2) hereof, and fifty percent (50%) of the expense and cost of the duties imposed upon him by section 3(a)(5) hereof. Such amount (hereinafter called "the trust fund"), which is estimated to be six hundred sixty-seven thousand dollars ($667,000), shall be held by the Administrator in trust for the foregoing purpose. Payment to the Administrator from the Company in the amount of five hundred thirty thousand dollars ($530,000), to be held in trust by the Administrator on account of such share of estimated cost, is hereby acknowledged. The Company will make further payments on account of such share of estimated cost quarterly in amounts requested by the Administrator and based on his latest estimate of need for additional funds for the ensuing calendar quarter. If at any time thereafter the Administrator estimates that such amounts are insufficient to pay during such quarter the Company's proportionate share of the expense and cost of completing performance of such duties, the Company will advance to the Administrator, when requested by the Administrator and in such installments as may be specified by him, such additional moneys as he estimates will be required for such completion.

The moneys so received by the Administrator, as aforesaid, together with all moneys, if any, advanced to him in trust under any other provisions of this agreement, will be placed in a trust account in the United States Treasury subject to withdrawal as provided in 31 U. S. C., sections 725r and 725s, for payment of the expenses and cost of performing the duties imposed on the Government by this agreement."

(b) Section 3 is hereby deleted and the following section substituted therefor:

"3. <u>Duties of the Administrator</u>.

"(a) The Administrator shall design, furnish all material and labor except that furnished by the Company pursuant to section 4 hereof, construct and test the following:

(1) five 500 kv line terminals complete with associated pedestal mounted 500 kv bus and necessary supports, bus insulators, conduit and manholes, and painting; and

(2) control house, fence, related substation site developments and improvements, and control facilities including power line carrier, supervisory control, telemetering, fault locator, tone equipment and protective relaying; and

(3) provide, at his sole expense, for installation under subsection (a)(1) of this section three sets of 300 kv 120/69 volt potential transformers and six 500 kv 3,000 ampere disconnect switches; and

(4) provide and install, at his sole expense, three 500 kv, 2,400 ampere, 35,000 mva power circuit breakers, each with 12 associated current transformers on foundations installed pursuant to said subsection (a)(1) of this section; and

(5) supervisory control and tone equipment for (i) control, alarm, and indication at Fort Rock capacitor station, and (ii) alarm and indication at Sand Spring and Sycan capacitor stations.

"(b) All work done at the Company's expense under this section will be performed by the Administrator in whole or in part by force account, by contract, or by both, in the same manner and subject to the same limitations as if all funds being expended therefor were Government funds."

(c) New subsection (c) is hereby added to section 5 as follows:

"(c) Title to and ownership of a 50% interest in the facilities constructed or installed pursuant to section 3(a)(5) hereunder shall be and remain in each party at all times."

IN WITNESS WHEREOF, the parties hereto have executed this amendatory agreement in several counterparts.

UNITED STATES OF AMERICA
Department of the Interior

(SEAL)

By J. N. O'Neal
ACTING Bonneville Power Administrator

PORTLAND GENERAL ELECTRIC COMPANY

(SEAL)

By E. C. Sammons
VICE PRESIDENT

ATTEST:
H. H. Phillips

APPROVED AS TO FORM
H. H. Phillips

Contract No. 14-03-56747
11-23-65

TRUST AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF THE INTERIOR

acting by and through the

BONNEVILLE POWER ADMINISTRATOR

and

PORTLAND GENERAL ELECTRIC COMPANY

providing for design, construction and test of the

Company's portion of the Grizzly Substation

Index to Sections

This TRUST AGREEMENT, executed January 3, 1966, by the UNITED STATES OF AMERICA (hereinafter called "the Government"), Department of the Interior, acting by and through the BONNEVILLE POWER ADMINISTRATOR (hereinafter called "the Administrator"), and PORTLAND GENERAL ELECTRIC COMPANY (hereinafter called "the Company"), a corporation organized and existing under the laws of the State of Oregon,

W I T N E S S E T H:

WHEREAS the Government plans to construct two 500 kv a-c circuits from its John Day substation to the proposed Grizzly substation and one 500 kv a-c circuit from said Grizzly substation to the proposed Malin substation and the Company plans to construct a 500 kv a-c circuit from its Round Butte substation to said Grizzly substation and a 500 kv a-c circuit from said Grizzly substation to said Malin substation; and

WHEREAS the Administrator plans to construct the proposed Grizzly substation to provide terminal facilities for the Company's Round Butte-Grizzly and Grizzly-Malin 500 kv transmission lines (hereinafter called the "Round Butte terminal" and the "Malin No. 2 terminal", respectively) as well as terminal facilities for the Government's Grizzly-Malin and two John Day-Grizzly 500 kv transmission lines (hereinafter called the "Malin No. 1 terminal" and "John Day No. 1 and No. 2 terminals", respectively); and

WHEREAS the 500 kv a-c circuits and the proposed Grizzly substation are a part of the Pacific Northwest-Pacific Southwest Intertie program as recommended to Congress by the Secretary of the Interior and approved by Congress by making appropriations for the construction of the Government's portion thereof; and

WHEREAS the Company desires that the Administrator design, furnish certain labor and material to construct, and test the Company's portion of the Grizzly substation in conjunction with the design, construction, and test of the Government's portion of such substation; and

WHEREAS the Company has agreed to pay forty percent (40%) of the total cost to the Government for design, construction and test of the Grizzly substation as the Company's pro rata share of the cost of said substation exclusive of the cost of certain equipment and labor which will be supplied individually by the parties hereto; and

WHEREAS the Company will furnish certain equipment for use in the Round Butte and Malin No. 2 terminal positions at Grizzly substation and will install some of such equipment in the said terminal positions and the Administrator will install the remainder of the material and equipment required at the substation; and

WHEREAS it will be beneficial to the Government if the work necessary to provide terminal positions were done by the Administrator; and

WHEREAS the Company has agreed to advance the necessary funds pursuant to this agreement; and

WHEREAS the Administrator is authorized to dispose of electric energy generated at various federal hydroelectric projects in the Northwest in accordance with the Bonneville Project Act, approved August 20, 1937, as amended, and pursuant to the following orders of the Secretary of the Interior: No. 2563 dated May 2, 1950, and No. 2860 dated January 19, 1962, as amended; and

WHEREAS the Administrator is authorized by said Order No. 2860, as amended, to enter into such contracts, agreements, and arrangements upon such terms and conditions and in such manner as he may deem necessary, as provided in said Bonneville Project Act, as amended;

NOW, THEREFORE, the parties hereto mutually agree that the trust herein referred to was created upon and subject to the terms, provisions, and covenants, as follows:

1. <u>Term of Agreement</u>. Each of the provisions of this agreement will be effective on the date of execution and, except as it is otherwise hereinafter provided, shall continue in effect until all acts required hereunder have been fully performed.

2. <u>Trust Fund</u>. The Company hereby agrees to pay the Administrator the amount of five hundred sixty-eight thousand six hundred fifty dollars ($568,650)(hereinafter called "the trust fund"), to be held by him in trust to defray forty percent (40%) of the estimated expense and cost of performing the duties imposed on him by sections 3(a)(1) and 3(a)(2) hereof. Payment to the Administrator from the Company in the amount of one hundred fifty thousand dollars ($150,000) is hereby acknowledged. Unless otherwise agreed to by the parties hereto, the Company agrees to make further payments to the Administrator of one hundred fifty thousand dollars ($150,000) on or before January 1, 1966, one hundred fifty thousand dollars ($150,000) on or before April 1, 1966, and one hundred eighteen thousand six hundred and fifty dollars ($118,650) on or before July 1, 1966.

If at any time hereafter the Administrator estimates that such amounts are insufficient to pay the Company's proportionate share (forty percent) of the expense and cost of completing performance of such duties, the Company will advance to the Administrator, when requested by the Administrator and in such installments as may be specified by him, such additional moneys as he estimates will be required for such completion.

The moneys so received by the Administrator, as aforesaid, together with all moneys, if any, advanced to him in trust under any other provisions of this agreement, will be placed in a trust account in the United States Treasury subject to withdrawal as provided in 31 U. S. C., sections 725r and 725s, for payment of the expenses and cost of performing the duties imposed on the Government by this agreement.

3. Duties of the Administrator.

(a) The Administrator shall design, furnish all material and labor except that furnished by the Company pursuant to section 4 hereof, construct, and test the following:

(1) five 500 kv line terminals complete with associated pedestal mounted 500 kv bus and necessary supports, bus insulators, conduit and manholes, and painting;

(2) control house, fence, and related substation site developments and improvements;

(3) provide, at his sole expense, for installation under subsection (a)(1) of this section three sets of 300 kv 120/69 volt-120/69 volt potential transformers and six 500 kv 3,000 ampere disconnect switches; and,

(4) provide and install, at his sole expense, three 500 kv, 2,400 ampere, 35,000 mva power circuit breakers, each with 12 associated current transformers on foundations installed pursuant to said subsection (a)(1) of this section.

(b) All work done at the Company's expense under this section will be performed by the Administrator in whole or in part by force account, by contract, or by both, in the same manner and subject to the same limitations as if all funds being expended therefor were Government funds.

4. <u>Duties of the Company</u>. The Company, at its sole expense shall:

(a) provide, for installation by the Administrator under section 3(a)(1) hereunder, two sets of 300 kv 120/69 volt-120/69 volt potential transformers and four 500 kv 3,000 ampere disconnect switches;

(b) provide and install two 500 kv 2,400 ampere 35,000 mva power circuit breakers, each with 12 associated current transformers, on foundations provided by the Administrator under said section 3(a)(1).

5. <u>Ownership of Facilities</u>.

(a) Title to and ownership of an undivided forty percent (40%) interest in the facilities constructed or installed pursuant to sections 3(a)(1) and 3(a)(2) hereunder shall be and remain in the Company at all times. Title to and ownership of an undivided sixty percent (60%) interest in the facilities constructed or installed pursuant to sections 3(a)(1) and 3(a)(2) hereunder shall be and remain in the Government. Title to and ownership of the equipment furnished by the Company pursuant to section 4 and by the Administrator pursuant to sections 3(a)(3) and 3(a)(4) shall be and remain in the Company and the Government, respectively, at all times.

(b) Each party shall identify all equipment which is owned by it, as provided in subsection (a) of this section, by permanently affixing thereto suitable tags, stencils, stamps, or other markers plainly stating that the property so identified is owned by such party.

6. <u>Accounting</u>.

(a) Within a reasonable time after completion of the work for which a deposit in trust has been made under the terms hereof, the Administrator will make a full accounting to the Company showing the receipts credited to, and the costs and expenses charged against, said trust fund. The Administrator will remit to the Company any unexpended balance of said trust fund within a reasonable time after accounting is made as herein provided.

(b) If at any time the Administrator requests the Company to advance additional moneys pursuant to section 2 hereof, the Administrator will, within a reasonable time after the Company so requests, make a full accounting to the Company showing the receipts credited to, and the costs and expenses charged against, said trust fund. The Administrator will, at the same time, submit a statement to the Company showing in detail his estimate of the additional moneys required to pay the expense and cost of completing performance of his responsibilities as specified in section 3(a)(1) and 3(a)(2) of this agreement.

(c) Forty percent (40%) of the costs and expenses of performing the work and furnishing the materials mentioned in sections 3(a)(1) and 3(a)(2) hereof shall be proper charges against said trust fund, and shall be determined by charging the cost elements exclusive of interest in the same manner as if Government funds were being expended, including among other things, labor, annual and sick leave obligations, contributions - employee benefits, equipment use, tool and stores expense, expense of transportation of any materials or equipment which is not included as stores expense, expense and cost incurred to make the accounts provided for in this section, and overheads reasonably allocable thereto.

7. Provisions Required by Statute. The provisions which are required to be inserted by applicable law are attached hereto as Exhibit A and are hereby made a part of this agreement. The Company shall be "the Contractor" mentioned in said Exhibit A.

8. Interest of Member of Congress. No Member of or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this agreement or to any benefit that may arise therefrom, but this provision shall not be construed to extend to this agreement if made with a corporation for its general benefit.

IN WITNESS WHEREOF, the parties hereto have executed this agreement in several counterparts.

UNITED STATES OF AMERICA
Department of the Interior

(SEAL)

By Charles F. Luce
Bonneville Power Administrator

PORTLAND GENERAL ELECTRIC COMPANY

(SEAL)

By Frank M. Warren

ATTEST: Clarence Phillips

approved as to form
H H Phillips

PROVISIONS REQUIRED BY STATUTE

Contract Work Hours Standards Act - Overtime Compensation.

This contract, to the extent that it is of a character specified in the Contract Work Hours Standards Act (Public Law 87-581, 76 Stat. 357-360) and is not covered by the Walsh-Healey Public Contracts Act (41 U. S. C. 35-45), is subject to the following provisions and to all other provisions and exceptions of said Contract Work Hours Standards Act.

(a) No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers or mechanics shall require or permit any laborer or mechanic in any workweek in which he is employed on such work, to work in excess of eight hours in any calendar day or in excess of forty hours in any workweek unless such laborer or mechanic receives compensation at a rate not less than one and one-half times his basic rate of pay for all hours worked in excess of eight hours in any calendar day or in excess of forty hours in such workweek, whichever is the greater number of overtime hours.

(b) In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible for such violation shall be liable to any affected employee for his unpaid wages. In addition, such Contractor or subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed, with respect to each individual laborer or mechanic employed in violation of the provisions of subsection (a), in the sum of $10 for each calendar day on which such employee was required or permitted to work in excess of eight hours or in excess of forty hours in a workweek without payment of the required overtime wages.

(c) The Administrator may withhold, or cause to be withheld, from any moneys payable on account of work performed by the Contractor or subcontractor, the full amount of wages required by this contract and such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for liquidated damages as provided in subsection (b).

(d) The Contractor shall require the foregoing subsections (a), (b), (c) and this subsection (d) to be inserted in all subcontracts.

(e) The Contractor shall keep and maintain for a period of three (3) years from the completion of this contract the information required by 29 CFR § 516.2(a). Such material shall be made available for inspection by authorized representatives of the Government, upon their request, at reasonable times during the normal work day.

Convict Labor. The Contractor shall not employ any person undergoing sentence of imprisonment at hard labor.

Nondiscrimination. During the performance of this contract, the Contractor agrees as follows:

(1) The Contractor will not discriminate against any employee or applicant for employment because of race, creed, color, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, creed, color, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by the Administrator setting forth the provisions of this nondiscrimination clause.

(2) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, creed, color, or national origin.

(3) The Contractor will send to each labor union or representative of workers with which he has a collective bargaining agreement or other contract or understanding, a notice, to be provided by the Administrator, advising the labor union or worker's representative of the Contractor's commitments under Section 202 of Executive Order No. 11246 of September 24, 1965, and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(4) The Contractor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(5) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and by the rules, regulations, and orders of the Secretary of Labor, or pursuant thereto, and will permit access to his books, records, and accounts by the Administrator and the Secretary of Labor for purposes of investigations to ascertain compliance with such rules, regulations and orders.

(6) In the event of the Contractor's noncompliance with the nondiscrimination clauses of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246

of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(7) The Contractor will include the provisions of paragraphs (1) through (7) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as the Administrator may direct as a means of enforcing such provisions including sanctions for noncompliance; provided, however, that in the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by the Administrator, the Contractor may request the United States to enter into such litigation to protect the interests of the United States.

AUTHENTICATED COPY

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208

In reply refer to: PSK

August 21, 1981

Mr. Leo A. DeGuire
District Manager
Montrose District Office
1800 South Rio Grande
Montrose, Colorado 81401

Dear Mr. DeGuire:

This letter is to confirm our mutual interest in extending our Memorandum of Understanding dated December 15, 1975 and the extension letter of November 23, 1976.

We agree that it would be of mutual benefit to continue transactions under the Power Storage Agreement for another year. We have reviewed the provisions in this Agreement and feel that the form and methods of accounting are acceptable. However, the charges for settlement of balances in the Storage and Delivery Loss Accounts provided for in Section 3 (a) will be changed to the rate for determining a value of energy provided for in BPA nonfirm energy rate (NF-1), or its successor, in effect on August 31, 1982.

We also agree that the existing balance in the Storage Account as of August 31, 1981, will be allowed to carry over into the next year. However, if such energy is settled out it will be at the rate specified in the BPA nonfirm energy rate (H-6) in effect when such energy was delivered.

Section 2 and Section 4 of this Agreement refer to terms and conditions for transmission of storage energy to and from your system. Montana Power Company has agreed to use our existing transmission agreement during the 1981-82 operating year. Copies of this agreement dated April 27, 1978, have previously been sent to your office.

I believe the arrangements stated above are in accord with previous discussions between our staffs. If you concur, please sign the duplicate copy and return to this office.

Sincerely,

/S/ Lawrence A. Dean

Lawrence A. Dean, Chief
Branch of Power Supply

In duplicate
ACCEPTED, WESTERN AREA POWER ADMINISTRATION

BY: /S/ Leo A. DeGuire

TITLE: District Manager

DATE: 8/31/81

Amendatory Agreement No. 1 to
Contract No. 14-03-59840

5-3-79

AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and the

WESTERN AREA POWER ADMINISTRATION

and

PACIFIC POWER & LIGHT COMPANY

and

PORTLAND GENERAL ELECTRIC COMPANY

(Construction and Operation of the Malin Substation)

This AMENDATORY AGREEMENT, executed March 26, 1985, by the UNITED STATES OF AMERICA (Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and the WESTERN AREA POWER ADMINISTRATION (WAPA), PACIFIC POWER & LIGHT COMPANY (Pacific), a corporation of the State of Maine, and PORTLAND GENERAL ELECTRIC COMPANY (Portland General), a corporation of the State of Oregon,

W I T N E S S E T H :

WHEREAS the parties hereto executed an agreement (Contract No. 14-03-59840, which is hereinafter referred to as "Agreement") which provides, among other matters, for joint ownership of facilities installed by the parties in areas 3, 4 and 5 of Malin substation (Malin), except as provided in section 5(a)(1) of the Agreement; and

WHEREAS the parties wish to amend the Agreement to further provide for exclusive ownership by Pacific of certain facilities in areas 3, 4 and 5 at Malin; and

WHEREAS Bonneville and Pacific expect to execute Table 8 to Exhibit B to Contract No. 14-03-29224 providing for the installation of additional facilities at Malin owned by Pacific; and

WHEREAS Bonneville and Pacific have agreed to provide for operation and maintenance of such facilities under the Operation and Maintenance agreement, Contract No. 14-03-62876, executed on October 13, 1967; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power and energy generated at various Federal hydroelectric projects in the Pacific Northwest, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. Term of Agreement. This agreement shall be effective at 2400 hours on the date of execution.

2. Amendment of Agreement.

(a) Section 5(a)(1) is deleted and replaced with the following:

"(1) control house, equipment installed therein, and associated site improvements; provided, however, that to the extent that Pacific can remove equipment without damage to jointly-owned property, Pacific shall own the equipment installed in the control house pursuant to section 4(b) of Contract No. 14-03-62876 as amended, and the equipment installed in the control

house and substation yard pursuant to Table 8 to Exhibit B to Contract No. 14-03-29224."

(b) All references to "the Administrator" are changed to "Bonneville."

(c) All references to "Bureau of Reclamation" are changed to "Western Area Power Administration", and all references to "the Bureau" are changed to "WAPA."

3. Execution by Counterpart. This agreement may be executed in a number of counterparts and shall be deemed to constitute a single document with the same force and effect as if all parties hereto having signed a counterpart had signed all other counterparts. This agreement shall become effective when counterparts have been signed by all parties. Bonneville will prepare and deliver to each party a certified, conformed, composite copy of this agreement when it has been executed.

IN WITNESS WHEREOF, the parties hereto have executed this agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy

By Ray Foleen
ACTING Bonneville Power Administrator

WESTERN AREA POWER ADMINISTRATION

By ______________________

Title ______________________

PORTLAND GENERAL ELECTRIC COMPANY

ATTEST:

By ______________________

Title ______________________

By ______________________

Title ______________________

PACIFIC POWER & LIGHT COMPANY

By R. B. Fishleder

Title Vice President

RB.

ATTEST:

By Dolores Kirby

Title Assistant Secretary

Effective Date: March 27, 1985

house and substation yard pursuant to Table 8 to Exhibit B to Contract No. 14-03-29224."

(b) All references to "the Administrator" are changed to "Bonneville."

(c) All references to "Bureau of Reclamation" are changed to "Western Area Power Administration", and all references to "the Bureau" are changed to "WAPA."

3. Execution by Counterpart. This agreement may be executed in a number of counterparts and shall be deemed to constitute a single document with the same force and effect as if all parties hereto having signed a counterpart had signed all other counterparts. This agreement shall become effective when counterparts have been signed by all parties. Bonneville will prepare and deliver to each party a certified, conformed, composite copy of this agreement when it has been executed.

IN WITNESS WHEREOF, the parties hereto have executed this agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy

By ______________________
Bonneville Power Administrator

WESTERN AREA POWER ADMINISTRATION

By David G Coleman

Title Area Manager

PORTLAND GENERAL ELECTRIC COMPANY

ATTEST:

By ______________________

Title ______________________

By ______________________

Title ______________________

house and substation yard pursuant to Table 8 to Exhibit B to Contract No. 14-03-29224."

(b) All references to "the Administrator" are changed to "Bonneville."

(c) All references to "Bureau of Reclamation" are changed to "Western Area Power Administration", and all references to "the Bureau" are changed to "WAPA."

3. Execution by Counterpart. This agreement may be executed in a number of counterparts and shall be deemed to constitute a single document with the same force and effect as if all parties hereto having signed a counterpart had signed all other counterparts. This agreement shall become effective when counterparts have been signed by all parties. Bonneville will prepare and deliver to each party a certified, conformed, composite copy of this agreement when it has been executed.

IN WITNESS WHEREOF, the parties hereto have executed this agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy

By ______________________
Bonneville Power Administrator

WESTERN AREA POWER ADMINISTRATION

By ______________________

Title ______________________

PORTLAND GENERAL ELECTRIC COMPANY

By Alan E. Bredemeier

Title VICE PRESIDENT

ATTEST:

By [signature]

Title Secretary

PACIFIC POWER & LIGHT COMPANY

By________________________________

Title________________________________

ATTEST:

By________________________________

Title________________________________

Effective Date: March 27, 1985

B/R Contract No. 14-06-200-3104A
BPA Contract No. 14-03-59840

8-15-66

AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF THE INTERIOR

acting by and through the

BONNEVILLE POWER ADMINISTRATOR

and the

BUREAU OF RECLAMATION

and

PACIFIC POWER & LIGHT COMPANY

and

PORTLAND GENERAL ELECTRIC COMPANY

(Construction and Operation of the Malin Substation)

Index to Sections

(Index to Sections Cont.)

This AGREEMENT, executed September 13, 196~~6~~7, by the UNITED STATES OF AMERICA (hereinafter called "the Government"), Department of the Interior, acting by and through the BONNEVILLE POWER ADMINISTRATOR (hereinafter called "the Administrator") and the BUREAU OF RECLAMATION (hereinafter called "the Bureau"), PACIFIC POWER & LIGHT COMPANY (hereinafter called "Pacific"), a corporation organized and existing under the laws of the State of Maine, and PORTLAND GENERAL ELECTRIC COMPANY (hereinafter called "Portland General"), a corporation organized and existing under the laws of the State of Oregon,

W I T N E S S E T H:

WHEREAS the proposed Malin substation, near Malin, Oregon, and the 500 kv a-c transmission lines which will enter said substation are a part of the Pacific Northwest-Pacific Southwest Intertie program recommended to Congress by the Secretary of the

Interior and approved by Congress by making appropriations for the Government's portion thereof; and

WHEREAS the parties hereto desire to build the proposed Malin substation which will provide (1) terminal facilities for each party's portion of the 500 kv a-c transmission lines, (2) series capacitor facilities, and (3) shunt reactor facilities; and

WHEREAS the parties hereto and the other participants in the Pacific Northwest-Pacific Southwest Intertie program have formed the Pacific Intertie Guidance Committee to establish design, operation, and maintenance criteria for the Intertie program; and

WHEREAS Pacific and the Administrator intend to enter into Intertie Agreement No. 14-03-56379 and Portland General and the Administrator have entered into Intertie Agreement No. 14-03-55063 (together hereinafter called "the Intertie Agreements"); and

WHEREAS Pacific and the Administrator intend to enter into a trust agreement (designated as Contract No. 14-03-59835) and Portland General and the Administrator intend to enter into a trust agreement (designated as Contract No. 14-03-59834)(together hereinafter called "the Construction Trust Agreements") which provide for construction by the Administrator of a part of each company's portion of the 500 kv switchyard (hereinafter called "the 500 kv Switchyard"), in the Malin substation, the Administrator having determined that it will be beneficial to the Government for him to perform such construction with funds advanced by the respective parties; and

WHEREAS the Administrator will operate the Malin substation and will maintain certain facilities in the portion of the 500 kv Switchyard owned by Pacific and Portland General as well as the Government's facilities, and the parties hereto desire to enter into an agreement outlining the responsibilities and rights of each party; and

WHEREAS Pacific has purchased the land and necessary easements for the proposed Malin substation site, and expects to convey certain portions of said site to Portland General and to the Government pursuant to the provisions of a proposed agreement with Portland General and the Administrator (designated as Contract No. 14-03-63626); and

WHEREAS the Administrator and the Bureau expect to enter into a Memorandum of Understanding (designated as Contract No. 14-03-63625), which provides for (1) purchase, construction, and installation of the Bureau's series capacitor facilities in the Malin substation, (2) the transfer from the Administrator to the Bureau of jurisdiction over (i) right-of-way to the Bureau's series capacitor facilities for the Bureau's Round Mountain-Malin 500 kv transmission line within Malin substation, and (ii) land for such series capacitor facilities of the Bureau, (3) the use of one-third of the capacity of the Administrator's shunt reactor facilities at the Malin substation, and (4) the operation and maintenance by the Administrator of the facilities of the Government within the Malin substation under the jurisdiction of the Bureau; and

WHEREAS the Administrator and Pacific intend to enter into a proposed agreement (designated as Contract No. 14-03-62876) and the Administrator and Portland General intend to enter into a proposed agreement (designated as Contract No. 14-03-63627)(together hereinafter called "the O&M Agreements") which will provide for operation and maintenance by the Administrator of certain solely-owned facilities of Pacific and Portland General and of jointly-owned facilities of the parties hereto in the 500 kv Switchyard; and

WHEREAS the Administrator is authorized to dispose of electric energy generated at various federal hydroelectric projects in the Northwest and enter into related agreements in accordance with the Bonneville Project Act, approved August 20, 1937, as amended, and pursuant to the following orders of the Secretary of the Interior: No. 2563 dated May 2, 1950, and No. 2860 dated January 19, 1962, as amended;

NOW, THEREFORE, the parties hereto mutually covenant and agree as follows:

1. Term of Agreement. This agreement shall be effective commencing on the date of execution and ending on the expiration of the term of the Government's Intertie Agreement with Pacific or Portland General as each agreement may be amended, extended, or renewed by a similar agreement or agreements, whichever is later.

2. Exhibits. A map of the Malin substation and the provisions required by statute or executive order are attached hereto as Exhibits A and B, respectively, and are hereby made a part of this agreement.

3. <u>Malin Substation</u>.

(a) The Malin substation shall include all facilities of the parties hereto which are located within the boundary of the Malin substation as shown in the map attached hereto as Exhibit A. Such substation is divided into the following sections:

(1) The 500 kv Switchyard (designated as areas 3, 4, and 5 of Exhibit A), which includes the 500 kv terminal facilities with associated 500 kv circuit breakers, disconnect switches, control house, 500 kv bus, ground mat, cable and ducts, water system, and associated site improvements.

(2) Portland General's shunt reactor yard (designated as area 1 on Exhibit A), which includes Portland General's shunt reactor facilities and associated disconnect switch, bus, supports and site improvements.

(3) The Government's shunt reactor yard (designated as area 2 on Exhibit A), which includes the Government's shunt reactor facilities, associated disconnect switch, bus, supports, site improvements and storage for a spare shunt reactor.

(4) The Government's series capacitor yard (designated as area 7 on Exhibit A), which includes the Government's series capacitor facilities, associated disconnect switches, bus, supports and site improvements.

(5) The remainder of the land owned in fee by Pacific within the Malin substation (designated as area 6 on Exhibit A), which includes Pacific's series capacitor facilities, associated disconnect switches, bus, supports, site

improvements, and a portion of Pacific's 500 kv transmission line.

(6) The Bureau's 500 kv transmission line and associated right-of-way within areas 8 and 10 as designated on Exhibit A.

(7) Pacific's 500 kv transmission line and associated right-of-way within area 9 as designated on Exhibit A.

(b) Upon transfer of land rights as provided in Contract No. 14-03-63626, the land areas or easements to use land areas shown in Exhibit A will be owned as follows:

(1) Areas 5, 6, and 9 by Pacific

(2) Areas 1 and 3 by Portland General

(3) Areas 2 and 4 by the Administrator

(4) Areas 7, 8, and 10 by the Bureau.

4. Construction by the Parties. In accordance with the design criteria specified and approved by the Pacific Intertie Guidance Committee:

(a) Pacific will:

(1) design, furnish all material and labor, construct, install, and test its transmission line described in section 3(a)(7) hereof, prior to May 1, 1967,

(2) purchase and install, prior to May 1, 1967, a 500 kv 2,000 ampere, 38,000 mva power circuit breaker on foundations installed by the Administrator pursuant to said Construction Trust Agreement No. 14-03-59835,

(3) design, furnish all material and labor, construct, install, and test its series capacitor facilities described in section 3(a)(5) hereof prior to April 1, 1968, and

(4) provide prior to November 15, 1966, for installation by the Administrator in the 500 kv Switchyard pursuant to the terms of the Construction Trust Agreement No. 14-03-59835, one set of 300 kv 120/69 volt potential transformers and two 500 kv 2,400 ampere disconnect switches.

(b) Portland General will:

(1) design, furnish all material and labor, construct, install, and test its shunt reactor facilities described in section 3(a)(2) prior to April 1, 1968,

(2) purchase and install prior to April 1, 1968, a 500 kv, 2,400 ampere, 35,000 mva power circuit breaker on foundations installed by the Administrator pursuant to the Construction Trust Agreement No. 14-03-59834,

(3) provide prior to October 15, 1966, for installation by the Administrator in the 500 kv Switchyard pursuant to the terms of the Construction Trust Agreement No. 14-03-59834, two 500 kv 2,400 ampere disconnect switches, and

(4) provide prior to April 1, 1968, for installation by the Administrator in the 500 kv Switchyard pursuant to the terms of the Construction Trust Agreement No. 14-03-59834, one set of 300 kv 120/69 kv potential transformers.

(c) The Administrator will:

(1) pursuant to the Construction Trust Agreements, design, furnish all material and labor, construct and install prior to May 1, 1967, all facilities in the 500 kv Switchyard, except those supplied and installed by Pacific

and Portland General as specified in Construction Trust Agreements, and test all facilities in the 500 kv Switchyard prior to regular operation, excepting Portland General's 500 kv power circuit breaker and potential transformers which will be tested by the Administrator after their installation,

(2) design, furnish all material and labor, construct, and install the Government's shunt reactor facilities described in section 3(a)(3) hereof prior to May 1, 1967,

(3) design, furnish all material and labor, construct, and install, prior to April 1, 1968, the Government's series capacitor as described in section 3(a)(4) hereof pursuant to Memorandum of Understanding No. 14-03-63625,

(4) provide, prior to September 1, 1966, for his installation in the 500 kv Switchyard pursuant to the terms of Construction Trust Agreements, two sets of 300 kv 120/69 volt potential transformers and four 500 kv 3,000 ampere disconnect switches, and

(5) purchase and install prior to May 1, 1967, two 500 kv 2,000 ampere, 38,000 mva power circuit breakers.

(d) The Bureau will design, furnish all material and labor, construct and install its transmission line described in section 3(a)(6) hereof prior to November 1, 1967.

(e) The time for each act specified in this section shall be extended for a time equivalent to such delays, if any, as are occasioned by events which the party hereto obligated to perform such act could not b reasonably be expected to oid by the exercise of reasonable diligence and foresight.

5. Ownership of Facilities. All facilities and site improvements installed on or above the land areas of each party hereto described in section 3(b) shall be solely owned by that party except as follows:

(a) Pacific shall own an undivided twenty-five percent (25%) interest, Portland General shall own an undivided twenty-five percent (25%) interest, and the Government, acting by and through the Administrator, shall own an undivided fifty percent (50%) interest in the following facilities located within areas 3, 4, and 5 as shown on Exhibit A:

(1) control house, equipment installed therein, and associated site improvements; provided, however, that Pacific shall own the equipment installed in the control house pursuant to section 4(b) of Contract No. 14-03-62876 to the extent that such equipment can be removed without damage to the jointly-owned property,

(2) water system,

(3) joint duct and control cable runs from control house to manhole No. IG and handholes Nos. 2C and 4C,

(4) ground mat,

(5) the internal 500 kv Switchyard roads.

(b) The Government shall own:

(1) the 500 kv strain bus between the 500 kv Switchyard and the Government's series capacitor yard which overhangs land owned by Pacific,

(2) the spare parts inventory maintained at Malin substation for the portion of the 500 kv Switchyard constructed by the Administrator pursuant to the Construction Trust Agreements.

(c) Pacific shall own an undivided forty-one and three-tenths percent (41.3%) interest, Portland General shall own an undivided sixteen and five-tenths percent (16.5%) interest and the Government, acting by and through the Administrator, shall own an undivided forty-two and two-tenths percent (42.2%) interest in the entrance road and necessary right-of-way therefor from the county road at Loveness Mill to the control house including the portions of entrance road within and outside the substation boundary.

6. Use of Facilities. Each of the parties may use the Malin substation for making or accepting deliveries of electric power or energy from or to any other party hereto, or from or to any third party; provided, however, that Pacific's use of the Malin substation shall be subject to any limitations provided in Intertie Agreement No. 14-03-56379, and Portland General's use of the Malin substation shall be subject to any limitations provided in Intertie Agreement No. 14-03-55063, as such Intertie Contracts may be amended, extended, or renewed. Such use shall be without charge to any party hereto.

7. Delivery Point. In any contract between parties hereto, or between parties hereto and third parties, which provides for delivery at the Malin substation or at the Oregon-California border, in either case such delivery shall be to the Malin substation facilities as described herein, and the respective party to this agreement making or accepting such delivery shall have the right to use of the facilities of the Malin substation, as described

in section 3 hereof for the purpose of making or accepting such delivery.

8. Operation.

(a) The Administrator shall operate the Malin substation pursuant to the provisions of the O&M Agreements. Operation of Pacific's and Portland General's terminal positions in the Malin substation shall be subject to the dispatching control of each company's dispatcher working through the Administrator's dispatcher. Operation of the companies' terminal positions, once it is determined supervisory control is feasible, will be resolved according to a mutually satisfactory agreement by the parties.

(b) All employees of the parties hereto who desire to enter the Malin substation shall obtain access clearance from the substation operator prior to entry.

9. Maintenance.

(a) Routine maintenance of all facilities in the Malin substation shall be performed in accordance with schedules agreed to in advance by the parties and in accordance with accepted utility standards.

(b) Pursuant to the terms of the O&M Agreements, the Administrator will (1) maintain such facilities of Pacific and Portland General within the 500 kv Switchyard as are specified in the O&M Agreements, and (2) maintain the entrance road from the county road at Loveness Mill to the control house.

(c) Any party hereto may make emergency repairs of the facilities to be maintained by another party. The repairing party shall be reimbursed by the party responsible for such maintenance for actual expenses incurred, including reasonable overheads.

10. Liability. Each party shall be solely liable for any loss or claim for damage or injury to persons or property which arises from its maintenance of, or failure to maintain its separately-owned property maintained by such party.

11. Enforcement of Warranties. The Government shall, at its option, have the right to enforce all warranties, express or implied, made in connection with jointly-owned property. Either Pacific or Portland General may, after refusal by the Government, enforce any warranty, express or implied, made in connection with jointly-owned property. The parties agree to execute all documents or instruments necessary or required for the purpose of enforcing such warranties, or the release or satisfaction thereof. Cost of such enforcement, including but not limited to the cost of any administrative proceedings, arbitration, or suit, if necessary, shall be borne by the parties on a pro rata basis according to each party's interest in such property.

12. Assignment. This agreement shall inure to the benefit of, and shall be binding upon the respective successors and assigns of the parties to this agreement; provided, however, that neither such agreement nor any interest therein shall be transferred or assigned by a party to any party other than the United States or an agency thereof without the written consent of the other parties; provided, further, that the interests of Pacific or Portland General

under this agreement, including the Malin substation or any portion thereof, may be conveyed to its respective trustees as security under a mortgage or deed of trust to secure indebtedness without such written consent, provided that each such trustee may act with respect to such interest only to the extent and in the manner that such act would have been authorized under this agreement.

13. <u>Additions to or Disposition of Property</u>. Equipment and property within the Malin substation may be added to or disposed of only by agreement of all of the parties. If at any time during the term hereof the parties agree that any property within the Malin substation is surplus to operating needs, such property shall be disposed of in the manner provided in section 14(c) hereof.

14. <u>Provisions Applicable after the Term of the Agreement</u>. From and after the end of the term of this agreement and unless the parties agree to a replacement or extension of this agreement, or to other similar arrangements, it is further agreed that:

(a) Unless all parties agree to dispose of the Malin substation, as provided in subsection (c) of this section, the parties will maintain both their jointly-owned and separately-owned facilities in the Malin substation in such manner so as to permit the continued use of facilities of other parties for delivery and receipt of power as provided in sections 6 and 7 hereof.

(b) If any party proposes to dispose of its jointly-owned facilities or of such of its separately-owned facilities as are required to be maintained under subsection (a) above it will, prior to such disposition, offer the same for sale to the other parties, in the ratio that the interest of each of such other party in the jointly-owned facilities bears to the total interest of such other parties in the jointly-owned facilities. The price at which such facilities and interests shall be offered shall be the cost of such facilities as shown on the books of the selling party, less depreciation reserves on the books of the selling party accrued thereon as of the date of sale. The other parties shall accept or reject the offer of sale in writing within sixty (60) days after receipt by them of the offer of sale. If either rejects such offer the other may purchase the whole of such facilities. Such purchasing party or parties shall continue to operate the facilities subject to the provisions of subsection (a) above. If neither of the other parties accepts such offer of sale, the disposing party may thereafter sell to any person its separately-owned facilities and its interest in the jointly-owned facilities or it may remove its separately-owned facilities; provided, however, that removal shall not take place until two (2) years after the offer of sale. If it removes its separately-owned facilities, the other parties shall purchase its interest in all jointly-owned facilities at such party's book cost, less depreciation. Each such purchasing party shall pay for and receive an undivided interest in such jointly-owned facility in the ratio that such party's interest in the jointly-owned facilities then bears to the total interest of both parties in the jointly-owned facilities.

(c) If all parties agree to dispose of the Malin substation, all property located within the Malin substation shall be disposed of as follows:

(1) Disposition of separately-owned property shall be the responsibility of the owner.

(2) All jointly-owned property shall be disposed of by the Government in accordance with the then applicable Government regulations. Cost of such disposal, including costs of removal or dismantling such property, shall be shared on a pro rata basis according to each party's interest in such property. Any proceeds from such disposal shall be shared on the same basis.

IN WITNESS WHEREOF, the parties hereto have executed this agreement in several counterparts.

UNITED STATES OF AMERICA
Department of the Interior

(SEAL)

By ____________________
Acting Bonneville Power Administrator

By ____________________
Regional Director, Region 2
Bureau of Reclamation

PACIFIC POWER & LIGHT COMPANY

(SEAL)

By ____________________
SENIOR VICE-PRESIDENT

ATTEST:

____
ASSISTANT SECRETARY

PORTLAND GENERAL ELECTRIC COMPANY

(SEAL)

By ____________________

VICE PRESIDENT

ATTEST:

____
SECRETARY

PROVISIONS REQUIRED BY STATUTE OR EXECUTIVE ORDER

Contract Work Hours Standards Act - Overtime Compensation.

This contract, to the extent that it is of a character specified in the Contract Work Hours Standards Act (Public Law 87-581, 76 Stat. 357-360) and is not covered by the Walsh-Healey Public Contracts Act (41 U. S. C. 35-45), is subject to the following provisions and to all other provisions and exceptions of said Contract Work Hours Standards Act.

(a) No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers or mechanics shall require or permit any laborer or mechanic in any workweek in which he is employed on such work, to work in excess of eight hours in any calendar day or in excess of forty hours in any workweek unless such laborer or mechanic receives compensation at a rate not less than one and one-half times his basic rate of pay for all hours worked in excess of eight hours in any calendar day or in excess of forty hours in such workweek, whichever is the greater number of overtime hours.

(b) In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible for such violation shall be liable to any affected employee for his unpaid wages. In addition, such Contractor or subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed, with respect to each individual laborer or mechanic employed in violation of the provisions of subsection (a), in the sum of $10 for each calendar day on which such employee was required or permitted to work in excess of eight hours or in excess of forty hours in a workweek without payment of the required overtime wages.

(c) The Administrator may withhold, or cause to be withheld, from any moneys payable on account of work performed by the Contractor or subcontractor, the full amount of wages required by this contract and such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for liquidated damages as provided in subsection (b).

(d) The Contractor shall require the foregoing subsections (a), (b), (c) and this subsection (d) to be inserted in all subcontracts.

(e) The Contractor shall keep and maintain for a period of three (3) years from the completion of this contract the information required by 29 CFR § 516.2(a). Such material shall be made available for inspection by authorized representatives of the Government, upon their request, at reasonable times during the normal work day.

Convict Labor. The Contractor shall not employ any person undergoing sentence of imprisonment at hard labor.

Nondiscrimination. During the performance of this contract, the Contractor agrees as follows:

(1) The Contractor will not discriminate against any employee or applicant for employment because of race, creed, color, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, creed, color, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by the Administrator setting forth the provisions of this nondiscrimination clause.

(2) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, creed, color, or national origin.

(3) The Contractor will send to each labor union or representative of workers with which he has a collective bargaining agreement or other contract or understanding, a notice, to be provided by the Administrator, advising the labor union or worker's representative of the Contractor's commitments under Section 202 of Executive Order No. 11246 of September 24, 1965, and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(4) The Contractor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(5) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and by the rules, regulations, and orders of the Secretary of Labor, or pursuant thereto, and will permit access to his books, records, and accounts by the Administrator and the Secretary of Labor for purposes of investigations to ascertain compliance with such rules, regulations and orders.

(6) In the event of the Contractor's noncompliance with the nondiscrimination clauses of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246

of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(7) The Contractor will include the provisions of paragraphs (1) through (7) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as the Administrator may direct as a means of enforcing such provisions including sanctions for noncompliance; provided, however, that in the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by the Administrator, the Contractor may request the United States to enter into such litigation to protect the interests of the United States.

Interest of Member of Congress. No Member of or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this contract or to any benefit that may arise therefrom. Nothing, however, herein contained shall be construed to extend to such contract if made with a corporation for its general benefit.

AREAS KEY

NO	DESCRIPTION	OWNERSHIP
1	SHUNT REACTORS	P G E
2	SHUNT REACTORS	B P A
3	SWITCHYARD	P G E
4	SWITCHYARD	B P A
5	SWITCHYARD	P P & L
6	SERIES CAPACITORS & ADJACENT AREA	P P & L
7	SERIES CAPACITORS	U S B R
8	LINE R/W	U S B R
9	LINE R/W	P P & L
10	LINE R/W	U S B R

NO.	102-51 REVISION	BY	DATE	APPROVED
2	R RELOCATED DISC. TWO AND 03 TWO SO. SOUTH END OF P.P.&L. LINE TOWERS			
1	R CHGD LOCATION OF FENCE & P.P.&L. DISC SW			

UNITED STATES DEPARTMENT OF THE INTERIOR
BONNEVILLE POWER ADMINISTRATION
HEADQUARTERS, PORTLAND, OREGON

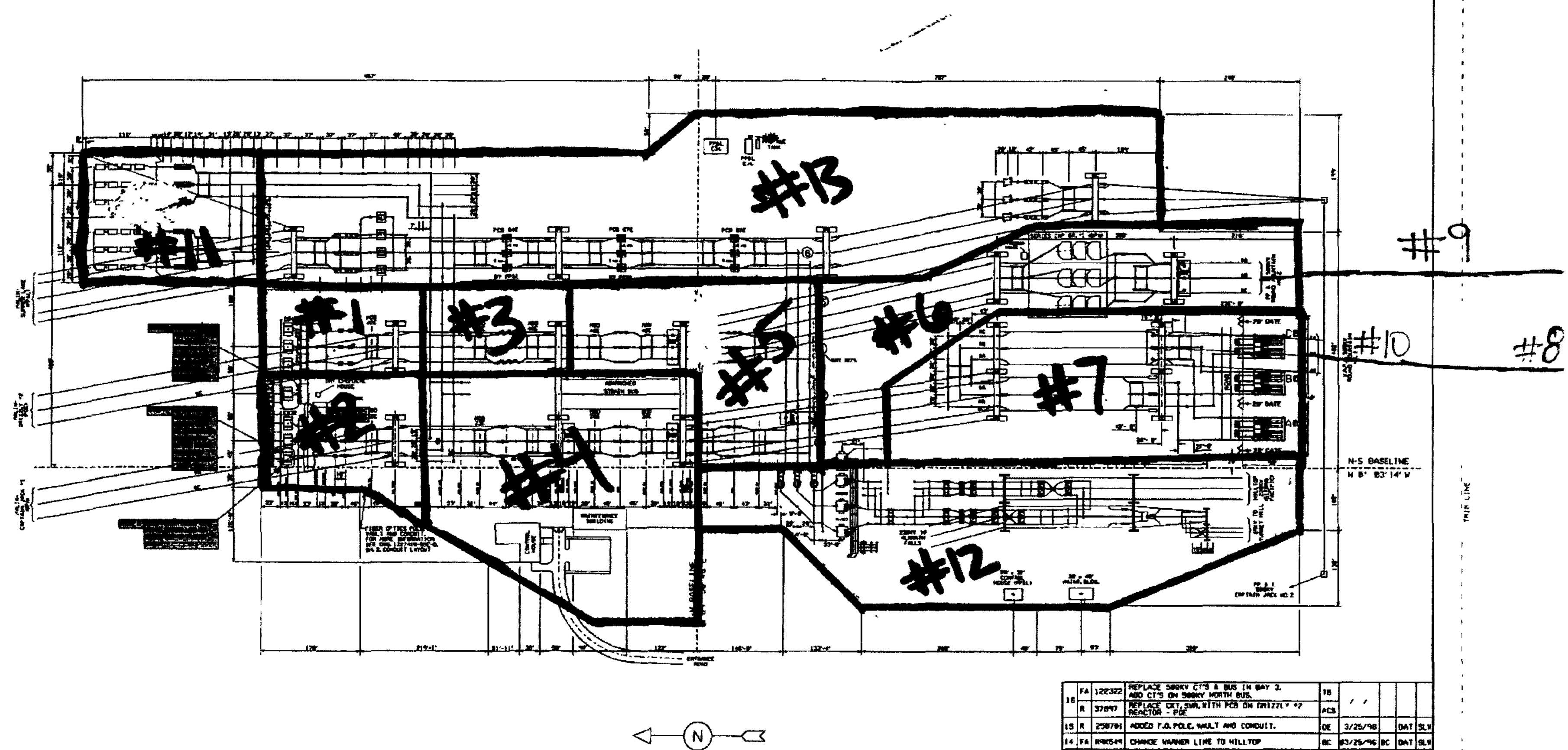
MALIN SUBSTATION
SITE PLAN

Dr. EWF
Ch. RHS
Date 8-4-66

140991-DSE-F

1409910 | 02 | DSE-F | 001 | 1112468120103 | SITE PLAN | MALIN

EXHIBIT "A"



SCALE: 1"=80'-0"

NO.			REVISION	BY	DATE	APPROVED		
16	FA	122322	REPLACE 500KV CT'S & BUS IN BAY 3. ADD CT'S ON 500KV NORTH BUS.	TB	/ /			
16	R	37897	REPLACE CKT. SWR. WITH PCB ON GRIZZLY #7 REACTOR - PGE	ACS				
15	R	250701	ADDED F.O. POLE, VAULT AND CONDUIT.	OE	3/25/98		DAT	SLW
14	FA	R9K549	CHANGE WARNER LINE TO HILLTOP	BC	03/25/96	BC	DAT	SLW
13	FA/C	R9B203	REPLACED CAP GROUP #1, AND RT #1, REPLACED BYPASS DISC. SW ADDED SHUFLY & TOWER	OA	03/07/95	EVO	DRA	JHG
12	R	962035	INCORPORATE PPAL CHANGES, REPLACE 500/230KV TRANSFORMER, ADD 2-230KV BREAKERS, REPLACE 500KV DISC. SWITCH WITH CIRCUIT SWITCHER	PEC	03/09/94	RLH	MAN JFD	MJB
11	FA	150137	REPLACED SHUNT REACTOR #1, SURGE ARRESTERS & LOB 21E WITH PCB'S, ADDED CT' REDRAWN ORIGINAL DWG. DATED 4-11-86	TB	03/15/93	MAN JFD	JHG	MJB
	FA	PL-6 150137	COMPUTER REVISION ONLY					

C=CONTRACT CONSTRUCTION, FA=FORCE ACCOUNT CONSTRUCTION, R=RECORD

UNITED STATES DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
HEADQUARTERS, PORTLAND, OREGON

DESIGN: DESIGN TB; DRAWN TB; CHKD TR
ENGINEERING: ENGR RPW; CHKD RPW

REC. R.A. MONTERO
REC. J.H. GALBRAITH
APPR. R.J. BROWN
DATE 3-15-93

MALIN SUBSTATION PLOT PLAN

SERIAL	SOURCE	SIZE	SHEET	REVISION
139411	ESB	A1	1 OF 1	16

Parcel	Description	Contract Section	Who performs Work	Who Pays	Ground Mat	Yard Rock, Risers, Footings, Drainage	Risers - Jointly Owned (if applicable)	Other
1	Shunt Reactors	59840 Sec 3(a)(2), 3(b)(2), and 9(a)	PGE, or, by agreement, BPA	PGE	100%	100%	-	100%
2	Shunt Reactors	59840 Sec 3(a)(3),	BPA	BPA	100%	100%	-	100%
3	Switchyard	59840 Sec 3(b), 5, 5(A)(3), 5(a)(4), 5(a)(5) 63627 Sec 3(a), 4(a)(3)	BPA	Shared (BPA/PAC/PGE)	50%/25%/25%	Land Ownership %, which is 100% PGE	50%/25%/25%	
4	Switchyard	59840 Sec 3(b), 5, 5(A)(3), (4), (5)	BPA	Shared (BPA/PAC/PGE)	50%/25%/25%	Land Ownership %, which is 100% BPA	50%/25%/25%	
5	Switchyard	59840 Sec 3(b), 5, 5(A)(3), (4), (5) 62876 Sec 3(a), 4(a)(3), Ex. A	BPA	Shared (BPA/PAC/PGE)	50%/25%/25%	Land Ownership %, which is 100% PAC	50%/25%/25%	
6	Series Capacitors & Adjacent Area	59840 Sec 3(b), 5 - Old series cap area. Mostly just land as equipment was removed.	PAC, or, by agreement, BPA	PAC	100%	100%	-	100%
7	Series Capacitors	59840 Sec 3(b), 5, 9(a)	WAPA, or, by agreement, BPA	WAPA	100%	100%	-	100%
8	Line ROW	ROW outside Malin Fence.		WAPA	-	-	-	100%
9	Line ROW	ROW outside Malin Fence.		PAC	-	-	-	100%
10	Line ROW	ROW outside Malin Fence.		WAPA	-	-	-	100%
11	Reactors	1988 Realty acquistion documents	BPA	BPA	100%	100%	-	100%
12	PAC 230 kV yard	Not covered by contracts	PAC, or, by agreement, BPA	PAC	100%	100%	-	100%
13	Malin - Meridian	29224 Ex B Table 8 Sec 3(a)	PAC, or, by agreement, BPA	PAC	100%	100%	-	100%

Department of Energy

Bonneville Power Administration
Seattle Customer Service Center
909 First Avenue, Suite 380
Seattle, Washington 98104-3636

POWER BUSINESS LINE

September 18, 2001

In reply refer to: PSW/Seattle

Amendment No. 1
Contract No. DE-MS79-80BP90066
General Transfer Agreement

Mr. William C. Dobbins
CEO/Manager
Public Utility District No. 1 of Douglas County
1151 Valley Mall Parkway
East Wenatchee, WA 98802-4497

Dear Mr. Dobbins:

This Amendment No. 1 (Amendment), between the Public Utility District No. 1 of Douglas County, Washington (Douglas) and the Bonneville Power Administration (BPA), extends the term of the General Transfer Agreement, No. DE-MS79-80BP90066 (Agreement), beyond the expiration date of the Power Sales Contract, No. DE-MS79-81BP90494, as replaced, on June 30, 2001.

BPA and Douglas agree:

1. **EFFECTIVE DATE**. This Amendment shall take effect on July 1, 2001.

2. **AMENDMENT OF THE AGREEMENT**. BPA and Douglas shall amend the Agreement as follows:

   Section 1, Term of Agreement, shall be deleted in its entirety and replaced by the following:

   "1. Term of Agreement. This Agreement shall be effective at 2400 hours on the date of execution (Effective Date), and shall terminate on the later of the following:

   (a) 2400 hours on September 30, 2006, or

   (b) one year after receipt of a notice of termination by either Party."

If the foregoing terms are acceptable, please sign all three originals of this Amendment and return them to me for my signature. A fully executed original will be sent to you for your files.

Sincerely,

Senior Account Executive

Name Stuart Clarke, Jr.
(Print/Type)

ACCEPTED:

PUBLIC UTILITY DISTRICT NO. 1
OF DOUGLAS COUNTY

By

Name William C. Dobbins
(Print/Type)

Title CEO/Manager

Date 9/24/2001

Contract No. DE-MS79-80BP90066

10-29-80

GENERAL TRANSFER AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PUBLIC UTILITY DISTRICT NO. 1 OF DOUGLAS COUNTY, WASHINGTON

Index to Sections

This GENERAL TRANSFER AGREEMENT, executed FEBRUARY 27, 1981, by the UNITED STATES OF AMERICA (Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and PUBLIC UTILITY DISTRICT NO. 1 OF DOUGLAS COUNTY, WASHINGTON (District), a corporation of the State of Washington,

W I T N E S S E T H :

WHEREAS Bonneville and the Water and Power Resources Service (Service), formerly the United States Bureau of Reclamation or Bureau have entered into a Memorandum of Agreement (Contract No. 14-03-17506 which as amended or replaced is hereinafter called "Memorandum") providing among other matters for delivery of reserved power and energy to the Service at the District's Foster Creek, Hanna and Orondo Substations; and

WHEREAS entities other than the Service may be listed in Exhibit E (Bonneville Customers) if power sales contracts or other agreements are executed which provide for the delivery of electric power and energy to such customers at various points of delivery in part by transfer over District facilities; and

WHEREAS the parties hereto executed a power sales contract (Contract No. 14-03-59202, which as amended or replaced is hereinafter referred to as "Power Sales Contract") which provides among other matters for points of delivery on the District's System; and

WHEREAS the parties hereto desire to provide that Bonneville or the District, as the case may be, transfer electric power and energy to the District or to Bonneville's Customers at various points of delivery described in Exhibits E and F; and

WHEREAS the Federal Power Commission, on June 10, 1977, conditionally approved new transmission rate schedules which are applicable to the transfer services provided herein; and

WHEREAS the parties hereto desire to incorporate the new transmission rate schedules into this agreement; and

WHEREAS the parties desire to include various provisions including revision of the rate adjustment provisions to allow more frequent review of transmission rate schedules in a manner consistent with the review of wholesale power rate schedules; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power and energy generated at various Federal hydroelectric projects in the Pacific Northwest, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. Term of Agreement. This agreement shall be effective at 2400 hours on the date of execution (Effective Date), and shall terminate on the earlier of the following:

(a) 2400 hours on the date of termination of the Power Sales Contract, or

(b) the date of the termination of all deliveries hereunder.

2. Exhibits. Exhibits A through G are made a part of this agreement. The District shall be the "Transferor" as that term is used in Exhibit A when transferring electric power and energy to Bonneville's Customers at points of delivery specified in Exhibit E, and each of Bonneville's Customers shall be

the "Transferee" mentioned therein. Bonneville shall be the "Transferor" as that term is used in Exhibit A when transferring electric power and energy to the District at points of delivery specified in Exhibit F, and the District shall be the "Transferee" mentioned therein. All references to "the Administrator" are changed to "Bonneville" in such exhibits.

3. Revision of Exhibits.

(a) Exhibits E, F, and G shall be revised at (1) any time by mutual agreement of the parties to add or remove points of delivery, or (2) the time specified by the party receiving transfer service in a written notice to the Transferor to remove any point of delivery specified in Exhibits E or F, as the case may be, but not before the expiration of one year from 2400 hours on the date notice is received by the Transferor, or (3) the time specified by the Transferor in a written notice to the party receiving transfer service to remove any point of delivery, but not before the expiration of three years from 2400 hours on the date such notice is received by the party receiving transfer service.

(b) Bonneville's rate schedules attached hereto as the initial Exhibits C and D have been conditionally confirmed and approved by the Federal Power Commission pursuant to Docket No. E-9563 and have subsequently received conditional approval by the agency designated by the Secretary of the Department of Energy to confirm and approve Bonneville's schedules of rates and charges for transmission of electric energy (Agency). If the final rate schedules which are confirmed and approved by the Agency are amendments or modifications of the initial rate schedules, such amended or modified rate schedules and associated general transmission rate schedule provisions shall be made a part of this agreement effective as of the date specified in the Agency's approval.

(c) Bonneville reserves the right to change its rate schedules provided herein pursuant to section 37 of Exhibit A and to change its charges provided herein pursuant to section 19 of Exhibit A.

(d) If the District determines that it is necessary to change its rates or charges provided herein, subject to section 19 of Exhibit A, the District shall notify Bonneville of its intention to apply proposed rates or charges together with such detail concerning said rates or charges as is then available. The parties hereto shall (1) use every effort in good faith to agree on such proposed changes and (2) proceed under section 20 of Exhibit A if such effort does not result in a mutually agreeable arrangement. There shall be no rate or charge change by the Utility during the 12-month period following the effective date of such new rates or charges unless otherwise agreed to by Bonneville.

(e) Upon any change in rates or charges pursuant to this section, the transfer charges specified in Exhibit G or any subsequent charges specified in this agreement shall be recalculated accordingly and the parties shall prepare a revised Exhibit G incorporating the new charges. Such revised Exhibit G shall be substituted for the Exhibit G then in effect and shall become effective as of the effective date of such new rates or charges.

(f) Any overpayment made by either party pursuant to the other party's rates or charges in this agreement shall be subject to refund with interest and such refunds shall either be sent to the overcharged party as soon as reasonably practicable after the effective date of such rates or charges, or shall be made by adjustment of such party's bill, as agreed by the parties.

4. Provisions Relating to Delivery. Electric power and energy shall be made available by the Transferor at all times during the term hereof at the points of delivery described in Exhibits E and F, in the amount of the

Transferee's requirements at such points and at the approximate voltages specifed therefor. The Transferor may, but shall not be obligated to, deliver such electric power and energy at a demand in excess of the number of kilowatts agreed upon in writing from time to time by representatives of the parties hereto. Amounts of electric energy, Integrated Demands therefor, and varhours delivered at such points during each month shall be determined from measurements, adjusted for losses as shown in Exhibit G, made by meters installed at the locations and in the circuits specified therefor in Exhibits E and F. On or before July 1 of each year each party shall furnish the other party with a five-year forecast of the maximum demands for each of the points of delivery described in Exhibit E or F.

5. Replacement of Power Delivered. In exchange for electric power and energy delivered by the Transferor hereunder, the party receiving transfer service shall make electric power and energy available to the Transferor during each month in the term hereof, at one or more of the points of delivery specified in, and subject to the applicable provisions of, the Power Sales Contract. Such electric power and energy to be made available by the party receiving transfer service shall be computed by adjusting metered amounts, determined as provided in Exhibits E and F for each point of delivery for replacement losses as agreed upon by representatives of the parties hereto.

The party receiving transfer service shall make available to the Transferor each hour in each month during the term hereof the amount of electric energy which is estimated to be the amount, so adjusted for losses, which the Transferor will deliver hereunder during such hour, and shall schedule such amount for delivery to the Transferor as provided in the Power Sales Contract.

6. Payment for Transfer of Power.

(a) For the use of Transferor services and facilities in transferring electric power and energy hereunder, the party receiving transfer service shall pay the Transferor each month during the term hereof the sum determined by adding the greater of (1) or (2) below for each point of delivery:

(1) the product of the transfer charge for such point of delivery and the transfer demand for such month after increasing such transfer demand by one percent for each one percent or major fraction thereof by which the average power factor at which electric energy is delivered hereunder during each month is less than 95 percent lagging; or

(2) the largest value obtained by multiplying the transfer demand of each of the 11 immediately preceding months by the respective transfer charge for each such month.

(b) The "transfer charge" for each point of delivery mentioned in subsection (a) above shall be as shown in Exhibit G. Transfer charges where Bonneville is the Transferor shall be determined pursuant to Exhibits C or D, as applicable.

(c) The "transfer demand" mentioned in subsection (a) above shall be the largest of the Integrated Demands at which electric energy is delivered by the Transferor hereunder during such month, determined as provided in Exhibit E or F, as the case may be, after eliminating all abnormal nonrecurring Integrated Demands resulting from emergency conditions.

7. Payment for Exclusive Use of Facilities. In addition to the payment due the Transferor in accordance with section 6, the party receiving transfer service shall pay the Transferor each month the amounts specified in Exhibit G under "Exclusive Use of Facilities Charges" exclusive for use of the facilities used to serve the party receiving transfer service. Bonneville's exclusive use of facilities charges shall be determined pursuant to Exhibit C.

8. Payment of Bills.

(a) The District shall reimburse Bonneville in accordance with the applicable provisions of Exhibit B.

(b) Bonneville shall reimburse the District by cash payment or by offsetting such amounts against all payments due Bonneville under this and other agreements between the parties.

9. Ratification of Interim Agreement. The District has agreed to provide transfer service to the Bonneville Customer listed in Table 1 of Exhibit E at Foster Creek and Hanna points of delivery commencing at 2400 hours on December 31, 1977, and at the Orondo point of delivery commencing at 2400 on July 31, 1979, and ending on the Effective Date hereof. Bonneville has agreed to deliver replacement losses pursuant to the terms of section 5 and to pay the District as follows:

Point of Delivery	Period	Transfer Charge ($/kW/Mo.)	Monthly Exclusive Use of Facilities Charge
Foster Creek	1/1/78-12/31/78	$0.339	-
	1/1/79-12/31/79	0.399	-
	1/1/80-Effective Date hereof	0.536	-
Hanna	1/1/78-12/31/78	0.073	$439.00
	1/1/79-12/31/79	0.123	$643.00.
	1/1/80-Effective Date hereof	0.123	$643.00
Orondo	8/1/79-Effective Date hereof	0.253	-

Bonneville has agreed to provide transfer service to the District at the points of delivery listed in Exhibit F commencing at 2400 hours on January 31, 1980, and the District has agreed to deliver replacement losses pursuant to the terms of Section 5 and to pay Bonneville the charges set out in Exhibit G.

The parties hereby ratify said interim agreements.

IN WITNESS WHEREOF, the parties hereto have executed this agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy

By Stanley E. Effending
ACTING Bonneville Power Administrator

PUBLIC UTILITY DISTRICT NO. 1 OF
DOUGLAS COUNTY, WASHINGTON

By Michael Doneen

Title President

ATTEST:

By Howard Trey

Title Secretary

By William E Bechtol

Title Vice President

0085A

EXHIBIT A

GWP Form-3 (7-27-77)

GENERAL WHEELING PROVISIONS

Index to Sections

GENERAL APPLICATION

1. Interpretation.

(a) The provisions in the agreement to which these General Wheeling Provisions are an exhibit shall be deemed to be a part hereof for the purpose of determining the meaning of any provision contained herein. If a provision in such agreement is in conflict with a provision contained herein, the former shall prevail.

(b) Nothing contained in this agreement shall, in any manner, be construed to abridge, limit, or deprive any party thereto of any means of enforcing any remedy, either at law or in equity, for the breach of any of the provisions thereof which it would otherwise have.

2. Definitions. As used in this agreement:

(a) the words "Contractor", "Utility" or "Borrower" as used herein shall mean the party to this agreement other than the Administrator;

(b) the word "month" shall mean the period commencing at the time when the meters mentioned in this agreement are read by the Administrator and ending approximately 30 days thereafter when a subsequent reading of such meters is made by the Administrator;

(c) the words "Integrated Demand" shall mean the number of kilowatts which is equal to the number of kilowatt-hours delivered at any point during a clock hour;

(d) the words "System" or "Facilities" shall mean the transmission facilities: (1) which are owned or controlled by either party, or (2) which either party may use under lease, easement, or license.

3. Prior Demands. In determining any credit demand mentioned in, or money compensation to be paid under this agreement for any month, Integrated Demands at which electric energy was delivered by the Transferor at points of delivery mentioned herein for the account of the other party to this agreement prior to the date upon which the agreement takes effect shall be considered in the same manner as if this agreement had been in effect.

4. Measurements. Except as it is otherwise provided in section 7 hereof, each measurement of each meter mentioned in this agreement shall be the measurement automatically recorded by such meter, but if not so recorded, shall be the measurement as determined by the parties hereto.

If it is provided in this agreement that measurements made by any of the meters specified therein are to be adjusted for losses, such adjustments shall be made by using factors, or by compensating the meters, as agreed upon by representatives designated by the parties to such agreement. If changes in conditions occur which substantially affect any such loss factor or compensation, it will be changed in a manner which will conform to such changes in conditions.

5. Measurements and Installation of Meters. The Administrator may at any time install a meter or metering equipment of the Government to make the measurements required for any computation or determination mentioned in this agreement, and if so installed such measurements shall be used thereafter in such computation or determination.

6. Tests of Meters. Each party to this agreement will, at its expense, test its meters mentioned in this agreement at least once every two years, and, if requested to do so by the other party, will make additional tests or inspections of such meters, the expense of which will be paid by such other party unless such additional tests or inspections show such meters to be inaccurate as specified in section 7 hereof. Each party will give reasonable notice of the time when any such test or inspection is to be made to the other party, who may have representatives present at such test or inspection. Meters found to be defective or inaccurate shall be adjusted, repaired or replaced to provide accurate metering.

7. Adjustment for Inaccurate Metering.

(a) If any meter mentioned in this agreement fails to register, or if the measurement made by such meter during a test made as provided in section 6 hereof varies by more than one percent from the measurement made by the standard meter used in such test, adjustment shall be made correcting all measurements made by such inaccurate meter during the period hereinafter stated. Such corrected measurements shall be used to recompute the amounts of any electric power and energy to be made available, of any credits to be made in any exchange energy account, and of any money compensation to be paid to the Transferor as provided in this agreement for (1) the actual period during which such inaccurate measurements were made if such period can be determined, or (2) if not, the period immediately preceding a test of such inaccurate meter which is equal to one-half the time from the date of the last preceding test of such meter; provided, however, that the period for which such recomputations are to be made shall not exceed six months.

(b) If the credit theretofore made to the Transferor in the exchange energy account varies from the credit to be made as recomputed, the amount of the variance will be credited in such exchange energy account to the party entitled thereto.

(c) If the money compensation theretofore paid to the Transferor varies from the money compensation to be paid as recomputed, the amount of the variance will be paid to the party entitled thereto within 30 days after the recomputation is made; provided, however, that the other party may deduct such amount due it from any money compensation which thereafter becomes due the Transferor under this agreement.

8. Character of Service. Unless otherwise specifically provided for in the agreement, electric power and energy made available pursuant to this agreement shall be in the form of three-phase current, alternating at a frequency of approximately 60 hertz.

9. Point of Delivery and Delivery Voltage. Electric power and energy shall be delivered to each Transferee at such point or points and at such voltage or voltages as are agreed upon by the parties hereto.

10. Combining Deliveries Coincidentally. If it is provided in this agreement that the amounts of electric energy and varhours, delivered at any point of delivery, and of the Integrated Demands for such electric energy, for any period,

shall be the amounts thereof determined by combining deliveries at two or more metering points coincidentally:

(a) the amounts of electric energy and varhours so delivered at such point of delivery during such period shall be the sums computed by adding together the amounts of electric energy and varhours, respectively, which flow during such period at such metering points, determined as provided in this agreement; and

(b) the amount of each Integrated Demand for such electric energy at such point of delivery shall be the sum computed by adding together the Integrated Demands for such hour at such metering points, determined as provided in this agreement.

11. Suspension of Deliveries. The other party to this agreement may at any time notify the Transferor in writing to suspend the deliveries of electric power and energy provided for in this agreement. Upon receipt of any such notice, the Transferor will forthwith discontinue, and will not resume, such deliveries until notified to do so by the other party, and upon receipt of such notice from the other party to do so, will forthwith resume such deliveries.

12. Continuity of Service. The Transferor may temporarily interrupt or reduce deliveries of electric power and energy to the Transferee if he determines that such interruption or reduction is necessary or desirable in case of system emergencies, Uncontrollable Forces, or in order to install equipment in, make repairs, replacements, investigations, and inspections of, or perform other maintenance work on, the Transferor's System. Except in case of emergency and in order that the Transferee's operations will not be unreasonably interfered with, the Transferor will give the Transferee advance notice of any such interruption or reduction, the reason therefor, and the probable duration thereof.

13. Uncontrollable Forces.

(a) Each party shall notify the other as soon as possible of any Uncontrollable Forces which may in any way affect the delivery of power hereunder. In the event the operations of either party are interrupted or curtailed due to such Uncontrollable Forces, such party shall exercise due diligence to reinstate such operations with reasonable dispatch.

(b) The term "Uncontrollable Forces" means:

(1) Strikes affecting the operation of either party's System or other Facilities upon which such operation is completely dependent; or

(2) Such of the following events as either party, by exercise of reasonable diligence and foresight, could not reasonably have been expected to avoid:

(i) Events, reasonably beyond the control of the party having jurisdiction thereof, causing failure, damage, or destruction of any such system or facilities. The word "failure" shall be deemed to include interruption of, or interference with, the actual operation of such System or Facilities; or

(ii) Floods which limit or prevent the operation of, or which constitute an imminent threat of damage to, any such system or facilities.

14. Reducing Charges for Interruptions. If deliveries of electric power and energy to the Transferee are suspended, interrupted, interfered with or curtailed due to Uncontrollable Forces, as defined in section 13 hereof, on either the Transferee's System or Transferor's System, or if the Transferor interrupts or reduces deliveries to the Transferee for any of the reasons stated in section 12 hereof, the credit in the exchange energy account which would otherwise be made, or the money compensation which would otherwise be paid, to the Transferor shall be appropriately reduced. No interruption, or equivalent interruption, of less than 30 minutes duration will be considered for computation of such reduction in charges.

15. Net Billing. Payments due one party may be offset against payments due the other party under all contracts between the parties hereto for the sale and exchange of electric power and energy, use of transmission facilities, operation and maintenance of electric facilities, lease of electric facilities, mutual supply of emergency and standby electric power and energy, and under such other contracts between such parties as the parties may agree. Under contracts included in this procedure all payments due one party in any month shall be offset against payments due the other party in such month, and the resulting net balance shall be paid to the party in whose favor such balance exists unless the latter elects to have such balance carried forward to be added to the payments due it in a succeeding month.

16. Power Factor.

(a) The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{\sqrt{(\text{Kilowatthours})^2 + (\text{Reactive Kilovolt-ampere-hours})^2}}$$

In applying the above formula, the meter for measurement of reactive kilovolt-ampere-hours will be ratcheted to prevent reverse registration.

(b) When delivery of electric power and energy by the Transferor at any point is commingled with any other class or classes of power and it is impracticable to separately meter the kilowatthours and reactive kilovolt-ampere-hours for each class, the average power factor of the total delivery of such electric power and energy for the month will be used, where applicable, as the power factor for each of the separate classes.

(c) Except as it is otherwise specifically provided in this agreement, no adjustment will be made for power factor at any point of delivery described in this agreement while the varhours delivered at such point are not measured.

(d) The Transferor may, but shall not be obligated to, deliver electric energy hereunder at a power factor of less than 0.85 lagging.

17. Permits.

(a) If by the terms of any contract between the parties any equipment or facilities of a party to this agreement are, or are to be, located on the property of the other at any point of delivery provided in this agreement, a permit to install, test, maintain, inspect, replace, repair, and operate during the term of this agreement and to remove such equipment and facilities at the expiration of said term, together with the right of ingress to and egress from the location thereof at all reasonable times in such term is hereby granted by the other party.

(b) Each party shall have the right to read, at all reasonable times, any and all meters mentioned in this agreement which are installed on the property of the other.

(c) If by the terms of any contract between the parties either party is required or permitted to install, test, maintain, inspect, replace, repair, remove, or operate equipment on the property of the other, the owner of such property shall furnish the other party accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other party of any subsequent modifications which may affect the duties of the other party in regard to such equipment, and furnish the other party accurate revised drawings, if possible.

18. Ownership of Facilities.

(a) Except as otherwise expressly provided, ownership of any and all equipment, and of all salvable facilities installed by a party to this agreement on the property of the other party shall be and remain in the installing party.

(b) Each party shall identify all movable equipment and, to the extent agreed upon by the parties, all other salvable facilities which are installed by such party on the property of the other. Within a reasonable time subsequent to initial installation, and subsequent to any modification of such installation, representatives of the parties shall jointly prepare an itemized list of said movable equipment and facilities.

19. Adjustment for Change of Conditions. If changes in conditions hereafter occur which substantially affect any factor required by this agreement to be used in determining (a) any credit in any exchange energy account to be made, money compensation to be paid, or amount of electric power and energy to be made available to one party by the other party, or (b) any maximum replacement demand, or average power factor mentioned in this agreement, such factor will be changed in a manner which will conform to such changes of conditions. If an increase in the capacity of the facilities being used by the Transferor in making deliveries hereunder is required at any time after execution of this agreement to enable the Transferor to make the deliveries herein required together with those required for its own operations, the construction or installation of additional or other equipment or facilities for that purpose shall be deemed to be a change of conditions within the meaning of the preceding sentence.

If, pursuant to the terms of the agreement establishing such exchange energy account, another rate is substituted for the rate to be used in settling the balance in such account, the number of kilowatthours to be credited to the Transferor in such account for each month as provided in this agreement, shall be changed for each month thereafter to the amount computed by multiplying such number of kilowatthours by 2.5 mills and dividing the resulting product by the currently effective substituted rate in mills per kilowatthour.

20. Arbitration. If the parties do not agree on the determination of any question of fact hereinafter stated, such determination will be made by arbitration. The party calling for arbitration shall serve notice in writing on the other party, setting forth in detail the question or questions to be arbitrated and the arbitrator appointed by such party. The other party shall, within ten days after the receipt of such notice, appoint a second arbitrator, and the two so appointed shall choose and appoint a third. In case such other party fails to appoint an arbitrator within said ten days, or in case the two so appointed fail for ten days to agree upon and appoint a third, the party calling for the arbitration, upon five days' written notice delivered to the other party, shall apply to the person who at the time shall be the presiding judge of the United States Court of Appeals for the Ninth Circuit for appointment of the second or third arbitrator, as the case may be.

The determination of the question or questions submitted for arbitration shall be made by a majority of the arbitrators, and shall be binding on the parties. Each party shall pay for the services and expenses of the arbitrator appointed by or for it, and all other costs incurred in connection with the arbitration shall be paid equally by the parties thereto.

The questions of fact to be determined as provided in this section shall be: (a) the determination of the measurements to be made by the parties hereto pursuant to section 4 hereof; (b) the correction of the measurements to be made as provided in section 7 hereof; (c) the amount of reduction in charges mentioned in section 14 hereof; (d) the duration of the interruption or equivalent interruption mentioned in section 14 hereof; (e) whether changes in conditions mentioned in section 19 hereof have occurred, and if so, the change to be made in the factor mentioned; (f) whether an increase or decrease in load or change in load factor mentioned in section 31 hereof is unusual; (g) any fact mentioned in sections 29 and 33 hereof; (h) whether an abnormal nonrecurring demand occurred and the amount and time thereof; (i) and the acceptable level of harmonics mentioned in section 34 hereof.

21. Contract Work Hours and Safety Standards. This agreement, to the extent that it is of a character specified in the Contract Work Hours and Safety Standards Act (40 U.S.C. 327-333), is subject to the following provisions and to all other applicable provisions and exceptions of such Act and the regulations of the Secretary of Labor thereunder.

(a) Overtime requirements. No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers, mechanics, apprentices, trainees, watchmen, and guards shall require or permit any laborer, mechanic, apprentice, trainee, watchman or guard in any workweek in which he is employed on such work to work in excess of eight hours in any calendar day or in excess of 40 hours in such workweek on work subject to the provisions of the Contract Work Hours and Safety Standards Act unless such laborer, mechanic, apprentice, trainee, watchman, or guard receives compensation at a rate not less than one and one-half times his basic rate of pay for all such hours worked in excess of eight hours in any calendar day or in excess of 40 hours in such workweek, whichever is the greater number of overtime hours.

(b) Violation; liability for unpaid wages; liquidation of damages. In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible therefor shall be liable to any affected employee for his unpaid wages. In addition, such Contractor and subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer, mechanic, apprentice, trainee, watchman, or guard employed in violation of the provisions of subsection (a) in the sum of $10 for each calendar day on which such employee was required or permitted to be employed on such work in excess of eight hours or in excess of his standard workweek of 40 years without payment of the overtime wages required by subsection (a).

(c) Withholding for unpaid wages and liquidated damages. The Administrator may withhold from the Government Prime Contractor, from any moneys payable on account of work performed by the Contractor or subcontractor, such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for unpaid wages and liquidated damages as provided in the provisions of subsection (b) above.

(d) Subcontracts. The Contractor shall insert subsections (a) through (d) of this section in all subcontracts, and shall require their inclusion in all subcontracts of any tier.

(e) Records. The Contractor shall maintain payroll records containing the information specified in 29 CFR 516.2(a). Such records shall be preserved for three years from the completion of the contract.

22. Convict Labor. In connection with the performance of work under this contract, the Contractor agrees not to employ any person undergoing sentence of imprisonment except as provided by Public Law 89-176, September 10, 1965 (18 U.S.C. 4082(c)(2)) and Executive Order 11755, December 29, 1973.

23. Equal Employment Opportunity. (The following clause is applicable unless this agreement is exempt under the rules, regulations and relevant orders of the Secretary of Labor [41 CFR, ch. 60].)

During the performance of this agreement, the Contractor agrees as follows:

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by the Administrator setting forth the provisions of this Equal Opportunity clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which he has a collective bargaining agreement or other contract or understanding, a notice, to be provided by the Administrator, advising the labor union or workers' representative of the Contractor's commitments under this Equal Opportunity clause and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractdor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and by the rules, regulations, and orders of the Secretary of Labor, or pursuant thereto, and will permit access to his books, records, and accounts by the Administrator and the Secretary of Labor for purposes of investigation to ascertain compliance with such rules, regulations and orders.

(f) In the event of the Contractor's noncompliance with the Equal Opportunity clause of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(g) The Contractor will include the provisions of paragraphs (a) through (g) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as the Administrator may direct as a means of enforcing such provisions, including sanctions for noncompliance; <u>provided, however</u>, that in the event the Contractor becomes involved in, or is threatened <u>with</u>, litigation with a subcontractor or vendor as a result of such direction by the Administrator, the Contractor may request the United States to enter into such litigation to protect the interests of the United States.

24. Reports. The other party to this agreement will furnish the Administrator such information as is necessary for making any computation required for the purposes of this agreement, and the parties will cooperate in exchanging such additional information as may be reasonably useful for their respective operations.

25. Assignment of Agreement. This agreement shall inure to the benefit of, and shall be binding upon the respective successors and assigns of the parties to this agreement; provided, however, that neither such agreement nor any interest therein shall be transferred or assigned by either party to any party other than the United States or an agency thereof without the written consent of the other; provided, further, that the consent of the Administrator is hereby given to any security assignment which may be required under terms of any mortgage, trust, or security agreement made by and between the Utility and any mortgage, trustee, or secured party, as security for bonds or other indebtedness of such Utility, present or future; such mortgagee, trustee, or secured party may realize upon such security in foreclosure or other suitable proceedings, and succeed to all right, title, and interests of such Utility.

26. Waiver of Default. Any waiver at any time by any party to this agreement of its rights with respect to any default of any other party thereto, or with respect to any other matter arising in connection with such agreement, shall not be considered a waiver with respect to any subsequent default or matter.

27. Notices and Computation of Time. Any notice required by this agreement to be given to any party shall be effective when it is received by such party, and in computing any period of time from such notice, such period shall commence at 2400 hours on the date of receipt of such notice.

28. Interest of Member of Congress. No Member of, or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this agreement or to any benefit that may arise therefrom, but this provision shall not be construed to extend to this agreement if made with a corporation for its general benefit.

APPLICABLE ONLY IF TRANSFEREE IS A PARTY TO THIS AGREEMENT

29. Balancing Phase Demands. The Administrator may, at any time during the term of this agreement, require the Transferee to make such changes as are necessary on its system to balance the phase currents at any point of delivery so that the current on any one phase shall not exceed the current on any other phase at such point by more than ten percent.

30. Adjustment for Unbalanced Phase Demands. If the Transferee fails to make promptly the changes mentioned in section 29 hereof, the Administrator, at the Transferee's expense, may determine, for each month thereafter until such changes are made, that the registered demand of the Transferee at the point of delivery in question is equal to the product obtained by multiplying by three the largest of the Integrated Demands of the Transferee on any phase at such point during such month. This section shall not apply with respect to any point of delivery where the current required to be supplied at such point is other than three-phase current.

31. Changes in Demands or Characteristics. The Transferee will, whenever possible, give reasonable notice to the Administrator of any unusual increase or decrease of its demands for electric power and energy on the Transferor's system, or of any unusual change in the load factor or power factor at which the Transferee will take delivery of electric power and energy under this contract.

32. Inspection of Transferee's Facilities. The Administrator may, but shall not be obligated to, inspect the Transferee's electric installation at any time, but such inspection, or failure to inspect, shall not render the Government, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this agreement. The Administrator shall observe written operating instructions posted in facilities and such other necessary instructions or standards for inspection as the parties agree to. Only those electric installations used in complying with the terms of this contract shall be subject to inspection.

33. Electric Disturbances.

(a) Each party shall design, construct, operate, maintain and use its electric system in conformance with accepted utility practices:

(1) to minimize electric disturbances such as, but not limited to, the abnormal flow of power which may damage or interfere with the electric system of the other party or any electric system connected with such other party's electric system; and

(2) to minimize the effect on its electric system and on its customers of electric disturbances originating on its own or another electric system.

(b) If both parties to this agreement are parties to the Agreement Limiting Liability Among Western Interconnected Systems, their relationship with respect to system damages shall be governed by that Agreement.

(c) During such time as a party to this agreement is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, its relations with the other party with respect to system damages shall be governed by the following sentence, notwithstanding the fact that the other party may be a party to said Agreement Limiting Liability Among Western Interconnected Systems. A party to this agreement shall not be liable to the other party for damage to the other party's system or facilities caused by an electric disturbance on the first party's system, whether or not such electric disturbance is the result of negligence by the first party, if the other party has failed to fulfill its obligations under subsection (a)(2) above.

(d) If one of the parties to this agreement is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, each party to this agreement shall hold harmless and indemnify the other party, its officers and employees, from any claims for loss, injury, or damage suffered by those to whom the first party delivers power not for resale, which loss, injury or damage is caused by an electric disturbance on the other party's system, whether or not such electric disturbance results from the negligence of such other party, if such first party has failed to fulfill its obligations under subsection (a)(2) above, and such failure contributed to the loss, injury or damage.

(e) Nothing in this section shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a party to this agreement.

34. Harmonic Control. Each party shall design, construct, operate, maintain, and use its electric system in accordance with good engineering practices to minimize to acceptable levels the production of harmonic currents and voltages injected or coupled into the other party's facilities.

APPLICABLE ONLY IF TRANSFEREE IS NOT A PARTY TO THIS AGREEMENT

35. Protection of the Transferor. Protection is or will be afforded to the Government or its Transferor under such of the following provisions and conditions as are specified in each contract executed or to be executed by the Administrator and each third party Transferee named in this agreement: the power factor clause of the applicable Bonneville Wholesale Rate Schedule and the subject matter set forth in the General Contract Provisions under the following titles, namely:

Adjustment for Unbalanced Phase Demands; Uncontrollable Forces; Continuity of Service; Changes in Demands or Characteristics; Electric Disturbances; Harmonic Control; Balancing Phase Demands; Permits; Ownership of Facilities; and Inspection of Purchaser's Facilities.

RELATING ONLY TO RURAL ELECTRIFICATION ADMINISTRATION BORROWERS

36. Approval of Agreement. This agreement shall not be binding on the parties thereto if it is not hereafter approved by the Administrator of the Rural Electrification Administration and any other entity from whom the Borrower borrows under an indenture which requires the lender's approval; provided, however, that the Borrower shall notify the Administrator of any such entity prior to the Administrator's execution of this agreement. If so approved it shall be effective at the time stated in the section of this agreement entitled "Term of Agreement."

APPLICABLE ONLY IF THE ADMINISTRATOR IS THE TRANSFEROR

37. Equitable Adjustment of Rates.

(a) As used in this section, the words "Rate Adjustment Date" shall mean any date designated by the Administrator after the date a new rate schedule is available for the class, quality, and type of service covered by this agreement; provided, however, that a Rate Adjustment Date shall not occur more frequently than once in any 12-month period. The Administrator may file with the Federal Power Commission or its successor for approval of a revised or new rate when he determines such revised or new rate is necessary to reflect the cost of the class, quality, and type of service covered by this agreement. The Administrator shall provide the Transferee with his then proposed schedule or schedules, supporting data, and a statement reflecting the effects of the proposed schedule or schedules on the charges specified in this agreement no less than 90 days prior to filing a proposed schedule or schedules with the Federal Power Commission or its successor, unless shorter periods are agreed upon by the parties hereto. The rate schedule in effect under this agreement on the Rate Adjustment Date shall continue in effect until the next Rate Adjustment Date on which revised or new rate schedules shall have been proposed by the Administrator and confirmed and approved by the Federal Power Commission or its successor.

(b) The Transferee shall pay the Administrator for the service made available under this agreement during the period commencing on each Rate Adjustment Date and ending at the beginning of the next Rate Adjustment Date at the rate specified in any rate schedule available at the beginning of such period which would be incorporated in a new agreement for service of the class, quality, and type provided for in this agreement, and in accordance with the terms hereof and of the General Transmission Rate Schedule Provisions incorporated or referred to in such rate schedule. If at the beginning of such period more than one rate is available for the class, quality, and type of service covered by this agreement, the Transferee shall, prior to 30 days after the later of the effective date of such rate or the date of approval of such rate by the Federal Power Commission or its successor, notify the Administrator in writing which of such rates the Transferee elects to have applied under this agreement during such period. If the Transferee fails to make such election, the Administrator shall determine the applicable rate. Such election by the Transferee or determination by the Administrator shall be applied as of the beginning of the first billing month following the effective date of such rate.

EXHIBIT B

Conditionally Approved
6-10-77

GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS

1. DEFINITIONS: Capitalized terms that are used in the Transmission Rate Schedules shall be as defined below, or, if not so defined, as defined in the Agreement.

   (a) Agreement means the transmission agreement to which this exhibit is attached.

   (b) Annual Cost means the cost to the Government for the operation, maintenance and amortization of the Federal Transmission System facilities, or any applicable portion thereof, with interest, including an appropriate share of the general plant and administrative and general costs.

   (c) Annual Cost Ratio means the annual cost of the Federal Transmission System, or any applicable portion thereof, divided by the investment in such system or portion thereof.

   (d) Capacity means the load carrying capability of a transmission facility determined by use of general utility standards adopted by the Administrator for the purpose of calculating a use-of-facilities charge.

   (e) Capacity Factor means the decimal fraction determined by dividing the average peak load carried by all comparable segments of the Federal Transmission System during the most recent heavy load periods, by the sum of their related Capacities.

   (f) Federal Transmission System. The words Federal Transmission System or Federal Transmission System facilities mean the transmission facilities of the Federal Columbia River Power System, which for the purpose of these rate schedules are deemed to include the transmission facilities owned by the Government and operated by the Administrator, and other facilities which the Administrator uses under lease, easement, license, or exclusive use-of-facilities charge.

   (g) Industrial Customer means a manufacturing firm which is being supplied electric power and energy under a power sales contract with the Administrator.

   (h) Industrial Delivery means the transformation and Terminal Facilities located at a Point of Delivery to an Industrial Customer.

   (i) Intertie means the Government's share of the 500 kV a-c and 800 kV d-c Pacific Northwest-Pacific Southwest transmission facilities extending from the vicinity of the Government's John Day and The Dalles substations to the Oregon-California and Oregon-Nevada borders, respectively.

(j) Main Grid means that portion of the Federal Transmission System rated 230 kV and higher, exclusive of the Intertie.

(k) Main Grid Delivery Terminal means 230 kV Terminal Facilities associated with a Point of Delivery.

(l) Main Grid Distance means the distance in airline miles on the Main Grid between the Point of Interconnection and the Point of Delivery, multiplied by 1.15.

(m) Main Grid Interconnection Terminal means the Main Grid Terminal Facilities located at the Point of Interconnection.

(n) Main Grid Miscellaneous Facilities means switching, transformation and other backup facilities of the Main Grid required to integrate the Main Grid.

(o) Main Grid Terminal means Terminal Facilities on the Main Grid adjacent to the Secondary System.

(p) Point of Delivery and Point of Interconnection mean such point or points as are specified in the Agreement.

(q) Replacement Energy means non-Federal energy acquired for another entity by the Administrator for delivery in lieu of Federal nonfirm energy which has been restricted.

(r) Secondary System means that portion of the Federal Transmission System facilities exclusive of Main Grid facilities, Intertie facilities, and lower voltage Federal Transmission System facilities which may be used on a use-of-facility basis.

(s) Secondary System Delivery Terminal means a Point of Delivery from a Main Grid substation at 115 kV, or a terminal located at a Point of Delivery from the Secondary System.

(t) Secondary System Distance means the number of circuit miles of Secondary System transmission line between the Main Grid and the Point of Delivery or the lower voltage Federal Transmission System facilities which may be used on a use-of-facility basis, as specified in the Agreement.

(u) Secondary System Interconnection Terminal means the first Terminal Facility in the Secondary System.

(v) Secondary System Intermediate Terminal means the final Terminal Facilities in the Secondary System.

(w) Secondary Transformation means transformation from Main Grid to Secondary System facilities.

(x) Terminal Facilities means Federal Transmission System facilities interconnecting a transmission line with a switching station or a substation, or such Federal facilities interconnecting with another entity's facilities at a Point of Delivery or a Point of Interconnection. Terminal Facilities normally consist of a power circuit breaker, associated protective equipment, and appurtenant structures.

2. TRANSMISSION CONTRACT DEMAND: The Transmission Contract Demand shall be the number of kilowatts specified in the Agreement for transmission over the Federal Transmission System facilities.

3. MEASURED DEMAND: The Measured Demand is the maximum Integrated Demand for a billing month determined from measurements made as specified in the Agreement or as determined in section 7 hereof when metering or other data are not available for such purpose. The Administrator, in determining the Measured Demand, will exclude any abnormal Integrated Demands due to, or resulting from (a) emergencies or breakdowns on, or maintenance of, the Federal Transmission System facilities, and (b) emergencies on facilities of the Transferee, provided that such facilities have been adequately maintained and prudently operated as determined by the Administrator.

If the Agreement provides for delivery of more than one class of power to the Transferee at any Point of Delivery, the portion of each Integrated Demand assigned to any class of power shall be determined as specified in the Agreement. The portion of the Integrated Demand so assigned shall constitute the Measured Demand for such class of power.

4. SCHEDULED DEMAND: The Scheduled Demand is the maximum hourly demand, in kilowatts, at which electric power and energy is scheduled by the Transferee to the Administrator for transmission under the terms of the Agreement.

5. AVERAGE POWER FACTOR: The formula for determining Average Power Factor (Power Factor) is as follows:

$$\text{Power Factor} = \frac{\text{Kilowatthours}}{\sqrt{(\text{kilowatthours})^2 + (\text{Reactive kilovoltamperehours})^2}}$$

In applying the above formula, the meter for measurement of reactive kilovoltamperehours will be ratcheted to prevent reverse registration.

When a class of electric power and energy delivered by the Administrator at any point is commingled with any other class or classes of power and it is impracticable to meter separately the kilowatthours and reactive kilovoltamperehours for each class, the Power Factor of the total delivery of such electric power and energy for the month will be used, where applicable, as the Power Factor for each of the separate classes.

Except as it is otherwise specifically provided in the Agreement, no adjustment will be made for Power Factor at any point of delivery described in the Agreement when the varhours delivered at such point are not measured.

6. BILLING MONTH: Bills for transmission service are normally computed at intervals of approximately 30 days, not always on a calendar month basis.

7. DETERMINATION OF ESTIMATED BILLING DATA: If the Integrated Demands for electric energy must be estimated from data other than metered or scheduled quantities, the Administrator and the Transferee will agree on billing data to be used in preparing the bill. If the parties cannot agree on the estimated billing quantities, a determination binding on both parties shall be made in accordance with the arbitration provisions of the Agreement.

8. PAYMENT OF BILLS: Bills for transmission service are rendered monthly and are payable at the Office of the Administrator. Failure to receive a bill does not release the Transferee from liability for payment. Billings under each rate schedule application are rounded to whole dollar amounts, by elimination of any amount of less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

If the Administrator is unable to render the Transferee a timely monthly bill which includes a full disclosure of all billing factors, he may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill. Such estimated bill, if so issued, has the validity of, and is subject to, the same payment provisions as a final bill.

Bills not paid in full on or before the close of business of the twentieth day after the date of the bill bear an additional charge which is the greater of one-fourth percent of the amount unpaid or $50. Thereafter, a charge of one-twentieth percent of the sum of the initial amount remaining unpaid and the additional charge herein described is added on each succeeding day until the amount due is paid in full. The provisions of this paragraph do not apply to bills rendered under contracts with other agencies of the United States.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the twentieth day after the date of the bill. If the twentieth day after the date of the bill is a Sunday or other nonbusiness day of the Transferee, the next following day is the last day on which payment may be made to avoid such further charges. Payment made by metered mail and received subsequent to the twentieth day must bear a postal department cancellation in order to avoid assessment of such further charges.

The Administrator may, whenever a transmission bill or a portion thereof remains unpaid subsequent to the twentieth day after the date of the bill, and after giving 30 days' advance notice in writing, cancel the Agreement, but such cancellation does not affect the Transferee's liability for any charges accrued prior thereto.

9. APPROVAL OF RATES: Schedules of rates and charges, or modifications thereof, for transmission of electric power and energy by the Administrator shall become effective only after confirmation and approval by the Federal Power Commission.

EXHIBIT C

Conditionally Approved
6-10-77

SCHEDULE UFT-1
Use-of-Facilities Transmission

Section 1. AVAILABILITY:

This schedule is available for the transmission of electric power and energy for another entity using specific Federal Transmission System facilities.

Section 2. RATES:

The monthly charge per kilowatt of Transmission Demand shall be one-twelfth of the Annual Cost per kilowatt of Capacity of the specific facilities. Such Annual Cost shall be determined in accordance with section 3.

Section 3. DETERMINATION OF TRANSMISSION RATE:

a. From time to time, but not more often than once in each Contract Year, the Administrator shall determine the following data for the facilities listed in the Agreement which have been constructed or otherwise acquired by the Administrator and are used to transmit electric power and energy thereunder:

(i) Capital cost of each segment of such facilities as specified in the most recently published plant investment records of the Administrator which are issued in support of the Federal Columbia River Power System financial statement certified by the Comptroller General.

(ii) Annual Cost Ratios for each segment of such facilities using the most recent system average cost factors developed from actual Annual Costs for specific categories of Federal Transmission System facilities and from data included in the financial statement certified by the Comptroller General.

(iii) The Capacity and Capacity Factor for each segment of such transmission facilities listed in the Agreement; provided, however, that the Capacity Factor shall in no event be less than 0.60.

b. The monthly charge per kilowatt of Transmission Demand shall be one-twelfth of the sum of the Annual Cost per kilowatt of each segment of the Federal Transmission System facilities listed in the Agreement. The Annual Cost per kilowatt of each segment of facilities constructed or otherwise acquired by the Administrator shall be determined in accordance with the following formula:

$$\frac{I \times R}{Ca \times Cf}$$

where I = capital cost of such segment

R = Annual Cost Ratio for each such segment

Ca = Capacity of the facility in kilowatts

Cf = Capacity Factor

The Annual Cost per kilowatt of facilities listed in the Agreement which are owned by another entity, and used by the Administrator for making deliveries to the Transferee, shall be determined from the costs specified in the agreement between the Administrator and such other entity.

Section 4. DETERMINATION OF TRANSMISSION DEMAND:

Unless otherwise stated in the Agreement, the factor to be used in determining the kilowatts of Transmission Demand shall be the largest of:

a. the Transmission Contract Demand;
b. the highest Measured or Scheduled Demand for the month, the Measured Demand being adjusted for power factor; or
c. the highest Measured or Scheduled Demand during the previous 11 months.

Section 5. ADJUSTMENT FOR CONDITIONS:

The Agreement shall list the specific facilities used to transmit power hereunder. If a Point of Delivery specified in the Agreement is served from more than one Point of Interconnection using separate Federal Transmission System facilities, or over parallel Federal Transmission System facilities, the facilities listed in the Agreement for use in determining the application of this rate schedule shall include all such facilities.

Section 6. POWER FACTOR ADJUSTMENT:

Except as hereinafter provided, the adjustment for Power Factor wherever specified in this rate schedule shall be made by increasing the Measured Demand for each month by one percent for each one percent or major fraction thereof by which the average lagging Power Factor at which energy is delivered during such month is less than 95 percent.

The Administrator may, if he considers it desirable, determine the average leading Power Factor. If leading Power Factor as well as lagging Power Factor is determined, the adjustment for Power Factor shall be made by increasing the Measured Demand for the month by one percent for each one percent or major fraction thereof by which the average lagging or the average leading Power Factor is less than 95 percent, whichever results in the larger adjustment.

The adjustment for Power Factor may be waived in whole or in part to the extent that the Administrator determines that an average Power Factor of less than 95 percent lagging or 95 percent leading would in any particular case be beneficial to the Federal Transmission System. Unless specifically otherwise agreed, the Administrator may, if necessary to maintain acceptable operating conditions on the Federal Transmission System, restrict deliveries of electric power and energy to the Transferee at a Point of Delivery or for a system at any time that the Power Factor for all classes of electric power and energy delivered to the Transferee at such Point of Delivery or from the Federal Transmission System is below 85 percent lagging or 85 percent leading.

Section 7. GENERAL PROVISIONS:

Services provided under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, the Federal Columbia River Transmission System Act, and to the General Transmission Rate Schedule Provisions. The meaning of terms used in this rate schedule shall be as defined in the General Transmission Rate Schedule Provisions attached to the Agreement.

EXHIBIT D

Conditionally Approved
6-10-77

SCHEDULE FPT-1
Formula Power Transmission

Section 1. AVAILABILITY:

This schedule is available under agreements which provide for the firm transmission of electric power and energy for another entity using unspecified portions of the Federal Transmission System.

Section 2. RATE:

The monthly charge per kilowatt of Transmission Demand shall be one-twelfth of the sum of the Main Grid Charge, the Secondary System Charge and Intertie Charge, as applicable and as specified in the Agreement.

a. Main Grid Charge. The Main Grid Charge shall be the sum of the following factors:

(1) Main Grid Distance Factor - The amount computed by multiplying the Main Grid Distance by $0.0135 per mile;

(2) Main Grid Interconnection Terminal Factor - $0.14;

(3) Main Grid Miscellaneous Facilities Factor - $0.58;

(4) Main Grid Terminal Factor - $0.14; and

(5) Main Grid Delivery Terminal Factor - $0.09.

b. Secondary System Charge. The Secondary System Charge shall be one of the following factors or combinations thereof:

(1) Industrial Delivery Factor - $1.49; and

(2) 115 kV and below Delivery Factor - which shall be the sum of the following applicable charges:

(i) Secondary Transformation Factor - $0.90;

(ii) Secondary System Interconnection Terminal Factor - $0.20;

(iii) Secondary System Distance Factor - The amount determined by multiplying the Secondary System Distance by $0.0360 per mile;

(iv) Secondary System Intermediate Terminal Factor - $0.20;

(v) Secondary System Delivery Terminal Factor - $0.12; and

(vi) Low Voltage Facilities Factor - The Federal Transmission System facilities used at less than 115 kV, calculated in the manner provided under Transmission Rate Schedule UFT-1.

c. Intertie Charge - for use of Intertie facilities - $2.50.

Section 3. DETERMINATION OF TRANSMISSION DEMAND:

Unless otherwise stated in the Agreement, the factor to be used in determining the kilowatts of Transmission Demand is the largest of:

a. the Transmission Contract Demand;

b. the highest Measured or Scheduled Demand for the month; or

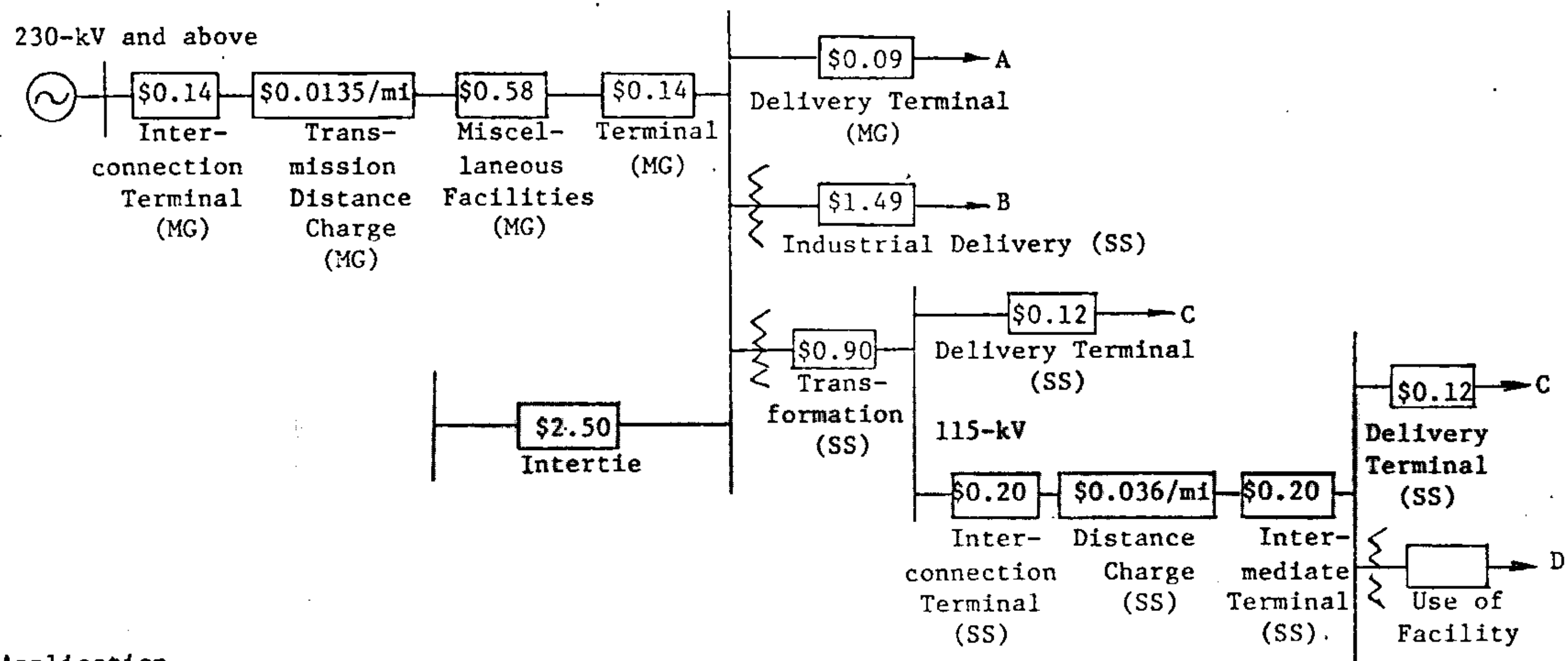
c. the highest Measured or Scheduled Demand during the previous 11 months.

Section 4. GENERAL PROVISIONS:

Services provided under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended; the Federal Columbia River Transmission System Act; and to the General Transmission Rate Schedule Provisions. The meaning of terms used in this rate schedule shall be as defined in the General Transmission Rate Schedule Provisions attached to the Agreement.

The attached diagram is representative of the components of this rate schedule, as related to the Federal Transmission System.

BONNEVILLE POWER ADMINISTRATION STANDARD WHEELING FORMULA DIAGRAM
(Charges per Kilowatt-year)



<u>Application</u>

1. Main Grid distance in airline miles from Main Grid Interconnection to Main Grid terminal multiplied by 1.15. Actual circuit miles apply to secondary system distance.

2. Type of wheeling customer
   - A. Delivery at 230-kV or above.
   - B. Industrial load.
   - C. 115-kV delivery at Main Grid Sub. or 115-kV delivery off secondary system.
   - D. Low voltage delivery by use of facility.

MG means Main Grid.
SS means Secondary System.

Branch of Customer Service
5-4-76

Points of Delivery for Bonneville's Customers

BONNEVILLE CUSTOMER: SERVICE

1. FOSTER CREEK POINT OF DELIVERY:

   Location: in the District's Foster Creek substation where its 13.8 kV distribution facilities are connected;

   Voltage: 13.8 kV;

   Metering: at the Bridgeport Bar metering point as described in the Memorandum;

   Adjustment: for losses between points of metering and delivery.

2. HANNA POINT OF DELIVERY:

   Location: in the District's Hanna substation where the 13.8 kV facilities of the District and the Service are connected;

   Voltage: 13.8 kV;

   Metering: at the point of delivery.

3. ORONDO POINT OF DELIVERY:

   Location: in the District's Orondo substation where its 34.5 kV facilities are connected;

   Voltage: 34.5 kV;

   Metering: at the Brays Landing metering point as described in the Memorandum;

   Adjustment: for losses between points of metering and delivery.

Points of Delivery for the District

1. COLUMBIA POINT OF DELIVERY:

Location: the point in the Government's Columbia substation where the 13.8 kV facilities of the parties hereto are connected;

Voltage: 13.8 kV;

Metering: in the Government's Columbia substation, in the 13.8 kV circuit over which such electric power and energy flows.

2. NILLES CORNER POINT OF DELIVERY:

Location: the point in the Government's Nilles Corner substation where the 13.8 kV facilities of the parties hereto are connected;

Voltage: 13.8 kV;

Metering: in the Government's Nilles Corner substation, in the 13.8 kV circuit over which such electric power and energy flows.

EXHIBIT G, Page 1 of 2
Contract No. DE-MS79-79BP90066
Douglas County PUD
Effective as of 2400 hours on the date of execution

Transfer Charges and Use of Facility Charges

Point of Delivery	Transferor	Transfer Charge ($/kW/Mo.)	Monthly Exclusive Use of Facilities Charge
Foster Creek	District	$0.536	--
Hanna	"	0.123	$ 643.00
Orondo	"	0.253	--
Columbia	Bonneville	0.098	1,880.00
Nilles Corner	Bonneville	0.037	1,221.00

EXHIBIT G, Page 2 of 2
Contract No. DE-MS79-79BP90066
Douglas County PUD
Effective as of 2400 hours on the
date of execution

Calculation of Transfer and Exclusive Use of Facility Charges

Facility	Schedule of Annual Charges	Applicable Annual Charges Per KW: Columbia 13.8 kV (Columbia 230 kV)	Applicable Annual Charges Per KW: Nilles Corner (Foster Creek)
Main Grid			
Delivery Terminal	$0.09		
Interconnect Terminal	0.14		
Transmission Distance 1/	0.0135/mi		
Miscellaneous	0.58		
Terminal	0.14		
Delivery Terminal	0.09		
Secondary System			
Transformation	0.90		
Delivery Terminal	0.12	0.12	
Interconnect Terminal	0.20	0.20	
Transmission Distance 1/ (Mileage)	0.036/mi	0.86 3/ (15.9 mi.)	0.447 (12.42 mi.)
Intermediate Terminal	0.20		
Delivery Terminal	0.12		
Low Voltage Facilities	2/		
Total Annual Charge	$/kW-Yr.	$1.18	$0.447
	$/kW-Mo.	0.098	0.037
Exclusive Use Charge	$/Yr.	$22,554.00	$14,646.00
	$/Mo.	1,880.00	1,221.00

1/ at Airline Miles + 15%
2/ Calculated Per UFT-1 Rate Schedule
3/ Eastmont-Valhalla, 10.7 miles at UFT-1 Rate Schedule
Valhalla-Columbia, 5.2 miles of FPT-1 Rate Schedule

0085A

Contract No. DE-MS79-82BP90049

5-3-82

GENERAL TRANSFER AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFIC POWER & LIGHT COMPANY

Index to Sections

This GENERAL TRANSFER AGREEMENT, executed May 4, 1982, by the UNITED STATES OF AMERICA (Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and PACIFIC POWER & LIGHT COMPANY (Company), a corporation of the State of Maine,

W I T N E S S E T H :

WHEREAS Bonneville and the entities named in Exhibit B (Bonneville's Customers) have entered into power sales contracts providing for the delivery of firm power and energy to such customers at various points of delivery in part by transfer over Company facilities; and

WHEREAS the parties hereto have executed agreements which provide that Bonneville or the Company, as the case may be, transfer electric power and energy to the Company or Bonneville's Customers at various points of delivery described in Exhibits B and C and now desire to replace such agreements in accordance with a letter agreement (Contract No. DE-MS79-82BP90924), with a single agreement; and

WHEREAS the parties, on August 9, 1973, executed an exchange agreement (Contract No. 14-03-29245, which as amended or replaced is called "Exchange Agreement") providing, among other matters, for an exchange energy account (Exchange Account), measurement and scheduling arrangements, and points of delivery; and

WHEREAS the parties hereto have agreed to a reciprocal transfer service philosophy which is recognized in this agreement and to consolidate and add various provisions to allow more frequent review of charges and loss factors in a manner consistent with the review of transmission rate schedules; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. Termination of Agreements. Contract No. 14-03-001-10010, as amended, Contract No. 14-03-001-10662, as amended, Contract No. 14-03-001-11343, as amended, Contract No. 14-03-001-11477, as amended, Contract No. 14-03-001-13386, as amended, Contract No. 14-03-001-13395, Contract No. 14-03-001-14609, Contract No. 14-03-17532, as amended, Contract No. 14-03-37030, Contract No. 14-03-47929, as amended, Contract No. 14-03-56743, as amended, Contract No. 14-03-75629, Contract No. 14-03-77652, Contract No. 14-03-84718, Contract No. 14-03-86605, as amended, Contract No. 14-03-86620, as amended, and Contract No. DE-MS79-79BP90043 are hereby terminated as of the effective date hereof, but all liabilities accrued thereunder shall be and are hereby preserved until satisfied.

2. Term of Agreement. This agreement shall be effective at 2400 hours on the date of execution, and shall terminate on the earlier of the following:

(a) 2400 hours on the date of termination of the Exchange Agreement, or

(b) the time of the termination of all deliveries hereunder.

3. Exhibits. Exhibits A through H are made a part of this agreement. The Company shall be the "Transferor" as that term is used in Exhibit A when transferring electric power and energy to Bonneville's Customers or Bonneville, as the case may be, at points of delivery specified in Exhibit B, and each of Bonneville's Customers or Bonneville, as the case may be, shall be the "Transferee" mentioned therein. Bonneville shall be the "Transferor" as that term is used in Exhibit A when transferring electric power and energy to the Company at points of delivery specified in Exhibit C, and the Company shall be the "Transferee" mentioned therein. All references to "the Administrator" in such exhibits are changed to "Bonneville."

4. Revision of Exhibits.

(a) Exhibits B, C, D, and H shall be revised at:

(1) any time by mutual agreement of the parties to add or remove points of delivery;

(2) the time specified by the party receiving transfer service in a written notice to the Transferor to remove any point of delivery specified in Exhibits B or C, as the case may be, but not before the expiration of 1 year from 2400 hours on the date notice is received by the Transferor; or

(3) the time specified by the Transferor in a written notice to the party receiving transfer service to remove any point of delivery in the situation where the facilities used to perform the transfer service are surplus to the needs of the Transferor, but not before the expiration of 3 years from 2400 hours on the date such notice is received by the party receiving transfer service.

(b) Exhibit F contains the methodology for calculating Transfer Charges and Sole Use of Facility Charges listed in Exhibit D and shall be used by both parties. This methodology is an application of Bonneville's UFT-2 rate schedule. The UFT-2 rate schedule is included as a part of Exhibit G. Any change to the methodology described in Exhibit F shall require mutual approval of the parties; however such methodology shall be periodically reviewed by the parties upon the request of either party to consider modifications. Such modifications shall not be allowed more often than once in each 3-year period and shall be applicable to both parties. The values of the variables I, R, and D used in the methodology are expected to change from time to time and such changes shall not be deemed to be a change in the methodology. Bonneville waives its right to unilaterally change its rates provided in Exhibit F pursuant to section 37 of Exhibit A, Equitable Adjustment of Rates Section, insofar as it applies to this contract.

(c) The charges and Loss Factors specified in Exhibit D and factors in Exhibit H shall be revised pursuant to section 19 of Exhibit A, Adjustment for Change of Conditions Section, upon mutual agreement of the parties. The Transferor shall submit notice of such revision including justification for any such revision 90 days prior to the date the revision is requested to be effective. The party receiving transfer service shall review such information and shall not unreasonably withhold agreement to change the affected Exhibit. Any Loss Factor, Transfer Charge, or Sole Use of Facilities Charge shall be reviewed if requested by either party, but such review shall not be required more often than once in any 12-month period for any point of delivery; and if parameters used to calculate such factors or charges have changed, the parties shall not unreasonably withhold their agreement to change the affected Exhibits.

(d) Upon any change in methodology or charges pursuant to this section, the Transfer Charges and Sole Use of Facilities Charges specified in Exhibit D or any subsequent charges specified in this agreement shall be recalculated accordingly and the parties shall prepare a revised Exhibit D incorporating the new charges. A revised Exhibit D shall also be prepared to incorporate any change in Loss Factors pursuant to this section. Such revised Exhibit D shall be substituted for the Exhibit D then in effect and shall become effective as of the effective date of such new methodology or charges.

5. Provisions Relating to Delivery. Electric power and energy shall be made available by the Transferor at all times during the term hereof at the points of delivery described in Exhibits B and C, in the amount of the Transferee's requirements at such points and at the approximate voltages specified therefor. Amounts of electric energy, Integrated Demands therefor, and varhours delivered at such points during each month shall be determined from measurements made by meters installed at the locations and in the circuits specified in Exhibits B and C. Such amounts shall be increased for losses as determined by the parties hereto and specified in Exhibit D (Loss Factors). Such Loss Factors reflect all losses from the point of metering to the point of replacement specified in Exhibit B or C. Losses shall be determined on an incremental basis and the Transferee shall be assessed the incremental losses so determined. On or before July 1 of each year each party shall furnish the other party a five year forecast of the maximum demand for each of the points of delivery described in Exhibits B or C, as the case may be.

6. Replacement of Power Delivered. In exchange for electric power and energy delivered by the Transferor hereunder, the party receiving transfer service shall make electric power and energy available to the Transferor during each month in the term hereof, at the points of replacement specified in Exhibit B or C as the case may be. Such electric power and energy to be made available by the party receiving transfer service shall be computed by

increasing metered amounts, determined as provided in Exhibit B or C for each point of delivery, by the Loss Factors specified in Exhibit D.

The party receiving transfer service shall make available to the Transferor each hour in each month during the term hereof the amount of electric energy which is estimated to be the amount, so increased for losses, which the Transferor will deliver hereunder during such hour, and shall schedule such amount for delivery to the Transferor as provided in the Exchange Agreement.

7. Payment for Transfer of Power.

(a) For the use of Transferor services and facilities in transferring electric power and energy hereunder, the party receiving transfer service shall pay the Transferor each month in the term hereof an amount equal to the sum for all points of delivery of the greater of (1) or (2) below for each point of delivery:

(1) the product of the Transfer Charge for each point of delivery and the Transfer Demand for that month for such point of delivery after increasing such Transfer Demand by one percent for each one percent or major fraction thereof by which the average power factor, at which electric energy is delivered at the point of delivery hereunder during each month, is less than 95 percent lagging; or

(2) the largest product obtained by multiplying the Transfer Demand of each of the 11 immediately preceding months by the respective Transfer Charge for each such month.

(b) The "Transfer Charge" for each point of delivery mentioned in subsection (a) above shall be as shown in Exhibit D. Transfer Charges shall be determined pursuant to Exhibit F.

(c) The "Transfer Demand" mentioned in subsection (a) above shall be the largest of the Integrated Demands, increased by the Loss Factors specified in Exhibit D, at which electric energy is delivered by the Transferor hereunder during such month, determined as provided in Exhibits B or C, as the case may be, after eliminating all abnormal nonrecurring Integrated Demands resulting from emergency conditions.

(d) For determining power factor in subsection (a)(1) above, metered amounts shall be adjusted for losses between the point of metering and the point of delivery. These losses shall be calculated from factors contained in Exhibit H which are different from the Loss Factors contained in Exhibit D.

8. Payment for Sole Use of Facilities. In addition to the payment due the Transferor in accordance with section 7, the party receiving transfer service shall pay the Transferor each month the amounts specified in Exhibit D under "Sole Use of Facilities Charge" for sole use of facilities by the party receiving transfer service. Sole Use of Facilities Charges shall be determined pursuant to Exhibit F.

9. Payment of Bills.

(a) The Company shall reimburse Bonneville in accordance with applicable provisions of Exhibit E by cash payment or, upon mutual agreement of the parties, in accordance with the provisions of section 15 of Exhibit A, Net Billing Section.

(b) Bonneville shall reimburse the Company for services hereunder within 30 days following its receipt of an itemized statement of payments due pursuant to sections 7 and 8 hereof by cash payment or, upon mutual agreement of the parties, in accordance with the provisions of section 15 of Exhibit A, Net Billing Section. If the Company is unable to render Bonneville a timely monthly bill which includes a full disclosure of all billing factors, it may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill.

10. Removal of Existing Facilities, Termination of Charges, and Installation of Additional Facilities.

(a) The parties shall exchange any necessary data and confer from time to time to determine the necessity for removal of existing facilities and for installation of additional facilities to enable the parties to fulfill their obligations hereunder. If the parties cannot agree on the need for addition or removal of facilities, the Transferor shall make such determination. The Transferor agrees to provide additional facilities at the Transferor's expense as required to serve the combined load growth of both parties; provided, however, that the Transferee may provide such facilities at the Transferee's expense, subject to mutual agreement of the parties and appropriate credit to the Transferee, if the Transferee can do so at less total expense to both parties. Any facilities provided by the Transferee shall be compatible with the specifications of the Transferor. The cost and ownership of such new facilities shall be reflected in the next amendment of the charges contained in Exhibit D in accordance with the methodology contained in Exhibit F.

(b) Upon removing or installing facilities as determined in subsection (a) above, the parties shall include such revisions in this agreement, including the applicable contract terms and termination charges, if any, by executing new Exhibits B, C, or D, as appropriate. Such new exhibit shall replace the existing exhibit on the effective date specified therein.

(c) The party receiving transfer service shall pay the Transferor an appropriate mutually agreeable termination charge to the extent that the capacity of such facilities which were provided to enable the transfer service would be excess to the Transferor's needs as a consequence of any of the following:

(1) the parties agree to remove facilities pursuant to subsection (a) above;

(2) a point of delivery is terminated pursuant to section 4(a)(1) or 4(a)(2); or

(3) this agreement is terminated as provided in section 2.

(d) If additional facilities must be constructed or installed by either party pursuant to subsection (a) above, a reasonable period of time shall be allowed for such construction or installation.

11. Ratification of Interim Agreement. During the period commencing:

(a) July 1973 to July 1, 1981, the parties hereto have provided each other services as described in Exhibit G and the settlement therefor shall be as specified therein;

(b) July 1, 1981, to the effective date of this agreement, the parties hereto have provided each other services as described herein and in Exhibit G and payment therefor shall be as specified in Exhibit G, except that the points of delivery and charges contained in Attachment 1 to Exhibit G are hereby replaced by the points of delivery and charges contained in Exhibits B, C, and D hereto, effective as of the dates specified in such exhibits. Some of the services covered by the retroactive provisions of this section were also covered by provisions of contracts which are being terminated pursuant to section 1 hereof (Prior Contracts). In such cases, the provisions and charges contained herein shall supercede the provisions and charges of such Prior Contracts and any payments made for such services subsequent to June 30, 1981, pursuant to such Prior Contracts shall be credited against payments due hereunder for such services. All liabilities accrued pursuant to Exhibit G shall be and are hereby preserved until satisfied.

IN WITNESS WHEREOF, the parties hereto have executed this agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy

By /s/ Edward W. Sienkiewicz
Bonneville Assistant Adminstrator
for Power Management

PACIFIC POWER & LIGHT COMPANY

By /s/ R. B. Lisbakken

Title Vice President

Date May 4, 1982

ATTEST:

By /s/ R. A. Sampson

Title Assistant Secretary

Date May 4, 1982

(WP-PCI-1185c)

Exhibit B, Table 1
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
City of Ashland
Effective at 2400 hours on
February 27, 1982

Points of Delivery for Bonneville

1. ASHLAND POINT OF DELIVERY:

   Location: the point in the Company's Ashland Substation where the 12.5 kV facilities of the Company and the City of Ashland are connected;

   Voltage: 12.5 kV;

   Metering: in the Company's Ashland Substation, in the 12.5 kV circuit over which such electric power and energy flows;

   Point of Replacement: the point in the Government's Fairview Substation where the Government's Fairview-Reston 230 kV line terminates;

2. OAK KNOLL POINT OF DELIVERY:

   Location: the point in the Company's Oak Knoll Substation where the 12.5 kV facilities of the Company and the City of Ashland are connected;

   Voltage: 12.5 kV;

   Metering: in the Company's Oak Knoll Substation, in the 12.5 kV circuit over which such electric power and energy flows;

   Point of Replacement: the point in the Government's Fairview Substation where the Government's Fairview-Reston 230 kV line terminates.

Exhibit B, Table 2
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Benton Rural Electrification Association, Inc.
Effective at 2400 hours on June 30, 1981

Points of Delivery for Bonneville

WHITE SWAN POINT OF DELIVERY:

Location: the point in the Government's White Swan Substation where the facilities of the parties are connected;

Voltage: 69 kV;

Metering: in the Government's White Swan Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point outside the Government's Moxee Switching Station where the 115 kV facilities of the parties are connected.

Exhibit B, Table 3
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Big Bend Electric
Cooperative, Inc.
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

STAR SCHOOL POINT OF DELIVERY:

Location: the point in township 11 north, range 33 east of the Willamette Meridian, where the 69 kV facilities of Big Bend and the Company's Pasco-~~Lind~~ KAHLOTUS 69 kV transmission line are connected;

Voltage: 69 kV;

Metering: in Big Bend's Star School Substation, in the 7.2 kV circuit over which such electric power and energy flows;

Point of Replacement: the point outside the Government's Franklin Substation where the 115 kV facilities of the parties are connected.

(WP-PCI-1185c)

Exhibit B, Table 4
Contract No. DE-MS79-82BP90049
Transferor: Company
Transferee: Bonneville
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

1. PENDLETON POINT OF DELIVERY:

Location: in the Government's Pendleton Substation where the 69 kV facilities of the Government and the Company are connected;

Voltage: 69 kV;

Metering: in the Government's Pendleton Substation, in the 69 kV circuit over which such electric power and energy flows;

Point of Replacement: the points in the Government's Roundup Substation where the 69 kV facilities of the parties are connected.

(WP-PCI-1185c)

Exhibit B, Table 5
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Central Electric Cooperative
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

1. NEFF ROAD POINT OF DELIVERY:

Location: the point on the Company's Pilot Butte-Deschutes 69 kV transmission line at the Neff Road Interconnection in the vicinity of Bend, Oregon, where the 69 kV facilities of the Company and the Cooperative are connected;

Voltage: 69 kV;

Metering: at the point of delivery in the 69 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Company's Pilot Butte Substation where the 230 kV facilities of the parties are connected.

Exhibit B, Table 6
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Public Utility District No. 1
of Clark County, Washington
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

1. CHELATCHIE POINT OF DELIVERY:

Location: the point on the Company's Yale-Merwin 115 kV transmission line where the 115 kV facilities of the Company and the Government are connected;

Voltage: 115 kV;

Metering: in the Government's Chelatchie Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point on the north side of the Kalama River at structure No. 1/1 of the Government's Cardwell-Cowlitz transmission line where the 115 kV facilities of the parties are connected;

2. VIEW POINT OF DELIVERY:

Location: the point on the Company's Merwin-St. Johns 115 kV transmission line where the 115 kV facilities of the Company and Clark County PUD are connected;

Voltage: 115 kV;

Metering: in Clark County PUD's View Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point on the north side of the Kalama River at structure No. 1/1 of the Government's Cardwell-Cowlitz transmission line where the 115 kV facilities of the parties are connected.

Exhibit B, Table 7
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Columbia Basin Electric Cooperative, Inc. and
Umatilla Electric Cooperative
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

PILOT ROCK POINT OF DELIVERY:

Location: the point in the Company's 12.5 kV Pilot Rock circuit where the facilities of the Company and Umatilla are connected:

Voltage: 12.5 kV;

Metering: on the second pole from the point of interconnection between the facilities of the Company and Umatilla, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the points in the Government's Roundup Substation where the 69 kV facilities of the parties are connected.

Exhibit B, Table 8
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Columbia Power Cooperative Association, Inc.
Effective at 2400 hours on June 30, 1981

Points of Delivery for Bonneville

UKIAH POINT OF DELIVERY:

Location: the point in the Company's Pilot Rock Substation where the Company's 69 kV facilities and Columbia Power's Ukiah 69 kV line leased by Bonneville are connected;

Voltage: 69 kV;

Metering: in Columbia Power's Ukiah Substation, in the 25 kV circuit over which such electric power and energy flows;

Point of Replacement: the points in the Government's Roundup Substation where the 69 kV facilities of the parties are connected.

Exhibit B, Table 9
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Columbia Rural Electric
Association, Inc.
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

DAYTON POINT OF DELIVERY:

Location: the point near Dayton, in Columbia County, Washington, where the 69 kV facilities of Columbia REA and the Company's 69 kV Dayton-Pomeroy transmission line are connected;

Voltage: 69 kV;

Metering: in the Government's Dayton Substation, in the 24.9 kV circuits over which such electric power and energy flows;

Point of Replacement: the point in the Government's Walla Walla Substation where the 69 kV facilities of the parties are connected.

Exhibit B, Table 10
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Douglas Electric
Cooperative, Inc.
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

LOOKINGGLASS POINT OF DELIVERY:

Location: the point in the Government's Lookingglass Substation where the 69 kV facilities of the parties are connected;

Voltage: 69 kV;

Metering: in the Government's Lookingglass Substation, in the 69 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's Fairview Substation where the Government's Fairview-Reston 230 kV line terminates.

(WP-PCI-1185c)

Exhibit B, Table 11
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Hanna Nickel Smelting Company
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

HANNA POINT OF DELIVERY:

Location: the points in the Government's Hanna Substation where the 230 kV facilities of the parties are connected;

Voltage: 230 kV;

Metering: in the Government's Hanna Substation, in the 13.8 kV circuits over which such electric power and energy flows;

Point of Replacement: the point in the Government's Fairview Substation where the Government's Fairview-Reston 230 kV line terminates.

(WP-PCI-1185c)

Exhibit B, Table 12
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Hood River Electric
Cooperative
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

WOODY GUTHRIE POINT OF DELIVERY:

Location: the point on the Company's 69 kV Powerdale-Dee transmission line where the Government's Woody Guthrie Substation is connected;

Voltage: 69 kV;

Metering: in the Government's Woody Guthrie Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's Hood River Substation where the 115 kV facilities of the parties are connected.

Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Public Utility District
No. 1 of Klickitat County,
Washington
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

1. BINGEN POINT OF DELIVERY:

   Location: the point where the Government's Bingen Substation connects to the Company's Powerdale-Condit 69 kV line;

   Voltage: 69 kV;

   Metering: in the Government's Bingen Substation, in the 12.5 kV circuit over which such electric power and energy flows;

   Point of Replacement: the point in the Government's Hood River Substation where the 115 kV facilities of the parties are connected;

2. GILMER POINT OF DELIVERY:

   Location: the point near Husum, Washington, where Klickitat's Husum-Gilmer 69 kV transmission line and the Company's Condit-Union Gap 69 kV line are connected;

   Voltage: 69 kV;

   Metering: in the Government's Gilmer Substation, in the 12.5 kV circuit over which such electric power and energy flows;

   Point of Replacement: the point in the Government's Hood River Substation where the 115 kV facilities of the parties are connected;

3. GLENWOOD POINT OF DELIVERY:

Location: the point where Klickitat's Glenwood Substation tap is connected to the Company's Condit-Union Gap 69 kV line;

Voltage: 69 kV;

Metering: in Klickitat's Glenwood Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's Hood River Substation where the 115 kV facilities of the parties are connected.

Exhibit B, Table 14
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Lane Electric
Cooperative, Inc.
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

DORENA POINT OF DELIVERY:

Location: the points in the Company's Alvey-Dixonville 115 kV transmission line where the Government's 115 kV transmission line is connected to the Company's Alvey-Dixonville 115 kV line for service to the Government's Dorena Substation;

Voltage: 115 kV;

Metering: in the Government's Dorena Substation, in the 34.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's Cottage Grove Substation where the 115 kV facilities of the parties are connected.

(WP-PCI-1185c)

Exhibit B, Table 15
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Oregon Metallurgical
Corporation (Oremet)
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

OREMET POINT OF DELIVERY:

Location: the point in the Company's Oremet Substation where the 12.5 kV facilities of the Company and Oremet are connected;

Voltage: 12.5 kV;

Metering: in Oremet's 12.5 kV magnesium cell line circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's Albany Substation where the 115 kV facilities of the parties are connected.

(WP-PCI-1185c)

Exhibit B, Table 16
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
City of Springfield, Oregon
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

ALVEY 115 kV POINT OF DELIVERY:

Location: in the Government's Alvey Substation, where the deadend termination of the Company's 115 kV transmission line (leased to Springfield Utility Board) at terminal position 7K connects to the Company's power circuit breaker;

Voltage: 115 kV;

Metering: in the Government's Alvey Substation, in the 115 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's Alvey Substation where the 115 kV facilities of the parties are connected.

(WP-PCI-1185c)

Exhibit B, Table 17
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Tillamook People's Utility District
Effective at 2400 hours on June 30, 1981

Points of Delivery for Bonneville

1. MOHLER POINT OF DELIVERY:

   Location: the point on the Company's Astoria-Tillamook 115 kV transmission line at which the Government's Mohler Substation is connected;

   Voltage: 115 kV;

   Metering: in the Government's Mohler Substation in the 24.9 kV circuits over which such electric power and energy flows;

   Point of Replacement: the point in the Government's Tillamook Substation where the 115 kV facilities of the parties are connected;

2. GARIBALDI POINT OF DELIVERY:

   Location: the point on the Company's Astoria-Tillamook 115 kV transmission line at which the Government's 115 kV Garibaldi tap line is connected;

   Voltage: 115 kV;

   Metering: in the Government's Garibaldi Substation, in the 24.9 kV circuit over which such electric power and energy flows;

   Point of Replacement: the point in the Government's Tillamook Substation where the 115 kV facilities of the parties are connected.

(WP-PCI-1185c)

Points of Delivery for Bonneville

1. ADIN POINT OF DELIVERY:

Location: the point in the vicinity of Surprise Valley's Canby Switching Station where the 69 kV facilities of the Company and Surprise Valley are connected;

Voltage: 69 kV;

Metering: in Surprise Valley's Canby Switching Station, in the 69 kV circuit over which such electric power and energy flows;

Point of Replacement: the point where the Government's Redmond-Yamsay 230 kV transmission line and the Company's Yamsay-Klamath Falls 230 kV transmission line are connected;

2. ALTURAS POINT OF DELIVERY:

Location: the point outside of the Company's Alturas Substation where the 12.5 kV facilities of the Company and Surprise Valley are connected;

Voltage: 12.5 kV;

Metering: outside of the Company's Alturas Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Exception: the potential and current transformers are owned by the Company;

Point of Replacement: the point where the Government's Redmond-Yamsay 230 kV transmission line and the Company's Yamsay-Klamath Falls 230 kV transmission line are connected;

3. AUSTIN POINT OF DELIVERY:

Location: the point in the vicinity of the Company's Alturas Substation where the 69 kV facilities of the Company and Surprise Valley are connected;

Voltage: 69 kV;

Metering: in Surprise Valley's Austin Switching Station, in the 69 kV loop circuit over which such electric power and energy flows;

Point of Replacement: the point where the Government's Redmond-Yamsay 230 kV transmission line and the Company's Yamsay-Klamath Falls 230 kV transmission line are connected;

4. CEDARVILLE POINT OF DELIVERY:

Location: the point in the vicinity of the Government's 115-69kV Cedarville Junction Substation (adjacent to SVEC 69 kV Substation) where the 115 kV facilities of the Company and the Government are connected;

Voltage: 115 kV;

Metering: in the Government's Cedarville Junction Substation, in the 69 kV circuit over which such electric power and energy flows;

Exception: the metered amounts of demand and energy shall be reduced by the amounts of demand and energy, adjusted for losses, registered on meters in Surprise Valley's Cedarville Substation, in the 12.5 kV circuit over which electric power and energy flows to the Company;

Point of Replacement: the point where the Government's Redmond-Yamsay 230 kV transmission line and the Company's Yamsay-Klamath Falls 230 kV transmission line are connected.

5. DAVIS CREEK POINT OF DELIVERY:

Location: the point in the vicinity of Surprise Valley's Davis Creek Substation where the 115 kV facilities of the Company and Surprise Valley are connected;

Voltage: 115 kV;

Metering: in Surprise Valley's Davis Creek Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point where the Government's Redmond-Yamsay 230 kV transmission line and the Company's Yamsay-Klamath Falls 230 kV transmission line are connected;

6. LAKEVIEW 69 kV POINT OF DELIVERY:

Location: the point in the vicinity of Surprise Valley's Lakeview Switching Station where the 69 kV facilities of the Company and Surprise Valley are connected;

Voltage: 69 kV;

Metering: in Surprise Valley's Lakeview Switching Station, in the 69 kV circuit over which such electric power and energy flows;

Point of Replacement: the point where the Government's Redmond-Yamsay 230 kV transmission line and the Company's Yamsay-Klamath Falls 230 kV transmission line are connected;

Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Umatilla Electric
Cooperative Association
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

HAT ROCK POINT OF DELIVERY:

Location: the point where the Government's Hat Rock Substation is connected to the Company's McNary-Walla Walla 230 kV transmission line;

Voltage: 230 kV;

Metering: in the Government's Hat Rock Substation, in the 115 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's McNary Substation where the 230 kV facilities of the parties are connected;

Switching Facilities:

(a) The Company has elected to operate said McNary-Walla Walla 230 kV transmission line in a manner which required Bonneville to install major switching facilities, suitable to the Company, at said Hat Rock point of delivery. Bonneville installed such switching facilities, to enable continued service to Umatilla at Hat Rock.

(b) The Company, at Government expense shall:

(1) operate and maintain the two 230 kV disconnect switches adjacent to the Hat Rock point of delivery in the same manner in which it maintains similar facilities of its own and furnish any parts necessary for such maintenance; and

(2) remove said switches and associated materials which can be removed without damage to Company property, when no longer required to provide service at said Hat Rock point of delivery, deliver said switches and salvable materials to such location as Bonneville shall designate, and restore the Company's transmission facilities to their original configuration, subsequent to such removal.

(c) The Company shall submit an itemized statement of charges for materials furnished and services performed, as specified in section (b), including a reasonable allowance for overheads, within 20 days after the end of the month in which they were incurred, and Bonneville shall pay such charges within 30 days after receipt of said statement;

(d) Title to and ownership of the two 230 kV disconnect switches and related salvable materials installed by Bonneville shall be in the Government at all times.

Exhibit B, Table 20
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Wasco Electric
Cooperative, Inc.
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

WARM SPRINGS POINT OF DELIVERY:

Location: the point in the Company's Warm Springs Substation where the 69 kV facilities of the Company and facilities leased by the Government are connected;

Voltage: 69 kV;

Metering: in the Kah-Nee-Ta Substation leased by the Government, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's Redmond Substation where the 69 kV facilities of the parties are connected.

(WP-PCI-1185c)

Points of Delivery for Bonneville

1. OLNEY POINT OF DELIVERY:

Location: at the point near Olney, Oregon, where 12.5 kV facilities of the Company and West Oregon are connected;

Voltage: 12.5 kV;

Metering: at the point of delivery, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Company's Astoria Switching Station where the 115 kV facilities of the parties are connected;

2. NECANICUM JUNCTION POINT OF DELIVERY:

Location: at the point approximately five miles west of Necanicum Junction, Oregon, where the 12.5 kV facilities of the Company and West Oregon are connected;

Voltage: 12.5 kV;

Metering: at or near the point of delivery, in the 12.5 kV circuit over which such electric power and energy flows;

Exception: the period of service shall terminate when the Necanicum Point of Delivery commences commercial operation;

Point of Replacement: the point in the Government's Clatsop Substation where the 115 kV facilities of the parties are connected.

3. NECANICUM POINT OF DELIVERY:

Location: at the point between structures 25/2 and 25/3 of the Company's Tillamook - Astoria 115 kV line where the 115 kV facilities of West Oregon Electric Cooperative and the Company are connected;

Voltage: 115 kV;

Metering: in West Oregon Electric Cooperative's Necanicum Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Exception: the period of service shall commence on the date of commercial operation of the proposed Necanicum Substation;

Point of Replacement: the point in the Government's Tillamook Substation where the 115 kV facilities of the parties are connected.

TEMPORARY POINTS OF DELIVERY FOR BONNEVILLE

1. Goshen Temporary Point of Delivery: 1/

Location: in the Company's Goshen Substation where the 20.8 kV facilities of the Company and Emerald People's Utility District (Emerald) are connected;

Voltage: 20.8 kV;

Metering: in the Company's Goshen Substation, in the 20.8 kV circuit over which such electric power and energy flows;

Exception: the metered amounts of power and energy shall be reduced by simultaneously metered amounts of power and energy, adjusted for losses, delivered to the Company at/or near Pole No. 1903/147503, and shall be increased by simultaneously metered amounts of power and energy, adjusted for losses, delivered to Emerald at/or near Pole No. 1903/158501;

Point of Replacement: in the Government's Alvey Substation where the 115 kV facilities of the parties are connected.

2. Village Green Temporary Point of Delivery: 1/

Location: in the Company's Village Green Substation where the 20.8 kV facilities of the Company and Emerald are connected;

Voltage: 20.8 kV;

Metering: in the Company's Village Green Substation in the 20.8 kV circuits over which such electric power and energy flows;

Exception: the metered amounts of demand and energy shall be increased by simultaneously metered amounts of power and energy, adjusted for losses, delivered to Emerald at/or near Pole No. 2003/324700;

Point of Replacement: the point where the Government's Cottage Grove-Drain 115 kV line connects to the Company's Alvey-Dixonville 115 kV line;

3. Coburg Temporary Point of Delivery: 1/

Location: in the Company's Coburg Substation where the 20.8 kV facilities of the Company and Emerald are connected;

Voltage: 20.8 kV;

Metering: in the Company's Coburg Substation, in the 20.8 kV circuit over which such electric power and energy flows;

Exception: the metered amounts of demand and energy shall be reduced by simultaneously metered amounts of power and energy, adjusted for losses, delivered to the Company at/or near Pole No. 1604/010002 and 1063/327961 and shall be increased by simultaneously metered amounts of power and energy, adjusted for losses, delivered to Emerald at/or near Pole No. 1603/333905;

Points of Replacement: In the Government's Alvey Substation where the 230 kV facilities of the parties are connected.

4. Junction City Temporary Point of Delivery: 1/

Location: in the Company's Junction City Substation where the 20.8 kV facilities of the Company and Emerald are connected;

Voltage: 20.8 kV;

Metering: in the Company's Junction City Substation, in the 20.8 kV circuit over which such electric power and energy flows;

Exception: the metered amounts of power and energy shall be reduced by simultaneously metered amounts of power and energy, adjusted for losses, delivered to the Company at/or near Pole No. 1504/316200, and shall be increased by simultaneoulsy metered amounts of power and energy, adjusted for losses, delivered to Emerald at/or near Pole No. 1604/050900;

Point of Replacement: in the Government's Alvey Substation where the 230 kV facilities of the parties are connected.

Points of Delivery for the Company

1. BANDON POINT OF DELIVERY:

   Location: the point in the Government's Bandon Substation where the 12.5 kV facilities of the parties are connected;

   Voltage: 12.5 kV;

   Metering: in the Government's Bandon Substation, in the 12.5 kV circuit over which such electric power and energy flows;

   Exception: the metered amounts of demand and energy shall be reduced by the amounts of demand and energy, adjusted for losses, registered on meters in the Company's Whiskey Run Substation;

   Point of Replacement: the point in the Government"s Fairview Substation where the 115 kV facilities of the parties are connected;

2. BOYER POINT OF DELIVERY:

   Location: the point near structure 34/6 of the Government's Salem-Tillamook 115 kV transmission line where the facilities of the parties are connected;

   Voltage: 115 kV;

   Metering: in the Company's Boyer Switching Station, in the 115 kV circuit over which such electric power and energy flows;

   Exception: the period of service shall commence on the date of commercial operation of the tap;

   Point of Replacement: the point in the Government's Salem Substation where the 115 kV facilities of the parties are connected;

3. COTTAGE GROVE POINT OF DELIVERY:

   Location: the point where the Government's Cottage Grove-Drain 115 kV line connects to the Company's Alvey-Dixonville 115 kV line;

   Voltage: 115 kV;

Metering: in the Government's Martin Creek Substation, in the Government's Cottage Grove-Drain 115 kV line over which such electric power and energy flows;

Exception: the metered amounts of demand and energy shall be reduced by the amounts of demand and energy, adjusted for losses, registered on meters in the Government's Dorena Substation;

Point of Replacement: the point in the Government's Alvey Substation where the 230 kV facilities of the parties are connected;

4. DALREED POINT OF DELIVERY:

Location: the point near structure 37/3 of the Government's McNary-Santiam 230 kV transmission line where the facilities of the parties are connected;

Voltage: 230 kV;

Metering: in the Company's Dalreed Substation, in the 34.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's McNary Substation where the 230 kV facilities of the parties are connected;

5. GORDON HOLLOW POINT OF DELIVERY:

Location: the point at structure 1/2 on the Government's DeMoss-Fossil 69 kV transmission line where such line connects to the Company's Gordon Hollow tapline;

Voltage: 69 kV;

Metering: in the Company's Gordon Hollow Substation, in the 20.8 kV circuit over which such electric power and energy flows;

Exception: metering equipment is owned by the Company;

Point of Replacement: the point in the Government's Hood River Substation where the 115 kV facilities of the parties are connected;

6. HAYDEN BRIDGE 69 kV POINT OF DELIVERY:

Location: the point where the 69 kV facilities of the Company and Eugene Water and Electric Board are connected;

Voltage: 69 kV;

Metering: in the 20.8 kV circuit in the Company's Hayden Bridge Substation;

Point of Replacement: the point in the Government's Alvey Substation where the 115 kV facilities of the parties are connected;

7. KLONDIKE POINT OF DELIVERY:

Location: the point adjacent to Wasco Electric Cooperative's Klondike Substation where the 69 kV facilities of the Company and Wasco Electric Cooperatives are connected;

Voltage: 69 kV;

Metering: at a point 1.5 miles north of Klondike Substation, in the Company's Klondike-Blalock-Arlington 69 kV transmission line over which such electric power and energy flows;

Point of Replacement: the point in the Government's Hood River Substation where the 115 kV facilities of the parties are connected;

8. KNAPPA-TAP POINT OF DELIVERY:

Location: the point near structure 37/4 of the Government's Longview-Astoria 115 kV transmission line where the facilities of the parties are connected;

Voltage: 115 kV;

Metering: in the Company's Knappa-Svensen Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Exception: the instrument transformers are owned by the Company;

Point of Replacement: the point in the Company's Astoria Substation where the 115 kV facilities of the parties are connected;

9. PLEASANT HILL POINT OF DELIVERY:

Location: the point near structure 10/1 on the Government's Lookout-Alvey 115 kV No. 1 line where such line is connected to the Company's Pleasant Hill Substation tapline;

Voltage: 115 kV;

Metering: in the Company's Pleasant Hill Substation, in the transformer low side 20.8 kV circuit over which such electric power and energy flows;

Exception: metering equipment is owned by the Company;

Point of Replacement: the point in the Government's Alvey Substation where the 115 kV facilities of the parties are connected;

Exhibit D

Contract No. DE-MS79-82BP90049
Pacific Power & Light Company
Effective at 2400 hours on
June 30, 1981

Transfer Charges, Sole Use of Facilities Charges, and Loss Factors

Point of Delivery	Transferor	Transfer Charge ($per kW/Mo.)	Sole Use of Facilities Charge ($ per Mo.)	Loss Factors Peak	Loss Factors Energy
Bandon	Bonneville	0.7430	0	1.0400	1.0300
Cottage Grove	Bonneville	0.4840	0	1.0199	1.0128
Dalreed	Bonneville	0.1482	0	1.0127	1.0100
Gordon Hollow	Bonneville	1.0771	0	1.0150	1.0070
Hayden Bridge	Bonneville	0.0450	0	1.0430	1.0270
Klondike	Bonneville	1.0748	0	1.0010	1.0040
Knappa Tap	Bonneville	0.2000	0	1.0090	1.0120
Pleasant Hill Tap	Bonneville	0.0700	0	1.0100	1.0130
White Swan (Benton)	Company	0.7480	0	1.0470	1.0460
Star School (Big Bend)	Company	0	9056	1.0220	1.0330
Chelatchie (Clark)	Company	0.1205	0	1.0080	1.0070
View (Clark)	Company	0.0882	0	1.0180	1.0160
Ukiah (Columbia Power)	Company	0.2457	0	1.0230	1.0210
Dayton (Columbia Rural)	Company	1.1990	0	1.1360	1.1090
Lookingglass (Douglas)	Company	0.2593	2215	1.0790	1.0550
Hanna	Company	0.1746	5645	1.0370	1.0310
Woody Guthrie (Hood River)	Company	0.6490	0	1.0440	1.0370
Bingen (Klickitat)	Company	0.3810	0	1.0420	1.0310
Gilmer (Klickitat)	Company	0.5850	770	1.0590	1.0480
Glenwood (Klickitat)	Company	0.5850	3647	1.0640	1.0510
Dorena (Lane)	Company	0.0116	0	1.0160	1.0130
Oremet (Oremet)	Company	0.2700	0	1.0140	1.0120
Alvey (Springfield)	Company	0	2166	1.0000	1.0000
Mohler (Tillamook)	Company	0.8490	0	1.0150	1.0120
Garibaldi (Tillamook)	Company	0.2388	0	1.0130	1.0130
Adin/Canby (Surprise Valley)	Company	3.1300	33	1.1125	1.0664

Exhibit D
Page 2 of 2
Contract No. DE-MS79-82BP90049
Pacific Power & Light Company
Effective at 2400 hours on
June 30, 1981

Transfer Charges, Sole Use of Facilities Charges, and Loss Factors

Point of Delivery	Transferor	Transfer Charge ($per kW/Mo.)	Sole Use of Facilities Charge ($ per Mo.)	Loss Factors Peak	Loss Factors Energy
Austin (Surprise Valley)	Company	3.6340	30	1.1057	1.0663
Lakeview 69 kV (Surprise Valley)	Company	1.0800	1234	1.2012	1.1293
Davis Creek (Surprise Valley)	Company	2.0771	396	1.1826	1.0950
Cedarville (Surprise Valley)	Company	2.9530	0	1.2474	1.1409
Alturas (Surprise Valley)	Company	4.2490	709	1.2145	1.1116
Ashland (City of Ashland)	Company	1.5213	736	1.0590	1.0380
Oak Knoll (City of Ashland)	Company	1.1813	768	1.0610	1.0410
Hat Rock (Umatilla)	Company	0.0693	0	1.0110	1.0110
Pilot Rock (Columbia Basin & Umatilla)	Company	0.6350	0	1.0250	1.0180
Warm Springs (Wasco)	Company	0.7170	0	1.0900	1.0720
Olney (West Oregon)	Company	1.9080	0	1.2820	1.1750
Necanicum (West Oregon)	Company	1.0217	0	1.2660	1.1920
Neff Road (Central Electric)	Company	0.2762	0	1.0090	1.0070
Pendleton	Company	0.0227	134	1.0150	1.0100

(WP-PCI-1185c)

Exhibit E

General Transmission Rate Schedule Provisions:

FOR SET A TRANSMISSION SCHEDULES

1. Interpretation. The provisions in the Agreement to which these General Transmission Rate Schedule Provisions (GTRSP) are attached as an exhibit shall be part of these GTRSP for the purpose of determining the meaning of any provision contained herein. If a provision in such Agreement is in conflict with a provision contained herein, the former provision shall prevail.

2. Bonneville Service Area. The Bonneville Power Administration (BPA) shall operate and maintain the Federal Columbia River Transmission System (FCRTS) within the Pacific Northwest and shall construct such improvements, betterments, system additions and replacements within the Pacific Northwest as it determines are appropriate and required to:

a. integrate and transmit "electric power" from existing or additional Federal or non-Federal generating units;

b. provide service to the BPA wholesale power and wheeling customers;

c. provide interregional transmission facilities; or

d. maintain the electrical stability and electric reliability of the Federal Columbia River Power System.

3. Availability of Transmission Service. Any capacity in the FCRTS which BPA determines to be in excess of the capacity required to transmit Federal power will be made available to all utilities on a fair and nondiscriminatory basis by the application of schedules identifed in the Schedule of Transmission Rates, dated 1981 or as subsequently revised.

4. Billing Details.

a. The Transmission Billing Determinant is the electric power quantified by the method specified in the Transmission Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

b. Bills for transmission service will be computed and rendered monthly, generally on a calendar-month basis.

c. Bills not paid in full on or before the close of business of the twentieth day after the date of the bill shall bear an additional charge which is the greater of one-fourth percent (0.25%) of the amount unpaid or $50. Thereafter, a charge of one-twentieth percent (0.05%) of the sum of the initial amount remaining unpaid and the additional charge herein described shall be added on each succeeding day until the amount due is paid in full. The provisions of this paragraph do not apply to bills rendered under contracts with other agencies of the United States.

Remittances received by mail shall be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark

(3) Point of Exchange (POE): Connection points listed in an Exchange Agreement. Power may be delivered or received at POE without special accounting.

c. Electric Power (or simply Power if no confusion would result without a modifier of mechanical, chemical, or electrical): Electric peaking capacity (kW), or electric energy (kWh), or both.

d. Firm Transmission Service: Firm availability of transmission service for any power scheduled or otherwise made available, limited only by the amount and time period specified in the Agreement. Firm transmission service is supplied for all types of power, such as firm, nonfirm, exchange, interruptible, or other.

e. Interest and Amortization Ratio: The annual interest and amortization costs of the Federal Columbia River Transmission System, or any applicable portion thereof, divided by the investment in such system or portion thereof.

f. Main Grid: That portion of the FCRTS with facilities rated 230 kV and higher, exclusive of the Intertie.

g. Main Grid Delivery Terminal: 230 kV Terminal Facilities associated with a Point of Delivery.

h. Main Grid Distance: The distance in airline miles on the Main Grid between the Point of Integration and the Point of Delivery, multiplied by 1.15.

i. Main Grid Integration Terminal: The Main Grid Terminal Facilities located at the Point of Integration.

j. Main Grid Miscellaneous Facilities: Switching, transformation and other backup facilities of the Main Grid required to integrate the Main Grid.

k. Main Grid Terminal: Terminal facilities on the Main Grid adjacent to the Secondary System.

l. NonFirm Transmission Service: Service for which BPA will accept power only when it determines excess capacity is available. Once BPA accepts power for transmission service, the service provided is the same for firm and nonfirm transmission service.

m. Ratchet Demand: The maximum past or present demand established during the previous 11 billing months based on the highest scheduled demand during that time.

n. Secondary System: That portion of the FCRTS facilities with operating voltage of 115 kV or 69 kV, exclusive of Main Grid facilities, Intertie facilities, and lower voltage (less than 69 kV) FCRTS facilities which may be used on a use-of-facility basis.

Methodology for Calculating Transfer Charges and Sole Use of Facilities Charges

The Transfer Charge is the monthly charge per kilowatt of transfer demand as transfer demand is defined in the contract of which this exhibit is a part. The Transfer Charge is equal to one-twelfth of the sum of the Annual Costs of all facilities used in providing the service hereunder divided by the sum of the yearly non-coincidental peak demands as determined in (c) below. The Annual Costs of each facility are defined as the product of: (1) the capital cost of such facility as determined in (a) below; and (2) the Annual Cost Ratio as determined in (b) below. The Transfer Charge is therefore calculated from the formula:

$$\frac{\text{sum of (I x R) for all applicable facilities}}{D} \times 1/12$$

where:

I = Capital cost of such facility as determined in (a) below,
R = Annual Cost Ratio as determined in (b) below,
D = The sum of the yearly non-coincidental peak demands as determined in (c) below.

(a) Capital cost of each such facility as in the most recently published plant investment records of the parties hereto.

(b) Annual Cost Ratio for each such Bonneville facility using the most recent system average cost factors, or Annual Cost Ratio for each such Company facility which incorporates the most recent rate of return approved by the ~~Idaho Public Utility Commission, the Montana Public Service Commission, the~~ Oregon Public Utility Commission~~, or the Washington Utilities and Transportation Commission, as the case may be, for facilities located in the respective states.~~ The Annual Cost Ratio used herein includes the operation and maintenance component defined as "B" in the UFT-2 rate schedule.

RBH
6/1/8

(c) The yearly noncoincidental peak demands of all users of such facilities, as determined in part by use of power flows agreed to by both parties and in part by forecasted peaks agreed to by both parties that are different from those used in the power flows. Since the noncoincidental peaks may occur at different times it may not be possible to include both in the same power flow. The parties shall initially use power flows, which are already existing as of January 1, 1982, which are based on 1981-82 Operating Year forecasted peak. Unless the parties subsequently agree to a different method, the following method shall be used to update power flows:

(1) the initial power flows shall be used through December 31, 1983 or such other date as agreed by the parties;

(2) new power flows shall then be prepared which shall use parameters forecasted to exist 2 years from the date that the power flow is prepared;

(3) such new power flows shall then be the basis for transfer charges for 3 years;

(4) every third year the procedure in (2) above shall be repeated and such new power flows shall be used for 3 years.

Sole Use of Facilities Charge

The Sole Use of Facilities Charge is the transfer charge where a party has sole use of a facility. In such cases the charge is expressed in dollars per month and is calculated as:

sum of (I x R) for all applicable facilities x 1/12

using the same quantities defined above.

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208

OFFICE OF THE ADMINISTRATOR

FEB 26 1982

In reply refer to: PCI

Contract No. DE-MS79-82BP90924

Mr. Robert W. Moench
Senior Vice President
Pacific Power & Light Company
Portland, Oregon 97204

Dear Mr. Moench:

During the past year, representatives of Pacific Power & Light Company (PP&L) and Bonneville Power Administration (BPA) have been meeting from time to time to reach settlement on transfer services to BPA's Hanna, Lookingglass, and Surprise Valley loads for the period from July 1973 to the present as well as other outstanding issues related to transfer services rendered to both parties. At meetings on February 23 and 24, 1982, agreement was reached between PP&L and BPA on certain of these issues. There are other issues, as well as final details of future charges for transfer services provided each other, which are yet to be resolved. BPA and PP&L, however, agree that final resolution of all remaining issues will be greatly facilitated as a result of these recent meetings and the agreement of principles upon which many of these decisions were made.

In accordance with these recent discussions, BPA and PP&L agree to the following terms and conditions:

A. <u>Settlement for services rendered prior to July 1, 1981</u>.

1. BPA shall pay PP&L $5,300,000 for transfer service provided by PP&L to BPA's Surprise Valley, Hanna, and Lookingglass loads from July 1973 through 2400 hours on June 30, 1981. The amount of the payment was computed using a fixed rate of .5 mill per kWh, a UFT methodology equivalent to BPA's approved UFT-1 rate methodology, and a transfer amount of 7,639,784,496 kWh.

2. BPA shall pay PP&L $319,789 for transfer service of the Lost Creek Project generation for the period from July 6, 1977, through October 1, 1978.

3. Payment pursuant to subsections 1 and 2 above shall be made in three equal payments, such payments shall be made at 30-day intervals. The first such payment shall be made within 30 days of receipt of an invoice for the full amount due. There shall be no interest paid on such payments.

4. BPA agrees to reimburse PP&L 62,000 MWh for losses which PP&L incurred during the period commencing at 2400 hours on June 30, 1973 and continuing through 2400 hours on June 30, 1981. Delivery of such energy will be made, to the extent possible, in equal hourly increments during the period commencing at 2400 hours on June 30, 1982 and continuing through 2400 hours on June 30, 1983.

B. Settlement for services rendered subsequent to July 1, 1981.

1. Payment

a. BPA shall pay PP&L each month in the amounts specified in Attachment 1, within 30 days of receipt of billing.

b. BPA shall pay PP&L the actual cost of the line transposition required on the Buckley-Summer Lake line. Such cost is estimated to be $40,000. BPA and PP&L shall execute an appropriate trust agreement for this transaction.

c. PP&L shall pay BPA an monthly charge of $32,100 from 2400 hours on November 30, 1981 through the date of Commercial Operation of the Buckley-Summer Lake-Malin line for the right to remove PP&L's 230 kV Malin phase shifter. Such monthly charge shall resume at 2400 hours on August 31, 1985, as established pursuant to Contract No. DE-MS79-79BP90091, unless BPA determines that, such date should be extended based upon studies done in a manner similar to those done in originally establishing such dates. PP&L shall, in consideration for the above and as mutually agreed upon by the parties, extend the period of time for which BPA shall have west to east transmission rights on PP&L's Summer-Lake - Midpoint line.

2. Calculation of Charges - Specific Provisions

a. Mile Hi - Alturas 115 kV line

(1) For the period of time from 2400 hours on June 30, 1981 to the date of energization of BPA's proposed 230 kV Malin - Alturas line, BPA shall pay charges calculated as if power flowed from Mile Hi to the Davis Creek, Cedarville, and Alturas Points of Delivery.

(2) For the period of time from the date of energization of BPA's proposed 230 kV Malin - Alturas line until 2400 hours on December 31, 1991 BPA shall pay charges calculated as if power flowed from Alturas to the Cedarville, Davis Creek, and Lakeview 69 kV points of delivery.

(3) Commencing at 2400 hours on December 31, 1991 BPA will pay charges calculated as if power flowed from Alturas to the Cedarville and Davis Creek points of delivery.

b. Transfer charges for service to the Hanna, Lookingglass, and Ashland Loads shall be calculated based on a Fairview point of replacement. These charges shall include payment to PP&L for BPA's use of the Government's Fairview - Reston 230 kV line for which PP&L is currently paying an exclusive use charge.

c. Following energization of the Buckley-Summer Lake - Malin 500 kV line and the 230 kV Malin-Alturas line, the point of replacement for transfer service to BPA's Surprise Valley Electrification load shall be the Malin 500 kV bus. BPA will pay UFT-2 charges for use of PP&L's's 500-230 kV Malin transformer. If BPA agrees that a second 500-230 kV transformer is a reasonable addition to provide reliable service to area loads and when PP&L adds such transformer, charges for such transformer shall be included in the UFT-2 calculations for the use of PP&L's Malin 500-230 kV facilities.

C. <u>General Transfer Agreement</u>.

1. Services rendered subsequent to July 1, 1981 shall be pursuant to the terms and conditions of the proposed General Transfer Agreement (draft dated September 10, 1980); provided, however, that charges and payments shall be based upon the amounts of electric power and energy delivered at the specified points of delivery adjusted for losses to the point of replacement.

2. BPA and PP&L agree that the General Transfer Agreement to be executed pursuant to subsection 3 below shall provide that the parties reciprocally apply the methodology contained in BPA's UFT - 2 rate schedule or its successor for transfer services rendered pursuant to the General Transfer Agreement. BPA and PP&L shall share in the cost of the unused capacity of facilities. This payment reflects the transferor's acceptance of the responsibility to provide additional facilities as required to serve the load growth of the parties.

3. The parties agree to execute the General Transfer Agreement no later than 60 days subsequent to the date of execution of this agreement.

D. <u>Term of Agreement</u>. This agreement shall be effective at 2400 hours on the date of execution and shall continue in effect until 2400 hours on the date of execution of the General Transfer Agreement, except that all obligations incurred hereunder shall be preserved until satisfied.

If the above listed conditions are acceptable to you, please countersign this letter and return it to me. BPA will then initiate the appropriate actions to

Exhibit G
4 of 4

implement these arrangements.

Sincerely,

/s/ Peter T. Johnson

Administrator

Enclosure:
Points of Delivery and Charges
UFT - 2 Rate Schedule

PACIFIC POWER & LIGHT COMPANY

By /s/ Robert W. Moench

Title Senior Vice President

Date March 4, 1982

ATTEST:
By /s/ Sally A. Nofziger

Title Assistant Secretary

(WP-PCI-1057c)

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

OFFICE OF THE ADMINISTRATOR

In reply refer to: PMT

July 28, 1988

Amendatory Agreement No. 1
Contract No. DE-MS79-86BP92277

Mr. Richard E. Dyer
Vice President, Power Systems
Portland General Electric Company
121 SW. Salmon Street
Portland, OR 97204

Dear Mr. Dyer:

Representatives of the Bonneville Power Administration (Bonneville) and Portland General Electric Company (Company) agree that it would be mutually beneficial to amend the Bonneville - Portland General Electric Company Grizzly Substation Construction Trust Agreement (Contract No. DE-MS79-86BP92277, executed September 10, 1987, and hereinafter referred to as "Primary Agreement") to:

1. permit the Primary Agreement to run until terminated by either party;

2. include Exhibit B, Tables 1 through 7; and

3. provide for the inclusion of additional Exhibit B Tables each time the parties agree that facilities and equipment shall be added or modified at Grizzly Substation (Grizzly).

I therefore propose that the above beneficial objectives be accomplished by amending the Primary Agreement as follows:

1. Effective Date of Amendment. This Amendatory Agreement No. 1 shall be effective as of 2400 hours on its date of execution.

2. Delete section 1 of the Primary Agreement and substitute the following therefor:

   "1. Term of Agreement. This agreement shall be effective at 2400 hours on the date of execution (Effective Date), and shall be coextensive with the intertie agreement between Bonneville and the Company (Contract No. DE-MS79-88BP92430), as each agreement may be amended, extended, or replaced. All liabilities incurred hereunder shall be and are hereby preserved until satisfied."

3. Delete section 2 of the Primary Agreement and substitute the following therefor:

   "2. Exhibits. Exhibits A and B, including Tables 1 through 7, are hereby made a part of this agreement. In Exhibit A, the Company shall be the "contractor"."

4. Add the following as section 11 of the Primary Agreement:

   "11. Additions to Exhibit B.

   (a) Bonneville shall prepare, for execution by the parties, an additional table to Exhibit B each time the parties agree that facilities shall be added or modified at Grizzly. Such table shall specify the facilities to be installed, the work to be performed by each party, and the estimated costs to be borne by the Company. Such estimated costs less any credit for facilities furnished by the Company shall constitute the amount of the Trust Deposit specified for each project. Final costs to be borne by the Company shall be based on actual costs.

   (b) Upon execution by the parties, new tables to Exhibit B shall be attached to and deemed to be a part of this agreement and shall be effective on the date specified therein."

If this Amendatory Agreement is acceptable to the Company, please indicate your approval by signing and returning two original copies to Bonneville. Bonneville will transmit a fully executed original copy for your records.

Sincerely,

James J. Jura
Administrator

Effective Date July 29, 1988

ACCEPTED:

PORTLAND GENERAL ELECTRIC COMPANY

By ____________

Title Vice President

Date July 29, 1988

(VS6-PMTT-3145e)

Contract No. DE-MS79-86BP92277
April 20, 1987

CONSTRUCTION TRUST AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PORTLAND GENERAL ELECTRIC COMPANY

providing for design, construction, installation, and test of certain additional facilities at Grizzly Substation

Index to Sections

This CONSTRUCTION TRUST AGREEMENT, executed Sept. 10, 1987 by the UNITED STATES OF AMERICA (Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and PORTLAND GENERAL ELECTRIC COMPANY (Company), a Corporation of the State of Oregon,

WITNESSETH:

WHEREAS the parties hereto, on August 27, 1982, executed a power sales contract designated as Contract No. DE-MS79-81BP90425 (which, as amended or replaced, is hereinafter referred to as "Power Sales Contract") which provided for the sale to the Company of all or part of its firm power requirements by Bonneville; and

WHEREAS the parties hereto, on January 3, 1966, executed a trust agreement designated as Contract No. 14-03-56747 which, as amended, provided for Bonneville to design, construct, and test the original jointly-owned, Government-owned, and portions of the Company-owned facilities at the Pacific Northwest-Pacific Southwest 500 kV AC Intertie Grizzly Substation (Grizzly); and

WHEREAS the parties hereto, on October 11, 1967, executed an O&M Trust Agreement designated as Contract No. 14-03-73941 which provides, among other matters, for Bonneville to operate the Company's facilities and to operate and maintain the jointly-owned facilities at Grizzly; and

WHEREAS the parties desire that Bonneville design, furnish certain labor and materials, construct, install, modify, and test additional facilities at Grizzly; and

WHEREAS the parties also wish to provide for Bonneville to operate and maintain the above-mentioned additional facilities constructed or installed hereunder; and

WHEREAS Bonneville is authorized pursuant to law to market electric power and energy generated at various Federal hydroelectric projects in the Pacific Northwest, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. Term of Agreement. This agreement shall be effective at 2400 hours on the date of execution (Effective Date) and, except as it is otherwise herein after provided, shall continue in effect until all acts required hereunder have been fully performed. All liabilities incurred hereunder shall be and are hereby preserved until satisfied.

2. Exhibits. Exhibits A and B, including Tables 1 through 5, are hereby made a part of this agreement. In Exhibit A, the Company shall be the "contractor".

3. Trust Account. Each party agrees to bear its percentage share of the cost determined by ownership shares, as defined in subsection 8(a), of

performing the work specified in each table of Exhibit B. The Company hereby agrees to deposit with Bonneville an amount equal to its said percentage share of the estimated total cost, less the cost of any materials it provides hereunder (Trust Deposit), for Bonneville to perform the work as specified in each table of Exhibit B. Such amount(s) shall be deposited in a trust account in the Bonneville Power Administration Fund in the United States Treasury (Trust Account) and shall be subject to withdrawal only for payment of the Company's share of the actual cost of performing the duties pursuant to section 4 below. The Company shall make payments, in the amounts and at the times requested by Bonneville, as provided in the appropriate table to Exhibit B. If at any time Bonneville determines that such amounts are insufficient to pay the actual cost of completing Bonneville's duties, the Company shall advance to Bonneville, upon completion of duties specified in subsection 6(b), when Bonneville, upon written notice, requests and in such installments as may be specified by Bonneville, such additional moneys as Bonneville estimates shall be required for such completion.

4. Duties of Bonneville.

(a) Bonneville shall furnish all materials and labor except that furnished by the Company pursuant to section 5 and shall design, construct, install, and test the facilities described in Exhibit B.

(b) All work done at the Company's expense hereunder shall be performed in whole or in part by force account, by contract, or by both, in the same manner and subject to the same limitations as if all funds being expended therefor were Government funds.

(c) Bonneville shall provide the Company with a bi-monthly progress report as appropriate to note significant milestones, delays, and final project completions. The report shall cover all the tables of Exhibit B, be bi-monthly commencing from the Effective Date, and terminate when the last project is completed.

(d) On completion of the work specified in each table of Exhibit B, Bonneville shall furnish the Company with accurate physical layout drawings and schematic wiring diagrams of the equipment and facilities installed or modified under such table.

5. Duties of the Company.

(a) The Company shall perform the duties specified for it in Tables 1 through 5 of Exhibit B.

(b) The Company may perform such duties in whole or in part by force account, by contract, or by both.

6. Accounting.

(a) Trust Account Charges. The necessary cost of performing the work and furnishing the materials referred to in section 4 above, as such work and materials relate to the appropriate table of Exhibit B, shall be proper charges against the Trust Account, and shall be determined by charging the cost elements exclusive of interest in the same reasonable and prudent manner as if Government funds were being expended, including among other items, salaries and wages and employee benefits, materials and supplies, equipment rental and utilization costs, transportation costs, and overheads reasonably allocable thereto.

(b) Additional Trust Funds. If at any time Bonneville requests the Company to advance additional moneys pursuant to section 3 above for work specified in a table of Exhibit B, Bonneville shall, at the same time, make a full accounting to the Company showing the receipts, expenditures, adjustments for salvage values, and the balance of the Trust Account. Bonneville shall also submit a statement to the Company showing in detail Bonneville's estimate of the additional moneys required to pay the cost of completing Bonneville's responsibilities as specified in section 4 above.

(c) Settlement of Trust Account. Within a reasonable time, not to exceed six months after completion of the work specified in each table of Exhibit B, Bonneville shall make a full accounting in regard to such work to the Company showing the receipts, expenditures, adjustments for salvage values, and the balance of the Trust Account. Such accounting shall be made in such manner so that the Company can place the various units of property on its books in the manner prescribed in the Federal Energy Regulatory Commission Uniform System of Accounts for Class A public utilities. Bonneville shall remit to the Company any unexpended balance of the Trust Account within a reasonable time, not to exceed 90 days, thereafter. Should Bonneville fail to complete its duties within one year beyond the estimated completion date specified in each Exhibit B table, such full accounting shall be made to the Company. Any unexpended balance of the Trust Account shall be refunded to the Company within a reasonable time thereafter, not to exceed 90 days.

7. Extension of Time. Estimated completion or energization dates specified for either party in each table of Exhibit B shall be extended for a time equivalent to such delays, if any, as are caused by events which such party could not have reasonably avoided by the exercise of reasonable diligence and foresight.

8. Ownership of Facilities

(a) Title to and ownership of the jointly-owned facilities constructed or installed hereunder shall be as defined in Contract No. 14-03-56747, as amended, such that an undivided forty percent (40%) interest shall be and remain in the Company at all times and an undivided sixty percent (60%) interest shall be and remain in the Government at all times.

(b) Title to and ownership of all facilities constructed or installed hereunder that are furnished by Bonneville will remain in the Government until such facilities have been approved and released for operation by Bonneville. Within 30 days beyond such release, the Company may inspect such facilities and, unless the Company declares the facilities to be unacceptable, title to and ownership of such facilities shall then pass to and shall remain in the parties as specified in subsection (a) above.

(c) Should Bonneville fail to approve and release for operation (for reasons not covered under section 7) any or all of the facilities specified in Tables 1 through 5, within one year beyond that facility's estimated completion or energization date, title to and ownership of such facility shall then pass to and remain in the parties as specified in subsection (a) above.

9. Operation and Maintenance of Facilities. Operation and Maintenance of the facilities installed hereunder shall be in accordance with the O&M Trust Agreement (Contract No. 14-03-73941).

10. Permit.

(a) For any equipment or facilities belonging to either party to this agreement at Grizzly, a permit to perform the duties listed in each table of Exhibit B, together with the right of entry to said property at all reasonable times in such term, is hereby granted by the other party.

(b) If either party is required or permitted to construct, install, test, maintain, inspect, replace, repair, remove, or operate equipment of the other at Grizzly, the owner of such property shall furnish the other party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other party of any subsequent modification which may affect the duties of the other party in regard to such equipment, and furnish the other party with accurate revised drawings, if possible.

IN WITNESS WHEREOF, the parties hereto have executed this agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By James J. Jura
Administrator

Effective Date: September 10, 1987

PORTLAND GENERAL ELECTRIC COMPANY

By ____________________

Title Vice President, Power Supply

Date May 15, 1987

(WP-PKT-0777e)

Installation of Facilities
(SUDS-To-SER Conversion)

The parties agree that it would be mutually beneficial to replace the present outdated, saturated-capacity Grizzly Substation Data System (SUDS) with a modern Sequential Events Recorder (SER) which has greatly expanded event/alarm capacity, time tagging to the nearest millisecond, and real-time telemetering links to Bonneville's Dittmer Control Center. Energization is scheduled for June 1987.

Replacement of the SUDS System with the SER System will, among other matters, improve post analysis of disturbances on the Pacific Northwest - Pacific Southwest AC Intertie and increase Intertie reliability.

Accordingly, Bonneville shall replace the present SUDS System subject to the following terms and conditions:

1. Term. This Table 1 shall be effective as of 2400 hours on the date of execution after Bonneville has received original signed copies of the Construction Trust Agreement, Contract No. DE-MS79-86BP92277 (Primary Agreement) and a check from the Company in the amount of the Trust Deposit.

2. Trust Deposit. The Trust Deposit shall be in the amount of $120,000.

3. Cost Sharing. The estimated total cost of replacing the SUDS System at Grizzly with a SER System, as described in section 4 below, is $300,000. This estimated amount is to be shared by the parties in proportion to their percentage ownerships of the Grizzly jointly-owned property as follows:

Party	Joint Ownership Percentage (%)	Estimated Share of SUDS-to-SER Conversion Costs ($)
Bonneville	60.0	180,000
Portland General Electric Company	40.0	120,000
Total	100.0	300,000

Final sharing will be based on actual costs.

(WP-PKT-0777e)

4. Duties of Bonneville. Bonneville shall design, provide all necessary labor and materials, and as soon as reasonably practicable after the Effective Date of this Table replace the SUD event/alarm disturbance system at Grizzly with a tested, energized, and operating SER System. All costs are to be shared in accordance with section 3 above.

5. Duties of the Company. The Company shall cooperate with Bonneville as necessary for Bonneville to make the SUDS-to-SER replacement specified in section 4 above.

6. Ownership. Title to and ownership of the equipment installed under this Table 1 shall be in accordance with section 8 of the Primary Agreement.

7. Operation and Maintenance. Operation and Maintenance of the equipment installed hereunder shall be in accordance with the O&M Trust Agreement (Contract No. 14-03-73941).

(WP-PKT-0777e)

Exhibit B
Table 2, Page 1 of 2
Contract No. DE-MS79-86BP92277
Portland General Electric Co.
Dated 4/20/87
Effective: See "Term" below

Installation of Facilities
(Stability Control Upgrade, Phase 1, Part 3)

The parties agree that it would be mutually beneficial for certain changes, additions, and modifications to be made at Grizzly as part of the AC Intertie Stability Control Upgrade Project, Phase I, Part 3, with the cost being shared by the parties. Energization is planned for June 1987.

Accordingly, Bonneville shall make these changes, additions, and modifications under this Table 2 subject to the following terms and conditions:

1. Term. This Table 2 shall be effective as of 2400 hours on the date of execution after Bonneville has received original signed copies of the Construction Trust Agreement, Contract No. DE-MS79-86BP92277 (Primary Agreement) and a check from the Company in the amount of the Trust Deposit specified in section 3(a) below.

2. Cost Sharing. The estimated total cost for these changes, additions, and modification at Grizzly as described in section 4 below is $490,000. This estimated amount is to be shared by the parties in proportion to their percentage ownerships of the Grizzly jointly-owned property as follows:

Party	Joint Ownership Percentage (%)	Estimated Share of Stability Controls Upgrade Costs ($)
Bonneville	60.0	294,000
Portland General Electric Company	40.0	196,000
	100.0	490,000

Final sharing shall be based on actual cost.

3. Trust Deposit. The Company agrees to pay $196,000 to Bonneville to be held in trust to defray the cost to the Government of performing the duties specified in section 4. The Company shall pay the Trust Deposit as follows:

a. $100,000 on the date of execution; and

b. $96,000 within 30 days after the date of execution.

4. Duties of Bonneville. As soon as reasonably practicable after the Effective Date of this Table, Bonneville shall design, provide all necessary labor and materials, and:

a. install equipment to generate a revised Malin-Grizzly "Intertie Trouble" transfer trip signal;

b. add transfer trip equipment to receive a line-loss signal from new logic installed at John Day;

c. replace obsolete transfer trip equipment on nine critical Remedial Action Scheme circuits;

d. replace obsolete Tone Test Panels on four critical transfer trip circuits; and

e. provide transfer trip equipment for three new control circuits which integrate the Remedial Action Scheme with Pacific Gas and Electric's Remedial Action Scheme.

5. Duties of The Company. The Company shall cooperate with Bonneville as necessary for Bonneville to make the changes and additions specified in section 4 above.

6. Ownership. Title to and ownership of the equipment installed under this Table 2 shall be in accordance with section 8 of the Primary Agreement.

7. Operation and Maintenance. Operation and Maintenance of the equipment installed hereunder will be in accordance with the O&M Trust Agreement (Contract No. 14-03-73941).

8. Microwave Facilities. All microwave facilities at Grizzly are solely owned and operated and maintained by Bonneville at Government expense. Accordingly, Bonneville shall own and make all additions, modifications, and replacements to microwave facilities for the AC Intertie Stability Control Upgrade, and shall O&M these facilities at Government expense. The duties listed in section 4 above do not include work on Bonneville's solely-owned microwave facilities.

Installation of Facilities
(Main Control House Expansion)

The parties agree that it would be mutually beneficial for the control house at Grizzly to be expanded by 1505 square feet and for the existing heating, ventilating and air conditioning system (HVAC) to be replaced. This additional floor space is required for the control and communication equipment associated with the new Stability Control Upgrade and will include sufficient space to house future control, protection, communication, and data systems. The current HVAC is past its nominal service life and suffers from frequent failures. Additional HVAC capacity is also needed because of the control house expansion. The control house expansion also requires relocation of the entrance road. Completion is planned for November 1987.

Accordingly, the work shall be performed by Bonneville subject to the following terms and conditions:

1. Term. This Table 3 shall be effective as of 2400 hours on the date of execution after Bonneville has received original signed copies of the Construction Trust Agreement, Contract No. DE-MS79-86BP92277 (Primary Agreement) and a check from the Company in the amount of the Trust Deposit specified in section 3(a) below.

2. Cost Sharing. The estimated total cost of constructing the 1505 square foot addition to the Grizzly control house and replacing the HVAC, as described in section 4 below, is $347,000. This amount is to be shared by the parties in proportion to their percentage ownerships of the Grizzly jointly-owned property as follows:

Party	Joint Ownership Percentage (%)	Estimated Share of Control House Expansion Costs ($)
Bonneville	60.0	208,200
Portland General Electric Company	40.0	138,800
	100.0	347,000

Final sharing shall be based on actual costs.

3. Trust Deposit. The Company agrees to pay $138,800 to Bonneville to be held in trust to defray the cost to the Government for performing the duties specified in section 4. The Company shall pay the Trust Deposit as follows:

a. $20,000 on the date of execution; and

b. $118,800 within 6 months after the date of execution.

4. Duties of Bonneville. Bonneville shall design, provide all necessary labor and materials, and within 8 months after the Effective Date of this Table construct the addition to the Grizzly control house and replace the existing HVAC as follows:

a. Control house addition. Construct a 35' x 43' addition to the Grizzly control house and relocate the entrance road; and

b. HVAC Replacement. Remove and replace the existing water-cooled air conditioning unit and water-heated boiler with a new outdoor air-cooled air conditioning unit and a new electric resistance heating unit.

All costs are to be shared in accordance with section 2 above.

5. Duties of The Company. The Company shall cooperate with Bonneville as necessary for Bonneville to make the additional replacements specified in section 4 above.

6. Ownership. Title to and ownership of the equipment installed under this Table 3 shall be in accordance with section 8 of the Primary Agreement.

7. Operation and Maintenance. Operation and Maintenance of the equipment installed hereunder shall in accordance with the O&M Trust Agreement (Contract No. 14-03-73941).

(WP-PKT-0777e)

Installation of Facilities
(Revenue Metering Replacement)

The parties agree that it would be mutually beneficial to replace the revenue meters at Grizzly. New solid state meters would replace the existing electro-mechanical Sangamo P30F revenue meters, which are less accurate and require more maintenance. Energization is planned for June 1987.

Accordingly, the work shall be performed by Bonneville subject to the following terms and conditions:

1. Term. This Table 4 shall be effective as of 2400 hours on the date of execution after Bonneville has received original signed copies of the Construction Trust Agreement, Contract No. DE-MS79-86BP92277 (Primary Agreement) and a check from the Company in the amount of the Trust Deposit.

2. Cost Sharing. The estimated total cost of replacing the revenue meters, as described in section 4 below, is $20,000. This amount is to be shared by the parties in proportion to their percentage ownerships of the Grizzly jointly-owned property as follows:

Party	Joint Ownership Percentage (%)	Estimated Share of Replacement Costs ($)
Bonneville	60.0	12,000
Portland General Electric Company	40.0	8,000
Total	100.0	20,000

Final sharing shall be based on actual costs.

3. Trust Deposit. The Trust Deposit shall be in the amount of $8,000.

4. Duties of Bonneville. As soon as reasonably practicable after the Effective Date of this Table, Bonneville shall design, provide all necessary labor and materials, and replace the existing Sangamo P30F revenue meters at Grizzly with solid state meters.

5. Duties of the Company. The Company shall cooperate with Bonneville as necessary to insure completion of the replacement of the revenue meters as specified in section 4 above.

6. Ownership. Title to and ownership of the equipment installed under this Table 4 shall be in accordance with section 8 of the Primary Agreement.

7. Operation and Maintenance. Operation and Maintenance of the equipment installed hereunder shall be in accordance with the O&M Trust Agreement (Contract No. 14-03-73941).

8. Accounting. If the parties agree that it is necessary for the Company to participate in the test and energization of the revenue meters replaced by Bonneville under this Table, the Company's appropriate costs incurred shall be proper charges against this trust. The Company shall submit to Bonneville a detailed invoice of its costs incurred and Bonneville shall give the Company appropriate credit against this trust.

(WP-PKT-0777e)

Installation of Facilities
(Oscillograph Replacement)

The parties agree that it would be mutually beneficial for Bonneville to replace the oscillograph at Grizzly with a less maintenance intensive, more reliable modern oscillograph. Energization is planned for April 1988.

Accordingly, the work shall be performed by Bonneville subject to the following terms and conditions:

1. Term. This Table 5 shall be effective as of 2400 hours on the date of execution after Bonneville has received original signed copies of the Construction Trust Agreement, Contract No. DE-MS79-86BP92277 (Primary Agreement) and a check from the Company in the amount of the Trust Deposit specified in section 3(a) below.

2. Cost Sharing. The estimated total cost of replacing the oscillograph as described in section 4 below, is $140,000. This amount is to be shared by the parties in proportion to their percentage ownerships of the Grizzly jointly-owned property as follows:

Party	Joint Ownership Percentage (%)	Estimated Share of Replacement Costs ($)
Bonneville	60.0	84,000
Portland General Electric Company	40.0	56,000
Total	100.0	140,000

Final sharing shall be based on actual costs.

3. Trust Deposit. The Company agrees to pay $56,000 to Bonneville to be held in trust to defray the cost to the Government of performing the duties specified in section 4. The Company shall pay the Trust Deposit as follows:

   a. $4,000 on the date of execution; and
   b. $28,000 within 6 months after the date of execution; and
   c. $24,000 within 9 months after the date of execution.

4. Duties of Bonneville. Bonneville shall design, provide all necessary labor and materials, and within 13 months after the Effective Date of this Table replace the existing analog 12-channel light sensitive paper film oscillograph at Grizzly with a 16-channel digital oscillograph to eliminate the need to develop the paper film and to obtain prefault and remote readout capabilities.

5. Duties of the Company. The Company shall cooperate with Bonneville as necessary to insure completion of the replacement of the oscillograph as specified in section 4 above.

6. Ownership. Title to and ownership of the equipment installed under this Table 5 shall be in accordance with section 8 of the Primary Agreement.

7. Operation and Maintenance. Operation and Maintenance of the equipment installed hereunder shall be in accordance with the O&M Trust Agreement (Contract No. 14-03-73941).

H. Thompson - DTK

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208

February 11, 1987

In reply refer to: PKT

Mr. Michael E. Mikolaitis
Manager of System Planning
Portland General Electric Company
121 SW. Salmon Street
Portland, OR 97204

Dear Mike:

BPA and PGE representatives (Substation Design and Control Engineering for BPA, and System Planning Engineering for PGE) have agreed that the following is generally true concerning lines of separation (demarcation) between control facilities/equipment and microwave facilities/equipment at any terminal. It is particularly true for the AC Stability Control Upgrade Projects at Malin (Trust Table 13 of Contract No. 14-03-29225) and Grizzly (Trust Table 2 of proposed Contract No. (DE-MS79-86BP92277) Substations.

> The line of separation (demarcation) between control and microwave (channel) facilities/equipment is <u>the wire</u> that connects the control equipment (a microwave transfer trip receiver in this instance) to the Interfacing Distribution Frame (IDF). The IDF is considered to be an item of the microwave facility.

For the AC Intertie Stability Control Upgrade Project, control equipment is jointly-owned by the parties; microwave facilities, on the other hand, are Government-owned and provided. Therefore, only the estimated costs of the control equipment is considered in arriving at The Trust Deposits for the parties.

As you requested, I am enclosing a copy of the Phase I, Part 3 Control Project Diagram (Serial EMB 1795) and the control facilities/equipment estimates used for Tables 2 & 13.

Substation	Table	Estimate	Total Cost
Malin	13	EC-8120	$[illegible],000
Grizzly	2	EC-8121	490,000

It is my understanding that Amendatory Agreement No. 3 to Malin O&M Trust Agreement (Contract No. 14-03-63537) and all the Malin Technical Improvement Trust Tables, except Table 15 (500 kV breaker additions for the Malin-Round Mountain lines) and Table 16 (addition of Dynamic Voltage Support), have been signed by PGE. It is my further understanding that after minor revisions requested by PGE, Table 16 will be ready for signature.

Because we both realize the close interdependence of Tables 13 & 14, it is BPA's hope that PGE will accelerate its procedures for signing Table 14.

BPA and PGE representatives will rewrite the January 23, 1987, signature draft of the proposed Grizzly Construction Trust Agreement (Contract No. 92277) to allow for construction and installation of only the facilities provided for in Trust Tables 1 through 6.

If I can assist you further in these or related matters, please call me at (503)230-3003.

Sincerely,

William A. Mittelstadt
Intertie Planning Project Manager - PK

4 Enclosures

cc:
H. Kirby - PGE (Power Contracts) (w/ 2enc)
J. Huntsinger - PGE (Power Contracts) (w/2 enc)

WJenkins:kls:5846 (WP-PKTD-1263g)

bcc:
H. Thompson - DTK
H. Klinger - E
C. Clark - E
M. Holm - EH
L. Keltner - ENBA
M. Westfahl - ENBA
L. Morales - EOFA (w/2 attachments)
L. Hill - ENR
J. Haner - ENRB
D. Larson - OG
P. McRae - OWC
S. Lee - OWC
A. Aplass - OWC (w/attachments)
J. Jones - P
J. Krier - P
W. Pollock - P
T. Noguchi - PK
T. Blankenship - PKT
D. Loraas - PKTD
W. Jenkins - PKTD
Official File - PKT [EDC-6]

cc for Ct. 92340

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

OFFICE OF THE ADMINISTRATOR

In reply refer to: PMT

Contract No. DE-MS79-90BP92865

Ms. Kay Stepp
President
Portland General Electric Company
121 SW. Salmon Street
Portland, Oregon 97204

Dear Ms. Stepp:

Continued discussions of the pending Contract No. DE-MS79-88BP92273 (IR Agreement) between our organizations have clarified Portland General Electric Company's (Portland General) and Bonneville Power Administration's (Bonneville) important needs. Bonneville recognizes the importance to Portland General to displace its firm resources. Bonneville intends to provide transmission for that displacement at most times under section 5(a)(3) of the IR Agreement subject to Bonneville's determination of available capacity based on (1) its need to provide reliable system operation; (2) its need to comply with its environmental obligations; and (3) its need to preserve its flexibility to transmit its own resources and to meet its nonfirm and firm wheeling and contractual obligations. When Portland General considers its supply options for such displacement, Portland General will consider purchasing its displacement supplies from Bonneville. If Bonneville offers terms and conditions substantially similar to other supply options, and such a purchase is consistent with Portland General's other contractual obligations, Portland General intends not to unreasonably discriminate against Bonneville in choosing a supplier.

In recognition of our respective needs, section 5(a)(3) of the IR Agreement was expanded to better reflect our current operating and scheduling practices.

Further, because of potential changes in the electric utility industry it is becoming increasingly likely that Bonneville will re-examine its regional transmission policies. Bonneville will consider as part of any such process the transmission services requested by Portland General in the July 18, 1989, letter from Mr. Lindblad to Bonneville Administrator, Jim Jura. If Bonneville adopts new policies as a result of such a process, Bonneville will offer to amend the IR Agreement to reflect any such policy changes.

In no case is this letter or the IR Agreement intended to expand or restrict the rights established under the Intertie Agreement, Contract No. DE-MS79-87BP92340, except that all charges related to delivery of half of Portland General's Intertie schedules to Portland General's system under section 15(c)(2) shall be waived by Bonneville. Such waiver shall continue despite termination of this Letter Agreement.

The factors used to calculate the transfer and sole use-of-facility charges in Contract No. DE-MS79-89BP92384 (GTA) have not been updated. The current charges established under the Prior Agreements, as defined in the recital section of the GTA, shall continue. However both parties agreed to revise the investment, ACRs and LARRs, proportional use loads, and operation and maintenance charges and to make other changes as necessary within 12 months of the execution of the GTA. Changes to the transfer and sole use-of-facility charges as a result of changes to these factors or any other change will not be made retroactive, but will become effective on the effective date shown on the revised exhibits.

Finally, both Portland General and Bonneville understand that this Letter Agreement was negotiated contemporaneously with the IR Agreement and the GTA such that Portland General and Bonneville benefit from favorable terms in one agreement in exchange for concessions in the other, and termination of the IR Agreement terminates this Letter Agreement.

If you concur with the above, please countersign this letter and return it along with signed copies of the IR Agreement and the GTA within 10 working days of the receipt of these agreements.

Sincerely,

James J. Jura

Administrator

PORTLAND GENERAL ELECTRIC CO.

CONCUR: E. Kay Stepp

TITLE: President

DATE: December 11, 1989

(VS6-PMTT-4000d)

AC INTERTIE FACILITY OWNER
MANAGEMENT COMMITTEE RESOLUTION

Following the meeting of the Management Committee of the AC Intertie Facility Owners on September 5, 2014, the following Resolution was proposed by motion and unanimously approved by the Management Committee through email communication:

Resolved:

WHEREAS the Bonneville Power Administration, Portland General Electric, and PacifiCorp (collectively the "AC Intertie Facility Owners") jointly own the AC intertie facilities, and the Management Committee is made up of representatives from each of the AC Intertie Facility Owners. The Management Committee believes it is in the best interest of each respective AC Intertie Facility Owner/Transmission Provider and its respective Transmission Customers to agree upon an allocation methodology and process for allocating Dynamic Transfer Capability ("DTC") on the northern California-Oregon Intertie ("COI") that recognizes the proportional ownership interest of each AC Intertie Facility Owner by allocating DTC based on a *pro rata* share of total COI Total Transfer Capability ("TTC") ownership;

WHEREAS it is further agreed that the AC Intertie Facility Owners/Transmission Providers will cap COI DTC requests submitted by their respective Transmission Customers (which, for purposes of this Resolution, include all entities using COI DTC) at the lesser of the Transmission Customer's firm COI rights or the total COI DTC scheduling limit, and an individual Transmission Customer's COI DTC allocation is determined on a *pro rata* basis as illustrated in the Exhibit to this Resolution, which the Management Committee may replace or revise from time to time;

WHEREAS it is further agreed that if, after the first round of allocating to all Transmission Customers making COI DTC requests, an AC Intertie Facility Owner/Transmission Provider has unallocated COI DTC remaining, the Transmission Provider will release its unused COI DTC share ("Remainder") to Transmission Providers with remaining unfulfilled requests for COI DTC ("Remaining TPs"), according to the transmission facility ownership share of each Remaining TP relative to the sum of the transmission facility ownership of all Remaining TPs, as illustrated in the Exhibit to this Resolution. Each AC Intertie Facility Owner/Transmission Provider will then allocate its share of the Remainder to its Transmission Customers with remaining unfulfilled COI DTC requests allocated in a manner consistent with the first round of allocations, as illustrated in the Exhibit to this Resolution. The sum of the two allocation distributions described above is the total COI DTC allocation per Transmission Customer for the time period calculated.

WHEREAS it is further agreed that, before Transmission Customers may begin to submit COI Dynamic e-Tags, AC Intertie Facility Owners/Transmission Providers will require advance notice and will work with Transmission Customers to: (i) coordinate with and provide data to Bonneville Power Administration, as path operator, sufficient to administer COI DTC allocation and process COI Dynamic e-Tags consistent with this Resolution; and (ii) ensure compliance with applicable operational requirements and business practices.

WHEREAS it is further agreed that this Resolution will be in effect until October 1, 2019. The AC Intertie Facility Owners will either renew or replace this Resolution prior to October 1, 2019.

WHEREAS it is further agreed that AC Intertie Facility Owners/Transmission Providers will require a minimum set of scheduling and e-Tagging requirements for their respective Transmission Customers, including the following:

- Requests for COI DTC must be submitted via a Dynamic e-Tag within a common timing window among all Transmission Customers of AC Intertie Facility Owners/Transmission Providers.
    - Starting October 1, 2014, the window for making a COI DTC request will close at 8 am on each Western Electricity Coordinating Council ("WECC") Preschedule day, including the following additional requirements:
        - Dynamic e-Tags must be in a "Confirmed" state in order to be considered for a COI DTC allocation.
        - The Transmission Profile of the Dynamic e-Tag(s) will be utilized in the COI DTC allocation process.
        - E-Tag tokens may be used to uniquely identify eligible e-Tags.
- The Transmission Customer must submit a COI Dynamic e-Tag for each hour covered by the WECC Preschedule day that the Transmission Customer desires to receive a COI DTC allocation.
- Bonneville Power Administration will administer an automated process that performs the COI DTC allocation for each WECC Preschedule day based on the agreed upon methodology set forth in this Resolution and its Exhibit and will apply a Reliability Limit on the Dynamic e-Tag to be no greater than the Transmission Customer's COI DTC allocation.
- AC Intertie Facility Owners/Transmission Providers will develop controls so that Bonneville Power Administration can manage the dynamic signal limits in real-time during active COI flow management conditions;
    - If such controls cannot be implemented in a timely manner, Transmission Providers may permit their Transmission Customers to temporarily utilize the CAISO's Automated Dispatch System, or some other automated system that is capable of enforcing the DTC allocation as an upper limit.

WHEREAS it is further agreed that the AC Intertie Facility Owners will continue to work together to develop and improve methodologies and systems and related requirements for allocation and use of COI DTC, including but not limited to the ability to allocate COI DTC in or close to real-time in a manner that recognizes actual usage of COI DTC as well as the potential for offsetting impacts of any COI DTC counter-schedules.

WHEREAS that the Management Committee of the AC Intertie Facility Owners supports and endorses the Resolution.

Management Committee of the AC Intertie Facility Owners

Signed:

Frank Afranji 10-15-2014

Frank Afranji, Director of Transmission and Reliability Services, Portland General Electric

Richard Shaheen, Acting Senior Vice President of Transmission Services, Bonneville Power Administration

Natalie Hocken, Senior Vice President Transmission and System Operations, PacifiCorp

WHEREAS that the Management Committee of the AC Intertie Facility Owners supports and endorses the Resolution.

Management Committee of the AC Intertie Facility Owners

Signed:

Frank Afranji, Director of Transmission and Reliability Services, Portland General Electric

10-17-14

Richard Shaheen, Acting Senior Vice President of Transmission Services, Bonneville Power Administration

Natalie Hocken, Senior Vice President Transmission and System Operations, PacifiCorp

WHEREAS that the Management Committee of the AC Intertie Facility Owners supports and endorses the Resolution.

Management Committee of the AC Intertie Facility Owners

Signed:

Frank Afranji, Director of Transmission and Reliability Services, Portland General Electric

Richard Shaheen, Acting Senior Vice President of Transmission Services, Bonneville Power Administration

Natalie Hocken

Natalie Hocken, Senior Vice President Transmission and System Operations, PacifiCorp

Contract No.
DE-MS79-89BP92821
6/22/89
Cross Reference Ct. 92340

LTIAP Litigation Settlement Agreement

This LONG TERM INTERTIE ACCESS POLICY LITIGATION SETTLEMENT AGREEMENT (Agreement) is executed this 22nd day of June, 1989 by the BONNEVILLE POWER ADMINISTRATION (Bonneville) and PORTLAND GENERAL ELECTRIC COMPANY (PGE) and PORTLAND GENERAL EXCHANGE, INC. (PGX).

W I T N E S S E T H:

WHEREAS PGE has intervened in certain appeals to Bonneville's Long Term Intertie Access Policy (LTIAP) brought by others in the United States Court of Appeals for the Ninth Circuit; and

WHEREAS PGX has certain disputes with Bonneville regarding interpretation of the LTIAP; and

WHEREAS PGE, PGX and Bonneville have agreed to resolve their disputes over portions of Bonneville's LTIAP.

NOW, THEREFORE, the parties agree as follows:

1. Dismissal of Appeal. PGE will dismiss its intervention in Docket No's. 88-7280, 88-7315, 88-7318, and 88-7319 (Ninth Circuit).

2. PGE's Rights Under LTIAP. Bonneville and PGE acknowledge that, due to their previously-executed Intertie Agreement (Contract No. DE-MS79-87BP92340), PGE's prevailing on its discrimination claim would result in no immediate change in the relationship or operation of their respective shares of the Intertie.

3. PGX and the LTIAP.

(a) In accordance with Bonneville's standard transmission policies and practices, Bonneville will grant firm transmission over its Intertie capacity to a Scheduling Utility (as defined in the LTIAP) for PGX's firm transactions with Southwest utilities if PGX acquires surplus Qualified Northwest Resources from the same Scheduling Utility with an LTIAP Exhibit B allocation greater than or equal to the amount of such acquisition; the Scheduling Utility agrees to reduce its Exhibit B allocation in the amount of PGX's acquisition and to waive Bonneville's service obligation as specified in section 4(a)(4) of the LTIAP; any energy returns utilizing Bonneville Intertie capacity comply with section 4(a)(5) of the LTIAP; Bonneville obtains mitigation under section 4(d) of the LTIAP; and the Protected Area remedies provided under section 7 of the LTIAP are incorporated. Real time adjustments to accomodate changes in prescheduled amounts may be arranged by agreement of Bonneville and PGX.

(b) The foregoing paragraph 3(a) governs PGX's utilization of Exhibit B Assured Delivery capacity available under the LTIAP. Bonneville and PGX are also free to arrange joint ventures that provide for firm transmission.

4. Delivery to PGE's Intertie. In delivering nonfederal power over the Federal Columbia River Transmission System (FCRTS) to the John Day Substation for delivery using PGE's Intertie capacity:

(a) Bonneville shall apply the same practices, terms and conditions to transmission of nonfederal power, owned at all times prior to delivery to the Southwest purchaser by an entity other than PGE, as would be applied to similarly-situated nonfederal power scheduled to John Day Substation for transmission over Bonneville's Intertie capacity. The foregoing shall include, but shall not be limited to, the following:

(i) Bonneville shall permit such nonfederal power to be delivered directly to John Day Substation for delivery using PGE's Intertie capacity without requiring intermediate delivery to the PGE system;

(ii) Bonneville shall deliver such nonfederal power to John Day Substation regardless of whether Bonneville has made its own operational Intertie capacity available for transmission of nonfederal power; and

(iii) Bonneville shall apply the same FCRTS transmission rate schedules to such nonfederal power as would be applied to similarly-situated nonfederal power scheduled to John Day for delivery using Bonneville's Intertie capacity.

(b) Coordination of schedules of such nonfederal power for delivery over FCRTS with schedules over PGE's Intertie capacity shall occur through the Joint Scheduling Office.

5. Inconsistent Provisions. The terms of this Agreement shall supersede and control any inconsistent terms or provisions in any agreement previously entered into between any of the parties.

6. Assignment.

(a) Except as provided in this Paragraph 6(b), this Agreement may not be assigned without each party's written consent, which may be withheld at the party's sole discretion.

(b) This Agreement or any part hereof may be assigned without any party's prior written consent if the assignment is made in conjunction with a merger of or the acquisition of all, or substantially all, of the properties of the assigning party.

7. Effect of Declaration of Invalidity. Paragraph 3 of this Agreement shall be subject to and governed by any court order which limits or holds invalid, in whole or in part, the rights granted under the LTIAP. This Agreement shall not be interpreted to withhold from PGE, PGX or Bonneville the benefits of any final court order respecting the LTIAP which would otherwise

accrue to them under the terms of the order, provided that the terms of Paragraph 4 shall not be subject to change by such order. If any portion of the LTIAP is remanded by the court in the above litigation, PGE and/or PGX shall be entitled to participate in the remand process conducted by Bonneville and may appeal any Bonneville determination on remand.

BONNEVILLE POWER ADMINISTRATION

James J. Jura

James J. Jura, Administrator

PORTLAND GENERAL ELECTRIC COMPANY

Richard E. Dyer, Vice President, Power Management

PORTLAND GENERAL EXCHANGE, INC.

Alvin Alexanderson, President

AUTHENTICATED COPY

Amendatory Agreement No. 1 to
Contract No. DE-MS79-87BP92340

INTERTIE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PORTLAND GENERAL ELECTRIC COMPANY

This Amendatory Agreement No. 1 (Amendment) is executed this 13th day of February, 1991, by United States of America acting by and through the Bonneville Power Administration ("Bonneville") and Portland General Electric Company ("Portland").

W I T N E S S E T H:

WHEREAS, Portland and Bonneville are parties to Contract No. DE-MS79-87BP92340 (Intertie Agreement); and

WHEREAS, by letter dated September 18, 1990, Portland requested this amendment to address cost-sharing and capacity rights related to Contract No. DE-ME79-91BP93158 (Interim Interconnection Agreement) between the Northwest Participants and the California-Oregon Transmission Project (COTP) Participants; and

WHEREAS, in order that the Interim Interconnection Agreement can be implemented, Portland and Bonneville desire to amend the Intertie Agreement.

NOW, THEREFORE, Bonneville and Portland agree as follows:

1. Term. Unless mutually terminated earlier, this Amendment shall terminate at such time as the Plan of Service, conforming to the Third AC Project Diagram incorporated as Exhibit C in the Intertie Agreement is energized. This Amendment shall become effective on the date of execution.

2. Construction. Portland and Bonneville agree to acquire, construct, and energize those facilities in the Joint AC Intertie identified in Exhibit B of the Intertie Agreement which are necessary for the Interim Interconnection Agreement. The Parties further agree to make good faith efforts to complete such facilities by December 1992. Nothing in this Amendment shall be construed as consent by PGE to a plan of service to increase the Rated Transfer Capability of the Northwest AC Intertie to 4800 MW other than the Plan of Service, conforming to the Third AC Project Diagram incorporated as Exhibit C in the Intertie Agreement.

3. Special Conditions.

(a) Upon completion of the facilities defined in Section 2 of this Amendment and for the remaining term of this Amendment, Subsection 7(b) of the Intertie Agreement shall be replaced with the following:

"7(b)(1)(A) During such time that the Rated Transfer Capability of the Northwest AC Intertie is greater than

3200 MW up to and including 4800 MW, Portland's share of the Rated Transfer Capability shall be 1) the share specified in subsection 7(a) plus 2) a share of the increased Rated Transfer Capability in the ratio of 120/500 times the increase in Rated Transfer Capability above 3200 MW up to and including 3700 MW plus 3) the share of the increased Rated Transfer Capability in the ratio of 30/300 times the increase in Rated Transfer Capability above 3700 MW up to and including 4000 MW.

7(b)(1)(B). If the Rated Transfer Capability of the Northwest AC Intertie is less than 4000 MW on December 31, 1994, and such rating is due primarily to restrictions north of the California - Oregon border (COB), or if the Operational Transfer Capability of the Northwest AC Intertie is less than 4000 MW for substantial periods of time solely due to overloading of the existing PacifiCorp Electric Operations' (PacifiCorp) Dixonville to Meridian 230 kV line, then Portland's share of the Rated Transfer Capability shall be 1) the share specified in subsection 7(a) plus 2) a share of the increased Rated Transfer Capability in the ratio of 150/500 times the increase in Rated Transfer Capability above 3200 MW up to and including 3700 MW provided, however, that if Bonneville and PacifiCorp execute a successor interconnection agreement to the Interim Interconnection Agreement as favorable as the Interim Interconnection Agreement, which requires completion of the Plan of Service conforming to the Third AC Project Diagram incorporated as Exhibit C in the

Intertie Agreement and Portland fails to execute such agreement, Portland's share of Rated Transfer Capability shall be 1) the share specified in subsection 7(a) plus 2) a share of the increased Rated Transfer Capability in the ratio of 150/800 times the increase in Rated Transfer Capability above 3200 MW up to and including 4000 MW. Should this subsection apply, Portland shall not be responsible for remedial action schemes required north of COB to improve the Rated Transfer Capability from such reduced level to 4000 MW except for those remedial action schemes required for the facilities associated with the Plan of Service shown in Exhibit C.

7(b)(1)(C) As between Bonneville and Portland, Bonneville's share of the Rated Transfer Capability shall be the share specified in subsection 7(a) plus the increased Rated Transfer Capability less Portland's share as determined in this subsection."

(b) For the term of this Amendment, subsection 8(c)(3) of the Intertie Agreement shall be replaced by the following:

"In consideration for the right to make deliveries to Southern Oregon Substation in paragraph 8(c)(1), Portland shall pay Bonneville 950/4800 of the annual cost of the Southern Oregon Substation, facilities connecting it to the Joint AC Intertie and the facilities connecting the Southern Oregon Substation to the COTP. Only such facilities and their estimated costs, as shown in Exhibit F and as are necessary to the Interim Interconnection Agreement, shall be included, and the cost of two of the three circuit breakers presently planned to be installed for loop-in of the Grizzly-Malin line shall be excluded if the Parties agree that such facilities are not necessary for the Interim Interconnection Agreement. Bonneville and Portland agree that the estimated investment costs and resultant annual costs shall be revised to reflect actual construction costs. The methodology to compute the annual cost of such facilities is described in Exhibit F and an example of the calculation applying such methodology is provided in Exhibit F. Such annual charge shall be billed and paid on a monthly basis according to the billing and payment provisions in Portland's Power Sales Agreement (Contract DE-MS79-81BP90425)."

(c) For the term of this Amendment, subsection 8(c)(1)(B) of the Intertie Agreement shall be replaced with the following:

"If the COTP and the presently existing AC Intertie lines in California are not operated as a single system, Portland may schedule through Southern Oregon Substation up to the lesser of 1) one-third of its share of the Rated Transfer Capability as such share may be reduced pursuant to paragraph 8(b)(1), or 2) the amount of Portland's share of the increase in Rated Transfer Capability as determined in subsection 7(b), as amended by this Amendment, provided this limitation is necessary to accommodate Bonneville's future or existing long-term firm transactions, up to 550 MW, able to be scheduled only through Southern Oregon Substation, and provided further both Parties agree to limit schedules to 800 MW through Southern Oregon Substation and on to the Point of Interconnection as defined in the Interim Interconnection Agreement. Long-term firm transactions as used in this subsection shall be those transactions which are one year or more in duration."

4. Minimum Transfer Capability. To the extent required, Bonneville shall provide, solely from its share of Rated Transfer Capability, any difference between the increase in Rated Transfer Capability attributable to the Northwest Plan of Service (as defined in the Interim Interconnection Agreement), and 800 MW, which is required by Section 10.3 of the Interim Interconnection Agreement to be maintained for Interregional Transfers, between the Northwest AC Intertie and the COTP.

5. Agreements for Implementation of this Agreement. Bonneville and Portland agree to negotiate in good faith any additional agreements that may be required to implement the terms and conditions of this Amendment.

6. No Modification. The Intertie Agreement is not modified or amended, except as expressly provided in this Amendment.

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION

By: James J Jura — /s/ James J. Jura
Administrator

Date: February 13, 1991 — February 13, 1991

PORTLAND GENERAL ELECTRIC COMPANY

By: — /s/ W. M. Higgins
W. M. Higgins

Title: Sr. Vice President — Sr. Vice President

Date: 2/6/91 — 2/6/91

AUTHENTICATED COPY

Contract No. DE-MS79-87BP92340

INTERTIE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PORTLAND GENERAL ELECTRIC COMPANY

Index to Sections

This INTERTIE AGREEMENT, executed July 29, 1988, by the BONNEVILLE POWER ADMINISTRATION (Bonneville) and PORTLAND GENERAL ELECTRIC COMPANY (Portland), a corporation organized and existing under the laws of the State of Oregon.

W I T N E S S E T H :

WHEREAS Bonneville and Portland are owners of facilities that comprise the existing Joint AC Intertie; and

WHEREAS Bonneville and Portland are parties to Contract No. 14-03-55063 (Intertie Operations Agreement), and to Contract No. DE-MS79-84BP91883 (Intertie Settlement Agreement), which provided rights and responsibilities of the parties regarding the Joint AC Intertie and which shall expire on December 15, 1988, unless extended or replaced; and

WHEREAS Bonneville and Portland desire to replace the Intertie Operations Agreement and Intertie Settlement Agreement with this Intertie Agreement; and

WHEREAS Bonneville and Portland desire to jointly operate their AC Intertie facilities as a single system in order to realize the full benefits of the combined facilities and to permit the ongoing use of the facilities for delivery and receipt of power and energy as described in this Agreement.

WHEREAS Bonneville, Portland, Pacific Power & Light Company (Pacific), and the Bureau of Reclamation entered into Contract No. 14-03-59840 (Malin Construction and Operations Agreement), Bonneville and Portland entered into Contract No. 14-03-29225 (Malin Construction Trust Agreement), and Contract No. 14-03-63627 (Malin Operation and Maintenance Trust Agreement) that include terms and provisions for facilities in the Joint AC Intertie in the Malin Substation; and

WHEREAS Bonneville and Portland entered into Contract No. 14-03-56747 (Grizzly Trust Agreement), Contract No. DE-MS79-86BP92277 (Grizzly Construction Trust Agreement), and Contract No. 14-03-73941 (Grizzly Operation and Maintenance Trust Agreement) that include terms and provision for facilities in the Joint AC Intertie at the Grizzly Substation; and

WHEREAS Bonneville and Pacific entered into Contract No. DE-MS79-86BP92299 (Pacific Intertie Agreement) that, among other things, gives Bonneville certain rights to establish a Plan-of-Service for the upgrade of the Northwest AC Intertie, and to construct and interconnect such intertie with Pacific's facilities; and

WHEREAS the California-Oregon Transmission Project (COTP) in California may be constructed and, if it is, Bonneville may desire to upgrade the Northwest AC Intertie to meet the expected increase in capacity, in which event Portland may desire to upgrade Portland's facilities in the Joint AC Intertie; and

WHEREAS Bonneville and Portland may, in the future, desire to further upgrade the facilities of the AC Intertie such that the Rated Transfer Capability of the AC Intertie is increased beyond the Transfer Capability of the COTP; and

WHEREAS Portland desires continuing ability to schedule power and energy for delivery to Pacific Southwest utilities at the Southern Oregon Substation; and

WHEREAS Bonneville and Portland agree to provide for the resolution of other agreements including a General Transfer Agreement, an Integration of Resources (IR) Agreement, and an exchange of a share of Portland's AC Rated Transfer Capability for an equal share of Bonneville's DC Rated Transfer Capability; and

WHEREAS Bonneville and Portland desire to resolve other outstanding issues regarding use of each other's system; and

WHEREAS nothing in this Intertie Agreement is intended to be determinative of transmission or ownership rights of utilities not party to this Agreement;

NOW, THEREFORE, in order to realize the full benefits from the facilities individually and jointly owned by the parties, to provide for the continuing use of those facilities, and to provide for planning, designing, operating, modifying, constructing, maintaining, and upgrading the individually and jointly owned facilities, known as the Joint AC Intertie, the parties hereto agree to the following:

1. Termination of Prior Agreements. The Intertie Operations Agreement and Intertie Settlement Agreement are hereby terminated on the Effective Date of this Agreement, but all obligations accrued thereunder are hereby preserved until satisfied.

2. Term of Agreement.

(a) With the exception of the provisions for operating and scheduling, which shall continue for 30 days from the Effective Date, this Agreement shall be effective on the date of execution (Effective Date) and shall continue in effect so long as the facilities of the Joint AC Intertie are in existence and operable.

(b) Should this Agreement terminate earlier than specified in subsection 2(a) for any reason except material breach of contract by either party, and the parties fail to agree to a replacement agreement, the parties agree to operate their jointly owned and separately owned facilities in such a manner to permit the continued use of the facilities for delivery and receipt of power and energy as described in this Agreement. Other than as excepted above, the parties intend this obligation to survive such earlier termination.

(c) Bonneville agrees not to participate in any renegotiation of provisions in the Pacific Intertie Agreement between Pacific and Bonneville effecting: (1) the ownership, operation, maintenance, or modification of the Joint AC Intertie; (2) the Rated Transfer Capability of the Northwest AC Intertie; or (3) Portland's right to make deliveries at Southern Oregon Substation as provided in subsection 8(c) of this Agreement, unless Portland is allowed to participate in the negotiations. In addition, Portland agrees not to participate in any negotiations with Pacific effecting: (1) ownership, operation, maintenance, or modification of the Northwest AC Intertie; or (2) the Rated Transfer Capability of the Northwest AC Intertie, unless Bonneville is allowed to participate in the negotiations.

(d) Bonneville and Portland agree to apply their best efforts to retain rights to deliver power and energy through Southern Oregon Substation.

3. Exhibits. Exhibits A through F are incorporated as part of this Agreement.

4. Definitions.

(a) COTP. The 500 kV transmission line proposed by the California-Oregon Transmission Project, or a successor line, which will operate in parallel with the existing 500 kV AC Intertie in California and that would increase the Rated Transfer Capability of the Northwest AC Intertie beyond the present capability of 3200 MW to as much as 4800 MW.

(b) DC Intertie. The DC Intertie consists of the Celilo converter station and the direct current line extending from the Celilo converter station to the Nevada-Oregon border, which are solely owned by Bonneville and which presently have a Rated Transfer Capability of approximately 2000 MW.

(c) DC Terminal Expansion. The planned increase in DC Intertie Rated Transfer Capability resulting from modifications to the Celilo and Sylmar Substations and the addition of new equipment to existing transmission facilities for the support of the DC Intertie. The planned Rated Transfer Capability of the Terminal Expansion is approximately 1100 MW, for a total DC Intertie Rated Transfer Capability of approximately 3100 MW.

(d) FCRTS or Federal Columbia River Transmission System. The transmission facilities of the Federal Columbia River Power System that include all transmission facilities owned and operated by Bonneville, and other regional facilities for which Bonneville has obtained transmission rights.

(e) Joint AC Intertie. For purposes of this Intertie Agreement, the Joint AC Intertie consists of alternating current (AC) transmission facilities, located in the State of Oregon, for transferring power and energy between the Pacific Northwest and California as follows: two 500 kV transmission lines extending from the John Day Substation to the Malin Substation, portions of John Day, Grizzly, and Malin Substations and the Bakeoven, Sand Springs, Fort Rock, and Sycan Compensation Stations. Consistent with the procedure specified in subsection 9(a), any modifications, additions, improvements, or other alterations to facilities in the Joint AC Intertie shall also become part of the Joint AC Intertie.

(f) Joint Intertie Scheduling Office. The group of Bonneville, Portland, and Pacific schedulers, which is presently located at Bonneville's Dittmer Control Center in Vancouver, Washington, and whose representatives are appointed from time-to-time to schedule energy over the Northwest AC Intertie.

(g) Northwest AC Intertie. The Northwest AC Intertie consists of those facilities in the Joint AC Intertie; and a portion of the Buckley-Summer Lake transmission line, Bonneville's rights in the 500 kV Summer Lake-Malin transmission line, and, should Bonneville require, the use of the 500 kV Meridian-Malin transmission line, the Southern Oregon Substation, and Bonneville's ownership of or rights to use the planned 500 kV Alvey-Meridian transmission line. Any modifications, additions, improvements, or other alterations to facilities in the Northwest AC Intertie shall also become part of the Northwest AC Intertie.

(h) Operational Transfer Capability. Rated Transfer Capability less reductions caused by, but not limited to, physical limitations beyond the control of the parties, and operational limitations as a result of among other things line or equipment outages, stability limits, or loopflow.

(i) Plan-of-Service. The project plans developed to realize an increase in the Rated Transfer Capability of the Northwest AC Intertie from 3200 MW up to approximately 4800 MW, which project plans shall include but are not necessarily limited to plans, schedules, costs, and facility and equipment requirements.

(j) Prudent Utility Practice. At any particular time, the generally accepted practices, methods, and acts in the electrical utility industry existing prior to the subject action or the practices, methods or acts, which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to accomplish the desired result consistent with reliability and safety.

(k) Rated Transfer Capability. The capability of a transmission line or system to transfer power in a reliable manner as determined in accordance with Prudent Utility Practice.

(l) Southern Oregon Substation. The proposed substation where the transmission line that interconnects with the COTP connects with the Northwest and Joint AC Interties in the Pacific Northwest.

(m) Unused Operational Transfer Capability. Operational Transfer Capability not being used during a given hour for a party's own schedules.

5. Ownership.

(a) Facilities in the Joint AC Intertie. Ownership of existing facilities is as follows:

(1) Bonneville has constructed and owns two 500 kV AC circuits from its John Day Substation to the Grizzly Substation, including two 500 kV terminal positions in said John Day Substation, and one 500 kV AC circuit from the Grizzly Substation to the Malin Substation (Grizzly-Malin No. 1

line). Bonneville also has constructed and owns the Bakeoven, and its Sand Springs, Fort Rock, and Sycan Compensation Stations.

(2) Portland has constructed and owns one 500 kV AC circuit from the Grizzly Substation to the Malin Substation (Grizzly-Malin No. 2 line). Portland also has constructed and owns its Sand Springs, Fort Rock, and Sycan Compensation Stations.

(3) Ownership of all facilities at the Grizzly Substation is as defined in the Grizzly Trust Agreement and the Grizzly Construction Trust Agreement.

(4) Ownership of all facilities at the Malin Substation is as defined in the Malin Construction and Operation Agreement and the Malin Construction Trust Agreement.

(b) By this Agreement, neither Bonneville nor Portland transfers to the other party ownership of existing or future facilities. While the provisions of section 8 provide Bonneville and Portland with scheduling rights based on the Rated Transfer Capability of the Northwest AC Intertie, there is no intention to transfer from one party to the other party any ownership in such facilities beyond those facilities presently owned by that party.

6. Operation of Northwest AC Intertie.

(a) Single System Operation. Bonneville and Portland, as between each other, hereby agree to operate their respective jointly owned and separately owned Northwest and Joint AC Intertie facilities as a single system so as to maximize, consistent with Prudent Utility Practice, the Rated and Operational Transfer Capability of the combined facilities.

(b) Committees.

(1) Management Committee. Bonneville and Portland shall form a Management Committee, consisting of one senior executive representative and an alternate from each organization possessing authority to commit their respective organization. The Management Committee shall oversee implementation of all provisions of this Agreement; designate representatives to and oversee the work of the Operations and Scheduling Committee and Engineering Committee; and resolve any disputes. Decisions of the Management Committee shall be by unanimous consent.

(2) Operation and Scheduling Committee. Among the duties of the Operation and Scheduling Committee are developing principles to guide the decisionmaking of the Operator and Joint Scheduling Office, and when the need arises to review the operation, maintenance, and scheduling of the Joint AC Intertie for consistency with the principles. The Management Committee may assign other duties to the Operation and Scheduling Committee where appropriate.

(3) Engineering Committee. Among the duties of the Engineering Committee are reviewing the plans for capital investments to the Joint AC Intertie. The Management Committee may assign other duties to the Engineering Committee where appropriate.

(c) Operator. Bonneville shall be the operator for the Northwest AC Intertie. As such, Bonneville shall be responsible for the dispatch of the Northwest AC Intertie in accordance with Prudent Utility Practice and the principles for operation developed by the Operation and Scheduling Committee, established pursuant to paragraph 6(b)(2). The duties of the operator include, but are not limited to, determining: (1) the Operational Transfer

Capability of the Northwest AC Intertie; (2) emergency outages; and (3) switching orders. In making such determination, Bonneville shall give fair consideration to Portland's interests in such matters, consistent with Prudent Utility Practice, to the extent those interests have been expressed to Bonneville in writing.

(d) Remedial Actions. Bonneville and Portland shall jointly develop through the Engineering Committee a plan for remedial actions, including generator dropping, required to support the Rated Transfer Capability of the Northwest AC Intertie. Each party shall provide, and be financially responsible for or make arrangements for, generator dropping or other remedial actions required to achieve the provisions of the plan. Each party's responsibility for such remedial actions, which may include generator dropping, shall be determined by dividing the party's share of Rated Transfer Capability in the Northwest AC Intertie by the total Rated Transfer Capability of the Northwest AC Intertie.

7. Shares of Rated Transfer Capability.

(a) Rated Transfer Capability at or below 3200 Megawatts (MW). During such time that the Rated Transfer Capability of the Northwest AC Intertie is less than or equal to 3200 MW, Portland's share of Rated Transfer Capability shall be equal to 25 percent of the Rated Transfer Capability of the Northwest AC Intertie. As between Bonneville and Portland, Bonneville's share of the Rated Transfer Capability of the Northwest AC Intertie shall be equal to 75 percent of the Rated Transfer Capability of the Northwest AC Intertie.

(b) Rated Transfer Capability greater than 3200 MW but not more than 4800 MW. During such time that the Rated Transfer Capability of the Northwest AC Intertie is greater than 3200 MW up to and including 4800 MW, Portland's share of Rated Transfer Capability shall be the share specified in subsection 7(a) plus a share of the increased Rated Transfer Capability in the ratio of 150/1600 times the increase in Rated Transfer Capability above 3200 MW. As between Bonneville and Portland, Bonneville's share of the Rated Transfer Capability shall be the share specified in subsection 7(a) plus a share of the increased Rated Transfer Capability in the ratio of 1450/1600 times the increase in Rated Transfer Capability above 3200 MW.

(c) Rated Transfer Capability greater than 4800 MW. Bonneville and Portland agree that any project to increase the Rated Transfer Capability of the Northwest AC Intertie above 4800 MW shall only be accomplished by distributing the increased Rated Transfer Capability such that at least two-thirds of the increase is distributed to the Joint AC Intertie. Portland shall have the right to participate in any such project to increase the Rated Transfer Capability of the Northwest AC above 4800 MW if Portland chooses to share in such increases. If so, both Portland's cost sharing and increased share of Rated Transfer Capability shall be at a ratio of 950/3200 of the project costs and increased Rated Transfer Capability so attributed to the Joint AC Intertie. Ownership of facilities providing the increased Northwest AC Intertie Rated Transfer Capability shall be determined by negotiation with and between facility owners.

8. Transmission Rights.

(a) Determination of Rated Transfer Capability and Operational Transfer Capability. Bonneville and Portland shall jointly determine the Rated Transfer Capability of the Joint AC Intertie. Portland agrees that Bonneville may determine the Rated Transfer Capability of the Northwest AC Intertie, provided such determination is in keeping with Prudent Utility Practice, and further provided that Bonneville consults with Portland and reasonably incorporates Portland's technical opinion.

(b) Intertie Scheduling Rights.

(1) During times when the Northwest AC Intertie Operational Transfer Capability is less than the Northwest AC Intertie Rated Transfer Capability, Bonneville and Portland's scheduling rights shall be limited to an amount determined by multiplying the Northwest AC Intertie Operational Transfer Capability by the ratio of the party's share of Northwest AC Intertie Rated Transfer Capability to the total Northwest AC Intertie Rated Transfer Capability.

(2) Bonneville and Portland, as between each other, have the exclusive right to use their own share of Northwest AC Intertie Operational Transfer Capability to schedule power or energy for delivery to and from Pacific Southwest utilities without regard to the ownership of the power or energy scheduled and hereby relinquish any rights to make use of the other party's Unused Operational Transfer Capability. Either party, at its discretion, may make its Unused Operational Transfer Capability available to the other party so that the other party may schedule up to its Rated Transfer Capability.

(c) Portland's Rights to Access at Southern Oregon Substation.

(1) Once the Southern Oregon Substation, and the facilities connecting it to the Joint AC Intertie, and the COTP, and the facilities connecting it to the Southern Oregon Substation, are in operation such that the Rated Transfer Capability of the Northwest AC Intertie has been increased to above 3200 MW, Portland shall have the right to schedule power or energy for delivery at all times to and from Pacific Southwest utilities through the Southern Oregon Substation as follows:

(A) If the COTP and the presently existing AC Intertie lines in California are operated as a single system (i.e., integrated with the existing AC Intertie system such that there is an equivalent sharing among the COTP owners and existing intertie owners of transfer capability under all conditions), Portland may schedule up to its share of Rated Transfer Capability, as such share may be reduced pursuant to paragraph 8(b)(1).

(B) If the COTP and the presently existing AC Intertie lines in California are not operated as a single system, Portland may schedule up to one third of its share of Rated Transfer Capability, as such share may be reduced pursuant to paragraph 8(b)(1).

(2) Such delivery right is intended to continue upon the terms and conditions specified in this subsection 8(c) for as long as the Southern Oregon Substation and the facilities connecting it to the COTP are in existence and operable and Bonneville has rights to schedule to Southern Oregon Substation. Should this Agreement terminate earlier than specified in subsection 2(a) for any reason except material breach of contract by either party, and the parties fail to agree to a replacement agreement, the rights of Portland under this subsection 8(c) shall survive for the period stated above, contingent upon Portland's satisfaction of its payment obligation under paragraph 8(c)(3). Therefore, other than as excepted above, the parties intend this obligation to survive such earlier termination.

(3) In consideration for the right to make deliveries to Southern Oregon Substation in paragraph 8(c)(1), Portland shall pay Bonneville 950/4800 of the annual cost of the Southern Oregon Substation, facilities connecting it to the Joint AC Intertie and the facilities connecting the Southern Oregon Substation to the COTP. All such facilities and their estimated costs are shown in Exhibit F. Bonneville and Portland agree

that the estimated investment costs and resultant annual costs shall be revised to reflect actual construction costs. The methodology to compute the annual cost of such facilities is described in Exhibit F and an example of the calculation applying such methodology is provided in Exhibit F. Such annual charge shall be billed and paid on a monthly basis according to the billing and payment provisions in Portland's Power Sales Agreement (Contract No. DE-MS79-81BP90425).

(4) Bonneville shall maintain the Southern Oregon Substation, the facilities connecting it to the Joint AC Intertie, and the facilities connecting the Southern Oregon Substation to the COTP according to Prudent Utility Practice so as to sustain their ability to transfer power and energy. In the event that these facilities are unable to transfer power and energy as a result of Bonneville's failure to maintain or replace such facilities such that Portland cannot transfer its share of Rated Transfer Capability, as such share may be reduced pursuant to paragraph 8(b)(1), through the Southern Oregon Substation for a period in excess of 120 days, then Portland shall be obligated to pay the annual charge specified in paragraph 8(c)(3) minus one-half the annual charge divided by 365 days times the number of days in which Portland is unable make such transfers (annual charge - [(1/2 annual charge/365 days) X days Portland is unable to schedule at Southern Oregon Substation]).

(d) <u>FCRTS Wheeling to Northwest AC Intertie</u>.

(1) Except as provided in paragraph 8(d)(2), all of Portland's schedules to Pacific Southwest utilities on the Northwest AC Intertie shall be deemed to be delivered at John Day Substation, or if Bonneville establishes other Northwest AC Intertie points of delivery, at Portland's

request such deliveries may be deemed to be delivered to such other points of delivery.

(2) *Except when Portland is accepting schedules under the provisions* of paragraph 8(d)(3), up to the greater of 150 MW of Portland's schedules to Pacific Southwest utilities, or an amount equal to the actual energy produced from Portland's Round Butte and Pelton projects when those projects are actually producing energy, not to exceed the capacity of the transformer for the Round Butte-Grizzly line, shall be deemed to be delivered over Portland's facilities to the Grizzly Substation.

(3) Portland can schedule power and energy from Pacific Southwest utilities over the Grizzly-Bethel line up to the actual east to west flow on the Grizzly-Round Butte line as metered at Grizzly.

(4) Transmission arrangements over the FCRTS, other than the Joint or Northwest AC facilities, shall be as provided in subsection 15(c).

9. Modification of and Addition to Facilities.

(a) Unless it has obtained the written consent of the other party, such consent not to be unreasonably withheld, neither party shall make any modifications, additions, improvements, or other alterations to facilities in the Joint AC Intertie. Ownership of modifications, additions, improvements, or other alterations made with such consent shall be as specified in the Malin Construction and Operation Agreement, the Grizzly Trust Agreement, and the Grizzly Construction Trust Agreement, where appropriate, or as agreed by the parties in advance of the performance of such work.

(b) Portland and Bonneville hereby consent to a Plan-of-Service for modifications and additions to the Joint AC Intertie to increase the Rated Transfer Capability of the Northwest AC Intertie to 4800 MW provided that such Plan-of-Service conforms to the Third AC Intertie Project Diagram, incorporated herein as Exhibit C. Bonneville and Portland shall share, in accordance with the percentages specified in Exhibit B, the actual cost of the facilities identified in the Plan-of-Service.

(c) In the event this Agreement terminates for any reason and implementation of such Plan-of-Service causes Portland to lose its physically and electrically connected transmission path through facilities in which it has ownership, from its service territory via Round Butte, through Grizzly substation to Malin substation over the Grizzly-Malin Number 2 line, Bonneville agrees to restore and share equally the costs of such restoration of Portland's continuous connection of facilities owned by Portland.

(d) Portland agrees that Bonneville shall have the right to plan, design, locate, construct, and own the Southern Oregon Substation and associated interconnection to the COTP. Should the basic configuration of the Southern Oregon Substation materially change from that shown in Exhibit C such that Portland's access under subsection 8(c) to the substation and the Pacific Southwest utilities is reduced or such that Portland's charges under paragraph 8(c)(3) substantially increase, then Bonneville will seek Portland's consent, such consent not to be unreasonably withheld.

(e) Portland hereby consents to any modifications consistent with Prudent Utility Practice to the Joint AC Intertie, at Bonneville's expense, necessary to accomplish the DC Terminal Expansion project up to a total DC Intertie Rated Transfer Capability of approximately 3100 MW, including the modifications shown in Exhibit A.

(f) Bonneville and Portland hereby consent to undertake those modifications to facilities in the Joint AC Intertie, as specified in Exhibit A, necessary to implement the reliability improvement projects. Portland shall permit Bonneville to make the modifications to the Malin, Grizzly, and Fort Rock Substations specified in Exhibit A, or Portland shall make such modifications. Portland shall pay the share of the actual costs of the modifications specified in Exhibit A. Bonneville and Portland's ownership of such modifications at Malin and Grizzly shall be equal to the percentages specified in Exhibit A.

10. Financing by Portland

(a) At Bonneville's request, Portland shall arrange to finance Bonneville's costs associated with the development of the project to increase the Northwest AC Intertie Rated Transfer Capability from 3200 MW up to approximately 4800 MW as provided for in this Agreement.

Such request shall be made in writing and Portland shall make such arrangements within 60 days after mutual consultations on alternatives. (Time is of the essence.) Bonneville shall have the right to approve or disapprove such arrangements prior to the sale or issuance of any obligation or financing arranged by Portland pursuant to this paragraph.

(b) The proceeds of any financing, net of issuance costs, shall be paid into a trust. Bonneville and Portland shall mutually agree on a form of trust agreement and the selection of a trustee. The trustee shall pay construction costs or amounts owing to Portland, as applicable, together with payments of any capitalized carrying financing costs incurred during construction and capitalized carrying costs on such costs, if any.

(c) Portland shall attempt to obtain the least possible cost financing available. Portland shall not be required to seek financing based on its own credit unless financing based solely on Bonneville's payment obligation is not available. Portland need not make available to Bonneville any financing opportunities that Portland intends to use to finance other Portland costs or to retire Portland debt. Portland will not use any financing opportunity that results from any financing proposal made at Bonneville's request to finance any other Portland costs.

(d) Portland need not attempt any formal financing that: (a) may cause Portland General Corporation to become a nonexempt Holding Company under the Public Utility Holding Company Act of 1935, 15 USC §79 et. seq.; (b) would be contrary to the restrictions of any law, regulation, judicial decree, or order of any applicable jurisdiction; or (c) would be contrary to any Portland bond indenture, preferred stock covenant, or other Portland financial commitment.

(e) Bonneville shall make all financing payments as stipulated in the mutually agreed upon financing arrangement.

11. Maintenance of Facilities.

(a) Each party is responsible for performing maintenance on and reinforcing its respective solely owned facilities so as to maintain the Rated Transfer Capability of the Northwest AC Intertie. Maintenance on the jointly owned facilities at Grizzly and Malin substations are provided for in the Grizzly Operation and Maintenance Trust Agreement and the Malin Operations and Maintenance Trust Agreement, respectively.

(b) Each party is responsible for performing maintenance on its respective existing facilities so as to maintain the Rated Transfer Capability of the existing DC Intertie and the DC Terminal Expansion. Bonneville is responsible for performing maintenance on the existing DC Intertie facilities and the DC Terminal Expansion facilities so as to maintain the Rated Transfer Capability of the Northwest AC Intertie.

(c) Each party shall carry out the requirements of section 11 consistent with Prudent Utility Practice.

(d) Bonneville and Portland shall negotiate in good faith a separate joint maintenance agreement for the jointly owned facilities of the Joint AC

Intertie to replace the existing agreements for maintenance.

12. Scheduling.

(a) Bonneville and Portland shall schedule through the Joint Intertie Scheduling Office all schedules to and from utilities in the Pacific Southwest to be delivered at the Malin and Southern Oregon Substations.

(b) Portland shall provide the Joint Scheduling Office an actual schedule of the generation at the Round Butte and Pelton projects by 1000 hours of the following workday for the previous day or days. Such schedule shall be consistent with section 8(d)(2) of this Agreement.

13. Northwest AC Intertie Charges.

(a) Charges for Portland's Own Schedules. Bonneville shall not assess Portland any charge to schedule power and energy for delivery to and from Pacific Southwest utilities over the Northwest AC Intertie on any hour up to Portland's share of the Rated Transfer Capability, as such share may be reduced pursuant to subsection 8(b)(1).

14. Losses. Bonneville and Portland shall replace losses for schedules on the Northwest AC Intertie as provided in Exhibit E.

15. Other Agreements.

(a) Agreement to an Exchange of Rights of Use of AC for DC Capability. Bonneville and Portland agree to terms and conditions for an exchange of the right to use a amount of Portland's share of the Northwest AC Intertie Rated Transfer Capability for a right to use an equal amount of Bonneville's DC Intertie Rated Transfer Capability as provided in Exhibit D to this Agreement.

(b) General Transfer Agreement. Bonneville and Portland agree to the negotiate a new general transfer agreement to be executed by January 1, 1989. During the negotiation period, Bonneville and Portland agree to continue the existing transfer services according to the terms and provisions of Contract No. DE-MS79-83BP91011 as such agreement has been amended.

(c) IR Agreement.

(1) Bonneville and Portland shall negotiate in good faith a general transmission agreement (IR Agreement) to be executed by January 1, 1989. Such agreement shall be executed concurrently with the general transfer agreement and shall include provisions for delivery from Portland's resources to the Northwest AC and DC Intertie points of delivery as well as to Portland's system points of delivery.

(2) Deliveries of power and energy over the FCRTS to points of delivery at the Northwest AC Intertie are not provided by this Agreement and must be provided for by separate agreement between Bonneville and Portland. However, until January 1, 1989, Bonneville agrees to provide Portland with the right to deliver energy to the Northwest AC Intertie point of delivery which would otherwise be delivered to Portland's system as specified in Contracts Nos. 14-03-001-13437, 14-03-001-13773, 14-03-28002, and 14-03-41848 (Mid-Columbia Agreements) subject in all other respect to the applicable terms and conditions of such agreements. After January 1, 1989, if an IR Agreement and a general transfer agreement have not been executed, half of Portland's schedules to the Northwest AC Intertie point of delivery will continue as specified above, but the other half of Portland's schedules shall be required to be delivered at Portland's system and shall be subject to Bonneville's rate schedule for nonfirm transmission and losses for subsequent delivery to the Northwest AC Intertie point of delivery, unless otherwise agreed by Bonneville and Portland.

(d) <u>Extension of Existing Agreements</u>. Bonneville and Portland agree that for the purpose of defining the term of the Malin Construction and Operations Agreement, Malin Operation and Maintenance Trust Agreement, and Grizzly Operation and Maintenance Trust Agreement, this Agreement shall be considered to be a renewal by a similar agreement of the Intertie Operations Agreement and the Intertie Settlement Agreement.

(e) <u>Agreements for Implementation of this Agreement</u>. In addition to the above agreements, Bonneville and Portland agree to negotiate in good faith any additional agreements that may be required to implement the terms and conditions of this Agreement, including but not limited to agreements for transmission, and operation and maintenance.

16. <u>Sale or Assignment</u>.

(a) Portland or Bonneville may sell, assign, lease, sublease or otherwise transfer (all hereafter referred to as "transfer") this Agreement, any interest herein or any direct or indirect interest in the Joint AC Intertie facilities or facilities directly affecting the Joint AC Intertie, without the consent of the other party, <u>provided</u>

(1) the agreement by which the transfer is accomplished contains the following language:

"Anything contained in this Agreement to the contrary notwithstanding, the transferor does not by this Agreement transfer any rights or obligations with respect to any of the following activities, and hereby specifically retains all such rights and obligations:

(A) scheduling the use of the transferor's interest (including the interest transferred herein) in the Joint AC Intertie as that interest is established pursuant to the Intertie Agreement between

Portland General Electric Company and the Bonneville Power Administration (Contract No. DE-MS79-87BP92340) executed July 29, 1988, as amended;

(B) operation, maintenance and repair of the Joint AC Intertie facilities (as defined in the Intertie Agreement);

(C) renewals, replacements and additions to the Joint AC Intertie facilities; and

(D) system planning for the Joint AC Intertie."

"Subsequent involuntary transfer, by law or otherwise, of any rights or obligations with respect to any of the foregoing activities shall be subject to the non-transferring owner's prior right to preclude such transfer by, at its election,

(i) remedying any and all defaults; or

(ii) acquiring the interest herein transferred at fair market value and assuming the rights and obligations respecting the foregoing activities."; and

(2) the agreement grants third party beneficiary status to the nontransferring owner with respect to enforcement of the above provisions.

(b) Notwithstanding the provisions of subparagraphs 16(a)(1)(B) and (C) above, the transferor may covenant to the transferee to perform maintenance to keep the Joint AC Intertie facilities in good working order pursuant to Prudent Utility Practice, and to maintain the Rated Transfer Capability (as defined in the above Intertie Agreement between Portland and the Bonneville) of the Joint AC Intertie.

(c) Portland or Bonneville may transfer this Agreement, any interest herein or any direct or indirect interest in the Joint AC Intertie facilities to an entity or entities if the transferring party is acquired in total by such other entities.

(d) Except as provided in subsections 16(a) and (c) above, Portland and Bonneville agree not to transfer this Agreement, any interest herein, any interest in the Joint AC Intertie facilities or any rights or obligations with respect to the activities listed in paragraph 16(a)(1) above without the written consent of the other party, such consent not to be unreasonably withheld. Wheeling and other transmission contracts which do not transfer legal rights or obligations with respect to scheduling, operations, maintenance, repair, improvement, modification or system planning of the Joint AC Intertie to other parties shall not be considered transfers of interests in this Agreement or in the Joint AC Intertie facilities. Scheduling of wheeling obligations shall be retained by Portland and Bonneville.

(e) A party proposing to transfer an interest in this Agreement or in the Joint AC Intertie facilities shall provide the other party at least 30 days notice prior to the earlier of: (1) the execution of the transfer or grant documents; or (2) filing of the proposed transfer with FERC or its successor agency, if such transfer must be filed with FERC. The party shall provide with such notice a description of the terms and conditions of the proposed transfer sufficient to allow the other party reasonable opportunity to evaluate the proposed transfer with respect to the requirements of this section (including the position of the party giving notice as to whether consent is required pursuant to subsection 16(d)), and shall thereafter provide to the other party copies of all final documents comprising the transfer agreement as early as possible prior to their execution. If the information provided is considered by the party providing such information to be proprietary and confidential, it shall label such information as proprietary and confidential. The party receiving the above information shall exert best efforts to keep all such labeled information confidential until it has been made public by the other party or others. The receiving party shall take steps necessary to have the information declared "proprietary" or otherwise categorized so as to protect such information from public disclosure to the extent legally allowable under the Federal Freedom of Information Act or similar applicable law or regulation.

(f) The nontransferring party shall notify the other party by the 30th day following actual receipt of the notice and description described in subsection 16(e) (or, if not a working day, the first working day thereafter) of its grant or withholding of consent requested pursuant to subsection 16(d) or its approval or disapproval of a transfer proposed to be made pursuant to subsection 16(a); provided, however, that such time shall be extended to 5 working days after actual receipt of copies of the final documents comprising the transfer or grant if receipt of such documents is on or after the 26th day of the 30-day period and such final documents reflect material changes from documents provided prior to such 26th day. Failure to provide notice of withholding of consent or disapproval within such required periods shall be deemed a grant of consent or approval, as the case may be. The nontransferring party shall be allowed to attend the closing of the transfer and retain all executed copies of its approval until it is satisfied that the final documents do not exhibit material changes from the documents provided earlier. If a party withholds any required consent or disapproves, then such party shall, within 15 days following notice of such withholding or disapproval, provide to the party requesting consent or approval a detailed written description of the reason(s) consent or approval was withheld.

(g) Portland and Bonneville agree that in the event of any dispute between them concerning the application of this section 16 they shall cooperate fully with each other to obtain final judicial resolution of such dispute in the most expeditious manner possible.

(h) Bonneville hereby consents to Portland's transfers of security interests in this Agreement and the Joint AC Intertie facilities pursuant to the Indenture of Mortgage and Deed of Trust dated July 1, 1945, between Portland and the Marine Midland Trust Company of New York, as supplemented.

(i) The restrictions contained in this section 16, and exceptions thereto, shall apply to any transferee to the same extent they are applicable to the parties to this Agreement.

(j) Transfers of any interest in this Agreement or in the Joint AC Intertie facilities that do not meet the requirements of this section 16 shall be void.

(k) The provisions of this section 16 shall not survive termination of this Agreement.

17. <u>Rules of Law</u>.

(a) Portland and Bonneville agree that each fully participated in the drafting of each provision of this Intertie Agreement. The rule of law interpreting ambiguities against the drafting party shall not be applicable to or utilized in resolving any dispute over the meaning or intent of this Intertie Agreement or any of its provisions.

(b) The construction and interpretation of this Intertie Agreement shall be governed solely by Federal law.

(c) This Intertie Agreement shall not be construed to establish a partnership, association, joint venture, or trust. Neither party shall be under the control of or shall be the agent of or have a right or power to bind the other party without the other's express written consent, except as provided in this Intertie Agreement.

18. Delay of Performance. The time for each act specified in this Intertie Agreement shall be extended for a time equivalent to such delays, if any, as are occasioned by events which the party hereto obligated to perform such act could not be reasonably expected to avoid by the exercise of reasonable diligence and foresight.

19. Continuity of Service.

(a) Either party may temporarily interrupt or reduce deliveries hereunder if such interruption or reduction is necessary or desirable in case of system emergencies, or in order to install equipment in, make repairs, replacements, investigations, and inspections of, or perform other maintenance work on, the electric system of such party. Except in case of emergency and in order that the other party's operations will not be unreasonably interfered with, notice shall be given of any such interruption or reduction, the reason therefore, and the probable duration thereof.

(b) If the operation of either party's transmission system is suspended, interrupted, or interfered with as the result of the occurrence of any event that is specified in subsection 19(a) or any event that is reasonably beyond such party's control (including, but not limited to, the failure or breakdown of generating or transmission facilities, floods, fire, strikes, or acts of God or the public enemy), it shall not be obligated to make deliveries as provided in this agreement, during such time and to such extent as such suspension, interruption, or interference makes it reasonably impracticable to do so, and shall not be liable for any damages sustained by the other party as a result of the failure to make such deliveries during such time.

(c) If the operations of either party are interrupted or curtailed, such party shall exercise due diligence to reinstate such operations with reasonable dispatch.

20. Arbitration. In the event of any dispute related to rights or obligations of the parties, or satisfaction thereof, under this Agreement, other than disputes arising under section 16, either party may elect to submit such dispute to nonbinding arbitration. If one party so elects, such party shall notify the other party in writing and both parties shall participate pursuant to the following.

(a) If the parties cannot agree on an arbiter within 10 days of such notification, the notifying party shall request the American Arbitration Association to designate an arbiter with sufficient expertise in the subject under dispute.

(b) After an arbiter is agreed to or designated, the arbiter shall establish a schedule for submission of the parties' written positions. The party electing the arbitration shall first state its position in a letter to the arbiter. The second party shall then state its position in a letter to the arbiter. The first party may then submit a response to the second party's position and the second party may thereafter submit a reply to the first party's response.

(c) Each letter submitted to the arbiter shall be no more than 5 pages in length, unless the parties otherwise mutually agree. The parties may attach exhibits that they consider relevant to the dispute. A copy of each submission also shall be simultaneously served on the other party.

(d) The arbiter shall provide the parties with a written analysis of the dispute, and his or her proposed resolution of the dispute.

(e) The parties shall equally share the fee and other costs of the arbiter.

In the event neither party submits the dispute to nonbinding arbitration or if either party elects not to accept the finding of the arbiter, the parties may elect other approaches, including litigation, to resolve the dispute.

21. Metering.

(a) Measurement. Measurement of electric energy and reactive power and of the 60-minute integrated demands for such electric energy flowing between Bonneville's facilities and Portland's facilities at the Grizzly substation shall be determined from measurements made by meters furnished and installed by Bonneville and Portland as agreed.

(b) Test of Meters. Each party to this Agreement shall, at its expense, test its meters mentioned in this Agreement periodically, and, if requested to do so by the other party, shall make additional tests or inspections of such meters, the expense of which shall be paid by such other party unless such additional tests or inspections show such meters to be inaccurate as specified in subsection 21(c). Each party shall give reasonable notice of the time when any such test or inspection is to be made to the other party who may have representatives present at such test or inspection. Metering equipment found to be defective or inaccurate in any degree shall be adjusted, repaired, or replaced to provide accurate metering.

(c) Adjustment for Inaccurate Metering. If any meter mentioned in this contract fails to register, or if the measurement made by such meter during a test made as provided in subsection 21(b) varies by more than one percent from the measurement made by the standard meter for: (a) the actual period, not to exceed 6 months, during which such inaccurate measurements were made if such period can be determined; or (b) if not, the period immediately preceding the test of such meter which is equal to one-half the time from the date of the last preceding test of such meter. Such corrected measurements shall be used to recompute the amounts due for the electric energy made available under this contract during such period. If the total amount due for such period as recomputed varies from the total amount due as theretofore computed, the amount of the variance shall be paid to the party entitled thereto within 30 days after the recomputation is made.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By /s/ James J. Jura
Administrator

Date July 29, 1988

PORTLAND GENERAL ELECTRIC COMPANY

By /s/ R. E. Dyer

Title Vice President

Date July 29, 1988

(VS6-PMT-2692d)

Sharing of Costs for Reliability Improvements and Other Projects

Description	Planned Energization Date	Total ($000)	PGE Share
1. Reliability Improvements			
Phase 2 (Stability Control Upgrade): Provide new remedial action schemes (RAS) for the AC Intertie and HVDC Intertie. This phase completes a new fully redundant RAS for the HVDC Intertie (two independent control and communication systems). Also this phase will provide the first controller of the new AC Stability Control Scheme including communications support. Output for the second controller (to be installed in Phase 3) are also provided in this phase.			
a. Malin	Jan 1990	932	25%
b. Grizzly	Jan 1990	480	40%
c. Fort Rock	Jan 1989	99	50%
Phase 3 (Stability Control Upgrade): Provide a new AC Intertie stability control system to replace the existing AC Intertie controller. This new control system will utilize some of the communication systems provided under Phase 2. This will complete a fully redundant RAS for the AC Intertie.			
a. Malin	Jan 1990	448	25%
b. Grizzly	Jan 1990	302	40%
2. DC Terminal Expansion Related Projects			
Install a mechanically switched capacitor at Malin Substation	Feb 1989	6,000	0%
Restore High Speed Switching at Fort Rock Compensation Station.	Feb 1989	272	1/

1/ Cost sharing responsibilities shall be as provided in Letter Agreement No. DE-MS79-88BP92446. Ownership of facilities shall be entirely with Portland.

(VS6-PMT-2692d)

Sharing of Costs for Plan-of Service in Joint AC Intertie
1988 ($)

Facility	Estimated Total 1/ Cost X 10 3/	Allocation PGE	BPA
Grizzly Substation			
7 PCB's	7309	0%	100%
1 PCB (Round Butte) and associated MOD's	1123	100%	0%
Line Relaying (Grizzly-S. Oregon, Grizzly-Malin #2, Grizzly-J.D. #1 Grizzly-J.D. #2, Grizzly-Buckley Grizzly-S. Lake) and Power System Control, Communication and Data System Facilities	3931	27%	73%
Sand Spring Compensation Station			
1 - 2400A Cont., 3800A 30 Min. Rated Bank (Grizzly-So. Oregon)	9695 2/	0%	100%
1 - 2400A Cont., 3800A 30 Min. Rated Bank(Grizzly-Malin #2)	6500 5/	100%	0%
Fort Rock Compensation Station			
1 - 2200A Cont., 3000A 30 Min. Rated Bank (Grizzly-So. Oregon)	6277 2/	0%	100%
1 - 2200A Cont., 3000A 30 Min. Rated Bank (Grizzly-Malin #2)	4700 5/	100%	0%
Sycan Compensation Station			
1 - 2400A Cont., 3800A 30 Min. Rated Bank (Grizzly-So. Oregon)	9535 2/	0%	100%
1 - 2400A Cont., 3800A 30 Min. Rated Bank (Grizzly-Malin No. 2)	6500 5/	100%	0%

Facility	Estimated Total 1/ Cost X 10 3/	Allocation PGE	BPA
Malin Substation			
Line Relaying Malin-S. Oregon (formerly Grizzly-Malin No. 1) Grizzly-Malin No. 2 line and Power System Control, Communication and Data System Facilities	2249	25%	50% 3/
Replace one 500 kV breaker and associated MOD's	775	0%	100%
Line relaying for Malin-S. Oregon #2	211	0%	50% 4/
John Day Substation			
Line Relaying for J.D.-Grizzly #1 & #2, Relaying for Breakers, CT Repl. Power system Controls	2808	0%	100%
Bakeoven Compensation Station			
(Removal and Disposal Costs Only)	1800	0%	100%

1/ Estimated costs include overheads assumed at 30%. Estimated costs are subject to inflation, escalation and minor changes to the plan-of-service.
2/ Estimated costs include removal and disposal costs for PCB contaminated facilities ($600K)
3/ BPA's share is 50%, PGE's share is 25%, PP&L's share is 25%.
4/ BPA's share is 50%, PP&L's share is 50%.
5/ Costs shown are PGE estimates, exclusive of overheads and removal and disposal costs for PCB contaminated facilities.

(VS6-PMT-2692d)

AC/DC Exchange

Bonneville and Portland hereby agree to exchange a right to use Intertie capability wherein Portland shall have a right to use a share of Bonneville's DC Intertie Rated Transfer Capability and Bonneville shall have a right to use an equal amount of Portland's share of Northwest AC Intertie Rated Transfer Capability under the following terms and conditions. Such exchange shall become effective when the parties execute the necessary agreement containing the terms and conditions as outlined in the memorandums of understanding (MOU) between Portland and Bonneville (Contract No. DE-MS79-88BP92375) and between Bonneville, Portland, and the cities of Burbank, Glendale, and Pasadena, California (Cities) (Contract No. DE-MS79-88BP92376).

1. Term. This Exhibit D shall become effective on the date Bonneville sells power to Portland (Exchange Effective Date) under the terms and provisions of Contract No. DE-MS79-88BP92432, and shall terminate the earlier of (a) 25 years from the date of execution of the Contract No. DE-MS79-88BP92376; or (b) the date of termination of the Intertie Agreement.

2. Extension and Termination of Prior Agreement. Portland and Bonneville's short term letter agreement, Contract No. DE-MS79-87BP92374, providing for the short term exchange of a right to use a share of Bonneville's DC Intertie Rated Transfer Capability for a right to use an equal amount of Portland's share of the AC Intertie Rated Transfer Capability shall be extended by this Exhibit D, and shall terminate on the earlier of 2400 hours on September 15, 1988, or the Exchange Effective Date, however, all liabilities accrued thereunder shall be preserved until satisfied.

3. Ownership. Bonneville shall remain the sole owner of the DC Intertie.

4. Operation and Maintenance of the DC Intertie. Bonneville shall have the sole right and responsibility to operate, maintain, and schedule the DC Intertie in the Pacific Northwest.

5. Exchange of a Right to Use.

(a) Portland shall have a right to use up to 100 MW of Bonneville's DC Intertie Rated Transfer Capability and Bonneville shall have a right to use an equal amount of Portland's share of the Northwest AC Intertie Rated Transfer Capability (Initial Exchange).

(b) Such Initial Exchange may, at Portland's request, be increased by up to 100 MW (Additional Exchange), not to exceed a total of 200 MW when combined with the Initial Exchange, after the DC Terminal Expansion is declared commercial by Bonneville, if Bonneville has not otherwise contractually committed, or is not in negotiations to contractually commit, the uncommitted DC Intertie Rated Transfer Capability to another use.

(c) Such exchange shall reduce Portland's share of the Northwest AC Intertie Rated Transfer Capability specified in subsections 8(a), (b), and (c) of this Intertie Agreement by the total amount of the exchange.

(d) Bonneville's exchange right to Portland's share of the Northwest AC Intertie shall be subject to paragraph 8(b)(1) of this Intertie Agreement.

6. Transmission Rights on the DC Intertie.

(a) On any hour Portland shall have the right to schedule power and energy up to the amount of the Initial Exchange plus the Additional Exchange to and from the Nevada-Oregon border without regard to the source of the power and energy scheduled. However, Portland's use of the DC Intertie shall be subject to provisions of section 7 of the Long-Term Intertie Access Policy issued by Bonneville on May 17, 1988. Portland shall not wheel for other parties on the DC Intertie. Portland's sales of power or energy at the Nevada-Oregon border are not wheeling under this Agreement.

(b) During times when the DC Intertie Operational Transfer Capability is less than the DC Intertie Rated Transfer Capability, and schedules must be reduced, Portland's right to use of a share of Bonneville's DC Intertie Rated Transfer Capability shall be limited to an amount determined by multiplying the Operational Transfer Capability by the ratio of Portland's right to use share of Bonneville's DC Intertie Rated Transfer Capability to the total DC Intertie Rated Transfer Capability.

(c) Deliveries over the FCRTS to the Big Eddy Substation for the DC Intertie shall be subject to the provisions of subsection 8(d) and 15(c) of this Intertie Agreement.

7. Payment Provisions.

(a) Portland shall pay Bonneville an annual charge of $250,000 for Portland's right to use in the Initial Exchange as defined below.

(b) If Portland acquires an Additional Exchange, the annual charge Portland shall pay to Bonneville shall increase to $1,000,000.

(c) The charges in (a) and (b) above shall be divided into 12 monthly installments and be subject to the billing and payment provisions in Portland's power sales agreement (Contract No. DE-MS79-81BP90425).

8. Losses.

(a) Portland shall be responsible for replacing DC Intertie losses to Bonneville at the Nevada-Oregon border under the provisions of Exhibit G.

(b) Portland shall not be responsible for losses resulting from Bonneville's use of Portland's share of the Northwest AC Intertie Rated Transfer Capability as provided in subsection 14(b) of this Intertie Agreement.

9. Assignment. Portland shall have no rights to sell, assign, lease, sublease, or otherwise transfer any right of use in the DC Intertie. Any such transfer without Bonneville's consent shall be null and void.

10. Waiver of Bonneville's Obligation to Serve Load.

(a) Portland agrees that the disposition of Pacific Northwest energy from Portland's resources for use outside of the Pacific Northwest shall result in a reduction of Bonneville's obligation to supply firm energy under section 5(b) of P.L. 96-501 (16 U.S.C. 839c(b), equal to the maximum amount of energy which Portland is obligated to provide for use outside of the Pacific Northwest for the period of such disposition. Bonneville may sell to Portland as replacement for such energy, under the Power Sales Contract, only what would otherwise be surplus energy. Bonneville shall implement such reduction as described in subsection (b) below.

(b) Effective on the date ~~Portland~~ of any sale by Portland outside the Pacific Northwest of a resource now dedicated to serve Portland's load in Portland's Power Sales Contract Firm Resource Exhibit, Portland shall submit a revised Firm Resources Exhibit and Assured Capability Exhibit to Bonneville under the Power Sales Contract. The Firm Resource Exhibit shall include, as a Firm Resource, Portland's obligation to provide during each calendar month, an amount of energy equal to the maximum amount of energy Portland is obligated to provide during each such month for use outside of the Pacific Northwest. The determination of Portland's Assured Energy Capability under the Assured Capability Exhibit shall include the monthly amounts of energy from such Firm Resource.

(c) If Portland fails to comply with the terms and conditions of this section, then Bonneville shall have the right to terminate this agreement.

(VS6-PMT-2692d)

Northwest AC Intertie Losses

Portland's 500-kV Grizzly-Malin line will be placed in Bonneville's generation control area and Bonneville shall absorb all losses on the line. Portland shall compensate Bonneville for Northwest AC Intertie losses by making available to Bonneville at points-of-delivery as included in the terms and provisions of Portland's transmission agreements with Bonneville for service over the FCRTS, at the corresponding hour 168 hours later, an amount of electric power calculated as follows:

Given:

Average Northwest AC Intertie losses are 3.0%

Portland can deliver a portion of its schedules through Grizzly Substation, as provided in §8(d)(2), reducing its average loss percentage to 2.5%

For a given hour:

S_{PGE} = Portland's net Northwest AC Intertie schedule, found as the absolute value of the sum of Portland's southbound schedules (positive) and northbound schedules (negative).

L_{PGE} = Portland's loss

Let:

$$L_{PGE} = 0.025 * S_{PGE}$$

This Exhibit E will become effective 90 days after the Effective Date.

The average Northwest AC Intertie loss percentage specified above shall be reviewed annually, and revised as mutually agreed by the parties.

(VS6-PMT-2692d)

Calculation of Charges for Access to Southern Oregon (SO) Substation
1988 ($)

Item 1/ No.	Description	2/ Investment	Annual Cost Ratio 3/	Subtotal	O&M Cost 4/	Grand Total
1.	Malin-Meridian Loop into SO 5/	904,000	0.1150	103,960	0 6/	103,960
2.	Grizzly-Malin Loop into SO	4,185,000	0.1150	481,390	3,582	484,972
3.	SO -Or/CA Border	5,265,000	0.1150	605,475	7,164	612,639
4.	SO PCB's, Comm. & Controls 7/	17,621,000	0.1170	2,061,657	282,300	2,343,957
5.	SO Capacitors (10%) 8/	669,000	0.1170	78,273	38,606	116,879
	TOTAL					$3,662,407

PGE Annual Charge = (950 / 4800) * $3,662,407 = $724,852 / YR

1/ BPA's share of Northwest Reinforcement facilities. PP&L's solely owned facilities are not included.
2/ Investment costs include 30% overheads. This column will be revised to reflect actual construction costs.
3/ BPA's Annual Cost Ratio represents recovery of BPA's plant investment costs, revised at time of construction and fixed for the duration of the agreement. When any of the facilities in the table above are replaced or enhanced, PGE shall pay 950/4800 of the associated annual costs, less retirements. Payment schedule for I&A ends, if facilities still exist and are not enchanced or replaced at the end of the service life specified in BPA's Annual Cost Ratio Tables.
4/ BPA's O&M dollars shown for Items 2, 3, 4 and 5 are based on O&M expenses averaged for FY 1985, '86, and '87. O&M charges will be reviewed annually and revised, as appropriate.
5/ BPA's share of the Malin-Meridian Loop-in costs is 50% and PP&L's share is 50%.
6/ PP&L is to operate and maintain the Malin-Meridian Line.
7/ BPA's share is assumed at 6/7th and PP&L's share is 1/7th of $20,558,000.
8/ BPA's share is assumed at 10% and COTP's share is 90% of $6,689,000.

(VS6-PMT-2692d)

This Revision No. 3 replaces Revision No. 2 and updates investment dollars for the Captain Jack substation, line item no. 4. This Revision also adjusts the Annual Cost Ratio and O&M costs to reflect BPA's current cost recovery of investment and annual maintenance costs at Captain Jack Substation. This Revision also updates SO in the description to "Southern Oregon" for Item No. 1.

Calculation of Charges for Access to Southern Oregon Substation (Captain Jack)

Item No.	Description[1]	Investments[2]	Annual Cost Ratio [3]	Subtotal	O&M Cost [4]	Total[5]
1.	Malin-Meridian Loop into Southern Oregon (SO)[6]	$ 1,484,242	0.0581	$ 86,234	Footnote 7	$ 86,234
2.	Grizzly-Malin Loop into SO	4,331,707	0.0581	251,672	5,107	256,779
3.	SO-OR/CA Border	7,759,680	0.0581	450,837	9,854	460,691
4.	SO PCB's, Communication & Controls [8]	33,186,207	0.0932	3,092,954	98,935	3,191,889
5.	SO Capacitors (8.21%) [9]	772,095	0.1272	98,210	Footnote 10	98,210
	GRAND TOTAL					$ 4,093,805

PGE Annual Charge = (950 / 4800) * $4,093,805 = $810,232/ Year $67,519/Month[5]

1 BPA's share of Northwest Reinforcement facilities.

2 Investment costs originate from BPA's Asset Accounting group. This column represents actual construction costs excluding PacifiCorp & COTP investment amounts.

3 BPA's Annual Cost Ratio represents recovery of BPA's plant investment costs, revised at time of construction and fixed for the duration of the agreement. When any of the facilities in the table above are replaced or enhanced, PGE shall pay 950/4800 of the associated annual costs, less retirements. Payment schedule for I&A ends, if facilities still exist and are not enhanced or replaced at the end of the service life specified in BPA's Annual Cost Ratio Tables.

4 O&M charges for items 2, 3 and 4 have been revised pursuant to BPA's new O&M tables dated September 30, 2007, based on average O&M expenses from fiscal years 2002, 2003, 2004, 2005 and 2006. O&M charges will be reviewed annually and revised, as appropriate.

5 The total dollar amounts have been rounded to ensure 12 equal whole dollar monthly payments.

6 BPA's share of the Malin-Meridian Loop-in costs is 50% and PacifiCorp share is 50%.

7 PacifiCorp is to operate and maintain the Malin-Meridian Line at no cost to BPA.

8 BPA's share excludes all PacifiCorp costs for bay 3.

9 BPA's share is 8.21% and COTP's share is 91.79% of $9,404,327.

10 O&M costs are included as a part of the Annual Cost Ratio.

JUL 17 2009

Bonneville Power Administration - Annual Cost Ratio Table - 5 Year Average of Fiscal Years 2002 to 2006

	Operations 1	Maintenance 2	Indirects 3	Total 4 1+2+3	General Administration Operations 5	General Administration Maintenance 6	General Administration Indirects 7	Total OM&A 8 4+5+6+7	Interest & Amortization 9	Total Costs 10 8+9	Allocation of General Plant	Total Incl Gen Plnt
Substations												
R7 Celilo	0.95%	0.46%	0.84%	2.24%	0.41%	0.19%	0.42%	3.26%	6.50%	9.76%	2.78%	12.54%
FO	2.77%	2.21%	4.32%	9.30%	1.17%	0.97%	2.18%	13.62%	6.50%	20.12%	5.73%	25.85%
H5	0.62%	0.54%	0.98%	2.14%	0.27%	0.22%	0.50%	3.13%	6.50%	9.63%	2.74%	12.37%
U	0.80%	0.53%	1.00%	2.33%	0.34%	0.22%	0.50%	3.40%	6.50%	9.90%	2.82%	12.72%
SA	0.40%	0.45%	0.78%	1.62%	0.17%	0.17%	0.39%	2.36%	6.50%	8.86%	2.52%	11.39%
SH	1.51%	0.80%	1.46%	3.78%	0.65%	0.33%	0.74%	5.50%	6.50%	12.00%	3.42%	15.41%
Metering	0.22%	0.09%	0.44%	0.75%	0.09%	0.10%	0.22%	1.16%	6.50%	7.66%	2.18%	9.84%
U/FO	2.42%	1.51%	2.98%	6.92%	1.04%	0.67%	1.50%	10.13%	6.50%	16.63%	4.74%	21.37%
Weighted	0.74%	0.53%	0.99%	2.26%	0.32%	0.22%	0.50%	3.30%	6.50%	9.80%	2.79%	12.60%
Lines												
1000kv DC	0.09%	0.98%	2.36%	3.44%	0.09%	0.41%	1.23%	5.17%	4.16%	9.33%	2.64%	11.97%
500 kv	0.03%	0.32%	0.74%	1.09%	0.03%	0.13%	0.38%	1.63%	4.16%	5.79%	1.64%	7.44%
115-345 St	0.07%	0.82%	1.91%	2.81%	0.07%	0.33%	1.00%	4.20%	4.16%	8.36%	2.37%	10.73%
115-230 W	0.13%	1.41%	3.23%	4.76%	0.13%	0.56%	1.68%	7.13%	4.16%	11.29%	3.19%	14.48%
Low Voltag	0.22%	2.43%	5.67%	8.32%	0.22%	0.98%	2.96%	12.47%	4.16%	16.63%	4.70%	21.33%
Submarine	0.00%	0.02%	0.05%	0.07%	0.00%	0.01%	0.03%	0.11%	4.16%	4.26%	1.21%	5.48%
Composite	0.07%	0.73%	1.69%	2.49%	0.07%	0.29%	0.88%	3.72%	4.16%	7.88%	2.23%	10.12%
Weighted	0.05%	0.59%	1.35%	1.99%	0.02%	0.23%	0.70%	2.95%	4.16%	7.11%	0.00%	7.11%
General Plant												
Land and Building		12.65%		12.65%		5.98%		18.64%	4.37%	23.01%		
Communication		1.37%		1.37%		0.65%		2.01%	8.15%	10.16%		
Other		1.65%		1.65%		0.80%		2.45%	14.37%	16.82%		
Weighted Average		3.72%		3.72%		1.76%		5.48%	8.87%	14.34%		

Legend

R7 Celilo =Rotating Shifts, full coverage, 24 hours/day, seven days per week
FO=Owned by a foreign company, operated by BPA
H5=Standard scheduel, 7:00 a.m. to 3:30 p.m., five days per week
U=Unattended
SA=On duty four hours per day, on availability 20 hours per day
SH=Shared facility, owned by BPA and another utility
U/FO=Unattended,Split substation part owned by BPA/Part owned by customer

Bonneville Power Administration - 5 Year Average of Fiscal Years 2002 to 2006
Cost per Circuit Mile

Transmission Lines	Circuit Miles	Cost Per Circuit Mile: Operations	Cost Per Circuit Mile: Maintenance	General Administration: Operations	General Administration: Maintenance		Total
DC Steel	265	87.19	935.29	37.46	386.54	$	1,446.47
500 Kv	4,514	86.88	983.96	37.32	385.18	$	1,493.35
115-345 Kv Steel	4,787	53.13	588.30	22.82	235.53	$	899.78
115-230 Kv Wood	3,799	98.39	1,109.75	42.27	436.19	$	1,686.59
Low Voltage	195	104.43	1,152.40	44.86	462.95	$	1,764.64
Submarine	26	13.63	147.06	5.86	60.43	$	226.97
Composite	1,244	64.47	713.92	27.70	285.81	$	1,091.90
	14,830						

Bonneville Power Administration
O & M Charges for Customer Owned or Leased Facilities
O & M Expense Averaged for Fiscal Year 2002, 2003, 2004, 2005, and 2006
Terminal Charges - Gas/Air Power Circuit Breakers
September 30, 2007

	Low Voltage Terminal	115 KV Terminal	230 KV Terminal	500 KV Terminal
Direct Maintenance				
Substation Mtce - directly identified	821	1,136	1,340	4,006
Relaying	152	201	231	607
Metering	43	57	65	171
Communications	200	263	302	797
Non Electric	129	169	195	513
Total Direct Maintenance	1,345	1,826	2,133	6,094
Indirect Maintenance	119	156	179	472
Direct operations	1,373	1,807	2,078	5,471
Indirect Operations				
Data Systems Hardware Maintenance	317	417	480	1,263
System Operations	343	451	519	1,367
Total Indirect Operations	660	868	999	2,630
Total O & M (excluding A & G and OH)	3,497	4,657	5,389	14,666
Station General Expense	584	822	911	2,444
Administration and General Expense	639	900	997	2,676
Annual Total	4,720	6,379	7,297	19,787
Monthly Total	393	532	608	1,649

Notes:
(1) 115 and 230 - include 1 oil breaker + 3 group switches
(2) LV - includes 1 oil breaker + 2 hook switches + 1 group switch
(3) These figures do not include interest and amortization.

Contract No. DE-MS79-89BP92384

12/05/89

GENERAL TRANSFER AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PORTLAND GENERAL ELECTRIC COMPANY

Index to Sections

RE INPUT 01/16/08 JSLO

This GENERAL TRANSFER AGREEMENT, executed December 11, 1989, by the UNITED STATES OF AMERICA (Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and PORTLAND GENERAL ELECTRIC COMPANY (Company), a corporation of the State of Oregon,

W I T N E S S E T H :

WHEREAS Bonneville and the entities named in Exhibit B (Bonneville's Customers) have entered into power sales contracts providing for the delivery of firm electric power and energy to such customers at various points of delivery; and

WHEREAS the Company has firm electric power and energy arrangements with its customers and consumers at various points of delivery; and

WHEREAS each party desires to provide for delivery of firm electric power and energy to its Customers and Consumers at various points of delivery; and

WHEREAS the parties hereto have entered into Contract No. 14-03-49110 effective 2400 hours August 31, 1976, and, commencing October 1, 1982, have entered into Contract No. DE-MS79-83BP91011, as amended (Prior Agreements); and

WHEREAS Contract No. DE-MS79-83BP91011 was specifically continued under Contract No DE-MS79-88BP92340 (Intertie Agreement); and

WHEREAS both parties desire to replace the Prior Agreements with this General Transfer Agreement; and

WHEREAS the parties have negotiated this agreement, the General Transmission Agreement (Integration of Resources) Agreement, Contract No. DE-MS79-89BP92273, and a Letter Agreement, Contract No. DE-MS79-90BP92865, contemporaneously such that the parties benefit from favorable terms in one agreement in exchange for concessions in the others; and

WHEREAS the parties hereto, on August 27, 1982, entered into Power Sales Agreement, Contract No. DE-MS79-81BP90425, and on September 13, 1973, entered into the Exchange Agreement, Contract No. 14-03-37017 (Exchange Agreement), which provided, among other matters, for the establishment of an exchange energy account, the exchange of excess energy, and metering and scheduling arrangements; and

WHEREAS Bonneville is authorized pursuant to law to market electric power and energy generated at various Federal hydroelectric projects in the Pacific Northwest, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. <u>Term of Agreement</u>.

(a) This agreement shall be effective at 2400 hours on December 31, 1989 (Effective Date), and shall terminate under the earliest of one of the following conditions:

(1) 2400 hours on the date of the termination of the Exchange Agreement;

(2) Upon 5-years' prior written notice by either party, but such notice may be given only after 2400 hours on December 31, 2004; or

(3) Termination of all points of delivery, as permitted under Section 5; provided however, that all liabilities incurred thereunder shall be preserved until satisfied.

(b) Upon notice of termination of this agreement, under paragraph 1(a)(2) above, the parties shall negotiate, in good faith, a new transfer agreement, which at a minimum provides a continuity of service to then existing loads.

(c) Upon termination of this agreement and in the absence of a follow-on agreement and with no intent to enter into an agreement pursuant to subsection (b) above, the Transferor shall cooperate such that Transferee shall be able to transmit to existing loads; provided however, that the Transferee shall assume all responsibility for such service, no later than 3 years after the termination of this agreement.

2. Termination of Prior Agreements. The Prior Agreements are hereby terminated as of the Effective Date; provided however, that all liabilities incurred thereunder shall be preserved until satisfied.

3. Definition and Explanation of Terms.

(a) "Consumer." An end-use purchaser of electric power and energy.

(b) "Customer." A wholesale purchaser of electric power and energy which is not a Consumer.

(c) "Point(s) of Delivery" or "POD." The point or points at which electric power and energy are made available by the Transferor on behalf of the Transferee, as specified in Exhibits B or C.

(d) "Point(s) of Replacement" or "POR." The point or points at which replacement electric power and energy are made available by the Transferee to the Transferor, as specified in Exhibits B or C.

(e) "Prudent Utility Practice." At any particular time, the generally accepted practices, methods, and acts in the electrical utility industry existing prior to the subject action or the practices, methods or acts, which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to accomplish the desired result consistent with reliability and safety.

(f) "Southern Intertie Terminals." The John Day and Big Eddy Substation facilities which terminate the lines for transferring power and energy between the Pacific Northwest and the Pacific Southwest.

(g) "Transfer Capability." The rated kilowatt capacity, as agreed upon in joint-planning, of the equipment in the contract paths, as such paths are specified in Exhibits B and C.

(h) "Transfer Charge." The monthly charge per kilowatt of Transfer Demand shown in Exhibit D used to calculate the payment due the Transferor as compensation for Transfer Service to be provided on behalf of the Transferee as agreed herein. The methodology for determining the Transfer Charge is as shown in Exhibit E.

(i) "Transfer Demand." The largest of the metered Integrated Demands defined in Exhibit A, adjusted for losses back to the Point of Delivery at which electric power and energy is made available by the Transferor on behalf of the Transferee hereunder during a month, as measured by meters at locations specified in Exhibit B or C, after eliminating all abnormal nonrecurring Integrated Demands resulting from emergency power system conditions.

(j) "Transfer Service." Delivery of electric power and energy provided by the Transferee over the facilities of the Transferor to loads of the Transferee.

4. Exhibits. Exhibits A through G are hereby made a part of this agreement. The Company shall be the "Transferor" as that term is used in this agreement and Exhibit A when transferring electric power and energy to Bonneville's Customers at Points of Delivery specified in Exhibit B, and Bonneville shall be the "Transferee" mentioned therein. Bonneville shall be the "Transferor" as that term is used in this agreement and Exhibit A when transferring electric power and energy to the Company at Points of Delivery specified in Exhibit C, and the Company shall be the "Transferee" mentioned therein.

5. Revision of Exhibits. Exhibits B, C, and D shall be revised at:

(a) any time, if the parties agree to add or remove Points of Delivery or Points of Replacement; or

(b) the time specified by the Transferee in a written notice to the Transferor to remove any Point of Delivery specified in Exhibits B or C, as the case may be, but not before the expiration of 1 year from 2400 hours on the date such notice is received by the Transferor.

(c) the time specified by the Transferor in a written notice to the Transferee to remove any Point of Delivery specified in Exhibits B or C, as the case may be, but not before the expiration of 3 years from 2400 hours on the date such notice is received by the Transferee.

6. Revision of Methodologies, Charges and Losses.

(a) The Loss Factor, Transfer Charge and Sole Use-of-Facilities Charge, specified in Exhibit D, and the System Loss Factors in Exhibit F shall be revised pursuant to Section 19 of Exhibit A, Adjustment for Change of Conditions Section, upon mutual agreement of the parties. The Transferor shall submit notice of such revision including justification for any such revision 90 days prior to the date the revision is requested to be effective.

The Transferee shall review such information and shall not unreasonably withhold agreement to change the affected exhibit. System Loss Factors, Loss Factor, Transfer Charge, or Sole Use-of-Facilities Charge may be reviewed at any time, but each shall not be changed more often than once in any 12-month period for any Point of Delivery.

(b) Exhibit E contains the methodologies for calculating the Transfer Charge and Sole Use-of-Facilities Charge listed in Exhibit D. The values of the variables used in the methodologies are expected to change from time to time, and such changes shall not be deemed to be a change in methodologies. Such methodologies shall be periodically reviewed by the parties upon the request of either party to consider modifications. Any change to the methodologies shall require mutual approval of the parties, provided however, approval for such change shall not be unreasonably withheld; and provided further, that such methodologies shall not be changed prior to 15 years after the Effective Date of this Agreement.

(1) Immediately following execution of this agreement, the Company shall seek approval of this agreement including the Transfer Charge and Sole Use-of-Facilities Charge methodology from the Federal Energy Regulatory Commission (Agency). This agreement shall not be effective until such approval is granted by the Agency without modifications unacceptable to either party. Upon the receipt of such approval, this agreement shall be deemed to have been in effect as of the earliest date consistent with the Agency's order. In the event the Company is unable to obtain approval of this agreement, the parties may agree upon other mutually agreeable terms and seek appropriate regulatory approval. If Bonneville and the Company cannot agree on such terms or obtain regulatory approval, then subparagraph (A) and (B) shall apply as follows:

(A) The parties shall cooperate such that service to each party's Customers and Consumers shall be sufficient to continue service to existing loads; provided however, that each party shall assume all responsibility for such service not later than 5 years after notice; and

(B) Bonneville shall have the right to terminate the Integration of Resources agreement upon 5-years' notice; provided however, Bonneville shall offer to extend resources integration transmission services including services to the Southern Intertie Terminals, of the same quality as, and on terms and conditions consistent with, those being offered at that time to other customers similarly situated.

(2) Bonneville shall, for the term of this agreement, seek continuance of the methodologies contained in Exhibit E by advocating a rate schedule or schedules which accommodate the methodologies to the Agency, or its successor, or a court of competent jurisdiction, and, except with mutual agreement or as provided below, to never propose a change in such methodology, applicable to this agreement, in any rate procedure conducted under Section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act, 16 USC Section 839e(i). In the event Bonneville is required by the Agency, or its successor, or a court of competent jurisdiction, to change either methodology, the Company and Bonneville may agree upon another mutually acceptable methodology, and shall seek appropriate regulatory approval, if necessary. If Bonneville and the Company fail to agree on a methodology, or if regulatory approval is not granted, then the Company shall have the right to terminate this

agreement. Upon such termination, subparagraph (A) and (B) shall apply as follows:

(A) The parties shall cooperate such that service to each party's Customers and Consumers shall be sufficient to continue service to existing loads; provided however, that each party shall assume all responsibility for such service not later than 5-years' after notice of termination; and

(B) Bonneville shall have the right to terminate the Integration of Resources Agreement, Contract No. DE-MS79-89BP92273, upon five (5) year's notice, provided, however, that Bonneville shall offer to extend resources integration transmission services including service to the Southern Intertie Terminals, of the same quality as, and on terms and conditions consistent with, those being offered at that time to other customers similarly situated.

(c) Likewise any change to the loss methodology, specified in Exhibit F, shall require mutual approval of the parties; provided however; that such methodology shall be periodically reviewed by the parties upon the request of either party to consider modifications. Consent for such change shall not be unreasonably withheld; provided however; such methodologies shall not be changed prior to 5 years after the Effective Date of this agreement. The values of the Loss Factors specified in Exhibit D and System Loss Factors specified in Exhibit F are expected to change from time to time and such changes shall not be deemed to be a change in methodology.

(d) Upon any change in methodology or charges pursuant to this Section, the Transfer Charges, Sole Use-of-Facilities Charges, and the Loss Factors specified in Exhibit D or any subsequent charges or losses specified in this agreement shall be recalculated accordingly and the parties shall prepare an executed Exhibit D incorporating the new charges or losses. Such revised Exhibit D shall be substituted for the Exhibit D then in effect and shall become effective as of the effective date of such new methodology or charges.

7. Provisions Relating to Delivery. Except for uncontrollable power system interruptions, electric power and energy shall be made available by the Transferor at all times during the term hereof and at the Points of Delivery described in Exhibits B and C, in the amount of the Transferee's requirements, up to the Transferee's forecasted loads; provided however, the Transferor may, but shall not be obligated to, deliver such electric power and energy in excess of this Transferee forecast, so long as the combined loads of the Transferor and Transferee and other transfer obligations of the Transferor are less than the Transfer Capability. When the forecast of Transferor's and Transferee's combined loads and other transfer obligations of the Transferor approaches the Transfer Capability of the facilities, the parties shall operate under the provisions of Section 13. Amounts of electric energy and varhours delivered at such points during each month shall be determined from measurements, adjusted as determined by the parties hereto for losses between each Point of Delivery and the metering points in Exhibits B and C, made by meters installed at the locations and in the circuits specified in Exhibits B and C.

8. Replacement of Power Delivered. In exchange for electric power and energy delivered by the Transferor hereunder, the Transferee shall make electric power and energy available to the Transferor during each month in the term hereof, at the Points of Replacement specified in Exhibits B or C, as provided therein and subject to the applicable provisions of the Exchange Agreement, as it may be amended or replaced. Such electric power and energy to be made available by the Transferee shall be computed by increasing metered

amounts, determined as provided in Exhibits B and C for each Point of Delivery, by the Loss Factor specified in Exhibit D.

The Transferee shall make available to the Transferor each hour during the term hereof the amount of electric energy which is estimated to be the amount, so adjusted for losses, which the Transferor will deliver hereunder during such hour, and shall schedule such amount for delivery to the Transferor at the Points of Replacement named in Exhibits B and C.

9. Quality of Service.

(a) The Transferor shall provide the Transferee's load the same quality of service as that of a similar type of load of the Transferor, in that same locality.

(b) The Transferor shall maintain records, in accordance with standard utility practice, of dispatching, switching, and outages associated with the Points of Delivery. Such records shall be made available, on request, for examination by the Transferee.

10. Transfer Charge Payment.

(a) For the use of Transfer Services, provided hereunder, the Transferee shall pay the Transferor each month during the term hereof an amount determined by adding, for all Points of Delivery, the largest product for each Point of Delivery obtained by:

(1) multiplying the Transfer Demand for such month by the current Transfer Charge for such Point of Delivery after increasing such Transfer Demand by one percent for each one percent or major fraction thereof by which the average power factor, at which electric energy is delivered hereunder during each month, is less than 95 percent lagging; and

(2) multiplying the Transfer Demand of each of the 11 immediately preceding months by the current Transfer Charge.

(b) For determining power factor in subsection (a)(1) above, metered amounts shall be adjusted for losses between the point of metering and the Point of Delivery. These losses shall be calculated from factors contained in Exhibit D.

11. Sole Use-of-Facilities Payment. *In addition to the payment due the* Transferor, in accordance with Section 10, the Transferee shall pay the Transferor each month the amounts, if any, specified in Exhibit D under Sole Use-of-Facilities Charge, for use of specified facilities required to serve the Transferee, if payment for such use is not otherwise included in the Transfer Charge, or is not otherwise provided for. The Sole Use-of-Facilities Charge shall be determined in accordance with Exhibit E.

12. Payment of Bills.

(a) The Company shall reimburse Bonneville by wire transfer or by offsetting such amounts against all payments due the Company for the month during which Transfer Service was provided in accordance with the billing information section of the General Transmission Rate Schedule Provisions in Exhibit G.

(b) Bonneville shall reimburse the Company for services provided hereunder by cash payment or by offsetting the amounts owed against all payments due Bonneville under this or other agreements between the parties on the wholesale power bill. If the net amount of the wholesale power bill is a credit due the Company then Bonneville shall pay the Company by close of business within twenty (20) days of the date of the wholesale power bill. Should the twentieth (20th) day fall on a Saturday, Sunday, or holiday as observed by Bonneville then the due date shall be the next following business day.

(c) If the Transferor is unable to render the Transferee a timely monthly bill which includes a full disclosure of billing factors, it may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill.

(d) The parties agree that in the event that Transfer Services are provided where final charges have not been agreed upon, invoices with reasonable interim charges shall be issued. When the final rate is determined, interest shall be paid on the difference between the interim and final charges. The interest rate charged shall be the weighted average interest rate charged to Bonneville by the U.S. Treasury.

13. Removal of Facilities, Termination Charges, and Installation of Additional Facilities for Existing Customers and Consumer(s).

(a) On or before July 1 of each year the Transferee shall furnish the Transferor a 5 year forecast of its maximum demand for each of the Points of Delivery described in Exhibit B or C for existing Customers and Consumers. The parties shall exchange and review any necessary data, annually and more frequently as necessary, to determine the adequacy of facilities to serve the combined forecasted loads of the Transferor and Transferee for existing Customers and Consumers and to plan such that construction can be completed prior to need.

(b) To enable the parties to provide Transfer Service to existing Customers and Consumer(s) as agreed hereunder, the parties shall meet to plan for removal of existing facilities, for installation of additional facilities or, at the request of the Transferee, for the addition of a new point of delivery for existing Customers and Consumer(s). Such meetings may include other impacted utilities, to discuss plans and resolve issues. Upon the review of data, exchanged from time to time, if it is determined that the combined loads are approaching the Transfer Capability, the Transferor shall initiate a plan-of-service study with input from the Transferee and other impacted utilities. The Transferee's load will be considered the same as the Transferor's load for planning purposes.

(c) For the purpose of establishing the pro rata share of use, any loads placed on the transfer facilities by a party, other than the Transferor or Transferee, shall be deemed to be a load of the Transferor. The Transferor shall have responsibility for adequate planning to meet the Transferee's load growth for existing Customers and Consumers, in addition to loads of its own Customers and Consumers.

(d) If the parties cannot agree on the plan-of-service for the addition or removal of facilities or addition of a new point of delivery for an existing Customer or Consumer, the Transferor shall determine the plan-of-service; provided however, such plan-of-service shall be in keeping with Prudent Utility Practice. Nothing in this agreement is intended to provide consent for the Transferee to control or construct connecting facilities with those of the Transferor, without the Transferor's approval.

(e) If the parties agree, the Transferor shall implement the plan-of-service as determined in (b) and (d) above, at the Transferor's expense, as required to serve the combined load of both parties; provided however:

(1) New facility investments should be delayed when other prudent utility service arrangements are possible. Such arrangements include the Transferor's facilities and the facilities of other utilities. The Transferor shall not refuse to provide Transfer Service, nor shall it place unusual or burdensome requirements on the Transferee as a condition for providing Transfer Service, to the extent that the Transferor has sufficient capacity to effect the transfer, and to the extent that Transfer Service requirements are beyond the control of the Transferee;

(2) If mutually agreed upon, the Transferee may provide all or a portion of such facilities, particularly when the Transferee can do so at less total expense to both parties, or when the Transferor is unable to complete construction in time to meet the Transferee's load requirements. Any facilities provided by the Transferee shall be compatible with the specifications of the Transferor. The cost of such facilities shall not be included in the calculation of charges to be paid by the Transferee if ownership resides with the Transferee; otherwise the Transferee shall be fully compensated for the cost of such facilities as soon as practicable if ownership passes to the Transferor. Exhibit D shall be amended to reflect the cost and ownership of such facilities effective when such facilities are placed in commercial operation;

(3) Subject to Section 6(b), charges for Transfer Service shall be developed, based on the cost of facilities and on the shortest path between Point of Replacement and Point of Delivery, unless such methodology was revised at some time pursuant to Section 6(b).

(f) Upon removing or installing facilities as determined in subsection (b) and (d) above, the parties shall, prepare new Exhibits B, C, or D as appropriate, including the applicable contract terms and termination charges, if any. Such new exhibit(s) shall replace the existing exhibit(s) on the effective date specified therein.

(g) If the parties agree to remove facilities pursuant to subsections (b) and (d) above; or a point of delivery is terminated pursuant to Section 5(b); or this agreement is terminated as provided in Section 1 or 6(b), and if the capacity of such facilities would then be excess to the Transferor's needs as a consequence of such removal or contract termination, the Transferee shall pay the Transferor an appropriate mutually agreeable termination charge to the extent that the capacity of such facilities which were provided to enable the Transfer Service would be excess to the Transferor's needs.

(h) If additional facilities must be constructed or installed by either party pursuant to subsection (e) above, a reasonable period of time shall be allowed for such construction or installation.

(i) This Section 13 shall not apply to new Customers or to loads served by the Transferor as of the Effective Date of this Agreement.

14. Addition of New Customers and Service to Loads Formerly Served by the Transferor. If a party desires to serve a new Customer or a load which was served by the other party as of the Effective Date of this agreement and requires transfer service, the sequence of events shall be as follows:

(a) The requesting party shall provide a written notice to the potential transferor of its intent to serve such new Customer or load and its request for Transfer Service. The parties agree to cooperate as necessary to study potential service arrangements.

(b) Within 6 months of any request, the potential transferor shall determine whether or not it desires to provide Transfer Service to serve such new Customer or load and shall provide the requesting party written notice of its intention.

(1) If the potential transferor gives notice that it will not provide Transfer Service, the potential transferor shall provide the requesting party any necessary information to aid the requesting party in planning for service to this Customer or load. If the parties agree to terms for temporary service, the potential transferor may provide service until such time as the requesting party can assume responsibility for service to this Customer or load; provided however, that the requesting party shall assume all responsibility for such service no later than

3 years after the date of the notice given pursuant to subsection (b), above; and provided further that nothing in this Section 14 shall preclude a party from seeking remedies outside of this agreement if a potential transferor declines to provide Transfer Service.

(2) If the potential transferor gives notice that it will provide Transfer Service, determination of new points of delivery and other necessary service arrangements shall be based on joint studies, involving both parties and impacted utilities using the potential transferor's and other utilities' facilities. If the parties cannot agree on a plan-of-service, the potential transferor shall make such determination. In any event, each party shall control its own facilities and any construction on its own facilities.

(c) Upon establishing service arrangements, as determined in this Section, the parties shall prepare and execute new Exhibits B, C, or D as appropriate, including the applicable contract terms and termination charges, if any. Such new exhibit(s) shall replace the existing exhibit(s) on the effective date specified therein.

15. Ratification of Interim Agreement. Commencing at 2400 hours on September 30, 1987 and continuing until the Effective Date of this Agreement,

the parties hereto provided services and billed for these in accordance with the Prior Agreements. The parties hereby ratify such interim agreements.

IN WITNESS WHEREOF, the parties hereto have executed this agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By James J. Jura

Title Administrator

Walter E. Pollock

PORTLAND GENERAL ELECTRIC COMPANY

By E. Kay Stepp

Title President

Date December 11, 1989

(VS6-PMT-3190e)

EXHIBIT A

GWP Form-4R (04-15-83)

GENERAL WHEELING PROVISIONS

- -

Index to Sections

- -

GENERAL APPLICATION

1. Interpretation.

(a) The provisions in this exhibit shall be deemed to be a part of the contract body to which they are an exhibit. If a provision in such contract body is in conflict with a provision contained herein, the former shall prevail.

(b) If a provision in the General Transmission Rate Schedule Provisions is in conflict with a provision in this exhibit or the contract body, this exhibit or the contract body shall prevail.

(c) Nothing contained in this contract shall, in any manner, be construed to abridge, limit, or deprive any party thereto of any means of enforcing any remedy, either at law or in equity, for the breach of any of the provisions thereof which it would otherwise have.

2. Definitions. As used in this contract:

(a) "Contractor," "Utility" or "Borrower" means the party to this contract other than Bonneville.

(b) "Federal System" or "Federal System Facilities" means the facilities of the Federal Columbia River Power System, which for the purposes of this contract shall be deemed to include the generating facilities of the Government in the Pacific Northwest for which Bonneville is designated as marketing agent; the facilities of the Government under the jurisdiction of Bonneville; and any other facilities:

(1) from which Bonneville receives all or a portion of the generating capability (other than station service) for use in meeting Bonneville's loads, such facilities being included only to the extent Bonneville has the right to receive such capability; provided, however, that "Bonneville's loads" shall not include that portion of the loads of any Bonneville customer which are served by a nonfederal generating resource purchased or owned directly by such customer which may be scheduled by Bonneville;

(2) which Bonneville may use under contract, or license; or

(3) to the extent of the rights acquired by Bonneville pursuant to the Treaty, between the Government and Canada, relating to the cooperative development of water resources of the Columbia River Basin, signed in Washington, D.C., on January 17, 1961.

(c) "Integrated Demand" means the number of kilowatts which is equal to the number of kilowatt-hours delivered at any point during a clock hour.

(d) "Measured Demand" means the maximum Integrated Demand for a billing month determined from measurements made as specified in the contract or as determined in section 4 hereof when metering or other data are not available for such purpose. Bonneville, in determining the Measured Demand, will exclude any abnormal Integrated Demands due to, or resulting from (a) emergencies or breakdowns on, or maintenance of, either parties' facilities, and (b) emergencies on facilities of the Transferee, provided that such facilities have been adequately maintained and prudently operated as determined by Bonneville.

If the contract provides for delivery of more than one class of power to a Transferee at any Point of Delivery, the portion of each Integrated Demand assigned to any class of power shall be determined as specified in the contract. The portion of the Integrated Demand so assigned shall constitute the Measured Demand for such class of power.

(e) "Month" means the period commencing at the time when the meters mentioned in this contract are read by Bonneville and ending approximately 30 days thereafter when a subsequent reading of such meters is made by Bonneville.

(f) "Point(s) of Delivery" means the point(s) of delivery listed either in the Points of Delivery Exhibit to this contract or in the body of this contract.

(g) "System" or "Facilities" means the transmission facilities: (1) which are owned or controlled by either party, or (2) which either party may use under lease, easement, or license.

(h) "Transferee" means an entity which receives power or energy from the system of the Transferor.

(i) "Transferor" means an entity which receives at one point on its system a supplying entity's power or energy and makes such power or energy available at another point on its system for the account of the delivering entity or a third party.

(j) "Uncontrollable Forces" means:

(1) strikes or work stoppage affecting the operation of the Contractor's works, system, or other physical facilities or of the Federal System Facilities or the physical facilities of any Transferee upon which such operation is completely dependent; the term "strikes or work stoppage" shall be deemed to include threats of imminent strikes or work stoppage which reasonably require a party or Transferee to restrict or terminate its operations to prevent substantial loss or damage to its works, system, or other physical facilities; or

(2) such of the following events as the Contractor or Bonneville or any Transferee by exercise of reasonable diligence and foresight, could not reasonably have been expected to avoid:

(A) events, reasonably beyond the control of either party or any Transferee, causing failure, damage, or destruction of any works, system or facilities of such party or Transferee; the word "failure" shall be deemed to include interruption of, or interference with, the actual operation of such works, system, or facilities;

(B) floods or other conditions caused by nature which limit or prevent the operation of, or which constitute an imminent threat of damage to, any such works, system, or facilities; and

(C) orders and temporary or permanent injunctions which prevent operation, in whole or in part, of the works, system, or facilities of either party or any Transferee, and which are issued in any bona fide proceeding by:

i. any duly constituted court of general jurisdiction; or

ii. any administrative agency or officer, other than Bonneville or its officers, provided by law (a) if said party or Transferee has no right to a review of the validity of such order by a court of competent jurisdiction; or (b) if such order is operative and effective unless suspended, set aside, or annulled by a court of competent jusidiction and such order is not suspended, set aside, or annulled in a judicial proceeding prosecuted by said party or Transferee in good faith; provided, however, that if such order is suspended, set aside, or annulled in such a judicial proceeding, it shall be deemed to be an "uncontrollable force" for the period during which it is in effect; provided, further, that said party or Transferee, shall not be required to prosecute such a proceeding, in order to have the benefits of this section, if the parties agree that there is no valid basis for contesting the order.

The term "operation" as used in this subsection shall be deemed to include construction, if construction is required to implement the contract and is specified therein.

3. Prior Demands.

(a) In determining any credit demand mentioned in, or money compensation to be paid under this contract for any month, Integrated Demands at which electric energy was delivered by the Transferor at Points of Delivery mentioned herein for the account of the other party to this contract prior to the date upon which the contract takes effect shall be considered in the same manner as if this contract had been in effect.

(b) If either party has delivered electric power and energy to the other party at any Point of Delivery specified in this contract or in any previous contract, and such Point of Delivery is superseded by another Point of Delivery specified in this contract, the Measured Demands, if any, at the superseded Point of Delivery shall be considered for the purpose of determining the charges paid to the Transferor for the electric power and energy delivered under this contract at such superseded point.

4. Measurements. Except as it is otherwise provided in section 7, each measurement of each meter mentioned in this contract shall be the measurement

automatically recorded by such meter or, at the request of either party, the measurement as mutually determined by the best available information.

If it is provided in this contract that measurements made by any of the meters specified therein are to be adjusted for losses, such adjustments shall be made by using factors, or by compensating the meters, as agreed upon by the parties hereto. If changes in conditions occur which substantially affect any such loss factor or compensation, it will be changed in a manner which will conform to such change in conditions.

5. Measurements and Installation of Meters. Bonneville may at any time install a meter or metering equipment to make the measurements for any Point of Delivery required for any computation or determination mentioned in this contract, and if so installed, such measurements shall be used thereafter in such computation or determination.

6. Tests of Metering Installations. Each party to this contract shall, at its expense, test its metering installations associated with this contract at least once every two years, and, if requested to do so by the other party, shall make additional tests or inspections of such installations, the expense of which shall be paid by such other party unless such additional tests or inspections show the measurements of such installations to be inaccurate as specified in section 7. Each party shall give reasonable notice of the time when any such test or inspection is to be made to the other party who may have representatives present at such test or inspection. Any component of such installations found to be defective or inaccurate shall be adjusted, repaired or replaced to provide accurate metering.

7. Adjustment for Inaccurate Metering

(a) If any meter mentioned in this contract fails to register, or if the measurement made by such meter during a test made as provided in section 6 varies by more than one percent from the measurement made by the standard meter used in such test, or if an error in meter reading occurs, adjustment shall be made correcting all measurements for the actual period during which such innacurate measurements were made, if such period can be determined. If such period cannot be determined, the adjustment shall be made for the period immediately preceding the test of such meter which is equal to the lesser of (a) one-half the time from the date of the last preceding test of such meter, or (b) six months. Such corrected measurements shall be used to recompute the amounts of any electric power and energy to be made available, or any credits to be made in any exchange energy account, and of any money compensation to be paid to the Transferor as provided in this contract.

(b) If the credit theretofore made to the Transferor in the exchange energy account varies from the credit to be made as recomputed, the amount of the variance will be credited in such exchange energy account to the party entitled thereto.

(c) If the money compensation theretofore paid to the Transferor varies from the money compensation to be paid as recomputed, the amount of the variance will be paid to the party entitled thereto after both parties have agreed to such recomputation and within 30 days after receipt of invoice by the designated payment office of the payer; provided, however, that the other party may deduct such amount due it from any money compensation which thereafter becomes due the Transferor under this contract.

8. Character of Service. Unless otherwise specifically provided for in the contract, electric power and energy made available pursuant to this contract shall be in the form of three-phase current, alternating at a nominal frequency of 60 hertz.

9. Point(s) of Delivery and Delivery Voltage. Electric power and energy shall be delivered to each Transferee at such point or points and at such voltage or voltages as are agreed upon by the parties hereto.

10. Combining Deliveries Coincidentally. If it is provided in this contract that charges for electric power and energy made available at two or more Points of Delivery will be made by combining deliveries at such points coincidentally:

(a) the total Measured Demand to be considered in determining the billing demand for each billing month shall be the largest sum obtained by adding for each demand interval of such month the corresponding Integrated Demands of the Transferee at all such points after adjusting said Integrated Demands as appropriate to such points;

(b) the number of kilowatthours to be used in determining the energy charge, if any, and the average power factor at which electric energy is delivered at such points under this contract, during such month, shall be the sum of the amounts of electric energy delivered at such points under this contract during such month; and

(c) the number of reactive kilovolt-ampere-hours to be used in determining such average monthly power factor shall be the sum of the reactive kilovolt-ampere-hours delivered at such points under this contract such month.

11. Suspension of Deliveries. The other party to this contract may at any time notify the Transferor in writing to suspend the deliveries of electric power and energy provided for in this contract. Upon receipt of any such notice, the Transferor will forthwith discontinue, and will not resume, such deliveries until notified to do so by the other party, and upon receipt of such notice from the other party to do so, will forthwith resume such deliveries.

12. Continuity of Service. Either party may temporarily interrupt or reduce deliveries of electric power and energy if such party determines that such interruption or reduction is necessary or desirable in case of system emergencies, Uncontrollable Forces, or in order to install equipment in, make repairs to, make replacements within, make investigations and inspections of, or perform other maintenance work on its system. Except in case of emergency and in order that each party's operations will not be unreasonably interfered with, such party shall give notice to the other party of any such interruption or reduction, the reason therefor, and the probable duration thereof to the extent such party has knowledge thereof. Each party shall effect the use of temporary facilities or equipment to minimize the effect of any such interruption or outage to the extent reasonable or appropriate.

13. Uncontrollable Forces. Each party shall notify the other as soon as possible of any Uncontrollable Forces which may in any way affect the delivery of power hereunder. In the event the operations of either party are interrupted or curtailed due to such Uncontrollable Forces, such party shall exercise due diligence to reinstate such operations with reasonable dispatch.

14. Reducing Charges for Interruptions. If deliveries of electric power and energy to the Transferee are suspended, interrupted, interfered with or curtailed due to Uncontrollable Forces on either the Transferee's System or Transferor's System, or if the Transferor interrupts or reduces deliveries to the Transferee for any of the reasons stated in section 12 hereof, the credit in the exchange energy account which would otherwise be made, or the money compensation which would otherwise be paid to the Transferor, shall be appropriately reduced. No interruption, or equivalent interruption, of less than 30 minutes duration will be considered for computation of such reduction in charges.

15. Net Billing. Upon mutual agreement of the parties, payment due one party may be offset against payments due the other party under all contracts between the parties hereto for the sale and exchange of electric power and energy, use of transmission facilities, operation and maintenance of electric facilities, lease of electric facilities, mutual supply of emergency and standby electric power and energy, and under such other contracts between such parties as the parties may agree, unless otherwise provided in existing contracts between the parties. Under contracts included in this procedure, all payments due one party in any month shall be offset against payments due the other party in such month, and the resulting net balance shall be paid to the party in whose favor such balance exists unless the latter elects to have such balance carried forward to be added to the payments due it in a succeeding month.

16. Average Power Factor.

(a) The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{\sqrt{(\text{Kilowatthours})^2 + (\text{Reactive Kilovolt-ampere-hours})^2}}$$

The data used in the above formula shall be obtained from meters which are ratcheted to prevent reverse registration.

(b) When delivery of electric power and energy by the Transferor at any point is commingled with any other class or classes of power and it is impracticable to separately meter the kilowatthours and reactive kilovolt-ampere-hours for each class, the average power factor of the total delivery of such electric power and energy for the month will be used, where applicable, as the power factor for each of the separate classes.

(c) Except as it is otherwise specifically provided in this contract, no adjustment will be made for power factor at any point of delivery described in this contract while the varhours delivered at such point are not measured.

(d) The Transferor may, but shall not be obligated to, deliver electric energy hereunder at a power factor of less than 0.85 leading or lagging.

17. Permits.

(a) If any equipment or facilities associated with any Point of Delivery and belonging to a party to this contract are or are to be located on the property of the other party, a permit to install, test, maintain, inspect, replace, repair, and operate during the term of this contract and to remove such equipment and facilities at the expiration of said term, together with the right of entry to said property at all reasonable times in such term, is hereby granted by the other party.

(b) Each party shall have the right at all reasonable times to enter the property of the other party for the purpose of reading any and all meters mentioned in this contract which are installed on such property.

(c) If either party is required or permitted to install, test, maintain, inspect, replace, repair, remove, or operate equipment on the property of the other, the owner of such property shall furnish the other party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other party of any subsequent modification which may affect the duties of the other party in regard to such equipment, and furnish the other party with accurate revised drawings, if possible.

18. Ownership of Facilities.

(a) Except as otherwise expressly provided, ownership of any and all equipment, and of all salvable facilities installed or previously installed by a party to this contract on the property of the other party shall be and remain in the installing party.

(b) Each party shall identify all movable equipment and all other salvable facilities which are installed by such party on the property of the other by permanently affixing thereto suitable markers plainly stating the name of the owner of the equipment and facilities so identified. Within a reasonable time subsequent to initial installation, and subsequent to any modification of such installation, representatives of the parties shall jointly prepare an itemized list of said movable equipment and facilities.

19. Adjustment for Change of Conditions. If changes in conditions hereafter occur which substantially affect any factor required by this contract to be used in determining (a) any credit in any exchange energy account to be made, money compensation to be paid, or amount of electric power and energy or losses to be made available to one party by the other party, or (b) any maximum replacement demand, or average power factor mentioned in this contract, such factor will be changed in an equitable manner which will conform to such changes of conditions. If an increase in the capacity of the facilities being used by the Transferor in making deliveries hereunder is required at any time after execution of this contract to enable the Transferor to make the deliveries herein required together with those required for its own operations, the construction or installation of additional or other

equipment or facilities for that purpose shall be deemed to be a change of conditions within the meaning of the preceding sentence.

If, pursuant to the terms of the agreement establishing such exchange energy account, another rate is substituted for the rate to be used in settling the balance in such account, the number of kilowatthours to be credited to the Transferor in such account for each month as provided in this agreement, shall be changed for each month thereafter to the amount computed by multiplying such number of kilowatthours by 2.5 mills and dividing the resulting product by the currently effective substituted rate in mills per kilowatthour.

20. Dispute Resolution and Arbitration.

(a) Pending resolution of a disputed matter the parties will continue performance of their respective obligations pursuant to this contract. If the parties cannot reach timely mutual agreement on any matter in the administration of this contract Bonneville shall, unless otherwise specifically provided for in subsection (b) below and, to the extent necessary for its continued performance, make a determination of such matter without prejudice to the rights of the other party. Such determination shall not constitute a waiver of any other remedy belonging to the Contractor.

(b) The questions of fact stated below shall be subject to arbitration. Other questions of fact under this contract may be submitted to arbitration upon written mutual agreement of the parties. The party calling for arbitration shall serve notice in writing upon the other party, setting forth in detail the question or questions to be arbitrated and the arbitrator appointed by such party. The other party shall, within 10 days after the receipt of such notice, appoint a second arbitrator, and the two so appointed shall choose and appoint a third. In case such other party fails to appoint an arbitrator within said 10 days, or in case the two so appointed fail for 10 days to agree upon and appoint a third, the party calling for the arbitration, upon 5 days' written notice delivered to the other party, shall apply to the person who at the time shall be the presiding judge of the United States Court of Appeals for the Ninth Circuit for appointment of the second and third arbitrator, as the case may be.

The determination of the question or questions submitted for arbitration shall be made by a majority of the arbitrators and shall be binding on the parties. Each party shall pay for the services and expenses of the arbitrator appointed by or for it, for its own attorney fees, and for compensation for its witnesses or consultants. All other costs incurred in connection with the arbitration shall be shared equally by the parties thereto.

The questions of fact to be determined as provided in this section shall be limited to:

(1) the determination of the measurements to be made by the parties hereto pursuant to section 4;

(2) the correction of the measurements to be made pursuant to section 7;

(3) the duration of the interruption or equivalent interruption in section 14;

(4) whether changes in conditions mentioned in section 19 have occurred;

(5) whether the changes mentioned in section 30 were made "promptly";

(6) whether an increase or decrease in load or change in load factor mentioned in section 32 is unusual;

(7) any issue which both parties agree is an issue of fact mentioned in sections 30, 31, and 34;

(8) the occurrence of an abnormal nonrecurring demand and the amount and time thereof;

(9) whether a party has complied with section 34(b); and

(10) the acceptable level of harmonics for purposes of section 35.

21. Contract Work Hours and Safety Standards.

This contract, if and to the extent required by applicable law and if not otherwise exempted, is subject to the following provisions:

(a) Overtime Requirements. No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall require or permit any laborer or mechanic in any workweek in which such worker is employed on such work to work in excess of 8 hours in any calendar day or in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than one and one-half times such worker's basic rate of pay for all hours worked in excess of eight hours in any calendar day or in excess of 40 hours in such workweek, as the case may be.

(b) Violation; Liability for Unpaid Wages; Liquidated Damages. In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible therefor shall be liable to any affected employee for such employee's unpaid wages. In addition, such contractor and subcontractor shall be liable to the Government for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions of subsection (a) in the sum of $10 for each calendar day on which such employee was required or permitted to be employed in such work in excess of eight hours or in excess of such employee's standard workweek of 40 hours without payment of the overtime wages required by subsection (a) above.

(c) Withholding for Unpaid Wages and Liquidated Damages. Bonneville may withhold or cause to be withheld, from any moneys payable on account of work performed by the Contractor or subcontractor, such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for unpaid wages and liquidated damages as provided in subsection (b) above.

(d) Subcontracts. The Contractor shall insert in any subcontracts the clauses set forth in subsections (a) through (c) of this provision and also a clause requiring the subcontractors to include these clauses in any lower tier subcontracts which they may enter into, together with a clause requiring this insertion in any further subcontracts that may in turn be made.

(e) Records. The Contractor shall maintain payroll records containing the information specified in 29 CFR 516.2(a). Such records shall be preserved for 3 years from the completion of the contract.

22. Convict Labor. In connection with the performance of work under this contract, the Contractor agrees, if and to the extent required by applicable law or if not otherwise exempted, not to employ any person undergoing sentence of imprisonment except as provided by Public Law 89-176, September 10, 1965 (18 U.S.C. 4082(c)(2)) and Executive Order 11755, December 29, 1973.

23. Equal Employment Opportunity. During the performance of this contract, if and to the extent required by applicable law or if not otherwise exempted, the Contractor agrees as follows:

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by Bonneville setting forth the provisions of the Equal Opportunity clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which said Contractor has a collective bargaining agreement or other contract or understanding, a notice, to be provided by Bonneville, advising the labor union or worker's representative of the Contractor's commitments under this Equal Opportunity clause and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and by the rules, regulations, and relevant orders of the Secretary of Labor, or pursuant thereto, and will permit access to said Contractor's books, records, and accounts by Bonneville and the Secretary of Labor for purposes of investigations to ascertain compliance with such rules, regulations, and orders.

(f) In the event of the Contractor's noncompliance with the Equal Opportunity clause of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(g) The Contractor will include the provisions of paragraphs (a) through (f) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as Bonneville may direct as a means of enforcing such provisions, including sanctions for noncompliance. In the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by Bonneville, the Contractor may request the Government to enter into such litigation to protect the interests of the Government.

24. Additional Provisions. The Contractor agrees to comply with the clauses for Government contracts contained in the following statutes, Executive Orders, and regulations to the extent applicable:

(a) the Rehabilitation Act of 1973, Public Law 93-112, as amended, and 41 CFR 60-741 (affirmative action for handicapped workers);

(b) the Vietnam Era Veterans Readjustment Assistance Act of 1974, Public Law 92-540, as amended, and 41 CFR 60-250 (affirmative action for disabled veterans and veterans of the Vietnam era);

(c) Executive Order 11625 and 41 CFR 1-1.1310-2 (utilization of minority business enterprises);

(d) the Small Business Act, as amended.

25. Reports. The other party to this contract will furnish Bonneville such information as is necessary for making any computation required for the purposes of this contract, and the parties will cooperate in exchanging such additional information as may be reasonably useful for their respective operations.

26. Assignment of Contract. This contract shall inure to the benefit of, and shall be binding upon the respective successors and assigns of the parties to this contract. Such contract or any interest therein shall not be transferred or assigned by either party to any party other than the Government or an agency thereof without the written consent of the other except as

specifically provided in this section. The consent of Bonneville is hereby given to any security assignment or other like financing instrument which may be required under terms of any mortgage, trust, security agreement or holder of such instrument of indebtedness made by and between the Contractor and any mortgagee, trustee, secured party, subsidiary of the Contractor or holder of such instrument of indebtedness, as security for bonds of other indebtedness of such Contractor, present or future; such mortagagee, trustee, secured party, subsidiary, or holder may realize upon such security in foreclosure or other suitable proceedings, and succeed to all right, title, and interests of such Contractor.

27. Waiver of Default. Any waiver at any time by any party to this contract of its rights with respect to any default of any other party thereto, or with respect to any other matter arising in connection with such contract, shall not be considered a waiver with respect to any subsequent default or matter.

28. Notices and Computation of Time. Any notice required by this contract to be given to any party shall be effective when it is received by such party, and in computing any period of time from such notice, such period shall commence at 2400 hours on the date of receipt of such notice.

29. Interest of Member of Congress. No Member of, or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this contract or to any benefit that may arise therefrom, but this provision shall not be construed to extend to this contract if made with a corporation for its general benefit.

APPLICABLE ONLY IF TRANSFEREE IS A PARTY TO THIS CONTRACT

30. Balancing Phase Demands. If required by the Transferor at any time during the term of this contract, the Transferee shall promptly make such changes as are necessary on its system to balance the phase currents at any Point of Delivery so that the current of any one phase shall not exceed the current on any other phase at such point by more than 10 percent.

31. Adjustment for Unbalanced Phase Demands. If the Transferee fails to promptly make the changes mentioned in section 30, the Transferor may, after giving written notice one month in advance, determine that the Measured Demand of the Transferee at the Point of Delivery in question during each month thereafter, until such changes are made, is equal to the product obtained by multiplying by three the largest of the Integrated Demands on any phase adjusted as appropriate to such point during such month.

32. Changes in Requirements or Characteristics. The Transferee will, whenever possible, give reasonable notice to the Transferor of any unusual increase or decrease of its demands for electric power and energy on the Transferor's system, or of any unusual change in the load factor or power factor at which the Transferee will take delivery of electric power and energy under this contract.

33. Inspection of Facilities. Each party may for any reasonable purpose under this contract inspect the other party's electric installation at any reasonable time. Such inspection, or failure to inspect, shall not render

such party, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this contract. The inspecting party shall observe written instructions and rules posted in facilities and such other necessary instructions or standards for inspection as the parties agree to. Only those electric installations used in complying with the terms of this contract shall be subject to inspection.

34. Electric Disturbances.

(a) For the purposes of this section, an electric disturbance is any sudden, unexpected, changed, or abnormal electric condition occurring in or on an electric system which causes damage.

(b) Each party shall design, construct, operate, maintain and use its electric system in conformance with accepted utility practices:

(1) to minimize electric disturbances such as, but not limited to, the abnormal flow of power which may damage or interfere with the electric system of the other party or any electric system connected with such other party's electric system; and

(2) to minimize the effect on its electric system and on its customers of electric disturbances originating on its own or another electric system.

(c) If both parties to this contract are parties to the Western Interconnected Electric System Agreement, their relationship with respect to system damages shall be governed by that Agreement.

(d) During such time as a party to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, its relations with the other party with respect to system damages shall be governed by the following sentence, notwithstanding the fact that the other party may be a party to said Agreement Limiting Liability Among Western Interconnected Systems. A party to this contract shall not be liable to the other party for damage to the other party's system or facilities caused by an electric disturbance on the first party's system, whether or not such electric disturbance is the result of negligence by the first party, if the other party has failed to fulfill its obligations under subsection (b)(2) above.

(e) If one of the parties to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, each party to this contract shall hold harmless and indemnify the other party, its officers and employees, from any claims for loss, injury, or damage suffered by those to whom the first party delivers power not for resale, which loss, injury or damage is caused by an electric disturbance on the other party's system, whether or not such electric disturbance results from the negligence of such other party, if such first party has failed to fulfill its obligations under subsection (b)(2) above, and such failure contributed to the loss, injury or damage.

(f) Nothing in this section shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a party to this contract.

35. Harmonic Control. Each party shall design, construct, operate, maintain and use its electric facilities in accordance with good engineering practices to reduce to acceptable levels the harmonic currents and voltages which pass into the other party's facilities. Harmonic reductions shall be accomplished with equipment which is specifically designed and permanently operated and maintained as an integral part of the facilities of the party which owns the system on which harmonics are generated.

APPLICABLE ONLY IF TRANSFEREE IS NOT A PARTY TO THIS CONTRACT

36. Protection of the Transferor. Protection is or will be afforded to Bonneville or its Transferor under such of the following provisions and conditions as are specified in each contract executed or to be executed by Bonneville and each third party Transferee named in this contract: the power factor clause of the applicable Bonneville Wholesale Rate Schedule and the subject matter set forth in the General Contract Provisions under the following titles, namely:

Adjustment for Unbalanced Phase Demands; Uncontrollable Forces; Continuity of Service; Changes in Demands or Characteristics; Electric Disturbances; Harmonic Control; Balancing Phase Demands; Permits; Ownership of Facilities; and Inspection of Facilities.

RELATING TO RURAL ELECTRIFICATION ADMINISTRATION BORROWERS

37. Approval of Contract. If the Contractor borrows from the Rural Electrification Administration or any other entity under an indenture which requires the lender's approval of contracts, this contract and any amendment thereto shall not be binding on the parties thereto if they are not approved by the Rural Electrification Administration or such other entity. The Contractor shall notify Bonneville of any such entity. If approval is given, such contract or amendment shall be effective at the time stated therein.

APPLICABLE ONLY IF BONNEVILLE IS THE TRANSFEROR

38. Equitable Adjustment of Rates.

(a) Bonneville shall establish, periodically review and revise rates for the wheeling of electric power and/or energy pursuant to the terms of this contract. Such rates shall be established in accordance with applicable law.

(b) As used in this section, the words "Rate Adjustment Date" shall mean any date specified by Bonneville in a notice of intent to file revised rates as published in the Federal Register; provided, however, that such date shall not occur sooner than (1) nine months from the date that such notice of intent is published; or (2) twelve months from any previous Rate Adjustment Date. By giving written notice to the Contractor 45 days prior to such Rate Adjustment Date, Bonneville may delay such Rate Adjustment Date for up to 90 days if Bonneville determines either that the revenue level of the proposed rates differs by more than five percent from the revenue requirements indicated by most recent repayment studies entered in the hearings record or that external events beyond Bonneville's control will prevent Bonneville from meeting such Rate Adjustment Date. Bonneville may cancel a notice of intent to file revised rates at any time (1) by written notice to the Contractor; or (2) by publishing in the Federal Register a new notice of intent to file revised rates which specifically cancels a previous notice.

(c) The Contractor shall pay Bonneville for the service made available under this contract during the period commencing on each Rate Adjustment Date and ending at the beginning of the next Rate Adjustment Date at the rate specified in any rate schedule available at the beginning of such period for service of the class, quality, and type provided for in this contract, and in accordance with the terms thereof, and of the General Transmission Rate Schedule Provisions, if any, as changed with, incorporated in or referred to in such rate schedule. New rates shall not be effective on any Rate Adjustment Date unless they have been approved on a final or interim basis by a governmental agency designated bv law to approve Bonneville's rates. Rates shall be applied in accordance witn the terms thereof, the General Transmission Rate Schedule Provisions as changed with, incorporated in or referred to in such rate schedule and the terms of this contract.

(WP-PKJ-0222f)

Exhibit B, Table 1, Page 1 of 2
Contract No. DE-MS79-87BP92384
Transferor: Company
Transferee: Bonneville
Customer: Canby Utility Board
Effective at 2400 hours
on the Effective Date

POINTS OF DELIVERY AND POINTS OF REPLACEMENT FOR BONNEVILLE'S CUSTOMERS

1. CANBY POINT OF DELIVERY:

Location: the point in the Company's Canby Substation where the facilities of the Company and the City are connected;

Voltage: 12.5 kV;

Metering: in the Company's Canby Substation, in the 12.5 kV circuits over which such electric power and energy is delivered;

Point of Replacement: the 57 kV terminal position at the Government's Oregon City Substation;

Contract Path: from the Point of Replacement at the 57 kV terminal at the Government's Oregon City Substation, over 1.52 miles of the Oregon City-Wilsonville 57 kV line, through the Company's Wilsonville Substation, over 3.79 miles of Wilsonville-Sullivan 57 kV line, 2.59 miles of the Sullivan Tap-Twilight Tap 57 kV line, and 2.3 miles of the Twilight Tap-Canby 57 kV line into the Company's Canby Substation and through the Company's 57/12.5 kV transformer bank and associated facilities;

Sole Use-of-Facilities: for exclusive use of transformer banks and associated facilities at the Company's Canby Substation per letter from Company dated May 7, 1982.

2. TWILIGHT POINT OF DELIVERY:

Location: the point in the Company's Twilight Substation where the facilities of the Company and the City are connected;

Voltage: 12.5 kV;

Metering: in the Company's Twilight Substation, in the 12.5 kV circuits over which such electric power and energy is delivered;

Point of Replacement: the 57 kV terminal position at the Government's Oregon City Substation;

Contract Path: from the Point of Replacement at the 57 kV terminal at the Government's Oregon City Substation, over 1.52 miles of the Oregon City-Wilsonville 57 kV line, through the Company's Wilsonville Substation, over 3.79 miles of Wilsonville-Sullivan 57 kV line, 2.59 miles of the Sullivan Tap-Twilight Tap 57 kV line, and 2.25 miles of the Twilight Tap 57 kV line, into the Company's Twilight Substation and through the Company's 57/12.5 kV transformer and associated facilities.

(VS6-PMT-3190e)

POINTS OF DELIVERY AND POINTS OF REPLACEMENT FOR BONNEVILLE'S CUSTOMERS

1. DIKE ROAD POINT OF DELIVERY:

Location: the point in the Company's Dike Road feeder where the 12.5 kV facilities of the Company and CRPUD are connected;

Voltage: 12.5 kV;

Metering: on pole 849 in the Company's Dike Road Feeder, in the 12.5 kV circuits over which such electric power and energy is delivered;

Point of Replacement: the point of interconnection between the Company's 115 kV switching station and the Government's St. Helens Tap to the Longview-Astoria 115 kV transmission line;

Contract Path: from the Point of Replacement at the interconnection between the Company's 115 kV Rainier switching station and the Government's St. Helens Tap to the Governments's Longview-Astoria 115 kV line, over 4100 feet of 115 kV line, into the Company's Rainier Substation, through the 115/12.5 kV transformer and associated facilities, and out over 1.63 miles of the Company's 12.5 kV Dike Road feeder.

2. ST. HELENS 115 KV POINT OF DELIVERY:

Location: the point in the Company's St. Helens Substation where the 115 kV facilities of the Company and CRPUD are connected;

Voltage: 115 kV;

Metering: in the Company's St. Helens Substation, in the 115 kV circuits over which such electric power and energy is delivered;

Point of Replacement: the Company's St. Helens tap;

Contract Path: from the Point of Replacement at the Company's St. Helens Tap, over 1.65 miles of 115 kV line, into the Company's St. Helens Substation and over the 115 kV incoming terminal, through 115 kV tie breaker position and out over the 115 kV outgoing terminal position;

Exception: there is no transfer or use-of-facility charge or losses because CRPUD purchased capacity rights from the Company for use of the Company's 115 kV facilities.

3. SCAPPOOSE POINT OF DELIVERY:

Location: the point in the Company's Scappoose Substation where the 12.5 kV facilities of the Company and CRPUD are connected;

Voltage: 12.5 kV;

Metering: in the Company's Scappoose Substation, in the 12.5 kV circuits over which such electric power and energy is delivered;

Point of Replacement: the Company's St. Helens Tap;

Contract Path: from the Point of Replacement at the Company's St. Helens Tap, over 1.65 miles of 115 kV line, through the Company's St. Helens Substation, over .3 mile of 115 kV line, then over 7 miles of 115 kV line, into the Company's Scappoose Substation, through the Company's 115/12.5 kV transformer and associated facilities.

4. TIMONEY ROAD POINT OF DELIVERY:

Location: the point in the Company's Rainier Substation where the 12.5 kV facilities of the Company and CRPUD are connected;

Voltage: 12.5 kV;

Metering: on pole 1868 adjacent to the Company's Rainier Substation, in the 12.5 kV circuits over which such electric power and energy is delivered;

Point of Replacement: the point of interconnection between the Company's 115 kV switch station and the Government's St. Helens Tap to the Longview-Astoria 115 kV transmission line;

Contract Path: from the Point of Replacement at the interconnection of the Company's 115 kV Rainier switch station and the Government's St. Helens Tap to the Longview-Astoria 115 kV line, over 4100 feet of 115 kV line, into the Company's Rainier Substation, through the 115/12.5 kV transformer and associated facilities.

5. TOWNSEND ROAD POINT OF DELIVERY:

Location: the point in the Company's Townsend Road feeder where the 12.5 kV facilities of the Company and CRPUD are connected;

Voltage: 12.5 kV;

Metering: on pole 890 in the Company's Townsend Road feeder, in the 12.5 kV circuits over which such electric power and energy is delivered;

Adjustments: the metered quantity includes the amount of electric power and energy plus losses delivered to CRPUD for delivery to West Oregon under Contract No. DE-MS79-87BP92151;

Point of Replacement: the point of interconnection between the Company's 115 kV switch station and the Government's St. Helens Tap to the Longview-Astoria 115 kV transmission line;

Contract Path: from the Point of Replacement at the interconnection of the Company's 115 kV switch station and the Government's St. Helens Tap to the Longview-Astoria 115 kV line, over 4100 feet of 115 kV line, through the Company's Rainier Substation, through the 115/12.5 kV transformer and associated facilities and out over 6.4 miles of the Company's 12.5 kV Townsend Road feeder.

6. WARREN POINT OF DELIVERY:

Location: the point in the Company's St. Helens Substation where the 12.5 kV facilities of the Company and CRPUD are connected;

Voltage: 12.5 kV;

Metering: in the Company's St. Helens Substation, in the 12.5 kV circuits over which such electric power and energy is delivered;

Point of Replacement: the Company's St. Helens tap;

Contract Path: from the Point of Replacement at the Company's St. Helens Tap, over 1.65 miles of 115 kV line, into the Company's St. Helens Substation, over the 115 kV incoming terminal, through the Company's 115/12.5 transformer bank and capacitor banks and through the 12.5 kV terminal position for Warren.

7. YANKTON POINT OF DELIVERY:

Location: the point in the Company's St. Helens Substation where the 12.5 kV facilities of the Company and CRPUD are connected;

Voltage: 12.5 kV;

Metering: in the Company's St. Helens Substation, in the 12.5 kV circuits over which such electric power and energy is delivered;

Point of Replacement: the Company's St. Helens tap;

Contract Path: from the Point of Replacement at the Company's St. Helens Tap, over 1.65 miles of 115 kV line, into the Company's St. Helens Substation, over the 115 kV incoming terminal, through the Company's 115/12.5 transformer bank and capacitor banks and through the 12.5 kV terminal position for Yankton.

(VS6-PMT-3190e)

POINTS OF DELIVERY AND POINTS OF REPLACEMENT FOR BONNEVILLE'S CUSTOMERS

1. HASKINS CREEK POINT OF DELIVERY:

Location: the point in the Company's Haskins Creek feeder where the 12.5 kV facilities of the Company and West Oregon are connected;

Voltage: 12.5 kV;

Metering: at the point where the facilities of the Company and West Oregon are connected in the 12.5 kV circuit over which such power and energy flow;

Adjustments: for losses between the point of delivery and the point of metering;

Point of Replacement: the dead-end tower in Bonneville's McMinnville Substation.

Contract Path: from the Point of Replacement at the dead-end tower in the Government's McMinnville Substation, over 4.68 miles of the Dayton-McMinnville 115 kV line, into the Company's Dayton Substation, through the Company's 115/57 transformer and associated facilities, over 9.84 miles of the Company's Yamhill-Dayton 57 kV line, into the Company's Yamhill Substation, through the Company's 57/12.5 kV transformer and associated facilities, and out over 5.1 miles of 12.5 kV feeder.

2. NORTH PLAINS POINT OF DELIVERY:

Location: the point in the Company's North Plains feeder where the 12.5 kV facilities of the Company and West Oregon are connected;

Voltage: 12.5 kV;

Metering: at the point where the facilities of the Company and the West Oregon are connected; in the 7.2 kV circuit over which such electric power and energy flow;

Adjustments:

(1) for losses between the point of delivery and the point of metering;

(2) delivery will be single phase;

Point of Replacement: the dead-end tower in Bonneville's Oregon City Substation;

Contract Path: from the Point of Replacement at the dead-end tower in the Government's Oregon City Substation, over 18.42 miles of the Orenco-Oregon City 57 kV line, through 3 breaker positions and associated equipment in the Company's Orenco Substation, over 3.31 miles of West Union-Orenco 57 kV line, through the Company's West Union Substation, over 5.58 miles of the North Plains-West Union 57 kV line, into the Company's North Plains Substation, through the Company's 57/12.5 kV transformer and associated facilities and out over 9 miles of 12.5 kV feeder.

3. PATTON VALLEY POINT OF DELIVERY:

Location: the point in the Company's Patton Valley feeder where the 12.5 kV facilities of the Company and West Oregon are connected;

Voltage: 12.5 kV;

Metering: at the point where the facilities of the Company and West Oregon are connected in the 7.2 kV circuit over which such power and energy flow;

Adjustments:

(1) for losses between the point of delivery and the point of metering;

(2) delivery will be single phase;

Point of Replacement: the dead-end tower in Bonneville's McMinnville Substation;

Contract Path: from the Point of Replacement at the dead-end tower in the Government's McMinnville Substation, over 4.68 miles of the Dayton-McMinnville 115kV line, into the Company's Dayton Substation, through the Company's 115/57 kV transformer and associated facilities, over 9.84 miles of the Company's Yamhill-Dayton 57 kV line, through the Company's Yamhill Substation, over 12.7 kV miles of the Scoggins-Yamhill 57 kV line, into the Company's Scoggins Substation, through the Company's 57/12.5 kV transformer and associated facilities, and out over 3.25 miles of 12.5 kV feeder.

4. PIKE POINT OF DELIVERY:

Location: the point in the Company's Pike feeder where the 12.5 kV facilities of the Company and West Oregon are connected;

Voltage: 12.5 kV;

Metering: at the point where the facilities of the Company and West Oregon are connected, in the 7.2 kV circuit over which such power and energy flow;

Adjustments:

(1) for losses between the point of delivery and the point of metering;

(2) delivery will be single phase;

Point of Replacement: the dead-end tower in Bonneville's McMinnville Substation;

Contract Path: from the Point of Replacement at the dead-end tower in the Government's McMinnville Substation, over 4.68 miles of the Dayton-McMinnville 115 kV line, into the Company's Dayton Substation, through the 115/57 transformer and associated facilities, out over 9.84 miles of the Company's Yamhill-Dayton 57 kV line, into the Company's Yamhill Substation, through the 57/12.5 kV transformer and associated facilities and out over 7.1 miles of 12.5 kV feeder.

5. SCOGGINS VALLEY POINT OF DELIVERY:

Location: the point in the Company's Scoggins Valley feeder where the 12.5 kV facilities of the Company and West Oregon are connected;

Voltage: 12.5 kV;

Metering: at the point where the facilities of the Company and West Oregon are connected; in the 12.5 kV circuit over which such electric power and energy flow;

Adjustments: for losses between the point of delivery and the point of metering;

Point of Replacement: the dead-end tower in Bonneville's McMinnville Substation;

Contract No: DE-MS79-87BP92384
Transferor: Company
Transferee: Bonneville
Customer: West Oregon Electric Cooperative, Inc. (West Oregon)
Effective at 2400 hours on the Effective Date

Contract Path: from the Point of Replacement at the dead-end tower in the Government's McMinnville Substation, over 4.68 miles of the Dayton-McMinnville 115 kV line, into the Company's Dayton Substation, through the 115/57 kV transformer and associated facilities, out over 9.84 miles of the Company's Yamhill-Dayton 57 kV line, through the Company's Yamhill Substation, over 12.7 miles of the Scoggins-Yamhill 57 kV line, into the Company's Scoggins Substation, through the 57/12.5 kV transformer and associated facilities and out over 1.8 miles of 12.5 kV feeder.

(VS6-PMT-3190e)

Contract No: DE-MS79-87BP92384
Transferor: Company
Transferee: Bonneville
Customer: Pacific Carbide & Alloys Company (Pacific Carbide)
Effective 2400 hours on the Effective Date

POINTS OF DELIVERY AND POINTS OF REPLACEMENT FOR BONNEVILLE'S CUSTOMERS

1. PACIFIC CARBIDE POINT OF DELIVERY: 1/

Location: the point in or near Pacific Carbide's plant where the facilities of Pacific Carbide and the Company are connected;

Voltage: 12.5 kV;

Metering: in the Company's Pacific Carbide Substation in the 12.5 kV circuit over which such electric power and energy is delivered;

Point of Replacement: 230 kV bus in the Company's Rivergate Substation;

Contract Path: from the Point of Replacement at the 230 kV bus in the Company's Rivergate Substation, through the 230/115 kV transformer and associated facilities in the Rivergate Substation, over 2.79 miles of the Rivergate-Portsmouth 115 kV line, through the Company's Portsmouth Substation and 115/12.5 kV transformer and associated facilities and out over .5 mile of 12.5 kV feeder line.

Sole Use-of-Facilities: for exclusive use of the 12.5 kV feeder and capacitors from the Company's Portsmouth Substation to Pacific Carbide.

1/ Bonneville has requested termination of this POD by letter dated October 21, 1988. All liabilities incurred hereunder shall be preserved until satisfied.

POINTS OF DELIVERY AND POINTS OF REPLACEMENT FOR THE COMPANY

1. BRUSH COLLEGE POINT OF DELIVERY

   Location: the point in the Government's Brush College Substation where the facilities of the Government and Salem Electric (Salem) are connected;

   Voltage: 12.5 kV;

   Metering: the point in Salem's 12.5 kV system where its facilities are connected to the Company's facilities for service to the Popcorn Hill Subdivision over which such electric power and energy flows;

   Exception: the period of service commenced on 1523 hours on May 5, 1980;

   Point of Replacement: the dead-end tower in the Government's Salem Substation where the Company's Salem/Bethel 115 kV transmission line terminates;

   Contract Path: from the Point of Replacement on the dead-end tower of the Company's Salem-Barnes 115 kV line through Bays 7 and 10 in the Government's Salem Substation, over 1.89 miles of 115 kV line and into the Government's Brush College Substation through the 115/12.5 kV transformer and associated facilities.

2. EAGLE POINT, POINT OF DELIVERY:

   Location: the point in the Government's Walnut City Substation where the facilities of the Government and the City of McMinnville (City) are connected;

   Voltage: 12.5 kV;

   Metering: at the point in the City's 12.5 kV system where the City's facilities are connected to the Company's facilities for service to the Eagle Point Subdivision over which such electric power and energy flows:

   Adjustment: no adjustment for losses between the point of delivery and the point of metering;

   Point of Replacement: the dead-end tower of the Company's McMinnville-Dayton 115 kV line;

   Contract Path: from the Point of Replacement on the dead-end tower of the Company's McMinnville-Dayton 115 kV line, over 6.99 miles of 115 kV line and into the Government's Walnut City 115 kV Substation and through the 115/12.5 kV transformer and associated equipment.

POINTS OF DELIVERY AND POINTS OF REPLACEMENT FOR THE COMPANY

3. FARGO POINT OF DELIVERY:

Location: the point in the Company's Fargo Substation where the 115 kV facilities of the Company and the Government are connected;

Voltage: 115 kV;

Metering: in the Company's Fargo Substation, in the 12.5 kV circuits over which such electric power and energy flow;

Adjustments: for losses between the point of delivery and the point of metering;

Point of Replacement: the point in the Government's Oregon City Substation where the 57 kV facilities of the Company are connected to those of the Government;

Contract Path: from the Point of Replacement on the Company's 57 kV dead-end tower in the Government's Oregon City Substation through the 115/57 kV transformer, the 115 kV outgoing terminal in the Government's Oregon City Substation and over 6.66 miles of Oregon City-Chemawa #2 115 kV line.

4. RAINIER TAP POINT OF DELIVERY:

Location: the point between structures 18/6 and 19/1 of the Government's St. Helens Tap to the Longview-Astoria 115 kV transmission line where the 115 kV facilities of the Company and the Government are connected;

Voltage: 115 kV;

Metering: in the Company's Rainier Substation, in the 12.5 kV circuits over which such electric power and energy is delivered;

Adjustments:

(1) the metered quantities shall be reduced by the amount of electric power and energy plus losses delivered at Dike, Timoney and Townsend Road Points of Delivery for CRPUD and the remainder shall be PGE's Net Transfer Load; and

(2) PGE's Net Transfer Load Shall be increased for losses between the point of delivery and the point of metering in accordance with the Loss Factors in Exhibit D of this Agreement - Rainier Tap Point of Delivery;

Point of Replacement: the Company's St. Helens Tap;

Contract Path: from the Point of Replacement at the Company's St. Helens Tap, over 17.04 miles, from structure 22/4 to 18.6, on the Government's Longview/St. Johns 115 kV line.

Transfer Charges, Sole Use-of-Facilities Charges, and Loss Factors

Point of Delivery	Transferor	Transfer Charge ($ per kW/Mo.)	Sole Use-of-Facilities Charge ($ per Mo.)	Loss Factors (%) Peak	Energy	Reactive
Canby	Company	0.184	4316	2.5	1.5	0
Twilight	Company	0.871 3/	0	2.5	1.5	0
Dike Rd.	Company	1.323	0	4.2	2.5	0
St. Helens 115 kV 1/	Company	0	0	--	--	--
Scappoose	Company	0.693	0	2.5	1.5	0
Timoney Rd.	Company	1.075	0	2.5	1.5	0
Townsend Rd.	Company	1.206	0	4.2	2.5	0
Warren	Company	0.342	0	2.5	1.5	0
Yankton	Company	0.790	0	2.5	1.5	0
Haskins Ck.	Company	1.500	0	4.7	2.8	0
North Plains	Company	2.873	0	4.2	2.5	0
Patton Valley	Company	3.388	0	4.7	2.8	0
Pike	Company	1.499	0	4.7	2.8	0
Scoggins Valley	Company	3.290	0	4.7	2.8	0
Pacific Carbide 2/	Company	0.450	267	4.7	2.8	0
Brush College	Bonneville	2.220	0	2.5	1.5	0
Eagle Point	Bonneville	0.156	0	2.5	1.5	0
Fargo	Bonneville	0.393	0	2.5	1.5	0
Rainier Tap.	Bonneville	0.854	0	1.7	1.0	0

1/ CRPUD has purchased capacity rights with a lump sum payment for use of the Company's 115 kV facilities.

2/ Bonneville has requested termination of this POD by letter dated October 21, 1988. All liabilities incurred hereunder shall be preserved until satisfied.

3/ Pursuant to Letter Agreement No. DE-MS79-83BP91011 the minimum demand at Twilight shall be 17.3 MW.

(VS6-PMT-3190e)

Calculation of Transfer Charges

CANBY

Total Facility	Investment	Proportional Use BPA 2/	Proportional Use PGE 3/	Use	LARR 4/	O&M	Facility Charge
1.52 miles of Oregon City-Wilsonville 57 kV Line 1/	$45,244.32	28,110 kW	33,100 kW	61,210 kW	.18129	$3,378.96	$0.189
One Motor operated 57 kV disconnect switch on Oregon City side of Wilsonville Tap	30,000.00	28,100 kW	33,100 kW	61,210 kW	.18129	396.00	0.095
One Motor operated 57 kV disconnect switch on Sullivan Tap side of Wilsonville Tap	30,000.00	28,100 kW	6,300 kW	34,410 kW	.18129	396.00	0.170
3.79 mi of Wilsonville-Sullivan 57 kV line	112,813.14	28,100 kW	6,300 kW	34,410 kW	.18129	8,425.17	0.839
2.59 mi of Sullivan Tap-Twilight Tap 57 kV line	77,093.94	28,100 kW	21,300 kW	49,410 kW	.18129	5,757.57	0.399
2.3 mi of Twilight Tap-Canby 57 kV line	68,461.80	18,970 kW	15,400 kW	34,370 kW	.18129	5,112.90	0.510
							$2.203/kW-yr
						$2.203/12 =	$0.184/kW-mo

1/ See Exhibit B, Table 1 for Point of Replacement
2/ Based on BPA's January 1983 load forecast.
3/ Based on PGE's January 1983 power flow without BPA load at Canby and Twilight Substations.
4/ PGE's Levelized Annual Revenue Requirement.

Calculation of Sole Use-of-Facilities Charges

CANBY

Facility	Investment	Proportional Use BPA	Proportional Use PGE	Total Use	LARR	O&M	Facility Charge
(List the specific transformers and associated facilities at PGE's Canby Substation per PGE letter dated May 7, 1982)			0				
							X

X ÷ 12 = Y
Y(kW) = $4,316 per mo

Calculation of Transfer Charges

TWILIGHT

Facility	Investment	Proportional Use BPA 2/	Proportional Use PGE 3/	Total Use	LARR 4/	O&M	Facility Charge
1.52 mi of Oregon City- 1/ Wilsonville 57 kV Line	$45,244.32	36,270 kW	33,100 kW	69,370 kW	.18129	$3,378.96	$0.167
1 Motor operated 57 kV disconnect switch on Oregon City side of Wilsonville Tap	30,000.00	36,270 kW	33,100 kW	69,370 kW	.18129	396.00	0.084
1 Motor operated 57 kV disconnect switch on Sullivan Tap side of Wilsonville Tap	30,000.00	36,270 kW	6,300 kW	42,570 kW	.18129	396.00	0.137
3.79 mi of Wilsonville-Sullivan 57 kV line	112,813.14	36,270 kW	6,300 kW	42,570 kW	.18129	8,425.17	0.678
2.59 mi of Sullivan Tap-Twilight Tap 57 kV line	77,093.94	36,270 kW	21,300 kW	57,570 kW	.18129	5,757.57	0.343
2.25 mi of Twilight Tap 57 kV	66,973.50	17,300 kW	6,000 kW	23,300 kW	.18129	5,001.75	0.736
Twilight Substation	1,004,150.00	17,300 kW	6,000 kW	23,300 kW	.17839	14,309.93	8.302
							$10.447/kW-yr
						$10.447/12 =	$0.871 kW-mo

1/ See Exhibit B, Table 1 for Point of Replacement
2/ Based on BPA's January 1983 load forecast.
3/ Based on PGE's January 1989 power flow without BPA load at Canby and Twilight Substations.
4/ PGE's Levelized Annual Revenue Requirement.

Contract No: DE-MS79-87BP92384
Transferor: Company
Transferee: Columbia River PUD (CRPUD)
Effective 2400 hours on
the Effective Date

Calculation of Transfer Charge

DIKE ROAD

Facility	Investment	Proportional Use BPA	Proportional Use PGE 3/	Total Use	LARR 4/	O&M	Facility Charge
115 kV Switching Station 1/	$30,795.00	5,046 kW 2/	3,200 kW	8,246 kW	.17839	$792.00	$.762
4,100 ft 115 kV Transmission Line	23,114.00	5,046 kW	3,200 kW	8,246 kW	.18129	1,726.00	.717
Rainier Substation 115/12.5 kV	490,147.76	5,046 kW	3,200 kW	8,246 kW	.17839	6,721.00	11.419
_____ miles 12.5 kV Dike Road Feeder	25,629.00	1,200 kW	1,300 kW	2,500 kW	.17396	3,000.00	2.983
							$15.882/kW-yr

$15.882/12 = $1.323 per kW-mo

1/ See Exhibit B, Table 2 for Point of Replacement.
2/ Based upon BPA's January 1985 peak load forecast.
3/ Based upon PGE's January 1985 peak load forecast.
4/ PGE's levelized annual revenue requirement.

Calculation of Transfer Charge

ST. HELENS SUBSTATION 115 kV

Facility	Investment	Proportional Use BPA 2/	Proportional Use PGE	Total Use	LARR 3/	O&M	Facility Charge 4/
1.65 Miles (Name of Line) 1/ 115 kV Transmission Line	$49,114.00	12,600 kW	47,800 kW	60,400 kW	.16453	0	0
Incoming 115 kV Terminal Position at St. Helens Substation	123,869.00	12,600 kW	47,800 kW	60,400 kW	.17251	0	0
115 kV Bus Tie Breaker Position	87,466.84	12,600 kW	22,100 kW	34,700 kW	.17251	0	0
Outgoing 115 kV Terminal Position at St. Helens Substation	109,083.27	12,600 kW	0	12,600 kW	.17251	0	0
							0

1/ See Exhibit B, Table 2 for Point of Replacement.
2/ Based upon BPA's January 1985 peak load forecast.
3/ PGE's levelized annual revenue requirement.
4/ CRPUD has capacity rights for use of the 115 kV facilities.

Calculation of Transfer Charge

SCAPPOOSE

Facility	Investment	Proportional Use 3/ BPA	Proportional Use 3/ PGE	Total Use 4/	LARR 5/	O&M	Facility Charge
1.65 Miles (Name of Line) 1/ 115 kV Transmission Line	$49,114.00	11,100 kW	37,900 kW	49,000 kW	.18129	$0	0 6/
Incoming 115 kV Terminal Position at St. Helens Substation	123,869.00	11,100 kW	37,900 kW	49,000 kW	.17839	0	0 6/
Outgoing 115 kV Terminal Position at St. Helens Substation	121,478.00	11,100 kW	20,500 kW	31,600 kW	.17839	8,963.00	.969
0.3 Miles 115 kV Transmission Line	8,930.00	11,100 kW	20,500 kW	31,600 kW	.18129	667.00	.072
7 Miles 115 kV Transmission Line	208,362.00	8,400 kW	20,500 kW	28,900 kW	.18129	15,561.00	1.845
Scappoose Substation	192,333.00 2/	8,400 kW	0	8,400 kW	.17839	11,300.00	5.430
							$8.317/kW-yr

$8.317/12 = $0.693 per kW-mo

1/ See Exhibit B, Table 2 for Point of Replacement.
2/ Based upon half of the total substation cost.
3/ Based upon BPA's January 1985 peak load forecast.
4/ Based upon PGE's January 1985 peak load forecast.
5/ PGE's levelized annual revenue requirement.
6/ CRPUD has capacity rights for use of the 115 kV facilities at PGE's St. Helens Substation.

Calculation of Transfer Charge

TIMONEY ROAD

Facility	Investment	Proportional Use BPA 2/	Proportional Use PGE 3/	Total Use	LARR 4/	O&M	Facility Charge
115 kV Switching Station 1/	$30,795.00	5,046 kW	3,200 kW	8,246 kW	.17839	$792.00	.762
4,100 ft 115 kV Transmission Line	23,114.00	5,046 kW	3,200 kW	8,246 kW	.18129	1,726.00	.717
Rainier Substation	490,147.76	5,046 kW	3,200 kW	8,246 kW	.17839	6,721.00	11.419
							$12.898/kW-yr

$12.898/12 = $1.075 per kW-mo

1/ See Exhibit B, Table 2 for Point of Replacement.
2/ Based upon BPA's January 1985 peak load forecast.
3/ Based upon PGE's January 1985 peak load forecast.
4/ PGE's levelized annual revenue requirement.

Calculation of Transfer Charge

TOWNSEND ROAD

Facility	Investment	Proportional Use BPA 3/	PGE 4/	Total Use	LARR 5/	O&M	Facility Charge
115 kV Switching Station 1/	$30,795.00	5,046 kW	3,200 kW	8,246 kW	.17839	$792.00	$.762
4,100 ft 115 kV Transmission Line	23,114.00	5,046 kW	3,200 kW	8,246 kW	.18129	1,726.00	.671
Rainier Substation 115/12.5 kV	490,147.76	5,046 kW	3,200 kW	8,246 kW	.17839	6,721.00	11.419
6.4 miles 12.5 kV Townsend Road Feeder 2/	29,127.00	3,574 kW	1,737 kW	5,407 kW	.17396	3,411.00	1.568
							$14.466 kW-yr

14.466/12 = $1.206 kW-mo

1/ See Exhibit C, Table 3 for Point of Replacement.
2/ The Townsend Road Feeder serves CRPUD load and West Oregon load at West Oregon's Apiary Road POD.
3/ Based on BPA's January 1985 peak load forecast, includes 46 kW January peak demand on West Oregon Electric Coop. Apiary Road POD.
4/ Based on PGE's January 1985 peak load forecast.
5/ PGE's Levelized Annual Revenue Requirement.

Calculation of Transfer Charge

WARREN

Facility	Investment	Proportional Use BPA [2/]	Proportional Use PGE	Total Use	LARR [3/]	O&M	Facility Charge
1.65 Miles (Name of Line) [1/] 115 kV Transmission Line	$49,114.00	12,800 kW	47,600 kW	60,400 kW	.18129	$0	$0
Incoming 115 kV Terminal Position at St. Helens Substation	123,869.00	12,800 kW	47,600 kW	60,400 kW	.17839	0	0 [4/]
St. Helens Substation 115/12.5 kV Transformer Bank	87,112.28	12,800 kW	0	12,800 kW	.17839	9,802.00	1.980
St. Helens Substation Capacitor Banks	23,061.25	12,800 kW	0	12,800 kW	.17839	1,181.00	.414
12.5 kV Terminal Position - Warren	79,359.00	10,368 kW	0	10,368 kW	.17839	3,591.00	1.712
							$4.105/kW-yr

$4.105/12 = $0.342 per kW-mo

1/ See Exhibit B, Table 2 for Point of Replacement.
2/ Based upon BPA's January 1985 peak load forecast.
3/ PGE's levelized annual revenue requirement.
4/ CRPUD has capacity rights for use of the 115 kV facilities.

Contract No: DE-MS79-87BP92384
Transferor: Company
Transferee: Columbia River PUD (CRPUD)
Effective 2400 hours on
the Effective Date

Calculation of Transfer Charge

YANKTON

Facility	Investment	Proportional Use BPA 2/	Proportional Use PGE	Total Use	LARR 3/	O&M	Facility Charge
1.65 Miles (Name of Line) 1/ 115 kV Transmission Line	$49,114.00	12,800 kW	47,600 kW	60,400 kW	.18129	$0	$0 4/
Incoming 115 kV Terminal Position at St. Helens Substation	123,869.00	12,800 kW	47,600 kW	60,400 kW	.17839	0	0 4/
St. Helens Substation 115/12.5 kV Transformer Bank	87,112.28	12,800 kW	0	12,800 kW	.17839	9,802.00	1.980
St. Helens Substation Capacitor Banks	23,061.25	12,800 kW	0	12,800 kW	.17839	1,181.00	.414
St. Helens Substation 12.5 kV Terminal Position - Yankton	76,475.00	2,432 kW	0	2,432 kW	.17839	3,591.00	7.086
							$9.480/kW-yr

$9.480/12 = $0.790 per kW-mo

1/ See Exhibit B, Table 2 for Point of Replacement.
2/ Based upon BPA's January 1985 peak load forecast.
3/ PGE's levelized annual revenue requirement.
4/ CRPUD has capacity rights for use of the 115 kV facilities.

Contract No: DE-MS79-87BP92384
Transferor: Company
Transferee: West Oregon Electric
Effective 2400 hours on
the Effective Date

Calculation of Transfer Charge

HASKINS CREEK

Facility	Investment	Proportional Use BPA 2/	Proportional Use PGE 3/	Total Use	LARR 4/	O&M	Facility Charge
4.68 miles 115 kV Dayton-McMinnville transmission line 1/	$139,304.88	1,590 kW	40,850 kW	42,440 kW	.18129	$10,403.64	$0.840
Dayton 57/115 kV Substation	582,413.62	1,590 kW	41,410 kW	43,000 kW	.17839	26,408.88	3.030
9.84 miles 57 kV Yamhill-Dayton transmission line	292,897.44	1,590 kW	14,410 kW	16,000 kW	.18129	21,874.00	4.686
Yamhill Substation 12.5/57 kV	331,962.97	770 kW	11,230 kW	12,000 kW	.17839	7,369.92	5.549
5.1 mi. 12.5 kV Feeder	69,360.00	540 kW	4,960 kW	5,500 kW	.17936	9,003.59	3.899
							$18.004 kW-yr

18.004/12 = $1.500 kW-mo

1/ See Exhibit B, Table 3 for Point of Replacement.
2/ Based on BPA's January 1983 load forecast.
3/ Based on PGE's January 1983 power flow.
4/ PGE's Levelized Annual Revenue Requirement.

(VS6-PMT-3190e)

Calculation of Transfer Charge

NORTH PLAINS

Facility	Investment	Proportional Use BPA 2/	Proportional Use PGE 3/	Total Use	LARR 4/	O&M	Facility Charge
18.42 mi 57 kW Orenco – Oregon City Transmission Line 1/	$548,289.72	110 kW	6,890 kW	7,000 kW	.18129	$40,947.66	$20.050
3 breaker positions, and 6 disconnect switches at Orenco Substation	138,935.12	110 kW	21,890 kW	22,000 kW	.17839	13,511.52	1.741
3.31 mi. West Union – Orenco 57 kW Transmission Line	98,525.46	110 kW	21,890 kW	22,000 kW	.18129	7,358.13	1.146
2 – 57 kV disconnect switches at West Union Substation	6,536.00	110 kW	15,890 kW	16,000 kW	.17839	792.00	0.122
5.58 mi. North Plains – West Union 57 kW Transmission Line	166,094.28	110 kW	15,890 kW	16,000 kW	.18129	12,404.34	2.657
12.5/57 kV North Plains Substation	121,070.29	110 kW	7,190 kW	7,300 kW	.17839	4,483.37	3.573
9 mi. 12.5 kV feeder	122,400.00	110 kW	7,190 kW	7,300 kW	.17936	15,888.69	5.184
							$34.473 kW-yr
							34.473/12 = $2.873 kW-mo

1/ See Exhibit B, Table 3 for Point of Replacement.
2/ Based on BPA's January 1983 load forecast.
3/ Based on PGE's January 1983 power flow.
4/ PGE's Levelized Annual Revenue Requirement.

Calculation of Transfer Charge

PATTON VALLEY

Facility	Investment	Proportional Use BPA 2/	Proportional Use PGE 3/	Total Use	LARR 4/	O&M	Facility Charge
4.68 miles 115 kV Dayton-McMinnville transmission line 1/	$139,304.88	1,590 kW	40,850 kW	42,440 kW	.18129	$10,403.64	$0.840
Dayton 57/115 kV Substation	582,413.62	1,590 kW	41,410 kW	43,000 kW	.17839	26,408.88	3.030
9.84 miles 57 kV Yamhill-Dayton transmission line	292,897.44	1,590 kW	14,410 kW	16,000 kW	.18129	21,874.00	4.686
Yamhill Substation - 1 breaker position 2 disconnect switches	60,584.41	820 kW	11,180 kW	12,000 kW	.17839	7,369.92	1.515
12.7 miles Scoggins-Yamhill 57 kV Transmission Line	378,028.20	820 kW	3,180 kW	4,000 kW	.18129	28,232.10	24.191
Scoggins Substation	158,592.05	820 kW	8,180 kW	9,000 kW	.17839	5,527.44	3.758
3.25 miles of 12.5 feeder	44,200.00	280 kW	4,900 kW	5,180 kW	.17936	5,737.58	2.638
							$40.658 kW-yr
						40.658/12 =	$3.388 kW-mo

1/ See Exhibit B, Table 3 for Point of Replacement.
2/ Transmission line costs based on PGE's average cost per conductor mile of $29,766.00.
3/ Based on PGE's January 1983 load forecast, 540 kW Scoggins Valley, 280 kW Patton Valley.
4/ PGE's Levelized Annual Revenue Requirement.

Calculation of Transfer Charge

PIKE

Facility	Investment	Proportional Use BPA 2/	Proportional Use PGE 3/	Total Use	LARR 4/	O&M	Facility Charge
4.68 miles 115 kV Dayton-McMinnville transmission line 1/	$139,304.88	1,590 kW	40,850 kW	42,440 kW	.18129	$10,403.64	$0.840
Dayton 57/115 kV Substation	582,413.62	1,590 kW	41,410 kW	43,000 kW	.17839	26,408.88	3.030
9.84 miles 57 kV Yamhill-Dayton transmission line	292,897.44	1,590 kW	14,410 kW	16,000 kW	.18129	21,874.00	4.686
Yamhill Substation 12.5/57 kV	331,962.97	770 kW	11,230 kW	12,000 kW	.17839	7,369.92	5.549
7.1 mi. 12.5 kV Feeder	96,560.00	230 kW	7,470 kW	7,700 kW	.17936	12,534.41	3.877
							$17.983 kW-yr

17.983/12 = $1.499 kW-mo

1/ See Exhibit B, Table 3 for Point of Replacement.
2/ Based on BPA's January 1983 load forecast.
3/ Based on PGE's January 1983 power flow.
4/ PGE's Levelized Annual Revenue Requirement.

Calculation of Transfer Charge

SCOGGINS VALLEY

Facility	Investment	Proportional Use BPA 2/	PGE 3/	Total Use	LARR 4/	O&M	Facility Charge
4.68 miles 115 kV Dayton-McMinnville transmission line 1/	$139,304.88	1,590 kW	40,850 kW	42,440 kW	.18129	$10,403.64	$0.840
Dayton 57/115 kV Substation	582,413.62	1,590 kW	41,410 kW	43,000 kW	.17839	26,408.88	3.030
9.84 miles 57 kV Yamhill-Dayton transmission line	292,897.44	1,590 kW	14,410 kW	16,000 kW	.18129	21,874.00	4.686
Yamhill Substation - 1 breaker position 2 disconnect switches	60,584.41	820 kW	11,180 kW	12,000 kW	.17839	7,369.92	1.515
12.7 miles Scoggins-Yamhill 57 kV Transmission Line	378,028.20	820 kW	3,180 kW	4,000 kW	.18129	28,232.10	24.191
Scoggins Substation	158,592.05	820 kW	8,180 kW	9,000 kW	.17839	5,527.44	3.758
1.8 miles of 12.5 feeder	24,480.00	820 kW	4,360 kW	5,180 kW	.17936	3,177.74	1.461
							$39.481 kW-yr
						39.481/12 =	$3.290 kW-mo

1/ See Exhibit B, Table 3 for Point of Replacement.
2/ Based on BPA's January 1983 load forecast, 540 kW Scoggins Valley, 280 kW Patton Valley.
3/ Based on PGE's January 1983 power flow.
4/ PGE's Levelized Annual Revenue Requirement.

Calculation of Transfer Charge

PACIFIC CARBIDE

Facility	Investment	Proportional Use BPA 2/	Proportional Use PGE 4/	Total Use	LARR 5/	O&M	Facility Charge
Rivergate Sub 230/115 kV transformer banks and associated facilities 1/	$3,110,594.00	9300 kW	308,700 kW	318,000 kW	0.17839	$195,303.00	$2.359
2.79 mi of Rivergate – Portsmouth 115 kV line	83,047.14	9300 kW	94,700 kW	104,000 kW	0.18129	6,202.17	0.204
Portsmouth Substation 115/12.5 kV transformer bank and associated facilities	507,083.30	9300 kW	34,500 kW	43,800 kW	0.17839	26,900.00	2.679
.5 mi of 12.5 kV feeder line	6,800.00	4650 kW 3/	8,350 kW	13,000 kW	0.17936	882.71	0.162
							$5.405/kW-yr

$5.405/12 = $0.450 per kW-mo

1/ See Exhibit B, Table 4 for Point of Replacement.
2/ Based upon Pacific Carbide's contract demand.
3/ Based on 50% of Pacific Carbide contract demand.
4/ Based on PGE's January 1983 power flow.
5/ PGE's Levelized Annual Revenue Requirements

Contract No: DE-MS79-87BP92384
Transferor: Company
Transferee: Pacific Carbide
Effective 2400 hours on
the Effective Date

Calculation of Sole Use-of-Facilities Charges

PACIFIC CARBIDE

Facility	Investment	Proportional Use BPA	Proportional Use PGE	Total Use	LARR	O&M	Facility Charge
Portsmouth Substation 11.5 kV feeder	?	?	0	9300	.1609	?	
Portsmouth Substation Capacitor Banks	?	?	0	9300	?	?	X

X ÷ 12 = Y
Y(kW) = $267.00 per mo

Contract No: DE-MS79-87BP92384
Transferor: Bonneville
Transferee: Company
Effective 2400 hours on
the Effective Date

Calculation of Transfer Charge

BRUSH COLLEGE

Facility	Investment	Proportional Use BPA 2	Proportional Use PGE 3/	Total Use	ACR 4/	O&M	Facility Charge
Brush College 115 kV Substation	$479,214	2,600 kW	1,020 kW	3,620 kW	.1633	—	$21.618
1.89 miles of 115 kV Salem - Chemawa Line	41,762	5,000 kW	1,020 kW	6,020 kW	.1742	—	1.208
Salem Substation 1/							
Bay 7	111,031	5,000 kW	1,020 kW	6,020 kW	.1633	—	3.012
Bay 10	112,701	21,000 kW	1,020 kW	22,920 kW	.1633	—	0.803
							$26.641/kW-yr

$26.641/12 = $2.220 kW-mo

1/ See Exhibit C for Point of Replacement.
2/ Based on BPA's January 1983 power flow.
3/ Based on PGE's January 1983 load forecast.
4 BPA's Annual Cost Ratio. (Need to separate O&M out of ACR when redoing)

Calculation of Transfer Charge

EAGLE POINT

Facility	Investment	Proportional Use BPA 2/	Proportional Use PGE 3/	Total Use	ACR 4/	O&M	Facility Charge
McMinnville Sub. 115 kW Bay 7 Terminal Position 1/	$108,805	28,900 kW	68 kW	28,968 kW	.1633	---	$0.613
Walnut City Sub. 115 kV	$142,907	18,480 kW	68 kW	18,548 kW	.1633	---	1.258
							$1.871 kW-yr
						$1.871/12 =	$0.156 per kW-mo

1/ See Exhibit C for Point of Replacement.
2/ Based upon BPA's January 1983 load forecast.
3/ Based upon PGE's January 1983 load forecast.
4/ BPA's Annual Cost Ratio. (Need to separate O&M out of ACR when redoing)

Calculation of Transfer Charge

FARGO

Facility	Investment	Proportional Use BPA [2]	Proportional Use PGE [3/]	Total Use	ACR [4/]	O&M	Facility Charge
57/115 kV Transformer Bank [1/]	$365,360	39,900 kW	1,500 kW	41,400 kW	.1001	$10,303	$1.132
Incoming 115 kV Terminal Position at Oregon City Substation	104,908	39,900 kW	1,500 kW	41,400 kW	.1001	9,371	0.480
Outgoing 115 kV Terminal Position at Oregon City Substation	93,824	13,000 kW	1,500 kW	14,500 kW	.1001	9,371	1.294
6.66 Miles of Oregon City Chemawa #2 - 115 kV line	100,266	13,000 kW	1,500 kW	14,500 kW	.0977	16,517	1.815
							$4.721 kW-yr

$4.721/12 = $0.393 per kW-mo

1/ See Exhibit C for Point of Replacement.
2/ Based upon BPA's January 1985 peak load forecast.
3/ Based upon PGE's January 1985 peak load forecast.
4/ BPA's Annual Cost Ratio.

Calculation of Transfer Charge

RAINIER TAP

Facility	Investment	Proportional Use BPA 2/	Proportional Use PGE 3/	Total Use	ACR 4/	O&M	Facility Charge
Structure 22/4 to 13/6 Longview - St. Johns 115 kV line - 11.74 miles 1/	$423,506	7,843 kW	3,200 kW	11,043 kW	.0977	$29,115	$6.383
Structure 13/7 to 18/6 Longview - St. Johns 115 kV line - 5.30 miles	$191,191	5,043 kW	3,200 kW	8,243 kW	.0977	13,144	3.861
							$10.244/kW-yr

$10.244/12 = $0.854/kW-mo

1/ See Exhibit C for Point of Replacement.
2/ Based upon BPA's January 1985 peak load forecast.
3/ Based upon PGE's January 1985 peak load forecast.
4/ BPA's Annual Cost Ratio.

(VS6-PMT-3190e)

Methodology for Calculating Transfer Charges and Sole Use-of-Facilities Charges

A. Transfer Charge

When Bonneville is the Transferor, the Transfer Charge is the methodology shown below and is an application of the UFT-83 rate schedule. When the Company is the Transferor, the Transfer Charge is the methodology shown below and filed with the Agency. The Transfer Charge shall be the monthly charge per kilowatt of Transfer Demand. The Transfer Charge shall be one-twelfth of the annual cost of the facilities (Facilities) which make up the Contract Path, specified in Exhibit B, divided by the yearly noncoincidental demands on such facilities. The Contract Path shall be the most direct transmission path with available capacity between the Point of Replacement and the Point of Delivery as agreed upon by the parties hereto. The Transfer Charge for each Point of Delivery for the specified Transferor's facilities shall be derived as follows:

The product of $\frac{(I \times R) + B}{(\ D\ )}$ for the specified facilities $\times$ 1/12

where:

I = The capital cost of the Contract Path facilities (Facilities) as allowed by the appropriate regulatory agency and published in the most recent plant investment records of the parties hereto.

R = For Bonneville, the Annual Interest and Amortization (I&A) Ratios for the Facilities using the most recent system average cost factor developed from actual I&A costs including general plant for specific categories of Federal Columbia River Transmission System (FCRTS) facilities.

R = For the Company, the levelized annual revenue requirements (LARR) for the Facilities as set forth in the following formula:

LARR = LF x [(De + PT + IT + ROI) x PVF]

where:

LF = the levelization factor which represents a composite present value factor based on the average service life of that type of facility and a discount rate equal to the Company's composite cost of capital. It is expressed as:

$$\frac{i \times (1 + i)^{\text{Average Service Life}}}{((1 + i)^{\text{Average Service Life}} - 1}$$

where "i" is the discount rate equal to the Company's composite cost of capital.

De = the annual depreciation associated with the facilities.

PT = the annual property tax associated with the facilities.

IT = the annual income taxes associated with the facilities including deferred income taxes.

ROI = the return on investment which is the product of the total debt plus equity times the composite rate of return on debt and equity as established in the Company's most recent filing with the Oregon Public Utilities Commission.

PVF = the present value factor associated with the facility based on the number of years in service and a discount rate equal to the Company's composite cost of capital. It is expressed as:

$$\frac{1}{(1 + i)^{\text{year from in service}}}$$

where "i" is the discount rate equal to the Company's composite cost of capital.

B = The annual operation and maintenance expenses associated with the Facilities.

D = The sum of the yearly noncoincidental demands of the Company and Bonneville associated with the Facilities, as determined in part by power flows agreed to by both parties and in part by forecasted peaks agreed to by both parties that are different from those used in the power flows. The parties shall initially use power flows, which are in existence as of January 1, 1987, which are based on 1986-87 Operating Year forecasted peak. The following method shall be used to update power flows:

(1) the initial power flows shall be used through December 31, 1990, or such other date as agreed by the parties;

(2) new power flows shall then be prepared which shall use parameters forecasted to exist 2 years from the date that the power flow is prepared;

(3) such new power flows shall then be the basis for Transfer Charges for 3 years;

(4) every third year the procedure in (2) and (3) above shall be repeated.

B. Sole Use-of-Facilities Charge

When Bonneville is the Transferor, the Sole Use-of-Facilities Charge is the methodology shown below and is an application of the UFT-83 rate schedule. When the Company is the Transferor, the Transfer Charge is the methodology shown below and filed with the Agency. The Sole Use-of-Facilities Charge shall be the charge for Facilities owned by the Transferor of which the Transferee has exclusive use. In such cases the charge is expressed in dollars per month and is calculated as follows:

the product of (I x R) + B for the specified Facilities x 1/12.

(VS6-PMT-3190e)

Loss Methodology

A. *Company's System Losses.*

Facilities	System Loss Factors 1/ Peak	Energy
Generation Step-up Transformation	0.5%	0.3%
Transmission (230, 115, 57 kV)	1.7%	1.0%
Bulk Power Transformation (230/115, 115/57kV)	0.5%	0.3%
Distribution Transformation (115/13, 57/13 kV)	0.8%	0.5%
Distribution (13 kV)	1.7%	1.0%

B. Bonneville's System Losses. 2/

Facilities	System Loss Factors 2/ Peak	Energy

1/ The loss factors are based on average system losses experienced on PGE's system from a study conducted in 1976 and reverified in 1988. The energy losses are calculated from the peak losses using a load factor of 57%.

2/ Bonneville will use the Company's System Loss Factors for those POD's where Bonneville is the Transferor, however, Bonneville reserves the right to develop and use its own System Loss Factors at any time.

Application of Loss Methodology

The Loss Factors used in Exhibit D are calculated by adding the system loss factors for the type of facility found in the contract path. The following is an illustration of how the methodology is applied.

Given:

Contract Path: from the Point of Replacement in A Substation, over 2 miles of ABC 115 kV line, through B Substation, out over 10 miles of DEF 115 kV line, into C Substation, through the 115/57 kV transformer at C Substation, over 1 mile of the GHI 57 kV line, through D Substation, over 1.5 miles of JKL 57 kV line, into E Substation, through the 57/13 kV transformer at E Substation, and out over .5 miles of 13 kV feeder.

Then:

Facilities	System Loss Factors		Illustration Loss Factors	
	Peak	Energy	Peak	Energy
Generation Step-up Transformation	0.5%	0.3%	0	0
Transmission (230, 115, 57 kV)	1.7%	1.0%	1.7	1.0
Bulk Power Transformation (230/115, 115/57kV)	0.5%	0.3%	0.5	0.3
Distribution Transformation (115/13, 57/13 kV)	0.8%	0.5%	0.8	0.5
Distribution (13 kV)	1.7%	1.0%	1.7	1.0
Total			4.7	2.8

Discussion:

Regardless of the number of times a certain voltage class of equipment occurs in a contract path, it is assigned only one loss factor value. In this illustration, two 115 kV and two 57 kV transmission lines are used but they are assigned only one loss factor, since they are considered the same voltage class. The 115/57 kV transformation is assigned a loss factor. However, if a 230/115 kV transformation occurred, the same loss factor would apply, regardless of the number of times transformation occurred at the 230/115 or 115/57 kV levels. The distribution transformation loss factor is assigned to the 57/13 kV substation and finally a loss factor is assigned to the 13 kV feeder. The sum of these losses is the percent loss for that contract path. This is the analysis done to calculate the Loss Factor column in Exhibit D. These losses are based on the contract paths found in Exhibits B and C.

(VS6-PMT-3190e)

This revision reflects the termination of Hughes as a Government POD effective December 31, 2012, due to the energization of the Company's Wallace-Willow Lake feeder, termination of Canby Tap as a Government POD effective on the energization of the CUB's Knights Bridge substation (Effective Date) and modifies the description of the Contract Paths for the Eagle Point and Fargo PODs.

1. CANBY TAP POINT OF DELIVERY:

   Location: the point in the Government's Oregon City-Canby #1 57kV line where the facilities of the Government and the Company are connected;

   Voltage: 57kV;

   Metering: in the City of Canby's Knights Bridge substation, in the 12.5kV circuits over which such electric power and energy flow;

   Adjustments: for losses between the point of delivery and the point of metering;

   Point of Replacement: the Company's 57kV terminal position at the Government's Oregon City substation;

   Contract Path: from the Point of Replacement on the Company's 57kV terminal position at the Government's Oregon City substation, over 5.5 miles of the Government's Oregon City-Canby #1 57kV line to the point near structure 6/11 where the facilities of the Government and the Company are connected.

   Note: Canby Tap was terminated as a Government POD effective on the energization of the CUB's Knights Bridge substation.

2. HUGHES POINT OF DELIVERY (formerly Brush College POD):

   Location: the point in Salem Electric's Hughes substation where the 115kV facilities of the Government and Salem Electric connected;

   Voltage: 115kV;

   Metering: the point in Salem's Hughes substation where the 12.5kV facilities of Salem and the Company are connected, over which such electric power and energy flow;

   Adjustments: for losses between the point of delivery and the point of metering;

   Point of Replacement: the dead-end tower in Bonneville’s Salem substation where the Company's Bethel-Salem BPA 115kV line terminates;

   Contract Path: from the Point of Replacement through Bays 7 and 10 in the Government's Salem substation, over 1.89 miles of the Government's Chemawa-Salem #2 115kV line, to the point in Salem's Hughes substation where the 115kV facilities of the Government and Salem are connected;

   Note: Hughes was terminated as a Government POD effective December 31, 2012 due to the energization of the Company’s Wallace-Willow Lake feeder.

3. EAGLE POINT POINT OF DELIVERY:

Location: the point in the Government's McMinnville substation where the 115kV facilities of the Government and the City of McMinnville are connected;

Voltage: 115kV;

Metering: at the point in the City's 12.5kV system where the City's facilities are connected to the Company's facilities at Gormley substation for service to the Eagle Point subdivision over which such electric power and energy flow;

Adjustments: for losses between the point of delivery and the point of metering;

Point of Replacement: the dead-end tower in Bonneville's McMinnville substation where the Company's Dayton-McMinnville BPA-Newberg 115kV line terminates;

Contract Path: from the Point of Replacement at the dead-end tower of the Company's Dayton- McMinnville BPA-Newberg 115kV line, over line terminals in bays 4 and 7 at the Government's McMinnville substation, to the City's McMinnville-Booth Bend 115kV line.

4. FARGO POINT OF DELIVERY:

Location: the point in the Company's Fargo substation where the 115kV facilities of the Company and the Government are connected;

Voltage: 115kV;

Metering: in the Company's Fargo substation in the 12.5kV circuit over which such electric power and energy flow;

Adjustments: for losses between the point of delivery and the point of metering;

Point of Replacement: the point in the Government's Chemawa substation where the 57kV facilities of the Company are connected to those of the Government;

Contract Path: from the Point of Replacement at the Company's 115kV dead-end tower in the Government's Chemawa substation, through the Government's Chemawa substation, and over 18.55 miles of the Government's Oregon City-Chemawa #2 115kV line.

Contract No. DE-MS79-93BP94278
Draft Date: 04/04/94

AUTHENTICATED

AC INTERTIE
OPERATION AND MAINTENANCE AGREEMENT
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
PACIFICORP

Index to Sections

This AC INTERTIE OPERATION AND MAINTENANCE AGREEMENT (Agreement), , executed ________, 1994, by the UNITED STATES OF AMERICA (Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and PACIFICORP a corporation organized and existing under the laws of the State of Oregon, (hereinafter collectively referred to as "Parties" and individually as "Party"),

W I T N E S S E T H :

WHEREAS, the Parties hereto, on July 8, 1986, executed an agreement, designated as Contract No. DE-MS79-86BP92299 which provided for, among other things, payment obligations throughout the construction phase of the Alvey-Meridian 500 kV Line; the Alvey, Dixonville, Meridian, and Captain Jack 500 kV Substations; and the Parties' intertie communication facilities; and for continued obligations related to the AC Intertie, and this agreement is replaced by a new agreement designated as Contract No. DE-MS79-94BP94332 (which, as amended or replaced, is hereinafter referred to as the "AC Intertie Agreement"); and

WHEREAS, the Parties hereto, on July 29, 1992, executed an agreement, designated as Contract No. DE-MS79-92BP93644 (which, as amended or replaced, is hereinafter referred to as the "Sycan Interconnection Agreement") which provides for, among other things, the installation and connection of series capacitors and new relays to PacifiCorp's Summer Lake-Malin 500 kV transmission line at the Sycan Compensation Station and related equipment installed at Summer Lake and Malin Substations; and

WHEREAS, the Parties will operate and maintain jointly-owned and solely-owned facilities and equipment for their mutual benefit; and

WHEREAS, Bonneville is authorized pursuant to law to dispose of electric power and energy generated at various Federal hydroelectric projects in the Pacific Northwest, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out-such authority;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. **TERM OF AGREEMENT.**

This Agreement shall be effective the date that the Alvey-Meridian 500 kV transmission line was available for commercial operation as part of the AC Intertie, December 7, 1993, (Effective Date) and upon acceptance by the Federal Energy Regulatory Commission of such Effective Date and shall coexist with the term of the AC Intertie Agreement. All liabilities accrued hereunder shall be and are hereby preserved until satisfied.

2. EXHIBITS.

Exhibits A, B and C are incorporated as part of this Agreement. In Exhibit A, the Company shall be the "Contractor" and all references to "the Administrator" are changed to "Bonneville."

3. REVISION OF EXHIBITS.

(a) Exhibits B and C may be revised to add or delete facilities and equipment to be operated and maintained, based upon mutual consent of the Parties. Such revisions shall specify the facilities to be operated and maintained, ownership of facilities, sharing of operation and maintenance costs between the Parties.

(b) Upon preparation by Bonneville and execution by the Parties, revisions to Exhibits B and C shall be attached to and deemed to be a part of this Agreement. They shall be effective on the effective date specified therein and shall supersede the respective exhibit then in effect.

4. OWNERSHIP OF FACILITIES AND EQUIPMENT.

(a) Title to and ownership of facilities and equipment shall be as specified in Exhibits B and C of this Agreement.

(b) Consistent with section 9(b) of Exhibit A to the AC Intertie Agreement, all jointly-owned equipment, facilities, and capital spare parts shall be identified as such with co-ownership tags and signs. Either Party, at such Party's sole expense, shall provide the tags and signs.

(c) Ownership of capital spare parts for jointly-owned facilities shall be in accordance with section 5(c) of Exhibit A to the AC Intertie Agreement.

(d) Decommissioning costs and proceeds from the disposal of jointly-owned facilities shall be in accordance with section 13 of Exhibit A to the AC Intertie Agreement.

5. OPERATION AND MAINTENANCE OF FACILITIES BY BONNEVILLE

(a) Bonneville shall:

(1) Operate and maintain the facilities which are described in Exhibit B in the same manner in which Bonneville operates and maintains similar facilities of the Government and consistent with prudent utility practices as defined in section 22 of the AC Intertie Agreement, and

(2) Operate and maintain the Government's power system control facilities which are necessary to integrate such facilities with the Government's control system and, from time to time when Bonneville determines it is necessary, modify or replace such Government power system control facilities.

(b) In the event of a major failure or obsolescence of any of the facilities specified in Exhibit B, the Parties shall, consistent with sections 7(e) and 12 of Exhibit A to the AC Intertie Agreement, provide for the replacement, repair, or removal of such equipment with the expenses to be shared by the Parties in accordance with the ownership percentages specified in Exhibit B.

(c) Informational Exchange:

(1) Bonneville shall provide PacifiCorp (Director, Power Operations, 1300 PSB, 920 SW Sixth Avenue, Portland, Oregon 97204) with maintenance records relevant to the facilities described in Exhibit B.

(2) This information will be provided semi-annually for the previous six month period and will include the anticipated maintenance for the next 12 months, the type of maintenance performed, and the date it was performed. In addition, such records shall be available for PacifiCorp's inspection upon reasonable notice.

(3) Bonneville shall automatically provide real time transmission status and operational data information, through resources such as Inter-

Utility Data Exchange, pertinent to PacifiCorp's responsibility as the operator of the Alvey-Meridian Line.

6. OPERATION AND MAINTENANCE OF FACILITIES BY PACIFICORP.

(a) PacifiCorp shall:

(1) Operate and maintain the facilities which are described in Exhibit C in the same manner in which PacifiCorp operates and maintains similar facilities of PacifiCorp and consistent with prudent utility practices as defined in section 22 of the AC Intertie Agreement, and

(2) Operate and maintain PacifiCorp's power system control facilities which are necessary to integrate such facilities with the PacifiCorp's control system and, from time to time when PacifiCorp determines it is necessary, modify or replace such PacifiCorp power system control facilities.

(b) In the event of a major failure or obsolescence of any of the facilities specified in Exhibit C, the Parties shall, consistent with sections 7(e) and 12 of Exhibit A to the AC Intertie Agreement, provide for the replacement, repair, or removal of such equipment with the expenses to be shared by the Parties in accordance with the ownership percentages specified in Exhibit C.

(c) Informational Exchange:

(1) PacifiCorp shall provide Bonneville (Bonneville Power Administration - Transmission Field Services, 905 N.E. 11th St., Portland, Oregon 97208) with maintenance records relevant to the facilities described in Exhibit C.

(2) This information will be provided semi-annually for the previous six month period and will include the anticipated maintenance for the next 12 months, the type of maintenance performed, and the date it was performed. In addition, such records shall be available for Bonneville's inspection upon reasonable notice.

(3) PacifiCorp shall automatically provide real time transmission status and operational data information, through resources such as Inter-Utility Data Exchange, pertinent to Bonneville's responsibility as the operator of the AC Intertie.

7. BILLING AND PAYMENT.

(a) At the end of each month, each Party shall prepare and forward to the other Party an invoice for actual operation and maintenance expenses incurred as identified in Exhibits B and C and as a result of such Party's obligations pursuant to sections 5 and 6 herein. Such invoice shall include labor, materials, indirect costs, and overheads. Indirect costs and overheads charged shall be in an amount similar to indirect costs and overheads allocated to such Party's operation and maintenance of its own facilities.

(b) Upon receipt of PacifiCorp's invoice, Bonneville shall pay PacifiCorp the invoiced amounts for the duties specified in section 6(a) of this Agreement. Upon receipt of Bonneville's invoice, PacifiCorp shall pay Bonneville the invoiced amounts for the duties specified in section 5(a) of this Agreement.

(c) Payment of such invoiced amount shall constitute payment in full for the cost of such operation and maintenance except for capital replacements which are addressed under sections 7(e) and 12 of Exhibit A to the AC Intertie Agreement. Such monthly amounts shall be rounded to whole dollar amounts, by elimination of any amount less than 50 cents, and increasing any amount from 50 cents through 99 cents to the next highest dollar.

(d) Operation and maintenance of specific facilities previously identified under Exhibit A to the AC Intertie Agreement (section 7(f)) and the Sycan Interconnection Agreement (section 5), and payment for such operation and maintenance charges, are superseded and replaced by this Agreement, however, any liabilities previously incurred shall remain until satisfied.

8. ENVIRONMENTAL REQUIREMENTS.

Environmental requirements with respect to historic contamination, disclosure of information, and emergency response plans shall be in accordance with section 11 of Exhibit A to the AC Intertie Agreement.

9. LIABILITY.

Bonneville and PacifiCorp assert that neither Party is the agent or principal for the other or that they are partners or joint venturers; and the Parties agree that they will not represent to any other party that they act in the capacity of agent or principal for the other. Each Party shall assume all liability for injury or damage to persons or property arising solely from the negligent acts of its own employees, agents, or contractors and shall indemnify and hold the other Party harmless from any liability arising therefrom.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement in several counterparts.

UNITED STATES OF AMERICA
Bonneville Power Administration

By **/S/ JOHN S. ROBERTSON**
Name________________________
(Print/type)
Effective Date **May 23, 1994**

PACIFICICORP

By **/S/ DENNIS P. STEINBERG**
Name________________________
(Print/type) **Senior Vice President**
Title ________________________
Date **May 19, 1994**

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REVISION NO. 1, EXHIBIT B
FACILITIES OPERATED AND MAINTAINED BY BONNEVILLE

This Revision No. 1 provides for access road snow removal and grading at Sycan and Summerlake substations.

Facility Description	Ownership Percentage Bonneville/ PacifiCorp	Operation & Maintenance Payments % Bonneville/ PacifiCorp	O&M Charge ($)
Alvey Substation			
3-500 kV Terminals This includes the breakers, CTs, buswork, towers, MODs, PTs, arresters, associated grounding, conduit, control and power cables, property and site development including landscaping, station service equipment for the 3-breaker ring bus layout, metering and telemetering, and 500 kV Relay House building (including associated relaying, controls and data system equipment for the Alvey-Dixonville, Marion-Alvey and 500 kV Tie Line	50/50	42/58	Actual Expense
Series capacitors and auxiliaries	50/50	42/58	Actual Expense
RAS-related equipment	100/0	42/58	Actual Expense
Captain Jack Substation			
Bay 3 Facilities including 2-500 kV breakers, 4-MODs, buswork, PTs, conduit, grounding, towers, metering and telemetering equipment on the Captain Jack-Meridian and Captain Jack-Malin #2 lines.	0/100	0/100	Actual Expense
RAS-related equipment	100/0	42/58	Actual Expense
Station Service facilities for the entire station	100/0	71/29	Actual Expense

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Facility Description	Ownership Percentage Bonneville/ PacifiCorp	Operation & Maintenance Payments % Bonneville/ PacifiCorp	O&M Charge ($)
Malin Substation			
Modifications in the Main Control House	50/25	50/25	[1]
Summerlake Substation			
Snowplow and grade access road	100/0	50/50	Actual Expense
Sycan Series Compensation Station			
New series capacitor bank in the Summerlake-Malin 500 kV Line	65/35	65/35	Actual Expense
Bypass switch and associated support structures and foundations, not including the dead-end tower	0/100	0/100	Actual Expense
Snowplow and grade access road	100/0	50/50	Actual Expense

PACIFICORP

By: David B Cory

Name: DAVID B CORY
(Print/Type)

Title: TRANSMISSION ACCT. MGR.

Date: 11/1/01

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: Clifford C Perigo

Name: Clifford C. Perigo
(Print/Type)

Title: Senior Transmission Account Executive

Date: 10-31-01

(W:\TMC\CT\PacifiCorp\Revisions\94278R1B.doc) 10/26/01

[1] Charges associated with the Main Control House at Malin are covered under Contract No. 14-03-29224, Table No. 25.

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

AUTHENTICATED COPY

JUL 6 1994

In reply refer to: PMCG

Contract No. DE-MS79-94BP94305

Mr. C.L. Dawsey, Benton Rural Electric Association, Prosser, WA
Mr. J.P. Ramseyer, Blachly-Lane Coop, Eugene, OR
Mr. L. Powell, Central Electric Coop, Redmond, OR
Mr. J. Pankey, Clearwater Power Company, Lewiston, ID
Mr. J. F. Mayse, Consumers Power Inc., Corvallis, OR
Mr. E. Schlender, Coos-Curry Electric Coop, Inc., Port Orford, OR
Mr. D. Sabala, Douglas Electric Coop, Inc., Roseburg, OR
Mr. D. Reynolds, Fall River Rural Electric Coop, Ashton ID
Mr. R. Byre, Lincoln Electric Coop, Davenport, WA
Mr. L. Greene, Lost River Electric Coop, Malta, ID
Mr. R.G. Peck, Lower Valley Power & Light, Afton, WY
Mr. B. Tracy, Raft River Rural Electric Coop, Hermiston, OR
Mr. S. Eldridge, Umatilla Electric Coop, Hermiston, OR
Mr. D. Seuss, West Oregon Electric Coop, Vernonia, OR
Mr. D. Piper, Pacific Northwest Generating Cooperative, Portland, OR

Dear PNGC Members and Officers:

The Bonneville Power Administration (Bonneville) and the Pacific Northwest Generating Cooperative (PNGC) contemplate executing a life-of-facilities contract under which PNGC would obtain a share of the Pacific Northwest-Pacific Southwest Intertie (Intertie). PNGC will execute the Pacific Northwest AC Intertie Capacity Ownership Agreement (Capacity Ownership Agreement) as owner. PNGC's members will not be executing the Capacity Ownership Agreement.

PNGC does not receive firm power requirements service from Bonneville and will be exporting resources on behalf of its members. Bonneville is concerned about meeting its statutory obligations under section 9(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act).

Therefore, PNGC, by signing this letter agreement, agrees that it will give Bonneville notice whenever a Pacific Northwest customer of Bonneville, as that term is defined in the Northwest Power Act, seeks to export a resource or any portion or share thereof, over PNGC's capacity ownership share, or whenever PNGC purchases or obtains contract rights to a resource which ownership or contract rights previously belonged to a Pacific Northwest customer of Bonneville, and such export would extend in duration into Bonneville's then current operational or planning horizon used for section 9(c) determinations. Unless PNGC is otherwise notified by Bonneville, at any given time, the operational horizon is 3 months to 1 year and the planning horizon is 2 years up to 7 years.

PNGC further agrees that it will, as a condition precedent to entering into participation agreements for a resource, insure that each member-participant in a resource executes a letter with the same terms as this letter and will deliver an executed original of such letter to Bonneville.

Each PNGC member by signing this letter agrees that if a resource or a portion or share thereof, owned by the member or by PNGC in which a member is a participant is exported over PNGC's capacity ownership share or otherwise, that member agrees to accept a reduction in Bonneville's firm load obligation to such member should such reduction be required as a result of a Bonneville determination under section 9(c) of the Northwest Power Act.

If the preceding provisions are acceptable, please sign and return two originals to Bonneville with the required authorizing resolutions containing original signatures. Each PNGC member will also send a signed original to PNGC. The remaining original is for your files.

/s/ WALTER E. POLLOCK

Assistant Administrator
for Power Sales

Sincerely,

Walter E. Pollock

Assistant Administrator
for Power Sales

Name Walter E. Pollock
(Print/Type)

ACCEPTED:

PACIFIC NORTHWEST GENERATING
COOPERATIVE

By ______________________

Name ______________________
(Print/Type)

Title ______________________

Date ______________________

(PMLAN-PMCG-W:\PMC\CT\PNGC\94305.DOC)

UMATILLA ELECTRIC
COOPERATIVE ASSOCIATION

By ______________________________

Name ______________________________
(Print/Type)

Title ______________________________

Date ______________________________

WEST OREGON ELECTRIC
COOPERATIVE

By ______________________________

Name ______________________________
(Print/Type)

Title ______________________________

Date ______________________________

(PMLAN-PMCG-W:\PMC\CT\PNGC\94305.DOC)

/s/ FRED R. GUYER

President of the Board of Trustees

August 31, 1994

UTILITIES

BENTON RURAL ELECTRIC ASSOCIATION

By Fred Guyer

Name (Print/Type) Fred R. Guyer

Title President Board of Trustees

Date August 31, 1994

BLACHLY-LANE COOPERATIVE

By ______

Name (Print/Type) ______

Title ______

Date ______

CENTRAL ELECTRIC COOPERATIVE, INC.

By ______

Name (Print/Type) ______

Title ______

Date ______

CLEARWATER POWER COMPANY

By ______

Name (Print/Type) ______

Title ______

Date ______

CONSUMERS POWER INC.

By ______

Name (Print/Type) ______

Title ______

Date ______

COOS-CURRY ELECTRIC COOPERATIVE, INC.

By ______

Name (Print/Type) ______

Title ______

Date ______

DOUGLAS ELECTRIC
COOPERATIVE, INC.

By ______________________

Name ______________________
(Print/Type)

Title ______________________

Date ______________________

LOST RIVER ELECTRIC
COOPERATIVE, INC.

By ______________________

Name ______________________
(Print/Type)

Title ______________________

Date ______________________

FALL RIVER RURAL ELECTRIC
COOPERATIVE, INC.

By ______________________

Name ______________________
(Print/Type)

Title ______________________

Date ______________________

LOWER VALLEY POWER &
LIGHT, INC.

By ______________________

Name ______________________
(Print/Type)

Title ______________________

Date ______________________

LINCOLN ELECTRIC
COOPERATIVE, INC.

By ______________________

Name ______________________
(Print/Type)

Title ______________________

Date ______________________

RAFT RIVER RURAL ELECTRIC
COOPERATIVE, INC.

By ______________________

Name ______________________
(Print/Type)

Title ______________________

Date ______________________

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Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

JUN 08 1994

In reply refer to: PSC

Mr. Elwyn Jon Kaake
Director, Power Scheduling
PacifiCorp
9951 SE. Ankeny
Portland, OR 97216

Dear Mr. Kaake:

This letter confirms your verbal agreement with Brenda Anderson of my staff in a telephone conversation on May 24, 1994. If the Bonneville Power Administration (BPA) is not marketing energy on a preschedule basis, BPA may purchase from PacifiCorp and only from PacifiCorp, an equivalent amount of energy, hour-by-hour, as the amount stored and returned under the spring and summer storage provisions of the Draft AC Intertie Agreement (Exhibit A to the Letter of Understanding, Contract No. DE-MS79-94BP94299 which was signed December 28, 1993) between BPA and PacifiCorp, Contract No. DE-MS79-94BP94332, Section 12.(b), at a price of 24 mills per kilowatthour, in order to fulfill BPA's obligation to PacifiCorp. This decision will be made on a preschedule basis and will be done for the entire day, not partial day, and for both the spring and summer storage energy, unless otherwise mutually agreed.

PacifiCorp's sale of such energy will be under the service agreement between PacifiCorp and BPA, dated February 14, 1992, (effective date July 24, 1992) under PacifiCorp's FERC Electric Tariff, First Revised Volume No. 3, Service Schedule PPL-3. Payments by BPA and billing by PacifiCorp for deliveries hereunder shall be in accordance with the terms specified in such Service Schedule PPL-3.

If you have any questions, please contact Brenda Anderson at (206) 418-2146.

Sincerely,

Mark W. Maher

Mark W. Maher
Director, Division of Power Supply

ACCEPTED:

PacifiCorp, Electric Operations

By Deviga-Jon Kaake

Title Director, Power Scheduling

Date June 16, 1994

PACIFICORP ENERGY
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 600
Portland, OR 97232

Stefan A. Bird
Senior Vice President,
Commercial & Trading
Direct Dial: (503) 813-5336
Fax: (503) 813-6260
Email: stefan.bird@pacifieorp.com

September 8, 2008

Mr. Alan Burns, PT Vice President
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621

RE: Letter of Clarification of Summer Storage Curtailment Procedures

Dear Alan:

This letter of clarification ("Letter") is between the United States of America, Department of Energy, acting by and through the Bonneville Power Administration, Power Services ("BPA"), and PacifiCorp, a corporation of the state of Oregon ("PacifiCorp"). BPA and PacifiCorp are referred to herein individually as "Party" and jointly as "Parties."

BPA and PacifiCorp are parties to the AC Intertie Contract, and Amendment No. 1 thereto, BPA Contract No. DE-MS79-94BP94332 (as amended from time to time, the "ACI"). Under Section 12 of the ACI, BPA may tender defined amounts of energy to PacifiCorp for "storage" in the summer, "provided that on any hour, PacifiCorp [is] not required to back down its thermal units to accept such energy" (the "Proviso"). The Proviso is silent as to whether unaccepted energy must be accepted at a later time. Accordingly, this Letter clarifies the meaning and interpretation of the Proviso, and resolves all issues related to the scope of the Proviso. It in no way alters any rates under the ACI and is not an amendment thereto, but rather a clarification of interpretation.

Therefore, to clarify, BPA and PacifiCorp agree:

1. TERM

This Letter is effective upon execution by the Parties and shall continue for a time period equal to the term of the ACI. All obligations incurred hereunder shall be preserved until satisfied.

//

2. CONDITIONS PRECEDENT

The following are conditions precedent to the clarifications of the Parties in this Letter. If any of the following conditions precedent are not met, then neither Party shall be obligated to perform as provided in this Letter, and this Letter shall be of no force and effect.

(a) Offer open for 15 days from the date hereof; and
(b) Solutions for both 2008 and 2009-2014 must be accepted as a package.

3. TRANSACTIONS ASSOCIATED WITH 2008 PACIFICORP CUTS

The following clarification is consistent with the ACI, requiring BPA to store energy in June and July and PacifiCorp to return the storage energy flat over September, October and November, while allowing BPA to hedge out the position at any time and book any value at its discretion. This maintains the fundamental concept that PacifiCorp stores and returns 100% of the energy BPA nominates under the ACI.

PacifiCorp will return the 172,273 MWhs of energy BPA stored in June and July 2008, flat, across all hours in September, October and November 2008, consistent with the ACI. In addition, BPA will deliver, and PacifiCorp will store, 100% of the 27,727 MWh of storage energy cut in June and July 2008, during off-peak hours in June and July 2009, and PacifiCorp will return 27,727 MWh to BPA, flat, in September, October and November 2009.

4. TRANSACTIONS ASSOCIATED WITH 2009-2014 TERM

PacifiCorp will store and return 100% of BPA ACI storage nominations over the years 2009 – 2014, based on all of the following principles, all of which shall apply as a package:

- PacifiCorp has the right to cut any MW of BPA-nominated schedule in any real time hour when PacifiCorp is forced to back down any portion of its thermal coal fleet, MW for MW. This determination shall be made at PacifiCorp's sole discretion and may be for economic reasons.
- In return, PacifiCorp agrees to increase the BPA pre-schedule storage schedule 7 days (168 hours) after the actual day of the real time hourly schedule cut by the quantity of energy cut in any given hour in real time over the 16 hours (on-peak) of the day ("Make-Up Energy"). The Make-Up Energy will be scheduled on a flat basis over the 16 on-peak hours of the pre-schedule day.

- PacifiCorp will only be entitled to real time storage cuts consistent with the above on the monthly nominated energy storage, and cannot cut the daily Make-Up Energy schedule.
- Prior to the last 7 days (168 hours) in July in any storage year, if there is Make-Up Energy which has not been added to BPA pre-schedule totals but is due, PacifiCorp agrees to settle out the daily Make-Up Energy by calculating the spread between the ICE daily firm Mid-C index for the day of make-up cuts, and the average ICE firm flat Mid-C index for September through December.
- PacifiCorp has the right, but not the obligation, to return stored energy at the Hot Springs delivery point.
- Finally, PacifiCorp will be obligated to return 100% of BPA energy which is delivered flat by BPA in June and July and returned flat in September through November in any storage year, less any financially-settled Make-Up Energy as explained above.

5. RELEASES

The Parties agree that this Letter constitutes a full and final clarification and resolution of all issues and claims related to the Proviso. This is full and complete satisfaction of any obligations owed by either Party to the other in regard to such claims, and each Party releases the other from such claims. Neither Party may pursue any further action against the other related to the Proviso, whether in dispute resolution, in court, at the Federal Energy Regulatory Commission or elsewhere, other than to enforce this Letter.

6. NEGOTIATION OF NEW AGREEMENT

If a final, non-appealable judicial order is entered in response to a petition for review that holds this Letter or BPA's execution of this Letter to be void, unenforceable, or unlawful in any material respect, then the Parties shall negotiate, in good faith, new provisions that shall replace those held to be unlawful, void, or unenforceable, with the objective of placing the Parties in the same financial and relational situation as existed prior to such final, non-appealable order.

7. INABILITY TO NEGOTIATE NEW AGREEMENT

If the Parties are unable in good faith to negotiate replacement provisions placing the Parties in the same financial and relational situation as existed prior to such final, non-appealable order within ninety (90) days of the issuance of such order, then this Letter shall have no further force or effect.

8. NO PRECEDENT

Any other disputes that may exist between the Parties, whether or not billed by BPA, are not settled or affected by this Letter. The Parties agree that this Letter shall not have any precedential effect as to any other dispute or any other matter, whether or not involving the Parties, and may not be cited as precedent by either Party or any other person in any proceeding or with respect to any other dispute or any other matter.

9. INTEGRATION

This Letter represents the entire agreement of the Parties as to the matters described herein. This Letter supersedes any agreements and representation made by the Parties in all prior discussions, negotiations and agreements, whether oral or written, relating to the Proviso.

If the foregoing clarification and interpretation is acceptable to BPA, please sign both originals of this Letter and return one executed original to PacifiCorp. The remaining executed original is for your files. If you have any questions, please do not hesitate to call me at (503) 813-5336.

Very truly yours,

Stefan A. Bird
Senior Vice President, Commercial & Trading

JBE:db

u:\legaldept\erb\bpa - summer storage agree\bpa clarifieation agreement (09-05-08 elean).doc

ACCEPTED:

UNITED STATES OF AMERICA
Department of Energy,
Bonneville Power Administration

By: ______________________________

Name:
Date: ______________________________

PACIFICORP ENERGY
A DIVISION OF PACIFICORP

8/29/14

Letter Agreement

8/29/14

Effective Date: August ~~28~~, 2014
29

Mark Miller
Account Executive, Power Services
Bonneville Power Administration
PO Box 3621
Portland, OR 99232

RE: Return of Storage Energy and New WSPP Confirmation

On June 5, 2014, Bonneville Power Administration ("BPA") provided notice ("Election Notice") to PacifiCorp that BPA was exercising a Storage Day(s) as described in Section 12(a)(9), Summer Storage, of the Amended and Restated AC Intertie Agreement, Contract No. DE-MS79-94BP94332 ("Storage Agreement") for the following period ("Term"):

Period begins:	Hour Ending 0100, June 7, 2014
Period ends:	Hour Ending 2400, June 7, 2014

On June 7, 2014, BPA delivered to PacifiCorp 3,125 megawatt-hours of storage energy ("Storage Energy"). 130 megawatts per hour were delivered from hour ending 0100 to hour ending 1900, and 131 megawatts per hour delivered from hour ending 2000 to hour ending 2400. Under section 12(a)(9)(iv), PacifiCorp must return the Storage Energy to BPA over the months of September, October and November of 2014.

In lieu of returning Storage Energy pursuant to section 12(a)(9)(iv), BPA and PacifiCorp now mutually agree to transact the delivery of Storage Energy provided during the Term under a Western System Power Pool ("WSPP") Agreement Confirmation (attached as WSPP Confirmation, dated 8/29/14). Upon completion of the deliveries and payment under the WSPP Confirmation, PacifiCorp's obligation to return Storage Energy to BPA shall be deemed satisfied.

IN WITNESS WHEREOF, PacifiCorp and BPA agree to this Letter Agreement as of the Effective Date.

PACIFICORP

Name: ____________________

Title: Director Shelton Origination

BPA

Name: Mark E Miller

Title: Account Executive

AC INTERTIE FACILITY OWNER
MANAGEMENT COMMITTEE RESOLUTION

Following the meeting of the Management Committee of the AC Intertie Facility Owners on September 5, 2014, the following Resolution was proposed by motion and unanimously approved by the Management Committee through email communication:

Resolved:

WHEREAS the Bonneville Power Administration, Portland General Electric, and PacifiCorp (collectively the "AC Intertie Facility Owners") jointly own the AC intertie facilities, and the Management Committee is made up of representatives from each of the AC Intertie Facility Owners. The Management Committee believes it is in the best interest of each respective AC Intertie Facility Owner/Transmission Provider and its respective Transmission Customers to agree upon an allocation methodology and process for allocating Dynamic Transfer Capability ("DTC") on the northern California-Oregon Intertie ("COI") that recognizes the proportional ownership interest of each AC Intertie Facility Owner by allocating DTC based on a *pro rata* share of total COI Total Transfer Capability ("TTC") ownership;

WHEREAS it is further agreed that the AC Intertie Facility Owners/Transmission Providers will cap COI DTC requests submitted by their respective Transmission Customers (which, for purposes of this Resolution, include all entities using COI DTC) at the lesser of the Transmission Customer's firm COI rights or the total COI DTC scheduling limit, and an individual Transmission Customer's COI DTC allocation is determined on a *pro rata* basis as illustrated in the Exhibit to this Resolution, which the Management Committee may replace or revise from time to time;

WHEREAS it is further agreed that if, after the first round of allocating to all Transmission Customers making COI DTC requests, an AC Intertie Facility Owner/Transmission Provider has unallocated COI DTC remaining, the Transmission Provider will release its unused COI DTC share ("Remainder") to Transmission Providers with remaining unfulfilled requests for COI DTC ("Remaining TPs"), according to the transmission facility ownership share of each Remaining TP relative to the sum of the transmission facility ownership of all Remaining TPs, as illustrated in the Exhibit to this Resolution. Each AC Intertie Facility Owner/Transmission Provider will then allocate its share of the Remainder to its Transmission Customers with remaining unfulfilled COI DTC requests allocated in a manner consistent with the first round of allocations, as illustrated in the Exhibit to this Resolution. The sum of the two allocation distributions described above is the total COI DTC allocation per Transmission Customer for the time period calculated.

WHEREAS it is further agreed that, before Transmission Customers may begin to submit COI Dynamic e-Tags, AC Intertie Facility Owners/Transmission Providers will require advance notice and will work with Transmission Customers to: (i) coordinate with and provide data to Bonneville Power Administration, as path operator, sufficient to administer COI DTC allocation and process COI Dynamic e-Tags consistent with this Resolution; and (ii) ensure compliance with applicable operational requirements and business practices.

WHEREAS it is further agreed that this Resolution will be in effect until October 1, 2019. The AC Intertie Facility Owners will either renew or replace this Resolution prior to October 1, 2019.

WHEREAS it is further agreed that AC Intertie Facility Owners/Transmission Providers will require a minimum set of scheduling and e-Tagging requirements for their respective Transmission Customers, including the following:

- Requests for COI DTC must be submitted via a Dynamic e-Tag within a common timing window among all Transmission Customers of AC Intertie Facility Owners/Transmission Providers.
    - Starting October 1, 2014, the window for making a COI DTC request will close at 8 am on each Western Electricity Coordinating Council ("WECC") Preschedule day, including the following additional requirements:
        - Dynamic e-Tags must be in a "Confirmed" state in order to be considered for a COI DTC allocation.
        - The Transmission Profile of the Dynamic e-Tag(s) will be utilized in the COI DTC allocation process.
        - E-Tag tokens may be used to uniquely identify eligible e-Tags.
- The Transmission Customer must submit a COI Dynamic e-Tag for each hour covered by the WECC Preschedule day that the Transmission Customer desires to receive a COI DTC allocation.
- Bonneville Power Administration will administer an automated process that performs the COI DTC allocation for each WECC Preschedule day based on the agreed upon methodology set forth in this Resolution and its Exhibit and will apply a Reliability Limit on the Dynamic e-Tag to be no greater than the Transmission Customer's COI DTC allocation.
- AC Intertie Facility Owners/Transmission Providers will develop controls so that Bonneville Power Administration can manage the dynamic signal limits in real-time during active COI flow management conditions;
    - If such controls cannot be implemented in a timely manner, Transmission Providers may permit their Transmission Customers to temporarily utilize the CAISO's Automated Dispatch System, or some other automated system that is capable of enforcing the DTC allocation as an upper limit.

WHEREAS it is further agreed that the AC Intertie Facility Owners will continue to work together to develop and improve methodologies and systems and related requirements for allocation and use of COI DTC, including but not limited to the ability to allocate COI DTC in or close to real-time in a manner that recognizes actual usage of COI DTC as well as the potential for offsetting impacts of any COI DTC counter-schedules.

WHEREAS that the Management Committee of the AC Intertie Facility Owners supports and endorses the Resolution.

Management Committee of the AC Intertie Facility Owners

Signed:

Frank Afranji 10-15-2014

Frank Afranji, Director of Transmission and Reliability Services, Portland General Electric

Richard Shaheen, Acting Senior Vice President of Transmission Services, Bonneville Power Administration

Natalie Hocken, Senior Vice President Transmission and System Operations, PacifiCorp

WHEREAS that the Management Committee of the AC Intertie Facility Owners supports and endorses the Resolution.

Management Committee of the AC Intertie Facility Owners

Signed:

Frank Afranji, Director of Transmission and Reliability Services, Portland General Electric

10-17-14

Richard Shaheen, Acting Senior Vice President of Transmission Services, Bonneville Power Administration

Natalie Hocken, Senior Vice President Transmission and System Operations, PacifiCorp

WHEREAS that the Management Committee of the AC Intertie Facility Owners supports and endorses the Resolution.

Management Committee of the AC Intertie Facility Owners

Signed:

Frank Afranji, Director of Transmission and Reliability Services, Portland General Electric

Richard Shaheen, Acting Senior Vice President of Transmission Services, Bonneville Power Administration

Natalie Hocken

Natalie Hocken, Senior Vice President Transmission and System Operations, PacifiCorp

Contract No. DE-MS79-94BP94332
Amendment No. 1

Amendment No. 1 to the AC INTERTIE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFICORP

This Amendment No. 1 to the AC INTERTIE AGREEMENT ("Amendment No. 1"), Contract No. DE-MS79-94BP94332, executed February 27, 1998 by the UNITED STATES OF AMERICA ("Government"), DEPARTMENT OF ENERGY, acting by and through the BONNEVILLE POWER ADMINISTRATION ("Bonneville") and PACIFICORP ("PacifiCorp"), a corporation organized and existing under the laws of Oregon, (hereinafter referred to individually as "Party" and collectively as "Parties").

W I T N E S S E T H :

WHEREAS the Parties entered into the AC Intertie Agreement (Contract No.DE-MS79-94BP94332) whichj was executed on June 1, 1994; and

WHEREAS the Federal Energy Regulatory Commission's Order No. 888 under FERC Docket No. RM95-8-000 effectuated a new Part 35.28 to Title 18 of the Code of Federal Regulations ("18 CFR") which requires the implementation of open **access** transmission tariffs by public utilities; and

WHEREAS Part 35.28(c)(iii) of 18 CFR requires that access to PacifiCorp's transmission rights associated with transmission facilities jointly owned with non-public utilities be made available to third parties under a pro-forma open access transmission tariff;

NOW, THEREFORE, the Parties hereto have entered into this Amendment No. **1** to the AC Intertie.

1. Term of Agreement. This Amendment No. **1** shall be effective when executed by the Parties and accepted for filing or otherwise approved without change by the Federal Energy Regulatory Commission and shall terminate upon the termination of the original AC Intertie Agreement.

2. evision of Section 5(e)(1). Section 5(e) **(1)** shall be replaced in its entirety by the following:

"(1) To preserve Bonneville's rights to use PacifiCorp's unused Scheduling Rights in a manner that allows third-party access to such rights in any hour, PacifiCorp and Bonneville agree to the following provisions. PacifiCorp or any successive assignee may make its Scheduling Rights available on a firm basis to all parties under the provisions of PacifiCorp's open access transmission tariff; provided, however, that neither PacifiCorp nor any successive assignee of PacifiCorp's Scheduling Rights may make such Scheduling Rights available for periods shorter than daily or on a nonfirm basis. To the extent that PacifiCorp or any successive assignee has unused Scheduling Rights available in any hour under this Agreement as of the close of the normal preschedule deadline for firm point-to-point transmission service in accordance with Bonneville's standard scheduling practices, Bonneville shall add such unused Scheduling Rights to its available nonfirm transmission capacity for AC Intertie transactions, which shall be posted on Bonneville's Open Access Same-time Information System and made available pursuant to the provisions of Bonneville's open access transmission tariff. After such unused Scheduling Rights are added to Bonneville's available nonfirm transmission capacity, PacifiCorp or any successive assignee of the Scheduling Rights may modify preschedules up to 30 minutes prior to the hour for service to be provided pursuant to such preschedules for use of such firm transmission capacity (with such right available even if a preschedule had not been submitted, and in such case, PacifiCorp or any successive assignee shall be deemed to have submitted, with rights to modify, a 0 (zero) preschedule) and any such use shall have priority over any use or sale of unused Scheduling Rights by Bonneville. After 30 minutes prior to the hour for service to be provided pursuant to such preschedule, these unused Scheduling Rights shall be relinquished to Bonneville. There shall be no charge to Bonneville for unused Scheduling Rights."

3. <u>evision of Section 7</u>. In Section 7 whenever the phrase "Joint Intertie Scheduling Office" is used the phrase "BPA Transmission Scheduling Office" shall be used instead.

IN WITNESS WHEREOF, the Parties hereto have executed this Amendment No. **1.**

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By ______________________

Date 2-27-98

PACIFICORP

By ______________________

Date 2-17-98

825 N.E. Multnomah
Portland, Oregon 97232
(503) 464-5000

PACIFICORP
PACIFIC POWER UTAH POWER

FEB 18 1998

February 17, 1998

Clifford C. Perigo
Senior Transmission Account Executive
Bonneville Power Administration
P.O. Box 491
Vancouver, WA 98666-0491

Dear Cliff:

Enclosed are two originals of Amendment No. 1 to the AC Intertie Agreement between PacifiCorp and the Bonneville Power Administration ("Bonneville") signed by PacifiCorp on February 17, 1998. After Bonneville has signed the originals, please return one fully executed original to PacifiCorp.

Sincerely,

David B. Cory
Transmission Account Manager

DBC:jr

Amendatory Agreement No. 2 to
Contract No. DE-MS79-94BP94332

AMENDATORY AGREEMENT NO 2 TO THE

AC INTERTIE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFICORP

Index to Sections

This AMENDATORY AGREEMENT NO. 2 to the AC INTERTIE AGREEMENT ("AA No. 2 to AC Intertie Agreement"), Contract No. DE-MS79-94BP94332, executed June ____, 1998 by the UNITED STATES OF AMERICA, DEPARTMENT OF ENERGY, acting by and through the BONNEVILLE POWER ADMINISTRATION ("Bonneville") and PACIFICORP ("PacifiCorp"), a corporation organized and existing under the laws of Oregon, (hereinafter referred to individually as "Party" and collectively as "Parties").

W I T N E S S E T H

WHEREAS, PacifiCorp's predecessor and Bonneville originally entered into the Intertie Agreement, Contract No. DE-MS79-86BP92299("Original Intertie Agreement"), and

WHEREAS, the Original Intertie Agreement was amended by, inter alia, Amendatory Agreement No. 2, ("AA No. 2 to Original Intertie Agreement"), subsection 7(e) of which provided for reimbursable Capital Replacements, and

WHEREAS, PacifiCorp and Bonneville have entered into a successor agreement, the AC Intertie Agreement, Contract No. DE-MS79-94BP94332 ("AC Intertie Agreement"), which superseded and replaced in its entirety the Original Intertie Agreement, and

WHEREAS, the AC Intertie Agreement creates construction obligations, assigns ownership rights, and allocates cost responsibility for operation and maintenance of new facilities to upgrade the transfer capability of the Pacific Northwest AC Intertie from 3,200 megawatts to approximately 4,800 megawatts, and

WHEREAS, certain payment and cost-sharing provisions of the Original Intertie Agreement were incorporated into the AC Intertie Agreement as Exhibit A thereto, and

WHEREAS, the Parties desire to amend the AC INTERTIE AGREEMENT by creating a new Exhibit F that will authorize reimbursable Capital Replacements and Capital Additions.

NOW, THEREFORE, in consideration of the mutual covenants and agreements contained herein, the Parties hereto undertake and agree as follows:

SECTION 1 - DEFINITIONS

1.1 "Capital Additions" means the addition of any new facilities under the AC Intertie Agreement (e.g., not replacements for assets already listed on Exhibit B)that are required to serve the common good of both Parties .

1.2 "Capital Replacements" means the replacement asset for the facilities listed in Exhibit B of the AC Intertie Agreement that are required to serve the common good of both Parties.

SECTION 2 - EFFECTIVE DATE AND TERM

This Amendatory Agreement No. 2 shall be effective on the date of execution and shall remain in effect concurrently with the AC Intertie Agreement; provided, all liabilities incurred hereunder shall be preserved until satisfied.

SECTION 3 - CAPITAL BUDGETS

Excluding any facilities designated for omission by footnote 1 of Exhibit B of the AC Intertie Agreement, each Party by July 1 of each year shall send a notice to the other Party containing (i) an estimate the capital budget amounts related to the planned construction activities of the facilities described in such Exhibit B such Party expects to incur four (4) years in the future, and (ii) an update of any capital budget amounts it expects to incur within the upcoming three (3) years. Except for emergency Capital Replacements or emergency Capital Additions, the Parties shall exchange and review any necessary data as needed to determine the necessity and adequacy of the proposed construction and operation activities.

SECTION 4 - PAYMENT PROVISIONS

4.1 For reimbursable Capital Replacements or Capital Additions, the Party proposing the action shall prepare a proposed revision to Exhibit F whenever the Parties concur that it is necessary to add to or to replace the facilities identified in Exhibit B of the AC Intertie Agreement. The Parties shall share the costs of such action according to the original cost share percentage of such facilities as set forth in Exhibit B in a manner consistent with the cost sharing methodologies contained in such exhibit, except that the replacement of facilities identified by footnote 1 of Exhibit B shall not be eligible for cost-sharing. Each revision of Exhibit F shall specify the facilities added or replaced.

4.2 The Party responsible to make payment shall pay according to the provisions of the revision of Exhibit F for the work performed in amounts and at times as negotiated by the Parties.

4.3 In the event of a dispute regarding billing, the Party owing the bill shall pay the amount in full and provide written notification of the disputed amount. Any adjustment shall be made on the next invoice allowing reasonable notice and time to make the adjustment. Refunds of the disputed amount shall include interest at the same interest rate specified in section 4.4.

4.4 Invoices not paid in full on or before the close of business on the date due shall be subject to an interest charge on the amount due from the due date to the date paid consistent with the Prompt Payment Act Renegotiation Board's Interest Rate published in the Federal Register.

SECTION 5 - AUDIT RIGHTS

5.1 Each Party, at its expense, may review and audit any cost on the other Party's books, records, and documents that directly pertain to the billings on the jointly owned facilities.

The Party undertaking the audit shall provide reasonable notice to the other Party and shall conduct such audit at reasonable times and in conformance with generally accepted auditing standards. The Party being audited shall cooperate fully with any such audit. Neither Party shall audit a cost incurred more than three (3) years following the last day of the fiscal year in which such cost was incurred under this Amendatory Agreement No.2. The Parties shall retain all records and documentation prepared in the normal course of business for the entire length of this audit period and in accordance with generally accepted accounting principles.

5.2 After completion of the audit, the Party conducting the audit shall promptly notify the other Party of any exception taken as a result of an audit, and the audited Party may review the notice of exception and basis therefor for a period of thirty (30) days. Upon agreement regarding the validity of any exception, the owing Party shall directly refund the amount of the exception within thirty (30) days of such agreement.

SECTION 6 - OWNERSHIP OF THE FACILITIES

6.1 Transfer of legal ownership pursuant to this Amendatory Agreement No. 2 shall be effective at such time as the facilities are energized and made available for commercial operation as part of the AC Intertie.

6.2 All jointly-owned equipment and facilities shall be identified as such with co-ownership tags and signs. Each Party shall provide the tags and signs for equipment which it operates. Costs for such tags and signs shall be shared equally by each Party.

SECTION 7 - INTEGRATION

7.1 To the extent that Exhibit A of the AC Intertie Agreement is inconsistent with provisions of this Amendatory Agreement No. 2, such Exhibit A is superseded by the provisions of this Agreement.

7.2 Any revisions to Exhibit F shall be attached to and deemed to be a part of the AC Intertie Agreement and shall be effective on the date specified therein.

SECTION 8 - EXHIBITS

Exhibit F is incorporated as part of this Intertie Agreement. Any revision of this exhibit to capture those capital facilities that qualify as Capital Replacements or Capital Additions shall be by mutual consent, except as noted in Section 3 of this Amendment No.2 regarding emergency Capital Replacements or emergency Capital Additions.

IN WITNESS WHEREOF, the Parties hereto have executed this Amendatory Agreement No.2.

PACIFICORP	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: Jerry D. Rust	By: Clifford C. Perigo
Name: Jerry D. Rust	Name: CLIFFORD C. PERIGO
Title: AVP, Transmission Sys.	Title: SR. ACCOUNT EXEC.
Date: June 3, 1998	Date: 6-26-98

Exhibit F
Amendatory Agreement No. 2
Contract No. DE-MS79-94BP94332
PacifiCorp
Effective upon execution

BPA 500KV 3RD AC INTERTIE - CAPITAL ADDITIONS & REPLACEMENTS
Dec 1996 Through April 1998

PROJECT	FACILITY DESCRIPTION	MATERIAL	LABOR	OUTSIDE SERVICES	MISC	100% CHARGES	COST SHARE %	BPA SHARE AMOUNT
64290	Dixonville Sub - SF6 Interrupters	10,199.74	2,568.17		4,151.45	16,919.36	50/50	8,459.68
420227	Dixonville Sub- Retire Excess Mat'l (Removal)		1,404.10		196.06	1,600.16	50/50	800.08
	Total	10,199.74	3,972.27		4,347.51	18,519.52		9,259.76

Payment: Bonneville shall remit payment for the BPA SHARE AMOUNT within 30 days of receipt of invoice from PacifiCorp.

Amendment No. 3 to the AC INTERTIE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFICORP

This Amendment No. 3 to the AC INTERTIE AGREEMENT ("Amendment No. 3"), Contract No. DE-MS79-94BP94332, executed Jan 26, 2005 by the UNITED STATES OF AMERICA ("Government"), DEPARTMENT OF ENERGY, acting by and through the BONNEVILLE POWER ADMINISTRATION ("Bonneville") and PACIFICORP ("PacifiCorp"), a corporation organized and existing under the laws of Oregon, (hereinafter referred to individually as "Party" and collectively as "Parties").

WITNESSETH:

WHEREAS the Parties entered into the AC Intertie Agreement, Bonneville Contract No.DE-MS79-94BP94332 (the "Agreement"), which was executed on June 1, 1994; and

WHEREAS Section 5(h) of the Agreement states, among other things, that PacifiCorp shall, upon request, provide Bonneville firm capacity in the existing 500/230 kV transformer at the Malin Substation at a use-of-facilities rate for Bonneville's firm requirements, subject to certain limitations, including availability and only up to 200 megawatts.

NOW, THEREFORE, the Parties hereto have entered into this Amendment No. 3 to the Agreement.

1. Effectiveness of Amendment. This Amendment No. 3 shall be effective when executed by the Parties and accepted for filing or otherwise approved without change by the Federal Energy Regulatory Commission and shall terminate upon the termination of the Agreement.

2. Revision of Section 2 - Exhibits. Section 2 shall be replaced in its entirety by the following:

"Exhibits A through G are incorporated as part of this Agreement. Revisions to the Exhibits shall be by mutual consent."

3. Addition of Exhibit G ("Malin Transformer - Use-of-Facilities Charge"). The attached Exhibit G shall become part of the Agreement and added to the "Index to Sections" in the Agreement.

IN WITNESS WHEREOF, the Parties hereto have executed this Amendment No. 3.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Anne E. Draper

Date 26 Jan 05

PACIFICORP

By [signature]

Date 1/21/2005

Attachment - Exhibit G

MALIN TRANSFORMER - USE-OF-FACILITIES

Pursuant to Section 5(h) of the Agreement, which states that PacifiCorp shall provide Bonneville firm capacity in its existing 500/230 kV transformer bank at the Malin Substation at a use-of-facilities rate for Bonneville's firm requirements, subject to certain limitations, including availability and only up to 200 megawatts, the Parties agree to the following:

Commencement Date

Bonneville commenced utilization of its rights to use the above referenced transformer bank on January 1, 1999, and payment to PacifiCorp shall be due from that date forward. For the period starting January 1, 1999 through December 31, 2003 the total charges shall be $1,237,037 for use-of-facilities and $366,350.85 for transformer losses. Starting on January 1, 2004 the charges shall be as described below.

Use of Facilities Charge: $233,057 per year, billed monthly at $19,421.42

The above charge is based on the following:

- Investment of $6,921,090
- Levelized Fixed computation methodology
- Utilization at 26.33% which is based on the ratio of Bonneville's exercised right to the average monthly transformer peak for the prior calendar year, inclusive of Bonneville's exercised right, provided, however, this ratio shall be capped at, and shall not exceed 200/650 = 30.77%, which equates to the maximum capacity share Bonneville could ever expect to request and be awarded under this agreement.
  - Example 1: For 2003, Bonneville's exercised right was 102 MW, as compared to the monthly average transformer peak inclusive of this right of 387.33 MW which was the basis for calculating the 26.33% utilization factor above.
  - Example 2: Suppose Bonneville requests to increase its exercised right to 130 MW, and the monthly average transformer peak inclusive of this right is

415 MW. The new ratio would be 130/415 = 31.33%, which exceeds the cap; therefore Bonneville's charge is based on 30.77% rather than 31.33%.

- FERC Authorized Rate of Return.
- FERC Methodology for OMAG Expenses.
- Thirty-nine year straight-line book depreciation.
- Twenty year (MACRS) tax depreciation.
- 1.2% property tax rate.
- 37.95% income tax rate.
- 7.5% discount rate.

Transformer Losses

In addition to the above use-of-facilities charge, the Parties agree that transformer losses (in megawatts) for the Malin 500/230 kV transformer shall be calculated with the following formula:

$$\mathbf{L = 0.4116 + k\,P^{2}}$$

Where:

L = total losses in MW
0.4116 MW is the magnetizing loss which is independent of transformer load
k = 2.8×10^{-6}
P = power through transformer in MW

Example 1: The transformer load is 300 MW. The total losses are:
$L = 0.4116 + (2.8 \times 10^{-6}) \times (300)^{2} = 0.664$ MW

Example 2: The transformer load is 650 MW. The total losses are:
$L = 0.4116 + (2.8 \times 10^{-6}) \times (650)^{2} = 1.59$ MW

This formula shall be applied through the entire range of transformer capacity, from zero to 650 MW, and Bonneville's share shall be based on its hourly schedule of energy across the transformer.

For any hour, Bonneville may return losses physically, concurrent with the associated hourly energy schedule. Provided, for any hour in which Bonneville does not schedule loss returns concurrent with the associated energy schedule, Bonneville shall pay PacifiCorp for losses valued at the "Hourly Pricing Proxy" as described or as may be updated from time to time in PacifiCorp's currently effective Open Access Transmission Tariff.

Revisions to Exhibit G

If Bonneville notifies PacifiCorp that it wishes to effect a change to it's existing exercised right of 102 MW, then Bonneville's utilization of transformer capacity shall be automatically updated upon the effective date of the election (subject to PacifiCorp's review of capacity availability pursuant to Section 5(h) of the Agreement) to reflect the full amount of Bonneville's election of transformer capacity pursuant to this Agreement. The availability of such capacity to Bonneville pursuant to the Agreement shall not exceed 200 MW and the charge factor applied to Bonneville's use of the Malin transformer shall not exceed 30.77%. The Parties agree that any other change to the above methodologies or factors shall be by mutual agreement and shall not be allowed more often than once per three year period. Either party may submit any recommended change to the other party on at least six-month notice and justification. Each party's agreement to recommended changes in input factors to the above methodologies shall not be unreasonably withheld, provided any such recommended changes have a reasonable basis in fact. The parties shall negotiate in good faith to address any requested change in underlying methodology or formulae. Such changes to input factors shall apply prospectively only.

Contract No. DE-MS79-94BP94332

AMENDED AND RESTATED

AC INTERTIE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFICORP

Dated as of August 2, 2011

Index to Sections

Exhibit J ("Example of PacifiCorp Contingent Spill Protection Day criteria validation email to Bonneville")
Exhibit K ("Sample of Bonneville Spill Conditions website posting")
Exhibit L ("Sample of Bonneville Spill Protection Day LD")
Exhibit M ("Sample of PacifiCorp Storage Cut LD")

This AMENDED AND RESTATED AC INTERTIE AGREEMENT (Amended and Restated AC Intertie Agreement), executed August 2 2011, by the UNITED STATES OF AMERICA ("Government"), DEPARTMENT OF ENERGY, acting by and through the BONNEVILLE POWER ADMINISTRATION ("Bonneville") and PACIFICORP ("PacifiCorp"), a corporation organized and existing under the laws of Oregon, (hereinafter referred to individually as "Party" and collectively as "Parties").

WITNESSETH:

WHEREAS the Parties have entered into the Transmission Agreement (Contract No. DE-MS79-79BP90091), as amended, which hereinafter is referred to as "Midpoint-Medford Agreement"; and

WHEREAS the Parties have entered into the Intertie Agreement (Contract No. DE-MS79-86BP92299, as amended, which hereinafter is referred to as "the July 1986 Intertie Agreement"; and

WHEREAS the Parties have entered into an Agreement of Principles, dated May 28, 1993, which hereinafter is referred to as "Letter of Understanding" and which provides, among other things, for the revision of certain terms and conditions in the Midpoint-Medford Agreement and the July 1986 Intertie Agreement; and

WHEREAS the Parties have entered into the Midpoint-Meridian Transmission Agreement (Contract No.DE-MS79-94BP94333) which hereinafter is referred to as "Midpoint-Meridian Transmission Agreement" which replaces and supersedes the Midpoint-Medford Agreement; and

WHEREAS the Parties have replaced and superseded the July 1986 Intertie Agreement with the June 1994 AC Intertie Agreement Contract No. DE-MS79-94BP94332, (hereinafter referred to as the June 1994 AC Intertie Agreement), and

WHEREAS the Parties have entered into the AC Intertie Operation and Maintenance Agreement (Contract No. DE-MS79- 93BP94278) which hereinafter is referred to as "AC Intertie O&M Agreement"; and

WHEREAS Bonneville and PacifiCorp are Parties to Contract No. 14-03-59840 ("Malin Substation Construction Agreement") which provides for rights and obligations regarding construction, operation, ownership and use of the Malin Substation and desire to continue such agreement for the term of this Amended and Restated AC Intertie Agreement; and

WHEREAS PacifiCorp has constructed a 500 kV line from the interconnection with Bonneville at Alvey Substation to Meridian Substation ("Alvey-Meridian Line") to provide increased Load Carrying Capability; and

WHEREAS Bonneville has expanded the Rated Transfer Capability of the AC Intertie to approximately 4800 megawatts and has acquired a 50 percent undivided ownership right in the Incremental Capacity of the Alvey-Meridian Line; and

WHEREAS PacifiCorp and Bonneville have acquired joint ownership in the Alvey-Meridian Line and related facilities as provided for in Amendatory Agreement No. 2 to the June 1994 AC Intertie Agreement ("Payment Agreement"), Amendatory Agreement No. 1 to the July 1986 Intertie Agreement ("Option Agreement") attached hereto as Exhibits A and D respectively and Exhibit B hereto; and

WHEREAS nothing in this Amended and Restated AC Intertie Agreement is intended to be determinative of transmission or ownership rights of utilities not party to this Amended and Restated AC Intertie Agreement; and

WHEREAS this Amended and Restated AC Intertie Agreement incorporates the terms and conditions of the June 1994 AC Intertie Agreement, as supplemented and amended by Amendatory Agreement Nos. 1 through 3 thereto in one complete document, in accordance with the Federal Energy Regulatory Commission requirements in Order No. 614, Designation of Electric Rate Schedule Sheet, 65 Fed. Reg. 18,221 (2000), FERC Statutes and Regulations ¶ 31,096 (2000); and

WHEREAS this Amended and Restated AC Intertie Agreement is entered into by the Parties for the sole purpose of incorporating Amendatory Agreements 1, 2 and 3 into this Amended and Restated AC Intertie Agreement and does not alter any of the Parties' rights, obligations or terms and conditions of the June 1994 AC Intertie Agreement in any way; and

WHEREAS the Parties agree that this Amended and Restated AC Intertie Agreement supersedes and replaces the Original version of the June 1994 AC Intertie Agreement and Amendatory Agreement Nos. 1 through 3 thereto in their entirety as from the effective date hereof.

NOW, THEREFORE, in the interest of resolving issues of AC Intertie rights and service to PacifiCorp's Load Area now and in the future, Bonneville and PacifiCorp are entering into this Amended and Restated AC Intertie Agreement to accomplish the following goals:

(a) To enable Bonneville's planning, construction, operation and maintenance of an AC Intertie with a bidirectional Rated Transfer Capability of approximately 4800 megawatts and to enable PacifiCorp's planning, construction, operation and maintenance of facilities to serve its Load Area.

(b) To permit the Parties' specified use of the Buckley- Alvey Loop in a manner that does not jeopardize reliable service on either Party's system.

(c) To limit PacifiCorp's right to use its own facilities to schedule power and energy from its Load Area to adjoining areas and to ensure that this right is exercised in a manner that does not reduce the Operational Transfer Capability of the AC Intertie.

(d) To facilitate joint development of facilities by Bonneville and PacifiCorp as specified in this Amended and Restated AC Intertie Agreement.

(e) As between the Parties, to facilitate the economical development and fair allocation of any AC Intertie transfer capability above 4800 megawatts.

It is the intention of the Parties that this Amended and Restated AC Intertie Agreement be implemented and interpreted to best effectuate the above stated goals. Where this Amended and Restated AC Intertie Agreement makes reference to not unreasonably withholding consent or agreement, the reasonableness of each Party's position will be judged with reference to the above stated goals.

1. Term of Agreement. This Amended and Restated AC Intertie Agreement shall be effective, and consistent with the 1994 AC Intertie Agreement, shall supersede the July 1986 Intertie Agreement in accordance with Section 15 herein when executed by the Parties and accepted for filing or otherwise approved without change by the Federal Energy Regulatory Commission and shall terminate when all of the facilities comprising the AC Intertie are permanently taken out of service. Upon termination of this Amended and Restated AC Intertie Agreement, all liabilities accrued hereunder shall be and are hereby preserved until satisfied.

2. Exhibits. Exhibits A through M are incorporated as part of this Amended and Restated AC Intertie Agreement. Revisions to the Exhibits shall be by mutual consent.

3. Plan-of-Service for AC Intertie.

(a) Bonneville's Right to Establish Plan-of-Service. PacifiCorp agrees that Bonneville alone shall have the right to establish any Plan-of-Service for upgrading the AC Intertie to approximately 4800 megawatts, provided such Plan-of-Service is in keeping with Prudent Utility Practice, and further provided such Plan-of-Service does not result in reducing PacifiCorp's Load Carrying Capability.

(b) PacifiCorp's Right to Comment. Bonneville shall provide PacifiCorp the opportunity to comment on any such Plan-of-Service Bonneville may establish.

4. AC Intertie Construction and Ownership up to Approximately 4800 Megawatts of Rated Transfer Capability.

(a) Alvey-Meridian Line Rights. To achieve the upgrade of the AC Intertie to a Rated Transfer Capability of approximately 4800 megawatts, Bonneville has acquired a 50 percent undivided ownership right in the Incremental Capacity of the Alvey-Meridian Line which is jointly owned by Bonneville and PacifiCorp as provided for in the Payment Agreement and Exhibit B. For the term of this Amended and Restated AC Intertie Agreement, Bonneville shall have the unrestricted right to use such ownership interest. Bonneville may use such unrestricted right for purposes including, but not limited to, the interregional transfer of electric power, the integration of the electric power output of generation resources, and for service to the electric power loads of Bonneville's customers. Bonneville and PacifiCorp have shared, in accordance with the percentages specified in Exhibit B, the actual costs of facilities associated with construction of the Alvey-Meridian Line and other related additions. Unless otherwise

stated in Exhibit B or in the AC Intertie O&M Agreement, Bonneville shall pay 42 percent and PacifiCorp shall pay 58 percent of the operation and maintenance costs of those facilities specified in Exhibit B. PacifiCorp shall bear all operation and maintenance costs for those facilities used exclusively to serve PacifiCorp's own loads. PacifiCorp and Bonneville shall act in good faith and use best efforts, including utilization of all reasonable legal remedies, to obtain and protect all necessary permits and licenses for the Alvey-Meridian Line.

(b) Captain Jack Substation. Bonneville has constructed and, except for those facilities which PacifiCorp owns pursuant to section 4(b)(3) herein, owns the Captain Jack Substation and the associated interconnection to COTP. Bonneville's ownership includes the land on which the substation and the interconnection are located. Bonneville has connected the Captain Jack Substation to PacifiCorp's 500 kV system between Meridian Substation and Malin Substation where the COTP interconnects with the AC Intertie subject to the following terms, conditions and exceptions:

(1) Bonneville has constructed and owns terminal equipment, lines, and facilities required to interconnect the COTP with the Captain Jack Substation.

(2) Bonneville has constructed and owns the series and shunt compensation equipment and facilities located in the Captain Jack Substation required to connect to the COTP.

(3) PacifiCorp and Bonneville have shared equally in the cost of the bay 3 terminal equipment and facilities, which PacifiCorp owns, including the land on which such facilities are located, required to loop PacifiCorp's Malin-Meridian 500 kV line("Malin-Meridian Line") into the Captain Jack Substation.

(4) PacifiCorp, at its expense and subject to Prudent Utility Practice, may install transformation equipment at the Captain Jack Substation. PacifiCorp agrees to provide Bonneville the one-line diagram and plot plan for the installation of transformation equipment in a timely fashion for inclusion in Bonneville's Plan-of-Service. Subsequent changes in the one-line diagram or plot plan of transformation equipment are subject to mutual consent.

(c) Modification of Facilities.

(1) Except in regard to the Malin Substation, PacifiCorp agrees that it will make or permit Bonneville to make, at Bonneville's expense, any improvements or modifications of PacifiCorp's facilities in the Buckley-Alvey Loop that are required to accomplish Bonneville's Plan-of-Service. Unless otherwise mutually agreed, Bonneville shall own such improvements or modifications unless they cannot be removed without impairment or damage to PacifiCorp's facilities, in which case such modifications or improvements shall be jointly owned by Bonneville and PacifiCorp.

(2) AC Intertie Reactive Support. After joint studies have been completed and the Parties have mutually agreed that additional reactive support is required at the Malin Substation or Captain Jack Substation to support the AC Intertie, PacifiCorp shall be financially responsible for its share of the cost of such added reactive support.

(3) At such time as the Parties mutually agree, which agreement shall not be unreasonably withheld, that a second 500/230 kV transformer is required at the Malin Substation or a 500/230 kV transformer is required at the Captain Jack Substation, the Parties shall jointly develop the plan of service for such transformer(s). Each Party shall have the right to acquire up to a one-half ownership interest in such transformer(s) at a

pro-rata share of cost, provided that PacifiCorp's Load Carrying Capability is not impacted. If a Party does not participate in the ownership of such transformer(s) at the Malin or Captain Jack Substations at the time such transformer(s) are installed, such Party shall have the unilateral right to acquire up to a one-half ownership interest based on a pro-rata share of the original cost plus capital additions, if any, at a future date to the extent that capacity is available.

(4) Except as provided for in subsection 4(c)(1) herein, any improvements or modifications of the Buckley-Alvey Loop shall be by mutual consent, which consent shall not be unreasonably withheld. Except as provided for in subsections 4(c)(2) and 4(c)(3) above, installation of any equipment in the Malin Substation shall be made pursuant to the terms of the Malin Substation Construction Agreement.

(5) If Bonneville determines additions or modifications to the Alvey-Meridian Line are necessary to maintain the Rated Transfer Capability or Operational Transfer Capability of the AC Intertie at 4800 megawatts, Bonneville may, by written notice, cause PacifiCorp to add such equipment or make such modifications, and Bonneville and PacifiCorp shall share equally in the costs and ownership of such additions and modifications unless otherwise mutually agreed. PacifiCorp and Bonneville shall share equally in any Incremental Capacity resulting from such modifications.

5. Rights of Use.

(a) Determination of AC Intertie Rated Transfer Capability and Operational Transfer Capability. PacifiCorp agrees that Bonneville may determine the Rated Transfer Capability and Operational Transfer Capability of the AC Intertie, provided such determination is in keeping

with Prudent Utility Practice, and further provided it does not have the effect of reducing PacifiCorp's ability to serve up to its Load Carrying Capability as specified in this section 5.

(b) Bonneville's Right to Use of PacifiCorp's Malin-Meridian Line. PacifiCorp shall provide Bonneville, at no charge, sufficient capacity in the Malin-Meridian Line for Bonneville's AC Intertie transactions for itself or on behalf of other parties to enable Bonneville to operate the AC Intertie at its Rated Transfer Capability. To the extent modifications in the Malin-Meridian Line are required to effectuate this subsection 5(b), the cost of such modifications shall be borne equally by Bonneville and PacifiCorp. PacifiCorp shall operate and maintain the Malin-Meridian Line to maintain the Rated Transfer Capability on the AC Intertie in keeping with Prudent Utility Practice.

(c) Bonneville's Rights and Obligations for Intertie Service. PacifiCorp agrees that Bonneville has the right to operate the AC Intertie up to its Rated Transfer Capability or Operational Transfer Capability, subject to the following terms and conditions:

(1) Subject to section 4(c)(2) herein, Bonneville shall provide reactive support to maintain the Rated Transfer Capability of the AC Intertie.

(2) Bonneville shall provide transmission reinforcement to maintain the Rated Transfer Capability of the AC Intertie.

(3) Bonneville shall not rate or operate the AC Intertie in a manner that interferes with PacifiCorp's use of its Load Carrying Capability as described in subsections 5(d)(1), 5(d)(2), and 5(d)(3) below. However, Bonneville may make use of PacifiCorp's unused Load Carrying Capability for AC Intertie transactions for itself or on behalf of other parties at no additional charge, except as otherwise provided in this Amended and Restated AC Intertie Agreement.

(d) PacifiCorp's Rights and Obligations for Service to Load.

(1) Upon energization of the Alvey-Meridian Line, PacifiCorp shall have the right to serve PacifiCorp's Load Area and parallel paths, pursuant to section 10 herein, up to the Load Carrying Capability specified as follows:

(A) PacifiCorp shall have a Load Carrying Capability of 1875 megawatts.

(B) By the date when PacifiCorp's Load is expected to exceed the Load Carrying Capability recognized in subsection 5(d)(1)(A) herein, PacifiCorp shall provide additional facilities to supply power to its Load Area.

(2) The Load Carrying Capability specified in this subsection 5(d) may be correspondingly increased if new transmission facilities are constructed or if modifications are made to transmission facilities that increase the Load Carrying Capability. The effect of any such additions or modifications of transmission facilities on Load Carrying Capability shall be established by mutual agreement of the Parties using the results of joint planning studies conducted pursuant to subsection 5(d)(3) herein, and such mutual agreement shall not be unreasonably withheld.

(3) PacifiCorp's Load in its Load Area, and the date that such load is expected to exceed the Load Carrying Capability, shall be mutually determined by joint planning studies conducted annually, or as otherwise mutually agreed, by PacifiCorp and Bonneville in accordance with normal utility planning criteria. Such studies shall be based on mutually agreed to load forecasts for PacifiCorp's Load, as well as records of actual metered power flows on the then existing transmission lines serving the Load

Area. PacifiCorp and Bonneville shall furnish any data reasonably required for the joint planning study.

(4) PacifiCorp shall provide reactive support and internal transmission reinforcement for PacifiCorp's Load, including, but not limited to, 500/230 kV transformation, and 230 kV and below transmission reinforcement. To the extent PacifiCorp fails to provide such reinforcements, Bonneville shall not be obligated to reduce the Rated Transfer Capability or Operational Transfer Capability of the AC Intertie.

(5) Use of the Summer Lake Substation as a point of delivery by the Parties shall not impact PacifiCorp's Load Carrying Capability or Bonneville's usage of the AC Intertie.

(e) <u>PacifiCorp's Scheduling Rights for AC Intertie Rated Transfer Capability in Excess of 4000 Megawatts</u>. PacifiCorp's Southbound Scheduling Rights are 400 megawatts. PacifiCorp's Northbound Scheduling Rights shall equal 400 megawatts multiplied by a fraction whose numerator is the northbound Rated Transfer Capability of the AC Intertie and whose denominator is the southbound Rated Transfer Capability of the AC Intertie. PacifiCorp shall have the right to net its total northbound and southbound schedules under this Amended and Restated AC Intertie Agreement. PacifiCorp agrees to cooperate with Bonneville in its efforts, if any, to secure a northbound AC Intertie Rated Transfer Capability of 4800 megawatts. PacifiCorp's Northbound Scheduling Rights and Southbound Scheduling Rights shall be subject to the following terms and conditions:

(1) To preserve Bonneville's rights to use PacifiCorp's unused Scheduling Rights in a manner that allows third-party access to such rights in any hour, PacifiCorp

and Bonneville agree to the following provisions. PacifiCorp or any successive assignee may make its Scheduling Rights available on a firm basis to all parties under the provisions of PacifiCorp's open access transmission tariff; provided however, that neither PacifiCorp nor any successive assignee of PacifiCorp's Scheduling Rights may make such Scheduling Rights available for periods shorter than daily or on a nonfirm basis. To the extent that PacifiCorp or any successive assignee has unused Scheduling Rights available in any hour under this Amended and Restated AC Intertie Agreement as of the close of the normal preschedule deadline for firm point-to- point transmission service in accordance with Bonneville's standard scheduling practices, Bonneville shall add such unused Scheduling Rights to its available nonfirm transmission capacity for AC Intertie transactions, which shall be posted on Bonneville's Open Access Same-time Information System and made available pursuant to the provisions of Bonneville's open access transmission tariff. After such unused Scheduling Rights are added to Bonneville's available nonfirm transmission capacity, PacifiCorp or any successive assignee of the Scheduling Rights may modify preschedules up to 30 minutes prior to the hour for service to be provided pursuant to such preschedules for use of such firm transmission capacity (with such right available even if a preschedule had not been submitted, and in such case, PacifiCorp or any successive assignee shall be deemed to have submitted, with rights to modify, a 0 (zero) preschedule) and any such use shall have priority over any use or sale of unused Scheduling Rights by Bonneville. After 30 minutes prior to the hour for service to be provided pursuant to such preschedule, these unused Scheduling Rights shall be relinquished to Bonneville. There shall be no charge to Bonneville for unused Scheduling Rights.

(2) Except as mutually agreed to, any net southbound schedules by PacifiCorp in excess of Southbound Scheduling Rights available to PacifiCorp pursuant to this subsection 5(e) and the southbound scheduling rights available to PacifiCorp pursuant to transmission agreements entered into in accordance with the Letter of Understanding, including future Pacific Northwest AC Intertie Capacity Ownership Agreements, shall be deemed to be transmitted over the AC Intertie from John Day Substation, or any other AC Intertie delivery point subsequently established by Bonneville. Except as mutually agreed to, any net northbound schedules by PacifiCorp in excess of Northbound Scheduling Rights available to PacifiCorp pursuant to this subsection 5(e) and the northbound scheduling rights available to PacifiCorp pursuant to transmission agreements entered into in accordance with the Letter of Understanding, including future Pacific Northwest AC Intertie Capacity Ownership Agreements, shall be deemed to be transmitted over the AC Intertie to the John Day Substation, or any other AC Intertie delivery point subsequently established by Bonneville. Such excess schedules shall be subject to Bonneville's then effective Long-Term Intertie Access Policy, PacifiCorp's rights under other agreements, and the IS-93 Rate Schedule, or its successor, plus losses applicable to the AC Intertie. In the event that PacifiCorp's net northbound/southbound schedules exceed PacifiCorp's scheduling rights as described above, Bonneville shall provide transmission services to PacifiCorp pursuant to the same policies and rates that are generally applicable to Bonneville's other regional utility customers.

(3) If insufficient capacity exists in the combined capability of PacifiCorp's Midpoint-Malin 500 kV line ("Midpoint-Malin Line"), the Malin-Meridian Line, and the Alvey-Meridian Line for PacifiCorp to use its net Southbound Scheduling Rights

available to it, any increment above the combined capability of such facilities shall be deemed to be transmitted from the John Day Substation, or any other AC Intertie delivery point subsequently established by Bonneville, and shall be subject to the IS- 93 Rate Schedule, or its successor, plus losses applicable to the AC Intertie. Net Northbound Scheduling Rights shall be deemed to be delivered to PacifiCorp at Malin Substation or Captain Jack Substation. If insufficient capacity exists in the combined capability of PacifiCorp's Midpoint- Malin Line, the Malin-Meridian Line, and the Alvey-Meridian Line for PacifiCorp to integrate deliveries associated with its net Northbound Scheduling Rights available to it, any increment in excess of PacifiCorp's Load that can be served using the combined capability of PacifiCorp's facilities still in service shall be deemed to be transmitted from the Malin Substation to the John Day Substation, or any other AC Intertie delivery point subsequently established by Bonneville, and shall be subject to the IS-93 Rate Schedule, or its successor, plus losses applicable to the AC Intertie. Transmission service over the Federal Transmission System shall carry charges and losses as specified in the Midpoint-Meridian Transmission Agreement.

(4) During times when the southbound AC Intertie Operational Transfer Capability is less then the southbound AC Intertie Rated Transfer Capability, PacifiCorp's reduced net southbound scheduling rights at Malin Substation and Captain Jack Substation as described herein shall be an amount determined by multiplying the southbound Operational Transfer Capability of the AC Intertie by the ratio of 400 megawatts to the southbound Rated Transfer Capability of the AC Intertie. During times when the northbound AC Intertie Operational Transfer Capability is less then the northbound AC Intertie Rated Transfer Capability, PacifiCorp's reduced net northbound

scheduling rights shall be an amount determined by multiplying the northbound Operational Transfer Capability of the AC Intertie by the ratio of the Northbound Scheduling Rights to the northbound Rated Transfer Capability of the AC Intertie.

(f) Additional PacifiCorp Wheeling Rights. Until December 31, 2023, during Off-Peak Hours when PacifiCorp's northbound scheduling capability is less than 582 megawatts, Bonneville will provide PacifiCorp the right to utilize Bonneville's unused northbound capability on the AC Intertie and the DC Intertie at the IS-A Rate, or its successor rate, so as to provide PacifiCorp with a total northbound scheduling capability of 582 megawatts. For the purposes of this subsection 5 (f), PacifiCorp's northbound scheduling capability for any hour shall equal the sum during such hour of its Northbound Scheduling Rights hereunder and its northbound scheduling rights under the AC Intertie Transmission Agreement, Contract No. DE-MS79-94BP94285, including rights under Future Pacific Northwest AC Intertie Capacity Ownership Agreements. Bonneville's unused AC Intertie capability and DC Intertie capability shall be deemed to be capability not required to satisfy Bonneville's firm contractual commitments, as determined by Bonneville. PacifiCorp shall use best efforts to provide Bonneville advance notice of its desire to utilize its rights pursuant to this subsection 5(f). To the extent possible, such notice shall be provided at the time that PacifiCorp submits its preschedules to Bonneville pursuant to section 7 herein, provided, however, that PacifiCorp's failure to provide such notice with preschedules shall not diminish in any way, PacifiCorp's rights under this subsection 5(f).

(g) Remedial Action Schemes. PacifiCorp shall be responsible for providing or assuring, at its cost, the provision of its pro-rata share of remedial action schemes required to support the Rated Transfer Capability and Operational Transfer Capability of the AC Intertie either northbound or southbound. In support of its obligations to provide generator dropping for

its net southbound AC Intertie schedules, PacifiCorp shall provide generator dropping from its share of Mid-Columbia generation on line at the time of a remedial action scheme requirement. Bonneville may, after it has exhausted its own capability to provide generator dropping in support of its obligation for net southbound AC Intertie schedules, have access to PacifiCorp's total Mid-Columbia rights on line at the time of a remedial action scheme requirement at no cost. To the extent PacifiCorp does not have the capability on line to provide generator dropping from its Mid-Columbia rights for its net southbound AC Intertie schedules, Bonneville shall, to the extent it has available on line generation, provide generator dropping capability to PacifiCorp at no cost. In the event that PacifiCorp no longer has rights to Mid- Columbia generation, PacifiCorp's obligation to provide or assure, at its cost, the provision of its pro-rata share of remedial action schemes required to support the Rated Transfer Capability and the Operational Transfer Capability of the AC Intertie either northbound or southbound shall not be diminished. In support of PacifiCorp's net northbound AC Intertie schedules or its northbound DC Intertie schedules, PacifiCorp shall be responsible for making arrangements for any load dropping requirements. To the extent possible, as determined by Bonneville, Bonneville shall offer to sell remedial action scheme service to PacifiCorp to enable PacifiCorp to meet its obligations pursuant to this subsection 5(g).

(h) PacifiCorp shall provide Bonneville firm capacity in the existing 500/230 kV transformer at the Malin Substation at a use-of-facilities rate for Bonneville's firm requirements, <u>provided</u> such capacity will be made available to Bonneville only after PacifiCorp has determined that it has the capacity necessary to meet its own requirements and <u>provided</u> further, that Bonneville's right to use the existing Malin transformer shall be limited to 200 megawatts.

6. Upgrades of the AC Intertie Above Planned Rated Transfer Capability of 4800 Megawatts. After Bonneville has determined that the southbound or northbound AC Intertie Rated Transfer Capability is at least 4800 megawatts, but not more than 4900 megawatts, Bonneville and PacifiCorp agree that if any additions or changes to the Buckley-Alvey Loop or other jointly-owned facilities are required to increase the Rated Transfer Capability of the AC Intertie, such additions or changes shall be by mutual consent of the Parties hereto, which consent shall not be unreasonably withheld. Bonneville and PacifiCorp shall have the right, but not the obligation, to participate equally in such increase in the AC Intertie Rated Transfer Capability resulting from such additions or changes, and, if they do so, each shall share equally in the costs of such additions or changes to the Buckley-Alvey Loop or other jointly owned facilities required for such increases.

7. Scheduling.

(a) Bonneville and PacifiCorp shall schedule through the Bonneville Transmission Scheduling Office all schedules with southwest entities at the Malin and Captain Jack Substations.

(b) Upon Bonneville's request, PacifiCorp shall notify the Bonneville Transmission Scheduling Office each recognized workday of the planned schedules over PacifiCorp's parallel facilities, as described and limited in section 10 herein, for the following day or days. PacifiCorp shall also provide Bonneville's schedulers with all preschedule modifications prior to the hour of such schedules in accordance with Bonneville's standard scheduling practices.

8. Losses. The Parties shall be compensated for electric power losses pursuant to Calculation of Losses as shown in Exhibit E. Such compensation shall be based upon an equitable allocation of the Parties' control area losses associated with this Amended and Restated

AC Intertie Agreement and with the Midpoint-Meridian Transmission Agreement (Contract No. DE-MS79-94BP94333). The loss allocation specified in Exhibit E shall be reviewed at least every five years, but a review may be requested by either Party annually. The loss allocation shall be reviewed by the Parties to reflect any changes to the loss allocation.

9. Waivers. Except as specified in this Amended and Restated AC Intertie Agreement and the Letter of Understanding, PacifiCorp waives any claim to any ownership share or right to use the AC Intertie Rated Transfer Capability or to additional scheduling rights based on its ownership in:(1) existing facilities as such facilities may be modified or (2) the Alvey-Meridian Line.

10. Construction and Operation of Parallel Facilities.

(a) PacifiCorp's right to construct and right to operate existing and new interconnections with Pacific Gas & Electric Company or other utilities adjoining PacifiCorp's service territory in southern Oregon and northern California in parallel with the AC Intertie shall be subject to the following terms and conditions:

(1) The interconnection shall operate at 230 kV or below and shall include a phase shifter, unless the Parties mutually agree that a phase shifter is not required.

(2) On any given hour the sum of PacifiCorp's Load and the schedule on the parallel path shall not exceed the Load Carrying Capability.

(3) Except as provided in subsection 10(c) herein, PacifiCorp's total Rated Transfer Capability on such interconnections shall not exceed 400 megawatts. The total Rated Transfer Capability on such interconnections shall include the 100 megawatt Cottonwood Interconnection with Pacific Gas and Electric Company. The Operational

Transfer Capability on such interconnections shall never exceed the Rated Transfer Capability on such interconnections.

(4) PacifiCorp shall schedule as provided in subsection 7(b) herein. In no case shall such schedules exceed the Operational Transfer Capability of such interconnections.

(5) PacifiCorp shall make available to Bonneville telemetry of the actual power flow over PacifiCorp's parallel path interconnections.

(6) Construction or operation of such interconnections shall not reduce or adversely impact the Operational Transfer Capability of the AC Intertie. If Bonneville determines the operation of any such interconnection reduces or impacts the Operational Transfer Capability of the AC Intertie on any hour, and AC Intertie users have need of additional Operational Transfer Capability on the AC Intertie, upon Bonneville's request PacifiCorp shall reduce schedules to the extent needed to eliminate such impact. PacifiCorp shall not be required to reduce schedules on the parallel paths if the Operational Transfer Capability of the AC Intertie is reduced as a result of outages on the AC Intertie.

(b) Except as provided in subsection 10(c) herein, PacifiCorp shall not construct, participate in, or allow new interconnections for any 345 kV or above transmission lines or facilities from any point on PacifiCorp's system in Oregon to the existing two Malin-Round Mountain-Table Mountain 500 kV lines or the COTP north of Table Mountain.

(c) Notwithstanding the provisions of subsections 10(a)(3) and 10(b) herein, PacifiCorp may (i) construct and operate existing and new interconnections, as referenced in subsection 10(a)(3) herein with Rated Transfer Capability in excess of 400 megawatts, and/or (ii)

construct, participate in, and allow new interconnections as referenced in subsection 10(b) herein, if:

(1) such increase in Rated Transfer Capability or new interconnection is needed for PacifiCorp to meet good faith third-party requests for transmission service; and

(2) Bonneville has declined to provide, or lacks transmission facilities to provide, the requested transmission service; and

(3) such actions do not reduce the Rated Transfer Capability of the AC Intertie.

11. Wheeling from Palo Verde. For a period coincident with the term of PacifiCorp's March 23, 1993, Transmission Service Agreement ("TSA") with Southern California Edison Company ("SCE"), PacifiCorp, on hours that PacifiCorp does not require all or a portion of its transmission capacity rights pursuant to the TSA, shall offer Bonneville a first right of refusal to utilize such excess transmission rights under the TSA. PacifiCorp shall have sole discretion to determine whether it is making use of its TSA transmission rights. If Bonneville exercises its right to use PacifiCorp's TSA transmission rights, Bonneville shall reimburse PacifiCorp for SCE's charges to PacifiCorp for such usage. Such reimbursement shall be based upon PacifiCorp's then-effective transmission demand charges from SCE under the TSA which shall initially be $4.00 per megawatt-hour. If Bonneville exercises its first right of refusal to utilize PacifiCorp's excess TSA transmission rights, Bonneville shall use its own AC Intertie or DC Intertie scheduling capability to accept and transmit power and energy scheduled under this section 11. Additionally, the exercise of such access by Bonneville shall not preclude PacifiCorp

from utilizing its transmission rights acquired from Bonneville on the AC Intertie or the DC Intertie.

12. Summer Storage and Spring Energy Option

(a) Summer Storage. For a period of 20 years commencing with the effective date of the June 1994 AC Intertie Agreement, PacifiCorp shall accept and store energy for Bonneville during the months of June and July of each year.

(1) Prior to each storage month, Bonneville shall nominate their Bonneville Requested Storage, as shown in **Exhibit H** hereto. Bonneville will deliver the Bonneville Requested Storage Hourly Schedule to PacifiCorp system to system (BPAT.PACW) as described in Exhibit C to this Agreement.

(2) On any day that is not a Contingent Spill Protection Day, PacifiCorp may cut Bonneville's Requested Storage Hourly Schedule in any hour of any storage month up to the PacifiCorp Monthly Storage Schedule Cut Cap quantity for any reason, without financial compensation or other documentary support to Bonneville.

(3) On any day that is a Contingent Spill Protection Day, PacifiCorp will not cut Bonneville's Requested Storage Hourly Schedule for any hours of the Contingent Spill Protection Day.

(4) Energy to be stored pursuant to this subsection 12 (a) shall be delivered to PacifiCorp at the points of delivery specified in Exhibit C of the Short-Term Surplus Firm Capacity Sales Agreement (Contract No. DE-MS79-92BP93757), as amended or superseded, or such other points as may be mutually agreed to. PacifiCorp may, but shall not be required to, accept more than 100,000 megawatt-hours per month for storage and Bonneville shall deliver no less than 25,000 megawatt-hours per month for storage.

Bonneville shall deliver energy to PacifiCorp for storage prior to entering into the market to sell surplus energy. Unless otherwise mutually agreed, the hourly rate of delivery shall be determined by dividing the total energy to be stored in the month by the number of hours in such month. Except in times of system emergency, Bonneville shall adhere to the agreed-upon schedule of deliveries.

(5) PacifiCorp shall return stored energy to Bonneville during the months of September, October and November of each year in which energy was delivered to PacifiCorp. Unless otherwise mutually agreed, the hourly rate of return of the energy to Bonneville shall be determined by summing the total energy delivered to PacifiCorp during the prior June and July period, dividing such sum by three (3) and dividing the result by the number of hours in the month in which the energy is to be returned to Bonneville. Except during times of system emergency, PacifiCorp shall adhere to this hourly return schedule. Except when prevented by constraints on the Parties' transmission systems, including both operational and scheduling constraints, returned energy in any hour shall be delivered to Bonneville at the Hot Springs Substation, at an amount not to exceed 110 MW unless otherwise mutually agreed to, Summer Lake Substation or other mutually-agreed upon points of delivery. Storage provided pursuant to this subsection 12(a) shall be at no charge to Bonneville.

(6) If PacifiCorp exceeds its Monthly Storage Schedule Cut Cap for a given storage month, and Bonneville has not declared a Spill Protection Day and operational constraints dictate further storage cuts, then PacifiCorp can cut Bonneville Requested Storage Hourly Schedule but will pay Bonneville the PacifiCorp Storage Cut LD.

(7) If Bonneville has met its Monthly Spill Protection Day Cap for a given

storage month, and environmental constraints dictate further Spill Protection Day(s), then Bonneville can provide notice for additional Contingent Spill Protection Day(s) and PacifiCorp will accept and store such Bonneville Requested Storage Hourly Schedules, but Bonneville will pay PacifiCorp the Bonneville Spill Protection Day LD for Bonneville Requested Storage Hourly Schedules for any Contingent Spill Protection Days in excess of the Bonneville Monthly Spill Protection Day Cap and for any Contingent Spill Protection Day that does not meet all the Spill Protection Day criteria in 27(gg).

(8) PacifiCorp will pay any accumulated PacifiCorp Storage Cut LD, and Bonneville will pay any accumulated Bonneville Spill Protection Day LD, due in any storage year by December 20th of such storage year, and any such payment shall be made in accordance with payment terms set forth in the current General Rate Provisions dated October 1, 2009.

(b) Spring Energy Option. For a period of 20 years following the effective date of the June 1994 AC Intertie Agreement, if requested by Bonneville, PacifiCorp shall deliver to Bonneville during Off- Peak Hours, at the Hot Springs Substation, or other mutually-agreed points of delivery, up to 50,000 megawatt-hours during the month of March of each such year. The maximum rate of delivery for such energy shall be 200 megawatts per hour. To exercise its option to take such energy, Bonneville shall notify PacifiCorp by February 15 of each year as to the amount of energy Bonneville desires to have delivered during the following March. Except in times of system emergency, PacifiCorp shall deliver such energy in accordance with Bonneville's request, subject to the limitations of this subsection 12(b). Bonneville shall return the energy delivered by PacifiCorp during the following June 1 through July 15 period during

Off-Peak hours at an hourly rate of delivery determined by dividing the amount of energy delivered by PacifiCorp during the previous March by the number of Off-Peak Hours in the June 1 through July 15 period or such other hourly rate of delivery as mutually agreed to. Such March Energy shall be returned to PacifiCorp at points of delivery as specified in Exhibit C of Contract No. DE-MS79-92BP93757 or such other points of delivery as are mutually agreed.

13. Sale or Assignment.

(a) This Amended and Restated AC Intertie Agreement shall inure to the benefit of, and shall be binding upon, the respective successors and assigns of the Parties to this Amended and Restated AC Intertie Agreement.

(b) PacifiCorp and Bonneville agree not to sell, assign, lease, sublease, or otherwise transfer this Amended and Restated AC Intertie Agreement or any interest therein, without the written consent of the other Party, such consent not to be unreasonably withheld. PacifiCorp and Bonneville also agree not to sell, assign, lease, sublease, or otherwise transfer any direct or indirect interest in the Malin Substation, the portion of the Midpoint-Malin Line between Summer Lake Substation and Malin Substation ("Summer Lake-Malin Line"), the Malin-Meridian Line, or the Alvey-Meridian Line, without the written consent of the other Party, such consent not to be unreasonably withheld, provided, however, that PacifiCorp's interest in such facilities may be conveyed to its respective trustees as security under a mortgage or deed of trust to secure indebtedness without such written consent, provided that each such trustee may act with respect to such interest only to the extent and in the manner that such act would have been authorized under this Amended and Restated AC Intertie Agreement.

(c) If Bonneville or PacifiCorp is acquired in total by other entities, subsection 13(b) shall not apply to such acquisition.

14. Extension of Existing Agreements. The Parties agree that the termination dates of the Midpoint-Meridian Transmission Agreement, the Malin Substation Construction Agreement and all agreements related to joint ownership or interconnection on the Buckley-Alvey Loop, including but not limited to arrangements for the operation and maintenance of new facilities, shall be coincident with the termination date of this Amended and Restated AC Intertie Agreement. The Payment Agreement and the Option Agreement are attached hereto as Exhibits A and D respectively and made a part of this Amended and Restated AC Intertie Agreement. The Payment Agreement and the Option Agreement provide for, among other things, certain construction, payment, ownership, operation and maintenance activities in progress at the time of execution of this Amended and Restated AC Intertie Agreement. As these activities are completed or superseded by future agreements, PacifiCorp and Bonneville may agree to terminate some or all of the Payment Agreement and the Option Agreement provisions. To the extent any provisions of the Payment Agreement or the Option Agreement are in conflict with this Amended and Restated AC Intertie Agreement, the terms and conditions of this Amended and Restated AC Intertie Agreement shall prevail.

15. Termination of Agreement. The Parties agree that this Amended and Restated AC Intertie Agreement consistent with the 1994 AC Intertie Agreement supersedes and terminates in its entirety, the July 1986 Intertie Agreement, Contract No. DEMS79-86BP92299, provided, however, that any liabilities incurred thereunder are hereby preserved until satisfied.

16. Execution of Other Agreements. The Parties agree to negotiate in good faith and execute construction agreements, operation and maintenance agreements, transmission agreements, and other such agreements that may be required to implement the provisions of this Amended and Restated AC Intertie Agreement.

17. Arbitration. In the event of any dispute related to rights or obligations of the Parties, or satisfaction thereof, under this Amended and Restated AC Intertie Agreement, including but not limited to the amount or reasonableness of costs, identification of exclusive use facilities, extent of amortization of past costs, and the reasonableness of withholding consent, either Party may elect to submit such dispute to nonbinding arbitration. If one Party so elects, such Party shall notify the other Party in writing and both Parties shall participate pursuant to the following:

(a) If the Parties cannot agree on an arbiter within 30 days of such notification, the notifying Party shall request the American Arbitration Association to designate an arbiter with sufficient expertise in the subject under dispute.

(b) After an arbiter is agreed to or designated, the arbiter shall establish a schedule for submission of the Parties' written positions. The Party electing the arbitration shall first state its position in a letter to the arbiter. The second Party shall then state its position in a letter to the arbiter. The first Party may then submit a response to the Second Party's position and the second Party may thereafter submit a reply to the first Party's response.

(c) Each letter submitted to the arbiter shall be no more than 5 pages in length, unless the Parties otherwise mutually agree. The Parties may attach exhibits that they consider relevant to the dispute. A copy of each submission also shall be simultaneously served on the other Party.

(d) The arbiter shall provide the Parties with a written analysis of the dispute, and his or her proposed resolution of the dispute.

(e) The Parties shall equally share the fee and other costs of the arbiter.

In the event neither Party submits the dispute to nonbinding arbitration or if either Party elects not to accept the finding of the arbiter, the Parties may elect other approaches, including litigation, to resolve the dispute.

18. Rules of Law.

(a) The Parties agree that each fully participated in the drafting of each provision of this Amended and Restated AC Intertie Agreement. The rule of law interpreting ambiguities against the drafting Party shall not be applicable to or utilized in resolving any dispute over the meaning or intent of this Amended and Restated AC Intertie Agreement or any of its provisions.

(b) The construction and interpretation of this Amended and Restated AC Intertie Agreement shall be governed solely by Federal law.

(c) This Amended and Restated AC Intertie Agreement shall not be construed to establish a partnership, association, joint venture, or trust. Neither Party shall be under the control of or shall be the agent of or have a right or power to bind the other Party without the other Party's express written consent, except as provided in this Amended and Restated AC Intertie Agreement.

19. Delay of Performance. The time for each act specified in this Amended and Restated AC Intertie Agreement shall be extended for a time equivalent to such delays, if any, as are occasioned by events which the Party hereto obligated to perform such act could not be reasonably expected to avoid by the exercise of reasonable diligence and foresight.

20. Regulatory Jurisdiction. The provisions of this Amended and Restated AC Intertie Agreement are subject to such regulatory agencies having jurisdiction thereof. Nothing contained herein shall be construed as affecting in any way the right of PacifiCorp to make application unilaterally to the Federal Energy Regulatory Commission for a change in rates,

charges, classification, or service, or any rule or regulation, or contract relating thereto, under Section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder.

21. Severability and Breach.

(a) It is the intention of the Parties that the provisions of this Amended and Restated AC Intertie Agreement be severable in the event that any of such provisions, or portions thereof, are held to be illegal, invalid or unenforceable by a court of competent jurisdiction; provided that if section 10 herein, or any portion thereof, is found to be illegal, invalid or unenforceable by a court of competent jurisdiction, Bonneville shall have firm transmission rights to 50 percent of the total Rated Transfer Capability of any parallel interconnections other than the 100 megawatt Cottonwood Interconnection between PacifiCorp and Pacific Gas & Electric or other utilities adjoining PacifiCorp's territory in southern Oregon and northern California. In any legal proceeding, Bonneville and PacifiCorp shall act in good faith to defend the enforceability of all provisions of this Amended and Restated AC Intertie Agreement.

(b) The Parties agree that breach of this Amended and Restated AC Intertie Agreement, or any of its provisions, will cause irreparable harm and that the appropriate remedy is injunctive relief.

22. Capital Budgets. Excluding any facilities designated for omission by footnote 1 of Exhibit B of this Amended and Restated AC Intertie Agreement, each Party by July 1 of each year shall send a notice to the other Party containing (i) an estimate of the capital budget amounts related to the planned construction activities of the facilities described in such Exhibit B such Party expects to incur four (4) years in the future, and (ii) an update of any capital budget amounts it expects to incur within the upcoming three (3) years. Except for emergency Capital

Replacements or emergency Capital Additions, the Parties shall exchange and review any necessary data as needed to determine the necessity and adequacy of the proposed construction and operation activities.

23. Payment Provisions.

(a) For reimbursable Capital Replacements or Capital Additions, the Party proposing the action shall prepare a proposed revision to Exhibit F whenever the Parties concur that it is necessary to add to or to replace the facilities identified in Exhibit B of this Amended and Restated AC Intertie Agreement. The Parties shall share the costs of such action according to the original cost share percentage of such facilities as set forth in Exhibit B in a manner consistent with the cost sharing methodologies contained in such exhibit, except that the replacement of facilities identified by footnote 1 of Exhibit B shall not be eligible for cost-sharing. Each revision of Exhibit F shall specify the facilities added or replaced.

(b) The Party responsible to make payment shall pay according to the provisions of the revision of Exhibit F for the work performed in amounts and at times as negotiated by the Parties.

(c) In the event of a dispute regarding billing, the Party owing the bill shall pay the amount in full and provide written notification of the disputed amount. Any adjustment shall be made on the next invoice allowing reasonable notice and time to make the adjustment. Refunds of the disputed amount shall include interest at the same interest rate specified in section 23(d).

(d) Invoices not paid in full on or before the close of business on the date due shall be subject to an interest charge on the amount due from the due date to the date paid consistent with the Prompt Payment Act Renegotiation Board's Interest Rate published in the Federal Register.

24. Audit Rights.

(a) Each Party, at its expense, may review and audit any cost on the other Party's books, records, and documents that directly pertain to the billings on the jointly owned facilities. The Party undertaking the audit shall provide reasonable notice to the other Party and shall conduct such audit at reasonable times and in conformance with generally accepted auditing standards. The Party being audited shall cooperate fully with any such audit. Neither Party shall audit a cost incurred more than three (3) years following the last day of the fiscal year in which such cost was incurred under Section 23 to this Amended and Restated AC Intertie Agreement. The Parties shall retain all records and documentation prepared in the normal course of business for the entire length of this audit period and in accordance with generally accepted accounting principles.

(b) After completion of the audit, the Party conducting the audit shall promptly notify the other Party of any exception taken as a result of an audit, and the audited Party may review the notice of exception and basis therefore for a period of thirty (30) days. Upon agreement regarding the validity of any exception, the owing Party shall directly refund the amount of the exception within thirty (30) days of such agreement.

25. Ownership of the Facilities.

(a) Transfer of legal ownership pursuant to Sections 22 and 23 to this Amended and Restated AC Intertie Agreement shall be effective at such time as the facilities are energized and made available for commercial operation as part of this Amended and Restated AC Intertie Agreement.

(b) All jointly-owned equipment and facilities shall be identified as such with co-ownership tags and signs. Each Party shall provide the tags and signs for equipment which it operates. Costs for such tags and signs shall be shared equally by each Party.

26. Integration.

(a) To the extent that Exhibit A of this Amended and Restated AC Intertie Agreement is inconsistent with provisions of Sections 22, 23 and 25 to this Amended and Restated AC Intertie Agreement, such Exhibit A is superseded by the provisions of this Amended and Restated AC Intertie Agreement.

(b) Any revisions to Exhibit F shall be attached to and deemed to be a part of this Amended and Restated AC Intertie Agreement and shall be effective on the date specified therein.

27. Definitions.

(a) AC Intertie. For the purposes of this Amended and Restated AC Intertie Agreement, the AC Intertie means Bonneville's rights in the alternating current ("AC") transmission facilities for transferring power and energy between Oregon and California as follows: two 500 kV lines extending from John Day Substation to Malin Substation and to the California-Oregon Border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's share of ownership of the Alvey-Dixonville and Dixonville-Meridian 500 kV transmission lines; portions of the Alvey, Dixonville, Meridian and Captain Jack Substations; the 500 kV transmission line extending from Captain Jack Substation to the California- Oregon Border; and any modifications, improvements, or additions to such facilities.

(b) Alvey-Meridian Line. The 500 kV transmission line facilities and substations constructed by PacifiCorp that extend from the interconnection with Bonneville's system at Alvey Substation to PacifiCorp's Meridian Substation.

(c) Bonneville Monthly Spill Protection Day Cap. Eight (8) Spill Protection Days in any storage month, without any carryover to the next month or year.

(d) Bonneville Requested Storage. The monthly energy Bonneville requests PacifiCorp to store as exercised under Section 12(a), hereof, as defined and confirmed in a nomination letter Exhibit H.

(e) Bonneville Requested Storage Hourly Schedule. The Bonneville Requested Storage (MWh/mn) for a storage month divided by the total hours (hours/mn) in the storage month and shall be the hourly flat schedule of Bonneville Requested Storage for all hours in the storage month

(f) Bonneville Spill Protection Day LD. The sum of the product of the Bonneville Requested Storage Hourly Schedules and the market price spread of the Powerdex Mid-Columbia Average Hourly Index price for all hours of the Spill Protection Day and the hourly weighted average of the settled ICE North American Power Day-Ahead Power Index Mid-Columbia price, for Peak and Off-Peak, from September through November of the storage cut year. (Example calculation found in Exhibit L).

(g) Bonneville Transmission Scheduling Office. The group of schedulers presently located at Bonneville's Dittmer Control Center in Vancouver, Washington, appointed by Bonneville, Portland General Electric Company and PacifiCorp and designated to coordinate the schedule of energy over the AC Intertie and the DC Intertie.

(h) Buckley-Alvey Loop. The 500 kV transmission lines, facilities, and substations from Buckley Substation south to Summer Lake Substation, continuing south to Malin Substation, west to Meridian Substation, including the Captain Jack Substation, and the Alvey-Meridian Line.

(i) California Intertie. The two existing 500 kV AC lines extending northward from within California at Round Mountain Substation and terminating at Malin Substation.

(j) Capital Additions. The addition of any new facilities under this Amended and Restated AC Intertie Agreement (e.g., not replacements for assets already listed on Exhibit B) that are required to serve the common good of both Parties.

(k) Capital Replacements. The replacement asset for the facilities listed in Exhibit B of this Amended and Restated AC Intertie Agreement that is required to serve the common good of both Parties.

(l) Captain Jack Substation. The substation where COTP interconnects with the AC Intertie in the Pacific Northwest.

(m) COTP. The 500 kV California-Oregon Transmission Project, which operates in parallel with the California Intertie and terminates at the California-Oregon Border.

(n) DC Intertie. For the purposes of this Amended and Restated AC Intertie Agreement, the DC Intertie means Bonneville's rights in the existing 1,000 kV direct current ("DC') transmission line, and associated substation facilities, extending from the Bonneville's Big Eddy Substation to the Nevada-Oregon Border.

(o) Federal Transmission System. The transmission facilities owned by Bonneville.

(p) Future Pacific Northwest AC Intertie Capacity Ownership Agreements. Agreements entered into by Bonneville and regional utilities providing for those utilities' ownership of AC Intertie capacity available as a result of increasing the Rated Transfer Capability of the AC Intertie to 4800 megawatts.

(q) Incremental Capacity. For the purpose of this Amended and Restated AC Intertie Agreement, Incremental Capacity means capacity realized through the construction of the Alvey-Meridian Line in excess of the capacity on the previously existing 230 kV Alvey-Meridian line that was removed as a result of construction of the Alvey-Meridian Line.

(r) IS-A Rate. The Nonfirm Transmission Rate specified in Section II.A. of Bonneville's Southern Intertie Transmission Schedule IS-93, or its successor.

(s) [Reserved]

(t) Load Area. The geographic area encompassing portions of southern Oregon and northern California which is generally south of Eugene, Oregon and Bonneville's Summer Lake Substation and west of Burns, Oregon. Such geographic area shall be limited to:

(1) That area in which PacifiCorp is authorized to provide retail electric service, now and in the future; and

(2) That area in which PacifiCorp provides wholesale electric service at the date of execution of the June 1994 AC Intertie Agreement; provided that such areas are normally within PacifiCorp's load control area, connected to PacifiCorp's transmission system, and served by the transmission lines in Exhibit C.

Revisions to the Load Area shall be by mutual agreement of the Parties, and such agreement shall not be unreasonably withheld.

(u) Load Carrying Capability. The capability of PacifiCorp's transmission system, as specified in Exhibit C, serving the Load Area and parallel paths as limited by section 10 herein to provide firm transmission service in accordance with Prudent Utility Practice.

(v) Northbound Scheduling Rights. PacifiCorp's right to schedule power and energy through the Malin Substation and the Captain Jack Substation in a northerly direction from the 500 kV lines which extend to California and interconnect with the California Intertie and the COTP as provided in this Amended and Restated AC Intertie Agreement.

(w) Off-Peak Hours. The first six and last two hours of each day Monday through Saturday and all day Sunday or other hours as mutually agreed to.

(x) Operational Transfer Capability. Rated Transfer Capability less reductions caused by, but not limited to, physical limitations beyond the control of the Parties, operational limitations imposed by California utilities, line or equipment outages, stability limits or loop flow.

(y) PacifiCorp's Load. PacifiCorp's net firm load obligations within the Load Area excluding Bonneville's Surprise Valley Electric Cooperative Load transferred by PacifiCorp pursuant to the General Transfer Agreement, Contract No. DEMS79-82BP90049.

(z) PacifiCorp Monthly Storage Schedule Cut Cap. Sixteen (16) percent of the Bonneville Requested Storage in any storage month. The quantity of energy is defined as Bonneville Requested Storage quantity (MWh/mn) multiplied by PacifiCorp Monthly Storage Schedule Cut Cap (16%) without any carryover to the next month or year.

(aa) PacifiCorp Storage Cut LD. The product of any storage cuts in excess of PacifiCorp's Monthly Storage Schedule Cut Cap, multiplied by the market price spread of Powerdex Mid-Columbia Average Hourly Index price at the time of cut and the hourly weighted average of the settled ICE North American Power Day-Ahead Power Index Mid-Columbia price, for Peak and Off-Peak, from September through November of the storage cut year. (Example found in Exhibit M)..

(bb) Plan-of-Service. The project plans that Bonneville develops to realize an increase of the AC Intertie Rated Transfer Capability up to approximately 4800 megawatts, which shall include but are not necessarily limited plans, schedules, costs, and facility and equipment requirements.

(cc) Prudent Utility Practice. At any particular time, the generally accepted practices, methods, and acts in the electrical utility industry prior thereto or the practices, methods or acts, which, in the exercise of reasonable judgment in the light of the facts known at the time the decision was made, could have been expected to accomplish the desired result consistent with reliability and safety.

(dd) Rated Transfer Capability. The ability of a transmission line or system to transfer power in a reliable manner as determined in accordance with Prudent Utility Practice.

(ee) Southbound Scheduling Rights. PacifiCorp's right to schedule power and energy through the Malin Substation and the Captain Jack Substation in a southerly direction to the 500 kV lines which extend to California and interconnect with the California Intertie and the COTP as provided in this Amended and Restated AC Intertie Agreement.

(ff) Spill Conditions. Individual calendar days with one or more hours in that day flagged to indicate that Bonneville has declared spill conditions. The hourly spill condition declarations are provided by Bonneville via public internet posting at: http://www.transmission.bpa.gov/Business/Operations/Misc/ , then click on: Hourly Spill Flag, Last Two Years & Day-Ahead Forecast (updated daily at 11:00 AM, Pacific Time). Flags are found in the column titled "Actual" (Sample displayed in Exhibit K).

(gg) Spill Protection Day. Any day(s) in which all of the following occur:

(1) Bonneville has been in Spill Conditions for two (2) consecutive

days prior to when the Spill Protection Day begins (it being understood that such two day period could occur in May for the beginning of the June storage month and/or in June for the beginning of the July storage month); and

(2) Bonneville is in Spill Conditions, as defined herein, for any hour in a declared Spill Protection Day; and

(3) Bonneville has specifically notified PacifiCorp it is declaring a period of Spill Protection Day(s), and that notification will be delivered no later than 10:00 am on the pre-schedule day for the Spill Protection Day, via sending an email to PacifiCorp at ctpreschd@pacificorp.com, an example of which is shown in Exhibit I hereto.

In each case, Spill Protection Day(s) will be for 24 hours and begin at HE0100 and end HE2400 as outlined in Bonneville notice (Exhibit I) and are day(s) in which Bonneville's Requested Storage Hourly Schedule cannot be cut by PacifiCorp. Bonneville will declare Spill Protection Days when a reduction in generation would cause a potential violation of Bonneville's total dissolved gas limits at the relevant hydroelectric projects, and a potential violation of relevant environmental statutes and regulations.

(hh) Contingent Spill Protection Day. Any day that has been noticed and scheduled by Bonneville as a Spill Protection Day, but that has not yet met all the conditions as described in section 27(gg) above. A Contingent Spill Protection Day will result in either:

(1) a Contingent Spill Protection Day that ultimately meets all of the Spill Protection Day criteria in 27(gg) above and is within Bonneville's eight (8) allowed days; or

(2) a Contingent Spill Protection Day that ultimately meets all of the Spill Protection Day criteria in 27(gg) above, but exceeds Bonneville's eight (8) allowed days (in which case Bonneville Spill Protection Day LDs apply); or

(3) a Contingent Spill Protection Day that ultimately fails to meet all the Spill Protection Day criteria in 27(gg) above (in which case, Bonneville Spill Protection Day LDs apply).

When Bonneville specifically notifies PacifiCorp it is declaring a Contingent Spill Protection Day(s), that notification will be delivered no later than 10:00 am on the pre-schedule day for the Spill Protection Day, via email to PacifiCorp at ctpreschd@pacificorp.com, an example of which is shown in Exhibit I hereto. PacifiCorp will provide notice to Bonneville by the 10th of the month following a storage month as to the number of Contingent Spill Protection Days that a) fall within Bonneville Monthly Spill Protection Day Cap and/or b) exceed Bonneville Monthly Spill Protection Day Cap and/or c) did not meet the Spill Protection Day criteria in 27(gg), via e-mail as described in Exhibit J.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement.

UNITED STATES OF AMERICA

Department of Energy

Bonneville Power Administration

By: Suzanne B Cooper

Date: 8/2/2011

PACIFICORP

By: K Houston

Date: Aug. 2, 2011

[NEW EXHIBITS]

Exhibit H
[Example of Bonneville Summer Storage nomination letter, on Bonneville letterhead, to PacifiCorp]

Supervisor, Contract Administration
PacifiCorp
825 NE. Multnomah, Suite 600
Portland, OR 97232

RE: Contract No. DE-MS79-94BP94332, Summer Energy Option

Dear Sirs:

This letter serves as notification from the Bonneville Power Administration (Bonneville) to PacifiCorp (PAC) that Bonneville chooses to exercise Section 12(a), Summer Storage, of our AC Intertie Agreement, Contract No. DE-MS79-94BP94332, by requesting PacifiCorp to store___________ [between 25,000 and 100,000] megawatt-hours (MWh) of energy in the month of ___________[June or July] ("Bonneville Requested Storage"). Bonneville shall deliver to PAC approximately______ [134] MWhs of energy flat over all hours for the month of [June or July ("Bonneville Requested Storage Hourly Schedule")].

Bonneville requests that PacifiCorp shall return storage energy to Bonneville through a system-to-system return schedule (BPAT.PACW). Bonneville is planning on these energy returns being prescheduled.

As set forth in the [Amended and Restated AC Intertie Agreement], and as such terms are defined therein, Bonneville may request **Spill Protection Day(s)** up to the **Bonneville Monthly Spill Protection Day Cap,** which is eight (8) total days per storage month.

Similarly, for those days Bonneville has not requested **Contingent Spill Protection Day(s)**, PacifiCorp may reject such Bonneville Requested Storage Hourly Schedule up to the **PacifiCorp Monthly Storage Schedule Cut Cap**, which for the storage month described in this letter equals 16 % of the Bonneville Requested Storage, or ______ MWh.
For any further discussions regarding this notice, please contact me at (503) 230-4003.

Sincerely,

Mark E. Miller
Account Executive

Cc: Bonneville Contracts Administration

Exhibit I
[Example of Contingent Spill Protection Day e-mail to PacifiCorp]

Subject: Contingent Spill Protection Day

This email serves as notification from the Bonneville Power Administration (Bonneville) to PacifiCorp (PAC) that Bonneville notices is a Contingent Spill Protection Day as described in Section 12(a), Summer Storage, of the Amended and Restated AC Intertie Agreement, Contract No. DE-MS79-94BP94332.

Period begins: **Hour Ending [0100, June 1, 2011]**
Period ends: **Hour Ending [2400, June 4, 2011]**

The Bonneville Monthly Spill Protection Day Cap is defined as eight (8) Spill Protection Days in this storage month. As described in this notice, Bonneville hereby declares __ Spill Protection Days in the month of June, for a total of ___ Spill Protection Days to date.

Bonneville will be in a Spill Condition for a period of 2 days prior to when this period of Spill Protection Day(s) begin.

PacifiCorp, please confirm this e-mail by a return e-mail acknowledgment to:
ajspain@bpa.gov
memiller@bpa.gov

For any further discussions regarding this notice, please contact me at (503) 230-4003, Alex Spain at (503) 230-5780.

Exhibit J
[Example of PacifiCorp Contingent Spill Protection Day criteria validation e-mail to Bonneville]

Subject: Contingent Spill Protection Day Criteria Validation
To: Mark Miller
Alex Spain

This email serves as notification from PacifiCorp (PAC) to Bonneville Power Administration (Bonneville) as to which Contingent Spill Condition Day(s) for the month of ____, 2011 trigger Bonneville Spill Protection Day LD(s).

Contingent Spill Protection Day that meet criteria in Section 27(gg) and fall within Bonneville Monthly Spill Protection Day Cap of 8 days

Date
Date
Date
Date

Contingent Spill Protection Day that meet criteria in Section 27(gg) and exceed Bonneville Monthly Spill Protection Day Cap of 8 days (Bonneville Spill Protection Day LD will apply)

Date
Date

Contingent Spill Protection Day that failed to meet criteria in Section 27(gg) (Bonneville Spill Protection Day LD will apply)

Date
date

PacifiCorp, please confirm this e-mail by a return e-mail acknowledgment to:
Jim.schroeder@pacificorp.com
Stacey.kusters@pacificorp.com
Mark.smith@pacificorp.com

For any further discussions regarding this notice, please contact Mark Smith at (503) 813-5393.

Exhibit K
Sample of Bonneville Spill Conditions website posting found at www.transmission.bpa.gov/Business/Operations/Misc/

HOURLY SPILL CONDITIONS
From 07/05/09 through 07/08/11 (illustratively shown 6/1/2011)

- This posting is provided as information to users of BPA's Energy Imbalance and Generation Imbalance services.
- Spill Conditions, for the purpose of determining credit or payment for Deviations under the EI and GI rates, exist when spill physically occurs on the BPA system due to lack of load or market. Spill due to lack of load or market typically occurs during periods of high flows or flood control implementation, but can also occur at other times. Discretionary spill, where BPA may choose whether to spill, does not constitute a Spill Condition. Spill for fish is included in discretionary spill and is not a Spill Condition.
- Account 501935 (Actual System Spill, After-The-Fact): A "1" indicates Spill conditions were declared for that hour. A "0" indicates No Spill was declared for that hour.
- Account 501936 (Forecasted System Spill, Before-The-Fact) : not utilized by BPA - will not be used for that hour. A "0" indicates No Spill is projected to occur for that hour.
- BPA will continue to use the Actual Spill conditions posted after-the-fact (Account 501935) for billing purposes.
- This file is updated daily at 11:00 AM, Pacific Time
- Source of Spill Flag: BPA Power Services
- Source of this Posting: BPA Transmission Services 05Jul2011 11:00
- For further information, please contact Harry Speropulos, Transmission Transaction Analysis & Reconciliation, at 360-418-8670.

Date	Time	# 501935 Actual	# 501936 Forecast
6/1/2011	1:00	1	
6/1/2011	2:00	1	
6/1/2011	3:00	1	
6/1/2011	4:00	1	
6/1/2011	5:00	1	
6/1/2011	6:00	1	
6/1/2011	7:00	0	
6/1/2011	8:00	0	
6/1/2011	9:00	0	
6/1/2011	10:00	0	
6/1/2011	11:00	0	
6/1/2011	12:00	0	
6/1/2011	13:00	0	
6/1/2011	14:00	0	
6/1/2011	15:00	0	
6/1/2011	16:00	0	
6/1/2011	17:00	0	
6/1/2011	18:00	0	
6/1/2011	19:00	0	
6/1/2011	20:00	1	
6/1/2011	21:00	1	
6/1/2011	22:00	1	
6/1/2011	23:00	1	
6/1/2011	24:00:00	1	

Exhibit L
Sample of Bonneville Spill Protection Day LD

Bonneville Spill Protection Day Cap LD

Bonneville declared a Contingent Spill Condition Day in excess of their cap of 8 days or declared a Spill Protection Day that failed to meet the Spill Protection Day criteria in 27(gg).

Date	Time	Bonneville Requested Storage Hourly Schedule	Powerdex Mid-Columbia Average Hourly Index Price	Hourly weighted average of daily ICE Day-Ahead Power Index for Mid-Columbia for Peak and Off-Peak from September - November 2011	Bonneville Spill Protection Day hourly Cap LD
	HE	MWh/hr	$/MWh	$/MWh	$/day
6/26/2010	100	139	$ (12.67)	$ 32.23	$ 6,241.07
6/26/2010	200	139	$ (2.58)	$ 32.23	$ 4,838.56
6/26/2010	300	139	$ (0.41)	$ 32.23	$ 4,536.93
6/26/2010	400	139	$ (2.95)	$ 32.23	$ 4,889.99
6/26/2010	500	139	$ (0.74)	$ 32.23	$ 4,582.80
6/26/2010	600	139	$ (0.08)	$ 32.23	$ 4,491.06
6/26/2010	700	139	$ (4.10)	$ 32.23	$ 5,049.84
6/26/2010	800	139	$ (2.12)	$ 32.23	$ 4,774.62
6/26/2010	900	139	$ 1.11	$ 32.23	$ 4,325.65
6/26/2010	1000	139	$ 0.50	$ 32.23	$ 4,410.44
6/26/2010	1100	139	$ (3.92)	$ 32.23	$ 5,024.82
6/26/2010	1200	139	$ (3.56)	$ 32.23	$ 4,974.78
6/26/2010	1300	139	$ (1.46)	$ 32.23	$ 4,682.88
6/26/2010	1400	139	$ (0.19)	$ 32.23	$ 4,506.35
6/26/2010	1500	139	$ (0.58)	$ 32.23	$ 4,560.56
6/26/2010	1600	139	$ 0.05	$ 32.23	$ 4,472.99
6/26/2010	1700	139	$ (0.40)	$ 32.23	$ 4,535.54
6/26/2010	1800	139	$ 0.07	$ 32.23	$ 4,470.21
6/26/2010	1900	139	$ (0.19)	$ 32.23	$ 4,506.35
6/26/2010	2000	139	$ 0.34	$ 32.23	$ 4,432.68
6/26/2010	2100	139	$ (0.08)	$ 32.23	$ 4,491.06
6/26/2010	2200	139	$ (4.15)	$ 32.23	$ 5,056.79
6/26/2010	2300	139	$ (2.25)	$ 32.23	$ 4,792.69
6/26/2010	2400	139	$ (0.70)	$ 32.23	$ 4,577.24
				Bonneville Spill Protection Day LD:	$ 113,226.01

Exhibit M
Sample of PacifiCorp Storage Cut LD

PacifiCorp exceeded their Monthly Storage Schedule Cut Cap in HE0400

Date	Time	Bonneville Requested Storage Hourly Schedule	PacifiCorp Storage Schedule Cut	PacifiCorp Storage Schedule Cut in excess of Cap	Powerdex Mid-Columbia Average Hourly Index Price	Hourly weighted average of daily ICE Day-Ahead Power Index for Mid-Columbia for Peak and Off-Peak prices from September - November 2011	Bonneville Spill Protection Day hourly Cap LD
	HE	MWh/hr	MWh/hr	MWh/hr	$/MWh	$/MWh	$/day
6/21/2010	100	139	139		$ (2.26)	$ 32.23	$ -
6/21/2010	200	139	139		$ (2.06)	$ 32.23	$ -
6/21/2010	300	139	139		$ (2.61)	$ 32.23	$ -
6/21/2010	400	139	139	139	$ (4.07)	$ 32.23	$ 5,045.67
6/21/2010	500	139	139	139	$ (1.31)	$ 32.23	$ 4,662.03
6/21/2010	600	139	139	139	$ 0.21	$ 32.23	$ 4,450.75
6/21/2010	700	139	139	139	$ 0.65	$ 32.23	$ 4,389.59
6/21/2010	800	139	139	139	$ 4.03	$ 32.23	$ 3,919.77
6/21/2010	900	139	139	139	$ 9.87	$ 32.23	$ 3,108.01
6/21/2010	1000	139	139	139	$ 9.37	$ 32.23	$ 3,177.51
6/21/2010	1100	139	139	139	$ 8.92	$ 32.23	$ 3,240.06
6/21/2010	1200	139	139	139	$ 9.71	$ 32.23	$ 3,130.25
6/21/2010	1300	139	139	139	$ 15.98	$ 32.23	$ 2,258.72
6/21/2010	1400	139	139	139	$ 21.70	$ 32.23	$ 1,463.64
6/21/2010	1500	139	139	139	$ 22.26	$ 32.23	$ 1,385.80
6/21/2010	1600	139	139	139	$ 24.54	$ 32.23	$ 1,068.88
6/21/2010	1700	139	139	139	$ 26.34	$ 32.23	$ 818.68
6/21/2010	1800	139	139	139	$ 25.93	$ 32.23	$ 875.67
6/21/2010	1900	139	139	139	$ 25.36	$ 32.23	$ 954.90
6/21/2010	2000	139	139	139	$ 15.59	$ 32.23	$ 2,312.93
6/21/2010	2100	139	139	139	$ 14.51	$ 32.23	$ 2,463.05
6/21/2010	2200	139	139	139	$ 15.21	$ 32.23	$ 2,365.75
6/21/2010	2300	139	139	139	$ 15.15	$ 32.23	$ 2,374.09
6/21/2010	2400	139	139	139	$ 11.30	$ 32.23	$ 2,909.24

Total daily PacifiCorp Storage Cut LD: $ 56,375.09

Exhibit B

Amendment No. 5
Amended and Restated AC Intertie
Contract No. DE-MS79-94BP94332

Bonneville Power Administration and PacifiCorp agree to amend the Amended and Restated AC Intertie Agreement, Contract No. DE-MS79-94BP94332, by adding the following subsection 12(a)(9), Exhibit N, Exhibit O, and Exhibit P.

12(a)(9) Summer Storage Settlement. Storage and return of energy as provided in this section 12(a) shall occur in calendar year.2014 pursuant to the terms of this section 12(a)(9). For calendar year 2014, subsections 12(a)(1)-(8) shall be inoperable.

(i) Bonneville may elect to store energy with PacifiCorp in either the month of June or July (but not both). Such month shall then be deemed the Delivery Month. Bonneville shall notify PacifiCorp of such election in a notice shown in **Exhibit N** hereto.

(ii) If Bonneville makes such election, PacifiCorp shall accept up to 25,000 megawatt-hours for storage over a maximum of 8 Storage Day(s) in the Delivery Month, as defined in section 12(a)(9)(v). The eight Storage Day(s) may, but need not be, consecutive. Deliveries of such energy shall be 130 MW per hour for each Storage Day.

(iii) Energy to be stored by Bonneville shall be pursuant to this subsection 12(a)(9) and shall be delivered to PacifiCorp system to system (BPAT.PACW) as described in Exhibit C of the Short-Term Surplus Firm Capacity Sales Agreement (BPA Contract No. DE-MS79-92BP93757), or such other points as may be mutually agreed to.

(iv) PacifiCorp shall return energy stored under this section 12(a)(9) to Bonneville during the months of September, October, and November of the year in which energy was delivered to PacifiCorp. Unless otherwise mutually agreed, the hourly rate of return of the energy to Bonneville shall be determined by summing the total energy delivered to PacifiCorp during the prior June or July period, dividing such sum by three (3) and dividing the result by the number of hours in the month in which the energy is to be returned to Bonneville. Except during times of system emergency, PacifiCorp shall adhere to this hourly return schedule. Except when prevented by constraints on the Parties' transmission systems, including both operational and scheduling constraints, returned energy in any hour shall be delivered to Bonneville at the Hot Springs Substation, at an amount not to exceed 110 MW unless otherwise mutually agreed to, Summer Lake Substation or other mutually-agreed upon points of delivery. Storage provided pursuant to this subsection 12(a) shall be at no charge to Bonneville, except as provided in section 12(a)(9)(vi).

(v) "Storage Day" as used in this section 12(a)(9) shall mean any calendar day in which all of the following occur:

(1) Bonneville anticipates that it will be in Spill Conditions, as defined in section 27 of this Agreement, for any hour in a declared Storage Day, and

(2) Bonneville has specifically notified PacifiCorp it is declaring a Storage Day, and that notification will be delivered no later than 10:00 a.m. on the pre-schedule day for the Storage Day(s), via sending an email to PacifiCorp at ctpreschd@pacificorp.com, an example of which is shown in **Exhibit O** hereto.

In each case, a Storage Day will be for 24 hours beginning at HE0100 and ending HE2400 as outlined in Bonneville notice (**Exhibit O**) and are day(s) in which BPA requested Storage Day schedule cannot be cut by PacifiCorp.

(vi) If Bonneville delivers energy to PacifiCorp on a declared Storage Day where Bonneville was not in Spill Conditions, then Bonneville will be subject to a Bonneville Storage Day Liquidated Damage (LD), as defined in section 12(a)(9)(vii).

(vii) "Bonneville Storage LD" as used in this section 12(a)(9) is defined as the sum of the product of the 3,120 MWh (24 hours of storage deliveries) and the market price spread of the Powerdex Mid-Columbia Average Hourly Index price for all hours of the Storage Day and the hourly weighted average of the settled ICE North American Power Day-Ahead Power Index Mid-Columbia price, for Peak and Off-Peak, from September through November of 2014. (Example in **Exhibit P**)

Bonneville will pay to PacifiCorp the BPA Storage Day LD, if any, by December 20th, 2014 and such payment shall be made in accordance with payment terms set forth in BPA's current Power General Rate Schedule Provisions.

Exhibit N

[Example of 2014 Bonneville Summer Storage nomination letter, on Bonneville letterhead, to PacifiCorp]

Supervisor, Contract Administration
PacifiCorp
825 NE. Multnomah, Suite 600
Portland, OR 97232

RE: Contract No. DE-MS79-94BP94332, Summer Energy Option

Dear Sirs:

This letter serves as notification from the Bonneville Power Administration (Bonneville) to PacifiCorp (PAC) that Bonneville chooses to exercise Section 12(a)(9), Summer Storage, of our AC Intertie Agreement, Contract No. DE-MS79-94BP94332, by requesting PacifiCorp to store up to 25,000 megawatt-hours (MWh) of energy in the month of <month>. Bonneville shall deliver the energy in anticipation of a Storage Day to PAC over eight calendar days at a rate of approximately 130 MW per hour subject to Spill Conditions.

For any further discussions regarding this notice, please contact me at (503) 230-4003.

Sincerely,

Mark E. Miller
Account Executive

Cc: Bonneville Contracts Administration

Exhibit O
Amended and Restated AC Intertie
Contract No. DE-MS79-94BP94332

Exhibit O
[Example of 2014 Storage Day Notice e-mail to PacifiCorp]

Subject: Storage Day

This email serves as notification from the Bonneville Power Administration (Bonneville) to PacifiCorp that Bonneville will be exercising a Storage Day(s) as described in Section 12(a)(9)(v), Summer Storage, of the Amended and Restated AC Intertie Agreement, Contract No. DE-MS79-94BP94332.

Period begins: Hour Ending 0100, <month> <day>, 2014
Period ends: Hour Ending 2400, <month> <day>, 2014

Bonneville may nominate eight (8) Storage Days for the Delivery Month subject to Spill Conditions. As described in this notice, Bonneville hereby declares_ Storage Day(s), for a total of_ Storage Day(s) used to Date in the Delivery Month.

PacifiCorp, please confirm this e-mail by a return e-mail acknowledgment to:
ajspain@bpa.gov
memiller@bpa.gov
rcjohnson@bpa.gov

For any further discussions regarding this notice, please contact me at (503) 230-4003, or Alex Spain at (503) 230-5780.

Exhibit P

Sample of Bonneville Storage Day LD Calculation for one Storage Day.

Description:
If Bonneville declared a Storage Day that does not meet the conditions described in section 12 (a) (9)(iii)
Bonneville will be subject to Storage Day LDs.

The following is an example of how the Storage Day LD is calculated for one day only:

Date	Time HE	Bonneville Deliveries MWh/hr	Powerdex Mid-Columbia Average Hourly Index Price $/MWh	Hourly weighted average of daily ICE Day-Ahead Pwer Index for Mid-Columbia for Peak and Off-Peak from Sept, Oct, Nov 2014 $/MWh	Liquidated Damages for each hour of the Storage Day $/day
6/26/2014	100	130	-12.67	32.23	5,837.00
6/26/2014	200	130	-2.58	32.23	4,525.30
6/26/2014	300	130	-0.41	32.23	4,243.20
6/26/2014	400	130	-2.95	32.23	4,573.40
6/26/2014	500	130	-0.74	32.23	4,286.10
6/26/2014	600	130	-0.08	32.23	4,200.30
6/26/2014	700	130	-4.1	32.23	4,722.90
6/26/2014	800	130	-2.12	32.23	4,465.50
6/26/2014	900	130	1.11	32.23	4,045.60
6/26/2014	1000	130	0.5	32.23	4,124.90
6/26/2014	1100	130	-3.92	32.23	4,699.50
6/26/2014	1200	130	-3.56	32.23	4,652.70
6/26/2014	1300	130	-1.46	32.23	4,379.70
6/26/2014	1400	130	-0.19	32.23	4,214.60
6/26/2014	1500	130	-0.58	32.23	4,265.30
6/26/2014	1600	130	0.05	32.23	4,183.40
6/26/2014	1700	130	-0.04	32.23	4,195.10
6/26/2014	1800	130	0.07	32.23	4,180.80
6/26/2014	1900	130	-0.19	32.23	4,214.60
6/26/2014	2000	130	0.34	32.23	4,145.70
6/26/2014	2100	130	-0.08	32.23	4,200.30
6/26/2014	2200	130	-4.15	32.23	4,729.40
6/26/2014	2300	130	-2.25	32.23	4,482.40
6/26/2014	2400	130	-0.7	32.23	4,280.90
Bonneville Storage Day LD:					105,848.60

Contract No. DE-MS79-94BP94332

AMENDED AND RESTATED

AC INTERTIE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFICORP

Index to Sections

Exhibit J ("Example of PacifiCorp Contingent Spill Protection Day criteria validation email to Bonneville")
Exhibit K ("Sample of Bonneville Spill Conditions website posting")
Exhibit L ("Sample of Bonneville Spill Protection Day LD")
Exhibit M ("Sample of PacifiCorp Storage Cut LD")
Exhibit N ("Example of 2014 Bonneville Summer Storage nomination letter, on Bonneville letterhead, to PacifiCorp")
Exhibit O ("Example of 2014 Storage Day Notice e-mail to PacifiCorp")
Exhibit P ("Sample of Bonneville Storage Day LD Calculation for one Storage Day")

This AMENDED AND RESTATED AC INTERTIE AGREEMENT (Amended and Restated AC Intertie Agreement), executed August 22, 2013, by the UNITED STATES OF AMERICA ("Government"), DEPARTMENT OF ENERGY, acting by and through the BONNEVILLE POWER ADMINISTRATION ("Bonneville") and PACIFICORP ("PacifiCorp"), a corporation organized and existing under the laws of Oregon, (hereinafter referred to individually as "Party" and collectively as "Parties").

WITNESSETH:

WHEREAS the Parties have entered into the Transmission Agreement (Contract No. DE-MS79-79BP90091), as amended, which hereinafter is referred to as "Midpoint-Medford Agreement"; and

WHEREAS the Parties have entered into the Intertie Agreement (Contract No. DE-MS79-86BP92299, as amended, which hereinafter is referred to as "the July 1986 Intertie Agreement"; and

WHEREAS the Parties have entered into an Agreement of Principles, dated May 28, 1993, which hereinafter is referred to as "Letter of Understanding" and which provides, among other things, for the revision of certain terms and conditions in the Midpoint-Medford Agreement and the July 1986 Intertie Agreement; and

WHEREAS the Parties have entered into the Midpoint-Meridian Transmission Agreement (Contract No.DE-MS79-94BP94333) which hereinafter is referred to as "Midpoint-Meridian Transmission Agreement" which replaces and supersedes the Midpoint-Medford Agreement; and

WHEREAS the Parties have replaced and superseded the July 1986 Intertie Agreement with the June 1994 AC Intertie Agreement Contract No. DE-MS79-94BP94332, (hereinafter referred to as the June 1994 AC Intertie Agreement), and

WHEREAS the Parties have entered into the AC Intertie Operation and Maintenance Agreement (Contract No. DE-MS79- 93BP94278) which hereinafter is referred to as "AC Intertie O&M Agreement"; and

WHEREAS Bonneville and PacifiCorp are Parties to Contract No. 14-03-59840 ("Malin Substation Construction Agreement") which provides for rights and obligations regarding construction, operation, ownership and use of the Malin Substation and desire to continue such agreement for the term of this Amended and Restated AC Intertie Agreement; and

WHEREAS PacifiCorp has constructed a 500 kV line from the interconnection with Bonneville at Alvey Substation to Meridian Substation ("Alvey-Meridian Line") to provide increased Load Carrying Capability; and

WHEREAS Bonneville has expanded the Rated Transfer Capability of the AC Intertie to approximately 4800 megawatts and has acquired a 50 percent undivided ownership right in the Incremental Capacity of the Alvey-Meridian Line; and

WHEREAS PacifiCorp and Bonneville have acquired joint ownership in the Alvey-Meridian Line and related facilities as provided for in Amendatory Agreement No. 2 to the June 1994 AC Intertie Agreement ("Payment Agreement"), Amendatory Agreement No. 1 to the July 1986 Intertie Agreement ("Option Agreement") attached hereto as Exhibits A and D respectively and Exhibit B hereto; and

WHEREAS nothing in this Amended and Restated AC Intertie Agreement is intended to be determinative of transmission or ownership rights of utilities not party to this Amended and Restated AC Intertie Agreement; and

WHEREAS this Amended and Restated AC Intertie Agreement incorporates the terms and conditions of the June 1994 AC Intertie Agreement, as supplemented and amended by Amendatory Agreement Nos. 1 through 3 thereto in one complete document, in accordance with the Federal Energy Regulatory Commission requirements in Order No. 614, Designation of Electric Rate Schedule Sheet, 65 Fed. Reg. 18,221 (2000), FERC Statutes and Regulations ¶ 31,096 (2000); and

WHEREAS this Amended and Restated AC Intertie Agreement is entered into by the Parties for the sole purpose of incorporating Amendatory Agreements 1, 2 and 3 into this Amended and Restated AC Intertie Agreement and does not alter any of the Parties' rights, obligations or terms and conditions of the June 1994 AC Intertie Agreement in any way; and

WHEREAS the Parties agree that this Amended and Restated AC Intertie Agreement supersedes and replaces the Original version of the June 1994 AC Intertie Agreement and Amendatory Agreement Nos. 1 through 3 thereto in their entirety as from the effective date hereof.

NOW, THEREFORE, in the interest of resolving issues of AC Intertie rights and service to PacifiCorp's Load Area now and in the future, Bonneville and PacifiCorp are entering into this Amended and Restated AC Intertie Agreement to accomplish the following goals:

(a) To enable Bonneville's planning, construction, operation and maintenance of an AC Intertie with a bidirectional Rated Transfer Capability of approximately 4800 megawatts and to enable PacifiCorp's planning, construction, operation and maintenance of facilities to serve its Load Area.

(b) To permit the Parties' specified use of the Buckley- Alvey Loop in a manner that does not jeopardize reliable service on either Party's system.

(c) To limit PacifiCorp's right to use its own facilities to schedule power and energy from its Load Area to adjoining areas and to ensure that this right is exercised in a manner that does not reduce the Operational Transfer Capability of the AC Intertie.

(d) To facilitate joint development of facilities by Bonneville and PacifiCorp as specified in this Amended and Restated AC Intertie Agreement.

(e) As between the Parties, to facilitate the economical development and fair allocation of any AC Intertie transfer capability above 4800 megawatts.

It is the intention of the Parties that this Amended and Restated AC Intertie Agreement be implemented and interpreted to best effectuate the above stated goals. Where this Amended and Restated AC Intertie Agreement makes reference to not unreasonably withholding consent or agreement, the reasonableness of each Party's position will be judged with reference to the above stated goals.

1. Term of Agreement. This Amended and Restated AC Intertie Agreement shall be effective, and consistent with the 1994 AC Intertie Agreement, shall supersede the July 1986 Intertie Agreement in accordance with Section 15 herein when executed by the Parties and accepted for filing or otherwise approved without change by the Federal Energy Regulatory Commission and shall terminate when all of the facilities comprising the AC Intertie are permanently taken out of service. Upon termination of this Amended and Restated AC Intertie Agreement, all liabilities accrued hereunder shall be and are hereby preserved until satisfied.

2. Exhibits. Exhibits A through P are incorporated as part of this Amended and Restated AC Intertie Agreement. Revisions to the Exhibits shall be by mutual consent.

3. Plan-of-Service for AC Intertie.

(a) Bonneville's Right to Establish Plan-of-Service. PacifiCorp agrees that Bonneville alone shall have the right to establish any Plan-of-Service for upgrading the AC Intertie to approximately 4800 megawatts, provided such Plan-of-Service is in keeping with Prudent Utility Practice, and further provided such Plan-of-Service does not result in reducing PacifiCorp's Load Carrying Capability.

(b) PacifiCorp's Right to Comment. Bonneville shall provide PacifiCorp the opportunity to comment on any such Plan-of-Service Bonneville may establish.

4. AC Intertie Construction and Ownership up to Approximately 4800 Megawatts of Rated Transfer Capability.

(a) Alvey-Meridian Line Rights. To achieve the upgrade of the AC Intertie to a Rated Transfer Capability of approximately 4800 megawatts, Bonneville has acquired a 50 percent undivided ownership right in the Incremental Capacity of the Alvey-Meridian Line which is jointly owned by Bonneville and PacifiCorp as provided for in the Payment Agreement and Exhibit B. For the term of this Amended and Restated AC Intertie Agreement, Bonneville shall have the unrestricted right to use such ownership interest. Bonneville may use such unrestricted right for purposes including, but not limited to, the interregional transfer of electric power, the integration of the electric power output of generation resources, and for service to the electric power loads of Bonneville's customers. Bonneville and PacifiCorp have shared, in accordance with the percentages specified in Exhibit B, the actual costs of facilities associated with construction of the Alvey-Meridian Line and other related additions. Unless otherwise

stated in Exhibit B or in the AC Intertie O&M Agreement, Bonneville shall pay 42 percent and PacifiCorp shall pay 58 percent of the operation and maintenance costs of those facilities specified in Exhibit B. PacifiCorp shall bear all operation and maintenance costs for those facilities used exclusively to serve PacifiCorp's own loads. PacifiCorp and Bonneville shall act in good faith and use best efforts, including utilization of all reasonable legal remedies, to obtain and protect all necessary permits and licenses for the Alvey-Meridian Line.

(b) Captain Jack Substation. Bonneville has constructed and, except for those facilities which PacifiCorp owns pursuant to section 4(b)(3) herein, owns the Captain Jack Substation and the associated interconnection to COTP. Bonneville's ownership includes the land on which the substation and the interconnection are located. Bonneville has connected the Captain Jack Substation to PacifiCorp's 500 kV system between Meridian Substation and Malin Substation where the COTP interconnects with the AC Intertie subject to the following terms, conditions and exceptions:

(1) Bonneville has constructed and owns terminal equipment, lines, and facilities required to interconnect the COTP with the Captain Jack Substation.

(2) Bonneville has constructed and owns the series and shunt compensation equipment and facilities located in the Captain Jack Substation required to connect to the COTP.

(3) PacifiCorp and Bonneville have shared equally in the cost of the bay 3 terminal equipment and facilities, which PacifiCorp owns, including the land on which such facilities are located, required to loop PacifiCorp's Malin-Meridian 500 kV line("Malin-Meridian Line") into the Captain Jack Substation.

(4) PacifiCorp, at its expense and subject to Prudent Utility Practice, may install transformation equipment at the Captain Jack Substation. PacifiCorp agrees to provide Bonneville the one-line diagram and plot plan for the installation of transformation equipment in a timely fashion for inclusion in Bonneville's Plan-of-Service. Subsequent changes in the one-line diagram or plot plan of transformation equipment are subject to mutual consent.

(c) Modification of Facilities.

(1) Except in regard to the Malin Substation, PacifiCorp agrees that it will make or permit Bonneville to make, at Bonneville's expense, any improvements or modifications of PacifiCorp's facilities in the Buckley-Alvey Loop that are required to accomplish Bonneville's Plan-of-Service. Unless otherwise mutually agreed, Bonneville shall own such improvements or modifications unless they cannot be removed without impairment or damage to PacifiCorp's facilities, in which case such modifications or improvements shall be jointly owned by Bonneville and PacifiCorp.

(2) AC Intertie Reactive Support. After joint studies have been completed and the Parties have mutually agreed that additional reactive support is required at the Malin Substation or Captain Jack Substation to support the AC Intertie, PacifiCorp shall be financially responsible for its share of the cost of such added reactive support.

(3) At such time as the Parties mutually agree, which agreement shall not be unreasonably withheld, that a second 500/230 kV transformer is required at the Malin Substation or a 500/230 kV transformer is required at the Captain Jack Substation, the Parties shall jointly develop the plan of service for such transformer(s). Each Party shall have the right to acquire up to a one-half ownership interest in such transformer(s) at a

pro-rata share of cost, provided that PacifiCorp's Load Carrying Capability is not impacted. If a Party does not participate in the ownership of such transformer(s) at the Malin or Captain Jack Substations at the time such transformer(s) are installed, such Party shall have the unilateral right to acquire up to a one-half ownership interest based on a pro-rata share of the original cost plus capital additions, if any, at a future date to the extent that capacity is available.

(4) Except as provided for in subsection 4(c)(1) herein, any improvements or modifications of the Buckley-Alvey Loop shall be by mutual consent, which consent shall not be unreasonably withheld. Except as provided for in subsections 4(c)(2) and 4(c)(3) above, installation of any equipment in the Malin Substation shall be made pursuant to the terms of the Malin Substation Construction Agreement.

(5) If Bonneville determines additions or modifications to the Alvey-Meridian Line are necessary to maintain the Rated Transfer Capability or Operational Transfer Capability of the AC Intertie at 4800 megawatts, Bonneville may, by written notice, cause PacifiCorp to add such equipment or make such modifications, and Bonneville and PacifiCorp shall share equally in the costs and ownership of such additions and modifications unless otherwise mutually agreed. PacifiCorp and Bonneville shall share equally in any Incremental Capacity resulting from such modifications.

5. Rights of Use.

(a) Determination of AC Intertie Rated Transfer Capability and Operational Transfer Capability. PacifiCorp agrees that Bonneville may determine the Rated Transfer Capability and Operational Transfer Capability of the AC Intertie, provided such determination is in keeping

with Prudent Utility Practice, and further provided it does not have the effect of reducing PacifiCorp's ability to serve up to its Load Carrying Capability as specified in this section 5.

(b) Bonneville's Right to Use of PacifiCorp's Malin-Meridian Line. PacifiCorp shall provide Bonneville, at no charge, sufficient capacity in the Malin-Meridian Line for Bonneville's AC Intertie transactions for itself or on behalf of other parties to enable Bonneville to operate the AC Intertie at its Rated Transfer Capability. To the extent modifications in the Malin-Meridian Line are required to effectuate this subsection 5(b), the cost of such modifications shall be borne equally by Bonneville and PacifiCorp. PacifiCorp shall operate and maintain the Malin-Meridian Line to maintain the Rated Transfer Capability on the AC Intertie in keeping with Prudent Utility Practice.

(c) Bonneville's Rights and Obligations for Intertie Service. PacifiCorp agrees that Bonneville has the right to operate the AC Intertie up to its Rated Transfer Capability or Operational Transfer Capability, subject to the following terms and conditions:

(1) Subject to section 4(c)(2) herein, Bonneville shall provide reactive support to maintain the Rated Transfer Capability of the AC Intertie.

(2) Bonneville shall provide transmission reinforcement to maintain the Rated Transfer Capability of the AC Intertie.

(3) Bonneville shall not rate or operate the AC Intertie in a manner that interferes with PacifiCorp's use of its Load Carrying Capability as described in subsections 5(d)(1), 5(d)(2), and 5(d)(3) below. However, Bonneville may make use of PacifiCorp's unused Load Carrying Capability for AC Intertie transactions for itself or on behalf of other parties at no additional charge, except as otherwise provided in this Amended and Restated AC Intertie Agreement.

(d) PacifiCorp's Rights and Obligations for Service to Load.

(1) Upon energization of the Alvey-Meridian Line, PacifiCorp shall have the right to serve PacifiCorp's Load Area and parallel paths, pursuant to section 10 herein, up to the Load Carrying Capability specified as follows:

(A) PacifiCorp shall have a Load Carrying Capability of 1875 megawatts.

(B) By the date when PacifiCorp's Load is expected to exceed the Load Carrying Capability recognized in subsection 5(d)(1)(A) herein, PacifiCorp shall provide additional facilities to supply power to its Load Area.

(2) The Load Carrying Capability specified in this subsection 5(d) may be correspondingly increased if new transmission facilities are constructed or if modifications are made to transmission facilities that increase the Load Carrying Capability. The effect of any such additions or modifications of transmission facilities on Load Carrying Capability shall be established by mutual agreement of the Parties using the results of joint planning studies conducted pursuant to subsection 5(d)(3) herein, and such mutual agreement shall not be unreasonably withheld.

(3) PacifiCorp's Load in its Load Area, and the date that such load is expected to exceed the Load Carrying Capability, shall be mutually determined by joint planning studies conducted annually, or as otherwise mutually agreed, by PacifiCorp and Bonneville in accordance with normal utility planning criteria. Such studies shall be based on mutually agreed to load forecasts for PacifiCorp's Load, as well as records of actual metered power flows on the then existing transmission lines serving the Load Area. PacifiCorp and

Bonneville shall furnish any data reasonably required for the joint planning study.

(4) PacifiCorp shall provide reactive support and internal transmission reinforcement for PacifiCorp's Load, including, but not limited to, 500/230 kV transformation, and 230 kV and below transmission reinforcement. To the extent PacifiCorp fails to provide such reinforcements, Bonneville shall not be obligated to reduce the Rated Transfer Capability or Operational Transfer Capability of the AC Intertie.

(5) Use of the Summer Lake Substation as a point of delivery by the Parties shall not impact PacifiCorp's Load Carrying Capability or Bonneville's usage of the AC Intertie.

(e) PacifiCorp's Scheduling Rights for AC Intertie Rated Transfer Capability in Excess of 4000 Megawatts. PacifiCorp's Southbound Scheduling Rights are 400 megawatts. PacifiCorp's Northbound Scheduling Rights shall equal 400 megawatts multiplied by a fraction whose numerator is the northbound Rated Transfer Capability of the AC Intertie and whose denominator is the southbound Rated Transfer Capability of the AC Intertie. PacifiCorp shall have the right to net its total northbound and southbound schedules under this Amended and Restated AC Intertie Agreement. PacifiCorp agrees to cooperate with Bonneville in its efforts, if any, to secure a northbound AC Intertie Rated Transfer Capability of 4800 megawatts. PacifiCorp's Northbound Scheduling Rights and Southbound Scheduling Rights shall be subject to the following terms and conditions:

(1) To preserve Bonneville's rights to use PacifiCorp's unused Scheduling Rights in a manner that allows third-party access to such rights in any hour, PacifiCorp

and Bonneville agree to the following provisions. PacifiCorp or any successive assignee may make its Scheduling Rights available on a firm basis to all parties under the provisions of PacifiCorp's open access transmission tariff; provided however, that neither PacifiCorp nor any successive assignee of PacifiCorp's Scheduling Rights may make such Scheduling Rights available for periods shorter than daily or on a nonfirm basis. To the extent that PacifiCorp or any successive assignee has unused Scheduling Rights available in any hour under this Amended and Restated AC Intertie Agreement as of the close of the normal preschedule deadline for firm point-to- point transmission service in accordance with Bonneville's standard scheduling practices, Bonneville shall add such unused Scheduling Rights to its available nonfirm transmission capacity for AC Intertie transactions, which shall be posted on Bonneville's Open Access Same-time Information System and made available pursuant to the provisions of Bonneville's open access transmission tariff. After such unused Scheduling Rights are added to Bonneville's available nonfirm transmission capacity, PacifiCorp or any successive assignee of the Scheduling Rights may modify preschedules up to 30 minutes prior to the hour for service to be provided pursuant to such preschedules for use of such firm transmission capacity (with such right available even if a preschedule had not been submitted, and in such case, PacifiCorp or any successive assignee shall be deemed to have submitted, with rights to modify, a 0 (zero) preschedule) and any such use shall have priority over any use or sale of unused Scheduling Rights by Bonneville. After 30 minutes prior to the hour for service to be provided pursuant to such preschedule, these unused Scheduling Rights shall be relinquished to Bonneville. There shall be no charge to Bonneville for unused Scheduling Rights.

(2) Except as mutually agreed to, any net southbound schedules by PacifiCorp in excess of Southbound Scheduling Rights available to PacifiCorp pursuant to this subsection 5(e) and the southbound scheduling rights available to PacifiCorp pursuant to transmission agreements entered into in accordance with the Letter of Understanding, including future Pacific Northwest AC Intertie Capacity Ownership Agreements, shall be deemed to be transmitted over the AC Intertie from John Day Substation, or any other AC Intertie delivery point subsequently established by Bonneville. Except as mutually agreed to, any net northbound schedules by PacifiCorp in excess of Northbound Scheduling Rights available to PacifiCorp pursuant to this subsection 5(e) and the northbound scheduling rights available to PacifiCorp pursuant to transmission agreements entered into in accordance with the Letter of Understanding, including future Pacific Northwest AC Intertie Capacity Ownership Agreements, shall be deemed to be transmitted over the AC Intertie to the John Day Substation, or any other AC Intertie delivery point subsequently established by Bonneville. Such excess schedules shall be subject to Bonneville's then effective Long-Term Intertie Access Policy, PacifiCorp's rights under other agreements, and the IS-93 Rate Schedule, or its successor, plus losses applicable to the AC Intertie. In the event that PacifiCorp's net northbound/southbound schedules exceed PacifiCorp's scheduling rights as described above, Bonneville shall provide transmission services to PacifiCorp pursuant to the same policies and rates that are generally applicable to Bonneville's other regional utility customers.

(3) If insufficient capacity exists in the combined capability of PacifiCorp's Midpoint-Malin 500 kV line ("Midpoint-Malin Line"), the Malin-Meridian Line, and the Alvey-Meridian Line for PacifiCorp to use its net Southbound Scheduling Rights

available to it, any increment above the combined capability of such facilities shall be deemed to be transmitted from the John Day Substation, or any other AC Intertie delivery point subsequently established by Bonneville, and shall be subject to the IS- 93 Rate Schedule, or its successor, plus losses applicable to the AC Intertie. Net Northbound Scheduling Rights shall be deemed to be delivered to PacifiCorp at Malin Substation or Captain Jack Substation. If insufficient capacity exists in the combined capability of PacifiCorp's Midpoint- Malin Line, the Malin-Meridian Line, and the Alvey-Meridian Line for PacifiCorp to integrate deliveries associated with its net Northbound Scheduling Rights available to it, any increment in excess of PacifiCorp's Load that can be served using the combined capability of PacifiCorp's facilities still in service shall be deemed to be transmitted from the Malin Substation to the John Day Substation, or any other AC Intertie delivery point subsequently established by Bonneville, and shall be subject to the IS-93 Rate Schedule, or its successor, plus losses applicable to the AC Intertie. Transmission service over the Federal Transmission System shall carry charges and losses as specified in the Midpoint-Meridian Transmission Agreement.

(4) During times when the southbound AC Intertie Operational Transfer Capability is less then the southbound AC Intertie Rated Transfer Capability, PacifiCorp's reduced net southbound scheduling rights at Malin Substation and Captain Jack Substation as described herein shall be an amount determined by multiplying the southbound Operational Transfer Capability of the AC Intertie by the ratio of 400 megawatts to the southbound Rated Transfer Capability of the AC Intertie. During times when the northbound AC Intertie Operational Transfer Capability is less then the northbound AC Intertie Rated Transfer Capability, PacifiCorp's reduced net northbound

scheduling rights shall be an amount determined by multiplying the northbound Operational Transfer Capability of the AC Intertie by the ratio of the Northbound Scheduling Rights to the northbound Rated Transfer Capability of the AC Intertie.

(f) Additional PacifiCorp Wheeling Rights. Until December 31, 2023, during Off-Peak Hours when PacifiCorp's northbound scheduling capability is less than 582 megawatts, Bonneville will provide PacifiCorp the right to utilize Bonneville's unused northbound capability on the AC Intertie and the DC Intertie at the IS-A Rate, or its successor rate, so as to provide PacifiCorp with a total northbound scheduling capability of 582 megawatts. For the purposes of this subsection 5 (f), PacifiCorp's northbound scheduling capability for any hour shall equal the sum during such hour of its Northbound Scheduling Rights hereunder and its northbound scheduling rights under the AC Intertie Transmission Agreement, Contract No. DE-MS79-94BP94285, including rights under Future Pacific Northwest AC Intertie Capacity Ownership Agreements. Bonneville's unused AC Intertie capability and DC Intertie capability shall be deemed to be capability not required to satisfy Bonneville's firm contractual commitments, as determined by Bonneville. PacifiCorp shall use best efforts to provide Bonneville advance notice of its desire to utilize its rights pursuant to this subsection 5(f). To the extent possible, such notice shall be provided at the time that PacifiCorp submits its preschedules to Bonneville pursuant to section 7 herein, provided, however, that PacifiCorp's failure to provide such notice with preschedules shall not diminish in any way, PacifiCorp's rights under this subsection 5(f).

(g) Remedial Action Schemes. PacifiCorp shall be responsible for providing or assuring, at its cost, the provision of its pro-rata share of remedial action schemes required to support the Rated Transfer Capability and Operational Transfer Capability of the AC Intertie either northbound or southbound. In support of its obligations to provide generator dropping for

its net southbound AC Intertie schedules, PacifiCorp shall provide generator dropping from its share of Mid-Columbia generation on line at the time of a remedial action scheme requirement. Bonneville may, after it has exhausted its own capability to provide generator dropping in support of its obligation for net southbound AC Intertie schedules, have access to PacifiCorp's total Mid-Columbia rights on line at the time of a remedial action scheme requirement at no cost. To the extent PacifiCorp does not have the capability on line to provide generator dropping from its Mid-Columbia rights for its net southbound AC Intertie schedules, Bonneville shall, to the extent it has available on line generation, provide generator dropping capability to PacifiCorp at no cost. In the event that PacifiCorp no longer has rights to Mid- Columbia generation, PacifiCorp's obligation to provide or assure, at its cost, the provision of its pro-rata share of remedial action schemes required to support the Rated Transfer Capability and the Operational Transfer Capability of the AC Intertie either northbound or southbound shall not be diminished. In support of PacifiCorp's net northbound AC Intertie schedules or its northbound DC Intertie schedules, PacifiCorp shall be responsible for making arrangements for any load dropping requirements. To the extent possible, as determined by Bonneville, Bonneville shall offer to sell remedial action scheme service to PacifiCorp to enable PacifiCorp to meet its obligations pursuant to this subsection 5(g).

(h) PacifiCorp shall provide Bonneville firm capacity in the existing 500/230 kV transformer at the Malin Substation at a use-of-facilities rate for Bonneville's firm requirements, provided such capacity will be made available to Bonneville only after PacifiCorp has determined that it has the capacity necessary to meet its own requirements and provided further, that Bonneville's right to use the existing Malin transformer shall be limited to 200 megawatts.

6. Upgrades of the AC Intertie Above Planned Rated Transfer Capability of 4800 Megawatts. After Bonneville has determined that the southbound or northbound AC Intertie Rated Transfer Capability is at least 4800 megawatts, but not more than 4900 megawatts, Bonneville and PacifiCorp agree that if any additions or changes to the Buckley-Alvey Loop or other jointly-owned facilities are required to increase the Rated Transfer Capability of the AC Intertie, such additions or changes shall be by mutual consent of the Parties hereto, which consent shall not be unreasonably withheld. Bonneville and PacifiCorp shall have the right, but not the obligation, to participate equally in such increase in the AC Intertie Rated Transfer Capability resulting from such additions or changes, and, if they do so, each shall share equally in the costs of such additions or changes to the Buckley-Alvey Loop or other jointly owned facilities required for such increases.

7. Scheduling.

(a) Bonneville and PacifiCorp shall schedule through the Bonneville Transmission Scheduling Office all schedules with southwest entities at the Malin and Captain Jack Substations.

(b) Upon Bonneville's request, PacifiCorp shall notify the Bonneville Transmission Scheduling Office each recognized workday of the planned schedules over PacifiCorp's parallel facilities, as described and limited in section 10 herein, for the following day or days. PacifiCorp shall also provide Bonneville's schedulers with all preschedule modifications prior to the hour of such schedules in accordance with Bonneville's standard scheduling practices.

8. Losses. The Parties shall be compensated for electric power losses pursuant to Calculation of Losses as shown in Exhibit E. Such compensation shall be based upon an equitable allocation of the Parties' control area losses associated with this Amended and Restated

AC Intertie Agreement and with the Midpoint-Meridian Transmission Agreement (Contract No. DE-MS79-94BP94333). The loss allocation specified in Exhibit E shall be reviewed at least every five years, but a review may be requested by either Party annually. The loss allocation shall be reviewed by the Parties to reflect any changes to the loss allocation.

9. Waivers. Except as specified in this Amended and Restated AC Intertie Agreement and the Letter of Understanding, PacifiCorp waives any claim to any ownership share or right to use the AC Intertie Rated Transfer Capability or to additional scheduling rights based on its ownership in:(1) existing facilities as such facilities may be modified or (2) the Alvey-Meridian Line.

10. Construction and Operation of Parallel Facilities.

(a) PacifiCorp's right to construct and right to operate existing and new interconnections with Pacific Gas & Electric Company or other utilities adjoining PacifiCorp's service territory in southern Oregon and northern California in parallel with the AC Intertie shall be subject to the following terms and conditions:

(1) The interconnection shall operate at 230 kV or below and shall include a phase shifter, unless the Parties mutually agree that a phase shifter is not required.

(2) On any given hour the sum of PacifiCorp's Load and the schedule on the parallel path shall not exceed the Load Carrying Capability.

(3) Except as provided in subsection 10(c) herein, PacifiCorp's total Rated Transfer Capability on such interconnections shall not exceed 400 megawatts. The total Rated Transfer Capability on such interconnections shall include the 100 megawatt Cottonwood Interconnection with Pacific Gas and Electric Company. The Operational

Transfer Capability on such interconnections shall never exceed the Rated Transfer Capability on such interconnections.

(4) PacifiCorp shall schedule as provided in subsection 7(b) herein. In no case shall such schedules exceed the Operational Transfer Capability of such interconnections.

(5) PacifiCorp shall make available to Bonneville telemetry of the actual power flow over PacifiCorp's parallel path interconnections.

(6) Construction or operation of such interconnections shall not reduce or adversely impact the Operational Transfer Capability of the AC Intertie. If Bonneville determines the operation of any such interconnection reduces or impacts the Operational Transfer Capability of the AC Intertie on any hour, and AC Intertie users have need of additional Operational Transfer Capability on the AC Intertie, upon Bonneville's request PacifiCorp shall reduce schedules to the extent needed to eliminate such impact. PacifiCorp shall not be required to reduce schedules on the parallel paths if the Operational Transfer Capability of the AC Intertie is reduced as a result of outages on the AC Intertie.

(b) Except as provided in subsection 10(c) herein, PacifiCorp shall not construct, participate in, or allow new interconnections for any 345 kV or above transmission lines or facilities from any point on PacifiCorp's system in Oregon to the existing two Malin-Round Mountain-Table Mountain 500 kV lines or the COTP north of Table Mountain.

(c) Notwithstanding the provisions of subsections 10(a)(3) and 10(b) herein, PacifiCorp may (i) construct and operate existing and new interconnections, as referenced in subsection 10(a)(3) herein with Rated Transfer Capability in excess of 400 megawatts, and/or (ii)

construct, participate in, and allow new interconnections as referenced in subsection 10(b) herein, if:

(1) such increase in Rated Transfer Capability or new interconnection is needed for PacifiCorp to meet good faith third-party requests for transmission service; and

(2) Bonneville has declined to provide, or lacks transmission facilities to provide, the requested transmission service; and

(3) such actions do not reduce the Rated Transfer Capability of the AC Intertie.

11. <u>Wheeling from Palo Verde.</u> For a period coincident with the term of PacifiCorp's March 23, 1993, Transmission Service Agreement ("TSA") with Southern California Edison Company ("SCE"), PacifiCorp, on hours that PacifiCorp does not require all or a portion of its transmission capacity rights pursuant to the TSA, shall offer Bonneville a first right of refusal to utilize such excess transmission rights under the TSA. PacifiCorp shall have sole discretion to determine whether it is making use of its TSA transmission rights. If Bonneville exercises its right to use PacifiCorp's TSA transmission rights, Bonneville shall reimburse PacifiCorp for SCE's charges to PacifiCorp for such usage. Such reimbursement shall be based upon PacifiCorp's then-effective transmission demand charges from SCE under the TSA which shall initially be $4.00 per megawatt-hour. If Bonneville exercises its first right of refusal to utilize PacifiCorp's excess TSA transmission rights, Bonneville shall use its own AC Intertie or DC Intertie scheduling capability to accept and transmit power and energy scheduled under this section 11. Additionally, the exercise of such access by Bonneville shall not preclude PacifiCorp

from utilizing its transmission rights acquired from Bonneville on the AC Intertie or the DC Intertie.

12. Summer Storage and Spring Energy Option

(a) Summer Storage. For a period of 20 years commencing with the effective date of the June 1994 AC Intertie Agreement, PacifiCorp shall accept and store energy for Bonneville during the months of June and July of each year.

(1) Prior to each storage month, Bonneville shall nominate their Bonneville Requested Storage, as shown in **Exhibit H** hereto. Bonneville will deliver the Bonneville Requested Storage Hourly Schedule to PacifiCorp system to system (BPAT.PACW) as described in Exhibit C to this Agreement.

(2) On any day that is not a Contingent Spill Protection Day, PacifiCorp may cut Bonneville's Requested Storage Hourly Schedule in any hour of any storage month up to the PacifiCorp Monthly Storage Schedule Cut Cap quantity for any reason, without financial compensation or other documentary support to Bonneville.

(3) On any day that is a Contingent Spill Protection Day, PacifiCorp will not cut Bonneville's Requested Storage Hourly Schedule for any hours of the Contingent Spill Protection Day.

(4) Energy to be stored pursuant to this subsection 12 (a) shall be delivered to PacifiCorp at the points of delivery specified in Exhibit C of the Short-Term Surplus Firm Capacity Sales Agreement (Contract No. DE-MS79-92BP93757), as amended or superseded, or such other points as may be mutually agreed to. PacifiCorp may, but shall not be required to, accept more than 100,000 megawatt-hours per month for storage and Bonneville shall deliver no less than 25,000 megawatt-hours per month for storage.

Bonneville shall deliver energy to PacifiCorp for storage prior to entering into the market to sell surplus energy. Unless otherwise mutually agreed, the hourly rate of delivery shall be determined by dividing the total energy to be stored in the month by the number of hours in such month. Except in times of system emergency, Bonneville shall adhere to the agreed-upon schedule of deliveries.

(5) PacifiCorp shall return stored energy to Bonneville during the months of September, October and November of each year in which energy was delivered to PacifiCorp. Unless otherwise mutually agreed, the hourly rate of return of the energy to Bonneville shall be determined by summing the total energy delivered to PacifiCorp during the prior June and July period, dividing such sum by three (3) and dividing the result by the number of hours in the month in which the energy is to be returned to Bonneville. Except during times of system emergency, PacifiCorp shall adhere to this hourly return schedule. Except when prevented by constraints on the Parties' transmission systems, including both operational and scheduling constraints, returned energy in any hour shall be delivered to Bonneville at the Hot Springs Substation, at an amount not to exceed 110 MW unless otherwise mutually agreed to, Summer Lake Substation or other mutually-agreed upon points of delivery. Storage provided pursuant to this subsection 12(a) shall be at no charge to Bonneville.

(6) If PacifiCorp exceeds its Monthly Storage Schedule Cut Cap for a given storage month, and Bonneville has not declared a Spill Protection Day and operational constraints dictate further storage cuts, then PacifiCorp can cut Bonneville Requested Storage Hourly Schedule but will pay Bonneville the PacifiCorp Storage Cut LD.

(7) If Bonneville has met its Monthly Spill Protection Day Cap for a given

storage month, and environmental constraints dictate further Spill Protection Day(s), then Bonneville can provide notice for additional Contingent Spill Protection Day(s) and PacifiCorp will accept and store such Bonneville Requested Storage Hourly Schedules, but Bonneville will pay PacifiCorp the Bonneville Spill Protection Day LD for Bonneville Requested Storage Hourly Schedules for any Contingent Spill Protection Days in excess of the Bonneville Monthly Spill Protection Day Cap and for any Contingent Spill Protection Day that does not meet all the Spill Protection Day criteria in 27(gg).

(8) PacifiCorp will pay any accumulated PacifiCorp Storage Cut LD, and Bonneville will pay any accumulated Bonneville Spill Protection Day LD, due in any storage year by December 20th of such storage year, and any such payment shall be made in accordance with payment terms set forth in the current General Rate Provisions dated October 1, 2009.

(9) Summer Storage Settlement. Storage and return of energy as provided in this section 12(a) shall occur in calendar year 2014 pursuant to the terms of this section 12(a)(9). For calendar year 2014, subsections 12(a)(1)-(8) shall be inoperable.

(i) Bonneville may elect to store energy with PacifiCorp in either the month of June or July (but not both). Such month shall then be deemed the Delivery Month. Bonneville shall notify PacifiCorp of such election in a notice shown in **Exhibit N** hereto.

(ii) If Bonneville makes such election, PacifiCorp shall accept up to 25,000 megawatt-hours for storage over a maximum of 8 Storage Day(s) in the Delivery Month, as defined in section 12(a)(9)(v). The eight Storage Day(s) may, but need not be, consecutive. Deliveries of such energy shall be 130 MW per hour for each Storage Day.

(iii) Energy to be stored by Bonneville shall be pursuant to this subsection 12(a)(9) and shall be delivered to PacifiCorp system to system (BPAT.PACW) as described in Exhibit C of the Short-Term Surplus Firm Capacity Sales Agreement (BPA Contract No. DE-MS79-92BP93757), or such other points as may be mutually agreed to.

(iv) PacifiCorp shall return energy stored under this section 12(a)(9) to Bonneville during the months of September, October, and November of the year in which energy was delivered to PacifiCorp. Unless otherwise mutually agreed, the hourly rate of return of the energy to Bonneville shall be determined by summing the total energy delivered to PacifiCorp during the prior June or July period, dividing such sum by three (3) and dividing the result by the number of hours in the month in which the energy is to be returned to Bonneville. Except during times of system emergency, PacifiCorp shall adhere to this hourly return schedule. Except when prevented by constraints on the Parties' transmission systems, including both operational and scheduling constraints, returned energy in any hour shall be delivered to Bonneville at the Hot Springs Substation, at an amount not to exceed 110 MW unless otherwise mutually agreed to, Summer Lake Substation or other mutually-agreed upon points of delivery. Storage provided pursuant to this subsection 12(a) shall be at no charge to Bonneville, except as provided in section 12(a)(9)(vi).

(v) "Storage Day" as used in this section 12(a)(9) shall mean any calendar day in which all of the following occur:

(1) Bonneville anticipates that it will be in Spill Conditions, as defined in section 27 of this Agreement, for any hour in a declared Storage Day, and

(2) Bonneville has specifically notified PacifiCorp it is declaring a Storage Day, and that notification will be delivered no later than 10:00 a.m. on the pre-schedule day for the Storage Day(s), via sending an email to PacifiCorp at ctpreschd@pacificorp.com, an example of which is shown in **Exhibit O** hereto.

In each case, a Storage Day will be for 24 hours beginning at HE0100 and ending HE2400 as outlined in Bonneville notice (**Exhibit O**) and are day(s) in which BPA requested Storage Day schedule cannot be cut by PacifiCorp.

(vi) If Bonneville delivers energy to PacifiCorp on a declared Storage Day where Bonneville was not in Spill Conditions, then Bonneville will be subject to a Bonneville Storage Day Liquidated Damage (LD), as defined in section 12(a)(9)(vii).

(vii) "Bonneville Storage LD" as used in this section 12(a)(9) is defined as the sum of the product of the 3,120 MWh (24 hours of storage deliveries) and the market price spread of the Powerdex Mid-Columbia Average Hourly Index price for all hours of the Storage Day and the hourly weighted average of the settled ICE North American Power Day-Ahead Power Index Mid-Columbia price, for Peak and Off-Peak, from September through November of 2014. (Example in **Exhibit P**)

Bonneville will pay to PacifiCorp the BPA Storage Day LD, if any, by December 20^{th}, 2014 and such payment shall be made in accordance with payment terms set forth in BPA's current Power General Rate Schedule Provisions.

(b) Spring Energy Option. For a period of 20 years following the effective date of the June 1994 AC Intertie Agreement, if requested by Bonneville, PacifiCorp shall deliver to Bonneville during Off- Peak Hours, at the Hot Springs Substation, or other mutually-agreed points of delivery, up to 50,000 megawatt-hours during the month of March of each such year. The maximum rate of delivery for such energy shall be 200 megawatts per hour. To exercise its option to take such energy, Bonneville shall notify PacifiCorp by February 15 of each year as to the amount of energy Bonneville desires to have delivered during the following March. Except in times of system emergency, PacifiCorp shall deliver such energy in accordance with Bonneville's request, subject to the limitations of this subsection 12(b). Bonneville shall return the energy delivered by PacifiCorp during the following June 1 through July 15 period during Off-Peak hours at an hourly rate of delivery determined by dividing the amount of energy delivered by PacifiCorp during the previous March by the number of Off-Peak Hours in the June 1 through July 15 period or such other hourly rate of delivery as mutually agreed to. Such March Energy shall be returned to PacifiCorp at points of delivery as specified in Exhibit C of Contract No. DE-MS79-92BP93757 or such other points of delivery as are mutually agreed.

13. Sale or Assignment.

(a) This Amended and Restated AC Intertie Agreement shall inure to the benefit of, and shall be binding upon, the respective successors and assigns of the Parties to this Amended and Restated AC Intertie Agreement.

(b) PacifiCorp and Bonneville agree not to sell, assign, lease, sublease, or otherwise transfer this Amended and Restated AC Intertie Agreement or any interest therein, without the written consent of the other Party, such consent not to be unreasonably withheld. PacifiCorp and Bonneville also agree not to sell, assign, lease, sublease, or otherwise transfer any direct or indirect interest in the Malin Substation, the portion of the Midpoint-Malin Line between Summer Lake Substation and Malin Substation ("Summer Lake-Malin Line"), the Malin-Meridian Line, or the Alvey-Meridian Line, without the written consent of the other Party, such consent not to be unreasonably withheld, provided, however, that PacifiCorp's interest in such facilities may be conveyed to its respective trustees as security under a mortgage or deed of trust to secure indebtedness without such written consent, provided that each such trustee may act with respect to such interest only to the extent and in the manner that such act would have been authorized under this Amended and Restated AC Intertie Agreement.

(c) If Bonneville or PacifiCorp is acquired in total by other entities, subsection 13(b) shall not apply to such acquisition.

14. Extension of Existing Agreements. The Parties agree that the termination dates of the Midpoint-Meridian Transmission Agreement, the Malin Substation Construction Agreement and all agreements related to joint ownership or interconnection on the Buckley-Alvey Loop, including but not limited to arrangements for the operation and maintenance of new facilities, shall be coincident with the termination date of this Amended and Restated AC Intertie Agreement. The Payment Agreement and the Option Agreement are attached hereto as Exhibits A and D respectively and made a part of this Amended and Restated AC Intertie Agreement. The Payment Agreement and the Option Agreement provide for, among other things, certain construction, payment, ownership, operation and maintenance activities in progress at the time of execution of this Amended and Restated AC Intertie Agreement. As these activities are completed or superseded by future agreements, PacifiCorp and Bonneville may agree to terminate some or all of the Payment Agreement and the Option Agreement provisions. To the

extent any provisions of the Payment Agreement or the Option Agreement are in conflict with this Amended and Restated AC Intertie Agreement, the terms and conditions of this Amended and Restated AC Intertie Agreement shall prevail.

15. Termination of Agreement. The Parties agree that this Amended and Restated AC Intertie Agreement consistent with the 1994 AC Intertie Agreement supersedes and terminates in its entirety, the July 1986 Intertie Agreement, Contract No. DEMS79-86BP92299, provided, however, that any liabilities incurred thereunder are hereby preserved until satisfied.

16. Execution of Other Agreements. The Parties agree to negotiate in good faith and execute construction agreements, operation and maintenance agreements, transmission agreements, and other such agreements that may be required to implement the provisions of this Amended and Restated AC Intertie Agreement.

17. Arbitration. In the event of any dispute related to rights or obligations of the Parties, or satisfaction thereof, under this Amended and Restated AC Intertie Agreement, including but not limited to the amount or reasonableness of costs, identification of exclusive use facilities, extent of amortization of past costs, and the reasonableness of withholding consent, either Party may elect to submit such dispute to nonbinding arbitration. If one Party so elects, such Party shall notify the other Party in writing and both Parties shall participate pursuant to the following:

(a) If the Parties cannot agree on an arbiter within 30 days of such notification, the notifying Party shall request the American Arbitration Association to designate an arbiter with sufficient expertise in the subject under dispute.

(b) After an arbiter is agreed to or designated, the arbiter shall establish a schedule for submission of the Parties' written positions. The Party electing the arbitration shall first state its position in a letter to the arbiter. The second Party shall then state its position in a letter to the arbiter. The first Party may then submit a response to the Second Party's position and the second Party may thereafter submit a reply to the first Party's response.

(c) Each letter submitted to the arbiter shall be no more than 5 pages in length, unless the Parties otherwise mutually agree. The Parties may attach exhibits that they consider relevant to the dispute. A copy of each submission also shall be simultaneously served on the other Party.

(d) The arbiter shall provide the Parties with a written analysis of the dispute, and his or her proposed resolution of the dispute.

(e) The Parties shall equally share the fee and other costs of the arbiter.

In the event neither Party submits the dispute to nonbinding arbitration or if either Party elects not to accept the finding of the arbiter, the Parties may elect other approaches, including litigation, to resolve the dispute.

18. Rules of Law.

(a) The Parties agree that each fully participated in the drafting of each provision of this Amended and Restated AC Intertie Agreement. The rule of law interpreting ambiguities against the drafting Party shall not be applicable to or utilized in resolving any dispute over the meaning or intent of this Amended and Restated AC Intertie Agreement or any of its provisions.

(b) The construction and interpretation of this Amended and Restated AC Intertie Agreement shall be governed solely by Federal law.

(c) This Amended and Restated AC Intertie Agreement shall not be construed to establish a partnership, association, joint venture, or trust. Neither Party shall be under the control of or shall be the agent of or have a right or power to bind the other Party without the other Party's express written consent, except as provided in this Amended and Restated AC Intertie Agreement.

19. Delay of Performance. The time for each act specified in this Amended and Restated AC Intertie Agreement shall be extended for a time equivalent to such delays, if any, as are occasioned by events which the Party hereto obligated to perform such act could not be reasonably expected to avoid by the exercise of reasonable diligence and foresight.

20. Regulatory Jurisdiction. The provisions of this Amended and Restated AC Intertie Agreement are subject to such regulatory agencies having jurisdiction thereof. Nothing contained herein shall be construed as affecting in any way the right of PacifiCorp to make application unilaterally to the Federal Energy Regulatory Commission for a change in rates, charges, classification, or service, or any rule or regulation, or contract relating thereto, under Section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder.

21. Severability and Breach.

(a) It is the intention of the Parties that the provisions of this Amended and Restated AC Intertie Agreement be severable in the event that any of such provisions, or portions thereof, are held to be illegal, invalid or unenforceable by a court of competent jurisdiction; provided that if section 10 herein, or any portion thereof, is found to be illegal, invalid or unenforceable by a court of competent jurisdiction, Bonneville shall have firm transmission rights to 50 percent of the total Rated Transfer Capability of any parallel interconnections other than the 100 megawatt Cottonwood Interconnection between PacifiCorp and Pacific Gas & Electric or other utilities adjoining PacifiCorp's territory in southern Oregon and northern California. In any legal proceeding, Bonneville and PacifiCorp shall act in good faith to defend the enforceability of all provisions of this Amended and Restated AC Intertie Agreement.

(b) The Parties agree that breach of this Amended and Restated AC Intertie Agreement, or any of its provisions, will cause irreparable harm and that the appropriate remedy is injunctive relief.

22. Capital Budgets. Excluding any facilities designated for omission by footnote 1 of Exhibit B of this Amended and Restated AC Intertie Agreement, each Party by July 1 of each year shall send a notice to the other Party containing (i) an estimate of the capital budget amounts related to the planned construction activities of the facilities described in such Exhibit B such Party expects to incur four (4) years in the future, and (ii) an update of any capital budget amounts it expects to incur within the upcoming three (3) years. Except for emergency Capital Replacements or emergency Capital Additions, the Parties shall exchange and review any necessary data as needed to determine the necessity and adequacy of the proposed construction and operation activities.

23. Payment Provisions.

(a) For reimbursable Capital Replacements or Capital Additions, the Party proposing the action shall prepare a proposed revision to Exhibit F whenever the Parties concur that it is necessary to add to or to replace the facilities identified in Exhibit B of this Amended and Restated AC Intertie Agreement. The Parties shall share the costs of such action according to the original cost share percentage of such facilities as set forth in Exhibit B in a manner consistent with the cost sharing methodologies contained in such exhibit, except that the replacement of facilities identified by footnote 1 of Exhibit B shall not be eligible for cost-sharing. Each revision of Exhibit F shall specify the facilities added or replaced.

(b) The Party responsible to make payment shall pay according to the provisions of the revision of Exhibit F for the work performed in amounts and at times as negotiated by the Parties.

(c) In the event of a dispute regarding billing, the Party owing the bill shall pay the amount in full and provide written notification of the disputed amount. Any adjustment shall be made on the next invoice allowing reasonable notice and time to make the adjustment. Refunds of the disputed amount shall include interest at the same interest rate specified in section 23(d).

(d) Invoices not paid in full on or before the close of business on the date due shall be subject to an interest charge on the amount due from the due date to the date paid consistent with the Prompt Payment Act Renegotiation Board's Interest Rate published in the Federal Register.

24. Audit Rights.

(a) Each Party, at its expense, may review and audit any cost on the other Party's books, records, and documents that directly pertain to the billings on the jointly owned facilities. The Party undertaking the audit shall provide reasonable notice to the other Party and shall conduct such audit at reasonable times and in conformance with generally accepted auditing standards. The Party being audited shall cooperate fully with any such audit. Neither Party shall audit a cost incurred more than three (3) years following the last day of the fiscal year in which such cost was incurred under Section 23 to this Amended and Restated AC Intertie Agreement. The Parties shall retain all records and documentation prepared in the normal course of business for the entire length of this audit period and in accordance with generally accepted accounting principles.

(b) After completion of the audit, the Party conducting the audit shall promptly notify the other Party of any exception taken as a result of an audit, and the audited Party may review the notice of exception and basis therefore for a period of thirty (30) days. Upon agreement regarding the validity of any exception, the owing Party shall directly refund the amount of the exception within thirty (30) days of such agreement.

25. Ownership of the Facilities.

(a) Transfer of legal ownership pursuant to Sections 22 and 23 to this Amended and Restated AC Intertie Agreement shall be effective at such time as the facilities are energized and made available for commercial operation as part of this Amended and Restated AC Intertie Agreement.

(b) All jointly-owned equipment and facilities shall be identified as such with co-ownership tags and signs. Each Party shall provide the tags and signs for equipment which it operates. Costs for such tags and signs shall be shared equally by each Party.

26. Integration.

(a) To the extent that Exhibit A of this Amended and Restated AC Intertie Agreement is inconsistent with provisions of Sections 22, 23 and 25 to this Amended and Restated AC Intertie Agreement, such Exhibit A is superseded by the provisions of this Amended and Restated AC Intertie Agreement.

(b) Any revisions to Exhibit F shall be attached to and deemed to be a part of this Amended and Restated AC Intertie Agreement and shall be effective on the date specified therein.

27. Definitions.

(a) AC Intertie. For the purposes of this Amended and Restated AC Intertie Agreement, the AC Intertie means Bonneville's rights in the alternating current ("AC") transmission facilities for transferring power and energy between Oregon and California as follows: two 500 kV lines extending from John Day Substation to Malin Substation and to the California-Oregon Border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's share of ownership of the Alvey-Dixonville and Dixonville-Meridian 500 kV transmission lines; portions of the Alvey, Dixonville, Meridian and Captain Jack Substations; the 500 kV transmission line extending from Captain Jack Substation to the California- Oregon Border; and any modifications, improvements, or additions to such facilities.

(b) Alvey-Meridian Line. The 500 kV transmission line facilities and substations constructed by PacifiCorp that extend from the interconnection with Bonneville's system at Alvey Substation to PacifiCorp's Meridian Substation.

(c) Bonneville Monthly Spill Protection Day Cap. Eight (8) Spill Protection Days in any storage month, without any carryover to the next month or year.

(d) Bonneville Requested Storage. The monthly energy Bonneville requests PacifiCorp to store as exercised under Section 12(a), hereof, as defined and confirmed in a nomination letter Exhibit H.

(e) Bonneville Requested Storage Hourly Schedule. The Bonneville Requested Storage (MWh/mn) for a storage month divided by the total hours (hours/mn) in the storage month and shall be the hourly flat schedule of Bonneville Requested Storage for all hours in the storage month

(f) Bonneville Spill Protection Day LD. The sum of the product of the Bonneville Requested Storage Hourly Schedules and the market price spread of the Powerdex Mid-Columbia Average Hourly Index price for all hours of the Spill Protection Day and the hourly weighted average of the settled ICE North American Power Day-Ahead Power Index Mid-Columbia price, for Peak and Off-Peak, from September through November of the storage cut year. (Example calculation found in Exhibit L).

(g) Bonneville Transmission Scheduling Office. The group of schedulers presently located at Bonneville's Dittmer Control Center in Vancouver, Washington, appointed by

Bonneville, Portland General Electric Company and PacifiCorp and designated to coordinate the schedule of energy over the AC Intertie and the DC Intertie.

(h) Buckley-Alvey Loop. The 500 kV transmission lines, facilities, and substations from Buckley Substation south to Summer Lake Substation, continuing south to Malin Substation, west to Meridian Substation, including the Captain Jack Substation, and the Alvey-Meridian Line.

(i) California Intertie. The two existing 500 kV AC lines extending northward from within California at Round Mountain Substation and terminating at Malin Substation.

(j) Capital Additions. The addition of any new facilities under this Amended and Restated AC Intertie Agreement (e.g., not replacements for assets already listed on Exhibit B) that are required to serve the common good of both Parties.

(k) Capital Replacements. The replacement asset for the facilities listed in Exhibit B of this Amended and Restated AC Intertie Agreement that is required to serve the common good of both Parties.

(l) Captain Jack Substation. The substation where COTP interconnects with the AC Intertie in the Pacific Northwest.

(m) COTP. The 500 kV California-Oregon Transmission Project, which operates in parallel with the California Intertie and terminates at the California-Oregon Border.

(n) DC Intertie. For the purposes of this Amended and Restated AC Intertie Agreement, the DC Intertie means Bonneville's rights in the existing 1,000 kV direct current ("DC') transmission line, and associated substation facilities, extending from the Bonneville's Big Eddy Substation to the Nevada-Oregon Border.

(o) Federal Transmission System. The transmission facilities owned by Bonneville.

(p) Future Pacific Northwest AC Intertie Capacity Ownership Agreements. Agreements entered into by Bonneville and regional utilities providing for those utilities' ownership of AC Intertie capacity available as a result of increasing the Rated Transfer Capability of the AC Intertie to 4800 megawatts.

(q) Incremental Capacity. For the purpose of this Amended and Restated AC Intertie Agreement, Incremental Capacity means capacity realized through the construction of the Alvey-Meridian Line in excess of the capacity on the previously existing 230 kV Alvey-Meridian line that was removed as a result of construction of the Alvey-Meridian Line.

(r) IS-A Rate. The Nonfirm Transmission Rate specified in Section II.A. of Bonneville's Southern Intertie Transmission Schedule IS-93, or its successor.

(s) [Reserved]

(t) Load Area. The geographic area encompassing portions of southern Oregon and northern California which is generally south of Eugene, Oregon and Bonneville's Summer Lake Substation and west of Burns, Oregon. Such geographic area shall be limited to:

(1) That area in which PacifiCorp is authorized to provide retail electric service, now and in the future; and

(2) That area in which PacifiCorp provides wholesale electric service at the date of execution of the June 1994 AC Intertie Agreement; provided that such areas are normally within PacifiCorp's load control area, connected to PacifiCorp's transmission system, and served by the transmission lines in Exhibit C.

Revisions to the Load Area shall be by mutual agreement of the Parties, and such agreement shall not be unreasonably withheld.

(u) Load Carrying Capability. The capability of PacifiCorp's transmission system, as specified in Exhibit C, serving the Load Area and parallel paths as limited by section 10 herein to provide firm transmission service in accordance with Prudent Utility Practice.

(v) Northbound Scheduling Rights. PacifiCorp's right to schedule power and energy through the Malin Substation and the Captain Jack Substation in a northerly direction from the 500 kV lines which extend to California and interconnect with the California Intertie and the COTP as provided in this Amended and Restated AC Intertie Agreement.

(w) Off-Peak Hours. The first six and last two hours of each day Monday through Saturday and all day Sunday or other hours as mutually agreed to.

(x) Operational Transfer Capability. Rated Transfer Capability less reductions caused by, but not limited to, physical limitations beyond the control of the Parties, operational limitations imposed by California utilities, line or equipment outages, stability limits or loop flow.

(y) PacifiCorp's Load. PacifiCorp's net firm load obligations within the Load Area excluding Bonneville's Surprise Valley Electric Cooperative Load transferred by PacifiCorp pursuant to the General Transfer Agreement, Contract No. DEMS79-82BP90049.

(z) PacifiCorp Monthly Storage Schedule Cut Cap. Sixteen (16) percent of the Bonneville Requested Storage in any storage month. The quantity of energy is defined as Bonneville Requested Storage quantity (MWh/mn) multiplied by PacifiCorp Monthly Storage Schedule Cut Cap (16%) without any carryover to the next month or year.

(aa) PacifiCorp Storage Cut LD. The product of any storage cuts in excess of PacifiCorp's Monthly Storage Schedule Cut Cap, multiplied by the market price spread of Powerdex Mid-Columbia Average Hourly Index price at the time of cut and the hourly weighted average of the settled ICE North American Power Day-Ahead Power Index Mid-Columbia price, for Peak and

Off-Peak, from September through November of the storage cut year. (Example found in Exhibit M).

(bb) Plan-of-Service. The project plans that Bonneville develops to realize an increase of the AC Intertie Rated Transfer Capability up to approximately 4800 megawatts, which shall include but are not necessarily limited plans, schedules, costs, and facility and equipment requirements.

(cc) Prudent Utility Practice. At any particular time, the generally accepted practices, methods, and acts in the electrical utility industry prior thereto or the practices, methods or acts, which, in the exercise of reasonable judgment in the light of the facts known at the time the decision was made, could have been expected to accomplish the desired result consistent with reliability and safety.

(dd) Rated Transfer Capability. The ability of a transmission line or system to transfer power in a reliable manner as determined in accordance with Prudent Utility Practice.

(ee) Southbound Scheduling Rights. PacifiCorp's right to schedule power and energy through the Malin Substation and the Captain Jack Substation in a southerly direction to the 500 kV lines which extend to California and interconnect with the California Intertie and the COTP as provided in this Amended and Restated AC Intertie Agreement.

(ff) Spill Conditions. Individual calendar days with one or more hours in that day flagged to indicate that Bonneville has declared spill conditions. The hourly spill condition declarations are provided by Bonneville via public internet posting at: http://www.transmission.bpa.gov/Business/Operations/Misc/ , then click on: Hourly Spill Flag, Last Two Years & Day-Ahead Forecast (updated daily at 11:00 AM, Pacific Time). Flags are found in the column titled "Actual" (Sample displayed in Exhibit K).

(gg) Spill Protection Day. Any day(s) in which all of the following occur:

(1) Bonneville has been in Spill Conditions for two (2) consecutivedays prior to when the Spill Protection Day begins (it being understood that such two day period could occur in May for the beginning of the June storage month and/or in June for the beginning of the July storage month); and

(2) Bonneville is in Spill Conditions, as defined herein, for any hour in a declared Spill Protection Day; and

(3) Bonneville has specifically notified PacifiCorp it is declaring a period of Spill Protection Day(s), and that notification will be delivered no later than 10:00 am on the pre-schedule day for the Spill Protection Day, via sending an email to PacifiCorp at ctpreschd@pacificorp.com, an example of which is shown in Exhibit I hereto.

In each case, Spill Protection Day(s) will be for 24 hours and begin at HE0100 and end HE2400 as outlined in Bonneville notice (Exhibit I) and are day(s) in which Bonneville's Requested Storage Hourly Schedule cannot be cut by PacifiCorp. Bonneville will declare Spill Protection Days when a reduction in generation would cause a potential violation of Bonneville's total dissolved gas limits at the relevant hydroelectric projects, and a potential violation of relevant environmental statutes and regulations.

(hh) Contingent Spill Protection Day. Any day that has been noticed and scheduled by Bonneville as a Spill Protection Day, but that has not yet met all the conditions as described in section 27(gg) above. A Contingent Spill Protection Day will result in either:

(1) a Contingent Spill Protection Day that ultimately meets all of the Spill Protection Day criteria in 27(gg) above and is within Bonneville's eight (8) allowed days; or

(2) a Contingent Spill Protection Day that ultimately meets all of the Spill Protection Day criteria in 27(gg) above, but exceeds Bonneville's eight (8) allowed days (in which case Bonneville Spill Protection Day LDs apply); or

(3) a Contingent Spill Protection Day that ultimately fails to meet all the Spill Protection Day criteria in 27(gg) above (in which case, Bonneville Spill Protection Day LDs apply).

When Bonneville specifically notifies PacifiCorp it is declaring a Contingent Spill Protection Day(s), that notification will be delivered no later than 10:00 am on the pre-schedule day for the Spill Protection Day, via email to PacifiCorp at ctpreschd@pacificorp.com, an example of which is shown in Exhibit I hereto. PacifiCorp will provide notice to Bonneville by the 10th of the month following a storage month as to the number of Contingent Spill Protection Days that a) fall within Bonneville Monthly

Spill Protection Day Cap and/or b) exceed Bonneville Monthly Spill Protection Day Cap and/or c) did not meet the Spill Protection Day criteria in 27(gg), via e-mail as described in Exhibit J.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement.

PACIFICORP	BONNEVILLE POWER ADMINISTRATION
By: Natalie L Hocken	By: Suzanne B Cooper
Name: Natalie Hocken	Name: Suzanne Cooper
Title: SVP, Transmission	Title: VP, Bulk Marketing
Date: 8/22/2013	Date: 8/21/2013

Exhibit A
Contract No. DE-MS79-94BP94332
PacifiCorp
AC Intertie Agreement

Amendatory Agreement No. 2 to
Contract No. DE-MS79-86BP92299
03/09/93

AMENDATORY AGREEMENT NO. _

TO THE INTERTIE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFICORP

Index to Sections

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This AMENDATORY AGREEMENT NO. 2 to the Intertie Agreement, Contract No. DE-MS79-86BP92299, executed March 16, 1993, by the BONNEVILLE POWER ADMINISTRATION (Bonneville) and PACIFICORP with its principal office in Portland, Oregon (hereinafter collectively referred to as "Parties" and individually as "Party").

W I T N E S S E T H :

WHEREAS the Parties hereto desire to make progress payments towards the design and construction of those facilities identified in Exhibit C to the Intertie Agreement, as amended; and

WHEREAS the Parties have entered into an Interim Payment Agreement, Contract No. DE-MS79-92BP93772 (Interim Payment Agreement), as amended, which provides for partial payment by Bonneville to PacifiCorp in the net amount of $10,000,000 for each Party's costs through May 31, 1992, related to the Alvey-Meridian Line and the AC Intertie (such payment represents a $16,000,000 payment to PacifiCorp and a $6,000,000 payment to Bonneville); and

WHEREAS the Parties have entered into a Cooperative Communication Agreement, Contract No. DE-MS79-92BP93740 (Communications Agreement), which provides for, among other things, construction of microwave communication facilities needed for the AC Intertie (Intertie Communication Facilities); and

WHEREAS the Parties have entered into a Remedial Action Scheme Agreement, Contract No. DE-MS79-92BP93039, which provides for, among other things, cost-sharing and payment by the Parties for the remedial action scheme equipment needed to support the rated transfer capability of the AC Intertie; and

WHEREAS the Parties have entered into the Sycan Interconnection Agreement, Contract No. DE-MS79-92BP93644 (Sycan Interconnection Agreement), which provides for, among other things, the installation and connection of series capacitors and related equipment (Sycan Addition) to PacifiCorp's Summer Lake-Malin 500 kV transmission line at the Sycan Compensation Station and Summer Lake and Malin Substations; and

NOW, THEREFORE, to establish the Parties' payment obligations throughout the construction phase of the Alvey-Meridian Line; the Alvey, Dixonville, Meridian, and Captain Jack 500 kV Substations; the Sycan Addition; and the Parties' Intertie Communication Facilities; and for continued obligations related to the AC Intertie, the Parties agree to the following:

1. Term of Amendment. This Amendatory Agreement No. 2 shall be effective on the date of execution (Amendment Effective Date) and shall remain in effect concurrently with the Intertie Agreement. All liabilities incurred hereunder shall be preserved until satisfied. Section 1 of the Intertie Agreement is hereby amended to include "Prior to the termination date of this Agreement, and no later than December 31, 2009, the Parties will commence negotiations for a follow-on agreement concerning services associated with the AC Intertie unless this Agreement is extended past 2016 then the Parties will commence negotiation of a follow-on agreement 7 years prior to termination."

2. Termination of Prior Agreement. The Interim Payment Agreement is hereby terminated upon the Amendment Effective Date. All obligations and liabilities incurred thereunder have been satisfied.

3. Definitions.

(a) Section 19(o) of the Intertie Agreement is hereby amended to read:

"(o) Captain Jack Substation. The Substation where the COTP interconnects with the AC Intertie in the Pacific Northwest and is sometimes referred to as the Southern Oregon Substation."

(b) Section 19 of the Intertie Agreement is hereby amended to add the following definitions:

"(p) Actual Costs are Bonneville and PacifiCorp Direct Costs, Indirect Costs, Overhead Costs, AFUDC, Interest and Credits as defined herein which are recorded monthly to construction work in progress (CWIP), retirement work in progress, removal work in progress, or electric plant in service according to generally accepted accounting principles and Prudent Utility Practice allocable to the Alvey-Meridian Line and other related facilities identified in Exhibit C herein. Costs related to construction that would not be capitalized, such as relocation, switching, and conductor transfer shall also be included in Actual Costs. The sharing of AFUDC on CWIP and Interest on electric plant in service is dependent on the timing of payments from the other Party relative to when costs are incurred. Bonneville's normal allocation of Bonneville Overheads and Bonneville Indirect Costs shall be included in the Actual Costs. PacifiCorp's normal allocation of PacifiCorp Overheads shall be included in the Actual Costs.

"(q) Advances are the monthly amounts of projected cash flow estimates for the Cost Shared Facilities expected to be incurred as Actual Costs in a given month as specified in Exhibits G and H.

"(r) Allowance for Funds Used During Construction (AFUDC) shall be as defined in the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts found in 18 CFR, Part 101, Electric Plant Instructions 3.A [17]. AFUDC shall be an Actual Cost until the Party constructing the Cost Shared Facilities is funded by the other Party. AFUDC shall be included in CWIP.

"(s) Bonneville Direct Costs are costs which are readily identifiable or obviously traceable to a specific program, project, or other cost objective and will not be included in Bonneville's Overhead or Indirect Costs.

"(t) Bonneville Indirect Costs are any costs incurred for common objectives which cannot be directly charged to any single point of cost application. Indirect costs are often allocated to various categories of work in proportion to the benefit to each category and will not be included in Bonneville's Direct or Overhead Costs.

"(u) Bonneville Overhead Costs. Bonneville's Overhead Costs are subject to change as Bonneville's methodology for computing Overhead Costs may change and shall be reflected in the Actual Costs. Bonneville's Overhead Costs include the following and will not be included in Bonneville's Direct or Indirect Costs:

"(1) Costs that are distributed each month to benefiting programs using an annual direction of effort basis which may include automated data processing, materials and procurement, tools and work equipment, fixed wing aircraft, helicopter, General Services Administration (GSA) rent and building management, general and administrative, laboratory, and Electric Power Research Institute;

"(2) Costs that are charged to benefiting projects and programs based upon a fixed rate for services performed which include vehicle maintenance, general shops, and equipment use;

"(3) Costs that are loaded to labor charged to specific projects or programs which include personnel benefits and leave accrual; and

"(4) Costs that benefit all construction projects and are charged to all projects as construction overhead.

"(v) Cost Shared Facilities are those facilities identified in the cost share percentage column of Exhibit C herein. Such facilities shall include but are not limited to costs for land, environmental impact studies, preconstruction materials, and construction which PacifiCorp and Bonneville agree to pay through an exchange of payments in accordance with the cost share percentages as provided in Exhibit C.

"(w) Credits are the applicable portion of any income, rebate, allowance, or other receivable relating to any Cost Shared Facilities received by either Party. This includes, but is not limited to, materials, surplus property, scrap, timber revenues and future sales of Jointly-Owned and cost-shared land (Fee-Owned and Easement Rights). Proceeds from Credits shall be paid to the other Party either as a billing credit or by cash refund based on the original Cost Shared Facility proration between Bonneville and PacifiCorp.

"(x) Hazardous Substances mean any hazardous, toxic, or dangerous substance, waste, or material that is now or becomes regulated under any federal, state or local statute, ordinance, rule, regulation or other law now or hereafter in effect pertaining to environmental protection, contamination, or cleanup, including without limitation, the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), 42 U.S.C.

9601 et seq., the Resource Conservation and Recovery Act (RCRA), 42 U.S.C. 6901 et seq., the Federal Water Pollution Control Act (CWA), 33 U.S.C. 1251 et seq., the Clean Air Act (CAA), 42 U.S.C. 7401 et seq., the Toxic Substances Control Act (TSCA), 15 U.S.C. 2601 et seq. and all comparable programs under Oregon Law.

"(y) Historic Contamination means all contamination through seepage, spill, disposal, or release by any other method, of a Hazardous Substance at or from any facility which occurred prior to the Amendment Effective Date.

"(z) Interest based on AFUDC rates and applicable to electric plant in service, shall be applied to Cost Shared Facilities placed in service before cost reimbursement has occurred.

"(aa) Jointly-Owned refers to those facilities identified in Exhibit C which are not solely owned by either Party.

"(bb) PacifiCorp Direct Costs are costs which are readily identifiable or obviously traceable to a specific program, project, or other cost objective and will not be included in PacifiCorp's Overhead Costs.

"(cc) PacifiCorp Overhead Costs are costs incurred which cannot be directly charged to any single point of application. PacifiCorp Overhead Costs are assigned to various categories in proportion to the benefit of each category. PacifiCorp overhead transactions are made by either allocations or by clearing. PacifiCorp's Overhead Costs are subject to change as PacifiCorp's methodology for computing Overhead Costs may change and shall be reflected in Actual Costs. PacifiCorp Overhead Costs include the following components and will not be included in PacifiCorp's Direct Costs:

"(1) Labor Loading. These costs are directly associated personnel costs and include payroll taxes, leave, and benefits.

"(2) Material Overheads (for stores issues and for direct purchases) includes the costs of purchase, storage, handling and distribution of materials and supplies.

"(3) Tool Overheads represent the costs incurred to the purchase, use, and maintenance of small tools for force account work.

"(4) Transportation Overheads represent the costs incurred to purchase, lease, rent, operate, and maintain the fleet of PacifiCorp vehicles.

"(5) Construction (General) Overheads are all other construction costs incurred as a corporation, but which are not assignable to a specific project. Construction Overheads are applied to PacifiCorp's Direct Costs plus PacifiCorp's Overhead Costs described above in Sections cc(1) through cc(4).

"(dd) Prior Costs. Actual Costs for Cost Shared Facilities incurred by the Parties through December 31, 1991, which are identified in section 7(b) to this Amendment.

"(ee) Project Diagram. Exhibit F to this Amendment describes the plan-of-service for the Eugene-Medford (Alvey-Meridian) project."

4. Revision of Exhibits. Section 2 of the Intertie Agreement is hereby deleted in its entirety and replaced with the following:

"2. Exhibits. Exhibits A through K are hereby incorporated as part of the Intertie Agreement as amended. Revisions to the Exhibits, except for Exhibit K shall be by mutual consent."

The monthly Operation and Maintenance (O&M) charge in Exhibit K may be revised unilaterally by Bonneville once every year to be effective on July 1, but not until after January 1, 1994.

5. Accounting and Record Keeping.

(a) Record Keeping. Each Party shall keep up-to-date books and records of financial transactions, and other arrangements in carrying out the terms of this Amendatory Agreement No. 2. Such books and records shall be kept in accordance with the system of accounts prescribed for electric utilities by FERC and shall be available for inspection on a regular basis to the other Party. Each Party shall have access to such records of the other Party as required for audit, for state and local tax preparation purposes, for regulatory purposes, and as necessary for engineering, design, and project management review.

(b) Continuing Property Records. Each Party shall maintain the complete cost records and investment reports on facilities they constructed in accordance with the Project Diagram, as well as investment records which delineate the ownership percentage in facilities constructed by the other Party.

For example, Bonneville will record 100 percent of the facilities constructed by Bonneville with an offsetting credit for PacifiCorp's percentage of ownership of those facilities and record Bonneville's ownership percentage of facilities constructed by PacifiCorp.

In conjunction with the final accounting and true-up of project costs, Bonneville and PacifiCorp shall exchange investment records and appropriate support documentation normally required for FERC account investment analysis. This may include, but is not limited to, structure/hardware lists, plan and profile drawings, and bills of materials. Bonneville and PacifiCorp shall provide periodic exchanges of information as necessary to properly identify replacements, retirements, additions and improvements as such activities occur on the Jointly-Owned facilities.

(c) Capital Spare Parts. Capital spare parts for the Jointly-Owned facilities are subject to joint-ownership and cost-sharing if they are unique to a specific Jointly-Owned or Cost Shared Facility and if they are stored at or near the Cost Shared Facilities. Spare parts that are charged to inventory shall not be cost-shared until the spare part is placed in service at a Jointly-Owned facility.

6. Capital Budgets. Four years prior to the year costs are expected to be incurred, each Party shall provide to the other Party a forecast of capital budget expenditures related to the planned construction and operation activities of the Cost Shared Facilities except for the excluded facilities identified by a footnote in Exhibit C. This forecast shall be provided to the other Party on or before July 1 of each year and shall include updates of any estimated costs for the next 3 years. The Parties shall exchange and review any necessary data as needed to determine the necessity and adequacy of the proposed construction and operation activities. This notification requirement shall not apply to emergency replacement of equipment.

7. Payment Provisions.

(a) Payments made under this Amendment shall be made in accordance with provisions in this section 7 and shall be made for the following periods:

(1) Actual Costs for Cost Shared Facilities incurred for Prior Costs;

(2) Advances and Actual Costs for the Cost Shared Facilities incurred for the period from January 1, 1992, through the last month listed in the cash flow exhibits, Exhibits G and H by monthly invoices in accordance with Section 7(c) Progress Payments;

(3) Payment or refund for the final accounting of Actual Costs in accordance with Section 7(d) Final Accounting of Costs;

(4) Payment for future capital replacements in accordance with Section 7(e) and tables to Exhibit J; and,

(5) Payment for Operation and Maintenance shall be in accordance with Exhibit K.

Bonneville and PacifiCorp shall specify the financial institution and account number in a written notice to each other at the invoicing address and provide updates as necessary for the transfer of funds. Each invoice shall include a reference to Contract No. DE-MS79-86BP92299 and an invoice number.

(b) Prior Costs Payments. Bonneville shall pay PacifiCorp by check or electronic transfer of funds within 30 days after the date of an itemized invoice for PacifiCorp's Prior Costs, $10,047,832.97 as agreed to by the Parties pursuant to the audit dated February 4, 1993. The date of such invoice shall be no earlier than the mailing date of such invoice. Such amount represents payment to PacifiCorp of Prior Costs through December 31, 1991, except for land and related land costs which may be subject to adjustment after Bonneville's receipt and review of all PacifiCorp's legal conveyance documents in accordance with Sections 8 and 14. Adjustments of Prior Costs as a result of PacifiCorp's final analysis of accounts performed for the final accounting of costs shall also be made upon mutual agreement of the Parties.

PacifiCorp shall pay Bonneville by check or electronic transfer of funds within 30 days after the date of an itemized invoice for Bonneville's Prior Costs, $4,920,877.92, as agreed to by the Parties pursuant to the audit dated December 31, 1992. The date of such invoice shall be no earlier than the mailing date of such invoice. Such amount represents payment to Bonneville of

Prior Costs through December 31, 1991, except for land and related land costs which may be subject to adjustment after PacifiCorp's receipt and review of all Bonneville's legal conveyance documents in accordance with Sections 8 and 14. Adjustments of Prior Costs as a result of Bonneville's final analysis of accounts performed for the final accounting of costs shall also be made upon mutual agreement of the Parties.

(c) Progress Payments. Each Party shall make monthly payments to the other Party for the Cost Shared Facilities incurred after January 1, 1992, in accordance with Sections 7(c)(1) and 7(c)(2) below. The initial invoice shall also include amounts due for all past months from January 1, 1992, through the Amendment Effective Date with a credit for the amount previously paid under the Interim Payment Agreement.

(1) Payment by PacifiCorp. Each month Bonneville shall submit an itemized invoice to PacifiCorp (Jerry Walker, 800 PSB, 920 SW. Sixth Avenue, Portland, Oregon 97204) for the next month's Advance, in accordance with Exhibit G, and any adjustments for the previously invoiced Advance amounts when Actual Costs for such month(s) are known. The date of such invoice shall be no earlier than the mailing date of such invoice. The Actual Costs adjustment shall identify the Cost Shared Facilities with an itemization of cost elements by Bonneville work functions (i.e., materials, design, construction, etc.)

PacifiCorp shall pay Bonneville by check or electronic transfer of funds within 30 days after the date of the invoice. Should the 30th day be a Saturday, Sunday, or holiday, as observed by PacifiCorp, then the due date shall be the next following business day.

A credit balance on an invoice of $100,000 or less shall be carried forward to the next month's invoice. A credit balance on an invoice of more than $100,000 shall be refunded to PacifiCorp by check or electronic transfer of funds within 15 days of the date of Bonneville's credit invoice. A refund of the credit balance shall also be made, regardless of the amount, if the sum of the remaining Advances is less than the credit balance.

(2) Payment by Bonneville. Each month PacifiCorp shall submit an itemized invoice to Bonneville (Bonneville Power Administration, P.O. Box 3621 - DSAC, Portland, Oregon 97208-3621) for the next month's Advance in accordance with Exhibit H, and any adjustments for the previously invoiced Advance amounts when Actual Costs for such month(s) are known. The date of such invoice shall be no earlier than the mailing date of such invoice. The Actual Costs adjustment shall identify the Cost Shared Facilities with an itemization of cost elements (i.e., labor, materials, purchase services, miscellaneous and overheads, etc.)

Bonneville shall pay PacifiCorp by check or electronic transfer of funds within 30 days after the date of the invoice. Should the 30th day be a Saturday, Sunday, or holiday as observed by Bonneville, then the due date shall be the next following business day.

A credit balance on an invoice of $100,000 or less shall be carried forward to the next month's invoice. A credit balance on an invoice of more than $100,000 shall be refunded to Bonneville by electronic transfer of funds within 15 days of the date of PacifiCorp's credit invoice. A refund of the credit balance shall also be made, regardless of the amount, if the sum of the remaining Advances is less than the credit balance.

(d) Final Accounting of Costs. Within 3 years after the date of commercial operation of all the Jointly-Owned and Cost Shared Facilities, Bonneville and PacifiCorp shall each prepare a final accounting of all Actual Costs incurred for the Cost Shared Facilities identified in Exhibit C.

Each Party shall prepare an itemized invoice for the total final Actual Costs with either a refund or payment due the other Party. Payments and refunds shall be made in accordance with Sections 7(c)(1) and 7(c)(2).

(e) Payment Provisions for Capital Replacements:

(1) For reimbursable Capital Replacements, either Party shall prepare, for execution by the Parties hereto, an additional table to Exhibit J each time the Parties hereto agree that facilities shall be added or replaced to those facilities identified in Exhibit C to the Intertie Agreement. Those facilities identified by footnote one in Exhibit C shall be exempt from further cost sharing on capital replacements. Each table shall specify the facilities to be installed, the work to be performed by each Party, and the estimated costs to be borne by each Party. Payments shall be made as provided in each table to Exhibit J for the work to be performed in amounts and at times requested by the Party due reimbursement.

(2) Upon execution by the Parties hereto, new tables to Exhibit J shall be attached to and deemed to be a part of this Amendment to the Intertie Agreement and shall be effective on the date specified therein.

(f) Operation and Maintenance Charges. Effective on December 18, 1992, and pursuant to Exhibit K, PacifiCorp shall pay Bonneville for 50 percent of the operation and maintenance of the three Alvey 500 kV power circuit breaker terminals. Such operation and maintenance charge shall be included in PacifiCorp's monthly Wholesale Power Bill and shall remain in effect until such time the Alvey 500 kV facilities are available for commercial operation as part of the AC Intertie. Effective on December 18, 1992, PacifiCorp shall pay Bonneville 35 percent of the operation and maintenance of the series capacitors at the Sycan Compensation Station (Sycan) pursuant to Exhibit K. Such operation and maintenance charge shall be included in PacifiCorp's monthly Wholesale Power Bill and shall remain in effect until such time as the Alvey-Meridian transmission line is available for commercial operation as part of the AC Intertie. However, the payments for such operation and maintenance charges shall be provided for in the follow-on Operations and Maintenance Agreement from the date of commercial operation as part of the AC Intertie.

(g) Disputed Billing. In the event of a disputed billing, full payment shall be made with written notification of the disputed amount. If it is determined that an adjustment is required, the adjustment shall be made on the next invoice allowing reasonable notice and time to make the adjustment. Refunds of the disputed amount shall include interest at the same interest rate specified in Section 7(h) below.

(h) Late Payment by Bonneville or PacifiCorp. Invoices not paid in full on or before the close of business on the due date shall be subject to an interest charge on the amount due from the due date to the date paid consistent with the Prompt Payment Act Renegotiation Board's Interest Rate published in the Federal Register.

8. Audit. Each Party, at its expense, shall have the right to review and audit any cost on the other Party's books, records, and documents that directly pertain to the billings, investments, and costs of the Cost Shared Facilities. Any audit(s) shall be undertaken by either Party's representative(s) upon reasonable notice to the other Party and at reasonable times and in conformance with generally accepted auditing standards. The foregoing shall not be construed to permit either Party to conduct a general audit of the other Party's records beyond those needed to perform an audit of the Cost Shared

Facilities. The Party being audited agrees to cooperate fully with any such audit(s). The right to audit a cost shall extend for a period of 3 years following the last day of the fiscal year in which such cost was incurred or the final accounting of costs under this Amendment. If either Party does not audit the costs of the other Party for fiscal years 1992, 1993, or 1994, prior to the completion of the final accounting of costs, the right to audit those costs shall extend for a period of 3 years after the date of completion of the final accounting of costs. The Parties agree to retain all records and documentation prepared in the normal course of business for the entire length of this audit period and in accordance with generally accepted accounting principles.

The Party being audited shall be notified promptly in writing of any exception taken as a result of an audit after completion of the audit. The Party being audited shall have 30 days to review the notice of exception. If the Parties agree upon any exception(s) found as a result of the audit, the owing Party shall directly refund the amount of such exception(s) within 30 days of such agreement to the other Party. In the event of late payment, the Late Payment Provisions of Section 7(h) shall apply to amounts not paid in full by the due date.

Prior to the Amendment Effective Date, the Parties performed audits of each Party's Prior Costs. Such costs shall not be subject to additional audits, except for the audit of supporting documentation required for accounting adjustments that may have originated from the Prior Cost audit. However, both Parties reserve the right to review Prior Costs billed under Section 7(b) for land and related land costs. Any Prior Cost adjustment shall be determined after a Party receives and reviews all legal conveyance documents from the other Party. The results of the Prior Cost audits and resulting amounts due are reflected in Section 7(b).

9. Ownership of Facilities.

(a) Transfer of legal ownership pursuant to Amendatory Agreement No. 2 shall be effective at such time the facilities are energized and made available for commercial operation as part of the AC Intertie and shall remain in effect so long as any facilities of the Alvey-Meridian Line are in existence and operable and shall survive the term of the Intertie Agreement.

(b) All Jointly-Owned equipment, facilities, and capital spare parts shall be identified as such with co-ownership tags and signs. Either Party, at such Party's sole expense, shall provide the tags and signs.

10. Operation and Maintenance of Facilities.

(a) The Parties agree that Section 1(b) to Amendment No. 1 to the Intertie Agreement is hereby replaced in its entirety by the following:

"(b) Maintenance and Operation. PacifiCorp shall assume system operation and maintenance responsibilities of the Dixonville 500 kV Substation including the series capacitors; the terminal facilities at Meridian Substation for the Dixonville-Meridian Line, including the series capacitors; the Alvey-Meridian Line; PacifiCorp's relays, digital fault recorder, and SCADA remote terminal unit at Captain Jack Substation; the loop-in of PacifiCorp's Malin-Meridian 500 kV Line at Captain Jack Substation; PacifiCorp's relays installed at Summer Lake and Malin Substations; PacifiCorp's Dead-End Tower installed at Sycan as part of the Sycan Addition; and all communication facilities owned by PacifiCorp. Bonneville shall assume system operation and maintenance responsibilities of the Alvey Substation including the series capacitors; all the facilities at Captain Jack Substation other than PacifiCorp's relays, digital fault recorder and SCADA remote terminal unit; the Sycan Addition other than PacifiCorp's Dead-End Tower; and all communication facilities owned by Bonneville. The Parties shall exchange maintenance standards with each other and shall carry out their respective maintenance responsibilities according to Prudent Utility Practices. Payment for operation and maintenance costs associated with these facilities shall be as specified in the Intertie Agreement, including Exhibit C, as amended."

(b) The Parties shall use best efforts to develop and execute a new AC Intertie Operation and Maintenance Agreement for the facilities identified in Exhibit C by December 1993. During the period between the energization date of any of these facilities and the date that such facilities are available for commercial operation as part of the AC Intertie, operation and maintenance shall be provided by the Parties as identified in Section 10(a) above and Exhibit C to the Intertie Agreement, without charge to the other Party, except for those facilities identified in Section 7(f) of this Amendatory Agreement.

11. Environmental Requirements.

(a) Historic Contamination. Neither Party shall be liable for any fines, penalties and assessments, costs for investigation, response, removal and remediation, arising from Historic Contamination of facilities owned by the other Party or operated by the other Party prior to becoming Jointly-Owned facilities pursuant to this Amendment.

(b) Disclosure of Information. Bonneville shall provide PacifiCorp, within 90 days after the Amendment Effective Date, a summary of all known and suspected Hazardous Substance release, spill and disposal events at facilities described herein which occurred prior to the Amendment Effective Date. PacifiCorp may request and Bonneville shall provide, for the purpose of establishing baseline contamination data for the facilities transferred to

Jointly-Owned facilities pursuant to this Amendment, all information including records, files and documentation pertaining to all known and suspected Hazardous Substance release, spill and disposal events at such transferred facilities. Such information shall also include correspondence, requests, determinations, findings and orders made by or to Federal, state or local agencies in connection with known and suspected Hazardous Substance release, spill and disposal events.

PacifiCorp shall provide Bonneville, within 90 days after the Amendment Effective Date, a summary of all known and suspected Hazardous Substance release, spill and disposal events at PacifiCorp's facilities described herein which occurred prior to the Amendment Effective Date. Bonneville may request and PacifiCorp shall provide, for the purpose of establishing baseline contamination data for the facilities transferred to Jointly-Owned facilities pursuant to this Amendment, all information including records, files, and documentation pertaining to all known and suspected Hazardous Substance release, spill and disposal events at such transferred facilities. Such information shall also include correspondence, requests, determinations, findings and orders made by or to Federal, state or local agencies in connection with known and suspected Hazardous Substance release, spill and disposal events.

(c) Emergency Environmental Responsibility. The Party in operational control of a Jointly-Owned facility shall prepare and obtain approval required for emergency response plans for Hazardous Substance releases from all appropriate Federal, state and local agencies and shall be responsible for management and implementation of all laws and regulations pertaining to Hazardous Substances at the Jointly-Owned facility. Costs associated with approval and implementation of such plans shall be included in the Actual Costs.

12. Capital Replacements. Cost sharing for replacement of facilities specified in Exhibit C, due to obsolescence or major failure, shall be shared by the Parties according to the original cost share percentage of such facilities and in accordance with Exhibit J and Section 7(e) except for the excluded facilities identified by footnote one in Exhibit C.

13. Decommissioning Costs. The Parties shall pay decommissioning costs of Jointly-Owned facilities in accordance with their ownership shares as specified in Exhibit C. Proceeds from the disposal of Jointly-Owned surplus property or facilities shall be equitably distributed or allocated to the Parties in accordance with their ownership shares as specified in Exhibit C. The cost-sharing of decommissioning costs shall survive the term of the Intertie Agreement.

14. Land and Improvements. Right-of-way and land costs for the Alvey-Meridian Line and for Alvey, Dixonville, Meridian, and Captain Jack Substations will be cost-shared consistent with Exhibit C and the following principles. Bonneville's land maps are attached as Exhibit I, 1 and 2. PacifiCorp's land drawings attached as Exhibit I 3 through I 9 represent the Parties intent using such generic examples.

(a) Alvey-Spencer Line. Right-of-way and/or land costs shall conform to the following:

(1) If Bonneville acquires new right-of-way (Easement Rights) on land not owned by Bonneville, Bonneville and PacifiCorp will each pay 50 percent of the Actual Cost to purchase such Easement Rights and will each receive 50 percent interest in such Easement Rights. Exhibit I, pages 1 of 13 and 2 of 13, provide an example of such right-of-way.

(2) If PacifiCorp uses existing right-of-way (Fee-Owned Land), Bonneville will not share in the cost and will receive easement for access only for such Fee-Owned Land. This includes land owned by PacifiCorp adjacent to PacifiCorp's Spencer Switchstation (Section 22, Township 18 South, Range 3 West, W.M.).

(b) Spencer-Meridian 500 kV Line. Right-of-way and/or land costs shall conform to the following:

(1) If PacifiCorp acquires new right-of-way (Easement Rights) on land not owned by PacifiCorp, Bonneville and PacifiCorp will each pay 50 percent of the Actual Cost to purchase such Easement Rights and will each receive 50 percent interest in such Easement Rights. Exhibit I, page 4 of 13, page 6 of 13, and page 7 of 13, provides examples of such right-of-way.

(2) If PacifiCorp acquires new land (Fee-Owned Land) for the sole purpose of providing right-of-way for the Spencer-Meridian Line, Bonneville and PacifiCorp will each pay 50 percent of the Actual Cost of acquiring such Fee-Owned Land and will each receive 50 percent ownership of the Fee-Owned Land actually utilized to provide the necessary right-of-way. This includes land that is excess to normal right-of-way requirements which was purchased to provide necessary right-of-way and has been rendered non-marketable due to the transmission line construction. Exhibit I, page 5 of 13 and page 8 of 13, provides examples of such right-of-way.

(3) If PacifiCorp acquires new land (Fee-Owned Land) to provide right-of-way for the Spencer-Meridian Line, which it intends to market or retain portions thereof for its own purposes, PacifiCorp will provide and maintain Easement Rights for the portion of such Fee-Owned Land necessary

for such right-of-way. Bonneville and PacifiCorp will each pay 50 percent of the Actual Costs to provide Easement Rights and will each receive 50 percent interest in such Easement Rights. Exhibit I, page 5 of 13, provides an example of such right-of-way.

(4) If PacifiCorp uses existing right-of-way (Easement Rights or Fee-Owned Land), Bonneville will not share in the cost and will receive easement for access only in addition to an ownership interest in the Alvey-Meridian 500 kV Transmission Line.

(5) If PacifiCorp secures any permits for right-of-way across public lands, Bonneville and PacifiCorp will each pay 50 percent of the Actual Costs associated with such permits and will each receive 50 percent interest in such permits. Exhibit I, page 7 of 13, provides an example of such right-of-way.

(6) If, in the future, PacifiCorp markets any of the Fee-Owned Land as described in Section 14(b)(2) herein for which Bonneville has paid PacifiCorp 50 percent of the Actual Costs, Bonneville will receive 50 percent of the sale proceeds, less expenses.

(c) Substations. Right-of-way and/or land costs shall conform to Exhibit C and the following:

(1) Alvey Substation. Land will be cost-shared jointly on square footage of usage within the area shown on Exhibit I, page 10 of 13, and each Party will receive a 50 percent ownership.

(2) Dixonville Substation. Land will be cost-shared jointly on square footage of usage within the area shown on Exhibit I, page 11 of 13, and each Party will receive a 50 percent ownership.

(3) Meridian Substation. Land will not be cost-shared jointly on the existing land as shown in Exhibit I, page 12 of 13. Bonneville will receive Easement Access only.

(4) Captain Jack Substation. Land will be cost-shared jointly on square footage of usage within the area shown on Exhibit I, page 13 of 13, and PacifiCorp will receive a 100 percent ownership of such specific area.

(d) Title Transfer. Title and easement rights will be transferred by and to the Parties by a recordable conveyance document agreeable to both Parties after energization of the Alvey-Meridian Line.

To accomplish this, each Party will provide the other a copy of each recorded conveyance instrument and all permits obtained. Each instrument will be identified by category Exhibit I, page 4 of 13 through page 9 of 13. A full set of property maps will also be provided by each Party to the other depicting ownership acquisition. Both acquisition documents and a full set of property records (Plans) will be given by each Party to the other within 30 days after execution of this Amendment.

15. Notices. Any notice required to be served in accordance with the terms of this Agreement, shall be in writing and sent by registered or certified mail, return receipt requested, to the appropriate address listed below:

Bonneville Power Administration
P.O. Box 3621 - P
Portland, OR 97228-3621

PacifiCorp
Jerry Walker, 800 PSB
920 SW. Sixth Ave.
Portland, OR 97204

16. Liability.

(a) Bonneville and PacifiCorp assert that neither Party is the agent or principal for the other or that they are partners or joint venturers; and the Parties agree that they will not represent to any other party that they act in The capacity of agent or principal for the other. Any judgments in tort obtained against either Party shall not be an Actual Cost of the Cost Shared Facilities.

IN WITNESS WHEREOF, the Parties hereto have executed this Amendatory Agreement in several counterparts.

PACIFICORP	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By	By
Name Dennis P. Steinberg (Print/type)	Name Randall W. Hardy (Print/type)
Title Vice President	Title Administrator
Date March 16, 1993	Effective Date March 16, 1993

(VS10-PMTT-3568e)

Exhibit F, Page 1 of 2
Amendatory Agreement No. 2
Contract No. DE-MS79-86BP92299
Pacificorp
Effective at 2400 hrs
on the effective date

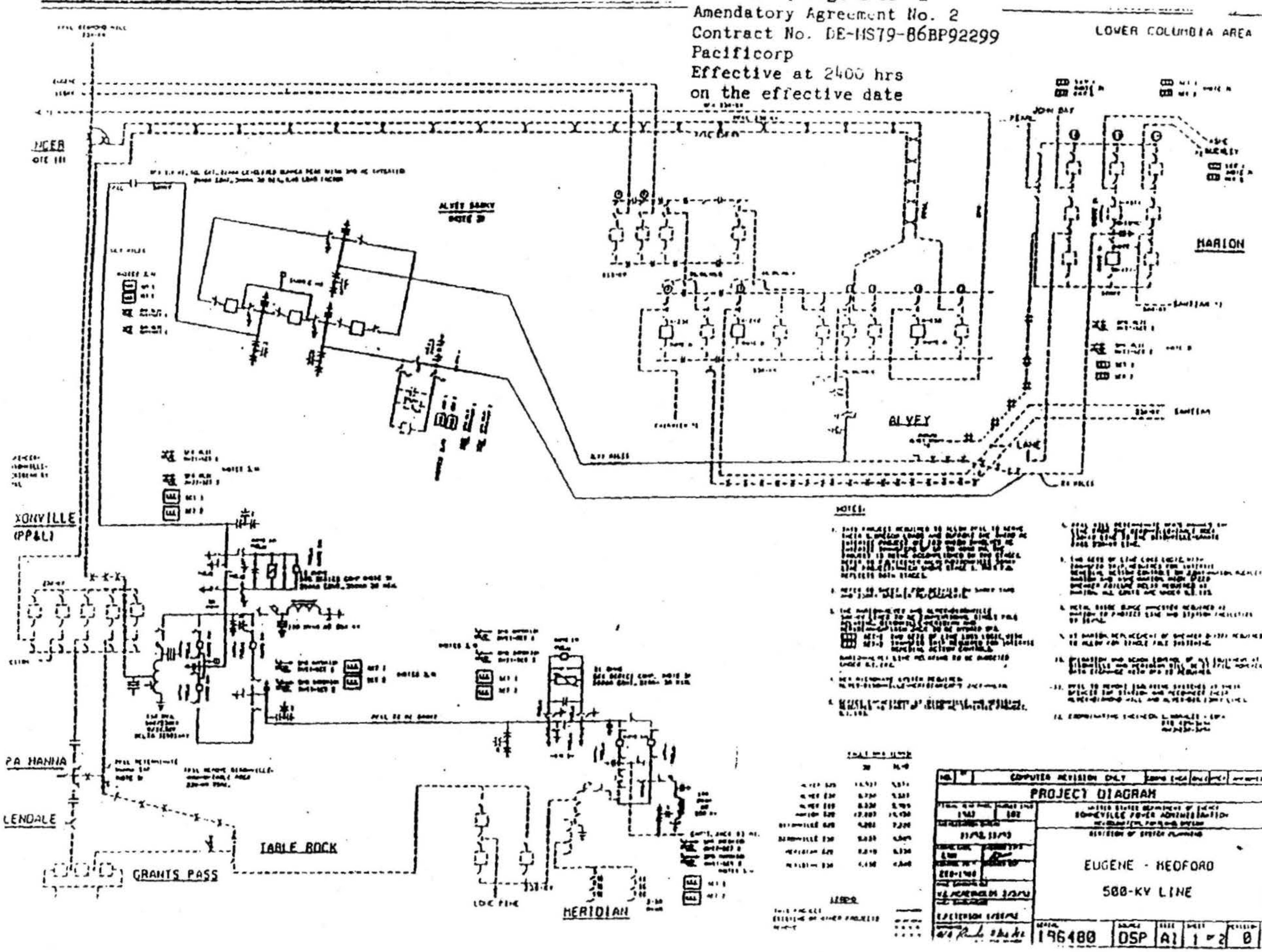
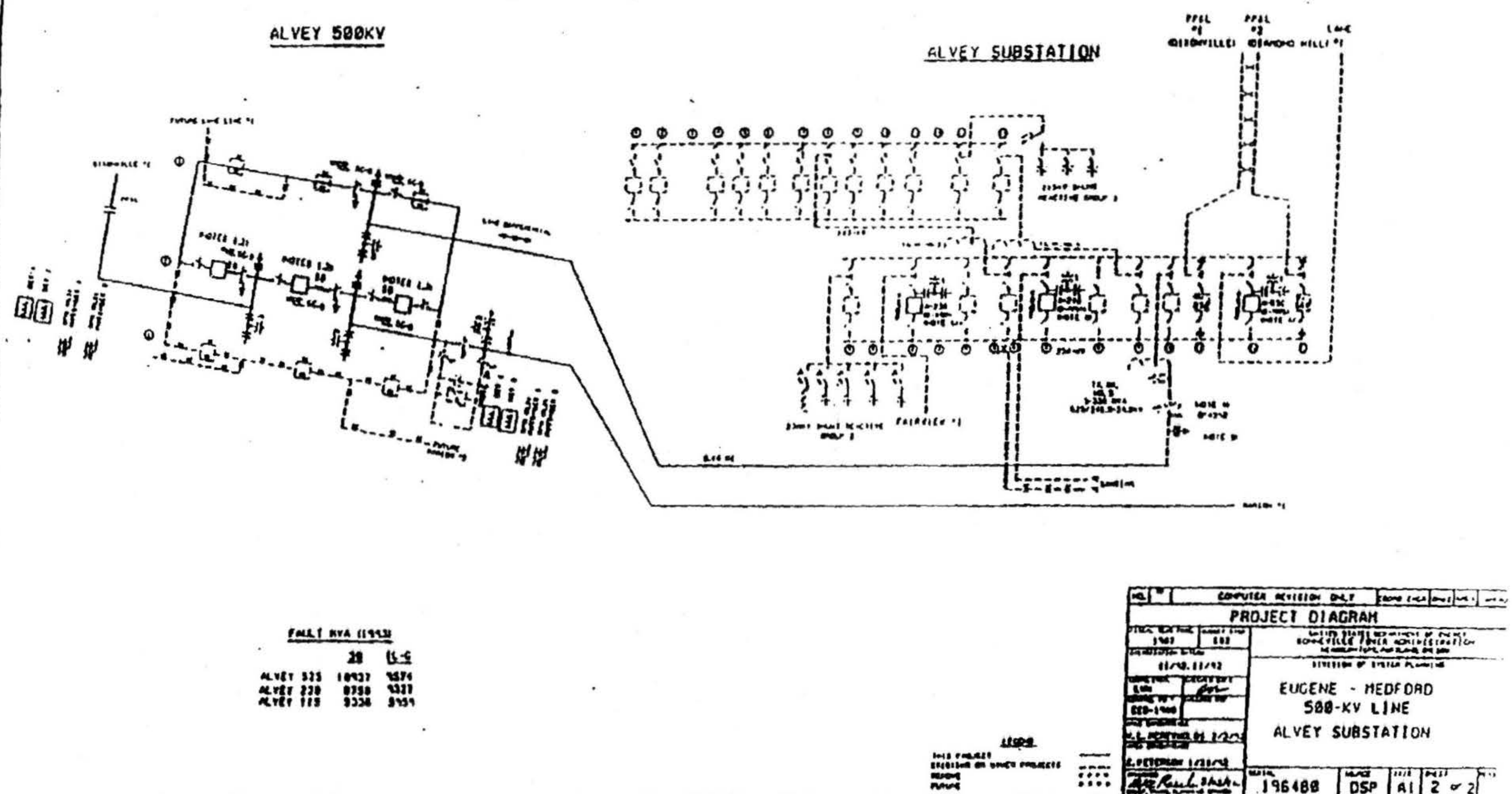


Exhibit F, Page 2 of 2
Amendatory Agreement No. 2
Contract No. DE-MS79-86BP92299
Pacificorp
Effective at 2400 hrs
on the effective date



Bonneville Cash Flow
(Dollars in Thousands)

Year	Month	Advances
1992	January through September	$ 5,534
	October	3,047
	Less Interim Payment	(6,000)
	November	392
	December	220
1993	January	585
	February	585
	March	769
	April	750
	May	325
	June	132
	July	166
	August	166
	September	78
	October	73
	Total	$ 6,822

Source Document:
Bonneville Eugene-Medford Project Cash Flow Estimates
Prepared by J. Quinata, dated 1/25/93
Prior Costs are excluded.

(VS10-PMTT-3596e)

PacifiCorp Cash Flow
(Dollars in Thousands)

Year	Month	Advances
1992	January through September	$ 25,125
	October	3,897
	Less Interim Payment	(16,000)
	November	3,000
	December	4,500
1993	January	2,896
	February	1,995
	March	1,853
	April	1,788
	May	2,076
	June	2,103
	July	2,026
	August	1,800
	September	1,492
	October	1,579
	November	1,101
	December	234
	Total	$ 41,465

Source Document:
PacifiCorp: October 1992 Project Forecast
Southern Oregon 500 kV Project
Prepared by T. Jestrab, dated 12/31/92
Prior Costs are excluded.

(VS10-PMTT-3596e)

Exhibit I, Page 1 of 13
Amendatory Agreement No. 2
Contract No. DE-MS79-86BP92299
PacifiCorp
Effective at 2400 Hours
~~on the Effective Date~~

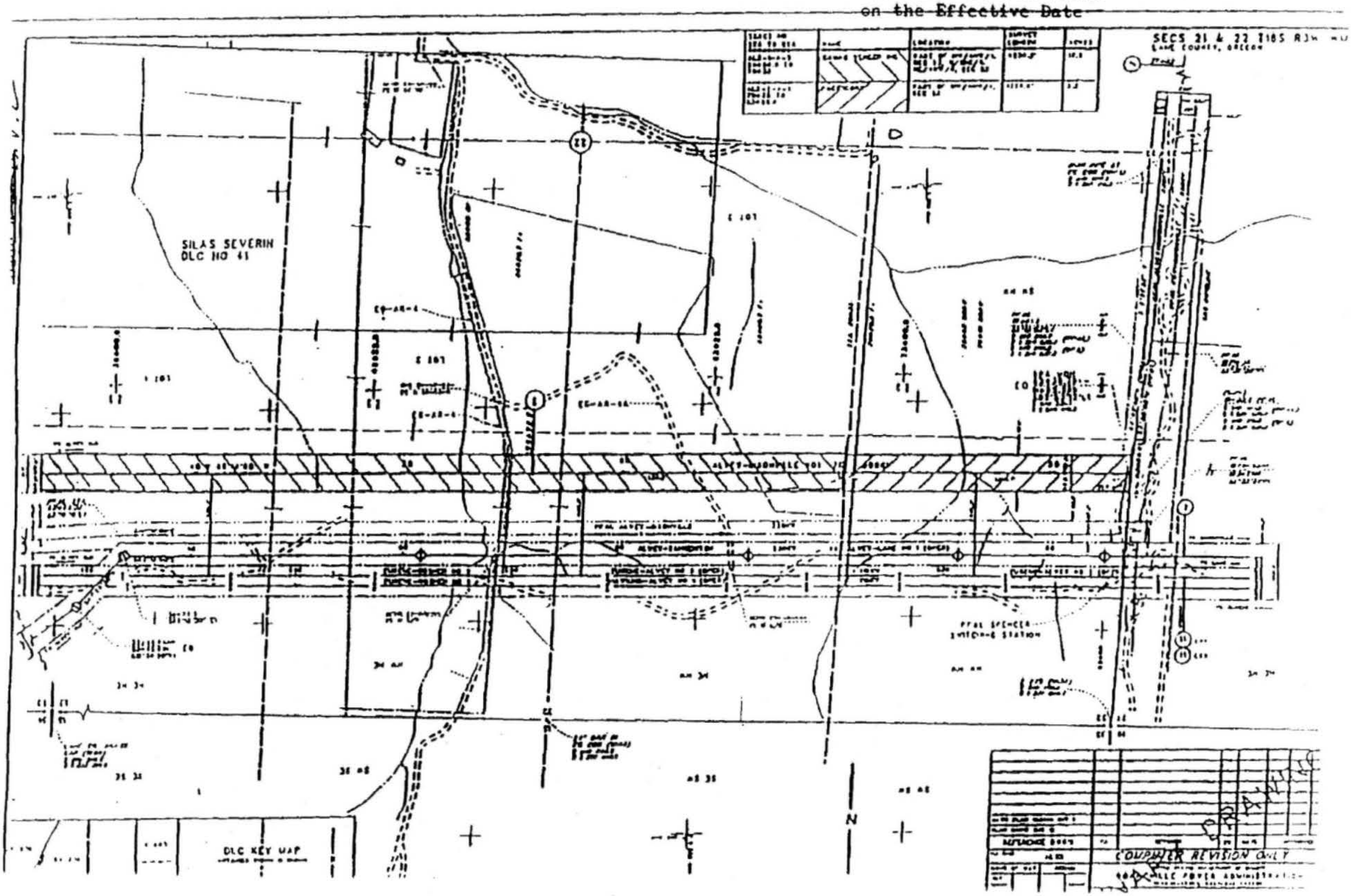
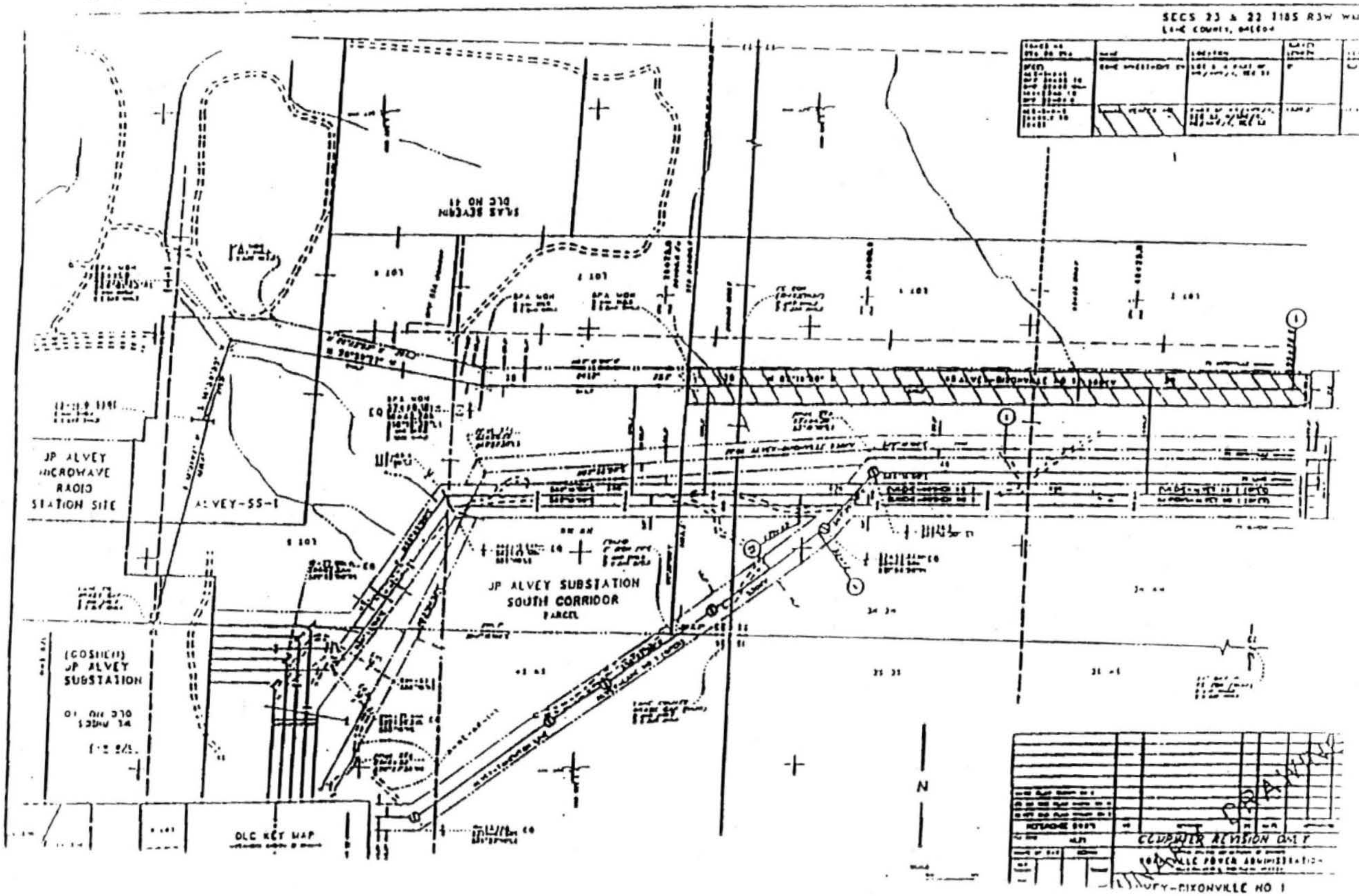


Exhibit 1, Page 2 of 13
Amendatory Agreement No. 2
Contract No. DE-MS79-86BP92299
PacifiCorp
Effective at 2400 Hours
~~on the Effective Date~~



LEGEND

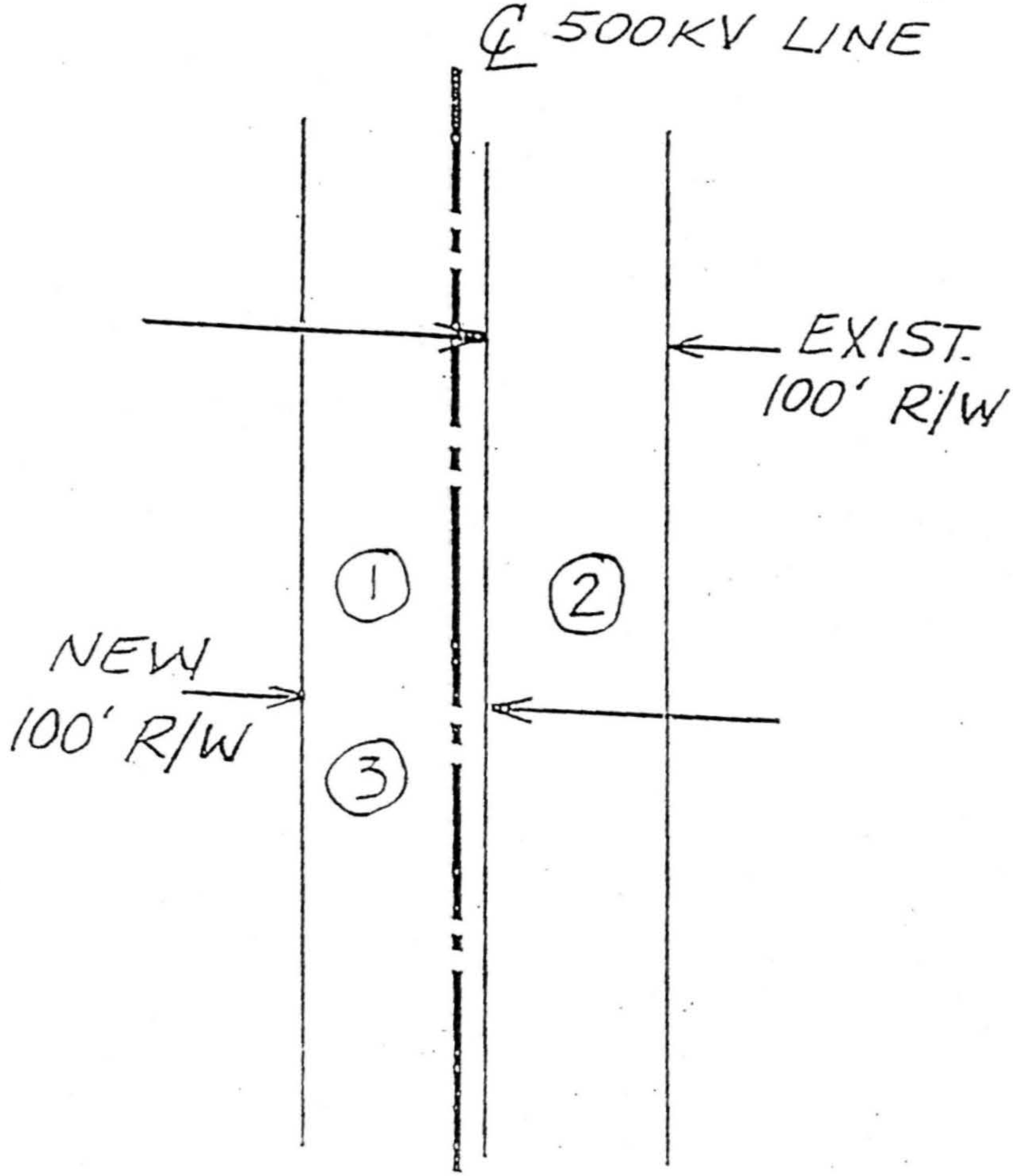
1 - SHARED COST

2 - SHARED EASEMENT ACCESS ONLY

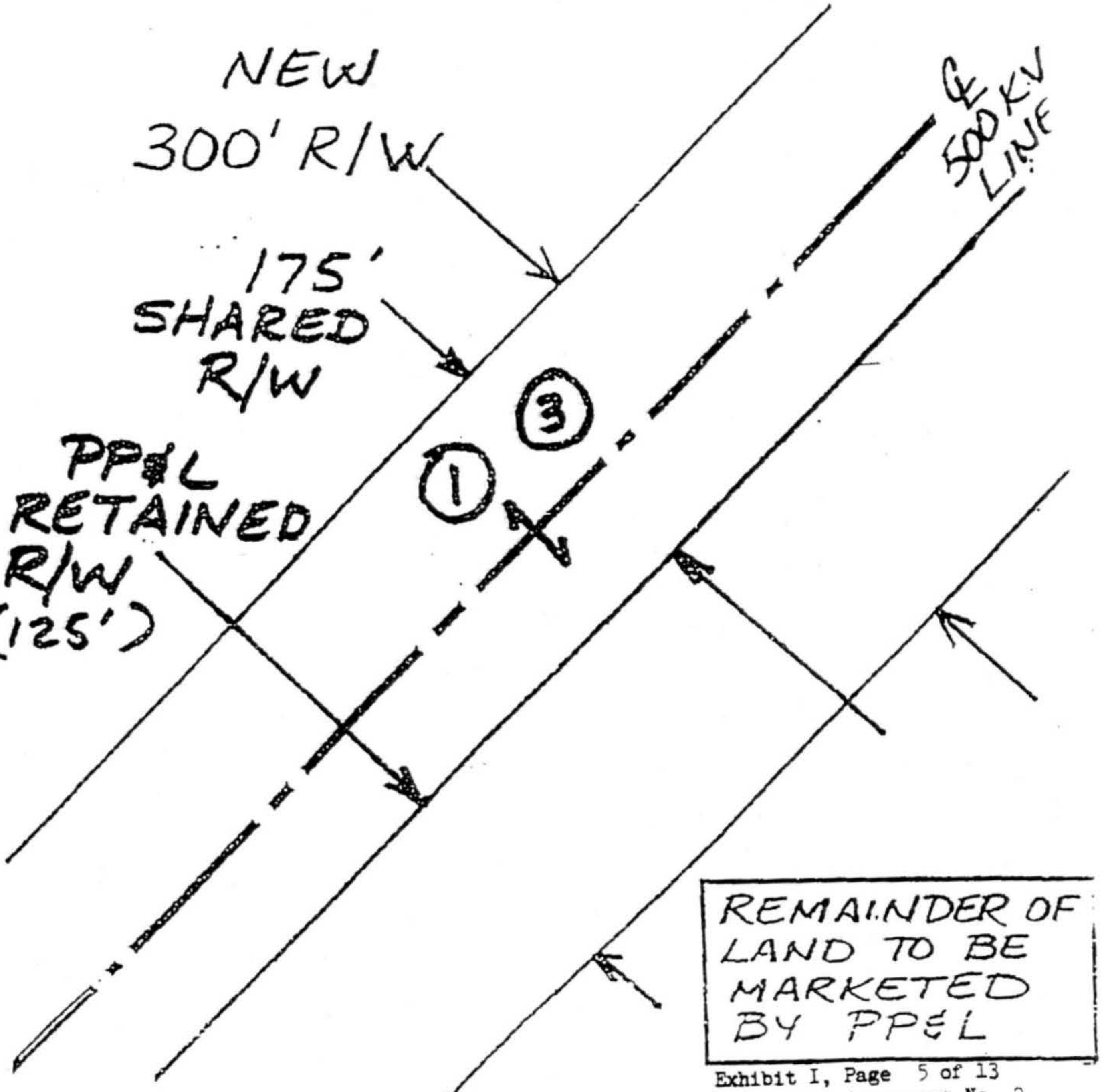
3 - SHARED EASEMENT RIGHTS

Exhibit I, Page 4 of 13
Amendatory Agreement No. 2
Contract No. DE-MS79-86BP92299
PacifiCorp
Effective at 2400 Hours
on the Effective Date

A. EXISTING R/W ON PRIVATE LAND - (1)



B. NEW R/W ON PP&L FEE OWNED LAND-(1



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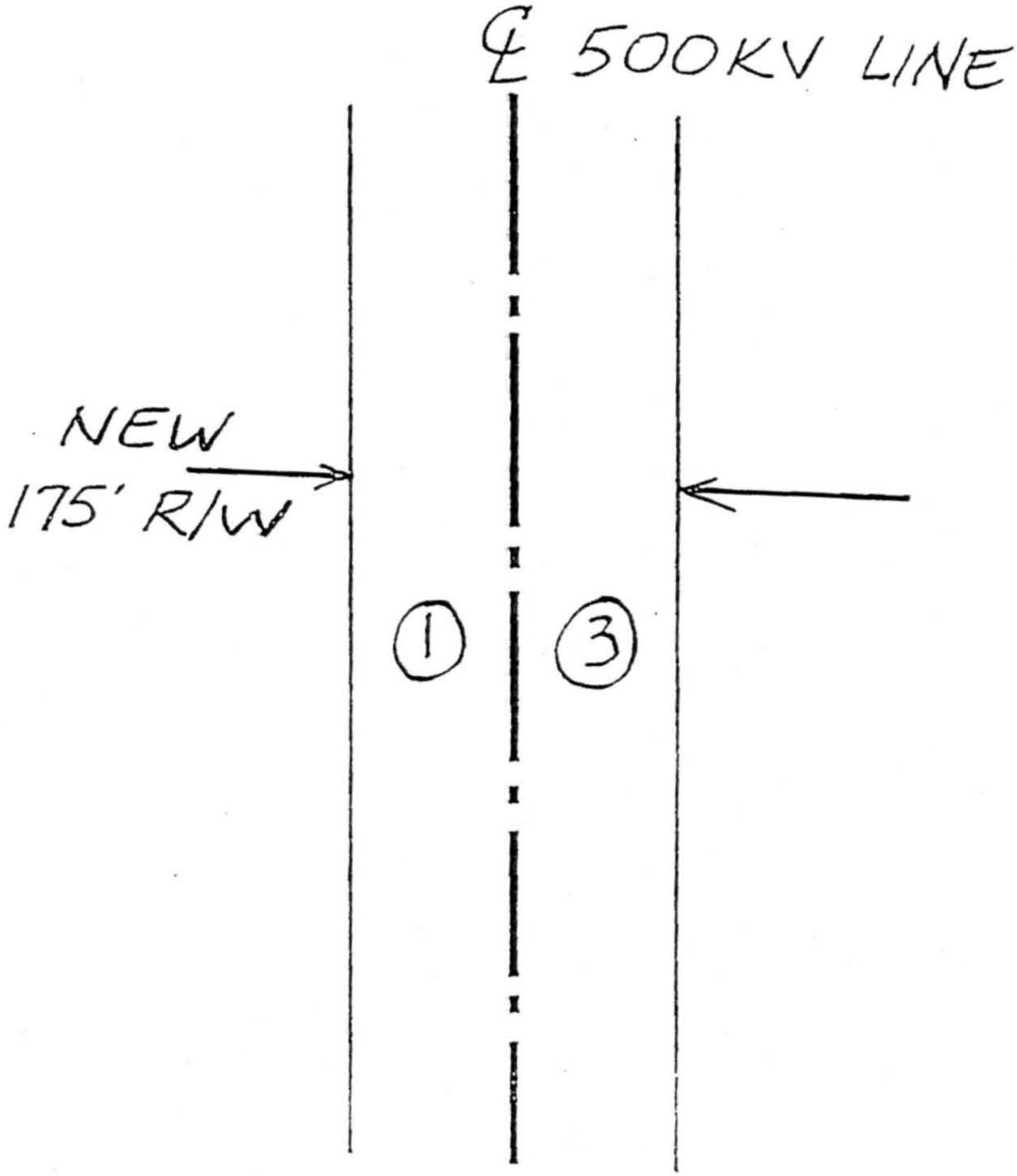
Amendatory Agreement No. [illegible]
Contract No. DE-MS79-86BP92299
PacifiCorp
Effective at 2400 Hours
on the Effective Date

C. NEW R/W ON PRIVATE LAND



D. NEW R/W ON GOVERNMENT LANDS

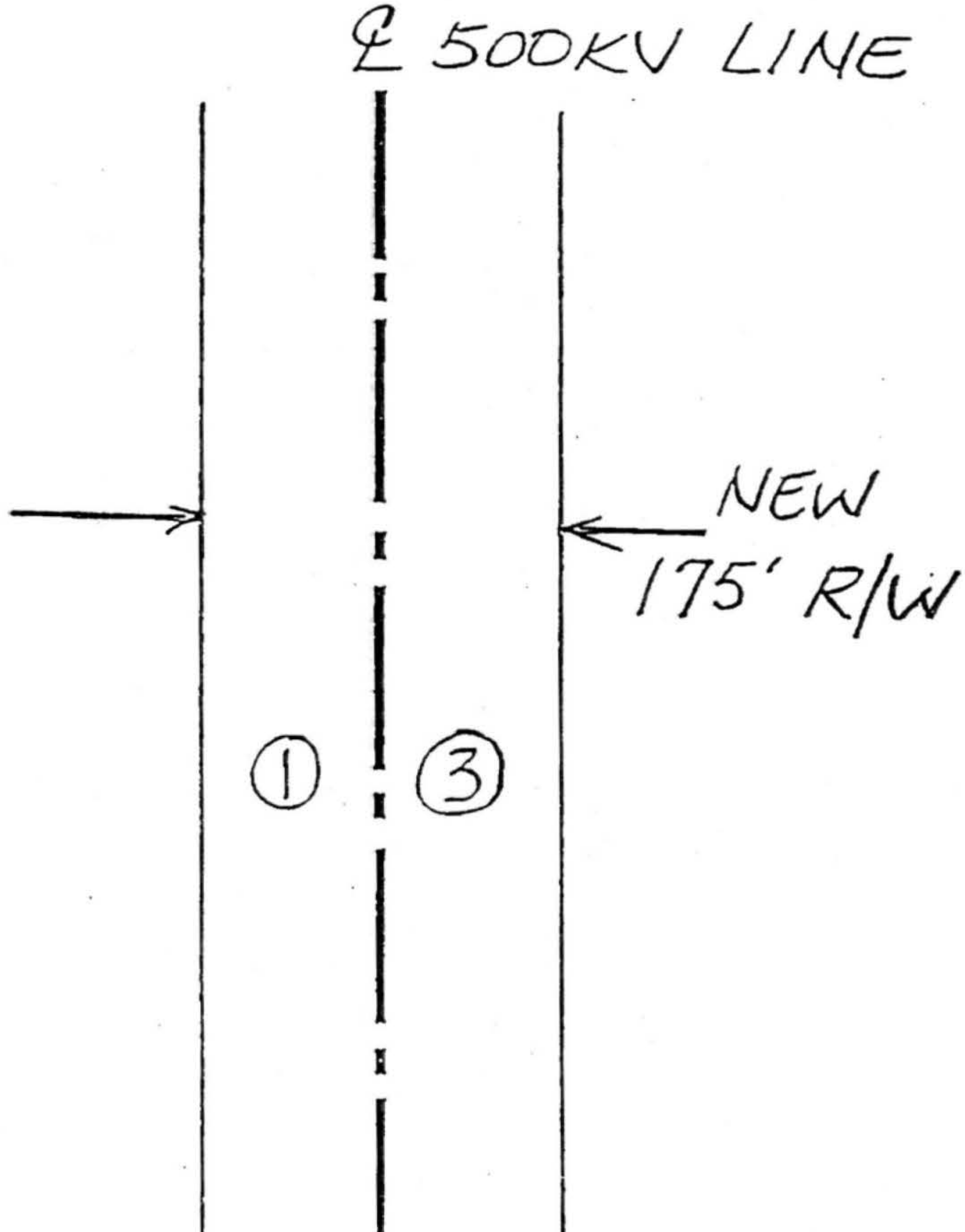


Exhibit I, Page 7 of 13
Amendatory Agreement No. 2
Contract No. DE-MS79-86BP92299
PacifiCorp
Effective at 2400 Hours
on the Effective Date

E. EXISTING R/W ON PP&L FEE OWNED LAND - (2)

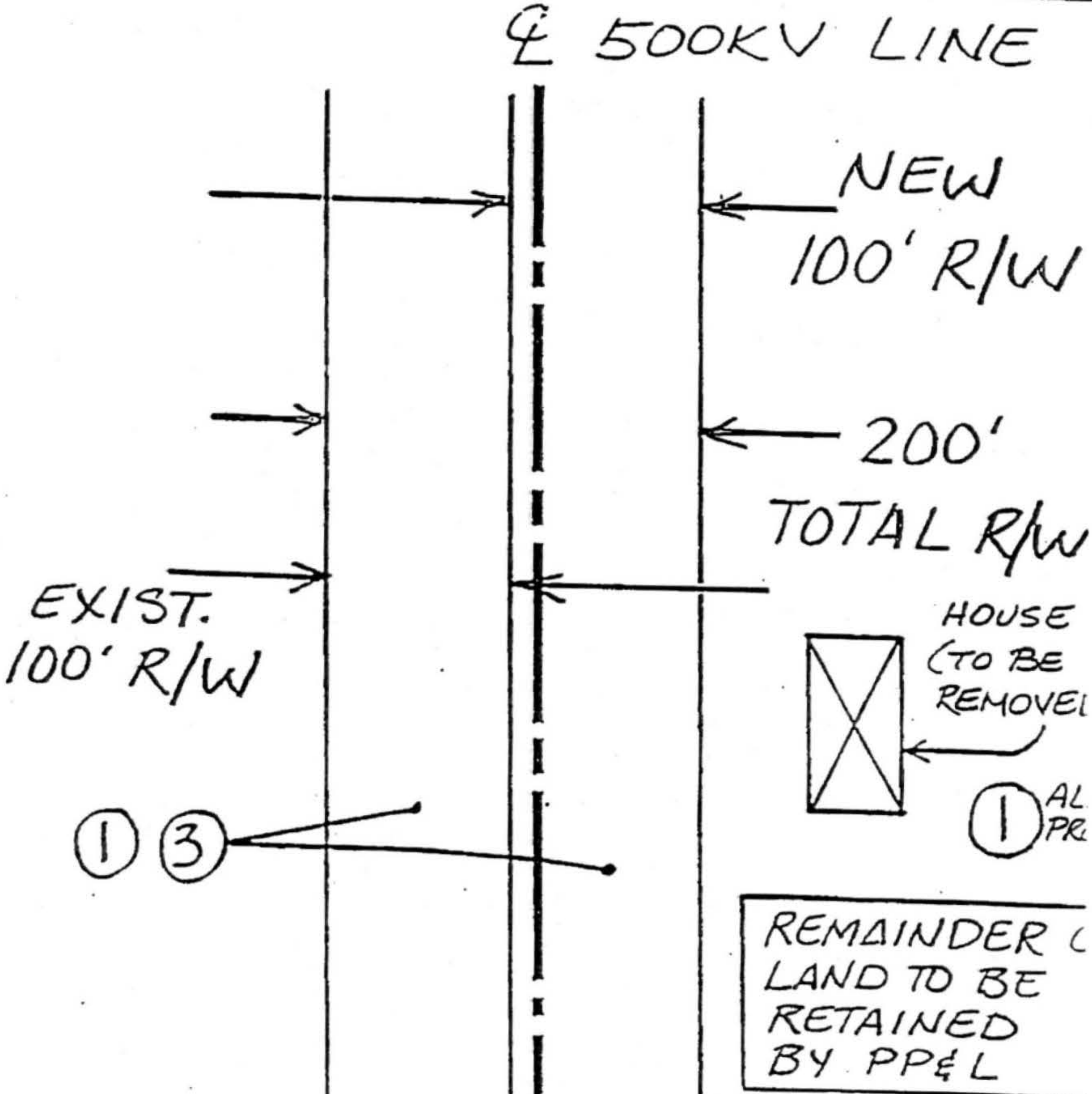
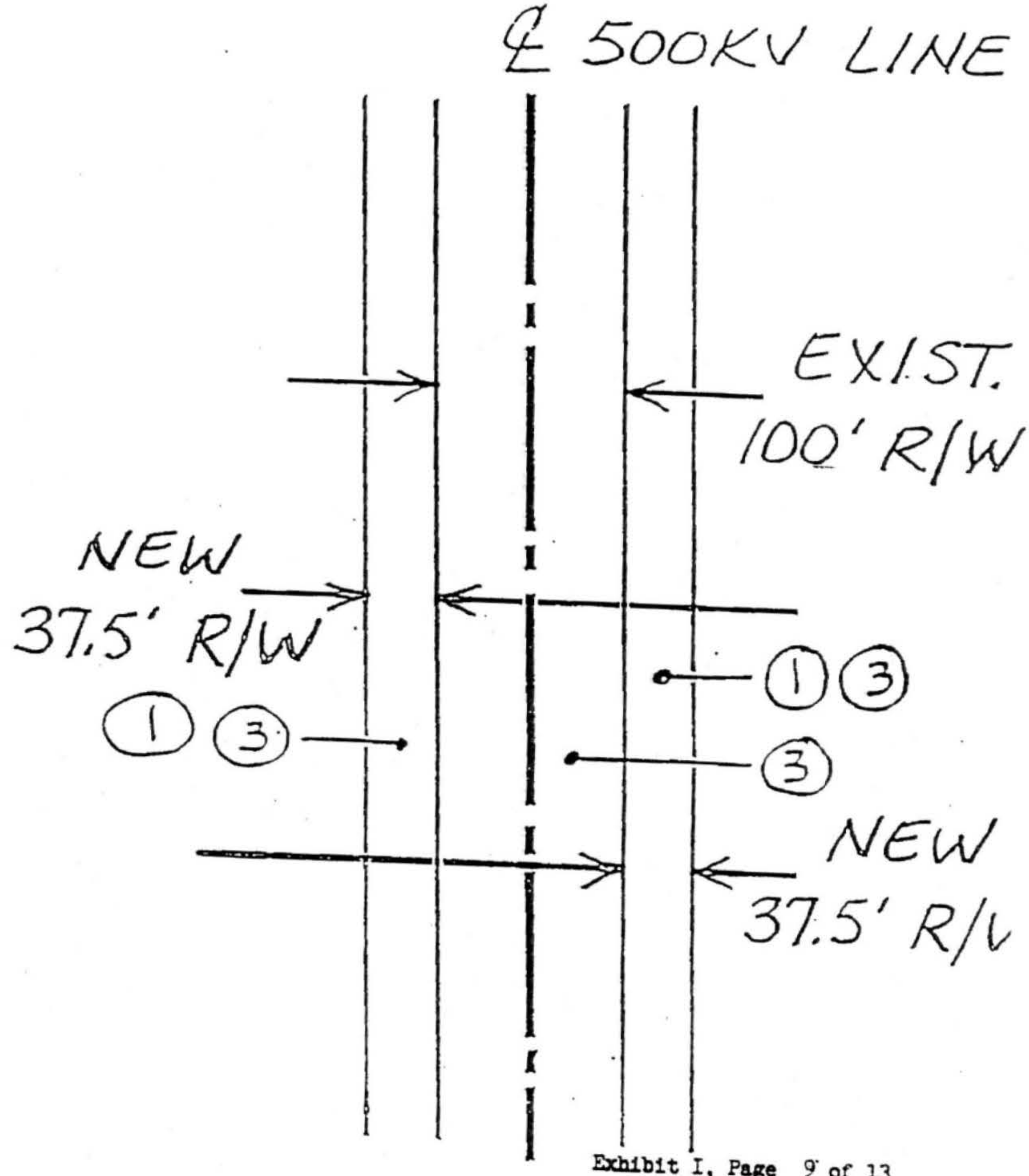


Exhibit I, Page 8 of 13
Amendatory Agreement No. 2
Contract No. DE-MS79-86BP92299
PacifiCorp
Effective at 2400 Hours
on the Effective Date

F. EXISTING R/W ON PRIVATE LAND – (2)



Contract No. DE-MS79-86BP92299
PacifiCorp
Effective at 2400 Hours
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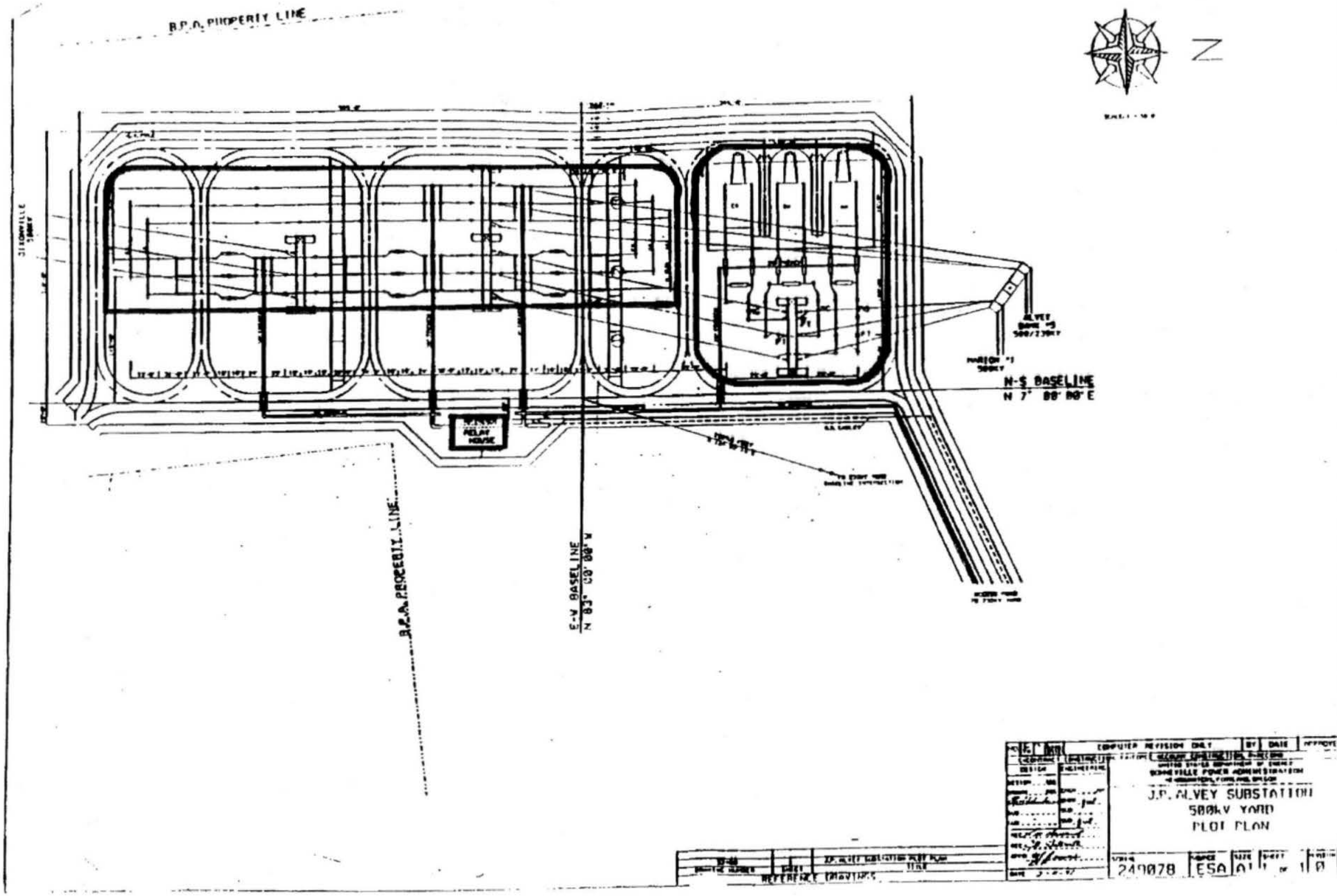

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PacifiCorp
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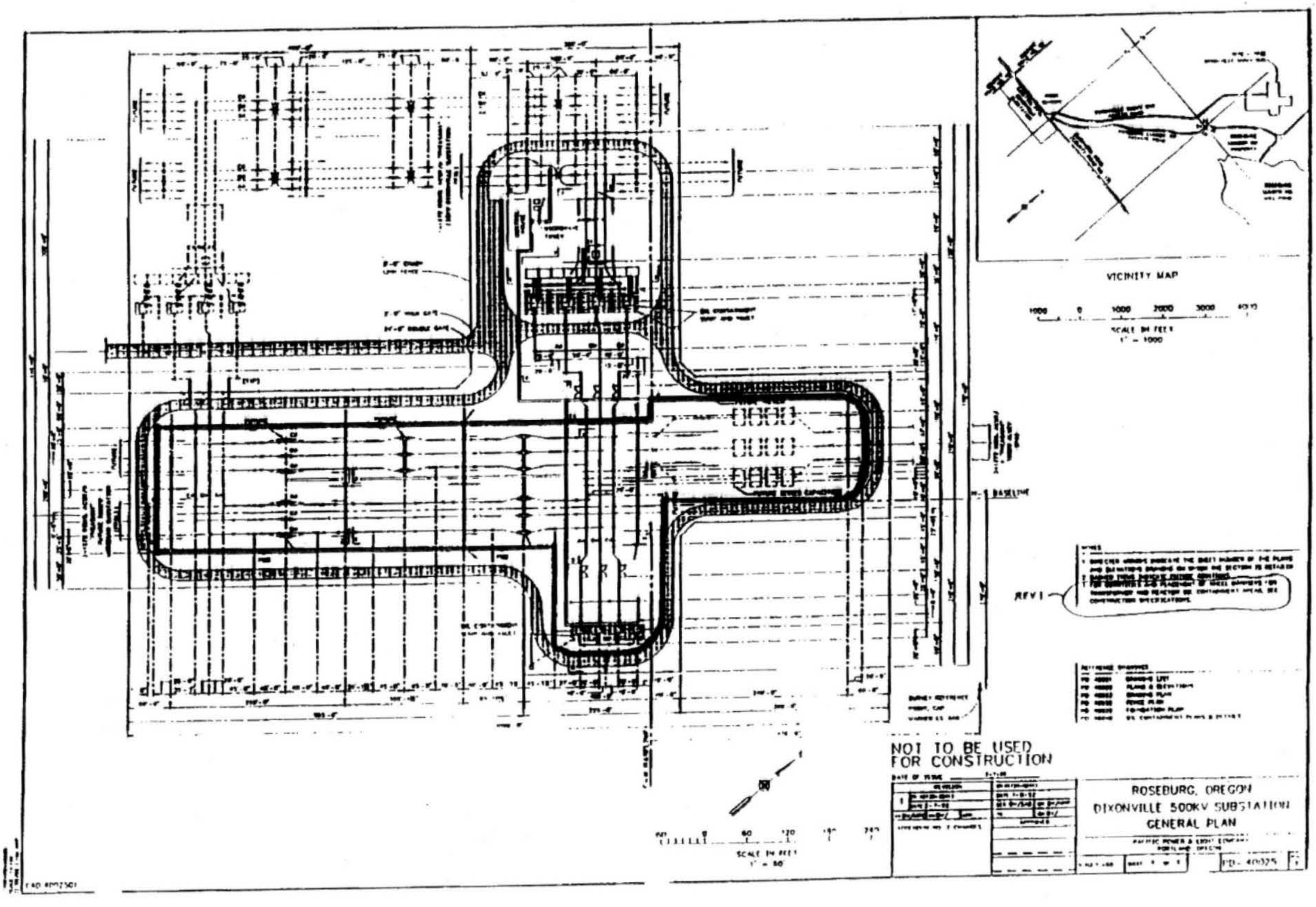
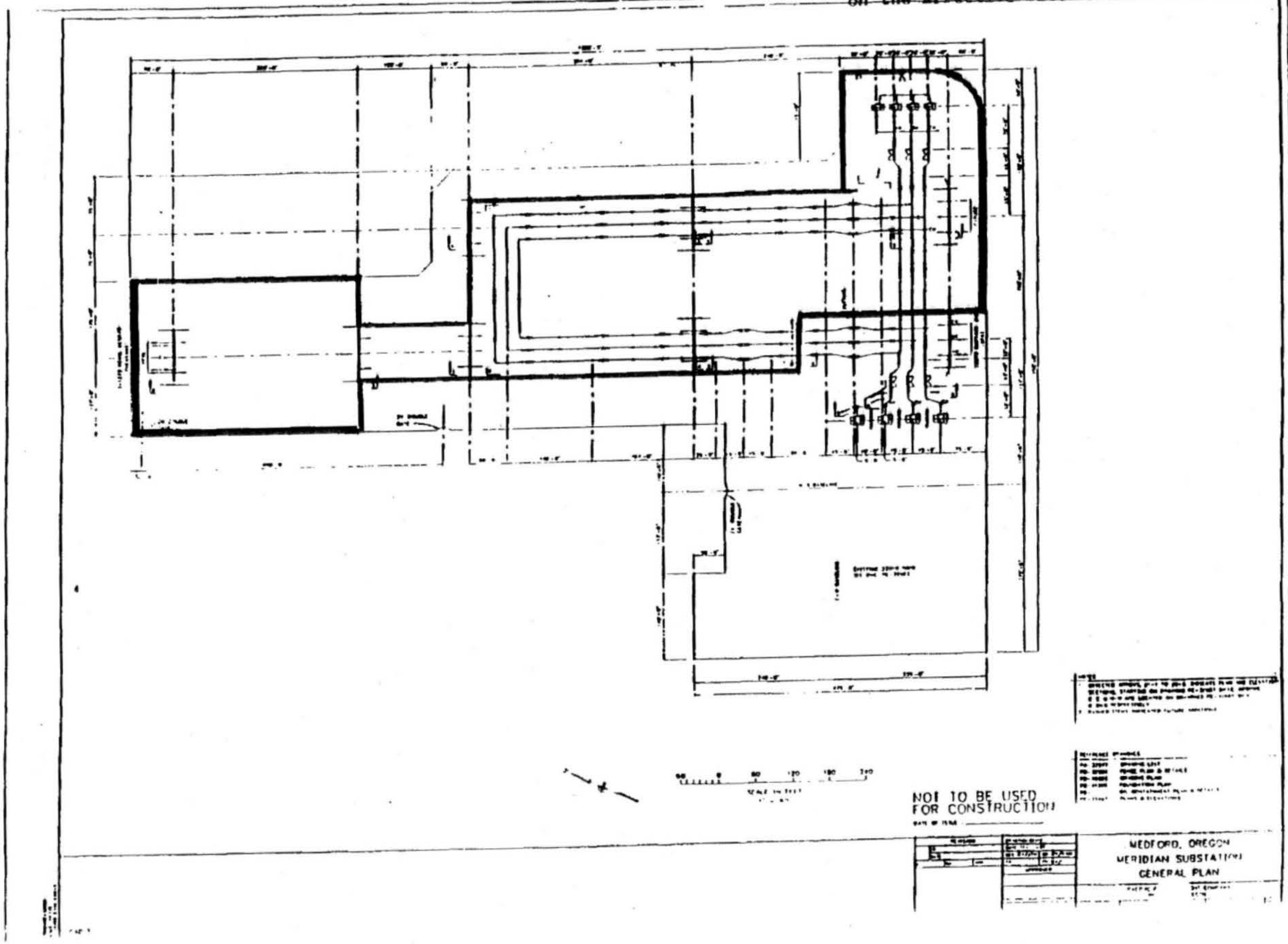
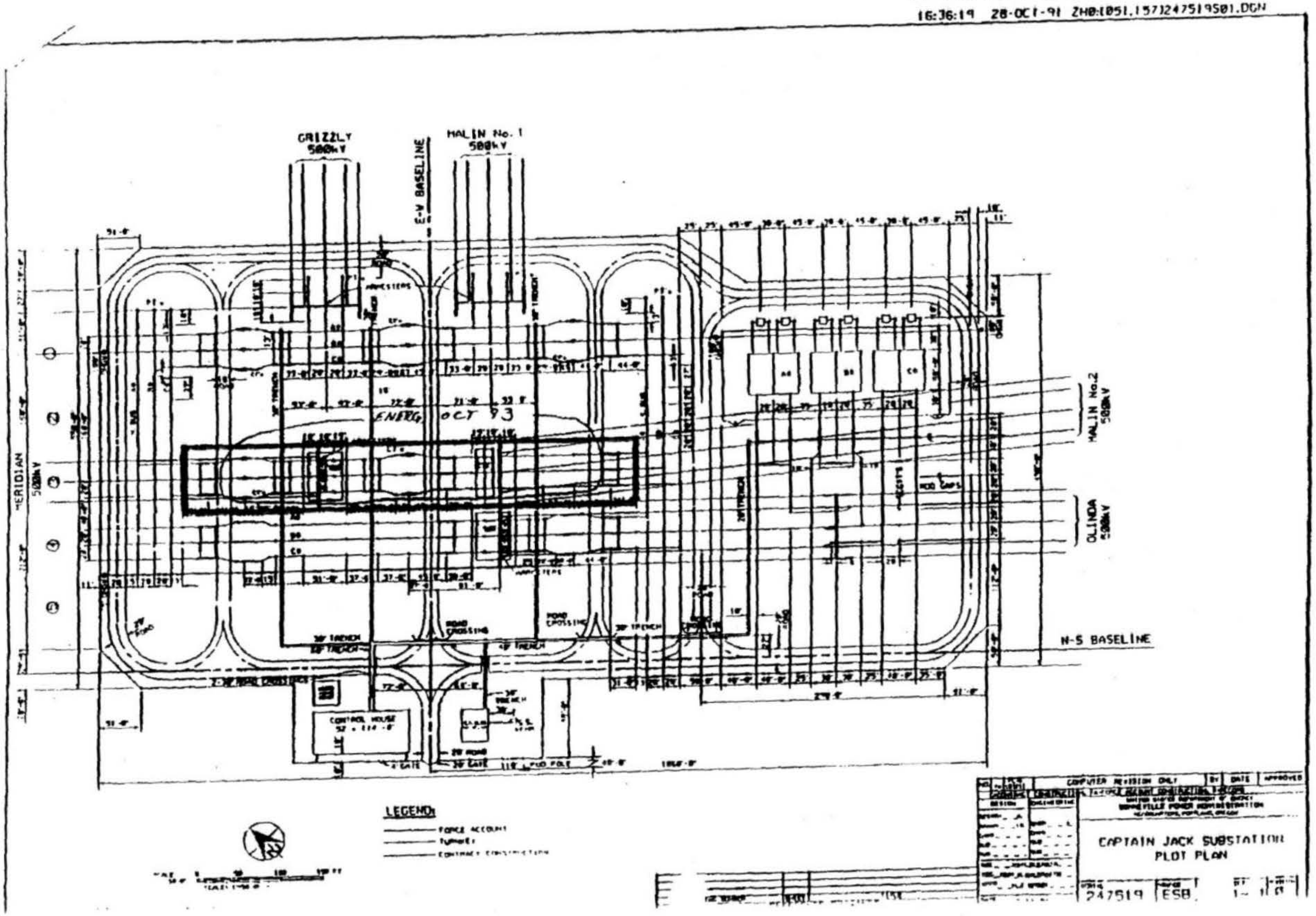
on the Effective Date



Contract No. DE-MS79-86BP92299
PacifiCorp
Effective at 2400 Hours
on the Effective Date



Amendatory Agreement No. 2
Contract No. DE-MS79-86BP92299
PacifiCorp
Effective at 2400 Hours
on the Effective Date



Capital Replacements

Either Party shall be able to initiate Capital Replacement projects to be added under this Exhibit as additional tables.

Exhibit K, Page 1 of 1
Amendatory Agreement No. 2
Contract No. DE-MS79-86BP92299
PacifiCorp
Effective as Stated Below

Calculation of O&M Charges

Facilities	Annual Operation and Maintenance Charge 1/	Annual Payment Due From PacifiCorp
Alvey		
(3) 500 kV PCB Terminals x ($46,018 terminal) Monthly Charge = $5752	$138,054	$69,027 2/
Sycan		
New Series capacitor bank (546 MVAR) in The Summer Lake-Malin 500 kV Line	$181,381	$63,483 2/

Monthly Charge = $5290

1/ O&M Cost: From Bonneville Power Administration's Annual O&M Charges for Customer-Owned or Leased Facilities dated September 30, 1991.
2/ Effective December 18, 1992

(VS10-PMTT-3568e)

ALVEY TO MERIDIAN INVESTMENT ALLOCATION

This Revision No. 1 adds the construction of a Storage Building to PacifiCorp's Dixonville 500 kV Substation.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
Alvey Substation						
• Three 500 kilovolt (kV) breakers/CT's buswork, towers, MOD's, PT's arresters, associated grounding, conduit, control and power cables, site dev. including landscaping, station service equipment for the three break ring bus layout.	Bonneville	50/50	50/50	Bonneville	42/58	Bonneville Power Administration (BPA) to operate and maintain (including maintenance of conduit, trench, and grounding systems at BPA discretion.)
• Environmental related work.	Bonneville	50/50	N/A	N/A	N/A	
• Series capacitors and auxiliaries.	Bonneville	50/50	50/50	Bonneville	42/58	BPA to operate and maintain (including maintenance of conduit, trench and grounding systems at BPA discretion.)
• Property acquired for 500 kV yard for Intertie purposes, excluding any additions, for future BPA projects.	Bonneville	50/50	50/50	Bonneville	42/58	Requires identification of boundaries. Operation and Maintenance (O&M) costs subject to nonroutine work. BPA to maintain at 100 percent BPA costs, things like surface rock, sidewalks, roads, fenceline, aesthetics.
• 500 kV Relay House building.	Bonneville	50/50	50/50	Bonneville	42/58	Future BPA/Pacific Power & Light (PP&L) expansion will be done at 100 percent BPA/PP&L costs, otherwise 50/50 if Intertie related. General building maintenance should be at BPA discretion with 42/58 cost sharing.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
• Relaying and controls, data system equipment inside the 500 kV Relay House for the Alvey-Dixonville, Marion-Alvey and 500 kV Tie Line.	Bonneville	50/50	50/50	Bonneville	42/58	BPA has future rights for BPA projects at 100 percent BPA costs otherwise 50/50 if Intertie related. O&M at 42/58 as per this Exhibit C for Intertie related facilities. BPA to maintain.
• RAS related equipment.	Bonneville					Refer to Contract No. 93039.
• Metering/Telemetering equipment on the Alvey-Dixonville Line.	Bonneville	50/50	50/50	Bonneville	42/58	BPA to do the maintenance at BPA discretion.
500 kV Tie Line (Alvey 500-Tx. Bank No. 5)						
• Transmission related costs.	Bonneville	50/50	50/50	Bonneville	100/0	50/50 ownership means PP&L has 50 percent capacity rights on the Tie Line but not physical ownership. Transfer rights over Bank No. 5 are not covered here.
Marion-Alvey 500 kV Line Modifications						
• Transmission costs only. [1]	Bonneville	50/50	100/0	Bonneville	100/0	
34.5 kV Line Relocation						
• Transmission costs only. [1]	Bonneville	50/50	100/0	Bonneville	100/0	

1 Credits and sharing of costs for capital replacements will not be applicable to this item after completion of the initial construction. Proceeds from credits realized by either Party during the initial construction phase of this item shall be subject to cost-share and the final accounting of costs.

Exhibit B
Revision No. 2 to Page 3 of 13
Sheet 1 of 2
Contract No. DE-MS79-94BP94332
PacifiCorp
Effective upon Execution

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	O&M	O&M Payment % Bonneville/ Pacific	Comments
Alvey-Dixonville 500 kV Line						
1.4 mile Alvey-Spencer Tap Section. 2/	Pacific	50/50	50/50	Pacific	42/58	Applicable only to the ROW for Intertie purposes. Additional ROW at 100% BPA costs.
Remaining 56.7 miles.2/	Pacific	50/50	50/50	Pacific	42/58	Requires identification of specific properties upon which these percentages are applicable. Access roads must also be considered. Timber costs and revenues also to be included.2/ KAC GEP
Landslide Abatement	Pacific	50/50	50/50	Pacific	42/58	Rock WALL and drain for slope stabilization tower 2/42 & 2/49
Spencer Tap						
Costs to reterminate the PP&L Alvey-Dix. 230 kV line.1/	Pacific	50/50	0/100	Pacific	0/100	
Costs to reterminate the PP&L Alvey-Diamond Hill 230 kV Line.1/	Pacific	0/100	0/100	Pacific	0/100	
Dixonville 500 kV Substation						
3-Breaker Ring Bus, 180 MVAR Reactor, arresters, grounding, conduit, control and power cables, site development, PT's, station service, isolating disconnect switches for 500 kV ring bus.	Pacific	50/50	50/50	Pacific	42/58	PP&L to operate and maintain (including maintenance of conduit, trench and grounding system at PP&L discretion).

DEC 12 2002 *uo*

Exhibit B
Revision No. 2 to Page 3 of 13
Sheet 2 of 2
Contract No. DE-MS79-94BP94332
PacifiCorp
Effective upon Execution

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	O&M	O&M Payment % Bonneville/ Pacific	Comments
Dixonville 500 kV Substation (cont)						
Series capacitors and Auxiliaries.	Pacific	50/50	50/50	Pacific	42/58	PP&L to operate and maintain (including maintenance of conduit, trench and grounding system at PP&L discretion).
SF6 Interrupters	Pacific	50/50	50/50	Pacific	42/58	

Bonneville Power Administration

By: *Clifford C. Perigo*

Title: *Sr. ACT Exec*

Date: *1-02-03*

PacifiCorp

By: *[signature]*

Title: *DIR. TRANS SERVICES*

Date: *12/12/02*

1/ Credits and sharing of costs for capitol replacements will not be applicable to this item after completion of the initial construction. Proceeds from credits realized by either Party during the initial construction phase of this item shall be subject to cost-share and final accounting of costs.

2/ Costs of: (1)removal of any existing 230 kV facilities;(2)permitting; and(3) incremental right-of-way to be included.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
• 500/230 kV Transformer and related equipment. [1]	Pacific	0/100	0/100	Pacific	0/100	PP&L to maintain.
• Wetland mitigation and other environmental requirements.	Pacific	50/50	N/A	N/A	N/A	
• Property acquired for 500 kV yard for Intertie purposes, excluding any additional future PP&L projects and any property for PP&L's 500/230 kV transformer.	Pacific	50/50	50/50	Pacific	42/58	Requires identification of boundaries. O&M costs subject to nonroutine work. PP&L to maintain at 100 percent PP&L costs, things like surface rock, sidewalks, roads, fenceline, aesthetics.
• 500 kV Control House building.	Pacific	50/50	50/50	Pacific	42/58	Future PP&L/BPA expansion will be done at 100 percent PP&L/BPA costs. Otherwise 50/50 if Intertie related. General building maintenance should be at PP&L discretion with 42/58 cost-sharing.
• Relaying and controls, data system equipment inside the 500 kV Control House, excluding that associated with PP&L's 500/230 kV transformer and 230 kV line position(s).	Pacific	50/50	50/50	Pacific	42/58	PP&L has future rights for PP&L projects at 100 percent PP&L costs. Otherwise 50/50 if Intertie related. O&M at 42/58 as per this Exhibit B for Intertie related facilities. PP&L to maintain.
• RAS related equipment.	Pacific					Refer to Contract No. 93039.
• Metering/Telemetering equipment on the Dixonville-Alvey Line.	Pacific	50/50	50/50	Pacific	42/58	PP&L to do the maintenance at PP&L discretion.
• Construction of a new storage building.	Pacific	50/50	50/50	Pacific	0/100	Use of building to be audited later to confirm cost sharing percentages.

1 Credits and sharing of costs for capital replacements will not be applicable to this item after completion of the initial construction. Proceeds from credits realized by either Party during the initial construction phase of this item shall be subject to the cost-share and the final accounting of costs.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
Dixonville-Meridian 500 kV Line						
• Transmission Costs. [2]	Pacific	50/50	50/50	Pacific	42/58	Requires identification of specific properties upon which these percentages are applicable. Access roads/bridge must also be considered. Timber costs and revenues also to be included.
Hanna Tap Relocation						
• Transmission and switching modification costs. [1]	Pacific	50/50	0/100	Pacific	0/100	Ownership and O&M costs percentages reflect existing arrangements which will be maintained.
Table Rock Switching Station						
• Costs to remove existing station.	Pacific	50/50	N/A	N/A	N/A	Existing station is in the path of the new 500 kV Line.
• Costs to reconnect Line No. 71 to south portion of Line No. 54. [1]	Pacific	50/50	0/100	Pacific	0/100	
Meridian Substation						
• Installation of 2-500 kV breakers, CT's, 180 MVAR reactor, 2 Line PT sets, isolating disconnect switches, arresters, buswork, conduit, control and power cables, grounding, including site development for Intertie purposes.	Pacific	50/50	50/50	Pacific	42/58	PP&L to operate and maintain (including maintenance of conduit, trench, and grounding systems at PP&L discretion). 50/50 ownership does not apply to the existing property upon which such facilities lie.

1 Credits and sharing of costs for capital replacements will not be applicable to this item after completion of the initial construction. Proceeds from credits realized by either Party during the initial construction phase of this item shall be subject to cost-share and the final accounting of costs.

2 Costs of: (1) removal of any existing 230 kV facilities; (2) permitting; and (3) incremental right-of-way to be included.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
• Environmental related work associated with the 500 kV expansions required.	Pacific	50/50	N/A	N/A	N/A	
• Any additional new property required to support the Project.	Pacific	50/50	50/50	Pacific	42/58	Requires identification of boundaries. O&M costs subject to nonroutine work. PP&L to maintain at 100 percent PP&L costs, things like surface rock, sidewalks, roads, fenceline, aesthetics.
• Access road improvements or new access road.	Pacific	50/50	50/50	Pacific	0/100	
• Existing property. [1]	Pacific	0/100	0/100	Pacific	0/100	Boundaries to be identified that conveys future BPA rights of use.
• Series capacitors and auxiliaries.	Pacific	50/50	50/50	Pacific	42/58	PP&L to operate and maintain (including maintenance of conduit, trench and grounding systems at PP&L discretion.)
• Data system equipment inside the existing 500 kV Control House associated with the two breakers, 180 MVAR reactor, and the Meridian-Dixonville and Meridian-Captain Jack Lines.	Pacific	50/50	50/50	Pacific	42/58	PP&L to maintain.
• Relaying and controls for the Meridian-Dixonville 500 kV Line.	Pacific	50/50	50/50	Pacific	42/58	PP&L to maintain.
• Relaying and controls for the Meridian-Captain Jack No. 2 500 kV Line. [1]	Pacific	50/50	0/100	Pacific	0/100	PP&L to maintain. BPA retains the right to review any future relay replacements/modifications.

1 Credits and sharing of costs for capital replacements will not be applicable to this item after completion of the initial construction. Proceeds from credits realized by either Party during the initial construction phase of this item shall be subject to cost-share and the final accounting of costs.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
• Any modifications to the existing Control House or construction of a new Control House as a result of the Eugene-Medford projects.	Pacific	50/50	50/50	Pacific	0/100	Future PP&L/BPA expansion will be done at 100 percent PP&L/BPA costs, otherwise 50/50 if Intertie related. PP&L to maintain at their discretion.
• Construction of a new storage building.	Pacific	50/50	50/50	Pacific	0/100	Use of building to be audited later to confirm cost sharing percentages.
• RAS related equipment.						Refer to Contract No. 93039.
Malin-Meridian 500 kV Line Loop Into Captain Jack Substation						
• Transmission Line modifications. [1]	Pacific	50/50	0/100	Pacific	0/100	[3]
Captain Jack Substation						
• Bay 3 facilities, including two 500 kV breakers, four MOD's buswork, PT's, conduit, grounding, towers.	Bonneville	50/50	0/100	Bonneville	0/100	BPA to operate and maintain (including maintenance of conduit, trench and grounding systems at BPA discretion.)
• Property under Bay 3.	Bonneville	50/50	0/100	Bonneville	Prorate	Prorate based on 2/7. BPA to maintain.
• Relays and controls, data systems equipment for Bay 3 facilities.	Bonneville	50/50	0/100	Pacific	0/100	PP&L to maintain. BPA retains the right to review any future relay replacements/modifications.

1 Credits and sharing of costs for capital replacements will not be applicable to this item after completion of the initial construction. Proceeds from credits realized by either Party during the initial construction phase of this item shall be subject to cost-share and the final accounting of costs.

3 Includes procurement of right-of-way from Meridian-Malin transmission line structures to Captain Jack Substation.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
• Remaining five 500 kV breakers, MOD's, buswork towers, conduit, grounding, site development. [1]	Bonneville	100/0	100/0	Bonneville	100/0	BPA to operate and maintain (including maintenance of conduit, trench, and grounding systems at BPA discretion.)
• Station service facilities for the entire station. [1]	Bonneville	100/0	100/0	Bonneville	Prorate	Prorate based on 2/7. BPA to maintain.
• Remaining relays and controls, data system equipment. [1]	Bonneville	100/0	100/0	Bonneville	100/0	BPA to maintain.
• Control House, exclusive of the property upon which it lies. [1]	Bonneville	100/0	100/0	Bonneville	100/0	Any future expansions due to PP&L additions will be at 100 percent PP&L costs but BPA to retain 100 percent ownership.
• All remaining property, including access road. [1]	Bonneville	100/0	100/0	Bonneville	100/0	Requires identification of boundaries. PP&L has right to add transformer in future.
• Series capacitors. [1]	Bonneville	100/0	100/0	Bonneville	100/0	Cost sharing/ownership is with TANC as per Interconnection Agreement (short-or long-term, whatever prevails). BPA to maintain.
• RAS related equipment.						Refer to Contract No. 93039.
• Metering/Telemetering equipment on the Captain Jack-Meridian and Captain Jack-Malin No. 2 Lines.	Bonneville	50/50	0/100	Bonneville	0/100	BPA to do the maintenance at BPA discretion.

1 Credits and sharing of costs for capital replacements will not be applicable to this item after completion of the initial construction. Proceeds from credits realized by either Party during the initial construction phase of this item shall be subject to cost-share and the final accounting of costs.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
Malin Substation						
• Any modifications/additions in PP&L's Control House in support of the Eugene-Medford/Third AC Intertie project, which includes the relay replacement for the Malin-Captain Jack Line. [1]	Pacific	50/50	0/100	Pacific	0/100	BPA retains the right to review any future relay replacements and/or modifications.
• Replacement of arresters on PacifiCorp's 500 kV reactor bank No. 4 [1]	Pacific	0/100	0/100	Pacific	0/100	
• Replacement of rod gaps with arresters on PacifiCorp's C.J. Line terminal. [1]	Pacific	50/50	0/100	Pacific	0/100	
• RAS related equipment.						Refer to Contract No. 93039.
• Any modifications in main control house.	Bonneville	50/25	50/25	Bonneville	50/25	
• Relay replacement for the Summer Lake Line.	Pacific	50/50	0/100	Pacific	42/58	Refer to Contract No. 93644.

1 Credits and sharing of costs for capital replacements will not be applicable to this item after completion of the initial construction. Proceeds from credits realized by either Party during the initial construction phase of this item shall be subject to cost-share and the final accounting of costs.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
Line Relays at Dixonville, Meridian, and Malin and Related Accessories						
• Line relays at Dixonville, Meridian, and Malin for the Dixonville-Alvey, Dixonville-Meridian, Meridian-Captain Jack, and Malin-Captain Jack No. 2 Lines are to be supplied to PP&L at BPA material cost plus BPA overheads. Any additional PP&L overheads, subject to 50/50 cost-share, is to be determined.	Pacific	50/50	See Comments			Ownership and O&M of such relays are as described under the respective substations.
• Spare Equipment.	Bonneville	50/50	50/50	N/A	N/A	Reference 7/12/91 Letter from Don Feltz to Susan Wiese. Such spare equipment are to be located at PP&L station(s) in southern Oregon. In addition to that referenced in the 7/12/91 Letter, there may be other spare equipment supplied by PP&L also located in southern Oregon and subject to cost-share. Required test equipment and tools are to be 100 percent respectively acquired by either BPA or PP&L for 100 percent discretionary use.
• Specialized relay training costs. [1]	N/A	50/50	N/A	N/A	N/A	Cost sharing only if agreed to capitalize such costs.

1 Credits and sharing of costs for capital replacements will not be applicable to this item after completion of the initial construction. Proceeds from credits realized by either Party during the initial construction phase of this item shall be subject to cost-share and the final accounting of costs.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
General PSC Modifications						
• PSC Modifications at Dittmer and ECC will be 100 percent BPA and similarly PSC modifications at PP&L control centers will be 100 percent PP&L.	100 percent respectively	100 percent respectively	100 percent respectively	100 percent respectively	100 percent respectively	
• Any other modifications at other wholly owned substations will be 100 percent of the respective party.	100 percent respectively	100 percent respectively	100 percent respectively	100 percent respectively	100 percent respectively	
Summer Lake Substation						
• Relay replacement for the Summer Lake-Malin 500 kV Line.	Pacific	50/50	0/100	Pacific	42/58	Refer to Agreement No. 93644.
• RAS related equipment.						Refer to Trust Tables 18 & 19, Contract No. 37013.
• Replacement of rod gaps with arrestors on PacifiCorp's Malin Line terminal. [1]	Bonneville	100/0	0/100	Pacific	0/100	
Sycan Series Compensation Station						
• New series capacitor bank in the South Lake-Malin 500 kV Line.	Bonneville	65/35	65/35	Bonneville	65/35	Refer to Agreement No. 93644.
• Bypass switch and associated support structures and foundations.	Bonneville	65/35	0/100	Bonneville	0/100	Refer to Agreement No. 93644.

1 Credits and sharing of costs for capital replacements will not be applicable to this item after completion of the initial construction. Proceeds from credits realized by either Party during the initial construction phase of this item shall be subject to cost-share and the final accounting of costs.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
• Dead-End Tower.	Pacific	65/35	0/100	Pacific	0/100	Refer to Agreement No. 93644.
Capital Spare Parts						
• Various spare parts.		50/50	50/50		42/58	Capital spare parts subject to cost sharing and joint ownership are to be mutually agreed upon and consistent with this Agreement.
Overall Planning, Preliminary Engineering, Project Management						
• Related costs for the Eugene-Medford Project, including any costs to resolve/mitigate legal matters (e.g., spotted owl and union vs. nonunion issues.)		50/50	50/50			
Communication						
• Summer Lake-Malin Communication, Two Downlinks. [1]	Pacific	50/50	0/100	Pacific	0/100	Refer to the Sycan Agreement Contract No. DE-MS79-92BP93644 and Cooperative Communications Agreement Contract No. DE-MS79-92BP93740.
• Dixonville-Two Microwave Terminals. [1]	Pacific	50/50	0/100	Pacific	0/100	Refer to the Cooperative Communications Agreement Contract No. DE-MS79-92BP93740.

1 Credits and sharing of costs for capital replacements will not be applicable to this item after completion of the initial construction. Proceeds from credits realized by either Party during the initial construction phase of this item shall be subject to cost-share and the final accounting of costs.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
• Meridian-Two Microwave Terminals. [1]	Pacific	50/50	0/100	Pacific	0/100	Refer to the Cooperative Communications Agreement, Contract No. DE-MS79-92BP93740.
• All other Bonneville Communication Facilities.	Bonneville	100/0	100/0	Bonneville	100/0	Refer to the Cooperative Communications Agreement, Contract No. DE-MS79-92BP93740.
• Other Pacific Communication Facilities.	Pacific	0/100	0/100	Pacific	0/100	Refer to the Cooperative Communications Agreement, Contract No. DE-MS79-92BP93740.

ACCEPTED:

PACIFICORP

By Brian D. Sickels

Name Brian D. Sickels
(Print/Type)

Title Vice President

Date June 23, 1995

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Adninistration

By [signature]
Senior Customer Account Executive

Name
(Print/Type)

Date 6/7/95

(MCPLAN-MPSM-W:\MPSM\CT\94332_B1.DOC)

1 Credits and sharing of costs for capital replacements will not be applicable to this item after completion of the initial construction. Proceeds from credits realized by either Party during the initial construction phase of this item shall be subject to cost-share and the final accounting of costs.

FACILITIES SERVING PACIFICORP'S LOAD AREA

PacifiCorp's Load Area is the area serviced by the following existing transmission lines and transformers.

1. PacifiCorp's Malin 500-230 kV transformer.
2. PacifiCorp's Yamsey-Chiloquin 230 kV line.
3. PacifiCorp's Dixonville 500-230 kV transformer.
4. PacifiCorp's Alvey-Dixonville 230 kV line.
5. PacifiCorp's Reston-Dixonville 230 kV line.
6. PacifiCorp's Meridian 500-230 kV transformer.

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

OFFICE OF THE ADMINISTRATOR

AUG 16 1991

In reply refer to: PMTI

Amendment No. 1
Contract No. DE-MS79-86BP92299

Mr. Thomas Lockhart, Vice President
Power Systems
PacifiCorp Electric Operations
920 SW. Sixth Avenue
Portland, OR 97208

Dear Mr. Lockhart:

Pursuant to subsection 4(a) of Contract No. DE-MS79-86BP92299, as amended, (Intertie Agreement) between PacifiCorp Electric Operations (Pacific) and Bonneville Power Administration (Bonneville), Bonneville hereby provides Pacific notice that, effective on the Effective Date, Bonneville is exercising its option to acquire a fifty percent undivided ownership interest in the Alvey-Meridian Line, as defined in such agreement and as modified herein. Pacific and Bonneville hereby agree to amend the Intertie Agreement by supplementing it with the following provisions, and replacing Exhibit C to such agreement with the attached Revision No. 1 to such Exhibit.

1. Completion of the Alvey-Meridian 500 kV Line.

(a) Design and Construction. Pacific and Bonneville shall use best efforts to complete the Alvey-Meridian Line by November 1993. Pacific shall design and construct the Dixonville 500 kV Substation including the series capacitors, the terminal facilities at Meridian Substation for the Dixonville-Meridian Line including series capacitors, and the Alvey-Dixonville portion of the Alvey-Meridian Line (Alvey-Dixonville Line) and the Dixonville-Meridian portion of the Alvey-Dixonville Line (Dixonville-Meridian Line). Bonneville shall design and construct the Alvey 500 kV Substation (Alvey Substation) including the Alvey Substation series capacitors. The Parties shall seek opportunities to utilize the capabilities of the other to minimize the installed cost and operation and maintenance cost and maintain schedules. The Parties shall agree at a later date upon the prudent design and construction of the Dixonville-Meridian Line, Dixonville 500 kV Substation series capacitors, and the Meridian Substation series capacitors. Each Party shall have the right to comment on the design and construction to be performed by the other Party.

(b) Maintenance and Operation. Pacific shall assume system operation and maintenance responsibilities of the Dixonville 500 kV Substation including the series capacitors, the terminal facilities at Meridian Substation for the Dixonville-Meridian Line including the series capacitors, and the Alvey-Meridian Line. Bonneville shall assume system operation and maintenance responsibilities of the Alvey Substation including the series capacitors. The Parties shall jointly develop maintenance standards and responsibilities that seek to limit the total annual operation and maintenance charges. Payment for operation and maintenance costs associated with these facilities shall be as specified in the Intertie Agreement, including Revision No. 1 to Exhibit C.

(c) Ownership.

(1) Pacific and Bonneville shall have undivided joint ownership of the Alvey-Meridian Line based upon the ownership percentages specified in Revision No. 1 to Exhibit C of the Intertie Agreement.

(2) Pacific and Bonneville shall have undivided joint ownership of incremental land acquisitions necessary to complete the Alvey-Meridian Line. Pacific shall convey to Bonneville any rights of use of Pacific's existing land sufficient to allow Bonneville to facilitate use of its right to fifty percent of the Incremental Capacity and ownership.

(3) The transfer of property titles (equipment, land, etc.) by the Parties in order to provide for undivided joint ownership shall occur at the time of energization of the Alvey-Meridian Line.

(4) Ownership of the communications systems shall be determined in accordance with section 6.

(d) Expansion of Facilities.

(1) Pacific shall have the right to modify the Dixonville 500 kV Substation and Meridian Substation, at its expense, as necessary for future required facilities without agreement by Bonneville, provided that Bonneville's ownership right to fifty percent of the Incremental Capacity of the Alvey-Meridian Line, as defined in the Intertie Agreement (Incremental Capacity), is not diminished.

(2) Upon expiration of the Intertie Agreement, Bonneville shall have the right to make additional facility connections at the Meridian Substation, at its expense, to facilitate use of its right to fifty percent of the Incremental Capacity, provided that such new connections do not increase loadings on Pacific's exclusively-owned facilities, diminish Pacific's rights to the Alvey-Meridian Line, or adversely impact Pacific's system.

(3) Bonneville shall have the right to modify the Alvey Substation, at its expense, as necessary for future required facilities without agreement by Pacific, provided that Pacific's ownership right to fifty percent of the Incremental Capacity is not diminished.

(4) Upon expiration of the Intertie Agreement, Pacific shall have the right to make additional facility connections at the Alvey Substation, at its expense, to facilitate use of its fifty percent share of the Incremental Capacity, provided that such new facility connections do not increase loadings on Bonneville's exclusively owned facilities, diminish Bonneville's rights to the Alvey-Meridian Line, or adversely impact Bonneville's system.

(e) Cost Sharing/Payment. Cost sharing for design and construction of the Alvey-Meridian Line shall be as specified in Revision No. 1 to Exhibit C. The Parties agree to develop mutually agreeable terms and conditions for payment for design and construction of the line. Such terms and conditions shall include provisions for progress payments, recognition of any payments made by either Party, or expenses incurred by either Party that are associated with the interim agreements (Contract Nos. DE-MS79-90BP92901, DE-MS79-91BP93112, DE-MS79-91BP93112, and DE-MS79-90BP93070) between the Parties as replaced by this amendment.

2. Alvey Substation 500 kV Terminal. Contract No. DE-MS79-90BP92901 shall terminate as of the Effective Date of this amendment.

3. Captain Jack Substation Connection/Terminal.

(a) Contract No. DE-MS79-91BP93112 shall terminate as of the Effective Date of this amendment.

(b) Pacific and Bonneville agree to equally share the cost of the following work performed by Pacific:

(1) procurement of the right-of-way from the Meridian-Malin transmission line structures to Captain Jack Substation;

(2) design and construction of the new 500 kV transmission line from Meridian-Malin 500 kV line structures to the Captain Jack Substation dead end towers;

(3) removal of certain Meridian-Malin 500 kV transmission line facilities; and

(4) design and construction of the strain bus connection between the Captain Jack dead end towers in Bay 3 to connect the Meridian-Malin line segments.

(c) Pacific and Bonneville agree to equally share the cost of the following work performed by Bonneville:

(1) design and construction of Captain Jack Substation dead end structures at Bay 3; and

(2) design and construction of power circuit breakers and associated Bay 3 terminal equipment including relays, and facilities to connect the Meridian-Malin line.

(d) Pacific shall own the land, right-of-way, power circuit breakers, terminal equipment including relays, and facilities up to the dead end towers, the dead end towers, and the strain bus between such towers at Bay 3.

(e) Bonneville shall assume system operation and maintenance responsibilities for all facilities at Captain Jack Substation except terminal Bay 3 relays and communications owned by Pacific, which shall be assumed by Pacific.

4. Sycan.

(a) The following provisions of Contract No. DE-MS79-91BP93157 shall terminate as of the Effective Date of this amendment:

(1) payment provisions specified in Section 4 and Exhibit A;

(2) cost sharing provisions specified in Sections 5 and 6; provided, however, the duties of the Parties described in such Sections shall remain; and

(3) ownership provisions specified in Section 7; provided, however, Pacific shall own the protective relays for the Summer Lake-Malin terminals pursuant to Revision No. 1 to Exhibit C of the Intertie Agreement.

(b) Contract No. DE-MS79-90BP93070 shall terminate as of the Effective Date of this amendment.

(c) Bonneville shall design and construct the series capacitors. Bonneville shall pay the design and construction costs and own the series capacitors until the Parties reach agreement pursuant to subsection 4(f) below.

(d) Bonneville shall operate and maintain the Sycan Compensation Station, including the series capacitors and bypass switch and associated structures; provided, however, the Summer Lake-Malin terminal relays shall be operated and maintained by Pacific. Payment for such operation and maintenance costs shall be as specified in Revision No. 1 to Exhibit C of the Intertie Agreement.

(e) The Sycan dead end tower shall be operated and maintained by Pacific.

(f) The Parties shall mutually agree to the terms and conditions for cost sharing for the Sycan series capacitors, bypass switch and associated structures, Summer Lake-Malin terminal relays, Summer Lake-Malin communications down-link, and dead end tower.

5. Coordinated Operations. The Parties shall jointly develop coordinated operating procedures for the Alvey-Meridian Line, Captain Jack Substation, and Sycan Compensation Station such that Bonneville may adequately perform as the system operator for the combined AC Intertie, and that maximize the Operational Transfer Capability of the AC Intertie and maximize Pacific's capability to serve its southern Oregon and northern California loads pursuant to Section 5(d)(2)(A) of the Intertie Agreement.

6. Communications. The Parties are in substantial agreement as to the terms, conditions, and ownership associated with requirements for communication facilities and equipment described herein, and shall complete such terms and conditions as soon as practicable following execution of this amendment. Such terms and conditions shall be incorporated in a separate agreement.

7. Liability. The Parties agree that if any injunction is issued by a court of competent jurisdiction against either Party's implementation of this amendment, such injunction shall not constitute a basis for a breach of contract action.

8. Effective Date. This amendment shall be effective on the later of:

(a) the issuance of a biological opinion by the United States Fish and Wildlife Service regarding the northern spotted owl which is acceptable to both Parties; or

(b) the date Bonneville receives a copy of this amendment signed by Pacific (Effective Date).

If this amendment is acceptable to Pacific, please sign and return one copy to Bonneville. The remaining copy is for your files. Please have your staff contact Allen Burns, at (503) 230-3367, to establish a schedule for discussions made necessary by the execution of this amendment.

Sincerely,

Administrator

ACCEPTED:

PACIFICORP ELECTRIC OPERATIONS

By ____________________
Thomas A. Lockhart

Title Vice President

Date August 16, 1991

Effective Date November 18, 1991

(VS6-PMTI-6802d)

CALCULATION OF LOSSES

Pursuant to Section 10 of the Letter of Understanding dated May 28, 1993, Bonneville and PacifiCorp have conducted a joint study of electrical losses related to AC Intertie transactions. Representatives of Bonneville and PacifiCorp jointly issued a letter dated April 21, 1994, which stated the conclusions reached as a result of this study. The treatment of electrical losses related to AC Intertie transactions shall be in accordance with the April 21, 1994 letter as summarized below.

Bonneville shall return losses to PacifiCorp. Such return of losses shall be calculated as 0.2 percent (0.2%) of Bonneville's Net AC Intertie Schedule, and shall be scheduled to PacifiCorp 168 hours later. "Bonneville's Net AC Intertie Schedule," means the net of all AC Intertie schedules, other than PacifiCorp's schedules associated with its Northbound and Southbound ownership rights in the AC Intertie. Returned losses shall be scheduled from Bonneville to PacifiCorp's main system points of delivery, or as otherwise agreed by the Parties.

EXAMPLE

On a given hour:

Net AC Intertie Schedule is 4,800 MW

PacifiCorp's Schedule over its AC Intertie capacity is 400 MW

Bonneville's Net AC Intertie Schedule is:

4,800 MW - 400 MW = 4,400 MW

Loss to be scheduled to PacifiCorp 168 hours later:

4,400 MW x 0.2% = 8.8 MW

Capital Replacements

Facility Description	Total Installed Cost	Cost Share Percentage Bonneville/ PacifiCorp	Ownership Percentage Bonneville/ PacifiCorp

Either Party may initiate Capital Replacement projects to be added under this Exhibit as revisions.

Exhibit F
Amendatory Agreement No. 2
Contract No. DE-MS79-94BP94332
PacifiCorp
Effective upon execution

BPA 500KV 3RD AC INTERTIE - CAPITAL ADDITIONS & REPLACEMENTS
Dec 1996 Through April 1998

PROJECT	FACILITY DESCRIPTION	MATERIAL	LABOR	OUTSIDE SERVICES	MISC	100% CHARGES	COST SHARE %	BPA SHARE AMOUNT
64290	Dixonville Sub - SF6 Interrupters	10,199.74	2,568.17		4,151.45	16,919.36	50/50	8,459.68
420227	Dixonville Sub- Retire Excess Mat'l (Removal)		1,404.10		196.06	1,600.16	50/50	800.08
	Total	10,199.74	3,972.27		4,347.51	18,519.52		9,259.76

Payment: Bonneville shall remit payment for the BPA SHARE AMOUNT within 30 days of receipt of invoice from PacifiCorp.

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Exhibit F
Contract No. DE-MS79-94BP94332
Revision No. 2, Effective upon Execution

Capital Additions

Facility Description	Total Installed Cost	Cost Share Percentage Bonneville/ PacifiCorp	Ownership Percentage Bonneville/ PacifiCorp
Alvey-Dixonville Line Landslide Abatement Tower 2/42 and 2/49	$434,446.33	50/50	50/50

Bonneville Power Administration

By: Clifford O Perigo

Title: Sr. VP Elec

Date: 1-02-03

PacifiCorp

By: [signature]

Title: DIR. TRANS. SERVICES

Date: 12/11/02

AUG 28 2003
9:43 AM VIA UPS
Exhibit F
Contract No. DE-MS79-94BP94332
Revision No. 3, Effective upon Execution
MO

Capital Replacements

Facility Description	Total Estimated Installed Cost	Cost Share Percentage Bonneville/ PacifiCorp	Ownership Percentage Bonneville/ PacifiCorp
Replace 6750 RFL equipment with RFL 9745 and SEL 2549 equipment at Alvey, Dixonville, Meridan, Captain Jack, Malin & Summer Lake Subs.	$544,172*	50/50	Per Exhibit B to Contract No. DE-MS79-94BP94332

* Reinbursment for cost sharing to be accomplished following completion of the work and determination of actual cost under Letter Agreement No. 03TX-11475.

Bonneville Power Administration

By: Clifford O Perigo

Title: SR. ACT EXEC

Date: 9-3-03

PacifiCorp

By: [signature]

Title: DIR. TRANS. SERVICES

Date: 8/27/03

TRANSMISSION SERVICES

DEC 0 4 2006

Revision No. 4
Exhibit F, Page 1 of 2
Contract No. DE-MS79-94BP94332
PacifiCorp
Effective on Date of Execution

CAPITAL REPLACEMENTS AND ADDITIONS

This Revision No. 4 adds numerous capital replacements and additions that were initiated by PacifiCorp during years 1999 through 2004. PacifiCorp neglected to completely bill Bonneville for these projects as they were completed.

CAPITAL REPLACEMENTS				
Description	Total Cost ($)	PacifiCorp Percent Share	Bonneville Percent Share	Amount Owed by Bonneville ($)
1. Alvey-Dixonville Line – Install erosion control	9,631.92	50%	50%	770.55[1]
2. Dixonville-Meridian Line – Rebuild R/W between 5/24 and 3/26	12, 333.48	50%	50%	986.68[1]
3. Dixonville-Meridian Line – Foundation treatment 4/74 – 4/52	11,089.16	50%	50%	887.13[1]
4. Dixonville-Meridian Line – R/W catwork 4/52 – 1/57	19,835.94	50%	50%	1,586.88[1]
5. Dixonville Substation – Storage yard improvement	8,190.02	50%	50%	655.20[1]
6. Alvey-Dixonville Line – Replace center phase Ins. 1/10	9,676.59	50%	50%	774.13[1]
7. Dixonville-Meridian Line – Replace insulators 3/7	5,398.33	50%	50%	431.87[1]
8. Meridian Substation – Replace fuses R1886, 87, 88	4,973.92	50%	50%	2,486.96
9. Meridian Substation – B/O VAC interrupter 4R20	8,595.91	50%	50%	4,297.96
10. Meridian Substation – Replace cable trench covers	8,034.14	50%	50%	4,017.07
11. Alvey-Dixonville Line – Replace insulators 1/30	6,161.87	50%	50%	3,080.94
12. Alvey-Dixonville Line – Replace culverts	18,582.58	50%	50%	9,291.29
13. Dixonville Substation – Replace communications batteries	24,587.87	50%	50%	12,293.94
14. Dixonville Substation – Replace battery bank	20,016.90	50%	50%	10,008.45
15. Alvey-Dixonville Line – Culverts, catwork, gates	98,035.92	50%	50%	49,017.96

[1] With regard to the capital replacements identified in Items 1 through 7 above, the amount owed by Bonneville reflects previous payments by Bonneville of 42% of total costs. The dollar amounts identified in Items 1 through 7 identify Bonneville's additional payment obligations to reflect Bonneville's 50% share.

Revision No. 4
Exhibit F, Page 2 of 2
Contract No. DE-MS79-94BP94332
PacifiCorp
Effective on Date of Execution

CAPITAL REPLACEMENTS (continued)				
Description	Total Cost ($)	PacifiCorp Percent Share	Bonneville Percent Share	Amount Owed by Bonneville ($)
16. Meridian Substation – Replace substation & Communication batteries	36,223,75	50%	50%	118,111.88
17. Meridian Substation – Upgrade SER modems and phones	4,810.94	50%	50%	2,405.47
18. Dixonville-Meridian Line – R/W work	24,373.28	50%	50%	12,186.64
19. Meridian Substation – Replace sump pump	1,209.92	50%	50%	604.96
20. Dixonville Substation – Substation battery replacement	11,506.69	50%	50%	5,753.35
CAPITAL ADDITIONS				
1. Alvey-Dixonville Line & Dixonville-Meridian Line – Purchase tools and equipment	21,931.49	50%	50%	10,965.75
2. Meridian Substation – Install corona rings (24)	7,187.21	50%	50%	3,593.61
TOTALS	**$372,387.83**			**$154,208.63**

PACIFICORP

By: David B Cory

Name: DAVID B CORY
(Print / Type)

Title: DIR. CUSTOMER SER

Date: 12/4/06

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: R A Gill

Name: Richard A. Gillman
(Print / Type)

Title: Senior Transmission Account Executive

Date: 12/1/06

W:TMC/CT/PacifiCorp/Revisions/94332R4F.doc

CAPITAL REPLACEMENTS AND ADDITIONS

This Revision No. 5 corrects two errors on Page 2 of Revision No. 4 to Exhibit F of Contract No. DE-MS79-94BP94332. The "Amount Owed by Bonneville" in Item 16 has been changed from $118,111.88 to $18,111.88; and the total amount owed by Bonneville has been changed from $154,208.63 to $154,208.67. PacifiCorp invoiced BPA for $154,208.67 and BPA paid such amount in full following the execution of Revision No. 4 to Exhibit F of Contract No. DE-MS79-94BP94332. As such, the sole purpose of this Revision No. 5 is to correct the errors noted above.

CAPITAL REPLACEMENTS				
Description	Total Cost ($)	PacifiCorp Percent Share	Bonneville Percent Share	Amount Owed by Bonneville ($)
1. Alvey-Dixonville Line – Install erosion control	9,631.92	50%	50%	770.55[1]
2. Dixonville-Meridian Line – Rebuild R/W between 5/24 and 3/26	12, 333.48	50%	50%	986.68[1]
3. Dixonville-Meridian Line – Foundation treatment 4/74 – 4/52	11,089.16	50%	50%	887.13[1]
4. Dixonville-Meridian Line – R/W catwork 4/52 – 1/57	19,835.94	50%	50%	1,586.88[1]
5. Dixonville Substation – Storage yard improvement	8,190.02	50%	50%	655.20[1]
6. Alvey-Dixonville Line – Replace center phase Ins. 1/10	9,676.59	50%	50%	774.13[1]
7. Dixonville-Meridian Line – Replace insulators 3/7	5,398.33	50%	50%	431.87[1]
8. Meridian Substation – Replace fuses R1886, 87, 88	4,973.92	50%	50%	2,486.96
9. Meridian Substation – B/O VAC interrupter 4R20	8,595.91	50%	50%	4,297.96
10. Meridian Substation – Replace cable trench covers	8,034.14	50%	50%	4,017.07
11. Alvey-Dixonville Line – Replace insulators 1/30	6,161.87	50%	50%	3,080.94
12. Alvey-Dixonville Line – Replace culverts	18,582.58	50%	50%	9,291.29
13. Dixonville Substation – Replace communications batteries	24,587.87	50%	50%	12,293.94
14. Dixonville Substation – Replace battery bank	20,016.90	50%	50%	10,008.45
15. Alvey-Dixonville Line – Culverts, catwork, gates	98,035.92	50%	50%	49,017.96

[1] With regard to the capital replacements identified in Items 1 through 7 above, the amount owed by Bonneville reflects previous payments by Bonneville of 42% of total costs. The dollar amounts identified in Items 1 through 7 identify Bonneville's additional payment obligations to reflect Bonneville's 50% share.

CAPITAL REPLACEMENTS (continued)				
Description	Total Cost ($)	PacifiCorp Percent Share	Bonneville Percent Share	Amount Owed by Bonneville ($)
16. Meridian Substation – Replace substation & Communication batteries	36,223.75	50%	50%	18,111.88
17. Meridian Substation – Upgrade SER modems and phones	4,810.94	50%	50%	2,405.47
18. Dixonville-Meridian Line – R/W work	24,373.28	50%	50%	12,186.64
19. Meridian Substation – Replace sump pump	1,209.92	50%	50%	604.96
20. Dixonville Substation – Substation battery replacement	11,506.69	50%	50%	5,753.35
CAPITAL ADDITIONS				
1. Alvey-Dixonville Line & Dixonville-Meridian Line – Purchase tools and equipment	21,931.49	50%	50%	10,965.75
2. Meridian Substation – Install corona rings (24)	7,187.21	50%	50%	3,593.61
TOTALS	**$372,387.83**			**$154,208.67**

PACIFICORP

By: [signature]

Name: DAVID B CORY
(Print / Type)

Title: DIRECTOR, CUSTOMER RELATIONS

Date: 2/12/07

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: [signature]

Name: Richard A. Gillman
(Print / Type)

Title: Senior Transmission Account Executive

Date: 1/18/07

TRANSMISSION SERVICES

DEC 30 2010

EXHIBIT F, REVISION NO. 6
CAPITAL REPLACEMENTS AND ADDITIONS
COMPLETED BY BONNEVILLE

This Revision No. 6 adds capital replacement projects that were initiated and completed by Bonneville at the Alvey Substation. Bonneville and PacifiCorp agree that these capital work orders are subject to cost sharing based on the terms of this contract.

COMPLETED CAPITAL REPLACEMENT				
Description	Total Cost ($)	PacifiCorp Percent Share %	Bonneville Percent Share %	Amount Owed by PacifiCorp ($)
1. Alvey Substation - Emergency Replacement of the station service cabinet, panels and cables due to fire at Alvey Substation. (Work Order 245663)	900,000	50%	50%	450,000
2. Alvey Substation - FIN expansion for NERC CIP compliance. (Work Order 221563)	109,046	50%	50%	54,523
3. Alvey Substation - NERC CIP-006 security work including card readers, motion detectors and door contacts. (Work Order 229829)	49,087	50%	50%	24,543
4. Alvey Substation - Replace the LCBII Fiber Optic Differential Relay at Alvey on the 500/230 kV tie line with two sets of line differential relays. (Work Order 206808)	373,565	50%	50%	186,783
Total	**$1,431,698**			**$ 715,849**

PACIFICORP	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By [signature]	By [signature]
Name LH Banks *(Print/Type)*	Name Kenneth H. Johnston *(Print/Type)*
Title Director Transmission	Title Transmission Account Executive
Date 30 Dec 2010	Date DEC 30, 2010

ContractAdministration/TXCustomerFolders/PacifiCorp_94332_ExFRev6_111910.doc

TRANSMISSION SERVICES

MAR 3 1 2011

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EXHIBIT F, REVISION NO. 7
CAPITAL REPLACEMENTS AND ADDITIONS

This Revision # 7 adds CAPITAL REPLACEMENTS AND ADDITIONS that were initiated, funded and completed by PacifiCorp during years 2007-2010. Bonneville and PacifiCorp agree that these capital projects are cost sharing based on the terms of this contract.

COMPLETED CAPITAL REPLACEMENT				
Description	Total Cost ($)	PacifiCorp Percent Share %	Bonneville Percent Share %	Amount Owed by Bonneville ($)
1.**Dixonville 500 kV Substation** NERC CIPS -006 security upgrade (SAP Project ID: TZRB/2007/C/001/B)	222,246 Note-1	50%	50%	111,123
2. **Meridian 500 kV Substation** NERC CIPS -006 security upgrade (SAP Project ID:CCBS/2006/C/002)	379,734 Note-1	50%	50%	189,867
3. **Dixonville - Meridian 500 kV line** Replace bridge on road easement (SAP Project ID: TROS/2010/C/TRF/10040359)	42,926	50%	50%	21,463
Total	**$644,906**			**$322,453**

Note-1:
Total cost shown is after deducting based on 230 kV yard allocation owned by PacifiCorp.

PACIFICORP	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By [signature]	By [signature]
Name L. H. BANKS (Print/Type)	Name KENNETH H. JOHNSTON (Print/Type)
Title DIRECTOR TRANSMISSION CUSTOMER ACCOUNTS	Title ACCOUNT EXECUTIVE
Date 3/31/11	Date 3/31/11

TRANSMISSION SERVICES rcvd via ups 9/2/11 @ 9:04 am mm
date rcvd fully executed
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TRANSMISSION SERVIC

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EXHIBIT F
CAPITAL REPLACEMENTS AND ADDITIONS

REVISION NO. 8

This Revision No. 8 adds cost sharing of NERC security enhancements for Critical Infrastructure facilities at Alvey Substation's 500 kV yard. Bonneville and PacifiCorp agree that this capital work order is subject to cost sharing based on the terms of this contract.

COMPLETED CAPITAL REPLACEMENT				
Description	Total Cost ($)	PacifiCorp Percent Share %	Bonneville Percent Share %	Amount Owed by PacifiCorp ($)
1. Alvey Substation- NERC security enhancements for Critical Infrastructure facilities at 500 kV yard. (Work Order 270672)	825,776.46	50%	50%	412,888.23
Total	**$ 825,776.46**			**$ 412,888.23**

SIGNATURES
The Parties have caused this Exhibit to be executed as of the date both Parties have signed this Exhibit.

PACIFICORP

By [signature]

Name Kenneth Houston
(Print/Type)

Title VP, Transmission

Date Sept. 1, 2011

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By [signature]

Name Kenneth H. Johnston
(Print/Type)

Title Transmission Account Executive

Date 9/2/11

ContractAdministration/TXCustomerFolders/PacifiCorp_94332_ExF_Revision 8.doc rcvd via ups 9/9/11 @ 9:28 am mo

EXHIBIT F
CAPITAL REPLACEMENTS AND ADDITIONS

REVISION NO. 9

This Revision No. 9 is for CAPITAL REPLACEMENTS AND ADDITIONS that were funded and completed by PacifiCorp during year 2010 through July 2011. Bonneville and PacifiCorp agree that these capital projects are subject to cost sharing based on the terms of this contract.

COMPLETED CAPITAL REPLACEMENT				
Description	Total Cost ($)	PacifiCorp Percent Share 50 %	Bonneville Percent Share 50 %	Amount Owed by BPA ($)
Dixonville: Repl CTs & Fuses on 500kV Series Capacitor Bank	309,602.05	50%	50%	154,801.02
Dixonville – Meridian (Line 91) Replace broken Insulator Str 2/72	13,140.47	50%	50%	6,570.23

SIGNATURES

The Parties have caused this Exhibit to be executed as of the date both Parties have signed this Exhibit.

PACIFICORP

By K Houston

Name Kenneth Houston
(Print/Type)

Title VP, Transmission

Date Sept. 19, 2011

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Kimberly D. Gilliland

for Name Kenneth H. Johnston
(Print/Type)

Title Transmission Account Executive

Date 9/15/11

TRANSMISSION SERVICES

JAN 20 2012

EXHIBIT F, REVISION NO. 10
CAPITAL REPLACEMENTS AND ADDITIONS

This Revision No. 10 adds cost sharing for the replacement of Digital Fault Recorders at the Alvey Substation. This Capital Replacement was funded and completed by Bonneville Power Administration (BPA). BPA and PacifiCorp agree that this capital project is subject to cost sharing based on the terms of the Amended and Restated AC Intertie Agreement.

COMPLETED CAPITAL REPLACEMENT				
Description	Total Cost ($)	PacifiCorp Percent Share	BPA Percent Share	Amount Owed by PacifiCorp ($)
Alvey Substation Replace Digital Fault Recorders (Work Order 270671)	$ 281,389.88	50%	50%	$ 140,694.94
Total	**$ 281,389.88**			**$ 140,694.94**

SIGNATURES

The Parties have caused this Exhibit to be executed as of the date both Parties have signed this Exhibit.

PACIFICORP

By: K Houston

Name: Kenneth Houston
(Print/Type)

Title: VP, Transmission

Date: Feb 14, 2012

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: [signature]

Name: Kenneth H. Johnston
for (Print/Type)

Title: Transmission Account Executive

Date: 19 JAN 2012

ContractAdministration/TXCustomerFolders/PacifiCorp_94332_ExF_Rev10.doc rwd via ups 5/29/13 @ 8:42am MO

EXHIBIT F
CAPITAL REPLACEMENTS AND ADDITIONS

REVISION NO. 11

This Revision No. 11 is for CAPITAL REPLACEMENTS AND ADDITIONS *that have been funded and completed by PacifiCorp. Bonneville and PacifiCorp agree that these capital projects are subject to cost sharing based on the terms of this contract.*

COMPLETED CAPITAL REPLACEMENT				
Description	Total Cost ($)	PacifiCorp Percent Share 50 %	Bonneville Percent Share 50 %	Amount Owed by BPA ($)
Meridian: Replace failed Reactor S-691 W Order: TZME/2007/C/003	1,186,743	50%	50%	593,371

SIGNATURES

The Parties have caused this Exhibit to be executed as of the date both Parties have signed this Exhibit.

PACIFICORP

By [signature]

Name Rick Vail
(Print/Type)

Title VP - Transmission

Date 5/28/13

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By [signature]

Name KENNETH H. JOHNSTON
(Print/Type)

Title ACCOUNT EXECUTIVE

Date 6/4/13

EXHIBIT F, REVISION NO. 12
CAPITAL REPLACEMENTS AND ADDITIONS

This Exhibit F, Revision No. 12 adds cost sharing for the emergency replacement of station control battery B-2611 located in the Alvey Substation's main control house. Bonneville and PacifiCorp agree that this capital project is subject to cost sharing based on the terms of the Amended and Restated AC Intertie Agreement (Agreement), Contract No. DE-MS79-94BP94332. PacifiCorp's 50% cost share of this capital project is based on PacifiCorp's ownership percentage as stated in Exhibit B of the Agreement.

COMPLETED CAPITAL REPLACEMENT				
Description	Total Cost ($)	PacifiCorp Percent Share	BPA Percent Share	Amount Owed by PacifiCorp ($)
Alvey Substation Emergency control battery replacement. (Work Order 297018)	$87,424.08	50%	50%	$43,712.04
Total	**$87,424.08**			**$43,712.04**

SIGNATURES
The Parties have executed this Exhibit as of the last date indicated below.

PACIFICORP

By: Laura Rayfusch

Name: Laura Rayfusch
(Print/Type)

Title: Account Manager

Date: 5/24/13

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: Kenneth H. Johnston

Name: Kenneth H. Johnston
(Print/Type)

Title: Transmission Account Executive

Date: 5/1/13

CCM/PacifiCorp/DE-MS79-94BP94332/Exhibit_F/Rev_12

MALIN TRANSFORMER – USE-OF-FACILITIES

Pursuant to Section 5 (h) of the AC Intertie Agreement, which states that PacifiCorp shall provide Bonneville firm capacity in its existing 500/230 kV transformer bank at the Malin Substation at a use-of-facilities rate for Bonneville's firm requirements, subject to certain limitations, including availability and only up to 200 megawatts, the Parties agree to the following:

Commencement Date

Bonneville has requested an increase in its firm capacity at the Malin Substation transformer bank from 102 MW to 110 MW commencing immediately upon FERC approval. This increase in capacity scheduling will alter the use of facilities charge based on the change in the percentage usage of the transformer by Bonneville. Currently Bonneville pays \$233,057 annually, \$19,421 monthly; based on a 26.33% ratio of Bonneville's exercised right to the average monthly transformer peak for the prior calendar year.

Upon FERC approval the revised use-of-facilities charge will be \$269,394 per year, billed monthly at \$22,449.50.

The above charge is based on the following:

- Investment of \$ 6,921,090.
- Levelized Fixed computation methodology.
- Utilization at 30.44% which is based on the ratio of Bonneville's new exercised right to the average monthly transformer peak for the prior calendar year, inclusive of Bonneville's new exercised right, provided, however, this ratio shall be capped at, and shall not exceed 200/650 = 30.77%, which equates to the maximum capacity share Bonneville could ever expect to request and be awarded under this agreement.
    - Example 1: For 2006, Bonneville's exercised right was 102 MW, as compared to the monthly average transformer peak inclusive of this right of 387.33 MW which was the bases for calculating the 26.33% utilization factor above.
    - Example 2: Bonneville's new exercised right will be 110 MW, as compared to the 2006 monthly average transformer peak inclusive of this new right of 361.42 MW. The new ratio will be 110/361.42 = 30.44%, which does not exceed the cap of 30.77%; therefore Bonneville's new use of facilities charge is based on the 30.44% utilization factor.

- FERC Authorized Rate of Return.
- FERC Methodology for OMAG Expenses.
- Thirty-nine year straight-line book depreciation
- Twenty year (MACRS) tax depreciation
- 1.2% property tax rate.
- 37.95% income tax rate.
- 7.5% discount rate.

Transformer Losses

In addition to the above use-of-facilities charge, the Parties agree that transfer losses (in megawatts) for the Malin 500/230 kV transformer shall be calculated with the following formula:

$$\mathbf{L = 0.4116 + k\, P^2}$$

Where:

L = total losses in MW
0.4116 MW is the magnetizing loss which is independent of transformer load
$k = 2.8 \times 10^{-6}$
P = power through transformer in MW

Example 1:

The transformer load is 300 MW. The total losses are:

$L = 0.4116 + (2.8 \times 10^{-6}) \times (300)^2 = 0.664$ MW

Example 2:

The transformer load is 650 MW. The total losses are:

$L = 0.4116 + (2.8 \times 10^{-6}) \times (650)^2 = 1.59$ MW

This formula shall be applied through the entire range of transformer capacity, from zero to 650 MW, and Bonneville's share shall be based on its hourly schedule of energy across the transformer.

For any hour, Bonneville may return losses physically, concurrent with the associated hourly energy schedule. Provided, for any hour in which Bonneville does not schedule loss returns concurrent with the associated energy schedule, Bonneville shall pay PacifiCorp for losses valued at the "Hourly Pricing Proxy" as described or as may be updated from time to time in PacifiCorp's currently effective Open Access Transmission Tariff.

Revisions to Exhibit G

If Bonneville notifies PacifiCorp that it wishes to effect a change to it's exercised right of 110 MW, then Bonneville's utilization of transformer capacity shall be automatically updated upon the effective date of the election (subject to PacifiCorp's review of capacity availability pursuant to Section 5 (h) of the Agreement) to reflect the full amount of Bonneville's election of transformer capacity pursuant to this Agreement. The availability of such capacity to Bonneville pursuant to the Agreement shall not exceed 200 MW and the charge factor applied to Bonneville's use of the Malin transformer shall not exceed 30.77%. The Parties agree that any other change to the above methodologies or factors shall be by mutual agreement and shall not be allowed more often than once per three year period. Each party's agreement to recommended changes in input factors to the above methodologies shall not be unreasonably withheld, provided any such recommended changes have a reasonable basis in fact. The parties shall negotiate in good faith to address any requested change in underlying methodology or formulae. Such changes to input factors shall apply prospectively only.

Bonneville Power Administration	PacifiCorp
By: Robert A. Rogers	By: K Houston
Title: Transfer Service Manager	Title: Director, Transmission
Date: 5/24/07	Date: May 22, 2007

Exhibit H
[Example of Bonneville Summer Storage nomination letter, on Bonneville letterhead, to PacifiCorp]

Supervisor, Contract Administration
PacifiCorp
825 NE. Multnomah, Suite 600
Portland, OR 97232

RE: Contract No. DE-MS79-94BP94332, Summer Energy Option

Dear Sirs:

This letter serves as notification from the Bonneville Power Administration (Bonneville) to PacifiCorp (PAC) that Bonneville chooses to exercise Section 12(a), Summer Storage, of our AC Intertie Agreement, Contract No. DE-MS79-94BP94332, by requesting PacifiCorp to store__________ [between 25,000 and 100,000] megawatt-hours (MWh) of energy in the month of __________[June or July] ("Bonneville Requested Storage"). Bonneville shall deliver to PAC approximately______ [134] MWhs of energy flat over all hours for the month of [June or July ("Bonneville Requested Storage Hourly Schedule")].

Bonneville requests that PacifiCorp shall return storage energy to Bonneville through a system-to-system return schedule (BPAT.PACW). Bonneville is planning on these energy returns being prescheduled.

As set forth in the [Amended and Restated AC Intertie Agreement], and as such terms are defined therein, Bonneville may request **Spill Protection Day(s)** up to the **Bonneville Monthly Spill Protection Day Cap,** which is eight (8) total days per storage month.

Similarly, for those days Bonneville has not requested **Contingent Spill Protection Day(s)**, PacifiCorp may reject such Bonneville Requested Storage Hourly Schedule up to the **PacifiCorp Monthly Storage Schedule Cut Cap**, which for the storage month described in this letter equals 16 % of the Bonneville Requested Storage, or ______ MWh.
For any further discussions regarding this notice, please contact me at (503) 230-4003.

Sincerely,

Mark E. Miller
Account Executive

Cc: Bonneville Contracts Administration

Exhibit I
[Example of Contingent Spill Protection Day e-mail to PacifiCorp]

Subject: Contingent Spill Protection Day

This email serves as notification from the Bonneville Power Administration (Bonneville) to PacifiCorp (PAC) that Bonneville notices is a Contingent Spill Protection Day as described in Section 12(a), Summer Storage, of the Amended and Restated AC Intertie Agreement, Contract No. DE-MS79-94BP94332.

Period begins:	**Hour Ending [0100, June 1, 2011]**
Period ends:	**Hour Ending [2400, June 4, 2011]**

The Bonneville Monthly Spill Protection Day Cap is defined as eight (8) Spill Protection Days in this storage month. As described in this notice, Bonneville hereby declares __ Spill Protection Days in the month of June, for a total of ___ Spill Protection Days to date.

Bonneville will be in a Spill Condition for a period of 2 days prior to when this period of Spill Protection Day(s) begin.

PacifiCorp, please confirm this e-mail by a return e-mail acknowledgment to:
ajspain@bpa.gov
memiller@bpa.gov

For any further discussions regarding this notice, please contact me at (503) 230-4003, Alex Spain at (503) 230-5780.

Exhibit J
[Example of PacifiCorp Contingent Spill Protection Day criteria validation e-mail to Bonneville]

Subject: Contingent Spill Protection Day Criteria Validation
To: Mark Miller
Alex Spain

This email serves as notification from PacifiCorp (PAC) to Bonneville Power Administration (Bonneville) as to which Contingent Spill Condition Day(s) for the month of ____, 2011 trigger Bonneville Spill Protection Day LD(s).

Contingent Spill Protection Day that meet criteria in Section 27(gg) and fall within Bonneville Monthly Spill Protection Day Cap of 8 days

Date
Date
Date
Date

Contingent Spill Protection Day that meet criteria in Section 27(gg) and exceed Bonneville Monthly Spill Protection Day Cap of 8 days (Bonneville Spill Protection Day LD will apply)

Date
Date

Contingent Spill Protection Day that failed to meet criteria in Section 27(gg) (Bonneville Spill Protection Day LD will apply)

Date
date

PacifiCorp, please confirm this e-mail by a return e-mail acknowledgment to:
Jim.schroeder@pacificorp.com
Stacey.kusters@pacificorp.com
Mark.smith@pacificorp.com

For any further discussions regarding this notice, please contact Mark Smith at (503) 813-5393.

Exhibit K
Sample of Bonneville Spill Conditions website posting found at www.transmission.bpa.gov/Business/Operations/Misc/

HOURLY SPILL CONDITIONS

From 07/05/09 through 07/08/11 (illustratively shown 6/1/2011)

- This posting is provided as information to users of BPA's Energy Imbalance and Generation Imbalance services.
- Spill Conditions, for the purpose of determining credit or payment for Deviations under the EI and GI rates, exist when spill physically occurs on the BPA system due to lack of load or market. Spill due to lack of load or market typically occurs during periods of high flows or flood control implementation, but can also occur at other times. Discretionary spill, where BPA may choose whether to spill, does not constitute a Spill Condition. Spill for fish is included in discretionary spill and is not a Spill Condition.
- Account 501935 (Actual System Spill, After-The-Fact): A "1" indicates Spill conditions were declared for that hour. A "0" indicates No Spill was declared for that hour.
- Account 501936 (Forecasted System Spill, Before-The-Fact) : not utilized by BPA - will not be used for that hour. A "0" indicates No Spill is projected to occur for that hour.
- BPA will continue to use the Actual Spill conditions posted after-the-fact (Account 501935) for billing purposes.
- This file is updated daily at 11:00 AM, Pacific Time
- Source of Spill Flag: BPA Power Services
- Source of this Posting: BPA Transmission Services 05Jul2011 11:00
- For further information, please contact Harry Speropulos, Transmission Transaction Analysis & Reconciliation, at 360-418-8670.

Date	Time	# 501935	# 501936
		Actual	Forecast
6/1/2011	1:00	1	
6/1/2011	2:00	1	
6/1/2011	3:00	1	
6/1/2011	4:00	1	
6/1/2011	5:00	1	
6/1/2011	6:00	1	
6/1/2011	7:00	0	
6/1/2011	8:00	0	
6/1/2011	9:00	0	
6/1/2011	10:00	0	
6/1/2011	11:00	0	
6/1/2011	12:00	0	
6/1/2011	13:00	0	
6/1/2011	14:00	0	
6/1/2011	15:00	0	
6/1/2011	16:00	0	
6/1/2011	17:00	0	
6/1/2011	18:00	0	
6/1/2011	19:00	0	
6/1/2011	20:00	1	
6/1/2011	21:00	1	
6/1/2011	22:00	1	
6/1/2011	23:00	1	
6/1/2011	24:00:00	1	

Exhibit L
Sample of Bonneville Spill Protection Day LD

Bonneville Spill Protection Day Cap LD

Bonneville declared a Contingent Spill Condition Day in excess of their cap of 8 days or declared a Spill Protection Day that failed to meet the Spill Protection Day criteria in 27(gg).

Date	Time	Bonneville Requested Storage Hourly Schedule	Powerdex Mid-Columbia Average Hourly Index Price		Hourly weighted average of daily ICE Day-Ahead Power Index for Mid-Columbia for Peak and Off-Peak from September - November 2011		Bonneville Spill Protection Day hourly Cap LD	
	HE	MWh/hr	$/MWh		$/MWh		$/day	
6/26/2010	100	139	$	(12.67)	$	32.23	$	6,241.07
6/26/2010	200	139	$	(2.58)	$	32.23	$	4,838.56
6/26/2010	300	139	$	(0.41)	$	32.23	$	4,536.93
6/26/2010	400	139	$	(2.95)	$	32.23	$	4,889.99
6/26/2010	500	139	$	(0.74)	$	32.23	$	4,582.80
6/26/2010	600	139	$	(0.08)	$	32.23	$	4,491.06
6/26/2010	700	139	$	(4.10)	$	32.23	$	5,049.84
6/26/2010	800	139	$	(2.12)	$	32.23	$	4,774.62
6/26/2010	900	139	$	1.11	$	32.23	$	4,325.65
6/26/2010	1000	139	$	0.50	$	32.23	$	4,410.44
6/26/2010	1100	139	$	(3.92)	$	32.23	$	5,024.82
6/26/2010	1200	139	$	(3.56)	$	32.23	$	4,974.78
6/26/2010	1300	139	$	(1.46)	$	32.23	$	4,682.88
6/26/2010	1400	139	$	(0.19)	$	32.23	$	4,506.35
6/26/2010	1500	139	$	(0.58)	$	32.23	$	4,560.56
6/26/2010	1600	139	$	0.05	$	32.23	$	4,472.99
6/26/2010	1700	139	$	(0.40)	$	32.23	$	4,535.54
6/26/2010	1800	139	$	0.07	$	32.23	$	4,470.21
6/26/2010	1900	139	$	(0.19)	$	32.23	$	4,506.35
6/26/2010	2000	139	$	0.34	$	32.23	$	4,432.68
6/26/2010	2100	139	$	(0.08)	$	32.23	$	4,491.06
6/26/2010	2200	139	$	(4.15)	$	32.23	$	5,056.79
6/26/2010	2300	139	$	(2.25)	$	32.23	$	4,792.69
6/26/2010	2400	139	$	(0.70)	$	32.23	$	4,577.24

Bonneville Spill Protection Day LD: $ 113,226.01

Exhibit M
Sample of PacifiCorp Storage Cut LD

PacifiCorp exceeded their Monthly Storage Schedule Cut Cap in HE0400

Date	Time	Bonneville Requested Storage Hourly Schedule	PacifiCorp Storage Schedule Cut	PacifiCorp Storage Schedule Cut in excess of Cap	Powerdex Mid-Columbia Average Hourly Index Price	Hourly weighted average of daily ICE Day-Ahead Power Index for Mid-Columbia for Peak and Off-Peak prices from September - November 2011	Bonneville Spill Protection Day hourly Cap LD
	HE	MWh/hr	MWh/hr	MWh/hr	$/MWh	$/MWh	$/day
6/21/2010	100	139	139		$ (2.26)	$ 32.23	$ -
6/21/2010	200	139	139		$ (2.06)	$ 32.23	$ -
6/21/2010	300	139	139		$ (2.61)	$ 32.23	$ -
6/21/2010	400	139	139	139	$ (4.07)	$ 32.23	$ 5,045.67
6/21/2010	500	139	139	139	$ (1.31)	$ 32.23	$ 4,662.03
6/21/2010	600	139	139	139	$ 0.21	$ 32.23	$ 4,450.75
6/21/2010	700	139	139	139	$ 0.65	$ 32.23	$ 4,389.59
6/21/2010	800	139	139	139	$ 4.03	$ 32.23	$ 3,919.77
6/21/2010	900	139	139	139	$ 9.87	$ 32.23	$ 3,108.01
6/21/2010	1000	139	139	139	$ 9.37	$ 32.23	$ 3,177.51
6/21/2010	1100	139	139	139	$ 8.92	$ 32.23	$ 3,240.06
6/21/2010	1200	139	139	139	$ 9.71	$ 32.23	$ 3,130.25
6/21/2010	1300	139	139	139	$ 15.98	$ 32.23	$ 2,258.72
6/21/2010	1400	139	139	139	$ 21.70	$ 32.23	$ 1,463.64
6/21/2010	1500	139	139	139	$ 22.26	$ 32.23	$ 1,385.80
6/21/2010	1600	139	139	139	$ 24.54	$ 32.23	$ 1,068.88
6/21/2010	1700	139	139	139	$ 26.34	$ 32.23	$ 818.68
6/21/2010	1800	139	139	139	$ 25.93	$ 32.23	$ 875.67
6/21/2010	1900	139	139	139	$ 25.36	$ 32.23	$ 954.90
6/21/2010	2000	139	139	139	$ 15.59	$ 32.23	$ 2,312.93
6/21/2010	2100	139	139	139	$ 14.51	$ 32.23	$ 2,463.05
6/21/2010	2200	139	139	139	$ 15.21	$ 32.23	$ 2,365.75
6/21/2010	2300	139	139	139	$ 15.15	$ 32.23	$ 2,374.09
6/21/2010	2400	139	139	139	$ 11.30	$ 32.23	$ 2,909.24

Total daily PacifiCorp Storage Cut LD: $ 56,375.09

Exhibit N

[Example of 2014 Bonneville Summer Storage nomination letter, on Bonneville letterhead, to
PacifiCorp]

Supervisor, Contract Administration
PacifiCorp
825 NE. Multnomah, Suite 600
Portland, OR 97232

RE: Contract No. DE-MS79-94BP94332, Summer Energy Option

Dear Sirs:

This letter serves as notification from the Bonneville Power Administration (Bonneville) to
PacifiCorp (PAC) that Bonneville chooses to exercise Section l2(a)(9), Summer Storage, of our AC Intertie Agreement, Contract No. DE-MS79-94BP94332, by requesting PacifiCorp to
store up to 25,000 megawatt-hours (MWh) of energy in the month of <month>. Bonneville shall deliver the energy in anticipation of a Storage Day to PAC over eight calendar days at a rate of approximately 130 MW per hour subject to Spill Conditions.

For any further discussions regarding this notice, please contact me at (503) 230-4003.

Sincerely,

Mark E. Miller
Account Executive

Cc: Bonneville Contracts Administration

Exhibit O
[Example of 2014 Storage Day Notice e-mail to PacifiCorp]

Subject: Storage Day

This email serves as notification from the Bonneville Power Administration (Bonneville)
to PacifiCorp that Bonneville will be exercising a Storage Day(s) as described in Section 12(a)(9)(v), Summer Storage, of the Amended and Restated AC Intertie
Agreement, Contract No. DE-MS79-94BP94332.

Period begins: Hour Ending 0100, <month> <day>, 2014
Period ends: Hour Ending 2400, <month> <day>, 2014

Bonneville may nominate eight (8) Storage Days for the Delivery Month subject to Spill Conditions.
As described in this notice, Bonneville hereby declares_ Storage Day(s), for a total of_ Storage Day(s) used to Date in the Delivery Month.

PacifiCorp, please confirm this e-mail by a return e-mail acknowledgment to:
ajspain@bpa.gov
memiller@bpa.gov
rcjohnson@bpa.gov

For any further discussions regarding this notice, please contact me at (503) 230-4003, or
Alex Spain at (503) 230-5780.

Exhibit P

Sample of Bonneville Storage Day LD Calculation for one Storage Day.

Description:
If Bonneville declared a Storage Day that does not meet the conditions described in section 12 (a)(9)(iii)
Bonneville will be subject to Storage Day LDs.

The following is an example of how the Storage Day LD is calculated for one day only.

	Time	Bonneville Deliveries	Powerdex Mid-Columbia Average Hourly Index Price	Hourly weighted average of daily ICE Day-Ahead Pwer Index for Mid-Columbia for Peak and Off-Peak from Sept, Oct, Nov 2014	Liquidated Damages for each hour of the Storage Day
Date	HE	MWh/hr	$/MWh	$/MWh	$/day
6/26/2014	100	130	-12.67	32.23	5,837.00
6/26/2014	200	130	-2.58	32.23	4,525.30
6/26/2014	300	130	-0.41	32.23	4,243.20
6/26/2014	400	130	-2.95	32.23	4,573.40
6/26/2014	500	130	-0.74	32.23	4,286.10
6/26/2014	600	130	-0.08	32.23	4,200.30
6/26/2014	700	130	-4.1	32.23	4,722.90
6/26/2014	800	130	-2.12	32.23	4,465.50
6/26/2014	900	130	1.11	32.23	4,045.60
6/26/2014	1000	130	0.5	32.23	4,124.90
6/26/2014	1100	130	-3.92	32.23	4,699.50
6/26/2014	1200	130	-3.56	32.23	4,652.70
6/26/2014	1300	130	-1.46	32.23	4,379.70
6/26/2014	1400	130	-0.19	32.23	4,214.60
6/26/2014	1500	130	-0.58	32.23	4,265.30
6/26/2014	1600	130	0.05	32.23	4,183.40
6/26/2014	1700	130	-0.04	32.23	4,195.10
6/26/2014	1800	130	0.07	32.23	4,180.80
6/26/2014	1900	130	-0.19	32.23	4,214.60
6/26/2014	2000	130	0.34	32.23	4,145.70
6/26/2014	2100	130	-0.08	32.23	4,200.30
6/26/2014	2200	130	-4.15	32.23	4,729.40
6/26/2014	2300	130	-2.25	32.23	4,482.40
6/26/2014	2400	130	-0.7	32.23	4,280.90

Bonneville Storage Day LD:					105,848.60

Contract No. DE-MS79-94BP94332

AMENDED AND RESTATED

AC INTERTIE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFICORP

Index to Sections

Exhibit J ("Example of PacifiCorp Contingent Spill Protection Day criteria validation email to Bonneville")
Exhibit K ("Sample of Bonneville Spill Conditions website posting")
Exhibit L ("Sample of Bonneville Spill Protection Day LD")
Exhibit M ("Sample of PacifiCorp Storage Cut LD")
Exhibit N ("Example of 2014 Bonneville Summer Storage nomination letter, on Bonneville letterhead, to PacifiCorp")
Exhibit O ("Example of 2014 Storage Day Notice e-mail to PacifiCorp")
Exhibit P ("Sample of Bonneville Storage Day LD Calculation for one Storage Day")

This AMENDED AND RESTATED AC INTERTIE AGREEMENT (Amended and Restated AC Intertie Agreement), executed __________, ______, by the UNITED STATES OF AMERICA ("Government"), DEPARTMENT OF ENERGY, acting by and through the BONNEVILLE POWER ADMINISTRATION ("Bonneville") and PACIFICORP ("PacifiCorp"), a corporation organized and existing under the laws of Oregon, (hereinafter referred to individually as "Party" and collectively as "Parties").

WITNESSETH:

WHEREAS the Parties have entered into the Transmission Agreement (Contract No. DE-MS79-79BP90091), as amended, which hereinafter is referred to as "Midpoint-Medford Agreement"; and

WHEREAS the Parties have entered into the Intertie Agreement (Contract No. DE-MS79-86BP92299, as amended, which hereinafter is referred to as "the July 1986 Intertie Agreement"; and

WHEREAS the Parties have entered into an Agreement of Principles, dated May 28, 1993, which hereinafter is referred to as "Letter of Understanding" and which provides, among other things, for the revision of certain terms and conditions in the Midpoint-Medford Agreement and the July 1986 Intertie Agreement; and

WHEREAS the Parties have entered into the Midpoint-Meridian Transmission Agreement (Contract No.DE-MS79-94BP94333) which hereinafter is referred to as "Midpoint-Meridian Transmission Agreement" which replaces and supersedes the Midpoint-Medford Agreement; and

WHEREAS the Parties have replaced and superseded the July 1986 Intertie Agreement with the June 1994 AC Intertie Agreement Contract No. DE-MS79-94BP94332, (hereinafter referred to as the June 1994 AC Intertie Agreement), and

WHEREAS the Parties have entered into the AC Intertie Operation and Maintenance Agreement (Contract No. DE-MS79- 93BP94278) which hereinafter is referred to as "AC Intertie O&M Agreement"; and

WHEREAS Bonneville and PacifiCorp are Parties to Contract No. 14-03-59840 ("Malin Substation Construction Agreement") which provides for rights and obligations regarding construction, operation, ownership and use of the Malin Substation and desire to continue such agreement for the term of this Amended and Restated AC Intertie Agreement; and

WHEREAS PacifiCorp has constructed a 500 kV line from the interconnection with Bonneville at Alvey Substation to Meridian Substation ("Alvey-Meridian Line") to provide increased Load Carrying Capability; and

WHEREAS Bonneville has expanded the Rated Transfer Capability of the AC Intertie to approximately 4800 megawatts and has acquired a 50 percent undivided ownership right in the Incremental Capacity of the Alvey-Meridian Line; and

WHEREAS PacifiCorp and Bonneville have acquired joint ownership in the Alvey-Meridian Line and related facilities as provided for in Amendatory Agreement No. 2 to the June 1994 AC Intertie Agreement ("Payment Agreement"), Amendatory Agreement No. 1 to the July 1986 Intertie Agreement ("Option Agreement") attached hereto as Exhibits A and D respectively and Exhibit B hereto; and

WHEREAS nothing in this Amended and Restated AC Intertie Agreement is intended to be determinative of transmission or ownership rights of utilities not party to this Amended and Restated AC Intertie Agreement; and

WHEREAS this Amended and Restated AC Intertie Agreement incorporates the terms and conditions of the June 1994 AC Intertie Agreement, as supplemented and amended by Amendatory Agreement Nos. 1 through 3 thereto in one complete document, in accordance with the Federal Energy Regulatory Commission requirements in Order No. 614, Designation of Electric Rate Schedule Sheet, 65 Fed. Reg. 18,221 (2000), FERC Statutes and Regulations ¶ 31,096 (2000); and

WHEREAS this Amended and Restated AC Intertie Agreement was entered into by the Parties for the sole purpose of incorporating Amendatory Agreements 1, 2 and 3 into this Amended and Restated AC Intertie Agreement and did not alter any of the Parties' rights, obligations or terms and conditions of the June 1994 AC Intertie Agreement in any way; and

WHEREAS the Parties agreed that this Amended and Restated AC Intertie Agreement would supersede and replace the Original version of the June 1994 AC Intertie Agreement and Amendatory Agreement Nos. 1 through 3 thereto in their entirety as from the effective date thereof; and

WHEREAS the Parties further amended Sections 5(e) and 27 of this Amended and Restated AC Intertie Agreement to reflect changes in PacifiCorp's Scheduling Rights; and

WHEREAS this Amended and Restated AC Intertie Agreement supersedes and replaces the version executed on August 22, 2013, with respect to Sections 5(e) and 27 only.

NOW, THEREFORE, in the interest of resolving issues of AC Intertie rights and service to PacifiCorp's Load Area now and in the future, Bonneville and PacifiCorp are entering into this Amended and Restated AC Intertie Agreement to accomplish the following goals:

(a) To enable Bonneville's planning, construction, operation and maintenance of an AC Intertie with a bidirectional Rated Transfer Capability of approximately 4800 megawatts and to enable PacifiCorp's planning, construction, operation and maintenance of facilities to serve its Load Area.

(b) To permit the Parties' specified use of the Buckley- Alvey Loop in a manner that does not jeopardize reliable service on either Party's system.

(c) To limit PacifiCorp's right to use its own facilities to schedule power and energy from its Load Area to adjoining areas and to ensure that this right is exercised in a manner that does not reduce the Operational Transfer Capability of the AC Intertie.

(d) To facilitate joint development of facilities by Bonneville and PacifiCorp as specified in this Amended and Restated AC Intertie Agreement.

(e) As between the Parties, to facilitate the economical development and fair allocation of any AC Intertie transfer capability above 4800 megawatts.

It is the intention of the Parties that this Amended and Restated AC Intertie Agreement be implemented and interpreted to best effectuate the above stated goals. Where this Amended and Restated AC Intertie Agreement makes reference to not unreasonably withholding consent or agreement, the reasonableness of each Party's position will be judged with reference to the above stated goals.

1. Term of Agreement. This Amended and Restated AC Intertie Agreement shall be effective, and consistent with the 1994 AC Intertie Agreement, shall supersede the July 1986 Intertie Agreement in accordance with Section 15 herein when executed by the Parties and accepted for filing or otherwise approved without change by the Federal Energy Regulatory Commission and shall terminate when all of the facilities comprising the AC Intertie are

permanently taken out of service. Upon termination of this Amended and Restated AC Intertie Agreement, all liabilities accrued hereunder shall be and are hereby preserved until satisfied.

2. Exhibits. Exhibits A through P are incorporated as part of this Amended and Restated AC Intertie Agreement. Revisions to the Exhibits shall be by mutual consent.

3. Plan-of-Service for AC Intertie.

(a) Bonneville's Right to Establish Plan-of-Service. PacifiCorp agrees that Bonneville alone shall have the right to establish any Plan-of-Service for upgrading the AC Intertie to approximately 4800 megawatts, provided such Plan-of-Service is in keeping with Prudent Utility Practice, and further provided such Plan-of-Service does not result in reducing PacifiCorp's Load Carrying Capability.

(b) PacifiCorp's Right to Comment. Bonneville shall provide PacifiCorp the opportunity to comment on any such Plan-of-Service Bonneville may establish.

4. AC Intertie Construction and Ownership up to Approximately 4800 Megawatts of Rated Transfer Capability.

(a) Alvey-Meridian Line Rights. To achieve the upgrade of the AC Intertie to a Rated Transfer Capability of approximately 4800 megawatts, Bonneville has acquired a 50 percent undivided ownership right in the Incremental Capacity of the Alvey-Meridian Line which is jointly owned by Bonneville and PacifiCorp as provided for in the Payment Agreement and Exhibit B. For the term of this Amended and Restated AC Intertie Agreement, Bonneville shall have the unrestricted right to use such ownership interest. Bonneville may use such unrestricted right for purposes including, but not limited to, the interregional transfer of electric power, the integration of the electric power output of generation resources, and for service to the electric power loads of Bonneville's customers. Bonneville and PacifiCorp have shared, in accordance with the percentages specified in Exhibit B, the actual costs of facilities associated with construction of the Alvey-Meridian Line and other related additions. Unless otherwise

stated in Exhibit B or in the AC Intertie O&M Agreement, Bonneville shall pay 42 percent and PacifiCorp shall pay 58 percent of the operation and maintenance costs of those facilities specified in Exhibit B. PacifiCorp shall bear all operation and maintenance costs for those facilities used exclusively to serve PacifiCorp's own loads. PacifiCorp and Bonneville shall act in good faith and use best efforts, including utilization of all reasonable legal remedies, to obtain and protect all necessary permits and licenses for the Alvey-Meridian Line.

(b) Captain Jack Substation. Bonneville has constructed and, except for those facilities which PacifiCorp owns pursuant to section 4(b)(3) herein, owns the Captain Jack Substation and the associated interconnection to COTP. Bonneville's ownership includes the land on which the substation and the interconnection are located. Bonneville has connected the Captain Jack Substation to PacifiCorp's 500 kV system between Meridian Substation and Malin Substation where the COTP interconnects with the AC Intertie subject to the following terms, conditions and exceptions:

(1) Bonneville has constructed and owns terminal equipment, lines, and facilities required to interconnect the COTP with the Captain Jack Substation.

(2) Bonneville has constructed and owns the series and shunt compensation equipment and facilities located in the Captain Jack Substation required to connect to the COTP.

(3) PacifiCorp and Bonneville have shared equally in the cost of the bay 3 terminal equipment and facilities, which PacifiCorp owns, including the land on which such facilities are located, required to loop PacifiCorp's Malin-Meridian 500 kV line("Malin-Meridian Line") into the Captain Jack Substation.

(4) PacifiCorp, at its expense and subject to Prudent Utility Practice, may install transformation equipment at the Captain Jack Substation. PacifiCorp agrees to provide Bonneville the one-line diagram and plot plan for the installation of transformation equipment in a timely fashion for inclusion in Bonneville's Plan-of-Service. Subsequent changes in the one-line diagram or plot plan of transformation equipment are subject to mutual consent.

(c) Modification of Facilities.

(1) Except in regard to the Malin Substation, PacifiCorp agrees that it will make or permit Bonneville to make, at Bonneville's expense, any improvements or modifications of PacifiCorp's facilities in the Buckley-Alvey Loop that are required to accomplish Bonneville's Plan-of-Service. Unless otherwise mutually agreed, Bonneville shall own such improvements or modifications unless they cannot be removed without impairment or damage to PacifiCorp's facilities, in which case such modifications or improvements shall be jointly owned by Bonneville and PacifiCorp.

(2) AC Intertie Reactive Support. After joint studies have been completed and the Parties have mutually agreed that additional reactive support is required at the Malin Substation or Captain Jack Substation to support the AC Intertie, PacifiCorp shall be financially responsible for its share of the cost of such added reactive support.

(3) At such time as the Parties mutually agree, which agreement shall not be unreasonably withheld, that a second 500/230 kV transformer is required at the Malin Substation or a 500/230 kV transformer is required at the Captain Jack Substation, the Parties shall jointly develop the plan of service for such transformer(s). Each Party shall have the right to acquire up to a one-half ownership interest in such transformer(s) at a

pro-rata share of cost, provided that PacifiCorp's Load Carrying Capability is not impacted. If a Party does not participate in the ownership of such transformer(s) at the Malin or Captain Jack Substations at the time such transformer(s) are installed, such Party shall have the unilateral right to acquire up to a one-half ownership interest based on a pro-rata share of the original cost plus capital additions, if any, at a future date to the extent that capacity is available.

(4) Except as provided for in subsection 4(c)(1) herein, any improvements or modifications of the Buckley-Alvey Loop shall be by mutual consent, which consent shall not be unreasonably withheld. Except as provided for in subsections 4(c)(2) and 4(c)(3) above, installation of any equipment in the Malin Substation shall be made pursuant to the terms of the Malin Substation Construction Agreement.

(5) If Bonneville determines additions or modifications to the Alvey-Meridian Line are necessary to maintain the Rated Transfer Capability or Operational Transfer Capability of the AC Intertie at 4800 megawatts, Bonneville may, by written notice, cause PacifiCorp to add such equipment or make such modifications, and Bonneville and PacifiCorp shall share equally in the costs and ownership of such additions and modifications unless otherwise mutually agreed. PacifiCorp and Bonneville shall share equally in any Incremental Capacity resulting from such modifications.

5. Rights of Use.

(a) Determination of AC Intertie Rated Transfer Capability and Operational Transfer Capability. PacifiCorp agrees that Bonneville may determine the Rated Transfer Capability and Operational Transfer Capability of the AC Intertie, provided such determination is in keeping

with Prudent Utility Practice, and further provided it does not have the effect of reducing PacifiCorp's ability to serve up to its Load Carrying Capability as specified in this section 5.

(b) Bonneville's Right to Use of PacifiCorp's Malin-Meridian Line. PacifiCorp shall provide Bonneville, at no charge, sufficient capacity in the Malin-Meridian Line for Bonneville's AC Intertie transactions for itself or on behalf of other parties to enable Bonneville to operate the AC Intertie at its Rated Transfer Capability. To the extent modifications in the Malin-Meridian Line are required to effectuate this subsection 5(b), the cost of such modifications shall be borne equally by Bonneville and PacifiCorp. PacifiCorp shall operate and maintain the Malin-Meridian Line to maintain the Rated Transfer Capability on the AC Intertie in keeping with Prudent Utility Practice.

(c) Bonneville's Rights and Obligations for Intertie Service. PacifiCorp agrees that Bonneville has the right to operate the AC Intertie up to its Rated Transfer Capability or Operational Transfer Capability, subject to the following terms and conditions:

(1) Subject to section 4(c)(2) herein, Bonneville shall provide reactive support to maintain the Rated Transfer Capability of the AC Intertie.

(2) Bonneville shall provide transmission reinforcement to maintain the Rated Transfer Capability of the AC Intertie.

(3) Bonneville shall not rate or operate the AC Intertie in a manner that interferes with PacifiCorp's use of its Load Carrying Capability as described in subsections 5(d)(1), 5(d)(2), and 5(d)(3) below. However, Bonneville may make use of PacifiCorp's unused Load Carrying Capability for AC Intertie transactions for itself or on behalf of other parties at no additional charge, except as otherwise provided in this Amended and Restated AC Intertie Agreement.

(d) PacifiCorp's Rights and Obligations for Service to Load.

(1) Upon energization of the Alvey-Meridian Line, PacifiCorp shall have the right to serve PacifiCorp's Load Area and parallel paths, pursuant to section 10 herein, up to the Load Carrying Capability specified as follows:

(A) PacifiCorp shall have a Load Carrying Capability of 1875 megawatts.

(B) By the date when PacifiCorp's Load is expected to exceed the Load Carrying Capability recognized in subsection 5(d)(1)(A) herein, PacifiCorp shall provide additional facilities to supply power to its Load Area.

(2) The Load Carrying Capability specified in this subsection 5(d) may be correspondingly increased if new transmission facilities are constructed or if modifications are made to transmission facilities that increase the Load Carrying Capability. The effect of any such additions or modifications of transmission facilities on Load Carrying Capability shall be established by mutual agreement of the Parties using the results of joint planning studies conducted pursuant to subsection 5(d)(3) herein, and such mutual agreement shall not be unreasonably withheld.

(3) PacifiCorp's Load in its Load Area, and the date that such load is expected to exceed the Load Carrying Capability, shall be mutually determined by joint planning studies conducted annually, or as otherwise mutually agreed, by PacifiCorp and Bonneville in accordance with normal utility planning criteria. Such studies shall be based on mutually agreed to load forecasts for PacifiCorp's Load, as well as records of actual metered power flows on the then existing transmission lines serving the Load Area. PacifiCorp and

Bonneville shall furnish any data reasonably required for the joint planning study.

(4) PacifiCorp shall provide reactive support and internal transmission reinforcement for PacifiCorp's Load, including, but not limited to, 500/230 kV transformation, and 230 kV and below transmission reinforcement. To the extent PacifiCorp fails to provide such reinforcements, Bonneville shall not be obligated to reduce the Rated Transfer Capability or Operational Transfer Capability of the AC Intertie.

(5) Use of the Summer Lake Substation as a point of delivery by the Parties shall not impact PacifiCorp's Load Carrying Capability or Bonneville's usage of the AC Intertie.

(e) PacifiCorp's Scheduling Rights for AC Intertie Rated Transfer Capability in Excess of 4000 Megawatts. PacifiCorp's Southbound Scheduling Rights are 400 megawatts. PacifiCorp's Northbound Scheduling Rights shall equal 400 megawatts multiplied by a fraction whose numerator is the northbound Rated Transfer Capability of the AC Intertie and whose denominator is the southbound Rated Transfer Capability of the AC Intertie. PacifiCorp shall have the right to net its total northbound and southbound schedules under this Amended and Restated AC Intertie Agreement. PacifiCorp agrees to cooperate with Bonneville in its efforts, if any, to secure a northbound AC Intertie Rated Transfer Capability of 4800 megawatts. PacifiCorp's Northbound Scheduling Rights and Southbound Scheduling Rights shall be subject to the following terms and conditions:

(1) To preserve Bonneville's rights to use PacifiCorp's unused Scheduling Rights in a manner that allows third-party access to such rights in any hour, PacifiCorp

and Bonneville agree to the following provisions. There shall be no charge to Bonneville for unused Scheduling Rights. PacifiCorp or any successive assignee may make its Scheduling Rights available on a firm basis to all parties under the provisions of PacifiCorp's open access transmission tariff; provided however, that neither PacifiCorp nor any successive assignee of PacifiCorp's Scheduling Rights may make such Scheduling Rights available for periods shorter than daily or on a nonfirm basis. To the extent that PacifiCorp or any successive assignee has unused Scheduling Rights available in any hour under this Amended and Restated AC Intertie Agreement as of the close of the normal preschedule deadline for firm point-to- point transmission service in accordance with Bonneville's standard scheduling practices, Bonneville shall add such unused Scheduling Rights to its available nonfirm transmission capacity for AC Intertie transactions, which shall be posted on Bonneville's Open Access Same-time Information System and made available pursuant to the provisions of Bonneville's open access transmission tariff. After such unused Scheduling Rights are added to Bonneville's available nonfirm transmission capacity, PacifiCorp or any successive assignee of the Scheduling Rights may modify preschedules up to 30 minutes prior to the hour for service to be provided pursuant to such preschedules for use of such firm transmission capacity (with such right available even if a preschedule had not been submitted, and in such case, PacifiCorp or any successive assignee shall be deemed to have submitted, with rights to modify, a 0 (zero) preschedule) and any such use shall have priority over any use or sale of unused Scheduling Rights by Bonneville. After 30 minutes prior to the hour for service to be provided pursuant to such preschedule, these unused Scheduling Rights shall be relinquished to Bonneville, except that such unused Scheduling Rights shall be subject to adjustment as provided for in subsection 5(e)(2).

(2) PacifiCorp or any successive assignee of the Scheduling Rights may submit Intra-Hour Scheduling Interval Schedules up to 20 minutes prior to the applicable Intra-Hour Scheduling Interval for service to be provided pursuant to such schedules for use of its firm transmission capacity. In instances where an Intra-Hour Scheduling Interval Schedule is not submitted, PacifiCorp or any successive assignee shall be deemed to have submitted a 0 (zero) schedule but shall retain the right to submit an Intra-Hour Scheduling Interval Schedule in any subsequent Intra-Hour Scheduling Interval. Use of firm transmission capacity associated with an Intra-Hour Scheduling Interval Schedule shall have priority over any use or sale of unused Scheduling Rights by Bonneville as described in subsection 5(e)(1). After 20 minutes prior to any Intra-Hour Scheduling Interval for service to be provided pursuant to Intra-Hour Scheduling Interval Schedules, any unused Scheduling Rights shall be relinquished to Bonneville for the hour; provided however, any unused Scheduling Rights shall be further subject to adjustment for Intra-Hour Scheduling Interval Schedules submitted pursuant to this subsection, by PacifiCorp or any successive assignee, for any subsequent Intra-Hour Scheduling Interval.

(3) Except as mutually agreed to, any net southbound schedules by PacifiCorp in excess of Southbound Scheduling Rights available to PacifiCorp pursuant to this subsection 5(e) and the southbound scheduling rights available to PacifiCorp pursuant to transmission agreements entered into in accordance with the Letter of Understanding, including future Pacific Northwest AC Intertie Capacity Ownership Agreements, shall be deemed to be transmitted over the AC Intertie from John Day Substation, or any other AC Intertie delivery point subsequently established by Bonneville. Except as mutually agreed to, any net northbound schedules by PacifiCorp in excess of Northbound Scheduling Rights available to PacifiCorp pursuant to this subsection 5(e) and the northbound

scheduling rights available to PacifiCorp pursuant to transmission agreements entered into in accordance with the Letter of Understanding, including future Pacific Northwest AC Intertie Capacity Ownership Agreements, shall be deemed to be transmitted over the AC Intertie to the John Day Substation, or any other AC Intertie delivery point subsequently established by Bonneville. Such excess schedules shall be subject to Bonneville's then effective Long-Term Intertie Access Policy, PacifiCorp's rights under other agreements, and the IS-93 Rate Schedule, or its successor, plus losses applicable to the AC Intertie. In the event that PacifiCorp's net northbound/southbound schedules exceed PacifiCorp's scheduling rights as described above, Bonneville shall provide transmission services to PacifiCorp pursuant to the same policies and rates that are generally applicable to Bonneville's other regional utility customers.

(4) If insufficient capacity exists in the combined capability of PacifiCorp's Midpoint-Malin 500 kV line ("Midpoint-Malin Line"), the Malin-Meridian Line, and the Alvey-Meridian Line for PacifiCorp to use its net Southbound Scheduling Rights

available to it, any increment above the combined capability of such facilities shall be deemed to be transmitted from the John Day Substation, or any other AC Intertie delivery point subsequently established by Bonneville, and shall be subject to the IS- 93 Rate Schedule, or its successor, plus losses applicable to the AC Intertie. Net Northbound Scheduling Rights shall be deemed to be delivered to PacifiCorp at Malin Substation or Captain Jack Substation. If insufficient capacity exists in the combined capability of PacifiCorp's Midpoint- Malin Line, the Malin-Meridian Line, and the Alvey-Meridian Line for PacifiCorp to integrate deliveries associated with its net Northbound Scheduling Rights available to it, any increment in excess of PacifiCorp's Load that can be served using the combined capability of PacifiCorp's facilities still in service shall be deemed to be transmitted from the Malin Substation to the John Day Substation, or any other AC Intertie delivery point subsequently established by Bonneville, and shall be subject to the IS-93 Rate Schedule, or its successor, plus losses applicable to the AC Intertie. Transmission service over the Federal Transmission System shall carry charges and losses as specified in the Midpoint-Meridian Transmission Agreement.

(5) During times when the southbound AC Intertie Operational Transfer Capability is less then the southbound AC Intertie Rated Transfer Capability, PacifiCorp's reduced net southbound scheduling rights at Malin Substation and Captain Jack Substation as described herein shall be an amount determined by multiplying the southbound Operational Transfer Capability of the AC Intertie by the ratio of 400 megawatts to the southbound Rated Transfer Capability of the AC Intertie. During times when the northbound AC Intertie Operational Transfer Capability is less then the northbound AC Intertie Rated Transfer Capability, PacifiCorp's reduced net northbound

scheduling rights shall be an amount determined by multiplying the northbound Operational Transfer Capability of the AC Intertie by the ratio of the Northbound Scheduling Rights to the northbound Rated Transfer Capability of the AC Intertie.

(f) Additional PacifiCorp Wheeling Rights. Until December 31, 2023, during Off-Peak Hours when PacifiCorp's northbound scheduling capability is less than 582 megawatts, Bonneville will provide PacifiCorp the right to utilize Bonneville's unused northbound capability on the AC Intertie and the DC Intertie at the IS-A Rate, or its successor rate, so as to provide PacifiCorp with a total northbound scheduling capability of 582 megawatts. For the purposes of this subsection 5 (f), PacifiCorp's northbound scheduling capability for any hour shall equal the sum during such hour of its Northbound Scheduling Rights hereunder and its northbound scheduling rights under the AC Intertie Transmission Agreement, Contract No. DE-MS79-94BP94285, including rights under Future Pacific Northwest AC Intertie Capacity Ownership Agreements. Bonneville's unused AC Intertie capability and DC Intertie capability shall be deemed to be capability not required to satisfy Bonneville's firm contractual commitments, as determined by Bonneville. PacifiCorp shall use best efforts to provide Bonneville advance notice of its desire to utilize its rights pursuant to this subsection 5(f). To the extent possible, such notice shall be provided at the time that PacifiCorp submits its preschedules to Bonneville pursuant to section 7 herein, provided, however, that PacifiCorp's failure to provide such notice with preschedules shall not diminish in any way, PacifiCorp's rights under this subsection 5(f).

(g) Remedial Action Schemes. PacifiCorp shall be responsible for providing or assuring, at its cost, the provision of its pro-rata share of remedial action schemes required to support the Rated Transfer Capability and Operational Transfer Capability of the AC Intertie either northbound or southbound. In support of its obligations to provide generator dropping for

its net southbound AC Intertie schedules, PacifiCorp shall provide generator dropping from its share of Mid-Columbia generation on line at the time of a remedial action scheme requirement. Bonneville may, after it has exhausted its own capability to provide generator dropping in support of its obligation for net southbound AC Intertie schedules, have access to PacifiCorp's total Mid-Columbia rights on line at the time of a remedial action scheme requirement at no cost. To the extent PacifiCorp does not have the capability on line to provide generator dropping from its Mid-Columbia rights for its net southbound AC Intertie schedules, Bonneville shall, to the extent it has available on line generation, provide generator dropping capability to PacifiCorp at no cost. In the event that PacifiCorp no longer has rights to Mid- Columbia generation, PacifiCorp's obligation to provide or assure, at its cost, the provision of its pro-rata share of remedial action schemes required to support the Rated Transfer Capability and the Operational Transfer Capability of the AC Intertie either northbound or southbound shall not be diminished. In support of PacifiCorp's net northbound AC Intertie schedules or its northbound DC Intertie schedules, PacifiCorp shall be responsible for making arrangements for any load dropping requirements. To the extent possible, as determined by Bonneville, Bonneville shall offer to sell remedial action scheme service to PacifiCorp to enable PacifiCorp to meet its obligations pursuant to this subsection 5(g).

(h) PacifiCorp shall provide Bonneville firm capacity in the existing 500/230 kV transformer at the Malin Substation at a use-of-facilities rate for Bonneville's firm requirements, provided such capacity will be made available to Bonneville only after PacifiCorp has determined that it has the capacity necessary to meet its own requirements and provided further, that Bonneville's right to use the existing Malin transformer shall be limited to 200 megawatts.

6. Upgrades of the AC Intertie Above Planned Rated Transfer Capability of 4800 Megawatts. After Bonneville has determined that the southbound or northbound AC Intertie Rated Transfer Capability is at least 4800 megawatts, but not more than 4900 megawatts, Bonneville and PacifiCorp agree that if any additions or changes to the Buckley-Alvey Loop or other jointly-owned facilities are required to increase the Rated Transfer Capability of the AC Intertie, such additions or changes shall be by mutual consent of the Parties hereto, which consent shall not be unreasonably withheld. Bonneville and PacifiCorp shall have the right, but not the obligation, to participate equally in such increase in the AC Intertie Rated Transfer Capability resulting from such additions or changes, and, if they do so, each shall share equally in the costs of such additions or changes to the Buckley-Alvey Loop or other jointly owned facilities required for such increases.

7. Scheduling.

(a) Bonneville and PacifiCorp shall schedule through the Bonneville Transmission Scheduling Office all schedules with southwest entities at the Malin and Captain Jack Substations.

(b) Upon Bonneville's request, PacifiCorp shall notify the Bonneville Transmission Scheduling Office each recognized workday of the planned schedules over PacifiCorp's parallel facilities, as described and limited in section 10 herein, for the following day or days. PacifiCorp shall also provide Bonneville's schedulers with all preschedule modifications prior to the hour of such schedules in accordance with Bonneville's standard scheduling practices.

8. Losses. The Parties shall be compensated for electric power losses pursuant to Calculation of Losses as shown in Exhibit E. Such compensation shall be based upon an equitable allocation of the Parties' control area losses associated with this Amended and Restated

AC Intertie Agreement and with the Midpoint-Meridian Transmission Agreement (Contract No. DE-MS79-94BP94333). The loss allocation specified in Exhibit E shall be reviewed at least every five years, but a review may be requested by either Party annually. The loss allocation shall be reviewed by the Parties to reflect any changes to the loss allocation.

9. Waivers. Except as specified in this Amended and Restated AC Intertie Agreement and the Letter of Understanding, PacifiCorp waives any claim to any ownership share or right to use the AC Intertie Rated Transfer Capability or to additional scheduling rights based on its ownership in:(1) existing facilities as such facilities may be modified or (2) the Alvey-Meridian Line.

10. Construction and Operation of Parallel Facilities.

(a) PacifiCorp's right to construct and right to operate existing and new interconnections with Pacific Gas & Electric Company or other utilities adjoining PacifiCorp's service territory in southern Oregon and northern California in parallel with the AC Intertie shall be subject to the following terms and conditions:

(1) The interconnection shall operate at 230 kV or below and shall include a phase shifter, unless the Parties mutually agree that a phase shifter is not required.

(2) On any given hour the sum of PacifiCorp's Load and the schedule on the parallel path shall not exceed the Load Carrying Capability.

(3) Except as provided in subsection 10(c) herein, PacifiCorp's total Rated Transfer Capability on such interconnections shall not exceed 400 megawatts. The total Rated Transfer Capability on such interconnections shall include the 100 megawatt Cottonwood Interconnection with Pacific Gas and Electric Company. The Operational

Transfer Capability on such interconnections shall never exceed the Rated Transfer Capability on such interconnections.

(4) PacifiCorp shall schedule as provided in subsection 7(b) herein. In no case shall such schedules exceed the Operational Transfer Capability of such interconnections.

(5) PacifiCorp shall make available to Bonneville telemetry of the actual power flow over PacifiCorp's parallel path interconnections.

(6) Construction or operation of such interconnections shall not reduce or adversely impact the Operational Transfer Capability of the AC Intertie. If Bonneville determines the operation of any such interconnection reduces or impacts the Operational Transfer Capability of the AC Intertie on any hour, and AC Intertie users have need of additional Operational Transfer Capability on the AC Intertie, upon Bonneville's request PacifiCorp shall reduce schedules to the extent needed to eliminate such impact. PacifiCorp shall not be required to reduce schedules on the parallel paths if the Operational Transfer Capability of the AC Intertie is reduced as a result of outages on the AC Intertie.

(b) Except as provided in subsection 10(c) herein, PacifiCorp shall not construct, participate in, or allow new interconnections for any 345 kV or above transmission lines or facilities from any point on PacifiCorp's system in Oregon to the existing two Malin-Round Mountain-Table Mountain 500 kV lines or the COTP north of Table Mountain.

(c) Notwithstanding the provisions of subsections 10(a)(3) and 10(b) herein, PacifiCorp may (i) construct and operate existing and new interconnections, as referenced in subsection 10(a)(3) herein with Rated Transfer Capability in excess of 400 megawatts, and/or (ii)

construct, participate in, and allow new interconnections as referenced in subsection 10(b) herein, if:

(1) such increase in Rated Transfer Capability or new interconnection is needed for PacifiCorp to meet good faith third-party requests for transmission service; and

(2) Bonneville has declined to provide, or lacks transmission facilities to provide, the requested transmission service; and

(3) such actions do not reduce the Rated Transfer Capability of the AC Intertie.

11. Wheeling from Palo Verde. For a period coincident with the term of PacifiCorp's March 23, 1993, Transmission Service Agreement ("TSA") with Southern California Edison Company ("SCE"), PacifiCorp, on hours that PacifiCorp does not require all or a portion of its transmission capacity rights pursuant to the TSA, shall offer Bonneville a first right of refusal to utilize such excess transmission rights under the TSA. PacifiCorp shall have sole discretion to determine whether it is making use of its TSA transmission rights. If Bonneville exercises its right to use PacifiCorp's TSA transmission rights, Bonneville shall reimburse PacifiCorp for SCE's charges to PacifiCorp for such usage. Such reimbursement shall be based upon PacifiCorp's then-effective transmission demand charges from SCE under the TSA which shall initially be $4.00 per megawatt-hour. If Bonneville exercises its first right of refusal to utilize PacifiCorp's excess TSA transmission rights, Bonneville shall use its own AC Intertie or DC Intertie scheduling capability to accept and transmit power and energy scheduled under this section 11. Additionally, the exercise of such access by Bonneville shall not preclude PacifiCorp

from utilizing its transmission rights acquired from Bonneville on the AC Intertie or the DC Intertie.

12. Summer Storage and Spring Energy Option

(a) Summer Storage. For a period of 20 years commencing with the effective date of the June 1994 AC Intertie Agreement, PacifiCorp shall accept and store energy for Bonneville during the months of June and July of each year.

(1) Prior to each storage month, Bonneville shall nominate their Bonneville Requested Storage, as shown in **Exhibit H** hereto. Bonneville will deliver the Bonneville Requested Storage Hourly Schedule to PacifiCorp system to system (BPAT.PACW) as described in Exhibit C to this Agreement.

(2) On any day that is not a Contingent Spill Protection Day, PacifiCorp may cut Bonneville's Requested Storage Hourly Schedule in any hour of any storage month up to the PacifiCorp Monthly Storage Schedule Cut Cap quantity for any reason, without financial compensation or other documentary support to Bonneville.

(3) On any day that is a Contingent Spill Protection Day, PacifiCorp will not cut Bonneville's Requested Storage Hourly Schedule for any hours of the Contingent Spill Protection Day.

(4) Energy to be stored pursuant to this subsection 12 (a) shall be delivered to PacifiCorp at the points of delivery specified in Exhibit C of the Short-Term Surplus Firm Capacity Sales Agreement (Contract No. DE-MS79-92BP93757), as amended or superseded, or such other points as may be mutually agreed to. PacifiCorp may, but shall not be required to, accept more than 100,000 megawatt-hours per month for storage and Bonneville shall deliver no less than 25,000 megawatt-hours per month for storage.

Bonneville shall deliver energy to PacifiCorp for storage prior to entering into the market to sell surplus energy. Unless otherwise mutually agreed, the hourly rate of delivery shall be determined by dividing the total energy to be stored in the month by the number of hours in such month. Except in times of system emergency, Bonneville shall adhere to the agreed-upon schedule of deliveries.

(5) PacifiCorp shall return stored energy to Bonneville during the months of September, October and November of each year in which energy was delivered to PacifiCorp. Unless otherwise mutually agreed, the hourly rate of return of the energy to Bonneville shall be determined by summing the total energy delivered to PacifiCorp during the prior June and July period, dividing such sum by three (3) and dividing the result by the number of hours in the month in which the energy is to be returned to Bonneville. Except during times of system emergency, PacifiCorp shall adhere to this hourly return schedule. Except when prevented by constraints on the Parties' transmission systems, including both operational and scheduling constraints, returned energy in any hour shall be delivered to Bonneville at the Hot Springs Substation, at an amount not to exceed 110 MW unless otherwise mutually agreed to, Summer Lake Substation or other mutually-agreed upon points of delivery. Storage provided pursuant to this subsection 12(a) shall be at no charge to Bonneville.

(6) If PacifiCorp exceeds its Monthly Storage Schedule Cut Cap for a given storage month, and Bonneville has not declared a Spill Protection Day and operational constraints dictate further storage cuts, then PacifiCorp can cut Bonneville Requested Storage Hourly Schedule but will pay Bonneville the PacifiCorp Storage Cut LD.

(7) If Bonneville has met its Monthly Spill Protection Day Cap for a given

storage month, and environmental constraints dictate further Spill Protection Day(s), then Bonneville can provide notice for additional Contingent Spill Protection Day(s) and PacifiCorp will accept and store such Bonneville Requested Storage Hourly Schedules, but Bonneville will pay PacifiCorp the Bonneville Spill Protection Day LD for Bonneville Requested Storage Hourly Schedules for any Contingent Spill Protection Days in excess of the Bonneville Monthly Spill Protection Day Cap and for any Contingent Spill Protection Day that does not meet all the Spill Protection Day criteria in 27(gg).

(8) PacifiCorp will pay any accumulated PacifiCorp Storage Cut LD, and Bonneville will pay any accumulated Bonneville Spill Protection Day LD, due in any storage year by December 20th of such storage year, and any such payment shall be made in accordance with payment terms set forth in the current General Rate Provisions dated October 1, 2009.

(9) Summer Storage Settlement. Storage and return of energy as provided in this section 12(a) shall occur in calendar year 2014 pursuant to the terms of this section 12(a)(9). For calendar year 2014, subsections 12(a)(1)-(8) shall be inoperable.

(i) Bonneville may elect to store energy with PacifiCorp in either the month of June or July (but not both). Such month shall then be deemed the Delivery Month. Bonneville shall notify PacifiCorp of such election in a notice shown in **Exhibit N** hereto.

(ii) If Bonneville makes such election, PacifiCorp shall accept up to 25,000 megawatt-hours for storage over a maximum of 8 Storage Day(s) in the Delivery Month, as defined in section 12(a)(9)(v). The eight Storage Day(s) may, but need not be, consecutive. Deliveries of such energy shall be 130 MW per hour for each Storage Day.

(iii) Energy to be stored by Bonneville shall be pursuant to this subsection 12(a)(9) and shall be delivered to PacifiCorp system to system (BPAT.PACW) as described in Exhibit C of the Short-Term Surplus Firm Capacity Sales Agreement (BPA Contract No. DE-MS79-92BP93757), or such other points as may be mutually agreed to.

(iv) PacifiCorp shall return energy stored under this section 12(a)(9) to Bonneville during the months of September, October, and November of the year in which energy was delivered to PacifiCorp. Unless otherwise mutually agreed, the hourly rate of return of the energy to Bonneville shall be determined by summing the total energy delivered to PacifiCorp during the prior June or July period, dividing such sum by three (3) and dividing the result by the number of hours in the month in which the energy is to be returned to Bonneville. Except during times of system emergency, PacifiCorp shall adhere to this hourly return schedule. Except when prevented by constraints on the Parties' transmission systems, including both operational and scheduling constraints, returned energy in any hour shall be delivered to Bonneville at the Hot Springs Substation, at an amount not to exceed 110 MW unless otherwise mutually agreed to, Summer Lake Substation or other mutually-agreed upon points of delivery. Storage provided pursuant to this subsection 12(a) shall be at no charge to Bonneville, except as provided in section 12(a)(9)(vi).

(v) "Storage Day" as used in this section 12(a)(9) shall mean any calendar day in which all of the following occur:

(1) Bonneville anticipates that it will be in Spill Conditions, as defined in section 27 of this Agreement, for any hour in a declared Storage Day, and

(2) Bonneville has specifically notified PacifiCorp it is declaring a Storage Day, and that notification will be delivered no later than 10:00 a.m. on the pre-schedule day for the Storage Day(s), via sending an email to PacifiCorp at ctpreschd@pacificorp.com, an example of which is shown in **Exhibit O** hereto.

In each case, a Storage Day will be for 24 hours beginning at HE0100 and ending HE2400 as outlined in Bonneville notice **(Exhibit O)** and are day(s) in which BPA requested Storage Day schedule cannot be cut by PacifiCorp.

(vi) If Bonneville delivers energy to PacifiCorp on a declared Storage Day where Bonneville was not in Spill Conditions, then Bonneville will be subject to a Bonneville Storage Day Liquidated Damage (LD), as defined in section 12(a)(9)(vii).

(vii) "Bonneville Storage LD" as used in this section 12(a)(9) is defined as the sum of the product of the 3,120 MWh (24 hours of storage deliveries) and the market price spread of the Powerdex Mid-Columbia Average Hourly Index price for all hours of the Storage Day and the hourly weighted average of the settled ICE North American Power Day-Ahead Power Index Mid-Columbia price, for Peak and Off-Peak, from September through November of 2014. (Example in **Exhibit P)**

Bonneville will pay to PacifiCorp the BPA Storage Day LD, if any, by December 20th, 2014 and such payment shall be made in accordance with payment terms set forth in BPA's current Power General Rate Schedule Provisions.

(b) Spring Energy Option. For a period of 20 years following the effective date of the June 1994 AC Intertie Agreement, if requested by Bonneville, PacifiCorp shall deliver to Bonneville during Off- Peak Hours, at the Hot Springs Substation, or other mutually-agreed points of delivery, up to 50,000 megawatt-hours during the month of March of each such year. The maximum rate of delivery for such energy shall be 200 megawatts per hour. To exercise its option to take such energy, Bonneville shall notify PacifiCorp by February 15 of each year as to the amount of energy Bonneville desires to have delivered during the following March. Except in times of system emergency, PacifiCorp shall deliver such energy in accordance with Bonneville's request, subject to the limitations of this subsection 12(b). Bonneville shall return the energy delivered by PacifiCorp during the following June 1 through July 15 period during Off-Peak hours at an hourly rate of delivery determined by dividing the amount of energy delivered by PacifiCorp during the previous March by the number of Off-Peak Hours in the June 1 through July 15 period or such other hourly rate of delivery as mutually agreed to. Such March Energy shall be returned to PacifiCorp at points of delivery as specified in Exhibit C of Contract No. DE-MS79-92BP93757 or such other points of delivery as are mutually agreed.

13. Sale or Assignment.

(a) This Amended and Restated AC Intertie Agreement shall inure to the benefit of, and shall be binding upon, the respective successors and assigns of the Parties to this Amended and Restated AC Intertie Agreement.

(b) PacifiCorp and Bonneville agree not to sell, assign, lease, sublease, or otherwise transfer this Amended and Restated AC Intertie Agreement or any interest therein, without the written consent of the other Party, such consent not to be unreasonably withheld. PacifiCorp and Bonneville also agree not to sell, assign, lease, sublease, or otherwise transfer any direct or indirect interest in the Malin Substation, the portion of the Midpoint-Malin Line between Summer Lake Substation and Malin Substation ("Summer Lake-Malin Line"), the Malin-Meridian Line, or the Alvey-Meridian Line, without the written consent of the other Party, such consent not to be unreasonably withheld, provided, however, that PacifiCorp's interest in such facilities may be conveyed to its respective trustees as security under a mortgage or deed of trust to secure indebtedness without such written consent, provided that each such trustee may act with respect to such interest only to the extent and in the manner that such act would have been authorized under this Amended and Restated AC Intertie Agreement.

(c) If Bonneville or PacifiCorp is acquired in total by other entities, subsection 13(b) shall not apply to such acquisition.

14. Extension of Existing Agreements. The Parties agree that the termination dates of the Midpoint-Meridian Transmission Agreement, the Malin Substation Construction Agreement and all agreements related to joint ownership or interconnection on the Buckley-Alvey Loop, including but not limited to arrangements for the operation and maintenance of new facilities, shall be coincident with the termination date of this Amended and Restated AC Intertie Agreement. The Payment Agreement and the Option Agreement are attached hereto as Exhibits A and D respectively and made a part of this Amended and Restated AC Intertie Agreement. The Payment Agreement and the Option Agreement provide for, among other things, certain construction, payment, ownership, operation and maintenance activities in progress at the time of execution of this Amended and Restated AC Intertie Agreement. As these activities are completed or superseded by future agreements, PacifiCorp and Bonneville may agree to terminate some or all of the Payment Agreement and the Option Agreement provisions. To the

extent any provisions of the Payment Agreement or the Option Agreement are in conflict with this Amended and Restated AC Intertie Agreement, the terms and conditions of this Amended and Restated AC Intertie Agreement shall prevail.

15. Termination of Agreement. The Parties agree that this Amended and Restated AC Intertie Agreement consistent with the 1994 AC Intertie Agreement supersedes and terminates in its entirety, the July 1986 Intertie Agreement, Contract No. DEMS79-86BP92299, provided, however, that any liabilities incurred thereunder are hereby preserved until satisfied.

16. Execution of Other Agreements. The Parties agree to negotiate in good faith and execute construction agreements, operation and maintenance agreements, transmission agreements, and other such agreements that may be required to implement the provisions of this Amended and Restated AC Intertie Agreement.

17. Arbitration. In the event of any dispute related to rights or obligations of the Parties, or satisfaction thereof, under this Amended and Restated AC Intertie Agreement, including but not limited to the amount or reasonableness of costs, identification of exclusive use facilities, extent of amortization of past costs, and the reasonableness of withholding consent, either Party may elect to submit such dispute to nonbinding arbitration. If one Party so elects, such Party shall notify the other Party in writing and both Parties shall participate pursuant to the following:

(a) If the Parties cannot agree on an arbiter within 30 days of such notification, the notifying Party shall request the American Arbitration Association to designate an arbiter with sufficient expertise in the subject under dispute.

(b) After an arbiter is agreed to or designated, the arbiter shall establish a schedule for submission of the Parties' written positions. The Party electing the arbitration shall first state its position in a letter to the arbiter. The second Party shall then state its position in a letter to the arbiter. The first Party may then submit a response to the Second Party's position and the second Party may thereafter submit a reply to the first Party's response.

(c) Each letter submitted to the arbiter shall be no more than 5 pages in length, unless the Parties otherwise mutually agree. The Parties may attach exhibits that they consider relevant to the dispute. A copy of each submission also shall be simultaneously served on the other Party.

(d) The arbiter shall provide the Parties with a written analysis of the dispute, and his or her proposed resolution of the dispute.

(e) The Parties shall equally share the fee and other costs of the arbiter.

In the event neither Party submits the dispute to nonbinding arbitration or if either Party elects not to accept the finding of the arbiter, the Parties may elect other approaches, including litigation, to resolve the dispute.

18. <u>Rules of Law.</u>

(a) The Parties agree that each fully participated in the drafting of each provision of this Amended and Restated AC Intertie Agreement. The rule of law interpreting ambiguities against the drafting Party shall not be applicable to or utilized in resolving any dispute over the meaning or intent of this Amended and Restated AC Intertie Agreement or any of its provisions.

(b) The construction and interpretation of this Amended and Restated AC Intertie Agreement shall be governed solely by Federal law.

(c) This Amended and Restated AC Intertie Agreement shall not be construed to establish a partnership, association, joint venture, or trust. Neither Party shall be under the control of or shall be the agent of or have a right or power to bind the other Party without the other Party's express written consent, except as provided in this Amended and Restated AC Intertie Agreement.

19. Delay of Performance. The time for each act specified in this Amended and Restated AC Intertie Agreement shall be extended for a time equivalent to such delays, if any, as are occasioned by events which the Party hereto obligated to perform such act could not be reasonably expected to avoid by the exercise of reasonable diligence and foresight.

20. Regulatory Jurisdiction. The provisions of this Amended and Restated AC Intertie Agreement are subject to such regulatory agencies having jurisdiction thereof. Nothing contained herein shall be construed as affecting in any way the right of PacifiCorp to make application unilaterally to the Federal Energy Regulatory Commission for a change in rates, charges, classification, or service, or any rule or regulation, or contract relating thereto, under Section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder.

21. Severability and Breach.

(a) It is the intention of the Parties that the provisions of this Amended and Restated AC Intertie Agreement be severable in the event that any of such provisions, or portions thereof, are held to be illegal, invalid or unenforceable by a court of competent jurisdiction; provided that if section 10 herein, or any portion thereof, is found to be illegal, invalid or unenforceable by a court of competent jurisdiction, Bonneville shall have firm transmission rights to 50 percent of the total Rated Transfer Capability of any parallel interconnections other than the 100 megawatt Cottonwood Interconnection between PacifiCorp and Pacific Gas & Electric or other utilities adjoining PacifiCorp's territory in southern Oregon and northern California. In any legal proceeding, Bonneville and PacifiCorp shall act in good faith to defend the enforceability of all provisions of this Amended and Restated AC Intertie Agreement.

(b) The Parties agree that breach of this Amended and Restated AC Intertie Agreement, or any of its provisions, will cause irreparable harm and that the appropriate remedy is injunctive relief.

22. Capital Budgets. Excluding any facilities designated for omission by footnote 1 of Exhibit B of this Amended and Restated AC Intertie Agreement, each Party by July 1 of each year shall send a notice to the other Party containing (i) an estimate of the capital budget amounts related to the planned construction activities of the facilities described in such Exhibit B such Party expects to incur four (4) years in the future, and (ii) an update of any capital budget amounts it expects to incur within the upcoming three (3) years. Except for emergency Capital Replacements or emergency Capital Additions, the Parties shall exchange and review any necessary data as needed to determine the necessity and adequacy of the proposed construction and operation activities.

23. Payment Provisions.

(a) For reimbursable Capital Replacements or Capital Additions, the Party proposing the action shall prepare a proposed revision to Exhibit F whenever the Parties concur that it is necessary to add to or to replace the facilities identified in Exhibit B of this Amended and Restated AC Intertie Agreement. The Parties shall share the costs of such action according to the original cost share percentage of such facilities as set forth in Exhibit B in a manner consistent with the cost sharing methodologies contained in such exhibit, except that the replacement of facilities identified by footnote 1 of Exhibit B shall not be eligible for cost-sharing. Each revision of Exhibit F shall specify the facilities added or replaced.

(b) The Party responsible to make payment shall pay according to the provisions of the revision of Exhibit F for the work performed in amounts and at times as negotiated by the Parties.

(c) In the event of a dispute regarding billing, the Party owing the bill shall pay the amount in full and provide written notification of the disputed amount. Any adjustment shall be made on the next invoice allowing reasonable notice and time to make the adjustment. Refunds of the disputed amount shall include interest at the same interest rate specified in section 23(d).

(d) Invoices not paid in full on or before the close of business on the date due shall be subject to an interest charge on the amount due from the due date to the date paid consistent with the Prompt Payment Act Renegotiation Board's Interest Rate published in the Federal Register.

24. Audit Rights.

(a) Each Party, at its expense, may review and audit any cost on the other Party's books, records, and documents that directly pertain to the billings on the jointly owned facilities. The Party undertaking the audit shall provide reasonable notice to the other Party and shall conduct such audit at reasonable times and in conformance with generally accepted auditing standards. The Party being audited shall cooperate fully with any such audit. Neither Party shall audit a cost incurred more than three (3) years following the last day of the fiscal year in which such cost was incurred under Section 23 to this Amended and Restated AC Intertie Agreement. The Parties shall retain all records and documentation prepared in the normal course of business for the entire length of this audit period and in accordance with generally accepted accounting principles.

(b) After completion of the audit, the Party conducting the audit shall promptly notify the other Party of any exception taken as a result of an audit, and the audited Party may review the notice of exception and basis therefore for a period of thirty (30) days. Upon agreement regarding the validity of any exception, the owing Party shall directly refund the amount of the exception within thirty (30) days of such agreement.

25. Ownership of the Facilities.

(a) Transfer of legal ownership pursuant to Sections 22 and 23 to this Amended and Restated AC Intertie Agreement shall be effective at such time as the facilities are energized and made available for commercial operation as part of this Amended and Restated AC Intertie Agreement.

(b) All jointly-owned equipment and facilities shall be identified as such with co-ownership tags and signs. Each Party shall provide the tags and signs for equipment which it operates. Costs for such tags and signs shall be shared equally by each Party.

26. Integration.

(a) To the extent that Exhibit A of this Amended and Restated AC Intertie Agreement is inconsistent with provisions of Sections 22, 23 and 25 to this Amended and Restated AC Intertie Agreement, such Exhibit A is superseded by the provisions of this Amended and Restated AC Intertie Agreement.

(b) Any revisions to Exhibit F shall be attached to and deemed to be a part of this Amended and Restated AC Intertie Agreement and shall be effective on the date specified therein.

27. Definitions.

(a) AC Intertie. For the purposes of this Amended and Restated AC Intertie Agreement, the AC Intertie means Bonneville's rights in the alternating current ("AC") transmission facilities for transferring power and energy between Oregon and California as follows: two 500 kV lines extending from John Day Substation to Malin Substation and to the California-Oregon Border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's share of ownership of the Alvey-Dixonville and Dixonville-Meridian 500 kV transmission lines; portions of the Alvey, Dixonville, Meridian and Captain Jack Substations; the 500 kV transmission line extending from Captain Jack Substation to the California- Oregon Border; and any modifications, improvements, or additions to such facilities.

(b) Alvey-Meridian Line. The 500 kV transmission line facilities and substations constructed by PacifiCorp that extend from the interconnection with Bonneville's system at Alvey Substation to PacifiCorp's Meridian Substation.

(c) Bonneville Monthly Spill Protection Day Cap. Eight (8) Spill Protection Days in any storage month, without any carryover to the next month or year.

(d) Bonneville Requested Storage. The monthly energy Bonneville requests PacifiCorp to store as exercised under Section 12(a), hereof, as defined and confirmed in a nomination letter Exhibit H.

(e) Bonneville Requested Storage Hourly Schedule. The Bonneville Requested Storage (MWh/mn) for a storage month divided by the total hours (hours/mn) in the storage month and shall be the hourly flat schedule of Bonneville Requested Storage for all hours in the storage month

(f) Bonneville Spill Protection Day LD. The sum of the product of the Bonneville Requested Storage Hourly Schedules and the market price spread of the Powerdex Mid-Columbia Average Hourly Index price for all hours of the Spill Protection Day and the hourly weighted average of the settled ICE North American Power Day-Ahead Power Index Mid-Columbia price, for Peak and Off-Peak, from September through November of the storage cut year. (Example calculation found in Exhibit L).

(g) Bonneville Transmission Scheduling Office. The group of schedulers presently located at Bonneville's Dittmer Control Center in Vancouver, Washington, appointed by

Bonneville, Portland General Electric Company and PacifiCorp and designated to coordinate the schedule of energy over the AC Intertie and the DC Intertie.

(h) Buckley-Alvey Loop. The 500 kV transmission lines, facilities, and substations from Buckley Substation south to Summer Lake Substation, continuing south to Malin Substation, west to Meridian Substation, including the Captain Jack Substation, and the Alvey-Meridian Line.

(i) California Intertie. The two existing 500 kV AC lines extending northward from within California at Round Mountain Substation and terminating at Malin Substation.

(j) Capital Additions. The addition of any new facilities under this Amended and Restated AC Intertie Agreement (e.g., not replacements for assets already listed on Exhibit B) that are required to serve the common good of both Parties.

(k) Capital Replacements. The replacement asset for the facilities listed in Exhibit B of this Amended and Restated AC Intertie Agreement that is required to serve the common good of both Parties.

(l) Captain Jack Substation. The substation where COTP interconnects with the AC Intertie in the Pacific Northwest.

(m) COTP. The 500 kV California-Oregon Transmission Project, which operates in parallel with the California Intertie and terminates at the California-Oregon Border.

(n) DC Intertie. For the purposes of this Amended and Restated AC Intertie Agreement, the DC Intertie means Bonneville's rights in the existing 1,000 kV direct current ("DC') transmission line, and associated substation facilities, extending from the Bonneville's Big Eddy Substation to the Nevada-Oregon Border.

(o) Federal Transmission System. The transmission facilities owned by Bonneville.

(p) Future Pacific Northwest AC Intertie Capacity Ownership Agreements. Agreements entered into by Bonneville and regional utilities providing for those utilities' ownership of AC Intertie capacity available as a result of increasing the Rated Transfer Capability of the AC Intertie to 4800 megawatts.

(q) Incremental Capacity. For the purpose of this Amended and Restated AC Intertie Agreement, Incremental Capacity means capacity realized through the construction of the Alvey-Meridian Line in excess of the capacity on the previously existing 230 kV Alvey-Meridian line that was removed as a result of construction of the Alvey-Meridian Line.

(q1) Intra-Hour Scheduling Interval. For the purpose of this Amended and Restated AC Intertie Agreement, Intra-Hour Scheduling Interval means each of the four 15-minute intervals during an operating hour, the first such 15-minute interval beginning at the start of the operating hour.

(q2) Intra-Hour Scheduling Interval Schedule. For the purpose of this Amended and Restated AC Intertie Agreement, Intra-Hour Scheduling Interval Schedule means a schedule representing an Intra-Hour Scheduling Interval, and may consist of either the submission of a new 15-minute schedule or adjustment to an hourly schedule.

(r) IS-A Rate. The Nonfirm Transmission Rate specified in Section II.A. of Bonneville's Southern Intertie Transmission Schedule IS-93, or its successor.

(s) [Reserved]

(t) Load Area. The geographic area encompassing portions of southern Oregon and northern California which is generally south of Eugene, Oregon and Bonneville's Summer Lake Substation and west of Burns, Oregon. Such geographic area shall be limited to:

(1) That area in which PacifiCorp is authorized to provide retail electric service, now and in the future; and

(2) That area in which PacifiCorp provides wholesale electric service at the date of execution of the June 1994 AC Intertie Agreement; provided that such areas are normally within PacifiCorp's load control area, connected to PacifiCorp's transmission system, and served by the transmission lines in Exhibit C.

Revisions to the Load Area shall be by mutual agreement of the Parties, and such agreement shall not be unreasonably withheld.

(u) Load Carrying Capability. The capability of PacifiCorp's transmission system, as specified in Exhibit C, serving the Load Area and parallel paths as limited by section 10 herein to provide firm transmission service in accordance with Prudent Utility Practice.

(v) Northbound Scheduling Rights. PacifiCorp's right to schedule power and energy through the Malin Substation and the Captain Jack Substation in a northerly direction from the 500 kV lines which extend to California and interconnect with the California Intertie and the COTP as provided in this Amended and Restated AC Intertie Agreement.

(w) Off-Peak Hours. The first six and last two hours of each day Monday through Saturday and all day Sunday or other hours as mutually agreed to.

(x) Operational Transfer Capability. Rated Transfer Capability less reductions caused by, but not limited to, physical limitations beyond the control of the Parties, operational limitations imposed by California utilities, line or equipment outages, stability limits or loop flow.

(y) PacifiCorp's Load. PacifiCorp's net firm load obligations within the Load Area excluding Bonneville's Surprise Valley Electric Cooperative Load transferred by PacifiCorp pursuant to the General Transfer Agreement, Contract No. DEMS79-82BP90049.

(z) PacifiCorp Monthly Storage Schedule Cut Cap. Sixteen (16) percent of the Bonneville Requested Storage in any storage month. The quantity of energy is defined as

Bonneville Requested Storage quantity (MWh/mn) multiplied by PacifiCorp Monthly Storage Schedule Cut Cap (16%) without any carryover to the next month or year.

(aa) PacifiCorp Storage Cut LD. The product of any storage cuts in excess of PacifiCorp's Monthly Storage Schedule Cut Cap, multiplied by the market price spread of Powerdex Mid-Columbia Average Hourly Index price at the time of cut and the hourly weighted average of the settled ICE North American Power Day-Ahead Power Index Mid-Columbia price, for Peak and Off-Peak, from September through November of the storage cut year. (Example found in Exhibit M).

(bb) Plan-of-Service. The project plans that Bonneville develops to realize an increase of the AC Intertie Rated Transfer Capability up to approximately 4800 megawatts, which shall include but are not necessarily limited plans, schedules, costs, and facility and equipment requirements.

(cc) Prudent Utility Practice. At any particular time, the generally accepted practices, methods, and acts in the electrical utility industry prior thereto or the practices, methods or acts, which, in the exercise of reasonable judgment in the light of the facts known at the time the decision was made, could have been expected to accomplish the desired result consistent with reliability and safety.

(dd) Rated Transfer Capability. The ability of a transmission line or system to transfer power in a reliable manner as determined in accordance with Prudent Utility Practice.

(ee) Southbound Scheduling Rights. PacifiCorp's right to schedule power and energy through the Malin Substation and the Captain Jack Substation in a southerly direction to the 500 kV lines which extend to California and interconnect with the California Intertie and the COTP as provided in this Amended and Restated AC Intertie Agreement.

(ff) Spill Conditions. Individual calendar days with one or more hours in that day flagged to indicate that Bonneville has declared spill conditions. The hourly spill condition declarations are provided by Bonneville via public internet posting at: http://www.transmission.bpa.gov/Business/Operations/Misc/ , then click on: Hourly Spill Flag, Last Two Years & Day-Ahead Forecast (updated daily at 11:00 AM, Pacific Time). Flags are found in the column titled "Actual" (Sample displayed in Exhibit K).

(gg) Spill Protection Day. Any day(s) in which all of the following occur:

(1) Bonneville has been in Spill Conditions for two (2) consecutivedays prior to when the Spill Protection Day begins (it being understood that such two day period could occur in May for the beginning of the June storage month and/or in June for the beginning of the July storage month); and

(2) Bonneville is in Spill Conditions, as defined herein, for any hour in a declared Spill Protection Day; and

(3) Bonneville has specifically notified PacifiCorp it is declaring a period of Spill Protection Day(s), and that notification will be delivered no later than 10:00 am on the pre-schedule day for the Spill Protection Day, via sending an email to PacifiCorp at ctpreschd@pacificorp.com, an example of which is shown in Exhibit I hereto.

In each case, Spill Protection Day(s) will be for 24 hours and begin at HE0100 and end HE2400 as outlined in Bonneville notice (Exhibit I) and are day(s) in which Bonneville's Requested Storage Hourly Schedule cannot be cut by PacifiCorp. Bonneville will declare Spill Protection Days when a reduction in generation would cause a potential violation of Bonneville's total dissolved gas limits at the relevant hydroelectric projects, and a potential violation of relevant environmental statutes and regulations.

(hh) Contingent Spill Protection Day. Any day that has been noticed and scheduled by Bonneville as a Spill Protection Day, but that has not yet met all the conditions as described in section 27(gg) above. A Contingent Spill Protection Day will result in either:

(1) a Contingent Spill Protection Day that ultimately meets all of the Spill Protection Day criteria in 27(gg) above and is within Bonneville's eight (8) allowed days; or

(2) a Contingent Spill Protection Day that ultimately meets all of the Spill Protection Day criteria in 27(gg) above, but exceeds Bonneville's eight (8) allowed days (in which case Bonneville Spill Protection Day LDs apply); or

(3) a Contingent Spill Protection Day that ultimately fails to meet all the Spill Protection Day criteria in 27(gg) above (in which case, Bonneville Spill Protection Day LDs apply).

When Bonneville specifically notifies PacifiCorp it is declaring a Contingent Spill Protection Day(s), that notification will be delivered no later than 10:00 am on the pre-schedule day for the Spill Protection Day, via email to PacifiCorp at ctpreschd@pacificorp.com, an example of which is shown in Exhibit I hereto. PacifiCorp will provide notice to Bonneville by the 10th of the month following a storage month as to the number of Contingent Spill Protection Days that a) fall within Bonneville Monthly

Spill Protection Day Cap and/or b) exceed Bonneville Monthly Spill Protection Day Cap and/or c) did not meet the Spill Protection Day criteria in 27(gg), via e-mail as described in Exhibit J.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement.

PACIFICORP	**BONNEVILLE POWER ADMINISTRATION**
By: Natalie L Hocken	By: Robert King
Name: Natalie Hocken	Name: Robert King
Title: SVP, Transmission & System Operations	Title: VP Transmission Marketing & Sales
Date: 8/5/14	Date: 8/5/14

EXHIBIT B, REVISION NO. 4
ALVEY TO MERIDIAN INVESTMENT ALLOCATION
Effective upon filing

This Exhibit B, Revision No. 4 (Revision No. 4) replaces Exhibit B, Revision No. 3 in its entirety and reflects the following: (1) corrects the ownership of the Motor Operated Disconnect switches (MODs) in Bay 3 of the Captain Jack Substation changing the number of PacifiCorp-owned MODs from four to five and adds a reference to one BPA owned MOD; and (2) cleans up the footnotes.

Facility Description	Design	Cost Share Percentage Bonneville / PacifiCorp	Ownership Percentage Bonneville / PacifiCorp	Operation & Maintenance	Operation & Maintenance Payments % Bonneville / PacifiCorp	Comments
Alvey Substation						
• Three 500 kilovolt (kV) breakers/CT's buswork, towers, MOD's, PT's arresters, associated grounding, conduit, control and power cables, site dev. including landscaping, station service equipment for the three break ring bus layout.	Bonneville	50/50	50/50	Bonneville	42/58	Bonneville to operate and maintain (including maintenance of conduit, trench, and grounding systems at Bonneville discretion.)
• Environmental related work.	Bonneville	50/50	N/A	N/A	N/A	
• Series capacitors and auxiliaries.	Bonneville	50/50	50/50	Bonneville	42/58	Bonneville to operate and maintain (including maintenance of conduit, trench and grounding systems at Bonneville discretion.)

Facility Description	Design	Cost Share Percentage Bonneville / PacifiCorp	Ownership Percentage Bonneville / PacifiCorp	Operation & Maintenance	Operation & Maintenance Payments % Bonneville / PacifiCorp	Comments
• Property acquired for 500 kV yard for Intertie purposes, excluding any additions, for future Bonneville projects.	Bonneville	50/50	50/50	Bonneville	42/58	Requires identification of boundaries. Operation and Maintenance (O&M) costs subject to nonroutine work. Bonneville to maintain at 100 percent Bonneville costs, things like surface rock, sidewalks, roads, fenceline, and aesthetics.
• 500 kV Relay House building.	Bonneville	50/50	50/50	Bonneville	42/58	Future Bonneville/PacifiCorp expansion will be done at 100 percent Bonneville/PacifiCorp costs, otherwise 50/50 if Intertie related. General building maintenance should be at Bonneville discretion with 42/58 cost sharing.
• Relaying and controls, data system equipment inside the 500 kV Relay House for the Alvey - Dixonville, Marion – Alvey and 500 kV Tie Line.	Bonneville	50/50	50/50	Bonneville	42/58	Bonneville has future rights for Bonneville projects at 100 percent Bonneville costs otherwise 50/50 if Intertie related. O&M at 42/58 as per Revision No. 3 for Intertie related facilities. Bonneville to maintain
• RAS related equipment.	Bonneville					Refer to Contract No. 93039
• Metering/Telemetering equipment on the Alvey – Dixonville Line.	Bonneville	50/50	50/50	Bonneville	42/58	Bonneville to do the maintenance at Bonneville discretion.
500 kV Tie Line (to Alvey 500/230 kV Tx. Bank No. 5)						
• Transmission related costs.	Bonneville	50/50	50/50	Bonneville	100/0	50/50 ownership means PacifiCorp has 50 percent capacity rights on the Tie Line but not physical ownership. Transfer rights over Bank No. 5 are not covered here.

Facility Description	Design	Cost Share Percentage Bonneville / PacifiCorp	Ownership Percentage Bonneville / PacifiCorp	Operation & Maintenance	Operation & Maintenance Payments % Bonneville / PacifiCorp	Comments
Marion – Alvey 500 kV Line Modifications						
• Transmission costs only. [1]	Bonneville	50/50	100/0	Bonneville	100/0	
34.5 kV Line Relocation						
• Transmission costs only. [1]	Bonneville	50/50	100/0	Bonneville	100/0	
Alvey – Dixonville 500 kV Line						
• 1.4 mile Alvey – Spencer Tap Section. [2]	PacifiCorp	50/50	50/50	PacifiCorp	42/58	Applicable only to the Right of Way (ROW) for Intertie purposes. Additional ROW at 100 percent Bonneville costs.
• Remaining 56.7 miles. [2]	PacifiCorp	50/50	50/50	PacifiCorp	42/58	Requires identification of specific properties upon which these percentages are applicable. Access roads must also be considered. Timber costs and revenues also to be included. [2]
• Landslide abatement.	PacifiCorp	50/50	50/50	PacifiCorp	42/58	Rock wall and drain for slope stabilization tower 2/42 & 2/49.

[1] Credits and sharing of costs for capital replacements will not be applicable to this item after completion of the initial construction. Proceeds from credits realized by either Party during the initial construction phase of this item shall be subject to cost-share and the final accounting of costs.

[2] Costs of: (1) removal of any existing 230 kV facilities; (2) permitting; and (3) incremental right-of-way to be included

Facility Description	Design	Cost Share Percentage Bonneville / PacifiCorp	Ownership Percentage Bonneville / PacifiCorp	Operation & Maintenance	Operation & Maintenance Payments % Bonneville / PacifiCorp	Comments
Spencer Tap						
• Costs to reterminate PacifiCorp's Alvey – Dixonville 230 kV Line. [1]	PacifiCorp	50/50	0/100	PacifiCorp	0/100	
• Costs to reterminate PacifiCorp's Alvey – Diamond Hill 230 kV Line. [1]	PacifiCorp	0/100	0/100	PacifiCorp	0/100	
Dixonville 500 kV Substation						
• Three breaker ring bus, 180 MVAR Reactor, arresters, grounding, conduit, control and power cables, site development, PTs, station service, isolating disconnect switches for 500 kV ring bus.	PacifiCorp	50/50	50/50	PacifiCorp	42/58	PacifiCorp to operate and maintain (including maintenance of conduit, trench, and grounding systems at PacifiCorp discretion.)
• Series capacitors and auxiliaries.	PacifiCorp	50/50	50/50	PacifiCorp	42/58	PacifiCorp to operate and maintain (including maintenance of conduit, trench, and grounding systems at PacifiCorp discretion.)
• SF6 Interrupters.	PacifiCorp	50/50	50/50	PacifiCorp	42/58	
• 500/230 kV Transformer and related equipment. [1]	PacifiCorp	0/100	0/100	PacifiCorp	0/100	PacifiCorp to maintain.
• Wetland mitigation and other environmental requirements.	PacifiCorp	50/50	N/A	N/A	N/A	
• Property acquired for 500 kV yard for Intertie purposes, excluding any additional future PacifiCorp projects and any property for PacifiCorp's 500/230 kV transformer.	PacifiCorp	50/50	50/50	PacifiCorp	42/58	Requires identification of boundaries. O&M costs subject to nonroutine work. PacifiCorp to maintain at 100 percent PacifiCorp costs, things like surface rock, sidewalks, roads, fenceline, aesthetics.
• 500 kV Control House building.	PacifiCorp	50/50	50/50	PacifiCorp	42/58	Future PacifiCorp/Bonneville expansion will be done at 100 percent PacifiCorp/Bonneville costs. Otherwise

Facility Description	Design	Cost Share Percentage Bonneville / PacifiCorp	Ownership Percentage Bonneville / PacifiCorp	Operation & Maintenance	Operation & Maintenance Payments % Bonneville / PacifiCorp	Comments
						50/50 if Intertie related. General building maintenance should be at PacifiCorp discretion with 42/58 cost sharing.
• Relaying and controls, data system equipment inside the 500 kV Control House, excluding that associated with PacifiCorp's 500/230 kV transformer and 230 kV line position(s).	PacifiCorp	50/50	50/50	PacifiCorp	42/58	PacifiCorp has future rights for PacifiCorp projects at 100 percent PacifiCorp costs. Otherwise 50/50 if Intertie related. O&M at 42/58 as per this Revision No. 3 for Intertie related facilities. PacifiCorp to maintain.
• RAS related equipment.	PacifiCorp					Refer to Contract No. 93039
• Metering/Telemetering equipment on the Alvey - Dixonville Line.	PacifiCorp	50/50	50/50	PacifiCorp	42/58	PacifiCorp to do the maintenance at PacifiCorp discretion
• Construction of a new storage building.	PacifiCorp	50/50	50/50	PacifiCorp	0/100	Use of building to be audited later to confirm cost sharing percentages.

Facility Description	Design	Cost Share Percentage Bonneville / PacifiCorp	Ownership Percentage Bonneville / PacifiCorp	Operation & Maintenance	Operation & Maintenance Payments % Bonneville / PacifiCorp	Comments
Dixonville – Meridian 500 kV Line						
• Transmission Costs. [2]	PacifiCorp	50/50	50/50	PacifiCorp	42/58	Requires identification of specific properties upon which these percentages are applicable. Access roads/bridges must also be considered. Timber costs and revenues also to be included.
Hanna Tap Relocation						
• Transmission and switching modification costs. [1]	PacifiCorp	50/50	0/100	PacifiCorp	0/100	Ownership and O&M costs percentages reflect existing arrangements which will be maintained.
Table Rock Switching Station						
• Costs to remove existing station.	PacifiCorp	50/50	N/A	N/A	N/A	Existing station is in the path of the new 500 kV Line.
• Costs to reconnect Line No. 71 to south portion of Line No. 54. [1]	PacifiCorp	50/50	0/100	PacifiCorp	0/100	
Meridian Substation						
• Installation of 2-500 kV breakers, CT's, 180 MVAR reactor, 2 Line PT sets, isolating disconnect switches, arresters, buswork, conduit, control and power cables, grounding, including site development for Intertie purposes.	PacifiCorp	50/50	50/50	PacifiCorp	42/58	PacifiCorp to operate and maintain (including maintenance of conduit, trench, and grounding systems at PacifiCorp discretion). 50/50 ownership does not apply to the existing property upon which such facilities lie.

Facility Description	Design	Cost Share Percentage Bonneville / PacifiCorp	Ownership Percentage Bonneville / PacifiCorp	Operation & Maintenance	Operation & Maintenance Payments % Bonneville / PacifiCorp	Comments
• Environmental related work associated with the 500 kV expansions required.	PacifiCorp	50/50	N/A	N/A	N/A	
• Any additional new property required to support the Project.	PacifiCorp	50/50	50/50	PacifiCorp	42/58	Requires identification of boundaries. O&M costs subject to nonroutine work. PacifiCorp to maintain at 100 percent PacifiCorp costs, things like surface rock, sidewalks, roads, fenceline, aesthetics.
• Access road improvements or new access road.	PacifiCorp	50/50	50/50	PacifiCorp	0/100	
• Existing Property. [1]	PacifiCorp	0/100	0/100	PacifiCorp	0/100	Boundaries to be identified that conveys future Bonneville rights of use.
• Series capacitors and auxiliaries.	PacifiCorp	50/50	50/50	PacifiCorp	42/58	PacifiCorp to operate and maintain (including maintenance of conduit, trench, and grounding systems at PacifiCorp discretion.)
• Data system equipment inside the existing 500 kV Control House associated with the two breakers, 180 MVAR reactor, and the Meridian – Dixonville and Meridian – Captain Jack Lines.	PacifiCorp	50/50	50/50	PacifiCorp	42/58	PacifiCorp to maintain
• Relaying and controls for the Meridian – Dixonville 500 kV Line.	PacifiCorp	50/50	50/50	PacifiCorp	42/58	PacifiCorp to maintain

Facility Description	Design	Cost Share Percentage Bonneville / PacifiCorp	Ownership Percentage Bonneville / PacifiCorp	Operation & Maintenance	Operation & Maintenance Payments % Bonneville / PacifiCorp	Comments
• Relaying and controls for the Meridian – Captain Jack No. 1 500 kV Line. [1]	PacifiCorp	50/50	0/100	PacifiCorp	0/100	PacifiCorp to maintain. Bonneville retains the right to review any future relay replacements / modifications.
• Any modifications to the existing Control House or construction of a new Control House as a result of the Eugene-Medford projects.	PacifiCorp	50/50	50/50	PacifiCorp	0/100	Future PacifiCorp/Bonneville expansion will be done at 100 percent PacifiCorp/Bonneville costs, otherwise 50/50 if Intertie related. PacifiCorp to maintain at their discretion.
• Construction of a new storage building.	PacifiCorp	50/50	50/50	PacifiCorp	0/100	Use of building to be audited later to confirm cost sharing percentages.
• RAS related equipment.						Refer to Contract No. 93039.
Malin – Meridian 500 kV Line Loop Into Captain Jack Substation						
• Transmission Line modifications. [1]	PacifiCorp	50/50	0/100	PacifiCorp	0/100	Includes procurement of right-of-way from Meridian-Malin transmission line structures to Captain Jack Substation

Facility Description	Design	Cost Share Percentage Bonneville / PacifiCorp	Ownership Percentage Bonneville / PacifiCorp	Operation & Maintenance	Operation & Maintenance Payments % Bonneville / PacifiCorp	Comments
Captain Jack Substation						
• PacifiCorp owned Bay 3 facilities, including two 500 kV breakers, five MOD's buswork, PT's, conduit, grounding, and towers.	Bonneville	50/50	0/100	Bonneville	0/100	Bonneville to operate and maintain (including maintenance of conduit, trench and grounding systems at Bonneville discretion.)
• Property under Bay 3.	Bonneville	50/50	0/100	Bonneville	Prorate	Prorate O&M costs based on 2/8 to PacifiCorp. Bonneville to maintain.
• One 500 kV breaker (4924), associated relays and one MOD (4923), connected to the south bus in Bay 3.	Bonneville	100/0	100/0	Bonneville	100/0	Installed under contract 08TX-13040.
• Relays and controls, data systems equipment for PacifiCorp owned Bay 3 facilities.	Bonneville	50/50	0/100	PacifiCorp	0/100	PacifiCorp to maintain. Bonneville retains the right to review any future relay replacements/modifications.
• Remaining five 500 kV breakers, MOD's, buswork towers, conduit, grounding, and site development. [1]	Bonneville	100/0	100/0	Bonneville	100/0	Bonneville to operate and maintain (including maintenance of conduit, trench and grounding systems at Bonneville discretion.)
• Station service facilities for the entire station. [1]	Bonneville	100/0	100/0	Bonneville	Prorate	Prorate O&M costs based on 2/8 to PacifiCorp. Bonneville to maintain.

Facility Description	Design	Cost Share Percentage Bonneville / PacifiCorp	Ownership Percentage Bonneville / PacifiCorp	Operation & Maintenance	Operation & Maintenance Payments % Bonneville / PacifiCorp	Comments
• Remaining relays and controls, data system equipment. [1]	Bonneville	100/0	100/0	Bonneville	100/0	Bonneville to maintain.
• Control House, exclusive of the property upon which it lies. [1]	Bonneville	100/0	100/0	Bonneville	100/0	Any future expansions due to PacifiCorp additions will be at 100 percent PacifiCorp costs but Bonneville to retain 100 percent ownership.
• All remaining property, including access road. [1]	Bonneville	100/0	100/0	Bonneville	100/0	Requires identification of boundaries. PacifiCorp has right to add transformer in future.
• Series Capacitors. [1]	Bonneville	100/0	100/0	Bonneville	100/0	Cost sharing/ownership is with Transmission Agency of Northern California (TANC) as per Interconnection Agreement (short or long-term, whatever prevails). Bonneville to maintain.
• RAS related equipment.						Refer to Contract No. 93039.
• Metering/Telemetering equipment on the Captain Jack – Meridian and Captain Jack – Malin No 2 Lines.	Bonneville	50/50	0/100	Bonneville	0/100	Bonneville to do the maintenance at Bonneville discretion.

Facility Description	Design	Cost Share Percentage Bonneville / PacifiCorp	Ownership Percentage Bonneville / PacifiCorp	Operation & Maintenance	Operation & Maintenance Payments % Bonneville / PacifiCorp	Comments
Malin Substation						
• Any modifications/additions in PacifiCorp's Control House in support of the Eugene Medford/Third AC Intertie project, which includes the relay replacement for the Malin – Captain Jack Line. [1]	PacifiCorp	50/50	0/100	PacifiCorp	0/100	Bonneville retains the right to review any future relay replacements and/or modifications.
• Replacement of arresters on PacifiCorp's 500 kV reactor bank No. 4. [1]	PacifiCorp	0/100	0/100	PacifiCorp	0/100	
• Replacement of rod gaps with arresters on PacifiCorp's C.J. Line terminal. [1]	PacifiCorp	50/50	0/100	PacifiCorp	0/100	
• RAS related equipment.						Refer to Contract No. 93039.
• Any modifications in main control house.	Bonneville	50/25	50/25	Bonneville	50/25	
• Relay replacement for the Summer Lake Line.	PacifiCorp	50/50	0/100	PacifiCorp	42/58	Refer to Contract No. 93644.

Facility Description	Design	Cost Share Percentage Bonneville / PacifiCorp	Ownership Percentage Bonneville / PacifiCorp	Operation & Maintenance	Operation & Maintenance Payments % Bonneville / PacifiCorp	Comments
Line Relays at Dixonville, Meridian, and Malin and Related Accessories						
• Line relays at Dixonville, Meridian, and Malin for the Dixonville – Alvey, Dixonville – Meridian, Meridian – Captain Jack, and Malin – Captain Jack No. 2 Lines are to be supplied to PacifiCorp at Bonneville material cost plus Bonneville overheads. Any additional PacifiCorp overhead, subject to 50/50 cost-share, is to be determined.	PacifiCorp	50/50	See Comments			Ownership and O&M of such relays are as described under the respective substations.
• Spare Equipment.	Bonneville	50/50	50/50	N/A	N/A	Reference 7/12/91 Letter from Don Feltz to Susan Wiese. Such spare equipment is to be located at PacifiCorp station(s) in southern Oregon. In addition to that referenced in the 7/12/91 Letter, there may be other spare equipment supplied by PacifiCorp also located in southern Oregon and subject to cost-share. Required test equipment and tools are to be 100 percent respectively acquired by either Bonneville or PacifiCorp for 100 percent discretionary use.
• Specialized relay training costs. [1]	N/A	50/50	N/A	N/A	N/A	Cost sharing only if agreed to capitalize such costs.

Facility Description	Design	Cost Share Percentage Bonneville / PacifiCorp	Ownership Percentage Bonneville / PacifiCorp	Operation & Maintenance	Operation & Maintenance Payments % Bonneville / PacifiCorp	Comments
General PSC Modifications						
• PSC Modifications at Dittmer and ECC will be 100 percent Bonneville and similarly PSC modifications at PacifiCorp control centers will be 100 percent PacifiCorp.	100 percent respectively	100 percent respectively	100 percent respectively	100 percent respectively	100 percent respectively	
• Any other modifications at other wholly owned substations will be 100 percent of the respective party.	100 percent respectively	100 percent respectively	100 percent respectively	100 percent respectively	100 percent respectively	
Summer Lake Substation						
• Relay replacement for the Summer Lake – Malin 500 kV Line.	PacifiCorp	50/50	0/100	PacifiCorp	42/58	Refer to Agreement No. 93644.
• RAS related equipment						Refer to Trust Tables 18 & 19, Contract No. 37013.
• Replacement of rod gaps with arresters on PacifiCorp's Malin Line terminal. [1]	Bonneville	100/0	0/100	PacifiCorp	0/100	
• Relay replacement for the Summer Lake – Grizzly 500 kV Line.	Bonneville	100/0	100/0	Bonneville	100/0	

Facility Description	Design	Cost Share Percentage Bonneville / PacifiCorp	Ownership Percentage Bonneville / PacifiCorp	Operation & Maintenance	Operation & Maintenance Payments % Bonneville / PacifiCorp	Comments
Sycan Series Compensation Station Bank 3						
• Series capacitor bank #3 in the Summer Lake – Malin 500 kV Line.	Bonneville	65/35	65/35	Bonneville	65/35	Refer to Agreement No. 93644.
• Bypass switch and associated support structures and foundations.	Bonneville	65/35	0/100	Bonneville	0/100	Refer to Agreement No. 93644.
• Dead-End Tower.	PacifiCorp	65/35	0/100	PacifiCorp	0/100	Refer to Agreement No. 93644.
Capital Spare Parts						
• Various spare parts.		50/50	50/50		42/58	Capital spare parts subject to cost sharing and joint ownership are to be mutually agreed upon and consistent with this Agreement.
Overall Planning, Preliminary Engineering, Project Management						
• Related costs for the Eugene-Medford Project, including any costs to resolve/mitigate legal matters (e.g., spotted owl and union vs. nonunion issues.)		50/50	50/50			
Communication						
• Summer Lake – Malin Communication, Two Downlinks. [1]	PacifiCorp	50/50	0/100	PacifiCorp	0/100	Refer to Sycan Agreement Contract No. DE-MS79-92BP93644 and Cooperative Communications Agreement No. DE-MS79-92BP93740.
• Dixonville – Two Microwave Terminals. [1]	PacifiCorp	50/50	0/100	PacifiCorp	0/100	Refer to Cooperative Communications Agreement No. DE-MS79-92BP93740.
• Meridian – Two Microwave Terminals. [1]	PacifiCorp	50/50	0/100	PacifiCorp	0/100	Refer to Cooperative Communications Agreement No. DE-MS79-92BP93740.

Facility Description	Design	Cost Share Percentage Bonneville / PacifiCorp	Ownership Percentage Bonneville / PacifiCorp	Operation & Maintenance	Operation & Maintenance Payments % Bonneville / PacifiCorp	Comments
• All other Bonneville Communication Facilities	Bonneville	100/0	100/0	Bonneville	100/0	Refer to Cooperative Communications Agreement No. DE-MS79-92BP93740.
• Other PacifiCorp Communication Facilities	PacifiCorp	0/100	0/100	PacifiCorp	0/100	Refer to Cooperative Communications Agreement No. DE-MS79-92BP93740.

SIGNATURES AND EFFECTIVE DATE

Bonneville and PacifiCorp (Parties) have caused this Revision No. 4 to be executed, and it shall be effective as of the date the Federal Energy Regulatory Commission (Commission) accepts PacifiCorp's filing; *provided that*, if PacifiCorp files this Revision No. 4 for acceptance by the Commission and the Commission does not accept this Revision No. 4 for filing or accepts this Revision No.4 for filing but in connection with such acceptance requires a change in, or imposes a new condition on, this Revision No. 4, this Revision No. 4 shall be effective thereafter only if both Parties agree in writing to such change or condition. If either Party fails to agree in writing to any such change or condition, or if the Commission does not accept this Revision No. 4 for filing, Bonneville may on written notice to PacifiCorp terminate the services it provides pursuant to those Exhibit provisions not accepted by the Commission without change or condition.

PACIFICORP

By: ______________________

Name: ______________________
(Print/Type)

Title: ______________________

Date: ______________________

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: ______________________

Name: David A. Fitzsimmons
(Print/Type)

Title: Manager, Transmission Sales

Date: ______________________

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

OFFICE OF THE ADMINISTRATOR

AUG 16 1991

In reply refer to: PMTI

Amendment No. 1
Contract No. DE-MS79-86BP92299

Mr. Thomas Lockhart, Vice President
Power Systems
PacifiCorp Electric Operations
920 SW. Sixth Avenue
Portland, OR 97208

Dear Mr. Lockhart:

Pursuant to subsection 4(a) of Contract No. DE-MS79-86BP92299, as amended, (Intertie Agreement) between PacifiCorp Electric Operations (Pacific) and Bonneville Power Administration (Bonneville), Bonneville hereby provides Pacific notice that, effective on the Effective Date, Bonneville is exercising its option to acquire a fifty percent undivided ownership interest in the Alvey-Meridian Line, as defined in such agreement and as modified herein. Pacific and Bonneville hereby agree to amend the Intertie Agreement by supplementing it with the following provisions, and replacing Exhibit C to such agreement with the attached Revision No. 1 to such Exhibit.

1. Completion of the Alvey-Meridian 500 kV Line.

   (a) Design and Construction. Pacific and Bonneville shall use best efforts to complete the Alvey-Meridian Line by November 1993. Pacific shall design and construct the Dixonville 500 kV Substation including the series capacitors, the terminal facilities at Meridian Substation for the Dixonville-Meridian Line including series capacitors, and the Alvey-Dixonville portion of the Alvey-Meridian Line (Alvey-Dixonville Line) and the Dixonville-Meridian portion of the Alvey-Dixonville Line (Dixonville-Meridian Line). Bonneville shall design and construct the Alvey 500 kV Substation (Alvey Substation) including the Alvey Substation series capacitors. The Parties shall seek opportunities to utilize the capabilities of the other to minimize the installed cost and operation and maintenance cost and maintain schedules. The Parties shall agree at a later date upon the prudent design and construction of the Dixonville-Meridian Line, Dixonville 500 kV Substation series capacitors, and the Meridian Substation series capacitors. Each Party shall have the right to comment on the design and construction to be performed by the other Party.

(b) Maintenance and Operation. Pacific shall assume system operation and maintenance responsibilities of the Dixonville 500 kV Substation including the series capacitors, the terminal facilities at Meridian Substation for the Dixonville-Meridian Line including the series capacitors, and the Alvey-Meridian Line. Bonneville shall assume system operation and maintenance responsibilities of the Alvey Substation including the series capacitors. The Parties shall jointly develop maintenance standards and responsibilities that seek to limit the total annual operation and maintenance charges. Payment for operation and maintenance costs associated with these facilities shall be as specified in the Intertie Agreement, including Revision No. 1 to Exhibit C.

(c) Ownership.

(1) Pacific and Bonneville shall have undivided joint ownership of the Alvey-Meridian Line based upon the ownership percentages specified in Revision No. 1 to Exhibit C of the Intertie Agreement.

(2) Pacific and Bonneville shall have undivided joint ownership of incremental land acquisitions necessary to complete the Alvey-Meridian Line. Pacific shall convey to Bonneville any rights of use of Pacific's existing land sufficient to allow Bonneville to facilitate use of its right to fifty percent of the Incremental Capacity and ownership.

(3) The transfer of property titles (equipment, land, etc.) by the Parties in order to provide for undivided joint ownership shall occur at the time of energization of the Alvey-Meridian Line.

(4) Ownership of the communications systems shall be determined in accordance with section 6.

(d) Expansion of Facilities.

(1) Pacific shall have the right to modify the Dixonville 500 kV Substation and Meridian Substation, at its expense, as necessary for future required facilities without agreement by Bonneville, provided that Bonneville's ownership right to fifty percent of the Incremental Capacity of the Alvey-Meridian Line, as defined in the Intertie Agreement (Incremental Capacity), is not diminished.

(2) Upon expiration of the Intertie Agreement, Bonneville shall have the right to make additional facility connections at the Meridian Substation, at its expense, to facilitate use of its right to fifty percent of the Incremental Capacity, provided that such new connections do not increase loadings on Pacific's exclusively-owned facilities, diminish Pacific's rights to the Alvey-Meridian Line, or adversely impact Pacific's system.

(3) Bonneville shall have the right to modify the Alvey Substation, at its expense, as necessary for future required facilities without agreement by Pacific, provided that Pacific's ownership right to fifty percent of the Incremental Capacity is not diminished.

(4) Upon expiration of the Intertie Agreement, Pacific shall have the right to make additional facility connections at the Alvey Substation, at its expense, to facilitate use of its fifty percent share of the Incremental Capacity, provided that such new facility connections do not increase loadings on Bonneville's exclusively owned facilities, diminish Bonneville's rights to the Alvey-Meridian Line, or adversely impact Bonneville's system.

(e) Cost Sharing/Payment. Cost sharing for design and construction of the Alvey-Meridian Line shall be as specified in Revision No. 1 to Exhibit C. The Parties agree to develop mutually agreeable terms and conditions for payment for design and construction of the line. Such terms and conditions shall include provisions for progress payments, recognition of any payments made by either Party, or expenses incurred by either Party that are associated with the interim agreements (Contract Nos. DE-MS79-90BP92901, DE-MS79-91BP93112, DE-MS79-91BP93112, and DE-MS79-90BP93070) between the Parties as replaced by this amendment.

2. Alvey Substation 500 kV Terminal. Contract No. DE-MS79-90BP92901 shall terminate as of the Effective Date of this amendment.

3. Captain Jack Substation Connection/Terminal.

(a) Contract No. DE-MS79-91BP93112 shall terminate as of the Effective Date of this amendment.

(b) Pacific and Bonneville agree to equally share the cost of the following work performed by Pacific:

(1) procurement of the right-of-way from the Meridian-Malin transmission line structures to Captain Jack Substation;

(2) design and construction of the new 500 kV transmission line from Meridian-Malin 500 kV line structures to the Captain Jack Substation dead end towers;

(3) removal of certain Meridian-Malin 500 kV transmission line facilities; and

(4) design and construction of the strain bus connection between the Captain Jack dead end towers in Bay 3 to connect the Meridian-Malin line segments.

(c) Pacific and Bonneville agree to equally share the cost of the following work performed by Bonneville:

(1) design and construction of Captain Jack Substation dead end structures at Bay 3; and

(2) design and construction of power circuit breakers and associated Bay 3 terminal equipment including relays, and facilities to connect the Meridian-Malin line.

(d) Pacific shall own the land, right-of-way, power circuit breakers, terminal equipment including relays, and facilities up to the dead end towers, the dead end towers, and the strain bus between such towers at Bay 3.

(e) Bonneville shall assume system operation and maintenance responsibilities for all facilities at Captain Jack Substation except terminal Bay 3 relays and communications owned by Pacific, which shall be assumed by Pacific.

4. Sycan.

(a) The following provisions of Contract No. DE-MS79-91BP93157 shall terminate as of the Effective Date of this amendment:

(1) payment provisions specified in Section 4 and Exhibit A;

(2) cost sharing provisions specified in Sections 5 and 6; provided, however, the duties of the Parties described in such Sections shall remain; and

(3) ownership provisions specified in Section 7; provided, however, Pacific shall own the protective relays for the Summer Lake-Malin terminals pursuant to Revision No. 1 to Exhibit C of the Intertie Agreement.

(b) Contract No. DE-MS79-90BP93070 shall terminate as of the Effective Date of this amendment.

(c) Bonneville shall design and construct the series capacitors. Bonneville shall pay the design and construction costs and own the series capacitors until the Parties reach agreement pursuant to subsection 4(f) below.

(d) Bonneville shall operate and maintain the Sycan Compensation Station, including the series capacitors and bypass switch and associated structures; provided, however, the Summer Lake-Malin terminal relays shall be operated and maintained by Pacific. Payment for such operation and maintenance costs shall be as specified in Revision No. 1 to Exhibit C of the Intertie Agreement.

(e) The Sycan dead end tower shall be operated and maintained by Pacific.

(f) The Parties shall mutually agree to the terms and conditions for cost sharing for the Sycan series capacitors, bypass switch and associated structures, Summer Lake-Malin terminal relays, Summer Lake-Malin communications down-link, and dead end tower.

5. Coordinated Operations. The Parties shall jointly develop coordinated operating procedures for the Alvey-Meridian Line, Captain Jack Substation, and Sycan Compensation Station such that Bonneville may adequately perform as the system operator for the combined AC Intertie, and that maximize the Operational Transfer Capability of the AC Intertie and maximize Pacific's capability to serve its southern Oregon and northern California loads pursuant to Section 5(d)(2)(A) of the Intertie Agreement.

6. Communications. The Parties are in substantial agreement as to the terms, conditions, and ownership associated with requirements for communication facilities and equipment described herein, and shall complete such terms and conditions as soon as practicable following execution of this amendment. Such terms and conditions shall be incorporated in a separate agreement.

7. Liability. The Parties agree that if any injunction is issued by a court of competent jurisdiction against either Party's implementation of this amendment, such injunction shall not constitute a basis for a breach of contract action.

8. Effective Date. This amendment shall be effective on the later of:

(a) the issuance of a biological opinion by the United States Fish and Wildlife Service regarding the northern spotted owl which is acceptable to both Parties; or

(b) the date Bonneville receives a copy of this amendment signed by Pacific (Effective Date).

If this amendment is acceptable to Pacific, please sign and return one copy to Bonneville. The remaining copy is for your files. Please have your staff contact Allen Burns, at (503) 230-3367, to establish a schedule for discussions made necessary by the execution of this amendment.

Sincerely,

James J Jura

Administrator

ACCEPTED:

PACIFICORP ELECTRIC OPERATIONS

By ______________________
Thomas A. Lockhart

Title Vice President

Date August 16, 1991

Effective Date November 18, 1991

(VS6-PMTI-6802d)

PDE-M879-93BP 943332 055

EXHIBIT F, REVISION NO. 17
CAPITAL REPLACEMENTS AND ADDITIONS

This Exhibit F, Revision No. 17 details the cost sharing obligations for:

1. *Replacement of the RALZ B protective relays at the jointly owned Dixonville Substation associated with the Dixonville-Meridian 500 kV transmission line. PacifiCorp has purchased and installed the new relays. Bonneville Power Administration (BPA) and PacifiCorp agree that this capital project is subject to cost sharing based on the terms of the Amended and Restated AC Intertie Agreement, Contract No. DE-MS79-94BP94332 (Agreement). BPA's 50% cost share of this capital project is based on the cost share percentage as stated in Exhibit B of the Agreement;*
2. *Replacement of the RALZ B protective relays at the jointly owned Meridian Substation associated with the Dixonville-Meridian 500 kV transmission line. PacifiCorp has purchased and installed the new relays. Bonneville Power Administration (BPA) and PacifiCorp agree that this capital project is subject to cost sharing based on the terms of the Agreement. BPA's 50% cost share of this capital project is based on the cost share percentage as stated in Exhibit B of the Agreement;*
3. *Emergency Capacitive Voltage Transformer (CVT) replacement on "A" phase of the Alvey-Marion 500 kV line at Alvey Substation. BPA has purchased and installed the new CVT. BPA and PacifiCorp agree that this capital project is subject to cost sharing based on the terms of the Agreement. PacifiCorp's 50% cost share of this capital project is based on the cost share percentage as stated in Exhibit B of the Agreement;*
4. *Replacement of interchange metering (WH0039) on the Alvey-Dixonville line at the Alvey Substation. BPA has purchased and installed the new metering. BPA and PacifiCorp agree that this capital project is subject to cost sharing based on the terms of the Agreement. PacifiCorp's 50% cost share of this capital project is based on the cost share percentage as stated in Exhibit B of the Agreement;*
5. *Replacement of interchange metering on the Captain Jack-Malin line at the Captain Jack Substation. BPA has purchased and installed the new metering. BPA and PacifiCorp agree that this capital project is subject to cost sharing based on the terms of the Agreement. PacifiCorp's 50% cost share of this capital project is based on the cost share percentage as stated in Exhibit B of the Agreement; and*
6. *Modifications to PacifiCorp systems in support of the Captain Jack meter replacement specified in number 5 above. PacifiCorp has performed the modifications. BPA and PacifiCorp agree that this work is subject to cost sharing based on the terms of the Agreement. BPAs 50% cost share of this capital project is based on the cost share percentage as stated in Exhibit B of the Agreement.*

COMPLETED CAPITAL REPLACEMENT					
Description	Total Cost ($)	PacifiCorp Share (%)	BPA Share (%)	Amount Owed by PAC ($)	Amount Owed by BPA ($)
Dixonville - Meridian 500 kV Line at the Dixonville Substation: Replace the existing RALZ B relays with SEL 421 relays. PacifiCorp Work Order: RB/2011/C/003/10044602.	$586,148	50%	50%		$293,074
Dixonville - Meridian 500 kV Line at the Meridian Substation: Replace the existing RALZ B relays with SEL 421 relays. PacifiCorp Work Order: RB/2011/C/003/10044602.	$672,869	50%	50%		$336,434
Alvey-Marion 500 kV line at the Alvey Substation: Replace CVT on the "A" phase. Work Order #00396932.	$13,084	50%	50%	$6,542	
Alvey-Dixonville 500 kV line at the Alvey Substation: Replace interchange metering (WH0039). Work Order #00396368.	$104,534	50%	50%	$52,267	
Captain Jack-Malin 500 kV line #2 at the Captain Jack Substation: Replace interchange metering. Work Order #00322855.	$158,990	50%	50%	$79,495	
Modifications to PacifiCorp systems in support of the interchange meter replacement on the Captain Jack-Malin 500 kV line #2.	$49,657	50%	50%		$24,828
Total				**$138,304**	**$654,336**

JOINT OWNERSHIP PAYMENT OBLIGATION

BPA agrees to pay PacifiCorp $654,336. PacifiCorp shall issue an invoice to BPA for this amount and BPA shall pay the invoice in accordance with the terms of this agreement.

PacifiCorp agrees to pay BPA $138,304. BPA shall issue an invoice to PacifiCorp for this amount and PacifiCorp shall pay the invoice in accordance with the terms of this agreement.

SIGNATURES

This Agreement may be executed in several counterparts, all of which taken together will constitute one single agreement, and the Agreement may be executed and delivered electronically. The parties have executed this Agreement as of the last date indicated below.

PACIFICORP		UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration	
By:		By:	Digitally signed by ehc2532@bud.bpa.gov Date: 2017.04.04 12:21:01 -07'00'
Title:	VP, Transmission	Title:	Senior Transmission Account Executive

If opting out of the electronic signature:

By: ______________________

Name: ______________________
(Print/Type)

Title: ______________________

Date: 4/12/17

MALIN TRANSFORMER - USE-OF-FACILITIES

Pursuant to Section 5 (h) of the AC Intertie Agreement, which states that PacifiCorp shall provide Bonneville firm capacity in its existing 500/230 kV transformer bank at the Malin Substation at a use-of-facilities rate for Bonneville's firm requirements, subject to certain limitations, including availability and only up to 200 megawatts, the Parties agree to the following:

Commencement Date

Bonneville has requested an increase in its firm capacity at the Malin Substation transformer bank from 110 MW to 200 MW commencing immediately upon FERC approval. This increase in capacity scheduling will alter the use of facilities charge based on the change in the percentage usage of the transformer by Bonneville. Currently Bonneville pays $272,315 annually, $22,693 monthly; based on a 30.44% ratio of Bonneville's exercised right to the average monthly transformer peak for the prior calendar year.

Upon FERC approval the revised use-of-facilities charge will be $253,589 per year, billed monthly at $21,132.

The above charge is based on the following:

- Investment of $ 6,921,090
- Levelized Fixed computation methodology
  The Utilization Factor will be 30.77%, which is Bonneville's capped maximum capacity share, because the ratio of Bonneville's new exercised right to the average monthly transformer peak for the prior calendar year would be 59.85%, which exceeds the cap of 30.77% under this agreement.
  - Example l: For 2007, Bonneville's exercised right was 110 MW, as compared to the monthly average transformer peak inclusive of this right of 361.42 MW which was the bases for calculating the 30.44% utilization factor above.
  - Example 2: For 2013 Bonneville's new exercised right will be 200 MW, as compared to the 2012 monthly average transformer peak inclusive of this new right of 334.16 MW. The new ratio will be 200/334.16 =59.85%, which does exceed the cap of 30.77%; therefore Bonneville's new use of facilities charge is based on the cap with a 30.77% utilization factor.

- FERC Authorized Rate of Return
- FERC Methodology for OMAG Expenses
- Thirty-nine year straight-line book depreciation
- Twenty year (MACRS) tax depreciation
- 1.2% property tax rate
- 37.95% income tax rate
- 7.5% discount rate

Transformer Losses

In addition to the above use-of-facilities charge, the Parties agree that transfer losses (in megawatts) for the Malin 500/230 kV transformer shall be calculated with the following formula:

$L=0.4116+k P^2$

Where:
L = total losses in MW
0.4116 MW is the magnetizing loss which is independent of transformer load
$k = 2.8 \times 10^{-6}$
P = power through transformer in MW

Example 1:

The transformer load is 300 MW. The total losses are:

$L= 0.4116 + (2.8 \times 10^{-6}) \times (300)^2 = 0.664$ MW

Example 2:

The transformer load is 650 MW. The total losses are:

$L = 0.4116 + (2.8 \times 10^{-6}) \times (650)^2 = 1.59$ MW

This formula shall be applied through the entire range of transformer capacity, from zero to 650 MW, and Bonneville's share shall be based on its hourly schedule of energy across the transformer.

Exhibit G
Revision No. ~~1~~2
Contract No. DE-MS79-~~94BP94332~~ 94BP94332
AC Intertie Agreement

URD 7/22/14

For any hour, Bonneville may return losses physically, concurrent with the associated hourly energy schedule. Provided, for any hour in which Bonneville does not schedule loss returns concurrent with the associated energy schedule, Bonneville shall pay PacifiCorp for losses valued at the "Hourly Pricing Proxy" as described or as may be updated from time to time in PacifiCorp's currently effective Open Access Transmission Tariff.

Revisions to Exhibit G

If Bonneville notifies PacifiCorp that it wishes to effect a change to its exercised right of 200 MW, then Bonneville's utilization of transformer capacity shall be automatically updated upon the effective date of the election (subject to PacifiCorp's review of capacity availability pursuant to Section 5 (h) of the Agreement) to reflect the full amount of Bonneville's election of transformer capacity pursuant to this Agreement. The availability of such capacity to Bonneville pursuant to the Agreement shall not exceed 200 MW and the charge factor applied to Bonneville's use of the Malin transformer shall not exceed 30.77%. The Parties agree that any other change to the above methodologies or factors shall be by mutual agreement and shall not be allowed more often than once per three year period. Each party's agreement to recommended changes in input factors to the above methodologies shall not be unreasonably withheld, provided any such recommended changes have a reasonable basis in fact. The parties shall negotiate in good faith to address any requested change in underlying methodology or formulae. Such changes to input factors shall apply prospectively only.

Bonneville Power Administration	PacifiCorp
By: [signature]	By: [signature]
Title: Transfer Services Manager	Title: VP - Transmission
Date: 7-21-14	Date: 7/22/14

~~Bent~~ Hand delive to Ken
7-28-11 @ 9:18 1?

Department of Energy

Bonneville Power Administration
P.O. Box 61409
Vancouver, WA 98666-1409

TRANSMISSION SERVICES

26 JL Kuy
July ~~27~~, 2011

In reply refer to: TSE/TPP-2

Contract No. 11TX-15452
Letter Agreement

Ms. Stacey Kusters, Director
Origination Commercial & Trading
PacifiCorp
825 NE Multnomah St., Suite 600
Portland, OR 97232

Dear Ms. Kusters:

This Reconciliation Letter Agreement, Contract No. 11TX-15452 (Agreement), between the Bonneville Power Administration (Bonneville), acting by and through its Transmission Services and Power Services, and PacifiCorp provides for the final reconciliation of net unreturned transmission losses for the time period July 1, 2001, through December 31, 2007, under the terms of the following agreements: Formula Power Transmission (FPT) Agreements No. 14-03-26811, DE-MS79-79BP90100, DE-MS79-94BP94280, and DE-MS79-94BP94333; Point-to-Point (PTP) Transmission Service Agreements, 02TX-10968 and 04TX-11722; AC Intertie Capacity Ownership Agreement No. DE-MS79-95BP94628; AC Intertie Transmission Agreement No. DE-MS79-94BP94285; and AC Intertie Agreement No. DE-MS79-94BP94332 (Contracts); and final reconciliation of over-returned losses for the time period October 1, 2003, through March 31, 2009, under the terms of the FPT Transmission Agreement DE-MS79-94BP94333 (collectively, Net Unreturned Losses). PacifiCorp and Bonneville are referred to individually as "Party" and jointly as "Parties".

The Parties agree as follows:

Background

From July 1, 2001, through December 31, 2007, PacifiCorp did not return all losses related to the Contracts, and from October 1, 2003, through March 31, 2009, PacifiCorp over returned losses under the above specified contract. This Agreement settles all claims arising from Net Unreturned Losses during such periods by establishing a settlement value of all Net Unreturned Losses during the aforementioned period and by establishing a contract administration protocol to prevent unnoticed accumulation of unreturned losses in the future.

RECEIVED
JUL 28 2011

Reconciliation of Past Unreturned Transmission Losses
The Parties agree that the dollar value of energy to be transferred from PacifiCorp to Bonneville under the schedule, terms, and conditions set forth in the enclosed Loss Return Confirmation, PacifiCorp Contract No. 860934/860935/860936 (Confirmation) reconciles the value of PacifiCorp's Net Unreturned Losses as of the date of this letter, which shall be equal to $651,190 (Settlement Value). The Confirmation contract quantity is based on a price of $36.14 per megawatt hour for the Confirmation term.

The Parties agree to execute the Confirmation as described above. In the event PacifiCorp is unable, in any hour, to deliver the energy to the Point of Delivery specified in the Confirmation, deliveries will be made to Mid-Columbia. Any inability by PacifiCorp to deliver energy as required under this Agreement and the Confirmation, shall not excuse PacifiCorp from delivering that energy as soon as reasonably possible thereafter.

Loss Reconciliations
For reconciliation of PacifiCorp's return of transmission losses to Bonneville (in connection with Bonneville Transmission service under the Agreements first referenced above) after the execution of this Agreement, the Parties will follow the "Loss Reconciliations" section of Bonneville's current Real Power Loss Return business practice (or its successor).

Confidentiality
For a period of 12 months after the date of this Agreement, neither Party, its employees or agents shall disclose to any third party: (i) this Agreement, (ii) the volume of the Net Unreturned Losses, or (iii) any materials or information related to the Parties' discussions concerning the Net Unreturned Losses (together the "Confidential Information") except to the extent required by law or regulation. If a Party receives a request to disclose any Confidential Information, it shall not disclose such information without first promptly notifying the other Party of the request in order to facilitate the other Party's efforts to prevent disclosure or otherwise preserve the confidentiality of the information. A Party shall immediately notify the other Party of any instance of any allowed or prohibited disclosure of any such Confidential Information to a third party. Notwithstanding the foregoing, the Parties acknowledge that each may be required by law or regulation to report certain information that could embody Confidential Information from time to time, and each may do so from time to time without providing prior notice. In so doing, the disclosing Party will identify Confidential Information as confidential, and shall, if practicable, require that the recipient treat it as such.

Resolution of Claims
The Parties agree that this Agreement constitutes the full and final reconciliation and satisfaction of Net Unreturned Losses by PacifiCorp to Bonneville under the Contracts and FPT Transmission Agreement DE-MS79-94BP94333 from the inception date of each of those documents, through March 31, 2009. Neither Party may pursue any further action against the other related to these losses, whether in dispute resolution, in court, at the FERC or elsewhere, other than to enforce this Agreement.

No Precedent
Any other disputes that may exist between the Parties, whether or not billed by Bonneville, are not settled or affected by this Agreement. The Parties agree that this Agreement shall not have any precedential effect as to any other dispute or any other matter, whether or not involving the Parties and may not be cited as precedent by either Party or any other person in any proceeding or with respect to any other dispute or any other matter. Each Party affirms that it has made a good-faith effort to identify unreturned transmission losses that may be owed to it by the other Party related specifically to the Contracts identified herein, and is unaware of any additional unasserted claims respecting unreturned transmission losses under the Contracts after March 31, 2009.

Integration
This Agreement and the enclosed Confirmation represent the entire agreement of the Parties. This Agreement supersedes any agreements and representation made by the Parties in all prior discussions, negotiations and agreements, whether oral or written, relating to the subject matter of this Agreement.

Notices
Any required notice concerning this Agreement shall be deemed delivered three business days after deposit in United States Mail, First Class postage, to the Party's address, below. An email to the Party at the address below, if acknowledged by the other Party in writing, shall also constitute Notice under this Agreement as of the date it was sent. Upon reasonable written notice either Party may update the Notice address at any time.

PacifiCorp
Supervisor, Marketing
& Trading Contracts
825 NE Multnomah St., Suite 600
Portland, OR 97232

Bonneville Power Administration
Transmission Account Executive for
PacifiCorp – TSE/TPP-2
7500 NE 41st St. – Suite 130
Vancouver, WA 98662

Handdeliver to Ken 7·28·11 @ 9:18 PS

If you concur with the foregoing terms and conditions, please indicate your assent to this Agreement by signing both originals of the Agreement and both of the originals of the Confirmation, returning all originals on or before Close of Business on July 29, 2011, to the attention of Kenneth Johnston at one of the following addresses:

<u>First Class Mail</u>
Bonneville Power Administration
Mail Stop: TSE/TPP-2
P.O. Box 61409
Vancouver, WA 98666-1409

<u>Overnight Delivery Service</u>
Bonneville Power Administration
Mail Stop: TSE/TPP-2
7500 NE 41st Street – Suite 130
Vancouver, WA 98662

If you have any questions, please do not hesitate to call Kenneth Johnston at (360) 619-6009.

Sincerely,

Brian Schroeder

FOR Cathy L. Ehli
Vice President
Transmission Marketing and Sales

CONCUR:
PACIFICORP

By: [signature]

Name: Stacey Kusters.
(Print/Type)

Title: Director, Origination

Date: July 26, 2011

Enclosure

Via Facsimile

Wholesale Energy Services
825 NE Multnomah, Suite 600
Portland, Oregon 97232
FAX (503)813-6291

LOSS RETURN CONFIRMATION

Pac# 860934/860935/860936

PacifiCorp
825 NE Multnomah, Suite 600
Portland, OR 97232

Date: July 26, 2011

The following Loss Return Confirmation (hereafter "Confirmation") memorializes the terms of a transaction agreed to by Bonneville Power Administration (BPA) and PacifiCorp (PAC) (together the "Parties") in the Reconciliation Letter Agreement Contract No. 11TX-15452 (hereafter "Reconciliation Agreement"). Transactions hereunder are in accordance with reference contracts as follows: FPT Transmission Agreements Nos. 14-03-26811, DE-MS79-79BP90100, DE-MS79-94BP94280 and DE-MS79-94BP94333; PTP Transmission Agreements Nos. 02TX-10968, and 04TX-11722; AC Intertie Capacity Ownership Agreement Nos. DE-MS79-95BP94628, AC Intertie Transmission Agreement, DE-MS79-94BP94285, and the AC Intertie Agreement No. DE-MS79-94BP94332, (hereafter "the Contracts"). Unless otherwise stated, transactions hereunder are in accordance with Western System Power Pool (WSPP) Agreement, as amended.

This Confirmation is not a BPA purchase of energy from PAC. The sole purpose of this Confirmation is to facilitate PAC's delivery of losses returned under the Contracts as described in the Reconciliation Agreement. This delivery satisfies the return of losses for transmission services provided during the period July 1, 2001, through December 31, 2007 and the over delivery of losses during the period October 1, 2003 through March 31, 2009 under the Contracts, as discussed in the Reconciliation Agreement.

Trade Date:	July 26, 2011	
Seller:	PacifiCorp	Purchaser: Bonneville Power Administration
Seller Trader:	Jim Schroeder	Purchaser Trader: Mark Miller
Seller phone:	(503) 813-5380	Purchaser phone: (503) 230-4003
Product:	Loss return	

Schedule:	flat -- Monday through Sunday including NERC Holidays
Term:	10/01/2011 - 12/31/2011
Type of Service:	WSPP Schedule C
Point of Delivery:	A point where PAC-West System is interconnected with BPA's transmission system, excluding constrained paths. Parties further agree that when system to system deliveries cannot be made due to transmission constraints the Point of Delivery will be Mid-C.
Contract Price:	N/A; this transaction returns previously unreturned transmission losses
Contract Quantity:	18,018 MWh

Delivery Rate: Delivery Rate (MW/hr) shall be equal to:

10/01/2011 (HE 0100) through and including 12/24/2011 (HE 2400)= 8 MW/hr
12/25/2011 (HE 0100) through and including 12/31/2011 (HE 1400)= 10 MW/hr
12/31/2011 (HE 1500) through and including 12/31/2011 (HE 2400)= 11 MW/hr

PacifiCorp Contacts	**Phone**	**Facsimile**
Preschedule:	503-813-6972	503-813-6265
Real Time:	503-813-5389/5374	503-813-5512
Contracts/Confirms:	@ContractPhone503-813-5954	503-813-6291

BPA Contacts	**Phone**	**Facsimile**
Preschedule:	503-230-3813	866-861-6371
Real Time:	503-230-3341	866-861-6371
Contracts/Confirms:	503-230-4003	503-230-7463

Scheduling: Pursuant to the WSPP, this transaction shall be pre-scheduled. The Pre-Schedule Day is defined by the Western Electricity Coordinating Council's Pre-Schedule Calendar. Energy shall be pre-scheduled, identifying source and sink, by 1100 on the Pre-Schedule Day; provided, however, that the Parties may mutually agree to other arrangements. Real Time modifications will not be allowed except by mutual agreement or due to an uncontrollable force.

Liquidated Damages: Per Section 21.3 of the WSPP Agreement.

Please indicate your acceptance of the terms stated herein by returning an executed copy of this Confirmation Agreement by facsimile to **503-813-6291** within 5 business days.

PacifiCorp
Authorized Signature:

Name: Stacey Kusters

Title: Director, Origination

Date: July 26, 2011

Bonneville Power Administration
Authorized Signature:

Name: Mark E Miller

Title: Account Executive

Date: July 26, 2011

Bonneville File Path:
(W:\TMC\CT\PacifiCorp\Contracts (Final)\15452_Losses Settlement Confirm.docx)

002

Department of Energy
Bonneville Power Administration
P.O. Box 491
Vancouver, Washington 98666-0491

MAY 25 1994

In reply refer to: PSC

Mr. Elwyn Jon Kaake
Director, Power Scheduling
PacifiCorp
9951 SE. Ankeny
Portland, OR 97216

Dear Mr. Kaake:

Under the provisions of the Draft AC Intertie Agreement (Exhibit A to the Letter of Understanding, Contract No. DE-MS79-94BP94229 which was signed December 28, 1993) between the Bonneville Power Administration (BPA) and PacifiCorp, Contract No. DE-MS79-94BP94332, Section 12.(a), BPA hereby provides notice that BPA intends to store 100,000 megawatthours in both June and July 1994.

This letter also confirms your verbal agreement with Brenda Anderson of my staff in a telephone conversation on May 24, 1994. If BPA is not marketing energy on a preschedule basis, BPA may purchase from PacifiCorp and only from PacifiCorp, an equivalent amount of energy, hour by hour, as the amount stored, at a price of 24 mills per kilowatthour, in order to fulfill this obligation to store in PacifiCorp. This decision will be made on a preschedule basis and will be done for the entire day, not partial day, unless otherwise mutually agreed.

PacifiCorp's sale of such energy will be under the service agreement between PacifiCorp and BPA, dated February 14, 1992, (effective date July 24, 1992) under PacifiCorp's FERC Electric Tariff, First Revised Volume No. 3, Service Schedule PPL-3. Payments by BPA and billing by PacifiCorp for deliveries hereunder shall be in accordance with the terms specified in such Service Schedule PPL-3.

If you have any questions, please contact Brenda Anderson at (206) 418-2146.

Sincerely,

Mark W. Maher
Director, Division of Power Supply

ACCEPTED:

PacifiCorp Electric Operations

By ______________________

Title Director, Power Scheduling

Date May 31, 1994

Aug 22, 2007 [illegible]
Rec'd 9:11 am [illegible]

CONFIDENTIALITY AGREEMENT

This CONFIDENTIALITY AGREEMENT (this "Agreement") is entered into as of the 23 day of August, 2007, by and between PacifiCorp, an Oregon corporation ("PPW"), and the United States of America, Bonneville Power Administration ("BPA") with reference to the following:

WHEREAS, PPW and BPA are discussing resolution of PPW's loss returns to BPA as required under several BPA Transmission Service Agreements with PPW (FPT Transmission Agreements No. 14-03-26811, DE-MS79-79BP90100, DE-MS79-94BP94280, and DE-MS79-94BP94333; PTP Transmission Agreements No. DE-MS79-94BP94285, 02TX-10968, and 04TX-11722; AC Intertie Capacity Ownership Agreement No. DE-MS79-95BP94628: AC Intertie Agreement No. DE-MS79-94BP94332.), and in connection therewith PPW wishes to provide certain Confidential Information (as hereinafter defined) to BPA, and require as a condition precedent execution of this Agreement;

NOW, THEREFORE, in consideration of the above and the mutual promises herein contained, the parties hereto agree as follows:

1. Confidential Information. "Confidential Information" means data or other written information which is made available by PPW to BPA after the date hereof for the purpose described above, regardless of the manner furnished, provided that such information is labeled or otherwise described in writing as confidential and not to be disclosed outside of BPA. Confidential Information does not include information which at the time of disclosure (i) is generally available to the public (other than as a result of disclosure by BPA), (ii) was available to BPA on a nonconfidential basis from a source other than a party under a duty of confidentiality to PPW, or (iii) independently developed by BPA without reliance on the Confidential Information.

2. Confidentiality; Disclosure. The Confidential Information will be kept confidential by BPA and will not be used knowingly for any purpose by BPA other than for the purpose set forth above. BPA shall restrict the dissemination of the Confidential Information to its employees who have a need to see it. BPA will keep confidential any Confidential Information contained in any analyses, compilations, studies or other documents prepared by BPA that contain or reflect any Confidential Information. Upon request from PPW, BPA promptly will return all copies of the Confidential Information.

3. Protective Order. If BPA receives a request under the Freedom of Information Act to disclose any Confidential Information, it shall provide PPW with prompt prior written notice so that PPW may seek a protective order or other appropriate remedy. If such protective order or other remedy is not obtained, BPA shall (i) furnish only that portion of the Confidential Information which, in accordance with the advice of its own counsel, is legally required to be furnished, (ii) raise all applicable exemptions and objections to disclosure and (iii) exercise reasonable efforts to obtain assurances that confidential treatment will be accorded the Confidential Information so furnished.

6. Intellectual Property Rights. Nothing contained herein grants any rights respecting any intellectual property (whether or not trademarked, copyrighted or patented) or uses thereof.

7. Costs and Expenses. Except as otherwise provided in any other written agreement between the parties, the parties shall bear their own costs and expenses, including without limitation fees of counsel, accountants and other consultants and advisors.

8. Remedies. PPW shall be entitled to injunctive relief in the event of any breach hereof, in addition to all other remedies available to it at law or in equity. No failure or delay by a party in exercising any right, power or privilege hereunder will operate as a waiver, nor will any single or partial exercise or waiver of a right, power or privilege preclude any other or further exercise thereof. .

9. Venue and Choice of Law. This Agreement shall in all respects be interpreted, construed and enforced in accordance with the laws of the United States.

10. Miscellaneous. The term of this Agreement is two years from the date hereof. This Agreement constitutes the entire agreement of the parties relating to its subject matter, and supersedes all prior communications, representations, or agreements, verbal or written. This Agreement may only be waived or amended in writing. Notices hereunder shall be in writing and be effective when actually delivered. This Agreement may be executed in counterparts, each of which, when taken together, shall constitute one and the same original instrument. Neither party may assign or otherwise transfer its rights or delegate its duties hereunder without prior written consent, and any attempt to do so is void.

IN WITNESS WHEREOF, the undersigned parties have executed this Confidentiality Agreement as of the date first written above.

PACIFICORP

an Oregon corporation

By: [illegible]
Its: [illegible]

UNITED STATES DEPARTMENT OF ENERGY,
BONNEVILLE POWER ADMINISTRATION

By: [illegible]
Its: Transmission Account Executive

AUG 22 2007 DRW
Rec'd 9.11am FedEx

PACIFICORP ENERGY
A MIDAMERICAN ENERGY HOLDINGS COMPANY

825 NE Multnomah, Suite 600
Portland, Oregon 97232

Rich Gillman
Transmission Account Executive
Transmission Marketing & Sales – TM – OPP-2
7600 NE 41st Street, Suite 201
Vancouver, WA 98662

Rich:

Please find enclosed a PacifiCorp executed confidentiality agreement to cover the distribution of data that will allow parties to settle the quantity of undelivered losses in connection with several contracts between the parties. Please execute and return an original and retain one for your records.

PacifiCorp further recognizes the time constraints under the Agreement To Toll Running of Limitations Period and upon signature of the confidentiality agreement will schedule a meeting to establish the scope of the data transfer between parties and the expected time frame for completion of either parties analysis.

Sincerely,

Jim Schroeder
Origination

Cc: Colin Persichetti
Karen Stuwe

Caro

AUTHENTICATED COPY

Contract No. DE-MS79-94BP94333

MIDPOINT-MERIDIAN TRANSMISSION AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFICORP

Index to Sections

- -

This MIDPOINT-MERIDIAN TRANSMISSION AGREEMENT ("Agreement"), executed June 1, 1994 by the UNITED STATES OF AMERICA ("Government"), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION ("Bonneville"), and PACIFICORP ("PacifiCorp"), a corporation organized and existing under the laws of the State of Oregon, (hereinafter referred to individually as "Party" and collectively as "Parties").

W I T N E S S E T H:

WHEREAS the Parties have entered into the Intertie Agreement (Contract No. DE-MS79-86BP92299), as amended, which hereinafter is referred to as "Intertie Agreement"; and

WHEREAS the Parties have entered into the Transmission Agreement (Contract No. DE-MS79-79BP90091), as amended, which hereinafter is referred to as "Midpoint-Medford Agreement"; and

WHEREAS the Parties have entered into an Agreement of Principles, dated May 28, 1993, which hereinafter is referred to as "Letter of Understanding" and which provides, among other things, for the revision of certain terms and conditions in the Intertie Agreement and the Midpoint-Medford Agreement; and

WHEREAS the Parties have entered into the AC Intertie Agreement (Contract No. DE-MS79-94BP94332) which hereinafter is referred to as "AC Intertie Agreement" which replaces and supersedes the Intertie Agreement; and

WHEREAS the Parties desire to replace and supersede the Midpoint-Medford Agreement with this Agreement; and

WHEREAS PacifiCorp has constructed a 500 kV transmission line from Midpoint Substation to Meridian Substation ("Midpoint-Meridian Line"), to transmit electric power and energy from resources which it owned or which were under construction by PacifiCorp, as of September 2, 1977, in Wyoming and adjacent states ("PacifiCorp's Eastern System") to the Pacific Northwest; and

WHEREAS the Midpoint-Meridian Line consists of three segments hereinafter referred to as "Midpoint-Summer Lake Line", "Summer Lake-Malin Line" and "Malin-Meridian Line"; and

WHEREAS PacifiCorp has constructed a 500 kV transmission line from the interconnection with Bonneville at Alvey Substation to Meridian Substation ("Alvey-Meridian Line") which is jointly owned by PacifiCorp and Bonneville; and

WHEREAS the Midpoint-Meridian Line is interconnected with the Alvey-Meridian Line at Meridian Substation; and

WHEREAS the Midpoint-Meridian Line is interconnected with the Federal Transmission System and the AC Intertie; and

WHEREAS the Midpoint-Meridian Line is interconnected with the California-Oregon Transmission Project at Captain Jack Substation; and

WHEREAS Bonneville has agreed to provide PacifiCorp transmission service hereunder over the Federal Transmission System; and

WHEREAS Bonneville has agreed to provide additional transmission services to PacifiCorp at times of abnormal operations of the Midpoint-Summer Lake Line and the Summer Lake-Malin Line ("Midpoint-Malin Line"); and

WHEREAS the Parties have entered into the Malin Operation and Maintenance Trust Agreement (Contract No. 14-03-62876), as amended which hereinafter is referred to as "Operation and Maintenance Agreement" and which provides, among other things, for the operation and maintenance of certain facilities at Malin Substation; and

WHEREAS Bonneville has constructed a 500 kV transmission line from the Government's Buckley Substation to its Summer Lake Substation ("Buckley-Summer Lake Line") to interconnect with PacifiCorp's Midpoint-Meridian Line at Summer Lake Substation, and the Parties have agreed to exchange rights to capacity in the Buckley-Summer Lake Line and Summer Lake-Malin Line and for Bonneville to provide additional service arrangements under the terms and conditions of this Agreement; and

WHEREAS the Parties have entered into the Exchange Agreement (Contract No. 14-03-29245) as amended or replaced which is hereinafter referred to as "Exchange Agreement" and which provides, among other things, for points of delivery, scheduling arrangements and an energy exchange account; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power and energy generated at various Federal hydroelectric projects in the Pacific Northwest, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the parties hereto mutually agree as follows;

1. Definition and Explanation of Terms.

(a) "AC Intertie" means Bonneville's rights in the alternating current ("AC") transmission facilities for transferring power and energy between Oregon and California as follows: two 500 kV lines extending from John Day Substation to Malin Substation and to the California-Oregon Border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's share of ownership of the Alvey-Dixonville and Dixonville-Meridian 500 kV transmission lines; portions of the Alvey, Dixonville, Meridian and Captain Jack Substations; the 500 kV transmission line extending from Captain Jack Substation to the

California-Oregon Border; and any modifications, improvements, or additions to such facilities.

(b) "Compensation Charge" means the charge specified in Exhibit E, which is the weighted average of the Transmission Charges.

(c) "East to West Schedule" means the total amounts of electric energy scheduled each hour from PacifiCorp's Eastern System to the Idaho Power Company for delivery on behalf of PacifiCorp to Bonneville at LaGrande Substation, to PacifiCorp at Enterprise Substation and to PacifiCorp at Midpoint Substation.

(d) "Federal Share" means a fraction, the numerator of which equals the Total Demand and the denominator of which equals the sum of the Total Demand and the scheduling capability of the Midpoint-Malin Line as specified in Exhibit H.

(e) "Federal Transmission System" means transmission facilities owned by Bonneville.

(f) "Points of Delivery" means the points specified in Exhibit E and described in the Exchange Agreement and/or the Surplus Firm Capacity Sales Agreement, Contract No. DE-MS79-88BP92497.

(g) "Points of Interconnection" means the points specified in Exhibit E.

(h) "Total Demand" means the sum of the Transmission Demands specified in Exhibit E.

(i) "Transmission Charge" means the charge specified in Exhibit E for each Point of Delivery.

(j) "Transmission Demand" means the amount specified in Exhibit E, expressed in kilowatts, for each Point of Delivery.

(k) "Workday" for the purpose of scheduling means a day which the Parties observe as a regular workday.

2. Term of Agreement. This Agreement shall be effective and shall supersede the Midpoint-Medford Agreement in accordance with section 11 herein upon execution by the Parties and approval or acceptance for filing without change by the Federal Energy Regulatory Commission for a term coincident with the AC Intertie Agreement. Upon termination of this Agreement, all liabilities accrued hereunder shall be and are hereby preserved until satisfied.

3. Exhibits. Exhibits A through H are incorporated herein as part of this Agreement. PacifiCorp shall be the "Transferee" mentioned in Exhibit A and Bonneville shall be the "Transferror" therein mentioned.

4. Right to Use Transmission Capacity.

(a) Buckley-Summer Lake/Summer Lake-Malin Exchange. During the term hereof, the Parties hereby exchange the right to use the capacity in the Buckley-Summer Lake Line and the Summer Lake-Malin Line. PacifiCorp shall have the use of 340 megawatts of bi-directional scheduling capability in the Buckley-Summer Lake Line; and Bonneville shall have the use of 1000 megawatts of bi-directional scheduling capability above PacifiCorp's 1000 megawatts of capability in the Summer Lake-Malin Line. Such rights of use shall include Bonneville's initial terminal facilities in the Buckley and Summer Lake Substations and PacifiCorp's terminal facilities in the Summer Lake and Malin Substations. Such right of use is based on the ratio of each Party's estimated investment in, and the transfer capability of, its respective lines and related facilities. PacifiCorp shall be responsible for the capital and annual costs of two 500 kV line terminal positions at Summer Lake Substation, including two power circuit breakers, and the additions required at Malin Substation in accordance with the Operation and Maintenance Agreement; provided, however, that Bonneville will operate all such equipment at PacifiCorp's expense. Bonneville shall be responsible for all other facilities at Summer Lake and, with other owners of the AC Intertie, for the facilities to connect Buckley to the AC Intertie. For amounts PacifiCorp schedules in or out of Buckley within its 340 megawatt capacity ("Buckley Schedule") PacifiCorp shall reimburse Bonneville for incidental transmission and the associated losses pursuant to the general transmission agreement (Contract No. EW-78-Y83-0035), or for firm transmission and associated losses under an appropriate firm wheeling agreement. Use of one Party's capacity in either of the Buckley-Summer Lake Line or the Summer Lake-Malin Line by the other shall be subject to availability, as determined by the other Party, and shall be subject to payment and loss provisions agreed upon by the Parties. The Parties shall be compensated for control area electric power losses pursuant to Section 8 of the AC Intertie Agreement.

(b) Bonneville's Right to Use PacifiCorp's Summer Lake-Midpoint Transmission Capacity. Commencing on the effective date of this Agreement and continuing until the earlier of (1) the date of commercial operation of an additional high voltage transmission line between the Federal Transmission System and the Idaho Power Company system or (2) the later of (a) January 1, 1997, or (b) the date that PacifiCorp's net firm load obligations in southern Oregon and northern California exceed 1150 megawatts; if Bonneville requires additional capacity to the east in excess of the 350 megawatts capacity of its present interconnections with Idaho Power Company at LaGrande Substation and Hines Substation to serve Bonneville's own loads, Bonneville shall have the use of 200 megawatts of eastbound scheduling capability in the Midpoint-Summer Lake Line to the point where PacifiCorp's facilities interconnect with facilities of Idaho Power Company at Midpoint Substation. Losses associated with amounts of power transmitted over the Midpoint-Summer Lake Line shall be assessed in a manner agreed upon by the parties. There shall be no transmission charges for such transmission service.

(c) Bonneville's Right to Obtain Additional Summer Lake-Midpoint Capacity. During the term of this Agreement, Bonneville shall have the option to acquire up to 400 megawatts of eastbound firm scheduling rights over the Midpoint-Summer Lake Line and an option to tap such line to serve loads and for inter-regional transfers. If Bonneville exercises its option to acquire up to 400 megawatts of eastbound firm scheduling rights over the

Midpoint-Summer Lake Line, Bonneville shall pay PacifiCorp based upon PacifiCorp's then-effective applicable FERC filed tariff for firm transmission services. If Bonneville exercises this option, during periods when the eastbound capability of the Midpoint-Summer Lake Line is reduced, Bonneville's eastbound scheduling rights shall be reduced pro-rata with such reduction. However, during periods when transfer capability is reduced, PacifiCorp shall provide Bonneville the right to use PacifiCorp's capability not required for PacifiCorp's firm need, as determined by PacifiCorp, at no additional cost. In the event Bonneville wishes to tap the Midpoint-Summer Lake Line, Bonneville and PacifiCorp shall mutually develop the plan of service for such tap. Such tap shall not degrade or reduce PacifiCorp's East to West transfer capability on the Midpoint-Malin Line or reduce PacifiCorp's Load Carrying Capability as defined in the AC Intertie Agreement. Unless otherwise mutually agreed, Bonneville shall be responsible for all costs associated with any such tap. Unless otherwise mutually agreed, such tap shall not increase Bonneville's eastbound transfer rights on the Midpoint-Summer Lake Line.

5. <u>Transmission of Electric Power and Energy</u>. The parties hereto agree that PacifiCorp may, upon 30 days' notice and for a period of not less than 12 months, designate the power transmitted under subsection 5(a) herein to meet its contractual rights and obligations in the Walla Walla and Yakima areas to the extent PacifiCorp owns or leases facilities other than Bonneville's which allow it to serve such loads. During such period Bonneville shall

deem all or a portion of the deliveries under subsection 5(a) herein to be made to the Walla Walla and Yakima Areas; provided, however, that PacifiCorp shall continue to deliver losses and pay for transmission services as if such power were designated to the Points of Delivery.

(a) During each hour of the term hereof, PacifiCorp shall make available to Bonneville at the Points of Interconnection and Bonneville shall make available to PacifiCorp at the Points of Delivery, an amount of electric energy equal to the product of the Federal Share and PacifiCorp's East to West Schedule for such hour reduced by the amounts of electric energy that PacifiCorp delivers on such hour to Bonneville in the Walla Walla and Yakima areas under contractual rights and obligations including the obligation accounts of California utilities and governmental agencies ("PacifiCorp's Obligations"), which such reduction shall not exceed 350 megawatts; provided, however, that the amount of electric energy transmitted under this subsection 5(a) shall not exceed the Total Demand less PacifiCorp's Obligations for such hour.

(b) During each hour of the term hereof that an outage or a loss of any component of the Midpoint-Malin Line reduces the scheduling capability thereof, Bonneville shall transmit over the Federal Transmission System to PacifiCorp's points of delivery an additional amount of electric energy equal to the amount of PacifiCorp's East to West Schedule for such hour which is in excess of the sum of the Total Demand and the scheduling capability of the Midpoint-Malin Line determined pursuant to Exhibit H for such hour; provided, however, that such additional amount shall not exceed 700 megawatts. The additional amounts of electric energy made available pursuant to this subsection 5(b) shall be made available at points of interconnection and delivery agreed upon by the Parties.

(c) If during the periods of reduction in the scheduling capability of the Midpoint-Malin Line PacifiCorp desires Bonneville to transmit during an hour an amount of electric energy in excess of the sum of the Total Demand and the 700 megawatts of transmission capability made available under subsection 5(b) herein, Bonneville shall make available to PacifiCorp transmission capability which Bonneville determines is available on the Federal Transmission System for such transmission during such hour; provided, however, that such excess amount shall not exceed 300 megawatts. The hourly amounts of electric energy transmitted for PacifiCorp pursuant to this subsection 5(c) shall be equal to the amount of PacifiCorp's East to West Schedule for such hour which is in excess of the sum of the Total Demand, 700 megawatts, schedules for transmission by other utilities, and the scheduling capability of the Midpoint-Malin Line, determined pursuant to Exhibit H for such hour. PacifiCorp shall make such amounts of electric energy available to Bonneville during each such hour and Bonneville shall on the same hour make equal amounts available to PacifiCorp at points of interconnection and delivery, respectively, agreed upon by the parties.

(d) To compensate Bonneville for losses incurred in providing the transmission services hereunder, PacifiCorp shall make available and schedule to Bonneville from the Points of Delivery, or other points of delivery on PacifiCorp's Main Subsystem as agreed upon by the parties, electric energy (1) for each hour or the corresponding hour 168 hours later, at Bonneville's option, or (2) at another hour mutually agreed upon, in an amount determined in the following manner:

(1) the losses associated with the amount of electric energy transmitted each hour pursuant to subsections 5(a) and 5(b) herein shall be determined by solving for Lw in the respective hourly loss calculations specified in the tables of Exhibit F; Pw in such calculations shall be the amount transmitted pursuant to subsections 5(a) and 5(b) herein on such hour; and

(2) the hourly losses associated with the amounts of electric energy transmitted each hour pursuant to subsection 5(c) herein shall be equal to the product of the amounts transmitted on such hour, and the appropriate loss specified in Exhibit D.

If either Party schedules electric energy in any hour on its share of capacity provided under section 4 herein, it shall schedule losses to the other Party in the manner described in this subsection 5(d), at points of delivery or points of interconnection agreed by the parties and in the amounts agreed by the parties.

(e) PacifiCorp shall, as soon as reasonably practicable upon a reduction of the scheduling capability of the Midpoint-Malin Line due to an outage or loss of any component thereof, notify Bonneville as to PacifiCorp's intent to transmit electric energy pursuant to subsections 5(b) and 5(c) herein.

(f) PacifiCorp shall not transmit electric power and energy west to east over the Midpoint-Meridian Line, or any segment thereof, in a manner which will adversely impact the operation of the Federal Transmission System or the AC Intertie. The determination of an adverse impact shall be made by Bonneville.

6. Scheduling.

(a) PacifiCorp shall submit to Bonneville each Workday pursuant to the scheduling provisions of the Exchange Agreement preschedules of each of the following amounts to be made available to Bonneville for each hour of the following day or days:

(1) the Buckley Schedule under section 4 herein;

(2) the amounts to be transmitted pursuant to subsection 5(c) herein; and

(3) the amount of losses to be delivered pursuant to subsection 5(d) herein.

(b) PacifiCorp shall submit to Bonneville each Workday retroactive reports of the hourly amounts of electric energy made available to Bonneville pursuant to subsections 5(a) and 5(b) herein, PacifiCorp's East to West Schedule for the previous day or days and PacifiCorp's use of its capacity in the Buckley-Summer Lake Line under subsection 4(a) herein for service to its Bend area loads. In addition, at Bonneville's request, PacifiCorp shall (1) at the end of each hour notify Bonneville of the amounts of electric energy so made available during such hour and (2) by 1200 hours on each Workday submit an estimate of the amounts of electric energy to be made available pursuant to subsections 5(a) and 5(b) for each hour of the following day or days.

(c) Bonneville shall submit to PacifiCorp each Workday (1) a retroactive report of the hourly amounts of electric energy made available to PacifiCorp for transmittal over the Midpoint-Summer Lake Line pursuant to subsections 4(b) and 4(c) herein and the Summer Lake-Malin Line pursuant to subsection 4(a) herein for the previous day or days and (2) a preschedule of the losses associated with the transmission services provided under (1) for the following day or days. In addition, at PacifiCorp's request, Bonneville shall (1) at the end of each hour notify PacifiCorp of the amounts of electric energy scheduled under this subsection 6(c) during such hour, and (2) by 1200 hours on each Workday submit an estimate of the amounts of electric energy to be scheduled under this subsection 6(c) for the following day or days.

(d) Scheduling provisions of the Exchange Agreement shall apply to scheduling hereunder. PacifiCorp shall schedule all transactions with California utilities and governmental agencies in California through the Joint Intertie Scheduling Office, as defined in the AC Intertie Agreement, and shall keep the appropriate scheduling personnel advised of all transactions over the Midpoint-Meridian Line and the Buckley-Summer Lake Line.

7. Payment for Transmission.

(a) PacifiCorp shall pay Bonneville each month for the transmission services provided in subsection 5(a) herein, in accordance with the provisions of Exhibit B, an amount equal to the product obtained by multiplying the Total Demand by the Compensation Charge as specified in Exhibit E.

(b) If Bonneville transmits electric energy for PacifiCorp pursuant to subsection 5(b) herein, PacifiCorp shall pay Bonneville for the services provided during each period of reduction, in accordance with the provisions of Exhibit B, in the amount of the Weighted Monthly Charge specified in the appropriate table of Exhibit G for the period of:

(1) one month if the duration of such reduction is at least 48 hours but less than 96 hours;

(2) two months if such duration is at least 96 hours but less than 168 hours;

(3) four months if such duration is at least 168 hours but less than 336 hours;

(4) eight months if such duration is at least 336 hours but less than 730 hours; or

(5) twelve months if such duration is 730 hours, plus one month for each additional increment of 730 hours that such reduction continues.

If a reduction is of a duration of less than 48 hours, the transmission services provided pursuant to subsection 5(b) herein shall be provided at no charge to PacifiCorp. The payment provisions of this subsection 7(b) may be changed upon mutual agreement of the parties.

(c) If Bonneville transmits electric energy for PacifiCorp pursuant to subsection 5(c) herein, PacifiCorp shall pay Bonneville at the rate specified in Exhibit D, in accordance with the provisions of Exhibit B.

8. Increase or Reduction of the Total Demand.

(a) The Total Demand may be increased or reduced upon the following terms and conditions, respectively:

(1) The Total Demand shall be increased if PacifiCorp constructs or purchases additional firm generation in PacifiCorp's Eastern System beyond those plants or units owned or under construction by it or those firm purchases in effect, as of September 2, 1977, for serving its Pacific Northwest obligations without constructing or acquiring additional transmission capability to transmit such purchases or generation to its Pacific Northwest loads. The amount of such increase shall be mutually agreed and shall be effective as of the effective date of such purchase of firm generation or the date of commercial operation of such plants or units.

(2) The Total Demand may be reduced by an amount agreed upon by the parties if PacifiCorp (i) constructs or acquires additional transmission capability which increases the amount of transmission capability available to PacifiCorp to transmit electric power and energy from PacifiCorp's Eastern

System to serve PacifiCorp's obligations in the Pacific Northwest, or (ii) reduces the amount of generation available to it for transmission from PacifiCorp's Eastern System to points of delivery on its system, and the parties agree that such changes will reduce the services provided by Bonneville hereunder.

PacifiCorp shall notify Bonneville in writing two years prior to the earliest of (1) the date of commercial operation of new generation facilities as described in subsection 8(a)(1) herein, (2) the date of commercial operation or acquisition of additional transmission capability as described in subsection 8(a)(2)(i) herein or (3) the date of reduction of the availability in generation as described in subsection 8(a)(2)(ii) herein.

(b) Unless mutually agreed to, the Transmission Demand specified for each Point of Delivery in Exhibit E shall not be changed until such time as the Total Demand is changed pursuant to the provisions of this section 8. In the event of such change, the new transmission demands and/or points of delivery shall be subject to the approval of Bonneville and shall, upon such approval, be incorporated in a new Exhibit E which shall replace the then effective Exhibit E as of the date specified in such new exhibit. Any notification specified herein shall be extended, if necessary, to ensure compliance with the National Environmental Policy Act.

9. <u>Revision of Exhibits</u>.

(a) The rate schedules attached hereto as the Exhibits

C and D have been confirmed and approved by the Federal Energy Regulatory Commission ("FERC") on an interim basis. If the final rate schedules which are confirmed and approved by the FERC are amendments or modifications of the initial rate schedules, such amended or modified rate schedules and associated General Transmission Rate Schedule provisions shall be attached hereto and made a part of this agreement effective as of the date specified in the FERC's approval. The Transmission Charges specified in the initial Exhibit E or any subsequent transmission charges specified in this Agreement, shall be recalculated according to the provisions of such amended or modified rate schedule and associated provisions, and Bonneville shall prepare a new Exhibit E incorporating the revised transmission charges which will become effective as of the date specified therein, and payments by PacifiCorp under section 7 shall be adjusted accordingly. Any overpayments made by PacifiCorp pursuant to the terms of the initial rate schedules as a result of payments made hereunder shall be subject to retroactive adjustment with interest in accordance with the terms of the FERC's approval of such amended or modified rate schedules and associated provisions, and such adjustments shall be made to PacifiCorp's wholesale power bill as soon as reasonably practicable after the effective date of such rate schedules.

(b) If Bonneville determines that the charges specified in Exhibits E and G or any subsequent charges specified in this Agreement must be changed pursuant to Sections 19 or 38 of

Exhibit A, Bonneville shall prepare new Exhibits E and G incorporating such changes which will become effective as of the date specified therein. Such new Exhibits E and G shall then be substituted for the Exhibits E and G, respectively, then in effect.

(c) Exhibit F may be revised from time to time by Bonneville to incorporate values which represent then current Federal Transmission System operating conditions, revised transmission demands, revised weighted mileages, or any value used therein to calculate the hourly losses pursuant to subsection 5(d) herein. Bonneville shall prepare a new Exhibit F incorporating such revisions and such revised exhibit shall become effective as of the date specified therein.

(d) The Parties shall, from time to time, review the scheduling capabilities and the outage conditions specified in Exhibit H and shall, upon mutual agreement, revise such exhibit.

10. Reactive Power. It is the intent of the Parties that the voltage level at the Points of Interconnection and the Points of Delivery be controlled in accordance with prudent utility practice. The Parties shall jointly plan and operate their systems so that the flow of reactive power accompanying or resulting from deliveries of electric power and energy hereunder will not adversely affect the system of either party.

11. Termination of Agreement. The Parties agree that this Midpoint-Meridian Transmission Agreement supersedes and terminates in its entirety the Midpoint-Medford Agreement, Contract No. DE-

MS79-79BP90091, provided, however, that any liabilities incurred thereunder are hereby preserved until satisfied.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

/s/ SYDNEY D. BERWAGER (acting)
Assistant Administrator ACTING
for Power Sales

May 26, 1994

By ______________________
(Assistant Administrator for Power Sales)

Date 5/26/94

PACIFICORP

By ______________________
(Senior Vice President)

Date June 1, 1994

/s/ DENNIS STEINBERG
Senior Vice President

June 1, 1994

EXHIBIT A

GWP Form-4R (04-15-83)

GENERAL WHEELING PROVISIONS

Index to Sections

GENERAL APPLICATION

1. Interpretation.

(a) The provisions in this exhibit shall be deemed to be a part of the contract body to which they are an exhibit. If a provision in such contract body is in conflict with a provision contained herein, the former shall prevail.

(b) If a provision in the General Transmission Rate Schedule Provisions is in conflict with a provision in this exhibit or the contract body, this exhibit or the contract body shall prevail.

(c) Nothing contained in this contract shall, in any manner, be construed to abridge, limit, or deprive any party thereto of any means of enforcing any remedy, either at law or in equity, for the breach of any of the provisions thereof which it would otherwise have.

2. Definitions. As used in this contract:

(a) "Contractor," "Utility" or "Borrower" means the party to this contract other than Bonneville.

(b) "Federal System" or "Federal System Facilities" means the facilities of the Federal Columbia River Power System, which for the purposes of this contract shall be deemed to include the generating facilities of the Government in the Pacific Northwest for which Bonneville is designated as marketing agent; the facilities of the Government under the jurisdiction of Bonneville; and any other facilities:

(1) from which Bonneville receives all or a portion of the generating capability (other than station service) for use in meeting Bonneville's loads, such facilities being included only to the extent Bonneville has the right to receive such capability; provided, however, that "Bonneville's loads" shall not include that portion of the loads of any Bonneville customer which are served by a nonfederal generating resource purchased or owned directly by such customer which may be scheduled by Bonneville;

(2) which Bonneville may use under contract, or license; or

(3) to the extent of the rights acquired by Bonneville pursuant to the Treaty, between the Government and Canada, relating to the cooperative development of water resources of the Columbia River Basin, signed in Washington, D.C., on January 17, 1961.

(c) "Integrated Demand" means the number of kilowatts which is equal to the number of kilowatt-hours delivered at any point during a clock hour.

(d) "Measured Demand" means the maximum Integrated Demand for a billing month determined from measurements made as specified in the contract or as determined in section 4 hereof when metering or other data are not available for such purpose. Bonneville, in determining the Measured Demand, will exclude any abnormal Integrated Demands due to, or resulting from (a) emergencies or breakdowns on, or maintenance of, either parties' facilities, and (b) emergencies on facilities of the Transferee, provided that such facilities have been adequately maintained and prudently operated as determined by Bonneville.

If the contract provides for delivery of more than one class of power to a Transferee at any Point of Delivery, the portion of each Integrated Demand assigned to any class of power shall be determined as specified in the contract. The portion of the Integrated Demand so assigned shall constitute the Measured Demand for such class of power.

(e) "Month" means the period commencing at the time when the meters mentioned in this contract are read by Bonneville and ending approximately 30 days thereafter when a subsequent reading of such meters is made by Bonneville.

(f) "Point(s) of Delivery" means the point(s) of delivery listed either in the Points of Delivery Exhibit to this contract or in the body of this contract.

(g) "System" or "Facilities" means the transmission facilities: (1) which are owned or controlled by either party, or (2) which either party may use under lease, easement, or license.

(h) "Transferee" means an entity which receives power or energy from the system of the Transferor.

(i) "Transferor" means an entity which receives at one point on its system a supplying entity's power or energy and makes such power or energy available at another point on its system for the account of the delivering entity or a third party.

(j) "Uncontrollable Forces" means:

(1) strikes or work stoppage affecting the operation of the Contractor's works, system, or other physical facilities or of the Federal System Facilities or the physical facilities of any Transferee upon which such operation is completely dependent; the term "strikes or work stoppage" shall be deemed to include threats of imminent strikes or work stoppage which reasonably require a party or Transferee to restrict or terminate its operations to prevent substantial loss or damage to its works, system, or other physical facilities; or

(2) such of the following events as the Contractor or Bonneville or any Transferee by exercise of reasonable diligence and foresight, could not reasonably have been expected to avoid:

(A) events, reasonably beyond the control of either party or any Transferee, causing failure, damage, or destruction of any works, system or facilities of such party or Transferee; the word "failure" shall be deemed to include interruption of, or interference with, the actual operation of such works, system, or facilities;

(B) floods or other conditions caused by nature which limit or prevent the operation of, or which constitute an imminent threat of damage to, any such works, system, or facilities; and

(C) orders and temporary or permanent injunctions which prevent operation, in whole or in part, of the works, system, or facilities of either party or any Transferee, and which are issued in any bona fide proceeding by:

i. any duly constituted court of general jurisdiction; or

ii. any administrative agency or officer, other than Bonneville or its officers, provided by law (a) if said party or Transferee has no right to a review of the validity of such order by a court of competent jurisdiction; or (b) if such order is operative and effective unless suspended, set aside, or annulled by a court of competent jusidiction and such order is not suspended, set aside, or annulled in a judicial proceeding prosecuted by said party or Transferee in good faith; provided, however, that if such order is suspended, set aside, or annulled in such a judicial proceeding, it shall be deemed to be an "uncontrollable force" for the period during which it is in effect; provided, further, that said party or Transferee, shall not be required to prosecute such a proceeding, in order to have the benefits of this section, if the parties agree that there is no valid basis for contesting the order.

The term "operation" as used in this subsection shall be deemed to include construction, if construction is required to implement the contract and is specified therein.

3. Prior Demands.

(a) In determining any credit demand mentioned in, or money compensation to be paid under this contract for any month, Integrated Demands at which electric energy was delivered by the Transferor at Points of Delivery mentioned herein for the account of the other party to this contract prior to the date upon which the contract takes effect shall be considered in the same manner as if this contract had been in effect.

(b) If either party has delivered electric power and energy to the other party at any Point of Delivery specified in this contract or in any previous contract, and such Point of Delivery is superseded by another Point of Delivery specified in this contract, the Measured Demands, if any, at the superseded Point of Delivery shall be considered for the purpose of determining the charges paid to the Transferor for the electric power and energy delivered under this contract at such superseded point.

4. Measurements. Except as it is otherwise provided in section 7, each measurement of each meter mentioned in this contract shall be the measurement

automatically recorded by such meter or, at the request of either party, the measurement as mutually determined by the best available information.

If it is provided in this contract that measurements made by any of the meters specified therein are to be adjusted for losses, such adjustments shall be made by using factors, or by compensating the meters, as agreed upon by the parties hereto. If changes in conditions occur which substantially affect any such loss factor or compensation, it will be changed in a manner which will conform to such change in conditions.

5. Measurements and Installation of Meters. Bonneville may at any time install a meter or metering equipment to make the measurements for any Point of Delivery required for any computation or determination mentioned in this contract, and if so installed, such measurements shall be used thereafter in such computation or determination.

6. Tests of Metering Installations. Each party to this contract shall, at its expense, test its metering installations associated with this contract at least once every two years, and, if requested to do so by the other party, shall make additional tests or inspections of such installations, the expense of which shall be paid by such other party unless such additional tests or inspections show the measurements of such installations to be inaccurate as specified in section 7. Each party shall give reasonable notice of the time when any such test or inspection is to be made to the other party who may have representatives present at such test or inspection. Any component of such installations found to be defective or inaccurate shall be adjusted, repaired or replaced to provide accurate metering.

7. Adjustment for Inaccurate Metering

(a) If any meter mentioned in this contract fails to register, or if the measurement made by such meter during a test made as provided in section 6 varies by more than one percent from the measurement made by the standard meter used in such test, or if an error in meter reading occurs, adjustment shall be made correcting all measurements for the actual period during which such innacurate measurements were made, if such period can be determined. If such period cannot be determined, the adjustment shall be made for the period immediately preceding the test of such meter which is equal to the lesser of (a) one-half the time from the date of the last preceding test of such meter, or (b) six months. Such corrected measurements shall be used to recompute the amounts of any electric power and energy to be made available, or any credits to be made in any exchange energy account, and of any money compensation to be paid to the Transferor as provided in this contract.

(b) If the credit theretofore made to the Transferor in the exchange energy account varies from the credit to be made as recomputed, the amount of the variance will be credited in such exchange energy account to the party entitled thereto.

(c) If the money compensation theretofore paid to the Transferor varies from the money compensation to be paid as recomputed, the amount of the variance will be paid to the party entitled thereto after both parties have agreed to such recomputation and within 30 days after receipt of invoice by the designated payment office of the payer; provided, however, that the other party may deduct such amount due it from any money compensation which thereafter becomes due the Transferor under this contract.

8. Character of Service. Unless otherwise specifically provided for in the contract, electric power and energy made available pursuant to this contract shall be in the form of three-phase current, alternating at a nominal frequency of 60 hertz.

9. Point(s) of Delivery and Delivery Voltage. Electric power and energy shall be delivered to each Transferee at such point or points and at such voltage or voltages as are agreed upon by the parties hereto.

10. Combining Deliveries Coincidentally. If it is provided in this contract that charges for electric power and energy made available at two or more Points of Delivery will be made by combining deliveries at such points coincidentally:

(a) the total Measured Demand to be considered in determining the billing demand for each billing month shall be the largest sum obtained by adding for each demand interval of such month the corresponding Integrated Demands of the Transferee at all such points after adjusting said Integrated Demands as appropriate to such points;

(b) the number of kilowathours to be used in determining the energy charge, if any, and the average power factor at which electric energy is delivered at such points under this contract, during such month, shall be the sum of the amounts of electric energy delivered at such points under this contract during such month; and

(c) the number of reactive kilovolt-ampere-hours to be used in determining such average monthly power factor shall be the sum of the reactive kilovolt-ampere-hours delivered at such points under this contract such month.

11. Suspension of Deliveries. The other party to this contract may at any time notify the Transferor in writing to suspend the deliveries of electric power and energy provided for in this contract. Upon receipt of any such notice, the Transferor will forthwith discontinue, and will not resume, such deliveries until notified to do so by the other party, and upon receipt of such notice from the other party to do so, will forthwith resume such deliveries.

12. Continuity of Service. Either party may temporarily interrupt or reduce deliveries of electric power and energy if such party determines that such interruption or reduction is necessary or desirable in case of system emergencies, Uncontrollable Forces, or in order to install equipment in, make repairs to, make replacements within, make investigations and inspections of, or perform other maintenance work on its system. Except in case of emergency and in order that each party's operations will not be unreasonably interfered with, such party shall give notice to the other party of any such interruption or reduction, the reason therefor, and the probable duration thereof to the extent such party has knowledge thereof. Each party shall effect the use of temporary facilities or equipment to minimize the effect of any such interruption or outage to the extent reasonable or appropriate.

13. Uncontrollable Forces. Each party shall notify the other as soon as possible of any Uncontrollable Forces which may in any way affect the delivery of power hereunder. In the event the operations of either party are interrupted or curtailed due to such Uncontrollable Forces, such party shall exercise due diligence to reinstate such operations with reasonable dispatch.

14. Reducing Charges for Interruptions. If deliveries of electric power and energy to the Transferee are suspended, interrupted, interfered with or curtailed due to Uncontrollable Forces on either the Transferee's System or Transferor's System, or if the Transferor interrupts or reduces deliveries to the Transferee for any of the reasons stated in section 12 hereof, the credit in the exchange energy account which would otherwise be made, or the money compensation which would otherwise be paid to the Transferor, shall be appropriately reduced. No interruption, or equivalent interruption, of less than 30 minutes duration will be considered for computation of such reduction in charges.

15. Net Billing. Upon mutual agreement of the parties, payment due one party may be offset against payments due the other party under all contracts between the parties hereto for the sale and exchange of electric power and energy, use of transmission facilities, operation and maintenance of electric facilities, lease of electric facilities, mutual supply of emergency and standby electric power and energy, and under such other contracts between such parties as the parties may agree, unless otherwise provided in existing contracts between the parties. Under contracts included in this procedure, all payments due one party in any month shall be offset against payments due the other party in such month, and the resulting net balance shall be paid to the party in whose favor such balance exists unless the latter elects to have such balance carried forward to be added to the payments due it in a succeeding month.

16. Average Power Factor.

(a) The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{\sqrt{(\text{Kilowatthours})^2 + (\text{Reactive Kilovolt-ampere-hours})^2}}$$

The data used in the above formula shall be obtained from meters which are ratcheted to prevent reverse registration.

(b) When delivery of electric power and energy by the Transferor at any point is commingled with any other class or classes of power and it is impracticable to separately meter the kilowatthours and reactive kilovolt-ampere-hours for each class, the average power factor of the total delivery of such electric power and energy for the month will be used, where applicable, as the power factor for each of the separate classes.

(c) Except as it is otherwise specifically provided in this contract, no adjustment will be made for power factor at any point of delivery described in this contract while the varhours delivered at such point are not measured.

(d) The Transferor may, but shall not be obligated to, deliver electric energy hereunder at a power factor of less than 0.85 leading or lagging.

17. Permits.

(a) If any equipment or facilities associated with any Point of Delivery and belonging to a party to this contract are or are to be located on the property of the other party, a permit to install, test, maintain, inspect, replace, repair, and operate during the term of this contract and to remove such equipment and facilities at the expiration of said term, together with the right of entry to said property at all reasonable times in such term, is hereby granted by the other party.

(b) Each party shall have the right at all reasonable times to enter the property of the other party for the purpose of reading any and all meters mentioned in this contract which are installed on such property.

(c) If either party is required or permitted to install, test, maintain, inspect, replace, repair, remove, or operate equipment on the property of the other, the owner of such property shall furnish the other party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other party of any subsequent modification which may affect the duties of the other party in regard to such equipment, and furnish the other party with accurate revised drawings, if possible.

18. Ownership of Facilities.

(a) Except as otherwise expressly provided, ownership of any and all equipment, and of all salvable facilities installed or previously installed by a party to this contract on the property of the other party shall be and remain in the installing party.

(b) Each party shall identify all movable equipment and all other salvable facilities which are installed by such party on the property of the other by permanently affixing thereto suitable markers plainly stating the name of the owner of the equipment and facilities so identified. Within a reasonable time subsequent to initial installation, and subsequent to any modification of such installation, representatives of the parties shall jointly prepare an itemized list of said movable equipment and facilities.

19. Adjustment for Change of Conditions. If changes in conditions hereafter occur which substantially affect any factor required by this contract to be used in determining (a) any credit in any exchange energy account to be made, money compensation to be paid, or amount of electric power and energy or losses to be made available to one party by the other party, or (b) any maximum replacement demand, or average power factor mentioned in this contract, such factor will be changed in an equitable manner which will conform to such changes of conditions. If an increase in the capacity of the facilities being used by the Transferor in making deliveries hereunder is required at any time after execution of this contract to enable the Transferor to make the deliveries herein required together with those required for its own operations, the construction or installation of additional or other

equipment or facilities for that purpose shall be deemed to be a change of conditions within the meaning of the preceding sentence.

If, pursuant to the terms of the agreement establishing such exchange energy account, another rate is substituted for the rate to be used in settling the balance in such account, the number of kilowatthours to be credited to the Transferor in such account for each month as provided in this agreement, shall be changed for each month thereafter to the amount computed by multiplying such number of kilowatthours by 2.5 mills and dividing the resulting product by the currently effective substituted rate in mills per kilowatthour.

20. Dispute Resolution and Arbitration.

(a) Pending resolution of a disputed matter the parties will continue performance of their respective obligations pursuant to this contract. If the parties cannot reach timely mutual agreement on any matter in the administration of this contract Bonneville shall, unless otherwise specifically provided for in subsection (b) below and, to the extent necessary for its continued performance, make a determination of such matter without prejudice to the rights of the other party. Such determination shall not constitute a waiver of any other remedy belonging to the Contractor.

(b) The questions of fact stated below shall be subject to arbitration. Other questions of fact under this contract may be submitted to arbitration upon written mutual agreement of the parties. The party calling for arbitration shall serve notice in writing upon the other party, setting forth in detail the question or questions to be arbitrated and the arbitrator appointed by such party. The other party shall, within 10 days after the receipt of such notice, appoint a second arbitrator, and the two so appointed shall choose and appoint a third. In case such other party fails to appoint an arbitrator within said 10 days, or in case the two so appointed fail for 10 days to agree upon and appoint a third, the party calling for the arbitration, upon 5 days' written notice delivered to the other party, shall apply to the person who at the time shall be the presiding judge of the United States Court of Appeals for the Ninth Circuit for appointment of the second and third arbitrator, as the case may be.

The determination of the question or questions submitted for arbitration shall be made by a majority of the arbitrators and shall be binding on the parties. Each party shall pay for the services and expenses of the arbitrator appointed by or for it, for its own attorney fees, and for compensation for its witnesses or consultants. All other costs incurred in connection with the arbitration shall be shared equally by the parties thereto.

The questions of fact to be determined as provided in this section shall be limited to:

(1) the determination of the measurements to be made by the parties hereto pursuant to section 4;

(2) the correction of the measurements to be made pursuant to section 7;

(3) the duration of the interruption or equivalent interruption in section 14;

(4) whether changes in conditions mentioned in section 19 have occurred;

(5) whether the changes mentioned in section 30 were made "promptly";

(6) whether an increase or decrease in load or change in load factor mentioned in section 32 is unusual;

(7) any issue which both parties agree is an issue of fact mentioned in sections 30, 31, and 34;

(8) the occurrence of an abnormal nonrecurring demand and the amount and time thereof;

(9) whether a party has complied with section 34(b); and

(10) the acceptable level of harmonics for purposes of section 35.

21. Contract Work Hours and Safety Standards.

This contract, if and to the extent required by applicable law and if not otherwise exempted, is subject to the following provisions:

(a) Overtime Requirements. No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall require or permit any laborer or mechanic in any workweek in which such worker is employed on such work to work in excess of 8 hours in any calendar day or in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than one and one-half times such worker's basic rate of pay for all hours worked in excess of eight hours in any calendar day or in excess of 40 hours in such workweek, as the case may be.

(b) Violation; Liability for Unpaid Wages; Liquidated Damages. In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible therefor shall be liable to any affected employee for such employee's unpaid wages. In addition, such contractor and subcontractor shall be liable to the Government for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions of subsection (a) in the sum of $10 for each calendar day on which such employee was required or permitted to be employed in such work in excess of eight hours or in excess of such employee's standard workweek of 40 hours without payment of the overtime wages required by subsection (a) above.

(c) Withholding for Unpaid Wages and Liquidated Damages. Bonneville may withhold or cause to be withheld, from any moneys payable on account of work performed by the Contractor or subcontractor, such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for unpaid wages and liquidated damages as provided in subsection (b) above.

(d) Subcontracts. The Contractor shall insert in any subcontracts the clauses set forth in subsections (a) through (c) of this provision and also a clause requiring the subcontractors to include these clauses in any lower tier subcontracts which they may enter into, together with a clause requiring this insertion in any further subcontracts that may in turn be made.

(e) Records. The Contractor shall maintain payroll records containing the information specified in 29 CFR 516.2(a). Such records shall be preserved for 3 years from the completion of the contract.

22. Convict Labor. In connection with the performance of work under this contract, the Contractor agrees, if and to the extent required by applicable law or if not otherwise exempted, not to employ any person undergoing sentence of imprisonment except as provided by Public Law 89-176, September 10, 1965 (18 U.S.C. 4082(c)(2)) and Executive Order 11755, December 29, 1973.

23. Equal Employment Opportunity. During the performance of this contract, if and to the extent required by applicable law or if not otherwise exempted, the Contractor agrees as follows:

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by Bonneville setting forth the provisions of the Equal Opportunity clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which said Contractor has a collective bargaining agreement or other contract or understanding, a notice, to be provided by Bonneville, advising the labor union or worker's representative of the Contractor's commitments under this Equal Opportunity clause and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and by the rules, regulations, and relevant orders of the Secretary of Labor, or pursuant thereto, and will permit access to said Contractor's books, records, and accounts by Bonneville and the Secretary of Labor for purposes of investigations to ascertain compliance with such rules, regulations, and orders.

(f) In the event of the Contractor's noncompliance with the Equal Opportunity clause of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(g) The Contractor will include the provisions of paragraphs (a) through (f) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as Bonneville may direct as a means of enforcing such provisions, including sanctions for noncompliance. In the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by Bonneville, the Contractor may request the Government to enter into such litigation to protect the interests of the Government.

24. Additional Provisions. The Contractor agrees to comply with the clauses for Government contracts contained in the following statutes, Executive Orders, and regulations to the extent applicable:

(a) the Rehabilitation Act of 1973, Public Law 93-112, as amended, and 41 CFR 60-741 (affirmative action for handicapped workers);

(b) the Vietnam Era Veterans Readjustment Assistance Act of 1974, Public Law 92-540, as amended, and 41 CFR 60-250 (affirmative action for disabled veterans and veterans of the Vietnam era);

(c) Executive Order 11625 and 41 CFR 1-1.1310-2 (utilization of minority business enterprises);

(d) the Small Business Act, as amended.

25. Reports. The other party to this contract will furnish Bonneville such information as is necessary for making any computation required for the purposes of this contract, and the parties will cooperate in exchanging such additional information as may be reasonably useful for their respective operations.

26. Assignment of Contract. This contract shall inure to the benefit of, and shall be binding upon the respective successors and assigns of the parties to this contract. Such contract or any interest therein shall not be transferred or assigned by either party to any party other than the Government or an agency thereof without the written consent of the other except as

specifically provided in this section. The consent of Bonneville is hereby given to any security assignment or other like financing instrument which may be required under terms of any mortgage, trust, security agreement or holder of such instrument of indebtedness made by and between the Contractor and any mortgagee, trustee, secured party, subsidiary of the Contractor or holder of such instrument of indebtedness, as security for bonds of other indebtedness of such Contractor, present or future; such mortagagee, trustee, secured party, subsidiary, or holder may realize upon such security in foreclosure or other suitable proceedings, and succeed to all right, title, and interests of such Contractor.

27. Waiver of Default. Any waiver at any time by any party to this contract of its rights with respect to any default of any other party thereto, or with respect to any other matter arising in connection with such contract, shall not be considered a waiver with respect to any subsequent default or matter.

28. Notices and Computation of Time. Any notice required by this contract to be given to any party shall be effective when it is received by such party, and in computing any period of time from such notice, such period shall commence at 2400 hours on the date of receipt of such notice.

29. Interest of Member of Congress. No Member of, or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this contract or to any benefit that may arise therefrom, but this provision shall not be construed to extend to this contract if made with a corporation for its general benefit.

APPLICABLE ONLY IF TRANSFEREE IS A PARTY TO THIS CONTRACT

30. Balancing Phase Demands. If required by the Transferor at any time during the term of this contract, the Transferee shall promptly make such changes as are necessary on its system to balance the phase currents at any Point of Delivery so that the current of any one phase shall not exceed the current on any other phase at such point by more than 10 percent.

31. Adjustment for Unbalanced Phase Demands. If the Transferee fails to promptly make the changes mentioned in section 30, the Transferor may, after giving written notice one month in advance, determine that the Measured Demand of the Transferee at the Point of Delivery in question during each month thereafter, until such changes are made, is equal to the product obtained by multiplying by three the largest of the Integrated Demands on any phase adjusted as appropriate to such point during such month.

32. Changes in Requirements or Characteristics. The Transferee will, whenever possible, give reasonable notice to the Transferor of any unusual increase or decrease of its demands for electric power and energy on the Transferor's system, or of any unusual change in the load factor or power factor at which the Transferee will take delivery of electric power and energy under this contract.

33. Inspection of Facilities. Each party may for any reasonable purpose under this contract inspect the other party's electric installation at any reasonable time. Such inspection, or failure to inspect, shall not render

such party, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this contract. The inspecting party shall observe written instructions and rules posted in facilities and such other necessary instructions or standards for inspection as the parties agree to. Only those electric installations used in complying with the terms of this contract shall be subject to inspection.

34. Electric Disturbances.

(a) For the purposes of this section, an electric disturbance is any sudden, unexpected, changed, or abnormal electric condition occurring in or on an electric system which causes damage.

(b) Each party shall design, construct, operate, maintain and use its electric system in conformance with accepted utility practices:

(1) to minimize electric disturbances such as, but not limited to, the abnormal flow of power which may damage or interfere with the electric system of the other party or any electric system connected with such other party's electric system; and

(2) to minimize the effect on its electric system and on its customers of electric disturbances originating on its own or another electric system.

(c) If both parties to this contract are parties to the Western Interconnected Electric System Agreement, their relationship with respect to system damages shall be governed by that Agreement.

(d) During such time as a party to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, its relations with the other party with respect to system damages shall be governed by the following sentence, notwithstanding the fact that the other party may be a party to said Agreement Limiting Liability Among Western Interconnected Systems. A party to this contract shall not be liable to the other party for damage to the other party's system or facilities caused by an electric disturbance on the first party's system, whether or not such electric disturbance is the result of negligence by the first party, if the other party has failed to fulfill its obligations under subsection (b)(2) above.

(e) If one of the parties to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, each party to this contract shall hold harmless and indemnify the other party, its officers and employees, from any claims for loss, injury, or damage suffered by those to whom the first party delivers power not for resale, which loss, injury or damage is caused by an electric disturbance on the other party's system, whether or not such electric disturbance results from the negligence of such other party, if such first party has failed to fulfill its obligations under subsection (b)(2) above, and such failure contributed to the loss, injury or damage.

(f) Nothing in this section shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a party to this contract.

35. Harmonic Control. Each party shall design, construct, operate, maintain and use its electric facilities in accordance with good engineering practices to reduce to acceptable levels the harmonic currents and voltages which pass into the other party's facilities. Harmonic reductions shall be accomplished with equipment which is specifically designed and permanently operated and maintained as an integral part of the facilities of the party which owns the system on which harmonics are generated.

APPLICABLE ONLY IF TRANSFEREE IS NOT A PARTY TO THIS CONTRACT

36. Protection of the Transferor. Protection is or will be afforded to Bonneville or its Transferor under such of the following provisions and conditions as are specified in each contract executed or to be executed by Bonneville and each third party Transferee named in this contract: the power factor clause of the applicable Bonneville Wholesale Rate Schedule and the subject matter set forth in the General Contract Provisions under the following titles, namely:

Adjustment for Unbalanced Phase Demands; Uncontrollable Forces; Continuity of Service; Changes in Demands or Characteristics; Electric Disturbances; Harmonic Control; Balancing Phase Demands; Permits; Ownership of Facilities; and Inspection of Facilities.

RELATING TO RURAL ELECTRIFICATION ADMINISTRATION BORROWERS

37. Approval of Contract. If the Contractor borrows from the Rural Electrification Administration or any other entity under an indenture which requires the lender's approval of contracts, this contract and any amendment thereto shall not be binding on the parties thereto if they are not approved by the Rural Electrification Administration or such other entity. The Contractor shall notify Bonneville of any such entity. If approval is given, such contract or amendment shall be effective at the time stated therein.

APPLICABLE ONLY IF BONNEVILLE IS THE TRANSFEROR

38. Equitable Adjustment of Rates.

(a) Bonneville shall establish, periodically review and revise rates for the wheeling of electric power and/or energy pursuant to the terms of this contract. Such rates shall be established in accordance with applicable law.

(b) As used in this section, the words "Rate Adjustment Date" shall mean any date specified by Bonneville in a notice of intent to file revised rates as published in the Federal Register; provided, however, that such date shall not occur sooner than (1) nine months from the date that such notice of intent is published; or (2) twelve months from any previous Rate Adjustment Date. By giving written notice to the Contractor 45 days prior to such Rate Adjustment Date, Bonneville may delay such Rate Adjustment Date for up to 90 days if Bonneville determines either that the revenue level of the proposed rates differs by more than five percent from the revenue requirements indicated by most recent repayment studies entered in the hearings record or that external events beyond Bonneville's control will prevent Bonneville from meeting such Rate Adjustment Date. Bonneville may cancel a notice of intent to file revised rates at any time (1) by written notice to the Contractor; or (2) by publishing in the Federal Register a new notice of intent to file revised rates which specifically cancels a previous notice.

(c) The Contractor shall pay Bonneville for the service made available under this contract during the period commencing on each Rate Adjustment Date and ending at the beginning of the next Rate Adjustment Date at the rate specified in any rate schedule available at the beginning of such period for service of the class, quality, and type provided for in this contract, and in accordance with the terms thereof, and of the General Transmission Rate Schedule Provisions, if any, as changed with, incorporated in or referred to in such rate schedule. New rates shall not be effective on any Rate Adjustment Date unless they have been approved on a final or interim basis by a governmental agency designated by law to approve Bonneville's rates. Rates shall be applied in accordance with the terms thereof, the General Transmission Rate Schedule Provisions as changed with, incorporated in or referred to in such rate schedule and the terms of this contract.

(WP-PKJ-0222f)

General Transmission Rate Schedule Provisions

SECTION I. ADOPTION OF REVISED TRANSMISSION RATE SCHEDULES AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS (GTRSPs)

A. Approval of Rates

These rate schedules and GTRSPs shall become effective upon interim approval or upon final confirmation and approval by FERC. BPA will request FERC approval effective October 1, 1993.

B. General Provisions

These 1993 Transmission Rate Schedules and associated GTRSPs are virtually identical to and supersede BPA's 1991 Transmission Rate Schedules and GTRSPs (which became effective October 1, 1991) but do not supersede prior rate schedules required by agreement to remain in force.

Transmission service provided shall be subject to the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act, and the Energy Policy Act of 1992, Pub. L. 102-486, 106 Stat. 2776 (1992).

The meaning of terms used in the transmission rate schedules shall be as defined in agreements or provisions which are attached to the Agreement or as in any of the above Acts.

C. Interpretation

If a provision in the executed Agreement is in conflict with a provision contained herein, the former shall prevail.

SECTION II. BILLING FACTOR DEFINITIONS AND BILLING ADJUSTMENTS

A. Billing Factors

1. Scheduled Demand

The largest of hourly amounts wheeled which are scheduled by the customer during the time period specified in the rate schedules.

2. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands measured by meters installed at each POD during each time period specified in the applicable rate schedule. Such measurements shall be made as specified in the Agreement. BPA, in determining the Metered Demand, will exclude any abnormal readings due to or resulting from: (a) emergencies or breakdowns on, or maintenance of, the FCRTS; or (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. If more than one class of power is delivered to any POD, the portion of the metered quantities assigned to any class of power shall be as agreed to by the parties. The amount so assigned shall constitute the Metered Demand for such class of power.

3. **Transmission Demand**

The demand as defined in the Agreement.

4. **Total Transmission Demand**

The sum of the transmission demands as defined in the Agreement.

5. **Ratchet Demand**

The maximum demand established during the previous 11 billing months. Exception: If a Transmission Demand or Total Transmission Demand has been decreased pursuant to the terms of the Agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

B. **Billing Adjustments**

Average Power Factor

The adjustment for average power factor, when specified in a transmission rate schedule or in the Agreement, shall be made in accordance with the average power factor section of the General Wheeling Provisions.

To maintain acceptable operating conditions on the Federal system, BPA may restrict deliveries of power at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 85 percent.

SECTION III. OTHER DEFINITIONS

Definitions of the terms below shall be applied to these provisions and the Transmission Rate Schedules, unless otherwise defined in the Agreement.

A. **Agreement**

An agreement between BPA and a customer to which these rate schedules and provisions may be applied.

B. **Eastern Intertie**

The segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment including related terminals at Garrison.

C. **Electric Power**

Electric peaking capacity (kW) and/or electric energy (kWh).

D. **Federal Columbia River Transmission System**

The transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

E. **Firm Transmission Service**

Transmission service which BPA provides for any non-BPA power except for transmission service which is scheduled as nonfirm. If the firm service is provided pursuant to the Agreement, the terms of the Agreement may further define the service.

F. **Integrated Network**

The segment of the FCRTS for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest, excluding facilities not segmented to the network as shown in the Wholesale Power Rate Development Study used in BPA's rate development.

G. **Main Grid**

As used in the FPT and IR rate schedules, that portion of the Integrated Network with facilities rated 230 kV and higher.

H. **Main Grid Distance**

As used in the FPT rate schedules, the distance in airline miles on the Main Grid between the POI and the POD, multiplied by 1.15.

I. **Main Grid Interconnection Terminal**

As used in the FPT rate schedules, Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

J. **Main Grid Miscellaneous Facilities**

As used in the FPT rate schedules, switching, transformation, and other facilities of the Main Grid not included in other components.

K. **Main Grid Terminal**

As used in the FPT rate schedules, the Main Grid terminal facilities located at the sending and/or receiving end of a line exclusive of the Interconnection terminals.

L. **Nonfirm Transmission Service**

Interruptible transmission service which BPA may provide for non-BPA power.

M. **Northern Intertie**

The segment of the FCRTS for which the transmission facilities consist of two 500 kV lines between Custer Substation and the United States-Canadian border, one 500 kV line between Custer and Monroe Substations, and two 230 kV lines from Boundary Substation to the United States-Canadian border, and the associated substation facilities.

N. **Point of Integration (POI)**

Connection points between the FCRTS and non-BPA facilities where non-Federal power is made available to BPA for wheeling.

O. **Point of Delivery (POD)**

Connection points between the FCRTS and non-BPA facilities where non-Federal power is delivered to a customer by BPA.

P. **Secondary System**

As used in the FPT and IR rate schedules, that portion of the Integrated Network facilities with operating voltage of 115 kV or 69 kV.

Q. **Secondary System Distance**

As used in the FPT rate schedules, the number of circuit miles of Secondary System transmission lines between the secondary POI and the Main Grid or the secondary POD, or the Main Grid and the secondary POD.

R. **Secondary System Interconnection Terminal**

As used in the FPT rate schedules, the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

S. **Secondary System Intermediate Terminal**

As used in the FPT rate schedules, the first and final terminal facilities in the Secondary System transmission path exclusive of the Secondary System Interconnection terminals.

T. **Secondary Transformation**

As used in the FPT rate schedules, transformation from Main Grid to Secondary System facilities.

U. Southern Intertie

The segment of the FCRTS for which the major transmission facilities consist of two 500 kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation; when completed, the Third AC facilities, which include Captain Jack Substation and the Alvey-Meridian 500 kV AC line; one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border; and associated substation facilities.

V. Transmission Service

As used in the MT rate schedule, Transmission Service is as defined in the Western Systems Power Pool Agreement.

SECTION IV. BILLING INFORMATION

A. Payment of Bills

Bills for transmission service shall be rendered monthly by BPA. Failure to receive a bill shall not release the customer from liability for payment. Bills for amounts due of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

The transmission billing determinant is the electric power quantified by the method specified in the Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

The transmission customer shall provide necessary information to BPA for any computation required to determine the proper charges for use of the FCRTS, and shall cooperate with BPA in the exchange of additional information which may be reasonably useful for respective operations.

Demand and energy billings for transmission service under each applicable rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill to be followed at a subsequent billing date by a final bill. The estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Billing Month

For charges based on scheduled quantities, the billing month is the calendar month. For charges based on metered quantities, the billing month is defined as the interval between scheduled meter-reading dates. The billing month will not exceed 31 days in any case. While it may be necessary to read meters on a day other than the scheduled meter-reading date, for determination of billing demand, the billing month will cease at 2400 hours on the last scheduled meter-reading date. Schedules will be predetermined. The customer must give 30 days notice to request a change to the schedule.

4. **Due Date**

Bills shall be due by close of business on the 20th day after the date of the bill (due date). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the customer), the due date shall be the next following business day.

5. **Late Payment**

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the customer. However, such cancellation shall not affect the customer's liability for any charges accrued prior thereto under such agreement.

6. **Disputed Billings**

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the customer is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

7. **Revised Bills**

As necessary, BPA may render a revised bill.

a. If the amount of the revised bill is less than or equal to the amount of the original bill, the revised bill shall replace all previous bills issued by BPA that pertain to the specified customer for the specified billing period and the revised bill shall have the same date as the replaced bill.

b. If a revision causes an additional amount to be due BPA or the specified customer beyond the amount of the original bill, a revised bill will be issued for the difference and the date of the revised bill shall be its date of issue.

Schedule FPT-93.1
Formula Power Transmission

SECTION I. AVAILABILITY

This schedule supersedes schedule FPT-91.1 for all firm transmission agreements which provide that rates may be adjusted not more frequently than once a year. It is available for firm transmission of electric power and energy using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System (FCRTS). This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm availability of service is required. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions (GTRSPs).

SECTION II. RATE

A. Full-Year Service

The monthly charge per kilowatt of billing demand shall be one-twelfth of the sum of the Main Grid Charge and the Secondary System Charge, as applicable and as specified in the Agreement.

1. **Main Grid Charge**

   The Main Grid Charge per kilowatt of billing demand shall be the sum of one or more of the following component factors as specified in the Agreement:

   a. Main Grid Distance Factor: The amount computed by multiplying the Main Grid Distance by $0.0371 per mile

   b. Main Grid Interconnection Terminal Factor: $0.27

   c. Main Grid Terminal Factor: $0.44

   d. Main Grid Miscellaneous Facilities Factor: $1.88

2. **Secondary System Charge**

   The Secondary System Charge per kilowatt of billing demand shall be the sum of one or more of the following component factors as specified in the Agreement:

   a. Secondary System Distance Factor: The amount determined by multiplying the Secondary System Distance by $0.2784 per mile

   b. Secondary System Transformation Factor: $4.10

   c. Secondary System Intermediate Terminal Factor: $1.29

   d. Secondary System Interconnection Terminal Factor: $0.68

B. Partial-Year Service

The monthly charge per kilowatt of billing demand shall be as specified in Section II.A. for all months of the year except for agreements with terms 5 years or less and which specify service for fewer than 12 months per year. The monthly charge shall be:

1. During months for which service is specified, the monthly charge defined in Section II.A., and

2. During other months, the monthly charge defined in Section II.A. multiplied by 0.2.

SECTION III. BILLING FACTORS

Unless otherwise stated in the Agreement, the billing demand shall be the largest of:

A. The Transmission Demand;

B. The highest hourly Scheduled Demand for the month; or

C. The Ratchet Demand.

Schedule ET-93

Energy Transmission

SECTION I. AVAILABILITY

This schedule supersedes ET-91, unless otherwise specified in the Agreement, with respect to delivery using Federal Columbia River Transmission System facilities other than the Southern Intertie, Eastern Intertie, or the Northern Intertie, and is available for firm (of not more than 1 year duration) or nonfirm transmission between points within the Pacific Northwest. BPA may interrupt nonfirm service which is provided under this rate schedule. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The charge for transmission of non-BPA power shall be 2.02 mills per kilowatthour.

SECTION III. BILLING FACTORS

Billing Energy

The billing energy shall be the monthly sum of scheduled kilowatthours.

(LaGrande-McNary to PacifiCorp's Main System)

Charges, Demands, Points of Interconnection and Points of Delivery

These charges are based on Transmission Rate Schedule FPT 93.1

Points of Interconnection	Points of Delivery	Transmission Demand (kW)	Transmission Charge $/kW/mo	Compensation Charge $/kW/mo
LaGrande 230 kV	Roundup 69 kV	55,000	0.770	0.071
LaGrande 230 kV	Alvey 500 kV	145,000	1.118	0.270
McNary 230 kV	Alvey 500 kV	241,000	0.993	0.399
McNary 230 kV	McNary 69 kV	35,000	0.555	0.032
McNary 230 kV	Santiam 69 kV	40,000	1.042	0.069
McNary 230 kV	Albany 115 kV	84,000	1.363	0.191
Total Demand		600,000		1.032

Calculation of Charges

Facility	Annual Charges per kW	Applicable Annual Charges ($/kW) from LaGrande 230 kV to Roundup 69 kV	Alvey 500 kV
Main Grid			
Interconnection Terminal	$0.27	0.00	0.00
Terminal	$0.44	0.44	0.44
Transmission Distance Charge (1.15 x $0.0371/mi x airline miles) (39.8 mi. LaGrande-Roundup) (259.9 mi. LaGrande-Alvey)	$0.0371/mi	1.70	11.09
Miscellaneous Facilities	$1.88	1.88	1.88
Terminal	$0.44	0.44	0.00
Interconnection Terminal	$0.27	0.00	0.00
Secondary System			
Transformation	$4.10	4.10	0.00
Interconnection Terminal	$0.68	0.00	0.00
Intermediate Terminal	$1.29	0.00	0.00
Transmission Distance Charge (1.15 x $0.2784/mi x airline miles)	$0.2784/mi	0.00	0.00
Intermediate Terminal	$1.29	0.00	0.00
Interconnection Terminal	$0.68	0.68	0.00
Use-of-Facilities		0.00	0.00
Total Annual Charge		$9.24/kW/yr	$13.41/kW/yr
Total Monthly Charge		$0.770/kW/mo	$1.118/kW/mo

Calculation of Charges

Facility	Annual Charges per kW	Applicable Annual Charges ($/kW) from McNary 230 kV to Alvey 500 kV	McNary 69 kV
Main Grid			
Interconnection Terminal	$0.27	0.00	0.00
Terminal	$0.44	0.44	0.00
Transmission Distance Charge (1.15 x $0.0371/mi x airline miles) (224.9 mi. McNary-Alvey) (0.0 mi. McNary-McNary)	$0.0371/mi	9.60	0.00
Miscellaneous Facilities	$1.88	1.88	1.88
Terminal	$0.44	0.00	0.00
Interconnection Terminal	$0.27	0.00	0.00
Secondary System			
Transformation	$4.10	0.00	4.10
Interconnection Terminal	$0.68	0.00	0.00
Intermediate Terminal	$1.29	0.00	0.00
Transmission Distance Charge (1.15 x $0.2784/mi x airline miles)	$0.2784/mi	0.00	0.00
Intermediate Terminal	$1.29	0.00	0.00
Interconnection Terminal	$0.68	0.00	0.68
Use-of-Facilities		0.00	0.00
Total Annual Charge		$11.92/kW/yr	$6.66/kW/yr
Total Monthly Charge		$0.993/kW/mo	$0.555/kW/mo

Calculation of Charges

Facility	Annual Charges per kW	Applicable Annual Charges ($/kW) from McNary 230 kV to Santiam 69 kV	Albany 115 kV
Main Grid			
Interconnection Terminal	$0.27	0.00	0.00
Terminal	$0.44	0.44	0.44
Transmission Distance Charge (1.15 x $0.0371/mi x airline miles) (182.0 mi. McNary-Santiam) (206.5 mi. McNary-Albany)	$0.0371/mi	7.77	8.81
Miscellaneous Facilities	$1.88	1.88	1.88
Terminal	$0.44	0.44	0.44
Interconnection Terminal	$0.27	0.00	0.00
Secondary System			
Transformation	$4.10	0.00	4.10
Interconnection Terminal	$0.68	0.00	0.00
Intermediate Terminal	$1.29	1.29	0.00
Transmission Distance Charge (1.15 x $0.2784/mi x airline miles)	$0.2784/mi	0.00	0.00
Intermediate Terminal	$1.29	0.00	0.00
Interconnection Terminal	$0.68	0.68	0.68
Use-of-Facilities		0.00	0.00
Total Annual Charge		$12.50/kW/yr	$16.35/kW/yr
Total Monthly Charge		$1.042/kW/mo	$1.363/kW/mo

Table 1

Calculation of Hourly Losses Associated with Firm Transmission

Assume:

Lp	=	Peak wheeling loss applicable to a specified amount of power wheeled under this Agreement during the time of peak Federal system generation. Lp is a constant for each hour of a billing period.
Dm	=	Weighted average airline transmission distance plus 15%.
Wm	=	Maximum power wheeled over main system under this Agreement.
Wt	=	Maximum power wheeled through step-down transformation to points of delivery under this Agreement.
Lm	=	Average loss per megawatt-mile on the main system. Lm is a constant for each hour of a billing period.
Lt	=	Average 230/115/69-kV transformation loss (percent).
Lw	=	Wheeling loss for the power scheduled for a particular hour under Section 5(a) of this Agreement.
Pf	=	Federal generation for a particular hour.
Pfp	=	Amount of Federal generation upon which the average wheeling loss, Lm, was based. Pfp is constant for each hour of a billing period.
Pw	=	Amount of power scheduled for a particular hour to be wheeled under section 5(a) of this Agreement.

Given:

Points of Interconnection	Points of Delivery	Transmission Demand (kW)	Airline Distance + 15% (miles)
LaGrande 230 kV	Roundup 69 kV	55,000	45.8
LaGrande 230 kV	Alvey 500 kV	145,000	298.9
McNary 230 kV	Alvey 500 kV	241,000	258.8
McNary 230 kV	McNary 69 kV	35,000	0.0
McNary 230 kV	Santiam 69 kV	40,000	209.3
McNary 230 kV	Albany 115 kV	84,000	237.6

Therefore,

Dm = 227.60

Wm = 600,000 kW

Also, as of January 1, 1993

Lm = 0.143 kW/mW-mi

Lt = 0.337 %

Pfp = 16,221,000 kW

<u>Peak Loss Calculation</u>:

$$Lp = (Dm)(Wm)(Lm) + (Wt)(Lt)$$
$$= (227.60)(600,000)(0.000143) + (214,000)(0.00337)$$
$$= 20,249 \text{ kW}$$

<u>Hourly Wheeling Loss Calculation</u>:

$$Lw = [(Lp)(Pf)(Pw)] + [(Pfp)(Wm)]$$

$$\text{Let } K = (Lp) + [(Pfp)(Wm)]$$
$$= 20,249 + [(16,221,000)(600,000)]$$
$$= 2.081 \times 10^{-9} \text{ /kW or } 2.081 \times 10^{-6} \text{ /MW}$$

Therefore

$$Lw = K(Pf)(Pw)$$
$$= (2.081 \times 10^{-6} \text{ /MW})(Pf)(Pw) \text{ megawatts of loss}$$

Hourly losses are determined by inserting the amounts of Pf and Pw for a particular hour.

Table 2

Calculation of Hourly Losses Associated with Backup Transmission

Assume:

Lp = Peak wheeling loss applicable to a specified amount of power wheeled under this Agreement during the time of peak Federal system generation. Lp is a constant for each hour of a billing period.

Dm = Weighted average airline transmission distance plus 15%.

Wm = Maximum power wheeled over main system under this Agreement.

Wt = Maximum power wheeled through step-down transformation to points of delivery under this Agreement.

Lm = Average loss per megawatt-mile on the main system. Lm is a constant for each hour of a billing period.

Lt = Average 230/115/69-kV transformation loss (percent).

Lw = Wheeling loss for the power scheduled for a particular hour under Section 5(b) of this Agreement.

Pf = Federal generation for a particular hour.

Pfp = Amount of Federal generation upon which the average wheeling loss, Lm, was based. Pfp is constant for each hour of a billing period.

Pw = Amount of power scheduled for a particular hour to be wheeled under section 5(b) of this Agreement.

Given:

Points of Interconnection	Points of Delivery	Transmission Demand (kW)	Airline Distance + 15% (miles)
LaGrande-Hatwai-McNary 230 kV	John Day 500 kV	255,000	130.0
	Alvey 230 kV	105,000	296.7
	Alvey 500 kV	340,000	296.7

Therefore,

Dm = 235.97

Wm = 700,000 kW

Also, as of January 1, 1993

Lm = 0.143 kW/mW-mi

Lt = 0.337%

Pfp = 16,221,000 kW

Peak Loss Calculation:

Lp = (Dm)(Wm)(Lm) + (Wt)(Lt)
= (235.97)(700,000)(0.000143) + 0.0
= 23,621 kW

Hourly Wheeling Loss Calculation:

Lw = [(Lp)(Pf)(Pw)] + [(Pfp)(Wm)] + (0.011)(Pw)[1]

Let K = (Lp) + [(Pfp)(Wm)]
= 31,714 + [(16,221,000)(700,000)]
= 2.080×10^{-9} /kW or 2.080×10^{-6} /MW

Therefore

Lw = K(Pf)(Pw)
= [(2.080×10^{-6} /MW)(Pf) + 0.011](Pw) megawatts of loss

Hourly losses are determined by inserting the amounts of Pf and Pw for a particular hour.

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1 This factor equates to the average losses on the AC Intertie weighted by the ratio of the demands designated for delivery over said facilities to the total demands (Wm).

(0.03) x (255,000) + (700,000) = .011

Calculation of Backup Charges

Facility	Annual Charges per kW	Applicable Annual Charges ($/kW) from LaGrande, McNary and Hatwai 230 kV to John Day 500 kV	Alvey 230 kV	Alvey 500 kV
Main Grid				
Interconnection Terminal	$0.27	$0.27	$0.27	$0.27
Transmission Distance Charge (1.15 x $0.0371/mi x airline miles)	$0.0371/mi			
(113 mi. to John Day)		4.82		
(258 mi. to Alvey)			11.01	11.01
Miscellaneous Facilities	$1.88	1.88	1.88	1.88
Terminal	$0.44	0.44	0.44	0.00
Total Unadjusted Annual Charge		$7.41	$13.60	$13.16
Intertie Charge	$8.47	8.47	0.00	0.00
Total Annual Charge		$15.88	$13.60	$13.16
Transmission Charge		$1.3233	$1.1333	$1.0967
Kilowatt Demand Weighting		255,000	105,000	340,000

Weighted Monthly Charge $829,316/mo.

Scheduling Capability of Midpoint-Malin Line (East to West)

Facility Outage	Scheduling Capability of Midpoint-Malin Line (East to West)
None	1,187 MW
Midpoint 500/345 kV Transformation [1]	0 MW
Midpoint-Summer Lake Line [1]	0 MW
Summer Lake-Malin Line [1]	340 MW
Midpoint Series Capacitors in the Midpoint-Summer Lake Line [1]	1,037 MW

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1 Partial outages of the identified facilities may result in less severe scheduling limitations of PacifiCorp's Midpoint-Malin Line.

AUTHENTICATED COPY Contract No. DE-MS79-94BP94521

PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PUGET SOUND POWER & LIGHT COMPANY

Index to Sections

This PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT (Agreement) is entered into as of October 11, 1994, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville or BPA) and PUGET SOUND POWER & LIGHT COMPANY (Puget), a corporation of the state of Washington. Each of Bonneville and Puget is sometimes referred to individually in this Agreement as "Party"; Bonneville and Puget are sometimes referred to together in this Agreement as "Parties."

WITNESSETH:

WHEREAS Bonneville, Portland General Electric Company (Portland), and PacifiCorp Electric Operations (PacifiCorp) planned and constructed improvements and additions to the Northwest portion of the PNW-PSW Intertie; and

WHEREAS such construction was completed in December 1993 resulting in 1600 MW of additional PNW AC Intertie Rated Transfer Capability in a north-to-south direction and 1225 MW of additional PNW AC Intertie Rated Transfer Capability in a south-to-north direction; and

WHEREAS pursuant to the Northwest Intertie Agreements, Bonneville operates the PNW AC Intertie, in coordination with Portland and PacifiCorp, as a single system so as to maximize PNW AC Intertie Rated Transfer Capability and Operational Transfer Capability consistent with Prudent Utility Practice; and

WHEREAS Bonneville has developed a proposal to offer to PNW non-Federal scheduling utilities and joint agencies capacity ownership rights in 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability; and

WHEREAS such proposal has been studied in Bonneville's Final Non-Federal Participation Environmental Impact Statement, dated January 1994, and was the selected alternative in the Administrator's Record of Decision, dated March 25, 1994; and

WHEREAS Bonneville and Puget executed a Memorandum of Understanding, DE-MS79-91BP93466, dated September 18, 1991, which, among other things, sets forth the principles for Puget's capacity ownership rights in Bonneville's PNW AC Intertie; and

WHEREAS interest expressed in capacity ownership by PNW non-Federal scheduling utilities and joint agencies exceeded the 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability offered by Bonneville, and as a result Bonneville developed and applied an allocation methodology selected in the Administrator's Capacity Ownership Record of Decision, dated March 25, 1994; and

WHEREAS concurrent with the execution of this Agreement, Bonneville and Puget are executing Contract No. DE-MS79-94BP93947 to provide Puget with, among other things, network wheeling between the John Day Substation and Puget's transmission system; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power generated at various Federal hydroelectric projects in the PNW, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, Bonneville and Puget agree as follows:

1. **DEFINITIONS**

(a) "Adjusted Capacity Ownership Price" means the price calculated pursuant to column 2, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(b) "Adjusted Lump Sum Payment" means the Adjusted Capacity Ownership Price multiplied by Puget's Capacity Ownership Share (in kilowatts), as described with more particularity in section D of Exhibit D.

(c) "Allocated Direct Costs" means for each fiscal year the Operations Cost as allocated to Bonneville's PNW AC Intertie in accordance with section I.C of Exhibit I for such fiscal year. Allocated Direct Costs are not included in Direct Costs, Indirect Costs, or Overhead Costs.

(d) "Allowance for Funds Used During Construction" or "AFUDC" constitutes interest on the funds used for utility plant under construction. The AFUDC rate approximates the cost of money being used to finance current construction work in progress and is calculated in accordance with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors. AFUDC shall be capitalized in accordance with Bonneville's accounting procedures and practices, and in any event consistent with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors.

(e) "Billing Provisions" means those provisions set forth in Exhibit B, Part B.

(f) "Bonneville's PNW AC Intertie" means facilities of the PNW AC Intertie owned partially or entirely by Bonneville specified in Exhibit F together with the equipment and facilities installed in or connected to such facilities specified in Exhibit F, to the extent such facilities are necessary for the transmission of power on the PNW AC Intertie.

(g) "Bonneville's PNW AC Intertie Operational Transfer Capability" means Bonneville's PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and by operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(h) "Bonneville's PNW AC Intertie Rated Transfer Capability" means Bonneville's share of the PNW AC Intertie Rated Transfer Capability as determined in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(i) "Capacity Owner" means each of the parties listed in Exhibit G to the extent that such party has entered into a Capacity Ownership Agreement.

(j) "Capacity Ownership Agreement" means, in the singular, this Agreement or the agreement, substantially identical to this Agreement, entered into by each Capacity Owner (other than Puget) and Bonneville, and in the plural, this Agreement and all such substantially identical agreements entered into respectively by

Capacity Owners (other than Puget) and Bonneville, as each such agreement may be amended or supplemented from time to time pursuant to the terms of such agreement, concerning (among other things) the rights of such Capacity Owner with respect to the PNW AC Intertie.

(k) "Capacity Ownership Percentage" means, as of the Effective Date, in the singular, the percentage of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Puget pursuant to this Agreement, which percentage is determined by dividing Puget's Capacity Ownership Share as of the Effective Date by Bonneville's PNW AC Intertie Rated Transfer Capability as of the Effective Date (such percentage being subject to change pursuant to the terms of this Agreement), and in the plural, the percentages of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which percentages are set forth in Exhibit G (each of such percentages being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(l) "Capacity Ownership Rights" means the rights of Puget pursuant to this Agreement.

(m) "Capacity Ownership Share" means, except as such term is otherwise used in sections III.A and III.B of the CO-94 rate set forth in Exhibit A on the Effective Date, in the singular, the MW amount of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Puget pursuant to this Agreement, which MW amount is set forth in Exhibit C (such amount being subject to change pursuant to the terms of this Agreement), and in the plural, the MW amounts of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which amounts are set forth in Exhibit G (each of such amounts being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(n) "Committee" has the meaning set forth in subsection 12(a).

(o) "Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

(p) "Direct Costs" means any costs incurred by Bonneville which are readily identifiable, or obviously traceable to, and directly benefit, a specific Bonneville program, project, or other cost objective. Direct Costs are not included in Allocated Direct Costs, Overhead Costs, or Indirect Costs. The methods for determining Direct Costs for Bonneville's PNW AC Intertie are set forth in sections II.B and III.A of Exhibit I.

(q) "Effective Date" means the date as of which this Agreement becomes effective pursuant to section 2.

(r) "End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

(s) "FERC" means the Federal Energy Regulatory Commission or its regulatory successor.

(t) "General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

(u) "GTRSP" or "GTRSPs" means Bonneville's General Transmission Rate Schedule Provisions, set forth in Exhibit A, as such provisions may be revised from time to time.

(v) "Indirect Costs" means any costs incurred by Bonneville which indirectly benefit and are directly charged to a specific Bonneville program, project, or other cost objective for which a Direct Cost or Allocated Direct Cost is charged. Indirect Costs shall not be included in Allocated Direct Costs, Direct Costs, or Overhead Costs. The methods for determining Indirect Costs for Bonneville's PNW AC Intertie are set forth in sections I.D, II.D, and III.B of Exhibit I.

(w) "Initial Capacity Ownership Price" means $215 per kilowatt, the calculation of which charge is set forth in column 1, section B of Exhibit D and in section III.A of the CO-94 rate in Exhibit A.

(x) "Initial Lump Sum Payment" means the Initial Capacity Ownership Price multiplied by Puget's Capacity Ownership Share (in kilowatts), as described with more particularity in section C of Exhibit D.

(y) "Interconnection Agreement" means the "Interim Interconnection Agreement Between Certain California-Oregon Transmission Project Participants and Northwest Participants," Contract No. DE-MS79-91BP93158, as amended or superseded.

(z) "Joint AC Intertie" is as defined in the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(aa) "Joint Intertie Scheduling Office" or "JISO" means the group of Bonneville, Portland, and PacifiCorp schedulers, which, among other things, accepts PNW-PSW Intertie Preschedules.

(bb) "Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

(cc) "MW" means megawatt.

(dd) "Northwest Intertie Agreements" means the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(ee) "Operating Plan" means, subject to subsection 13(o), with respect to any fiscal year commencing on or after the day on which the annual costs rate set forth in Exhibit B has been approved on an interim or final basis by FERC, the written document containing the information described in subsection 13(c), as such document may be amended pursuant to section 13, 14, or 16.

(ff) "Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

(gg) "Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

(hh) "Overhead Cost" means administrative and general costs, support service costs, or other costs similar in nature which are distributed or allocated by Bonneville to Bonneville's PNW AC Intertie. Overhead Costs are not included in Direct Costs, Allocated Direct Costs, or Indirect Costs. The methods for determining Overhead Costs are set forth in sections I.E, II.E, and III.B of Exhibit I.

(ii) "Pacific Northwest" or "PNW" means the area defined as the Pacific Northwest in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. section 839a(14).

(jj) "Pacific Time" means Pacific Standard Time and Pacific Daylight Time as each is in force.

(kk) "PNW AC Intertie" means facilities including, but not limited to, the following: two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's rights in the Meridian-Malin 500 kV transmission line and Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, additions, improvements, or other alterations thereto.

(ll) "PNW AC Intertie Operational Transfer Capability" means the PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(mm) "PNW AC Intertie Rated Transfer Capability" means the north-to-south and south-to-north capability of the PNW AC Intertie to transfer power in a reliable manner as determined consistent with Prudent Utility Practice.

(nn) "Pacific Northwest-Pacific Southwest Intertie" or "PNW-PSW Intertie" means the DC transmission line between the Celilo Converter Station in The Dalles, Oregon, and the Sylmar Converter Station near Los Angeles, California, the PNW AC Intertie, and the AC Intertie in California including, without limitation, the California-Oregon Transmission Project.

(oo) "Pacific Northwest Non-Federal Utility" means any electric utility that serves retail load in the region consisting of (1) the states of Oregon, Washington, and Idaho, the portion of the state of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River Basin drainage basin, and (2) any contiguous areas, not in excess of seventy-five air miles from the area referred to in (1) above, which areas are a part of the service area of a rural electric cooperative power customer served by Bonneville on the effective date of the Pacific Northwest Power Planning and Conservation Act (P.L. 96-501) having a distribution system from which it serves both within and without such region.

(pp) "Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit

I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

(qq) "Preschedule" means the schedule submitted by Puget to the JISO pursuant to paragraph 4(b)(1) for transactions prepared each Working Day for the period beginning 2400 hours of the current Working Day through 2400 hours of the next Working Day.

(rr) "Prudent Utility Practice" means, at any particular time, the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto that would achieve the desired result or, if there are no such practices, methods, and acts, the practices, methods, and acts which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to achieve the desired result consistent with reliability and safety.

(ss) "Real-time Schedule" means a schedule, or change to the Preschedule, submitted during the period which begins when the Preschedule is deemed by the JISO to be complete and concludes at 2400 hours on the day for which the Preschedule is submitted by Puget.

(tt) "Reinforcement" means any transmission plant modification, addition, improvement, or other alteration to the Federal Columbia River Transmission System which is not a Replacement or an Upgrade and which is made pursuant to subsection 7(c).

(uu) "Reinforcement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Puget for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Reinforcement. Reinforcement Costs do not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(vv) "Replacement" means for any transmission plant addition, betterment, renewal and equipment or facility that takes the place of or adds to any existing equipment or facility on Bonneville's PNW AC Intertie that does not increase Bonneville's PNW AC Intertie Rated Transfer Capability.

(ww) "Replacement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Puget for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Replacement. General Plant Cost is not included in Replacement Costs. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(xx) "Revised Adjusted Capacity Ownership Price" means a price calculated pursuant to column 3, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(yy) "Revised Adjusted Lump Sum Payment" means a Revised Adjusted Capacity Ownership Price multiplied by Puget's Capacity Ownership Share (in kilowatts), as described with more particularity in section E of Exhibit D.

(zz) "Scheduler" means the person authorized by a Party to accept or submit schedules pursuant to section 4 and authorized to implement, interpret, and vary the scheduling procedures set forth in such section pursuant to this Agreement.

(aaa) "Scheduling Percentage" means the percentage of the PNW AC Intertie Rated Transfer Capability owned by Puget pursuant to this Agreement, which percentage is determined by dividing Puget's Capacity Ownership Share by the PNW AC Intertie Rated Transfer Capability.

(bbb) "Scheduling Share" means, for any given hour, the MW amount equal to the product of Puget's Scheduling Percentage and the PNW AC Intertie Operational Transfer Capability for such hour.

(ccc) "Scheduling Utility" means either (i) a Pacific Northwest Non-Federal Utility that serves a retail service area and operates a generation control area, or (ii) a Pacific Northwest Non-Federal Utility designated by Bonneville as a "computed requirements customer" or its equivalent.

(ddd) "Term" means the period of effectiveness of this Agreement set forth in subsection 2(a).

(eee) "Third AC Intertie" means the Third AC Intertie Project, which project increased the PNW AC Intertie Rated Transfer Capability by 1600 MW in a north-to-south direction and by 1225 MW in a south-to-north direction.

(fff) "Third AC Intertie Project" means the Third AC Intertie System Reinforcement and the construction of the Alvey-Meridian 500 kV transmission line and of facilities related to such transmission line during the period from July 1984 through December 1993.

(ggg) "Third AC Intertie System Reinforcement" means the improvements, additions and modifications to the PNW AC Intertie constructed during the period from July 1984 through December 1993 plus the construction of the Captain Jack substation and of facilities related to such substation during the period from July 1984 through December 1993.

(hhh) "Upgrade" means any MW increase to Bonneville's PNW AC Intertie Rated Transfer Capability which arises from or is related to an increase to the PNW AC Intertie Rated Transfer Capability.

(iii) "Working Day" means any day other than Saturday, Sunday, and a legal holiday recognized by the Federal government or Puget.

2. TERM AND TERMINATION

(a) This Agreement shall become effective as of the later of (1) the date of execution and delivery of this Agreement by both of the Parties, and (2) the date by which this Agreement has, with respect to Puget, been approved, accepted for filing or otherwise permitted to become effective by FERC; provided, that if FERC approves this Agreement for filing or otherwise permits this Agreement to become effective with any change or new condition, this Agreement shall not be or become effective unless both of the Parties have agreed in writing, and until the date by which both of the Parties have so agreed to such change or new condition. To the extent Puget is required to submit this Agreement to FERC, Puget shall submit this Agreement to FERC for approval no later than three Working Days after the date on which this Agreement is executed and delivered by both Parties. Bonneville shall provide Puget with a copy of the executed Agreement on the next Working Day after Bonneville executes the Agreement. Without limiting any of the foregoing, Puget shall use best efforts to obtain from FERC on the earliest possible date (following the date on which Puget is required to submit this Agreement to FERC pursuant to this subsection 2(a)) FERC's acceptance for filing or permission that this Agreement become effective in accordance with this subsection 2(a). This Agreement shall continue in effect so long as any facilities of the PNW AC Intertie are in existence and operable, unless otherwise earlier terminated by written agreement of both of the Parties or unless terminated pursuant to the terms of this Agreement. All liabilities incurred under this Agreement shall be preserved until satisfied.

(b) Notwithstanding subsection 2(a), no Capacity Ownership Rights may be exercised by Puget until payment is made by Puget pursuant to paragraph 9(a)(1) and received by Bonneville.

(c) If Bonneville does not receive the payment from Puget pursuant to paragraph 9(a)(1), then Bonneville shall have the option to terminate this Agreement by delivering to Puget written notice of such termination.

(d) Notwithstanding subsection 2(a), if Bonneville incurs End of Term Costs, the following provisions of this Agreement, and all rights and obligations thereunder, shall continue in full force and effect until Bonneville renders its final bill to Puget pursuant to subsection 9(b), unless this Agreement is earlier terminated by mutual agreement of the Parties: subsections 2(b), 2(c), and 2(d), sections 1, 7, 8, 9, 12, 13, 14, 15, 16, 18, 19, 20, 21, 22, and 23, and Exhibits A, B, C, D, F, G, H, and I. All liabilities incurred under such provisions of this Agreement shall be preserved until satisfied.

(e) If this Agreement has not become effective pursuant to subsection 2(a) within 12 months following the date upon which Bonneville executes and delivers this Agreement to Puget, this Agreement shall be void ab initio and of no force or effect.

3. CAPACITY RIGHTS

(a) Purchase and Sale of Capacity

Pursuant to the terms and conditions of this Agreement, Puget purchases from Bonneville and Bonneville sells to Puget the Capacity Ownership Rights.

(b) **Right to Wheel for Third Parties**

No later than 30 days after the Effective Date, Puget shall notify Bonneville in writing of Puget's decision to utilize its Scheduling Share pursuant to either paragraph 3(b)(1) or paragraph 3(b)(2), and Puget shall have the right to utilize its Scheduling Share pursuant to the paragraph Puget elects. Prior to Bonneville's receipt of such notification, Puget shall utilize its Scheduling Share pursuant to paragraph 3(b)(1). If Puget fails to make an election within the prescribed time period, Puget shall be deemed to have elected the option set forth in paragraph 3(b)(1).

(1) **No Third Party Wheeling**

(A) Except as expressly provided in subparagraph 3(b)(1)(B), Puget shall not use its Scheduling Share to transmit power or energy (except for inadvertent power flows) that Puget does not own at the California-Oregon border or for which transmission Puget receives any revenue that would be reportable in Puget's accounting system where revenues received for wheeling for other entities would be booked.

(B) If Puget's Scheduling Share is not fully utilized by Puget in any hour, Bonneville may schedule for such hour Bonneville's transactions (including, without limitation, Bonneville wheeling for other entities) and wheel such transactions over the unused portion of Puget's Scheduling Share for such hour but no longer than such hour. Puget shall be compensated for such wheeling solely by the payments as described in sections 3(b)(1)(B)(i) and (ii) below. For purposes of this subparagraph 3(b)(1)(B), Puget's Scheduling Share shall be deemed to be not fully utilized in a given hour to the extent that Puget has not scheduled, or does not schedule, on a Preschedule or Real-time Schedule basis, any transaction for such hour on any MW amount of Puget's Scheduling Share. In return for Puget's Scheduling Share being made available to Bonneville pursuant to this subparagraph 3(b)(1)(B), Bonneville shall pay Puget

(i) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a north-to-south direction under the IS-93 rate, section II.A, or its successor to other entities in such hour, and (2) the ratio of Puget's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour, and

(ii) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a south-to-north direction under the IS-93 rate, section II.A or its successor to other entities in such hour, and (2) the ratio of Puget's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour; provided, however, that Bonneville shall not be required to make payments for such south-to-north wheeling pursuant to this section 3(b)(1)(B)(ii) earlier than two years after the Effective Date.

Bonneville shall make payments pursuant to this subparagraph 3(b)(1)(B) in accordance with paragraph 9(f)(1).

(C) During an outage resulting from maintenance activities on the PNW AC Intertie performed by Bonneville other than maintenance activities undertaken due to emergencies or uncontrollable forces, the following shall apply:

(i) When Puget's Scheduling Share for any given hour is reduced as a consequence of such outage which reduces in Bonneville's PNW AC Intertie Operational Transfer Capability such that Puget's Scheduling Share for such hour is less than the MW amount of the aggregate of Puget's net firm transactions identified by Puget to Bonneville pursuant to section 3(b)(1)(C)(iv) for such hour, Bonneville shall, subject only to sections 3(b)(1)(C)(ii) and (iii) and to the immediately succeeding sentence, wheel on a firm basis that portion of Puget's firm transactions that equals the difference between Puget's Scheduling Share for such hour and the MW amount of the aggregate of Puget's firm transactions for such hour up to, but not in excess of, Puget's Capacity Ownership Share. Notwithstanding the foregoing, Bonneville shall only be obligated to provide such wheeling to the extent that each party with whom Puget is conducting such firm transactions has received a sufficient AC Intertie capacity allocation in California to accommodate such transactions. Puget shall pay the IS-93 rate, section II.A, or its successor for such wheeling pursuant to this section 3(b)(1)(C)(i) in accordance with subsection 9(d).

(ii) Bonneville shall not be obligated to provide such wheeling to Puget pursuant to section

3(b)(1)(C)(i) if no PNW AC Intertie Operational Transfer Capability is available to Bonneville after Bonneville has scheduled all of Bonneville's Firm Schedules. For purposes of this section, "Bonneville's Firm Schedules" shall mean schedules for assured delivery or other firm transmission contracts pursuant to the Long-Term Intertie Access Policy, as revised or amended, or its successor, and schedules for Bonneville's firm power and energy sales and exchange transactions.

(iii) Bonneville shall not be obligated to provide such wheeling to Puget pursuant to section 3(b)(1)(C)(i) until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to Puget or until October 1, 1994, whichever occurs sooner.

(iv) No later than ten Working Days prior to the first day of deliveries under a firm transaction, Puget shall identify such firm transaction to Bonneville. Puget shall identify such firm transaction to Bonneville by providing to Bonneville a copy of Puget's contract for such firm transaction (after information considered proprietary by Puget has been redacted by Puget). Bonneville shall review such contract to verify that the transaction is firm. If Puget and its contractor represent or state in writing that the transaction set forth in their contract is firm, Bonneville shall accept that written representation or statement as dispositive of the question of whether such transaction is firm. Implementation of such procedures in this section 3(b)(1)(C)(iv) may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written.

(D) Puget retains any and all rights of access which it would otherwise have to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(2) **Third Party Wheeling**

(A) Puget may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by Puget. Puget shall have no obligation under this Agreement to make available to Bonneville any portion of Puget's Scheduling Share which is unused in any hour, and Bonneville shall not schedule over Puget's Scheduling Share without Puget's prior consent.

(B) Puget hereby waives any and all rights of access to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor; provided, however, that Bonneville may, at its option, provide Puget with access to Bonneville's PNW-PSW Intertie pursuant to any provision of the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(C) Puget shall provide Bonneville with the information set forth in sections 3(b)(2)(C)(i) through 3(b)(2)(C)(iii) when Puget uses its Scheduling Share to export from the Pacific Northwest energy or power received from third parties. Such exports of energy or power on a real-time basis or for durations of less than four months are excluded from this obligation. For exports of four months or longer duration made on behalf of third parties pursuant to paragraph 3(b)(2), such information shall include:

(i) the name and business address of the third party;

(ii) the amount of power or energy and the duration of the transaction; and

(iii) the name of the recipient or purchaser of such power.

Any additional information needed by Bonneville will be obtained from such third party.

4. **SCHEDULING**

(a) Puget (and only Puget) shall be entitled to schedule on the PNW AC Intertie, in any hour, a MW amount up to Puget's Scheduling Share for such hour. The MW amount of Puget's Scheduling Share deemed to be scheduled on the PNW AC Intertie pursuant to this Agreement, in any hour, shall be determined as the net of Puget's north-to-south schedules and south-to-north schedules (net schedules) for such hour.

(b) Puget shall submit all schedules of its Scheduling Share on its own behalf in accordance with the procedures set forth in paragraphs 4(b)(1) and 4(b)(2). Such procedures may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written. All hours referenced in paragraphs 4(b)(1) and 4(b)(2) are Pacific Time.

(1) **Preschedules**

(A) Bonneville shall make available to Puget on each Working Day as soon as practicable after 0800 hours information regarding the PNW AC Intertie Operational Transfer Capability with respect to Preschedules. In the event an emergency or uncontrollable force causes a change in the PNW AC Intertie Operational Transfer Capability, Bonneville shall notify Puget of such change as soon as practicable.

(B) If Long-Term Intertie Access Policy Condition 1 Formula Allocation Procedures or their successor (Condition 1) are expected by Bonneville to become effective, Bonneville shall so notify Puget no later than 0930 hours on the Working Day prior to the day on which Condition 1 is expected to become effective. Bonneville shall notify Puget no later than 0930 hours on the Working Day prior to the day on which Condition 1 ceases to be in effect.

(C) Puget shall submit its Preschedule to the Joint Intertie Scheduling Office no later than 1000 hours on each Working Day if Condition 1 is in effect. If Condition 1 is not in effect, Puget shall submit its Preschedule to the JISO no later than 1430 hours on each Working Day.

(2) **Real-time Scheduling**

(A) Real-time Schedules shall be arranged through Bonneville's real-time scheduling office. Bonneville's real-time Scheduler shall make reasonable efforts to receive Real-time Schedules; provided, however, that Bonneville's real-time Scheduler may, but is not required to, accept Real-time Schedules between 1500 and 2200 hours on the Working Day preceding the day for which such Real-time Schedule is submitted.

(B) Real-time Schedules shall be arranged for a full hour. Arrangements shall be completed no later than 30 minutes prior to that hour.

(C) Puget shall use best efforts to keep schedule changes to a minimum; provided, however, that for purposes of this subparagraph 4(b)(2)(C), "best efforts" shall not be deemed to refer to efforts made regardless of their economic effect.

(D) The requirements set forth in subparagraphs 4(b)(2)(B) and 4(b)(2)(C) do not preclude schedule changes at other times as may be deemed necessary by any control area operators or other entities involved in effectuating such schedule changes. Such control area operators and other entities shall be notified by Bonneville of such schedule changes as soon as practicable in accordance with Prudent Utility Practice for purposes of coordinating ramps and proper accounting. Such schedule changes shall be deemed to occur at mid-ramp. The mid-ramp time and the integrated value for the hour shall be subject to the mutual agreement by such control area operators and other entities.

(E) Subject to compliance with subparagraphs 4(b)(2)(A) through 4(b)(2)(D) and with other applicable PNW AC Intertie scheduling practices then in effect, Bonneville shall make Puget's schedule change.

(c) Bonneville shall make deliveries of power or energy to the California-Oregon border or the John Day Substation, as appropriate, pursuant to schedules submitted in accordance with this section 4; provided, however, that Bonneville shall not be required to make such deliveries in an hour to the extent that Puget's schedule exceeds Puget's Scheduling Share for such hour, except as may be expressly provided pursuant to subparagraph 3(b)(1)(C).

5. **UPGRADES**

(a) Bonneville shall consult with the Committee one time each year regarding any plans for Upgrades.

(b) Prior to the completion of an Upgrade, Bonneville shall provide to Puget information in writing regarding estimated costs and the MW amount of such Upgrade, to the extent that such information is available to Bonneville.

(c) As soon as practicable following the completion of an Upgrade, Bonneville shall notify Puget in writing of the following: (1) the MW amount of such Upgrade; (2) the capital and related costs (less any amount of such costs collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, to Bonneville for completing or implementing such Upgrade; and (3) calculations of (A) Puget's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade and (B) Puget's Capacity Ownership Percentage multiplied by the capital and related costs, if any, to Bonneville for completing or implementing such Upgrade. Puget may elect to acquire a share of such Upgrade in an amount up to Puget's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade. Within 100 days from receipt of such written notice from Bonneville, Puget shall notify Bonneville in writing of Puget's decision regarding such acquisition. If Puget elects to acquire, pursuant to this subsection 5(c), a portion of such Upgrade, Puget's notice to Bonneville shall include the percentage of such Upgrade that Puget elects to acquire (Acquisition Percentage). If

Puget fails to notify Bonneville within such 100-day period, Puget shall be deemed to have elected not to acquire any of such Upgrade.

(d) If Puget elects to acquire a portion of an Upgrade pursuant to subsection 5(c), the cost to Puget shall be Puget's Acquisition Percentage multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such cost collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, incurred by Bonneville for completing or implementing such Upgrade. Puget shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(e) If Puget's Acquisition Percentage with respect to an Upgrade equals its Capacity Ownership Percentage and the Acquisition Percentage of any other Capacity Owner with respect to such Upgrade is less than its Capacity Ownership Percentage, then the following shall apply:

(1) Bonneville shall, in a timely manner, provide written notice simultaneously to Puget and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage) of the MW amount equal to 100 percent of that portion of an Upgrade offered to, but not acquired by, the Capacity Owners pursuant to subsection 5(c) (Unacquired Share). If Puget and each of such other Capacity Owners have agreed in writing to an apportionment as among themselves of the Unacquired Share (Apportionment), Puget may, within 45 days following receipt of such written notice from Bonneville, by written notice request Bonneville to offer in writing to Puget such portion of the Unacquired Share as has been apportioned to Puget pursuant to the Apportionment, and Bonneville shall offer to Puget such portion of the Unacquired Share.

(2) If Bonneville does not receive from Puget and from each Capacity Owner referred to in paragraph 5(e)(1) the requests for offer pursuant to paragraph 5(e)(1) within the 45-day period

specified in such paragraph, Bonneville shall, in a timely manner, offer in writing simultaneously to Puget and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage), respectively, a portion of an Upgrade offered to, but not acquired by, the other Capacity Owners pursuant to paragraph 5(e)(1) (Second Unacquired Share) up to the "Additional Share Offered" determined as follows:

Additional Share Offered = (A + B) x C

where: A = Puget's Capacity Ownership Percentage.

B = Percentage equal to the sum of Capacity Ownership Percentages of Capacity Owners that acquired respectively an Acquisition Percentage equal to their Capacity Ownership Percentage.

C = Second Unacquired Share.

(3) Within 30 days following Puget's receipt of Bonneville's written offer pursuant to paragraph 5(e)(2), Puget shall notify Bonneville in writing of Puget's decision regarding acquisition of the Additional Share Offered. If Puget fails to notify Bonneville within such 30-day period, Puget shall be deemed to have elected not to acquire any of the Additional Share Offered. If Puget elects pursuant to this paragraph 5(e)(3) to acquire any or all of the Additional Share Offered, then:

(A) Puget shall include in its notice to Bonneville pursuant to this paragraph 5(e)(3) such share (Additional Share Acquired) of the Additional Share Offered as Puget elects to acquire pursuant to this paragraph 5(e)(3), and

(B) the cost to Puget with respect to such acquisition shall be equal to the proportion of the Additional Share Acquired to such Upgrade multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such costs collected by Bonneville through charges other than payments by Puget pursuant to subsection 5(d) or subparagraph 5(e)(3)(B)), if any, to Bonneville for completing or implementing such Upgrade. Puget shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(f) All capacity offered but not acquired pursuant to subsections 5(c) and (e) shall for purposes of this Agreement remain with Bonneville.

(g) After Puget has either accepted or declined all offers of capacity by Bonneville pursuant to subsections 5(c) and (e), Puget's Capacity Ownership Share, Capacity Ownership Percentage, and Scheduling Percentage in Exhibit C shall be revised to reflect changes resulting from Puget's elections pursuant to subsections 5(c) and (e). Revision of Exhibit C shall be pursuant to subsection 19(d). Exhibit G shall be revised accordingly pursuant to subsection 19(i).

6. SALE OR ASSIGNMENT

(a) This Agreement or any interest herein shall not be transferred, sold, alienated, or assigned by Puget to any person without Bonneville's prior and express written consent. Such consent shall not be unreasonably withheld. In determining whether to grant its consent under this subsection 6(a), Bonneville shall take into consideration information including, but not limited to, whether the person or entity to whom this Agreement or any interest therein is proposed to be transferred, sold, alienated, or assigned is a person or entity entitled to request and receive transmission services pursuant to section 211 of the Federal Power Act, whether such person or entity can either provide its own scheduling services or has contracted with another entity to provide such scheduling services, whether such person or entity has the financial capability to meet the payment obligations under this Agreement, and whether the person or entity is either electrically interconnected to Bonneville's transmission system or has contractual arrangements for wheeling with others who are electrically interconnected to Bonneville's transmission system. This Agreement shall inure to the benefit of and be binding upon the Parties, their respective legal representatives, permitted assigns, and successors in interest. Any transfer, sale, alienation, or assignment made by Puget in violation of this section 6 shall be void ab initio and without any force or effect whatsoever.

(b) Bonneville hereby consents to the transfer, sale, alienation, or assignment by Puget to any other Capacity Owner of all or part of its Capacity Ownership Share and all of Puget's rights and obligations pursuant to this Agreement with respect thereto. Bonneville hereby further consents to the transfer, sale, alienation, or assignment by Puget of the entire Agreement and of all of Puget's rights and obligations under this Agreement to a Scheduling Utility.

(c) Bonneville hereby consents to the assignment by Puget of this Agreement or of any of Puget's rights under this Agreement as security for any indebtedness, whether present or future, of Puget pursuant to any mortgage, trust, security agreement or similar instrument of indebtedness (each such instrument, a Debt Instrument) made by and between Puget and any mortgagee, trustee, secured party or holder of such instrument of indebtedness, respectively; provided, however, that if Puget has defaulted in the performance of its obligations under any Debt Instrument, such that the mortgagee, trustee, secured party or holder of such Debt Instrument, as the case may be, would be entitled at that time to accelerate the amount of indebtedness under such Debt Instrument, Puget shall give Bonneville prompt written notice in reasonable detail of such default and shall, at Bonneville's election, enter into good faith discussions with Bonneville regarding the cure of such default.

(d) If Puget transfers, sells, alienates, or assigns, with Bonneville's consent, all or any portion of this Agreement and any rights and obligations pursuant to this Agreement to any person or party, Puget shall give Bonneville written notice of such transfer, sale, alienation, or assignment within 10 days after the execution and delivery of the agreement effectuating such transaction by all parties to such transaction.

7. OPERATION, MAINTENANCE, AND MANAGEMENT

(a) Pursuant to the terms and conditions of the Northwest Intertie Agreements, Bonneville is the operator of the PNW AC Intertie. As such, Bonneville is responsible for the dispatch of the PNW AC Intertie in accordance with Prudent Utility Practice. Bonneville's duties as operator of the PNW AC Intertie shall include, but are not limited to, consistent with Prudent Utility Practice and Northwest Intertie Agreements: (1) determining the PNW AC Intertie Operational Transfer Capability; (2) implementing and assisting in rectifying emergency outages on the PNW AC Intertie due to system emergencies or uncontrollable forces; (3) implementing maintenance outages; and (4) giving and receiving switching orders on the PNW AC Intertie. In making any determination or in taking any other action referred to in the immediately preceding sentence, Bonneville shall give fair consideration to Puget's interests to the extent such interests have been expressed to Bonneville in writing. Bonneville shall operate, maintain, and manage Bonneville's PNW AC Intertie, and study, plan, and implement Upgrades, consistent with Prudent Utility Practice.

(b) Bonneville shall determine and revise as necessary the PNW AC Intertie Rated Transfer Capability consistent with Prudent Utility Practice and engineering studies based on then existing reliability criteria developed by the North American Electric Reliability Council, the Western Systems Coordinating Council, the Northwest Power Pool, and Bonneville. In the event the PNW AC Intertie Rated Transfer Capability is changed, Bonneville shall promptly notify Puget in writing of such change and the new PNW AC Intertie Rated Transfer Capability. If and to the extent that the reliability criteria for determining the PNW AC Intertie Rated Transfer Capability change substantially, Bonneville shall notify Puget in writing of such change.

(c) If at any time during the Term, Bonneville's PNW AC Intertie Rated Transfer Capability becomes less than 3450 MW, or if at any time during the Term there is an imminent likelihood that Bonneville's PNW AC Intertie Rated Transfer Capability would become less than 3450 MW, then Bonneville shall reinforce the Federal Columbia River Transmission System so as to raise Bonneville's PNW AC Intertie Rated Transfer Capability to 3450 MW or otherwise to prevent Bonneville's PNW AC Intertie Rated Transfer Capability from becoming less than 3450 MW. Puget's Capacity Ownership Share shall not be decreased on account of any failure by Bonneville to reinforce the Federal Columbia River Transmission System pursuant to this subsection 7(c).

(d) In the event that Bonneville implements a Reinforcement pursuant to subsection 7(c), Bonneville shall equitably allocate the Reinforcement Cost for such Reinforcement between Bonneville and Puget based on factors including, but not limited to, load responsibility, contractual obligation and generation integration responsibility. Any equitable allocation or agreed to allocation (pursuant to the immediately succeeding sentence) of a Reinforcement Cost pursuant to this subsection 7(d) shall be reflected as a Reinforcement Cost in an Operating Plan proposed by Bonneville pursuant to section 13. To the extent that Bonneville and Puget have agreed in writing to an allocation of a Reinforcement Cost incurred by Bonneville pursuant to an agreement or modification referred to in subsection 8(b), the Reinforcement Cost so allocated shall not be subject to arbitration pursuant to section 14 or section 15. Any Reinforcement Cost not allocated to Puget pursuant to this subsection 7(d) shall not be payable by Puget pursuant to this Agreement.

(e) Bonneville shall provide Puget notice of maintenance outages in accordance with the accepted standards for notice on the PNW AC Intertie. Such notice shall include an evaluation of the impact on

Puget's Scheduling Share. In scheduling or planning maintenance on PNW AC Intertie, Bonneville shall give fair consideration to Puget's interests to the extent such interests have been expressed to Bonneville in writing.

8. **EXISTING AGREEMENTS**

(a) Bonneville shall use good faith efforts to maintain in effect the Interconnection Agreement or its successor.

(b) Bonneville shall use its best efforts to maintain Puget's rights under this Agreement (i) by making no modification to the Northwest Intertie Agreements, (ii) by not entering into any other agreement with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie, and (iii) by making no modification to the agreements referred to in the immediately preceding clause (ii) that would have a substantial negative impact on Puget's rights pursuant to sections 3, 4, 7, or to subsection 9(b), 9(c), or 11(a) without Puget's prior written consent. Without limiting, modifying, or otherwise affecting any of its rights pursuant to sections 9, 13, 14, 15, and 16, Puget hereby consents to Bonneville's modification of the Northwest Intertie Agreements or Bonneville's entering into other agreements or modification to such Agreements with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie to the extent that such modification or such agreement is made or entered into by Bonneville for the purpose of performing Bonneville's obligations pursuant to subsection 7(c).

9. **PAYMENT PROVISIONS**

As full compensation for their respective payment obligations under this Agreement, Puget shall make payments to Bonneville in accordance with the provisions of this section 9, and Bonneville shall make payments and refunds to Puget in accordance with the provisions of this section 9.

(a) **Lump Sum Payment**

(1) As soon as practicable after the Effective Date, Bonneville shall render a bill to Puget for the Initial Lump Sum Payment (less the negotiation deposit, if any, with applicable interest as described in section C of Exhibit D) and such bill shall include as an attachment and as part of such bill a completed section C of Exhibit D, setting forth the calculation of such Initial Lump Sum Payment due Bonneville in accordance with section IV.A of the CO-94 rate set forth in Exhibit A. Puget shall make such payment pursuant to the CO-94 rate and the applicable GTRSPs set forth in Exhibit A. Each of Bonneville and Puget agrees that section C of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(2) **Calculation and Billing of the Adjusted Capacity Ownership Price**

(A) Approximately December 1995, or as soon as practicable thereafter, Bonneville shall, in accordance with section IV.B of the CO-94 rate set forth in Exhibit A, calculate the Adjusted Capacity Ownership Price to reflect actual construction costs of the facilities listed in section A of Exhibit D and the actual AFUDC with respect to such facilities. Such calculation shall be made in accordance with column 2, section B of Exhibit D.

(B) Promptly after Bonneville has calculated the Adjusted Capacity Ownership Price pursuant to subparagraph 9(a)(2)(A), Bonneville shall render a bill or refund voucher to Puget, and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2), section B of Exhibit D (with a completed column 2), and a completed section D of Exhibit D reflecting the Adjusted Lump Sum Payment. If the

Adjusted Lump Sum Payment is greater than the Initial Lump Sum Payment, Puget shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in such bill, which amount shall be equal to the amount set forth on line 7, section D of Exhibit D (such amount including interest as set forth on line 6, section D of Exhibit D). If the Adjusted Lump Sum Payment is less than the Initial Lump Sum Payment, Bonneville shall pay to Puget, within 30 days after the date of such refund voucher, the amount set forth in such refund voucher, which amount shall be equal to the amount set forth on line 7, section D, of Exhibit D (such amount including interest as set forth on line 6, section D, of Exhibit D). Each of Bonneville and Puget agrees that sections A, B, and D of Exhibit D are consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(3) **Calculation and Billing of the Revised Adjusted Capacity Ownership Price**

(A) After payment is made by Puget pursuant to subparagraph 9(a)(2)(B), or a refund is made by Bonneville to Puget pursuant to subparagraph 9(a)(2)(B), Bonneville may, in accordance with the CO-94 rate set forth in Exhibit A, make one or more adjustments to the Adjusted Capacity Ownership Price; provided, that any such adjustment shall be made by Bonneville within 30 days after the date on which (i) Bonneville receives, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp or any other entity performing work for Bonneville on the Third AC Intertie Project, payment from Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, or (ii) Bonneville pays, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, any amount to Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project; and provided, further, that no adjustment of the Adjusted Capacity Ownership Price or of any Revised Adjusted Capacity Ownership Price shall be made by Bonneville after December 31, 2005.

(B) Promptly after Bonneville has calculated a Revised Adjusted Capacity Ownership Price, Bonneville shall render to Puget a bill or refund voucher with respect to such Revised Adjusted Capacity Ownership Price and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), section B of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), and a completed section E of Exhibit D reflecting the current Revised Adjusted Capacity Ownership Price and the current Revised Adjusted Lump Sum Payment. If the current Revised Adjusted Lump Sum Payment with respect to such Revised Adjusted Capacity Ownership Price is greater than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, then Puget shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in the bill referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E, of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E, of Exhibit D). If the current Revised Adjusted Lump Sum Payment is less than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, Bonneville shall pay to Puget, within 30 days after the date of such refund voucher, the amount set forth in the refund voucher referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E of Exhibit D). Each of Bonneville and Puget agrees that section E of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(4) For purposes of implementing the CO-94 rate, the following shall apply:

(A) the calculations pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the adjustment "to reflect the difference between the actual and the estimated Capacity Ownership Price" required under section IV.B of the CO-94 rate;

(B) the calculations of interest pursuant to footnote 2 of section D of Exhibit D and footnote 2 of section E of Exhibit D shall be deemed to be the computation of "interest using the weighted average interest rate on Bonneville's outstanding bonds" required pursuant to section IV.B of the CO-94 rate;

(C) the calculations of the Adjusted Capacity Ownership Price and of the Revised Adjusted Capacity Ownership Price pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the determination of the "actual Capacity Ownership Price" required pursuant to section IV.B of the CO-94 rate;

(D) as used in the CO-94 rate, the terms "Bonneville's PNW AC Intertie," "PNW AC Intertie," "Third AC Intertie," "Third AC Intertie Project," and "Third AC Intertie System Reinforcement" shall be deemed to have the respective meanings of such terms set forth in section 1;

(E) as used in the CO-94 rate, the term "Capacity Ownership Share" shall be deemed to mean "Capacity Ownership Percentage" as defined in section 1;

(F) the indirect costs and overhead costs described in footnote 5 of section B of Exhibit D shall be deemed to be the indirect costs and overhead costs referred to in section III.A of the CO-94 rate; and

(G) the last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(5) For purposes of application of the CO-94 rate set forth in Exhibit A, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(A) section I;

(B) section III.A;

(C) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(D) subsection 4 of section IV.A;

(E) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A; and

(F) for purposes of subsection 16(e) of this Agreement and as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(b) **Annual Charges**

(1) **Payments Pursuant to AC-93 Rate**

(A) From and after the first Working Day after Bonneville receives payment from Puget pursuant to paragraph 9(a)(1), Bonneville shall bill Puget on the monthly power bill in accordance with the AC-93 rate set forth in Exhibit A. Puget shall pay such bill in accordance with the applicable GTRSPs set forth in Exhibit A.

(B) For purposes of application of the AC-93 rate, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(i) section I;

(ii) section III.A;

(iii) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(iv) the first sentence of subsection 3 of section IV.A;

(v) subsection 4 of section IV.A;

(vi) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A;

(vii) the first paragraph of subsection 6 of section IV.A; and

(viii) as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(C) The last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(D) Bonneville hereby agrees that the provisions of the AC-93 rate shall have no application or effect with respect to the following:

(i) any replacement of the series capacitor banks containing polychlorinated biphenyl at the Sand Springs, Sycan and Fort Rock Substations; and

(ii) any replacement commenced prior to the Effective Date or not completed prior to September 30, 1995.

(E) Upon and after the effective date of the annual costs rate set forth in Exhibit B, Bonneville shall cease billing Puget pursuant to the AC-93 rate.

(2) **Payments Pursuant to Annual Costs Rate**

From and after the date the annual costs rate set forth in Exhibit B becomes effective, the following shall apply:

(A) **Operations Costs, Maintenance Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs**

(i) During each fiscal year during the Term, Bonneville shall bill Puget on the monthly power bill, and Puget shall pay, pursuant to Exhibit B, forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for such fiscal year. Such costs shall be, respectively, the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the fiscal year in which such month occurs.

(ii) Within eight months after the end of each fiscal year during the Term (such fiscal year being hereinafter referred to as a "Fiscal Year"), Bonneville shall determine and calculate, pursuant to Exhibit I, Schedules A, B, D, E, F, G, and H, actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year most recently ended.

(iii) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year is greater than the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year, Bonneville shall refund to Puget the difference between such forecast costs and such actual costs as a lump sum payment, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Bonneville shall, promptly following the date on which the calculation of such difference is made, provide Puget written notice of such refund. Within the 30-day period referred to in the first sentence of this section 9(b)(2)(A)(iii), Bonneville shall provide to Puget an Operating Plan amended in accordance with subsection 13(k) containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(iv) If, based on the calculation performed pursuant to subparagraph 9(b)(2)(A)(ii), the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is equal to or less than 105 percent, but greater than 100 percent, of the sum of the forecast Operations costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and

Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs in the Operating Plan for the Fiscal Year, Bonneville shall bill to Puget on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Puget shall pay such bill in accordance with the Billing Provisions. Within the 30-day period referred to in the immediately preceding sentence, Bonneville shall provide to Puget an amended Operating Plan containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(v) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the actual Operations Cost, actual Maintenance Cost, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is greater than 105 percent of the sum of the forecast Operations Cost, forecast Maintenance Cost, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast

End of Term Costs for the Fiscal Year, Bonneville shall bill to Puget on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Puget shall pay such bill in accordance with the Billing Provisions; provided, however, that Bonneville shall not bill Puget pursuant to this section 9(b)(2)(A)(v) any amount which exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year unless and until such amount which exceeds 100 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year has been included in an Operating Plan amended pursuant to subsection 13(k).

(vi) Simple interest shall be accrued on payments or refunds due pursuant to this paragraph 9(b)(2) with respect to any fiscal year during the Term using the weighted average interest rate on Bonneville's outstanding bonds or other debt instruments then used by Bonneville and such interest shall accrue from (and including) the date of the last day of such fiscal year to (but excluding) the date of refund to Puget or to (but excluding) the due date of a payment due Bonneville.

(B) **Replacement Cost and Reinforcement Cost**

Bonneville shall bill Puget on the monthly power bill Replacement Costs for any Replacement and Reinforcement Costs for any Reinforcement. Bonneville shall render such bill within 15 months following the date on which the project work order for such Replacement or such Reinforcement, as the case may be, is closed. Puget shall pay such bill pursuant to Exhibit B and sections 9(b)(2)(B)(i), 9(b)(2)(B)(ii), 9(b)(2)(B)(iii) and 9(b)(2)(B)(iv).

(i) If the forecast Replacement Cost for a Replacement is greater than the actual Replacement Cost for such Replacement or if the forecast Reinforcement Cost for a Reinforcement is greater than the actual Reinforcement Cost for such Reinforcement, Bonneville shall bill Puget the actual Replacement Cost for such Replacement or the actual Reinforcement Cost for such Reinforcement, as the case may be. Bonneville shall provide to Puget an Operating Plan amended in accordance with subsection 13(k) containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement, as the case may be.

(ii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual

Reinforcement Cost is equal to or less than 105 percent, but greater than 100 percent, of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill Puget such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Puget shall pay such bill pursuant to subparagraph 9(b)(2)(B). Bonneville shall provide to Puget an amended Operating Plan containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the difference between the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement.

(iii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is greater than 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill Puget such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Puget shall pay such bill pursuant to subparagraph 9(b)(2)(B); provided, however, that Bonneville shall not bill Puget pursuant to this subparagraph 9(b)(2)(B) any amount which exceeds 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, as the case may be, unless and until such amount which exceeds 100 percent of such forecast Replacement or such forecast Reinforcement Cost, as the case may be, has been included in an amended Operating Plan pursuant to subsection 13(k).

(iv) Charges pursuant to sections 9(b)(2)(B)(i), (ii) and (iii) for Replacement Costs and Reinforcement Costs shall accrue simple interest pursuant to section III.D of Exhibit I.

(c) **Upgrade Charges**

For purposes of implementing the CO-94 rate, the following shall apply:

(1) as used in the CO-94 rate, the term "upgrade" shall be deemed to mean "Upgrade" as defined in section 1, the term "rated transfer capability" shall be deemed to mean "PNW AC Intertie Rated Transfer Capability" as defined in section 1 and the term "AFUDC" shall be deemed to have the meaning set forth for such term in section 1;

(2) the "Capacity Ownership Share of the capital and related cost of the upgrade," referred to in section III.B of the CO-94 rate shall be deemed to be the costs pursuant to subsection 5(d) and subparagraph 5(e)(3)(B), as applicable; and

(3) "construction costs (including direct, indirect and overhead costs) and AFUDC" referred to in section III.B of the CO-94 rate and "related costs" referred to in section III.B of the CO-94 rate together shall be deemed to be Upgrade costs and shall be determined in the same manner in which Replacement Costs are determined pursuant to section III of Exhibit I; provided, however, that expenses that are properly allocable to an Upgrade (i.e., "related costs" referred to in section III.B of the CO-94 rate) in accordance with generally accepted accounting principles (as defined in Exhibit I) may be included by Bonneville in Upgrade costs for such Upgrade.

(d) **Payments of Charges Pursuant to Section 3(b)(1)(C)(i)**

Bonneville shall bill Puget for wheeling provided pursuant to section 3(b)(1)(C)(i) on Puget's monthly power bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A and Puget shall pay such bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A; provided, however, that under any successor to the IS-93 rate, Puget shall not be obligated to pay any rate or charge greater than the rate or charge payable by any other party to which Bonneville provides nonfirm wheeling services on Bonneville's PNW AC Intertie for such party's nonfirm transaction of a duration similar to Puget's wheeling transaction pursuant to section 3(b)(1)(C)(i).

(e) **Suspension for Failure to Perform**

(1) If at any time during the term of this Agreement Bonneville does not receive payment due and owing to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d), Bonneville shall be entitled to suspend performance of its obligations to Puget pursuant to section 4 without incurring any liability to Puget therefor; provided, that Bonneville shall not be entitled to suspend performance pursuant to this paragraph 9(e)(1) earlier than five Working Days following receipt from Bonneville by Puget of written notice of such suspension. Such suspension shall continue in effect until the next Working Day following the Working Day on which Puget makes payment in full to Bonneville of the balance owed to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d). During the period of such suspension, Puget shall not be entitled to participate through the Committee in any review of an Operating Plan commenced by the Committee pursuant to section 13 during such period of suspension, or to participate in any arbitration commenced by the Committee pursuant to sections 14 and 15 during such period of suspension, or to participate in any audit commenced

by the Committee pursuant to section 16 during such period of suspension.

(2) If during any period in any month Bonneville fails to make deliveries in accordance with subsection 4(c), Puget shall be entitled, without incurring any liability to Bonneville therefor, to delay any payment due and owing to Bonneville by Puget pursuant to subsection 9(b) or 9(d) for a period, equal to the period during which Bonneville failed to make such deliveries, commencing on the date the monthly power bill for such month would otherwise be payable by Puget pursuant to this Agreement; provided, however that Puget's entitlement pursuant to this paragraph 9(e)(2) shall apply only with respect to the amount of such monthly power bill to be paid directly to Bonneville or its agent.

(f) **Payments or Refunds by Bonneville**

(1) Bonneville shall make any payment to Puget pursuant to subparagraph 3(b)(1)(B) within 30 days following the end of the month in which such payment becomes due to Puget pursuant to subparagraph 3(b)(1)(B).

(2) Bonneville shall pay to Puget, in a lump sum, any refund due to Puget pursuant to subsection 16(e) or paragraph 16(f)(2) within 30 days following the date on which such refund becomes due to Puget pursuant to subsection 16(e) or paragraph 16(f)(2), respectively.

(3) Bonneville shall pay any refund, credit, or payment due to Puget under section 18 pursuant to the terms and conditions set forth in section 18.

(4) Each payment, credit or refund due to Puget by Bonneville pursuant to this Agreement shall be made by Bonneville, at Bonneville's option, (A) by check payable to the order of Puget,

(B) by electronic funds transfer of immediately available funds into such account as may be designated in writing by Puget from time to time for such purpose or (C) by crediting the amount of such payment, credit or refund on Puget's power bill.

10. TRANSMISSION LOSSES

(a) To compensate Bonneville for transmission losses incurred by Bonneville in making deliveries scheduled by Puget pursuant to this Agreement, Puget shall make available, or arrange to have made available, to Bonneville, at any point mutually acceptable to the Parties at which the respective electric systems of Puget and Bonneville are interconnected, on the corresponding hour 168 hours later or on another hour to be agreed upon, the amounts of electric power equal to Puget's net PNW AC Intertie schedule multiplied by the appropriate loss factor specified in Exhibit E. Puget's net PNW AC Intertie schedule shall be, for any given hour, the absolute value of the sum of Puget's north-to-south schedules (positive) and south-to-north schedules (negative) for such hour.

(b) Upon the conclusion of any review by Bonneville of the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan provided to the Committee pursuant to section 13. The Committee may make recommendations regarding such results and any revisions to the loss factor in Exhibit E, Part A. Only recommendations regarding assumptions (including, without limitation, data inputs and source of date) made by Bonneville in its review or revision of the loss factor in Exhibit E, Part A, and recommendations regarding the results of such review or revision shall be subject to arbitration pursuant to section 14.

(c) Puget's Scheduling Share shall not be reduced by any amount of losses returned to Bonneville pursuant to subsection 10(a).

11. **REMEDIAL ACTIONS**

(a) **Bonneville's Responsibilities**

(1) Within five days after the Effective Date, Bonneville shall notify Puget in writing of the plan for remedial actions required to maintain the PNW AC Intertie Rated Transfer Capability, which plan shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice. If and to the extent that such plan is amended, modified, or replaced, Bonneville shall, promptly following such amendment, modification, or replacement, provide written notice to Puget of such amendment, modification, or replacement, as the case may be. Bonneville shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, required to maintain the portion of Bonneville's PNW AC Intertie Rated Transfer Capability not purchased by Capacity Owners. Such remedial actions shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice.

(2) Bonneville shall be responsible for generating appropriate control signals for transmission to Puget for purposes of effectuating remedial actions pursuant to this section.

(b) **Puget's Responsibilities**

(1) Puget shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other remedial actions required to maintain Puget's Capacity Ownership Share. Such remedial actions shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1) and Prudent Utility Practice. Bonneville

may perform engineering analyses to confirm Puget's providing capability to arm and having available appropriate remedial actions pursuant to this paragraph 11(b)(1).

(2) In any given hour, Puget shall be responsible for providing sufficient remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, to maintain Puget's schedule on the PNW AC Intertie for such hour. To the extent that load tripping or generator dropping is required as a remedial action by Puget pursuant to this paragraph 11(b)(2) in any given hour, the required amount of such load tripping or such generator dropping shall be determined by dividing the amount of power scheduled by Puget on Puget's Scheduling Share in such hour by the total amount of power scheduled on the PNW AC Intertie in such hour and multiplying the result by the total amount of generation or load (in MW) to be armed for the PNW AC Intertie in such hour.

(3) Puget shall provide, design, operate, and maintain the necessary equipment to accept control signals from Bonneville and to transmit such signals to Puget's generator dropping, load tripping, or other remedial action sites, and to arm and initiate the appropriate control action(s). Such design, operation, and maintenance shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1), and Prudent Utility Practice.

(4) Puget and Bonneville may mutually agree that Bonneville will, pursuant to terms and conditions mutually acceptable to the Parties, provide the remedial actions required of Puget pursuant to subsection 11(b).

12. CAPACITY OWNERS' COMMITTEE

(a) Composition of Committee

Puget may appoint one representative (and an alternate who may act in the absence of such representative) as a member of the Capacity Owners' Committee (Committee). If during any period Puget fails to appoint a representative to the Committee, Puget waives any and all rights during such period that would otherwise have accrued to it, individually or as a member of the Committee, pursuant to sections 12, 13, 14, 15, and 16 of this Agreement. Puget hereby appoints as its representative pursuant to this subsection the following representative and alternate to the Committee:

Representative: Vice President Power Planning

Alternate: Manager Power Contracts

(b) Convening Meetings

(1) Any Capacity Owner that has appointed a representative to the Committee may convene a meeting of the Committee pursuant to the procedures set forth in subsection 12(e). The Capacity Owner convening a Committee meeting shall be responsible for preparing any necessary notices, identifying the subject matter and issues to be discussed, and transmitting notices and relevant documents to the other Committee members and, if appropriate, to Bonneville.

(2) At the written request of any Capacity Owner that has appointed a representative to the Committee, Bonneville shall attend Committee meetings.

(3) The Committee may conduct business only at a properly convened meeting at which a quorum, as defined in subsection 12(c), is present. The Committee shall make or convey any

request, designation, recommendation, notice, appointment, submission, audit report or exception, or statement to which Bonneville is required to respond or which creates or triggers an obligation of Bonneville, pursuant to this Agreement, only upon a decision of the Committee made at a properly convened meeting at which a quorum is present.

(4) Each fiscal year, Bonneville shall convene an annual meeting of the Committee. The purpose of such annual meeting shall be to discuss the Operating Plan delivered, pursuant to subsection 13(b), to each Capacity Owner that has appointed a representative to the Committee. Bonneville shall convene such annual meeting no earlier than 15 days, but no later than 30 days, following the date of such delivery of the Operating Plan.

(5) In addition to the meeting referred to in paragraph 12(b)(4), Bonneville may, at its discretion, convene meetings of the Committee, pursuant to the procedures set forth in subsection 12(e), to present to the Committee any information Bonneville deems relevant.

(c) **Meeting Quorum**

The respective representatives of all of the Capacity Owners that have appointed a representative to the Committee, less one, shall constitute a quorum.

(d) **Meetings by Telephone Conference**

Committee meetings pursuant to the Capacity Ownership Agreements may be conducted by telephone provided all Capacity Owners and, if appropriate, Bonneville, are notified pursuant to the procedures set forth in subsection 12(e) of any such meeting.

(e) **Meeting Notices**

(1) All Committee meeting notices pursuant to the Capacity Ownership Agreements shall be provided in writing no less than 14 days prior to such meeting.

(2) Any Committee meeting notice required by this section shall be deemed properly made if delivered in person, by electronic facsimile, or by mail or other qualified delivery service, postage prepaid, to the person specified below:

If to Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232
Telephone (503) 230-5152
Facsimile (503) 230-5207

If to Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515
Telephone (206) 462-3137
Facsimile (206) 462-3175

If to Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101
Telephone (206) 386-4530
Facsimile (206) 386-4955

If to PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232
Telephone (503) 288-1234
Facsimile (503) 288-2334

If to Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201
Telephone (206) 258-8211
Facsimile (206) 258-8305

If to Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411
Telephone (206) 502-8294
Facsimile (206) 502-8628

Attendance at a meeting by a representative of a Capacity Owner constitutes waiver by such Capacity Owner of notice of such meeting.

(3) Either Party may, by written notice to the other Party and to the Capacity Owners other than Puget, change the designation, address, or facsimile number of the person so specified by it in subsection 12(a) or paragraph 12(e)(2).

13. OPERATING PLAN AND AMENDMENTS TO THE OPERATING PLAN

(a) The provisions of this section shall become effective commencing August 1, 1995; provided, however, that unless and until the annual costs rate set forth in Exhibit B is approved by FERC on an interim basis, Bonneville shall not have any right pursuant to this Agreement to bill or charge to Puget, and Puget shall not have any obligation pursuant to this Agreement to pay to Bonneville, any amount pursuant to any Operating Plan.

(b) **Delivery of Operating Plan**

(1) On or before August 1, 1995, Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1996 and an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1997.

(2) Not later than one year preceding the first day of each fiscal year, other than the fiscal years specified in paragraph 13(b)(1), Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for such fiscal year.

(c) Each Operating Plan delivered pursuant to subsection 13(b) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast costs for the fiscal year to which such Operating Plan pertains, and such Operating Plan may contain such other information as Bonneville may deem relevant; and each amendment of an Operating Plan delivered pursuant to subsection 13(k) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast or actual costs, as appropriate, for the fiscal year to which such Operating Plan pertains, and such amendment may contain such other information as Bonneville may deem relevant:

(1) a forecast of, or the actual, Allocated Direct Cost of Operations Cost (pursuant to section I.C of Exhibit I), Indirect Cost of Operations Cost (pursuant to section I.D of Exhibit I), and Overhead Cost of Operations Cost (pursuant to section I.E of Exhibit I) in the format set forth in Exhibit I, Schedule A;

(2) a forecast of, or the actual, Direct Cost of Maintenance Cost (pursuant to section II.B of Exhibit I), Indirect Cost of Maintenance Cost (pursuant to section II.D of Exhibit I), and Overhead Cost of Maintenance Cost (pursuant to section II.E of Exhibit I) in the format set forth in Exhibit I, Schedule B;

(3) a forecast of, or the actual, Direct Cost of Replacements and Reinforcements (pursuant to section III.A of Exhibit I), Indirect Cost and Overhead Cost of Replacements and Reinforcements (pursuant to section III.B of Exhibit I), and AFUDC of Replacements and Reinforcements (pursuant to section III.C of Exhibit I) in the format set forth in Exhibit I, Schedule C, for each Reinforcement and Replacement which is expected to be, in the fiscal year to which the Operating Plan pertains, a planned new start, construction work in progress on a previously initiated Reinforcement or Replacement, as the case may be, or a closed work order. The forecast shall include for each such Reinforcement or Replacement an estimate of the total cost of construction and the cost to be incurred with respect to such Reinforcement or Replacement during each fiscal year until the work order for such Reinforcement or Replacement has been closed. Bonneville may elect, but shall not be required, to include in any such forecast the information set forth in the immediately preceding sentence regarding any Replacement and Reinforcement which is expected to be planned a new start in any fiscal year following the fiscal year to which the Operating Plan pertains. In the event Bonneville elects to forecast Direct Cost, Indirect Cost, and Overhead Cost of any Reinforcement or Replacement which is expected to be a

planned new start in any fiscal year subsequent to the fiscal year to which the Operating Plan pertains, Bonneville shall provide to the Committee such forecast costs, in the format set forth in Exhibit I, Schedule C (together with additional information pertinent to such forecast costs as required by paragraph 13(c)(9)), 30 days prior to the date such Operating Plan is delivered to the Committee pursuant to subsection 13(b). In addition, Bonneville shall include such forecast costs in the Operating Plan delivered to the Committee pursuant to subsection 13(b);

(4) the General Plant Cost (pursuant to section IV of Exhibit I) in the format set forth in Exhibit I, Schedule D;

(5) a forecast of, or the actual, Other Costs (pursuant to section V of Exhibit I) in the format set forth in Exhibit I, Schedule E;

(6) a forecast of, or the actual, Contracts and Rates Costs (pursuant to section VI of Exhibit I) in the format set forth in Exhibit I, Schedule F;

(7) a forecast of, or the actual, Power Scheduling Costs (pursuant to section VII of Exhibit I) in the format set forth in Exhibit I, Schedule G;

(8) a forecast of, or the actual, End of Term Costs (pursuant to section VIII of Exhibit I) in the format set forth in Exhibit I, Schedule H. Such forecast shall include Bonneville's proposed apportionment of such End of Term Costs among Puget and Capacity Owners other than Puget and Bonneville's rationale for such apportionment;

(9) additional information pertinent to the forecast costs, actual costs, and General Plant Cost provided pursuant to paragraphs 13(c)(1) through 13(c)(8), including, without limitation, descriptions of the activities or projects and explanations of the

costs comprising the Direct Cost components of such forecast costs, actual costs, and General Plant Cost, and explanations of MFU counts; and

(10) if Bonneville has reviewed the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), the Operating Plan shall contain the results of such review, including any revision to the loss factor in Exhibit E, Part A, pursuant to subsection 10(b), and any additional information pertinent to such review.

(d) **Requests by Committee**

(1) No later than 15 days after the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), the Committee may make a single request of Bonneville in writing for:

(A) such supporting documentation, data, and information as may be reasonably necessary to analyze (i) the Operating Plan, or its constituent parts, delivered to the Committee pursuant to subsection 13(b), or (ii) any amendment to an Operating Plan pursuant to subsection 13(k); and

(B) such documentation, data, and information relating to Bonneville's present or past activities or practices concerning Bonneville's PNW AC Intertie and to alternatives considered by Bonneville to costs or activities described in the Operating Plan or any amendment to an Operating Plan as may be reasonably necessary for the Committee to formulate recommendations pursuant to subsection 13(e);

provided, however, that with regard to requests for documentation, data, and information pursuant to this paragraph 13(d)(1), the Committee must designate in such request the specific item in the Operating Plan or in any amendment to an Operating Plan to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information. Such single request may contain multiple parts.

(2) The Committee shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to paragraph 13(d)(1).

(3) Bonneville shall have 20 days from the date it receives any request pursuant to paragraph 13(d)(1) to provide the documentation, data, and information requested; provided, however, that Bonneville shall be under no obligation (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Committee, or (D) to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or any regulation and Executive Order applicable to Bonneville.

(4) The Committee in such request shall designate one of its members to be its representative for the sole purpose of receiving such documentation, data, or information from Bonneville pursuant to this subsection 13(d). Bonneville shall deliver such documentation, data, or information to the representative designated by the Committee to receive such materials.

(5) For purposes of this subsection 13(d) and subsection 13(f), each of Bonneville and the Committee shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests for, documentation, data, and information and responses to such requests.

(e) The Committee shall have 20 days from the date on which it receives documentation, data, or information from Bonneville pursuant to subsection 13(d) or, if none was requested, 50 days from the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), whichever date is later, to recommend to Bonneville in writing a revision or revisions to any forecast cost or General Plant Cost in the Operating Plan. The Committee shall have the time periods set forth in subsection 13(m) to recommend to Bonneville in writing a revision or revisions to a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan. Such recommendation shall set forth, at a minimum, the exact revisions to the forecast cost or General Plant Cost proposed by the Committee and the reasons for such revisions. Failure of the Committee to recommend a revision or revisions to all or any portion of a forecast cost or General Plant Cost in the Operating Plan or a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan within the applicable time limit set forth above shall be deemed to constitute acceptance by the Committee of all portions of the forecast costs and General Plant Cost of the Operating Plan for which the Committee has not recommended a revision.

(f) No later than 15 days after receipt of a Committee recommendation made pursuant to subsection 13(e), Bonneville may make a single request (which may contain multiple parts) in writing of the Committee for such supporting documentation, data, and information as may be reasonably necessary to analyze the Committee's recommendation, including without limitation, any estimated costs or forecast costs contained in such recommendation; provided, however, that the Capacity Owners that have appointed a representative to the Committee shall be under no obligation (1) to create additional documentation, data, or information, (2) to provide documentation, data, or information that is not readily available to the Committee or to any Capacity Owner that has appointed a member to the Committee, (3) to provide to Bonneville documentation, data, or information that the Committee has previously provided to Bonneville; provided, further, that with regard to requests for documentation, data, and information pursuant to this subsection 13(f), (1) Bonneville must designate in such request the specific item in the Committee's recommendation to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information, and (2) Bonneville shall use reasonable efforts, consistent with Bonneville's needs as set forth in this subsection 13(f), to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to this subsection. Such single request shall be made of the Committee by delivering a copy of the request to each Capacity Owner that has appointed a representative to the Committee. The Committee shall have 20 days from the date of its receipt of Bonneville's request to provide a single response containing the documentation, data, and information requested.

(g) If the Committee makes any recommendation in writing pursuant to subsection 13(e), Bonneville shall have the greater of 15 days from the date of receipt of the requested documentation, data, and information requested pursuant to subsection 13(f) or, if none was requested, 30 days from the date of receipt of the Committee's recommendations made pursuant to subsection 13(e) to, by written notice to each Capacity Owner that has appointed a representative to the Committee, accept the recommendation, accept the recommendation in part, reject the recommendation, or propose an action that is responsive to the Committee's recommendation and that is different from Bonneville's proposal contained in the Operating Plan. If Bonneville makes such a proposal, Bonneville shall set forth in such written notice the exact revisions to the Operating Plan. The Committee shall have 7 days from the date of receipt of Bonneville's proposal to make any requests in writing for supporting documentation, data, and information as set forth in subsection 13(d). Bonneville shall have 7 days to respond to those requests as set forth in subsection 13(d). Failure of Bonneville to respond in writing to any recommendation of the Committee within the applicable time period set forth in this subsection 13(g) shall be deemed to constitute rejection of such recommendation.

(h) If Bonneville rejects all or any portion of the Committee's recommendation, or if the Committee elects not to accept a proposal made by Bonneville pursuant to subsection 13(g), then the Committee may

(1) elect by written notice to Bonneville to refer to binding arbitration, pursuant to section 14 and consistent with subsections 13(i) and 14(b), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g); and

(2) elect by written notice to Bonneville to refer to nonbinding arbitration pursuant to section 15 and consistent with subsections 15(a) and 15(d), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g).

Failure of the Committee to elect to refer to arbitration

(A) such portion of any recommendation of the Committee not accepted by Bonneville within 15 days following Bonneville's rejection or acceptance in part of such recommendation of the Committee pursuant to subsection 13(g), or

(B) any proposal made by Bonneville pursuant to subsection 13(g) within 15 days following Bonneville's written notice of such proposal or, if documentation, data, or information was requested by the Committee pursuant to subsection 13(g), within 15 days following receipt by the Committee of such documentation, data, or information pursuant to subsection 13(g),

shall be deemed to constitute acceptance by the Committee of Bonneville's rejection or acceptance in part of the recommendation of the Committee or of Bonneville's proposal and waiver by the Committee of any right pursuant to this section 13 or to section 15 to arbitrate such recommendation or portion thereof.

(i) The Committee may, subject to the immediately succeeding sentence, arbitrate, pursuant to subsection 13(h); any recommendation by the Committee concerning a revision pursuant to this Agreement to a loss factor set forth in any Operating Plan or in any amendment to an Operating Plan or concerning any forecast cost or actual (allocated or otherwise) cost set forth in any Operating Plan or in any amendment to an Operating Plan (including the following costs and related items set forth in any Operating Plan, or in any amendment to an Operating Plan, pursuant to Exhibit I, Schedule A, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12 and 13; Exhibit I, Schedule B, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14 and 15; Exhibit I, Schedule C, lines 1, 2, 3, 4 and 5; Exhibit I, Schedule D, lines 3, 4, 5, 6, 7, 8, 9, 10 and 11; Exhibit I, Schedule E, lines 2 and 3; Exhibit I, Schedule F, lines 1, 2, 3, 4, 5, 6, 7, 8, and 9; Exhibit I, Schedule G, lines 1, 2, 3, 4, 5, 6 7, 8, and 9; and Exhibit I, Schedule H, lines 1, 2, 3, and 4). The Committee's right pursuant to this subsection 13(i) to arbitrate any such recommendation shall be subject to the following limitations:

(1) if such recommendation, or portion thereof, includes a Replacement Cost for a Replacement or a Reinforcement Cost for a Reinforcement, and such Replacement Cost or Reinforcement Cost was included in a previous Operating Plan

(either of such costs, a Previous Operating Plan Cost), the Committee may arbitrate pursuant to this subsection 13(i) such recommendation, or portion thereof, only to the extent that such recommendation, or portion thereof, includes any Replacement Cost or Reinforcement Cost in excess of the Previous Operating Plan Cost;

(2) the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, pertaining to a revision to a loss factor pursuant to this Agreement only to the extent such arbitration is permitted by subsection 10(b);

(3) the Committee may arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning an Other Cost only to the extent that such Other Cost is a cost set forth in an Operating Plan or amendment to an Operating Plan pursuant to Exhibit I, Schedule E, line 2 and such recommendation, or portion thereof pertains to whether such Other Cost is properly allocated to Bonneville's PNW AC Intertie pursuant to Exhibit I, section V;

(4) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in such Operating Plan or in any amendment to an Operating Plan, the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan only to the extent that such actual cost exceeds 105 percent of the forecast cost for such activity or such project; provided, however, that, without limiting any of Puget's rights

and benefits pursuant to subsection 16(c), the Committee may not arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan or in any amendment to an Operating Plan if such actual cost is less than 105 percent of the forecast for such activity or such project;

(5) the Committee may not arbitrate, pursuant to this subsection 13(i), (a) the allocation by Bonneville pursuant to this Agreement of any of its costs to overall overhead costs or to overall indirect costs, or (b) the allocation by Bonneville pursuant to this Agreement of a portion of Bonneville's overall overhead costs and overall indirect costs to its total system operations costs, its total system maintenance costs, its total capital costs or its total indirect and overhead power scheduling costs; provided, however, that nothing in this paragraph (5) shall be deemed to prevent or restrict the Committee from arbitrating pursuant to this subsection 13(i) the level (rather than the allocation) of any of Bonneville's Exhibit I, Schedule A, line 9 total system operations indirect costs and line 11 total system operations overhead costs; Bonneville's Exhibit I, Schedule B, line 11 total system maintenance indirect costs and line 13 total system maintenance overhead costs; Bonneville's total capital costs; Bonneville's Exhibit I, Schedule F, line 6 total indirect contracts and rates costs and Bonneville's Exhibit I, Schedule F, line 7 total overhead contracts and rates costs; or Bonneville's Exhibit I, Schedule G, line 6 total indirect power scheduling costs and Bonneville's Exhibit I, Schedule G, line 7 total overhead power scheduling costs;

(6) the Committee may not arbitrate any recommendation, or any portion thereof, regarding any amendment to an Operating Plan made pursuant to sections 9(b)(2)(A)(iv) and 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2);

(7) the Committee may not arbitrate any such recommendation, or portion thereof, to the extent that in doing so the arbitrators would be required to decide a matter of law in order to render a decision pursuant to subsection 14(h). If, subsequent to the Effective Date, Bonneville is given legal authority to submit to binding arbitration matters of law, Bonneville shall enter into good faith negotiations with Puget and Capacity Owners other than Puget regarding a revision to this paragraph 13(i)(7) enabling arbitration of matters of law pursuant to this subsection 13(i) consistent with such legal authority; and

(8) the Committee may not arbitrate any recommendation, or portion thereof, regarding an allocation of a Reinforcement Cost to the extent prohibited by subsection 7(d).

In arbitrating any recommendation, or portion thereof, pursuant to this subsection 13(i), the Committee may raise in support of such recommendation arguments regarding whether any forecast or actual cost should be based upon activities different in degree, but not in kind, from the activities upon which such forecast or actual cost in the Operating Plan is based.

(j) Each Operating Plan provided pursuant to subsection 13(b) which has completed the Committee review process set forth in subsections 13(d) through 13(g) shall take effect on the first day of the fiscal year to which such Operating Plan pertains and shall remain in effect for the duration of such fiscal year.

(k) At any time during the fiscal year in which an Operating Plan is in effect, or within 8 months after the end of such fiscal year, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast or actual Operations Cost, Maintenance Cost, General Plant Cost, Other Cost, Contracts and Rates Cost, Power Scheduling Cost, or End of Term Cost in such Operating Plan. At any time during the fiscal year an Operating Plan is in effect, or within 30 months after a work order for a Replacement or Reinforcement is closed, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast cost or actual cost component for such Replacement or Reinforcement.

(l) Any amendment made to any Operating Plan pursuant to subsection 13(k) shall be provided by delivery of a copy in writing of such amendment by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(m) Consideration of amendments to the Operating Plan pursuant to subsection 13(l) shall be consistent with the procedures set forth above in subsections 13(c) through 13(k), except that the time limits set forth in such subsections shall be reduced as follows: 15 days shall be 7 days, 20 days shall be 10 days, 30 days shall be 15 days, and 50 days shall be 25 days. For purposes of computing the time limits in this subsection 13(m), the date Bonneville provides the Capacity Owners with a proposed amendment, pursuant to subsection 13(k), shall be deemed to be the date the annual meeting was convened for purposes of paragraph 13(d)(1) and subsection 13(e).

(n) Without limiting any of Puget's rights and benefits pursuant to subsection 13(i) and sections 14 and 15, any Operating Plan amended pursuant to section 9(b)(2)(A)(v) or 9(b)(2)(B)(iii), or subsection 13(k) shall take effect when such amendment is accepted by the Committee pursuant to subsection 13(e) or 13(h). Any Operating Plan amended pursuant to section 9(b)(2)(A)(iii), 9(b)(2)(A)(iv), 9(b)(2)(B)(i), or 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2) shall take effect as soon as such amendment is delivered by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(o) An Operating Plan shall, during the fiscal year in which such Operating Plan is in effect, establish the costs which Puget is obligated to pay pursuant to the terms and conditions of this

Agreement. In no event shall such Operating Plan, or any portion thereof, contain or constitute an obligation of Bonneville to undertake, or to expend funds on, activities described or indicated in such Operating Plan.

14. **ARBITRATION**

(a) During any arbitration process conducted pursuant to this section 14, Puget shall act through the Committee. Each of Bonneville and Puget agrees to be bound by any decision rendered by the arbitrators in any arbitration brought pursuant to subsection 13(i) and this section 14.

(b) The Committee may initiate arbitration pursuant to subsection 13(i) by taking the following actions:

(1) an affirmative vote to initiate arbitration by at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(2) either of the following:

(a) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to subsection 13(i) within the applicable time period established in subsection 13(h); or

(b) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subsection 14(b) shall set forth in detail the matter or matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(c) Bonneville shall, within 10 Working Days after receipt of the notice by the Committee referred to in subsection 14(b), appoint a second arbitrator and provide by written notice to each Capacity Owner that has appointed a representative to the Committee the name, street address and telephone number of the arbitrator appointed by Bonneville. The two arbitrators appointed by the Committee and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville.

(1) If the arbitrators appointed by the Committee and by Bonneville, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville, then within 30 days after the date of the appointment of an arbitrator by Bonneville, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(2) If Bonneville fails to appoint an arbitrator within 15 days after receipt of the notice by the Committee referred to in subsection 14(b), then within 30 days after the date of such notice, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(3) If, pursuant to either paragraph 14(c)(1) or 14(c)(2), the Committee applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Committee shall give Bonneville written notice of such application within 5 days after the date of filing such application.

(d) The three arbitrators appointed pursuant to subsections 14(b) and 14(c) shall select by a majority vote an alternative pursuant to subsection 14(g).

(e) Within 10 days after the appointment of a third arbitrator pursuant to subsection 14(c), the arbitrators shall establish a schedule for submission of written positions by Bonneville and Puget, respectively. The arbitrators must establish a schedule for such submissions pursuant to this subsection 14(e) that will allow the arbitration to be concluded, and the decision of the arbitrators rendered pursuant to subsection 14(g), within 120 days following the date of the appointment of the third arbitrator. A copy of any submission by the Committee to the arbitrators pursuant to this section 14 shall be simultaneously served by the Committee on Bonneville, and a copy of any submission by Bonneville to the arbitrators pursuant to this section 14 shall be simultaneously served by Bonneville on each Capacity Owner that has appointed a representative to the Committee. The Committee shall state, in a letter to the arbitrators, as its proposed alternative to each Bonneville proposal in dispute, the recommendation proposed by the Committee pursuant to subsection 13(g) and rejected in whole or in part by Bonneville pursuant to subsection 13(g). Bonneville shall state its position and proposed resolution of the dispute in a letter to the arbitrators. If Bonneville made a proposal in response to such recommendation of the Committee pursuant to subsection 13(g), then such position and proposed resolution shall set forth such proposal, or if Bonneville made no such proposal, then such position and proposed resolution shall set forth the relevant portion of the Operating Plan. If, however, the arbitration concerns an exception pursuant to paragraph 16(f)(3), then the positions and proposed resolutions of Bonneville and the Committee shall be as established pursuant to such subsection. The Committee may then submit a response to Bonneville's letter, and Bonneville may thereafter submit a reply to the Committee's response. Bonneville and the Committee shall have an equal number of days to prepare and serve their replies.

(f) No submission by either the Committee or Bonneville to the arbitrators pursuant to subsection 14(e) shall be more than 50 pages in length (not including exhibits). If requested in writing by either the

Committee or Bonneville, and for good cause shown, the arbitrators may permit any submission by such Party to exceed 50 pages.

(g) The arbitrators shall select, as between the Committee's recommendation pursuant to subsection 13(e), on the one hand, and the portion of Bonneville's proposed Operating Plan to which the Committee's recommendation pertains or Bonneville's proposal pursuant to subsection 13(g) not accepted by the Committee, on the other, the alternative which

(1) is consistent with the provisions of this Agreement and

(2) (A) in conformity with the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto, would better achieve the desired result consistent with safety, reliability, and cost-benefit or (B) if there are no such generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area, would, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, be reasonably expected to better achieve the desired result consistent with safety, reliability, and cost-benefit.

(h) In applying the standards set forth in subsection 14(g), the arbitrators shall take into consideration, among other things (a) that Bonneville and Puget each have responsibilities for service to customers within and without the Pacific Northwest region in accordance with applicable law, (b) that Bonneville and others jointly own the PNW AC Intertie and Bonneville owes contractual obligations to those parties regarding the PNW AC Intertie, (c) that Bonneville must operate, as a practical matter, the PNW AC Intertie in coordination with the operation of the interconnected intertie facilities in California, and (d) that the PNW AC Intertie is a major import-export facility important to the service of loads in and out of the region.

(i) In any arbitration pursuant to this section 14, the arbitrators shall choose, pursuant to subsection 14(g), only between the alternatives proposed by Bonneville and the Committee and shall have no authority to resolve such arbitration other than by selecting an alternative proposed by either Bonneville or the Committee.

(j) Upon selection by the arbitrators of an alternative pursuant to subsection 14(g), then Bonneville shall amend the Operating Plan to cause it to conform to the decision of the arbitrators.

(k) If the arbitrators have not made a selection of an alternative pursuant to subsection 14(i) before the date on which the Operating Plan becomes effective pursuant to subsection 13(j), then Puget shall make payments of annual charges pursuant to such Operating Plan. If the arbitrators subsequently select the Committee's alternative, then Bonneville shall, subsequent to amending such Operating Plan pursuant to subsection 14(j), refund to or bill Puget its pro rata share of the amount of the incremental difference between the costs set forth in such Operating Plan as amended pursuant to subsection 14(j) and 105 percent of the costs set forth in such Operating Plan, prior to its amendment pursuant to subsection 14(j), to the extent that such costs were incurred during the period from the first day of effectiveness of such Operating Plan pursuant to subsection 13(j) to the date of the arbitrators' decision, such refund to be made pursuant to subsection 9(f) and such payment to be made pursuant to subsection 9(b).

(l) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 14 equal to 1 ÷ (n + 1), where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay its own expenses related to the arbitration proceeding including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(m) Any judgment rendered by a court of competent jurisdiction upon an award made by the arbitrators pursuant to this section 14 may be entered in any court having jurisdiction thereof.

15. **NONBINDING ARBITRATION**

(a) The Initiating Party (as defined in paragraph 15(e)(1)) may, subject to the immediately succeeding sentence, elect by written notice to Responding Party (as defined in paragraph 15(e)(1)) to refer to nonbinding arbitration pursuant to the other provisions of this section 15 the following: (i) if the Initiating Party is the Committee, any recommendation by the Committee, or any portion thereof, concerning any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 and (ii) any other issue, dispute, or controversy regarding the Parties' respective rights and obligations pursuant to this Agreement. The Initiating Party's right pursuant to this subsection 15(a) to arbitrate any recommendation or any issue, dispute or controversy shall be subject to the following limitations:

(1) the Initiating Party may not arbitrate pursuant to this subsection 15(a): (A) any recommendation with respect to an Operating Plan or any amendment to an Operating Plan or (B) any issue, dispute, or controversy, which recommendation, issue, dispute or controversy may be arbitrated pursuant to subsection 13(i) or 16(f);

(2) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation not permitted to be arbitrated pursuant to paragraphs 13(i)(1), 13(i)(3), 13(i)(4), and 13(i)(8);

(3) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or

controversy concerning a loss factor or revision to a loss factor set forth in Exhibit E, Part A or Part B pursuant to this Agreement;

(4) the Committee may not (but the Puget or Bonneville may) arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning any right or obligation of Puget pursuant to this Agreement that is not a right or obligation, as the case may be, of each other Capacity Owner under its respective Capacity Ownership Agreement; or

(5) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operating Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs and forecast End of Term Costs set forth in such Operating Plan, the Committee may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 only to the extent that such actual cost exceeds 105 percent of the forecast for such activity or such project; provided, however, that, without limiting any of Puget's rights and benefits pursuant to section 16(f), no Initiating Party may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B,

lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 if such actual cost is less than 105 percent of the forecast for such activity or such project; and

(6) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any issue, dispute, or controversy (A) concerning matters of ratemaking (for purposes of this subsection 15(a), the term "ratemaking" shall mean the determination of matters appropriately determined pursuant to section 7(i) of the Regional Act, including (i) Bonneville's revenue requirements (including without limitation Bonneville's depreciation and repayment standards and planned net revenues for risk, but excluding program level issues determined in the Federal budget process), (ii) Bonneville's cost of service analysis (including functionalization, segmentation, and allocation of costs contained in such analysis, but excluding any allocation of costs contemplated in Exhibit I), (iii) Bonneville's rate design, and (iv) any related environmental analysis of proposed rates; (B) concerning a final action of Bonneville, which final action is not itself performance of any obligation of Bonneville or Bonneville's Administrator under this Agreement; or (C) concerning, or requiring the decision of, a matter not arising under this Agreement or the other Capacity Ownership Agreements.

(b) Except as otherwise provided in paragraph 15(a)(4), all arbitrations pursuant to this section 15 shall be between Bonneville and the Committee.

(c) A copy of any submission (including, without limitation, any statement of position or any brief) by the Initiating Party or the Responding Party to the arbitrators pursuant to this section 15 shall be simultaneously served by such party on the Responding Party or Initiating Party, respectively. No submission by either the Initiating

Party or the Responding Party to the arbitrators shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Initiating Party or the Responding Party, and for good cause shown, the arbitrators may permit any submission by such party to exceed 50 pages.

(d) With respect to any arbitration pursuant to this section 15 of any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) Only the Committee may initiate arbitration with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7. The Committee may initiate nonbinding arbitration pursuant to this section 15 by taking the following actions:

(A) an affirmative vote to initiate arbitration pursuant to this section 15 by the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(B) either of the following:

(i) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to this section 15 within the applicable time period set forth in subsection 13(h); or

(ii) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subparagraph 15(d)(1)(B) shall (x) indicate that such vote has been taken and (y) set forth in detail the matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(2) The respective rights and obligations of the Committee and of Bonneville with respect to arbitration pursuant to this subsection 15(d), unless otherwise provided in this subsection 15(d), shall be as set forth in subsections 14(d) through 14(l).

(e) With respect to any arbitration pursuant to this section 15 of any issue, dispute, or controversy other than with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) The party (which term, for purposes of this subsection 15(e), shall refer to Bonneville, on the one hand, and to the Committee or Puget, on the other) initiating arbitration (Initiating Party) shall initiate arbitration pursuant to this section 15 by serving written notice on the other party (Responding Party) of its initiation of arbitration. If the Committee is the party initiating arbitration, the Committee, in addition to serving such notice, shall initiate such arbitration by an affirmative vote to do so of at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one.

The Committee shall indicate that such vote has been taken in such notice to Bonneville. Any such notice by an Initiating Party shall set forth in detail the following: (A) the issue, dispute, or controversy to be arbitrated and the Initiating Party's position regarding such issue, dispute, or controversy; (B) the relief sought by the Initiating Party; and (C) the name, street address, and telephone number of the arbitrator appointed by the Initiating Party. The Responding Party shall, within 15 days after receipt of the notice by the Initiating Party referred to in this subsection 15(e), appoint a second arbitrator and provide written notice to the Initiating Party and to the arbitrator appointed by the Initiating Party of the name, street address and telephone number of the arbitrator appointed by the Responding Party. The arbitrators appointed by the Initiating Party and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party.

(A) If the arbitrators appointed by the Initiating Party and by the Responding Party, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party, then within 30 days after the date of the appointment of an arbitrator by the Responding Party the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(B) If the Responding Party fails to appoint an arbitrator within 15 days after receipt of the notice by the Initiating Party referred to in paragraph 15(e)(1), then within 30 days after the date of such notice the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(C) If, pursuant to either subparagraph 15(e)(1)(A) or 15(e)(1)(B), the Initiating Party applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Initiating Party shall give the Responding Party written notice of such application within one day after the date of filing such application.

(2) The three arbitrators appointed pursuant to paragraph 15(e)(1) shall decide any issue, dispute, or controversy by majority vote.

(3) Within 20 days after the appointment of a third arbitrator pursuant to paragraph 15(e)(1) with respect to any arbitration pursuant to this subsection 15(e), the arbitrators shall establish a schedule for the completion of such arbitration. The first day pursuant to such schedule shall be hereafter referred to in this subsection 15(e) as the "Arbitration Commencement Date."

(4) No later than 15 days after the Arbitration Commencement Date, the Initiating Party may make a single request in writing to the Responding Party for documentation, data, and information relevant to or reasonably necessary to support the Initiating Party's position communicated to the Responding Party pursuant to paragraph 15(e)(1). Such single request may contain multiple parts. The Initiating Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information pursuant to this paragraph.

(5) The Responding Party shall have 20 days from the date it receives the request from the Initiating Party pursuant to paragraph 15(e)(4) to provide the documentation, data, and information requested; provided, however, that the Responding Party shall be under no obligation pursuant to this paragraph 15(e)(5) (A) to create additional documentation, data, or

information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Initiating Party or (D) if Bonneville is the Responding Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(6) No later than 15 days after the Arbitration Commencement Date, the Responding Party may make a single request in writing to the Initiating Party for documentation, data and information relevant to Initiating Party's position communicated to the Responding Party pursuant to subsection 15(e)(4). Such single request may contain multiple parts. The Responding Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data and information pursuant to this paragraph.

(7) The Initiating Party shall have 20 days from the date it receives the request from the Responding Party pursuant to paragraph 15(e)(6) to provide the documentation, data and information requested; provided, however, that the Initiating Party shall be under no obligation pursuant to this paragraph 15(e)(7) (A) to create additional documentation, data, or information, (B) to provide documentation, data or information that is not readily available to it, (C) to provide to the Responding Party documentation, data, or information that the Initiating Party has previously provided to the Responding Party or (D) if Bonneville is the Initiating Party, to provide documentation, data, or information that Bonneville would not

otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(8) For purposes of this subsection 15(e), each of the Initiating Party and the Responding Party shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests by it for, documentation, data, and information and responses to such requests.

(9) Within 65 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may state in reasonable detail its position regarding any issue, dispute or controversy to be arbitrated pursuant to this subsection 15(e) in a letter to the arbitrators and to the other party to the arbitration of such issue, dispute, or controversy Within 85 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may submit a letter to the arbitrators and to the other party responding to the letter that the other submitted to the arbitrators pursuant to the immediately preceding sentence.

(10) The arbitrators shall resolve any issue, dispute, or controversy pursuant to this subsection 15(e) by deciding (taking into consideration, among other things, any letter submitted by the Initiating Party or the Responding Party with respect to such issue, dispute, or controversy) whether the position of the Initiating Party or the position of the Responding Party regarding the action taken or proposed to be taken by the Responding Party conforms more closely with the standard for such action set forth in this Agreement. The arbitrators shall have no authority to fashion a resolution of such arbitration other than pursuant to this paragraph 15(e)(10).

(f) Any selection by the arbitrators of an alternative pursuant to subsection 15(d) and any decision by the arbitrators pursuant to subsection 15(e) shall be reported by the Initiating Party to the Bonneville Administrator (Administrator) for review within 30 days after such selection or decision is made. The Administrator shall either accept or reject in writing such selection or decision. If the Administrator fails to either accept or reject such selection or decision, as the case may be, within 90 days after such selection or decision is made, such selection or decision, as the case may be, shall be deemed to be accepted by the Administrator.

(g) If the Administrator accepts any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e), such selection or decision shall become binding upon Puget and Bonneville at the time of its acceptance.

(h) The Administrator may reject any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e) only for one or more of the following reasons:

(1) the arbitrators did not follow the arbitration procedures set forth in this section 15;

(2) the arbitrators decided a matter that is not a matter arising under this Agreement as set forth in paragraph 15(a)(6);

(3) the arbitrators did not completely apply the appropriate standard for arbitration pursuant to this section 15;

(4) the arbitrators granted relief in contravention of this Agreement;

(5) the arbitrators' decision is not supported by substantial, competent evidence; or

(6) implementation of the arbitrators' decision would cause Bonneville to violate a statutory obligation of Bonneville's or would cause Bonneville to breach a contractual obligation not in contravention of this Agreement.

(i) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 15 equal to $1 \div (n + 1)$, where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay for its own expenses related to the arbitration proceeding, including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(j) If the Initiating Party elects to arbitrate any issue, dispute, or controversy pursuant to this section 15, the Initiating Party must initiate arbitration of such issue, dispute, or controversy within one year following the occurrence of the event giving rise to such issue, dispute, or controversy. Failure of the Initiating Party to initiate arbitration of any such issue, dispute, or controversy within such one-year period shall constitute a waiver of the Initiating Party's right to arbitrate such issue, dispute, or controversy pursuant to this section 15.

16. AUDIT RIGHTS

(a) The Committee shall have the right to perform an audit of Bonneville's books, records, and documents used in or relating to the determination of the Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to the Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(2)(B).

(b) The Committee shall have the right to perform an audit of Bonneville's books, records and documents used in or relating to the determination of any Revised Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to any Revised Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(3)(B).

(c) The Committee shall have the right to audit Bonneville's books, records, and documents (i) used in or relating to the determination of any charge (including, without limitation, any MFU count made pursuant to section I.A of Exhibit I) billed to Puget pursuant to paragraph 9(b)(2) and subsection 9(c), or (ii) used in or relating to any billing or refund with respect to any such charge. Such audit shall be performed within 36 months after the date of Bonneville's bill or refund voucher for such charge rendered by Bonneville to Puget pursuant to paragraph 9(b)(2) or subsection 9(c), as the case may be.

(d) Bonneville shall not be responsible to pay any of the expenses incurred by any of the Capacity Owners in performing any audit pursuant to this section 16. Bonneville shall not directly charge Puget or any Capacity Owner other than Puget for Bonneville's costs incurred by Bonneville with respect to any audit pursuant to this section 16 unless Bonneville develops a general practice of charging, through direct charges, each of its customers for such costs incurred by Bonneville in connection with audits undertaken pursuant to those customers' respective contracts with Bonneville.

(e) After completing any audit specified above, the Committee shall promptly provide to Bonneville a written report of the results of such audit. If such audit report includes any exception taken as a result of such audit and Bonneville agrees with such exception, Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such audit exception,

(1) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Puget a revised bill or refund voucher pursuant to paragraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(2) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and either (A) render to Puget a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (B) cause to be refunded to Puget as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Puget's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this subsection 16(e) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such audit report is received by Bonneville to (but excluding) the date on which such amount is refunded to Puget.

(f) If an audit report provided to Bonneville by Puget pursuant to subsection 16(e) includes any exception taken as a result of such audit and Bonneville does not agree with such exception, then the following shall apply:

(1) Bonneville may, within 30 days following its receipt of such audit report, propose to the Committee a resolution of any

inconsistency noted in any exception taken as a result of such audit;

(2) If the Committee accepts such resolution proposed by Bonneville, then Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such resolution,

(A) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Puget a revised bill or refund voucher pursuant to subparagraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(B) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and shall either (i) render to Puget a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (ii) cause to be refunded to Puget as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Puget's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this paragraph 16(f)(2) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such resolution is accepted by the Committee to (but excluding) the date on which such amount is refunded to Puget; and

(3) If the Committee does not accept such resolution, if any, proposed by Bonneville with respect to any such exception, or if Bonneville does not propose any such resolution, then the Committee

(A) shall have the right to arbitrate, pursuant to section 14, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to subsection 13(i); and

(B) shall have the right to arbitrate, pursuant to section 15, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to section 15.

The Committee must refer to arbitration pursuant to subparagraph 16(f)(3)(A) or 16(f)(3)(B) any cost to which exception is taken as a result of any audit within eight months after the date the Committee commences such audit. Failure of the Committee to elect to so refer to arbitration any cost within such eight-month period shall be deemed to constitute waiver by the Committee of any right pursuant to this section 16 to arbitrate such cost.

(g) Puget shall have the right to participate in any audit pursuant to this section 16 only by acting through the Committee. If Puget chooses not to participate in any audit undertaken by the Committee, then Puget shall accept the findings of the Committee with respect to such audit and any resolution by the Committee and Bonneville of any inconsistency noted in any exception taken as a result of such audit.

(h) Any audits undertaken by the Committee shall be upon reasonable notice to Bonneville and at reasonable times and shall commence no more frequently than once in any 24 consecutive months. The audit rights provided in this section shall not be construed to permit a general audit of Bonneville's books, records, and documents. Audits shall be in conformance with generally accepted auditing standards.

Prior to and for the duration of any audit, Bonneville shall retain all pertinent books, records, and documents prepared in the normal course of business. After commencement of an audit pursuant to subsection 16(a), 16(b), or 16(c), the Committee may request and Bonneville shall promptly provide reasonably available supporting documentation for any cost or charge subject to audit. If the Committee fails to commence an audit pursuant to subsection 16(a), 16(b), or 16(c) within the time periods set forth in subsection 16(a), 16(b), or 16(c), such failure shall constitute waiver by Puget of any right pursuant to this section 16 to arbitrate any charge or refund billed or refunded by Bonneville.

(i) If Puget is operating pursuant to paragraph 3(b)(1), Bonneville shall have the right, at its own expense, to review Puget's books, records, and documents that directly pertain to the revenue reportable in Puget's accounting system where revenues received for wheeling for other entities would be booked for the purpose of verifying compliance with paragraph 3(b)(1). Bonneville shall have the right to perform such audit no more frequently than once every 36 months.

17. PROTECTED AREAS

Puget shall not use its Scheduling Share for transmission of power on the PNW AC Intertie from new hydroelectric projects which are constructed in Columbia River Basin Protected Areas after designation thereof by Bonneville unless Puget is required by regulatory authority to purchase or provide transmission for the output of such project or unless Bonneville receives sufficient demonstration that a particular project would provide benefits to Bonneville's existing or planned fish and wildlife investments or the Pacific Northwest Electric Power and Conservation Planning Council's Fish and Wildlife Program. The Parties agree that System Sales shall not be taken into consideration in any determination of whether Puget has used its Scheduling Share for transmission of power on the PNW AC Intertie from the hydroelectric projects referred to in the immediately preceding sentence. For purposes of this section 17, "System Sale" means any sale of power or energy to Puget or by a seller of power or energy, which power or energy is not resource-specific and is delivered to Puget at a point that connects one or more resources or transmission systems.

18. ESTABLISHMENT AND MAINTENANCE OF RATES AND RELIEF FROM REGULATORY ACTION

(a) Bonneville shall use good faith efforts to maintain in effect such of the following rates that has been approved by FERC on an interim or final basis, during the rate approval period established by FERC for such rate:

(1) any rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date;

(2) the Initial Successor Rate;

(3) the Alternative Successor Rate; and

(4) the Bonneville Successor Rate.

(b) If Bonneville's Administrator submits to FERC a rate that is different from that set forth in Exhibit B, Part A and Part B, on the Effective Date, as the first rate proposed by Bonneville (Initial Successor Rate) to replace the AC-93 rate set forth in Exhibit A or that is for a rate approval period which is less than the remainder of the Term following the expiration of the AC-93 rate, Puget may, within 90 days after Bonneville submits the Initial Successor Rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Puget may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Puget may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Puget's notification to terminate this Agreement pursuant to this subsection 18(b) except for those rights and obligations set forth in this paragraph 18(b)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Puget has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Puget's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

A - ((B/540) X A) + I = Refunded Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(b).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

I = Interest on A - ((B/540) X A), accruing from (and including) the date of Bonneville's receipt of Puget's Initial Lump Sum Payment to (but excluding) the date on which Bonneville receives Puget' notification to terminate this Agreement pursuant to this subsection 18(a), at the 5-year Treasury note rate in effect on the date on which Bonneville receives Puget's Initial Lump Sum Payment.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(b)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(b)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(b)(2)(B), Bonneville may accelerate payment to Puget of the amount of the Refunded Lump Sum Payment.

If Puget elects to proceed under this paragraph 18(b)(2), Bonneville shall not develop a rate or charge that would inequitably allocate to Puget and Capacity Owners other than Puget, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Puget or any Capacity Owner other than Puget.

(c) If FERC approves the Initial Successor Rate, the Alternative Successor Rate (as defined in subsection 18(d)), or the Bonneville Successor Rate (as defined in subsection 18(d)) for a term less than the remainder of the Term following the expiration of the AC-93 rate, and if Bonneville's Administrator thereafter submits to FERC a rate (Replacement Rate) that is different from the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis) or that is for a rate approval period which is less than the remainder of the Term following the expiration of the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis), Puget may, within 90 days after Bonneville submits such rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Puget may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Puget may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Puget's notification to terminate this Agreement pursuant to this subsection 18(c) except for those rights and obligations set forth in this paragraph 18(c)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Puget has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Puget's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

$$A - ((B/540) \times A) + R = \text{Refunded Lump Sum Payment}$$

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement.

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

R = 2.5 times the amount paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the immediately preceding fiscal year times the ratio of (a) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the first fiscal year during the proposed rate approval period pursuant to the rate submitted by Bonneville to FERC to replace the immediately preceding annual costs rate over (b) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the same fiscal year were the immediately preceding annual costs rate to remain in effect; provided, however, that the ratio of (a) over (b) shall in no event be less than one for purposes of this subsection.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(c)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(c)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(c)(2)(B), Bonneville may accelerate payment to Puget of the amount of Refunded Lump Sum Payment.

If Puget elects to proceed under this paragraph 18(c)(2), Bonneville shall not develop a special rate or charge that would inequitably allocate to Puget and Capacity Owners other than

Puget, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Puget or any Capacity Owner other than Puget.

The terms of this subsection 18(c) shall be effective through December 31, 2040.

(d) If (i) FERC remands or approves a rate which materially differs from the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, or (ii) FERC grants final approval to a rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date, or to the Initial Successor Rate for a rate approval period of less than the remainder of the Term following the expiration of the AC-93 rate, or (iii) FERC remands or disapproves the Initial Successor Rate, then in any such event Bonneville, Puget, and Capacity Owners other than Puget shall use good faith efforts to develop an alternative successor rate (Alternative Successor Rate) which would place Puget in substantially the same position with respect to Puget's rights and obligations under this Agreement as if the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, had been approved by FERC for the remainder of the Term following the expiration of the AC-93 rate. Bonneville, Puget, and Capacity Owners other than Puget shall use good faith efforts to reach agreement on an Alternative Successor Rate within 6 months after the date of the FERC order regarding the Initial Successor Rate contemplated in this subsection 18(d) or within the time period established in such FERC order, whichever is earlier.

(1) If Bonneville, Puget, and Capacity Owners other than Puget reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, then Bonneville shall, subject

to section 7(i) of the Regional Act, submit such Alternative Successor Rate to FERC for approval and confirmation.

(2) If Bonneville, Puget, and Capacity Owners other than Puget do not reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, Bonneville shall develop a rate, which, among other things, in Bonneville's judgment, protects the rights and obligations of Puget and Capacity Owners other than Puget and, subject to section 7(i) of the Regional Act, shall submit such rate (Bonneville Successor Rate) to FERC for approval and confirmation.

Nothing in this subsection 18(d) shall limit or otherwise affect any provisions of subsection 18(b) or 18(c).

(e) If Bonneville, Puget, and Capacity Owners other than Puget are unable to agree upon an Alternative Successor Rate pursuant to subsection 18(d), or if FERC approves the Alternative Successor Rate for a period of less than 15 years or with terms and conditions that differ from the terms and conditions of the Alternative Successor Rate, or if FERC remands the Alternative Successor Rate, or if FERC approves the Bonneville Successor Rate, Puget may elect, within 6 months of any of the foregoing events, to terminate this Agreement and execute a long-term contract with Bonneville for firm wheeling on the PNW-PSW Intertie for a term not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Puget's Capacity Ownership Share, pursuant to subsection 18(f).

(f) Should Puget elect to proceed pursuant to paragraph 18(b)(1) or 18(c)(1) or subsection 18(e), the Parties shall take the following steps:

(1) Puget shall provide Bonneville with written notification of its election to terminate this Agreement and with a written request for a long-term contract for firm wheeling on the PNW-

PSW Intertie for a period not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Puget's Capacity Ownership Share.

(2) As soon as practicable after receipt by Bonneville of the written notice sent pursuant to paragraph 18(f)(1), Bonneville shall offer to Puget a long-term contract for firm wheeling on the PNW-PSW Intertie of an amount of power equal to the amount of power specified in Puget's written request pursuant to paragraph 18(f)(1), such offered contract to contain other terms and conditions substantially similar to those then being offered by Bonneville to its other firm wheeling customers for transactions on the PNW-PSW Intertie.

The termination date of this Agreement shall be the same date as the effective date of the long-term contract for firm wheeling referred to in this paragraph 18(f)(2), and such date shall in any event be no more than 6 months after Bonneville's receipt of Puget's notification pursuant to paragraph 18(f)(1).

(3) The long-term contract for firm wheeling offered to Puget pursuant to paragraph 18(f)(2) shall also contain provisions which:

(A) Require Bonneville to credit or pay (any such payment to be made pursuant to paragraph 9(f)(4)), in equal monthly amounts during the term of such long-term contract for firm wheeling, against the amount payable by Puget to Bonneville pursuant to such long-term wheeling agreement an amount equal to the "Credited Lump Sum Payment" calculated as follows:

A - ((B/540) X A) = Credited Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(e).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

(B) Require Bonneville, subject to the immediately succeeding sentence, to credit or pay interest on the Credited Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest to be credited or paid pursuant to this provision shall be credited or paid by Bonneville on the amount of each monthly amount of the Credited Lump Sum Payment to be credited or paid by Bonneville pursuant to the provision set forth in subparagraph 18(f)(3)(A).

(C) Permit Bonneville to accelerate payment to Puget of the amount of Credited Lump Sum Payment which remains uncredited at any time during the term of such long-term contract for firm wheeling.

(g) Puget's right to terminate this Agreement pursuant to subsections 18(d) through 18(f) is a one-time only right that must be exercised after FERC action pursuant to subsection 18(d). If Puget fails to terminate the Agreement pursuant to subsection 18(e) as prescribed therein as a result of FERC action, Puget shall have no future rights to terminate the Agreement under this section 18 as a result of FERC action.

(h) Bonneville shall use best efforts to establish and maintain in effect the AC-93 rate, set forth in Exhibit A, during the remainder of the Term, but only until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), that is confirmed and approved by FERC on an interim or final basis, becomes effective. If FERC does not confirm and approve on a final basis the AC-93 rate for a rate approval period of sufficient duration so that the AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or such other rate, becomes effective, then upon expiration of the rate approval period of such AC-93 rate, Bonneville shall submit to FERC a rate based on the methodology used to determine the AC-93 rate (revised AC-93 rate) and shall use best efforts to obtain a rate approval period for the revised AC-93 rate of sufficient duration so that the revised AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), becomes effective. If, at any time during the Term, FERC does not confirm and approve on an interim or final basis the AC-93 rate or revised AC-93 rate for any reason other than the duration of the rate approval period, Bonneville and Puget shall use best efforts to develop a rate that would replace the AC-93 rate or revised AC-93 rate, and Bonneville shall submit such rate to FERC, pursuant to section 7(i) of the Regional Act, for confirmation and approval if such rate is agreed to by Bonneville, Puget and Capacity Owners other than Puget. If Bonneville and Puget do not succeed in developing such rate, Bonneville shall submit to FERC, pursuant to section 7(i) of the Regional Act, a rate which in Bonneville's judgment recovers Bonneville's costs. Bonneville shall bill Puget, and Puget shall pay Bonneville, in accordance with the AC-93 rate or, if FERC does not confirm and approve on an interim or final basis the AC-93 rate, the rate confirmed and approved by FERC on an interim or final basis.

Bonneville shall revise Exhibit A so that it contains, at a given time, the AC-93 or other rate confirmed and approved by FERC on an interim or final basis.

19. **EXHIBITS**

(a) Exhibits A through J attached to this Agreement are by this reference made a part of this Agreement. In the event of a conflict between any provision in Exhibits A through J and the provisions of sections 1 through 23 of this Agreement, the provisions of sections 1 through 23 of this Agreement shall prevail.

(b) Bonneville shall revise Exhibit A pursuant to subsections 18(g) and 18(h) and this subsection 19(b). The rate schedules attached hereto as Exhibit A have been conditionally or finally confirmed by FERC. If the final rate schedules which are approved by FERC are an amendment or modification of the initial rate schedules, the applicable amended or modified rate schedules and associated GTRSPs shall be attached to and made part of this Agreement effective as of the date specified in FERC's approval. The rate schedules and GTRSPs included in Exhibit A shall be replaced by successor rate schedules and provisions in accordance with the provisions of section 7(i) of the Regional Act and FERC rules.

(c) Upon interim or final approval by FERC of any rate submitted to FERC pursuant to subsections 18(a) through 18(g), Bonneville shall revise Exhibit B so that Exhibit B contains such rate approved by FERC as contemplated in this subsection 19(c). For purposes of this Agreement, such rate shall be effective as of the date of effectiveness specified in FERC's approval of such rate. Subject to the provisions of subsections 18(a) through 18(g), the rate schedule set forth in Exhibit B, Part A and Part B, on the Effective Date, shall be replaced by successor rate schedules and provisions pursuant to section 7(i) of the Northwest Power Act and applicable FERC rules.

(d) Bonneville shall revise or modify Exhibit C from time to time to reflect changes hereafter agreed to in writing by the Parties in Puget's Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share.

(e) Bonneville shall revise Exhibit D pursuant to subsection 9(a). Revision or modification of Exhibit D shall not require an executed amendment or revision to this Agreement.

(f) Not more frequently than annually, Bonneville shall review and, as appropriate, revise Exhibit E, Part A, in accordance with Bonneville's standard methodology and formula for calculation of average losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie. Such methodology and formula are intended to forecast average annual actual losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie Operational Transfer Capability. Any changes to the loss methodology or formula, other than numerical values, shall be made only after consultation with the Committee. During such consultation, Bonneville shall provide to the Committee material pertinent to such changes to the loss methodology or formula. Upon conclusion of any review of the loss factor in Exhibit E, Part A, Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan pursuant to section 13. If the Committee pursues arbitration pursuant to subsection 10(b) and section 14, Bonneville shall revise Exhibit E, Part A, to reflect the selection of the arbitrators pursuant to subsection 14(j).

(g) Bonneville shall revise the loss factor in Exhibit E, Part B, as necessary to equal the same factor for average losses as Bonneville generally applies to transmission over Bonneville's share of the PNW-PSW Intertie. Revision of Exhibit E, Part B, shall not require an executed amendment or revision to this Agreement.

(h) Bonneville shall revise Exhibit F as appropriate to reflect the facilities in Bonneville's PNW AC Intertie. Revision or modification of

Exhibit F shall not require an executed amendment or revision to this Agreement.

(i) Bonneville shall revise Exhibit G as appropriate to reflect the complete list of all of the Capacity Owners and their respective Capacity Ownership Shares and Capacity Ownership Percentages from time to time pursuant to this Agreement.

(j) Bonneville shall revise Exhibit H as appropriate to reflect all provisions required by statute or Executive Order. Revision or modification of Exhibit H shall not require an executed amendment or revision to this Agreement.

(k) Bonneville shall revise Exhibit I to reflect changes as agreed to in writing by Puget and Capacity Owners other than Puget.

(l) Bonneville shall revise Exhibit J as mutually agreed to in writing by the Parties.

20. **RULES OF LAW**

(a) Bonneville and Puget agree that each fully participated in the drafting of each provision of this Agreement. The rule of law interpreting ambiguities against the drafting Party shall not be applicable to or utilized in resolving any dispute over the meaning or intent of this Agreement or any of its provisions.

(b) This Agreement shall not be construed to establish a partnership, association, agency relationship, joint venture, or trust. Neither Party shall be under the control of or shall be or represent itself as, the agent of, or have a right or power to bind, the other Party without the other's express written consent, except as provided in this Agreement.

(c) All applicable law is incorporated in and made part of this Agreement.

21. NOTICES

(a) Unless the Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be served, given, or made if delivered in person or sent by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons addressed as set forth below:

To Bonneville:
Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232

To Puget:
Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515

To Seattle:
Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101

To PNGC:
Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232

To Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201

To Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411

(b) Either Party may, by written notice to the other Party pursuant to subsection 21(a), change the address set forth in subsection 21(a) for the notifying Party.

(c) All notices pursuant to this Agreement shall be effective on the date of receipt.

22. WAIVER

Any waiver at any time by a Party of its rights with respect to any matter arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent or other matter. Except as otherwise provided herein or as agreed in writing by the Parties, no provision in this Agreement may be waived except as documented or confirmed in writing.

23. MISCELLANEOUS

(a) Effect of Section Headings

Section headings and subheadings appearing in this Agreement are inserted for convenience only and shall not be construed as interpretations of provisions of this Agreement.

(b) **Amendments**

Except as may be expressly otherwise provided in this Agreement, this Agreement may be amended only with the express written consent of both of the Parties, and no provision of this Agreement shall be varied or contradicted by any oral agreement, course of dealing or performance or any other matter not hereafter set forth in a written agreement signed by both of the Parties.

(c) **Entire Agreement**

This Agreement constitutes, on and as of the date hereof, the entire agreement of the Parties with respect to the subject matter of this Agreement, and all prior understandings or agreements, whether written or oral, between the Parties with respect to the subject matter of this Agreement are hereby superseded in their entireties.

(d) **No Third Party Beneficiaries**

There are no third party beneficiaries of this Agreement. This Agreement shall not be construed to create rights in, or to grant remedies to, any third party as a beneficiary of this Agreement or of any duty, obligation, or undertaking established herein.

(e) **Regulatory Approvals**

Each Party shall use its best efforts to obtain and maintain in effect regulatory approvals that are necessary to permit such Party to perform its obligations under this Agreement in accordance with its terms and conditions. Neither Party shall oppose in any way or seek to alter or amend the terms and conditions of this Agreement by application to or participation in any application of any regulatory authority or court having jurisdiction. Puget shall not oppose in any way or seek to alter or amend the terms or conditions of the annual costs rate set forth in Exhibit B, the CO-94 rate, the AC-93 rate, or any rate described in section 18 that is agreed to by the Parties subsequent to each entering into this Agreement, in any proceeding pursuant to section 7 of the Pacific Northwest Electric Power Planning and Conservation Act before FERC or in any court of competent jurisdiction.

(f) **Other Capacity Ownership Agreements**

If Bonneville offers to enter into (i) a Capacity Ownership Agreement with any other Capacity Owner or (ii) any written amendment of any Capacity Ownership Agreement (other than this Agreement), then Bonneville shall offer to Puget an amendment of this Agreement that contains the terms and conditions of such Capacity Ownership Agreement with such other Capacity Owner or of such written amendment, as the case may be. Bonneville shall advise, and use reasonable efforts to consult with, Puget during the development or consideration of any offer to any Capacity Owner other than Puget to enter into a Capacity Ownership Agreement or any amendment of such agreement.

(g) **Singular and Plural Forms**

For purposes of interpreting and construing this Agreement, the singular form of a word shall include its plural and the plural form of a word shall include its singular, unless otherwise expressly provided by this Agreement.

(h) **Performance Pending Dispute**

Except as otherwise expressly provided in this Agreement, pending resolution of any dispute, issue, or controversy arising under this Agreement, the Parties shall each continue performance of their respective obligations pursuant to this Agreement.

(i) **Time Periods**

For purposes of calculating any time period prescribed by this Agreement, if the last day of the time period falls on a day that is not a Working Day, then the last day of the time period shall be the first Working Day following such day as would otherwise be the last day of the time period.

(j) **Double Counting**

In developing rates or charges under section 7 of the Pacific Northwest Electric Power Planning and Conservation Act for any rate period, Bonneville shall not set rates or charges that recover, more than once, the costs associated with capital projects that are paid or forecast to be paid under the CO-94 rate and the AC-93 rate and annual costs rate set forth in Exhibit B, or the remaining Bonneville's PNW AC Intertie costs forecast to be paid under the AC-93 rate and annual costs rate set forth in Exhibit B. Bonneville's forecast of revenues chargeable under the CO-94 rate, AC-93 rate, and annual costs rate set forth in Exhibit B shall be based on the best available information, including information provided pursuant to section 13 of this Agreement.

In the event Bonneville proposes any wheeling rate for transmission service on Bonneville's main grid that includes costs of the PNW AC Intertie, such proposed rate shall include a credit or other mechanism that ensures that Puget is not charged any of the PNW AC Intertie costs for deliveries of power that utilize up to the Puget's Capacity Ownership Share, as that term is defined in this Agreement.

(k) **Committee Action**

Each of the Parties agrees that to the extent it is provided in sections 13, 14, and 16 that the Committee shall take any action or shall make any decision, such action or decision shall be taken or made, as the case may be, by the Committee, and not by Puget acting individually.

(l) **Fiscal Year**

For purposes of this Agreement, the term "fiscal year" shall mean Bonneville's fiscal year.

(m) **Rights and Remedies Cumulative**

All rights and remedies of either Party under this Agreement and at law and in equity shall be cumulative and not mutually exclusive and the exercise of one right or remedy shall not be deemed a waiver of any other right or remedy. Nothing contained in any provision of this Agreement shall be construed to limit or exclude any right or remedy of either Party (arising on account of the breach or default by the other Party or otherwise) now or hereafter existing under any other provision of this Agreement, at law or in equity.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

/s/ WALTER E. POLLOCK
Group Vice President for Marketing,
Conservation and Production

By Walter E. Pollock
Group Vice President for Marketing, Conservation and Production

Name Walter E. Pollock
(Print/Type)

October 11, 1994

Date October 11, 1994

Puget Sound Power & Light Company

By J R Lauckhart

/s/ J. R. LAUCKHART

Name J. R. Lauckhart
(Print/Type)

Title VP Power Planning

Vice President, Power Planning

Date 9/26/94

September 26, 1994

Effective Date __________________

CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions

Schedule CO-94

CAPACITY OWNERSHIP RATE SCHEDULE

Section I. Availability

This schedule applies to all agreements which provide life-of-facilities capacity rights to non-Federal participants (Capacity Owners) in 725 MW of Bonneville's PNW AC Intertie and any upgrades thereto. Service under this schedule is subject to Bonneville's General Transmission Rate Schedule Provisions.

Section II. Rate

The charge for capital and related costs for non-Federal capacity ownership in Bonneville's PNW AC Intertie shall be determined by the methodologies set out in Section III below.

Section III. Determination of Rate

A. Capacity Ownership Price

The charge for capacity ownership in Bonneville's PNW AC Intertie shall be the Capacity Ownership Share of the actual capital and related costs of facilities as determined by the formula shown below. The Capacity Ownership Share shall be determined pursuant to the Capacity Ownership agreement.

$$\frac{(A - B) + C + D}{E} = \text{Capacity Ownership Price in \$/kW}$$

Capacity Ownership Price in $/kW x number of kW contracted for by Capacity Owner = Capacity Owner's payment to Bonneville

Where:

A = Bonneville's cost of new facilities for the Third AC Intertie, which increased the rat[ed] transfer capability of the PNW AC Intertie by approximately 1600 MW, is the construction costs (including direct, indirect and overhead costs) of the facilities associated with the Third AC Intertie System Reinforcements and the Alvey-Merid[ian]

Transmission Line (also known as Eugene-Medford 500-kV Transmission Line), referred to jointly as the Third AC Intertie Project.

B = Bonneville's cost of new facilities needed for the first 800 MW increment of the 1600 MW Third AC Intertie Project, which includes a portion of the construction costs (including direct, indirect and overhead costs) associated with the Third AC Intertie System Reinforcement.

A-B = The cost of new facilities for the second 800 MW increment of the 1600 MW Third AC Intertie Project (presented in Exhibit C of the Capacity Ownership agreement).

C = Allowance for Funds Used During Construction (AFUDC) constitutes interest on the funds used for the Third AC Intertie Project while it was under construction. AFUDC is calculated and capitalized consistent with FERC requirements as described in FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions, 3.A(17). The AFUDC applies to that amount capitalized on the second 800 MW increment of the 1600 MW Third AC Intertie Project, or A - B.

D = Book value of existing Bonneville support facilities that are dedicated to the PNW AC Intertie equal to $19,100,000.

E = 725,000 kW, which equals Bonneville's share of the second 800 MW of the Third AC Intertie.

B. PNW AC Intertie Upgrade Price

The charge for upgrades to Bonneville's PNW AC Intertie facilities that occur after December 1993, and which result in an increase of rated transfer capability, shall be the Capacity Ownership Share of the capital and related costs of the upgrade. The Capacity Ownership Share of any upgrades shall be determined pursuant to the Capacity Ownership agreement. The capital costs shall consist of the construction costs (including direct, indirect and overhead costs) and AFUDC (as described in Section III.A. above) of the facilities associated with such upgrades.

Section IV. Adjustments and Special Provisions

A. Initial Lump Sum Payment

Capacity Owners shall make an initial, lump sum payment of an estimate of the Capacity Ownership Price equal to $215/kW pursuant to the Capacity Ownership agreement.

B. Adjustment to Reflect Actual Construction Costs

Approximately December 1995 or as soon as practicable thereafter, the Capacity Owner's initial lump sum payment shall be adjusted to reflect the difference between the actual and the estimated Capacity Ownership Price. The actual Capacity Ownership Price shall be determined pursuant to Section III.A. above. There will be no adjustment for the book value of the support facilities dedicated to the PNW AC Intertie. Capacity Owners will either receive a refund, with interest, from Bonneville or make an additional payment, with interest, to Bonneville. Bonneville shall compute interest using the weighted average interest rate on Bonneville's outstanding bonds.

C. PNW AC Intertie Upgrade Payments

Capacity Owners shall pay a share of the upgrades to Bonneville's PNW AC Intertie in the manner and time to be determined when participation in such upgrades are agreed to pursuant to the Capacity Ownership agreement.

Schedule AC-93

Southern Intertie Annual Cost

SECTION I. AVAILABILITY

This schedule is applicable to all parties (New Owners) that execute PNW AC Intertie Capacity Ownership Agreements (Agreements) and will be effective on the date described in the Agreement. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The rate charges reflect the terms of the Memorandum of Understanding (MOU), signed in the Fall of 1991, between BPA and potential New Owners. The MOU provides for the payment by New Owners of their prorated share of: (1) BPA's annual operations, maintenance, and general plant expense (including applicable overheads) properly chargeable to the AC Intertie facilities; and (2) BPA's share of capitalized replacements on the AC Intertie. The monthly charge shall be the sum of the charges specified in sections II.A and II.B.

A. Operations, Maintenance, and General Plant

The monthly charge shall equal $325 per megawatt of billing demand.

B. Replacements

The monthly charge shall equal $0 per megawatt of billing demand.

SECTION III: ADJUSTMENT TO REPLACEMENTS RATE

A. Determination of Billing Adjustment

New Owners will receive a billing adjustment if BPA incurs AC Intertie replacement cost during the rate period. The Replacements Rate Adjustment equals:

$$\frac{\text{AC Intertie work orders (\$000)} * \%}{725 \text{ MW} * \text{\# months}}$$

where:

"# months" equals: (1) the number of months that this rate schedule is in effect during the fiscal year for the Initial Replacements Rate Adjustment; or (2) the number of months in the rate period for the Final Replacements Rate Adjustment; and

"%" equals the New Owners' percentage share of BPA's total AC Intertie Rated Transfer Capability as specified in the Agreements.

B. Initial Replacements Rate Adjustment

New Owners will receive a billing adjustment for each fiscal year that BPA incurs AC Intertie replacement cost. At the end of each fiscal year, the cost associated with AC Intertie capital replacement work orders that have closed during the fiscal year will be determined. The unit rate that would result using these closed work orders is the basis of the Initial Replacements Rate Adjustment.

1. Notice Provisions

Following each fiscal year, BPA shall notify all New Owners by December 15 of the proposed Replacements Rate Adjustment. BPA will provide the calculation of the adjustment and a short description of the work performed and the associated cost used as the basis for the billing adjustment. In addition to written notification, BPA may, but is not obligated to, hold a public meeting to clarify its determinations.

Written comments on the Initial Replacements Rate Adjustment will be accepted through the end of January. Consideration of comments submitted by the New Owners may result in the billing adjustment differing from the initially proposed adjustment. BPA shall notify all New Owners of the Initial Replacements Rate Adjustment by the last day of February.

2. **Adjustment of Monthly Bills**

An adjustment will be made on the New Owner's monthly bill prepared during March. The Initial Replacements Rate adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal year (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal year). The Initial Replacements Rate Adjustment will appear as a charge to the New Owner on the monthly bill prepared during March.

C. **Final Replacements Rate Adjustment**

The actual costs associated with the AC Intertie capital replacement work orders that occur during the rate period may change after BPA performs its final analysis of the work orders. BPA shall compare the unit rate for the rate period using the results of the final work order analysis to the weighted average of the unit rates from the Initial Replacements Rate Adjustments.

1. **Notice Provisions**

BPA shall notify all New Owners in May 1998 of the results of the calculations, an explanation of work order change(s), and any resulting billing adjustment. Written comments from New Owners will be accepted through the end of June. BPA shall notify all New Owners of the Final Replacements Rate Adjustment by July 31. Consideration of comments submitted by the New Owners may result in the Final Replacements Rate Adjustment differing from the initially proposed adjustment.

2. **Adjustment of Monthly Bills**

If the absolute value of the Final Replacements Rate Adjustment is greater than or equal to $1 per megawatt per month, an adjustment will be made on the New Owner's monthly bill prepared during August. For each New Owner, the Final Replacements Rate Adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal years (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal years). The Final Replacements Rate Adjustment will appear as a charge or credit to the New Owner on the monthly bill prepared during August. Interest, as determined by BPA's Office of Financial Management, will be included in any adjustment.

SECTION IV. BILLING FACTOR

The billing demand shall be the New Owner's capacity ownership share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability as specified in the Agreement.

Schedule IS-93

Southern Intertie Transmission

SECTION I. AVAILABILITY

This schedule supersedes IS-91 and is available for all transmission on the Southern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. Nonfirm Transmission Rate

The charge for nonfirm transmission of non-BPA power shall be 3.11 mills per kilowatthour of billing energy. This charge applies for both north-to-south and south-to-north transactions.

B. Firm Transmission Rate

The charge for firm transmission service shall be $0.706 per kilowatt per month of billing demand and 1.69 mills per kilowatthour of billing energy. Firm transmission will only be made available to customers under this rate schedule who have executed a contract with BPA specifying use of the Firm Transmission rate for either north-to-south or south-to-north transactions.

SECTION III. BILLING FACTORS

A. For services under Section II.A, the billing energy shall be the monthly sum of the scheduled kilowatthours, plus the monthly sum of kilowatthours allocated but not scheduled. The amount of allocated but not scheduled energy that is subject to billing may be reduced pro rata by BPA due to forced Intertie outages and other uncontrollable forces that may reduce Intertie capacity. The amount of allocated but not scheduled energy that is subject to billing also may be reduced upon mutual agreement between BPA and the customer.

B. For services under Section II.B, the billing demand shall be the Transmission Demand as defined in the Agreement. The billing energy shall be the monthly sum of scheduled kilowatthours, unless otherwise specified in the Agreement.

SECTION I. ADOPTION OF REVISED TRANSMISSION RATE SCHEDULES AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS (GTRSPs)

A. Approval of Rates

These rate schedules and GTRSPs shall become effective upon interim approval or upon final confirmation and approval by FERC. BPA will request FERC approval effective October 1, 1993.

B. General Provisions

These 1993 Transmission Rate Schedules and associated GTRSPs are virtually identical to and supersede BPA's 1991 Transmission Rate Schedules and GTRSPs (which became effective October 1, 1991) but do not supersede prior rate schedules required by agreement to remain in force.

Transmission service provided shall be subject to the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act, and the Energy Policy Act of 1992, Pub. L. 102-486, 106 Stat. 2776 (1992).

The meaning of terms used in the transmission rate schedules shall be as defined in agreements or provisions which are attached to the Agreement or as in any of the above Acts.

C. Interpretation

If a provision in the executed Agreement is in conflict with a provision contained herein, the former shall prevail.

SECTION II. BILLING FACTOR DEFINITIONS AND BILLING ADJUSTMENTS

A. Billing Factors

1. Scheduled Demand

The largest of hourly amounts wheeled which are scheduled by the customer during the time period specified in the rate schedules.

2. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands measured by meters installed at each POD during each time period specified in the applicable rate schedule. Such measurements shall be made as specified in the Agreement. BPA, in determining the Metered Demand, will exclude any abnormal readings due to or resulting from: (a) emergencies or breakdowns on, or maintenance of, the FCRTS; or (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. If more than one class of power is delivered to any POD, the portion of the metered quantities assigned to any class of power shall be as agreed to by the parties. The amount so assigned shall constitute the Metered Demand for such class of power.

3. Transmission Demand

The demand as defined in the Agreement.

4. Total Transmission Demand

The sum of the transmission demands as defined in the Agreement.

5. Ratchet Demand

The maximum demand established during the previous 11 billing months. Exception: If a Transmission Demand or Total Transmission Demand has been decreased pursuant to the terms of the Agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

B. Billing Adjustments

Average Power Factor

The adjustment for average power factor, when specified in a transmission rate schedule or in the Agreement, shall be made in accordance with the average power factor section of the General Wheeling Provisions.

To maintain acceptable operating conditions on the Federal system, BPA may restrict deliveries of power at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 85 percent.

SECTION III. OTHER DEFINITIONS

Definitions of the terms below shall be applied to these provisions and the Transmission Rate Schedules, unless otherwise defined in the Agreement.

A. Agreement

An agreement between BPA and a customer to which these rate schedules and provisions may be applied.

B. Eastern Intertie

The segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment including related terminals at Garrison.

C. Electric Power

Electric peaking capacity (kW) and/or electric energy (kWh).

D. Federal Columbia River Transmission System

The transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

E. Firm Transmission Service

Transmission service which BPA provides for any non-BPA power except for transmission service which is scheduled as nonfirm. If the firm service is provided pursuant to the Agreement, the terms of the Agreement may further define the service.

F. Integrated Network

The segment of the FCRTS for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest, excluding facilities not segmented to the network as shown in the Wholesale Power Rate Development Study used in BPA's rate development.

G. Main Grid

As used in the FPT and IR rate schedules, that portion of the Integrated Network with facilities rated 230 kV and higher.

H. Main Grid Distance

As used in the FPT rate schedules, the distance in airline miles on the Main Grid between the POI and the POD, multiplied by 1.15.

I. Main Grid Interconnection Terminal

As used in the FPT rate schedules, Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

J. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, switching, transformation, and other facilities of the Main Grid not included in other components.

K. Main Grid Terminal

As used in the FPT rate schedules, the Main Grid terminal facilities located at the sending and/or receiving end of a line exclusive of the interconnection terminals.

L. Nonfirm Transmission Service

Interruptible transmission service which BPA may provide for non-BPA power.

M. Northern Intertie

The segment of the FCRTS for which the transmission facilities consist of two 500 kV lines between Custer Substation and the United States-Canadian border, one 500 kV line between Custer and Monroe Substations, and two 230 kV lines from Boundary Substation to the United States-Canadian border, and the associated substation facilities.

N. Point of Integration (POI)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is made available to BPA for wheeling.

O. Point of Delivery (POD)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is delivered to a customer by BPA.

P. Secondary System

As used in the FPT and IR rate schedules, that portion of the Integrated Network facilities with operating voltage of 115 kV or 69 kV.

Q. Secondary System Distance

As used in the FPT rate schedules, the number of circuit miles of Secondary System transmission lines between the secondary POI and the Main Grid or the secondary POD, or the Main Grid and the secondary POD.

R. Secondary System Interconnection Terminal

As used in the FPT rate schedules, the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

S. Secondary System Intermediate Terminal

As used in the FPT rate schedules, the first and final terminal facilities in the Secondary System transmission path exclusive of the Secondary System Interconnection terminals.

T. Secondary Transformation

As used in the FPT rate schedules, transformation from Main Grid to Secondary System facilities.

U. Southern Intertie

The segment of the FCRTS for which the major transmission facilities consist of two 500 kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation; when completed, the Third AC facilities, which include Captain Jack Substation and the Alvey-Meridian 500 kV AC line; one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border; and associated substation facilities.

V. Transmission Service

As used in the MT rate schedule, Transmission Service is as defined in the Western Systems Power Pool Agreement.

SECTION IV. BILLING INFORMATION

A. Payment of Bills

Bills for transmission service shall be rendered monthly by BPA. Failure to receive a bill shall not release the customer from liability for payment. Bills for amounts due of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

The transmission billing determinant is the electric power quantified by the method specified in the Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

The transmission customer shall provide necessary information to BPA for any computation required to determine the proper charges for use of the FCRTS, and shall cooperate with BPA in the exchange of additional information which may be reasonably useful for respective operations.

Demand and energy billings for transmission service under each applicable rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill to be followed at a subsequent billing date by a final bill. The estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Billing Month

For charges based on scheduled quantities, the billing month is the calendar month. For charges based on metered quantities, the billing month is defined as the interval between scheduled meter-reading dates. The billing month will not exceed 31 days in any case. While it may be necessary to read meters on a day other than the scheduled meter-reading date, for determination of billing demand, the billing month will cease at 2400 hours on the last scheduled meter-reading date. Schedules will be predetermined. The customer must give 30 days notice to request a change to the schedule.

4. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the customer), the due date shall be the next following business day.

5. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the customer. However, such cancellation shall not affect the customer's liability for any charges accrued prior thereto under such agreement.

6. **Disputed Billings**

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the customer is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

7. **Revised Bills**

As necessary, BPA may render a revised bill.

a. If the amount of the revised bill is less than or equal to the amount of the original bill, the revised bill shall replace all previous bills issued by BPA that pertain to the specified customer for the specified billing period and the revised bill shall have the same date as the replaced bill.

b. If a revision causes an additional amount to be due BPA or the specified customer beyond the amount of the original bill, a revised bill will be issued for the difference and the date of the revised bill shall be its date of issue.

Annual Costs Rate

A. PROPOSED SOUTHERN INTERTIE ANNUAL COST RATE

SECTION I. AVAILABILITY

This schedule is applicable to each party (Capacity Owner) that executes a PNW AC Intertie Capacity Ownership Agreement (Agreement). Billings pursuant to this schedule is subject to the Billing Provisions in Exhibit B of the Agreement. This rate schedule shall be effective on the first day of the fiscal year following the earlier of interim or final FERC approval of this rate schedule. Unless otherwise defined in this rate schedule, capitalized terms used in this rate schedule shall have the respective definitions set forth in section 1 of this Agreement.

SECTION II. RATE

A. Operations

The monthly charge equals:

$$\frac{\text{Operations Cost * Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Operations Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Operations rate shall be calculated using the forecast Operations Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Operations Cost shall be calculated using the forecast Operations Cost less the Operations Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

B. Maintenance

The monthly charge equals:

$$\frac{\text{Maintenance Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Maintenance Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Maintenance rate shall be calculated using the forecast Maintenance Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Maintenance Cost shall be calculated using the forecast Maintenance Cost less the Maintenance Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

C. General Plant

The monthly charge equals:

$$\frac{\text{General Plant Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to General Plant Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the General Plant rate shall be calculated using the General Plant Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for General Plant Cost shall be calculated using the General Plant Cost less the General Plant Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

D. Other Costs

The monthly charge equals:

$$\frac{\text{Other Costs * Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Other Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Other Costs rate shall be calculated using the forecast Other Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Other Costs shall be calculated using the forecast Other Costs less the Other Costs already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

E. Contracts and Rates

The monthly charge equals:

$$\frac{\text{Contracts and Rates Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Contracts and Rates Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Contracts and Rates Cost is determined in accordance with section VI of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Contracts and Rates Cost determined in accordance with section VI of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Contracts and Rates rate shall be calculated using the forecast Contracts and Rates Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Contracts and Rates Cost shall be calculated using the forecast Contracts and Rates Cost less the Contracts and Rates Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

F. Power Scheduling

The monthly charge equals:

$$\frac{\text{Power Scheduling Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Power Scheduling Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Power Scheduling Cost is determined in accordance with section VII of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Power Scheduling Cost determined in accordance with section VII of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Power Scheduling rate shall be calculated using the forecast Power Scheduling Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Power Scheduling Cost shall be calculated using the forecast Power Scheduling Cost less the Power Scheduling Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

G. End of Term

The monthly charge shall equals:

$$\frac{\text{End of Term Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to End of Term Costs, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the End of Term rate shall be calculated using the forecast End of Term Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for End of Term Costs shall be calculated using the forecast End of Term Costs less the End of Term Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

H. Replacements and Reinforcements

1. For each Replacement, the charge equals:

   Replacement Cost * Capacity Ownership Percentage

2. For each Reinforcement, the charge equals:

   Reinforcement Cost * Capacity Ownership Percentage

Where

"Replacement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Replacement Cost does not include capitalized general plant cost. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Reinforcement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Reinforcement Cost does not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The charge for the Replacements and Reinforcements rate shall use the actual Replacement Cost and Reinforcement Cost in the Operating Plan.

SECTION III. ADJUSTMENTS

If an amendment to the Operating Plan results in a net amount that Bonneville owes the Capacity Owners pursuant to sections II.A-G or pursuant to section II.H, Bonneville shall refund such net amount pursuant to paragraph 9(f)(4) of the Agreement.

The monthly charges assessed Capacity Owners under sections II.A-G shall be adjusted, and payment or refund made with interest, pursuant to paragraphs 9(b)(2) or 9(f)(4) of the Agreement, to reflect amendments to the Operating Plan that occur after the year to which such Operating Plan pertains.

A Capacity Owner's share of the adjustment shall be determined using the same Capacity Ownership Percentage used in the billings under sections II.A-G during the fiscal year that such Operating Plan is effective.

B. BILLING PROVISIONS

I. General Provisions

A. Approval of Rates

The annual costs rate shall become effective upon interim approval or upon final confirmation and approval by FERC. Bonneville will request FERC approval of such rate schedule effective on the first day of a Bonneville fiscal year.

B. Application of Billing Provisions

These Billing Provisions shall apply to bills rendered by Bonneville pursuant to the annual costs rate.

C. Definition of Terms

The meaning of terms used in the AC-95 rate shall be as defined in the Agreement or, if no definition is provided by the Agreement, such terms shall be defined according to applicable Federal law.

II Billing Information

Payment of Bills

Charges pursuant to the AC-95 rate shall be included in Bonneville's monthly power bill to Capacity Owner. Failure to receive a power bill shall not release Capacity Owner from liability for payment. Power bills for amounts due of $50,000 or more must be paid by direct wire transfer. If Capacity Owner anticipates special difficulties in meeting this requirement, Capacity Owner may request and Bonneville may approve an exemption from this requirement. Power bills for amounts due Bonneville under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by Bonneville. The procedures to be followed in making direct wire transfers will be provided by Bonneville's Financial Services Group and updated as necessary.

(1) Computation of Bills

(a) Bonneville shall bill Capacity Owner in accordance with the annual costs rate.

(b) Capacity Owner shall provide necessary information to Bonneville for any computation required to determine proper charges pursuant to the Agreement and shall cooperate with Bonneville in the exchange of additional information which may be reasonably useful for respective operations.

(c) Bills rendered pursuant to this Agreement shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents to 99 cents to the next higher whole dollar.

(2) Billing Month

For charges pursuant to the annual costs rate the billing month shall be the same as for the power bill rendered by Bonneville to Capacity Owner.

(3) Due Date

Charges pursuant to the annual costs rate shall be included in the power bill rendered by Bonneville to Capacity Owner and shall be due as part of the power bill when such power bill is due.

(4) Late Payment

The penalties for failure to pay a bill in full on or before close of business on the due date shall be the same as those contained in the late payment provisions in Bonneville's General Transmission Rate Schedule Provisions in effect on the date of the bill; provided, however, that no other provision of any such General Transmission Rate Schedule Provisions, including, but not limited to, provisions regarding cancellation, termination, or suspension of service, shall have application with respect to the payment of any rate or charge pursuant to the annual costs rate set forth in Exhibit B. Bonneville's right to suspend service for late payment under the Agreement shall be pursuant to paragraph 9(e)(1) of this Agreement, which right shall in no way be limited by this section.

(5) Disputed Bills

In the event of a disputed bill, full payment shall be rendered to Bonneville and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified in section II(4) of the Billing Provisions of this Exhibit B. Bonneville shall separately account for the disputed amount. If it is determined that Capacity Owner is entitled to the disputed amount, Bonneville shall refund the disputed amount with interest, such interest to be determined by Bonneville's Financial Services Group. In the event that Bonneville and Capacity Owner do not resolve such dispute, Capacity Owner shall not be prevented by this section II(5)of the Billing Provisions of this Exhibit B from initiating arbitration pursuant to and to the extent allowed by section 15 of this Agreement.

(6) Revised Bills

If Bonneville determines that it has over- or under-charged Capacity Owner due to a computational error or pursuant to an amendment to the Operating Plan in any given billing month, Bonneville may render to Capacity Owner a revised bill.

(i) If the amount of the revised bill is less than or equal to the amount of the original bill for such billing month, the revised bill shall replace the original bill issued by Bonneville. The revised bill shall have the same date as the original bill.

(ii) If the amount of the revised bill is greater than the amount of the original bill for such billing month, a new bill will be issued for the difference between the revised bill and the original bill. The date of the new bill shall be its date of issuance, and Capacity Owner shall make payment to Bonneville as specified in the Billing Provisions of this Exhibit B.

Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share

Capacity Ownership Share	=	400 MW
Capacity Ownership Percentage	=	Capacity Ownership Share ÷ Bonneville's PNW AC Intertie Rated Transfer Capability[1]
Scheduling Percentage	=	Capacity Ownership Share ÷ PNW AC Intertie Rated Transfer Capability
Scheduling Share	=	Scheduling Percentage × PNW AC Intertie Operational Transfer Capability

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1/ As of the Effective Date, Bonneville's PNW AC Intertie Rated Transfer Capability in a north-to-south direction, calculated in accordance with the Northwest Intertie Agreements equals 3450 MW (total PNW AC Intertie Rated Transfer Capability (4800 MW) – Portland's PNW AC Intertie Rated Transfer Capability (950 MW) – PacifiCorp's PNW AC Intertie Rated Transfer Capability (400 MW)).

Lump Sum Payment Calculation

A. SECOND 800 MW COSTS, ESTIMATED[1], ACTUAL[2], AND REVISED ACTUAL[3]

		($ in Thousands) (1) BPA's Costs Estimated	(2) BPA's Costs Actual	BPA's Costs Revised Actual
Facilities whose costs will be adjusted using change Between Estimate and Actual				
1.	Alvey (Marion-Alvey Caps)	$5,739		
2.	Slatt (Loop in - Breaker)	3,044		
3.	Grizzly (BPA Breakers)	11,044		
4.	Loop into Slatt	656		
5.	Malin-Meridian loop into Captain Jack	982		
6.	Alvey Substation - BPA	8,168		
7.	Dixonville - PacifiCorp	8,635		
8.	Meridian - PacifiCorp	6,548		
9.	Power System Control	3,575		
10.	Alvey-Spencer - BPA	1,346		
11.	Spencer-Dixonville - PacifiCorp	20,388		
12.	Dixonville-Meridian - PacifiCorp	32,140		
	SUBTOTAL	102,265		
Facilities whose costs will be adjusted using Change Between Estimate and Actual, multiplied by 50 percent				
13.	Captain Jack (BPA Breakers)	$14,335		
14.	Captain Jack (Communication and Control)	5,100		
15.	Captain Jack (Series Capacitors)	722		
16.	Power System Control	5,596		
17.	Captain Jack line to Oregon-Calif. border	5,724		
	SUBTOTAL	$31,477		
	50 PERCENT OF SUBTOTAL	15,739		
	TOTAL	$118,004		

1/ Based on mid-1989 program planning levels.

2/ Actual costs will be available approximately December 1995, or as soon as practicable thereafter. Supporting documentation will be provided including work orders and accounting data for each line item.

3/ For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the revised actual costs of facilities pertaining to each such calculation of the Revised Adjusted Capacity Ownership Price.

B. INITIAL, ADJUSTED, AND REVISED ADJUSTED CAPACITY OWNERSHIP PRICE[1]

		($ in Millions)		
		(1)	(2)	
		Initial Capacity Ownership Price	Adjusted Capacity Ownership Price	Revised Adjusted Capacity Ownership Price[2]
	Cost Item			
1.	Second 800 MW	$118	$___	$___
2.	AFUDC[3] on Second 800 MW	+ 19	+ ___	+ ___
3.	Existing Support Facilities	+ 19.1	+ 19.1[4]	+ 19.1[4]
4.	Total Cost[5]	$156	$___	$___
5.	PRICE PER KW (CO-94)[6]	$215	$___	$___

1/ Initial, Adjusted, and Revised Adjusted Capacity Ownership Price are determined in accordance with the CO-94 rate in Exhibit A.

2/ Bonneville may make multiple calculations of the Revised Adjusted Capacity Ownership Price pursuant to paragraph 9(a)(3). For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the column pertaining to such calculation and the columns for any previous calculations of the Revised Adjusted Capacity Ownership Price.

3/ AFUDC will be calculated in accordance with the CO-94 rate in Exhibit A.

4/ Not adjusted in calculating the Adjusted Capacity Ownership Price or the Revised Adjusted Capacity Ownership Price.

5/ Bonneville's indirect costs and overhead costs shall be included. Such indirect costs and overhead costs shall be allocated or distributed to the Third AC Intertie Project using the indirect and overhead allocation and distribution methodologies employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Third AC Intertie Project was under construction. Such allocation or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's Third AC Intertie Project than with respect to any other transmission projects under construction at the same time.

6/ Price per kW is derived by dividing the Total Cost by 725 MW.

C. INITIAL LUMP SUM PAYMENT

1.	Puget's Capacity Ownership Share	=	400 MW
2.	Initial Capacity Ownership Price	X	$215 ($215,000/MW)
3.	Initial Lump Sum Payment[1]	=	$86,000,000
4.	Deduction: Negotiation Deposit with Interest[2]	-	
5.	Due to Bonneville:	=	

1/ Initial Lump Sum Payment is calculated in accordance with section IV.A of the CO-94 rate in Exhibit A.

2/ Interest is calculated as specified in Bonneville's April 23, 1993, letter to Puget. The rate of interest for the computation is the interest rate applicable to 3-month Treasury Bills as specified in the FEDERAL RESERVE Statistical Release G.13. The rates are determined for the 3-month yield reported on the first day of the month of receipt of the negotiation deposit and on the first day of each subsequent third month thereafter. Interest is compounded quarterly from May 11, 1993, through the date Bonneville receives payment pursuant to paragraph 9(a)(1).

D. ADJUSTED LUMP SUM PAYMENT

1.	Puget's Capacity Ownership Share	=	400 MW
2.	Adjusted Capacity Ownership Price	X	$
3.	Adjusted Lump Sum Payment[1]	=	
4.	Initial Lump Sum Payment	-	____________
5.	SUBTOTAL due to Bonneville, or Refund Due to Puget	=	
6.	Interest[2]	+	
7.	Due to Bonneville, or Refund due to Puget	=	

1/ Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A.

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from the date Bonneville receives payment pursuant to paragraph 9(a)(1) through the date Bonneville or Puget receives payment pursuant to subparagraph 9(a)(2)(B).

E. REVISED ADJUSTED LUMP SUM PAYMENT

1.	Puget's Capacity Ownership Share	=	400 MW
2.	Current Revised Adjusted Capacity Ownership Price	X	$
3.	Current Revised Adjusted Lump Sum Payment[1]	=	
4.	Adjusted Lump Sum Payment/immediately preceding Revised Adjusted Lump Sum Payment	-	____________
5.	SUBTOTAL due to Bonneville, or Refund Due to Puget	=	
6.	Interest[2]	+	
7.	Due to Bonneville, or Refund due to Puget	=	

1/ Revised Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A. Bonneville will calculate a Revised Adjusted Lump Sum Payment each time a Revised Adjusted Capacity Ownership Price is calculated pursuant to paragraph 9(a)(3).

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from (a) the date Bonneville or Puget receives payment with respect to the Adjusted Lump Sum Payment pursuant to paragraph 9(a)(2)(B) or (b) the date Bonneville or Puget receives payment with respect to the Revised Adjusted Lump Sum Payment immediately preceding the current Revised Adjusted Lump Sum Payment through the date Bonneville or Puget receives payment with respect to the current Revised Adjusted Lump Sum Payment pursuant to subparagraph 9(a)(3)(B).

Transmission Loss Factors

A. The transmission loss factor to be applied to Puget's schedules for transactions transmitted on Puget's Scheduling Share shall be 2.5 percent.

B. The transmission loss factor to be applied to Puget's schedules for transactions transmitted pursuant to subparagraph 3(b)(1)(C) shall be 3.0 percent.

Bonneville's PNW AC Intertie

A. TRANSMISSION LINE FACILITIES

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1. McNary-John Day 500 kV Line Loop into Slatt: • McNary-Slatt Str. 108/1 to substation dead end tower, 155 meters • Slatt-John Day Str. 1/1 to substation dead end tower, 194 meters	100	100
2. John Day-Grizzly No. 1 500 kV	100	100
3. John Day-Grizzly No. 2 500 kV	100	100
4. Grizzly-Captain Jack No. 1 500 kV	100	100
5. Captain Jack-Malin No. 1 500 kV	100	100
6. Buckley-Grizzly 500 kV	100	57
7. Grizzly-Summer Lake 500 kV	100	57
8. 500 kV double circuit between Buckley and Marion that supports the Buckley-Marion No. 1 and the Ashe-Marion No. 2 500 kV circuits (Str. No. 1/3 to Marion, 159 km)	100	25
9. Marion-Alvey 500 kV	100	50
10. Captain Jack-COB (10 km) 500 kV	100	100
11. Alvey-Dixonville 500 kV	50	100
12. Dixonville-Meridian 500 kV	50	100

B. SUBSTATION FACILITIES 1/ 2/

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1. **Slatt 500 kV** (Dispatch one-line diagram No. 228962)		
John Day line terminal		
• New Breaker D#5021	100	100
• Existing 500 kV MOD D#5020/7022	100	100
• New 500 kV MOD D#5022	100	100
• Existing 500 kV MOD D#5019	100	50
• Existing Breaker D#5018	100	50

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	McNary line terminal		
	• 500 kV MOD D#5023/7847	100	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Station General		
2.	**John Day 500 kV** (Dispatch one-line diagram No. 132281)		
	Grizzly No.2 line terminal		
	• Breaker D#4131	100	50
	• Breaker D#4134	100	100
	• MOD D#4132	100	50
	• MOD D#4133/7867	100	100
	• MOD D#4135	100	100
	• Associated Line PTs	100	100
	Grizzly No.1 line terminal		
	• Breaker D#4140	100	50
	• Breaker D#4143	100	100
	• MOD D#4141	100	50
	• MOD D#4142/7869	100	100
	• MOD D#4144	100	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Station General		
3.	**Buckley 500 kV, Gas Insulated Substation** (Dispatch one-line diagram No. 232583)		
	Slatt No. 1 line terminal		
	• Breaker D#4967	100	57
	• Isolating switch D#4966/7328	100	57
	• Isolating switch D#4968/7355	100	57
	• Ground switch D#7415	100	57
	• Associated Terminal Arresters	100	57
	• Associated Line PTs	100	57
	Summer Lake No. 1 line terminal		
	• Breaker D#4961	100	57

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
	• Isolating switch D#4960/7312	100	57
	• Isolating switch D#4962/7313	100	57
	• Ground switch D#7311	100	57
	• Associated Terminal Arresters	100	57
	• Associated Line PTs	100	57
	Marion No. 1 line terminal		
	• Breaker D#4964	100	57
	• Isolating switch D#4963/7314	100	57
	• Isolating switch D#4965/7321	100	57
	• Ground switch D#7477	100	57
	• Associated Terminal Arresters	100	57
	• Associated Line PTs	100	57
	Station General		
4.	**Marion 500 kV** (Dispatch one-line diagram No. 136180)		
	Buckley line terminal		
	• Breaker D#4389	100	50
	• Breaker D#4386	100	25
	• MOD D#4387	100	25
	• MOD D#4390	100	50
	• MOD D#4388/7751	100	50
	• Associated Line PTs	100	50
	Alvey line terminal		
	• Breaker D#4374	100	50
	• Breaker D#4377	100	25
	• MOD D#4376	100	25
	• MOD D#4375/7922	100	50
	• MOD D#4373	100	50
	• Associated Line PTs	100	50
	Station General		
5.	**Alvey 500 kV** (Dispatch one-line diagram No. 121424)		
	Bank No. 5 terminal		
	• Breaker D#5081	50	100
	• MOD D#5080	50	100
	• MOD D#5082	50	100
	• MOD D#5090	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#5089/8157	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Marion No. 1 line terminal		
• Breaker D#5084	50	100
• MOD D#5083/8155	50	100
• MOD D#5085	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Dixonville No. 1 line terminal		
• Breaker D#5087	50	100
• MOD D#5086/8156	50	100
• MOD D#5088	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
500 kV Series Capacitor Bank (Marion-Alvey 500 kV line)	50	100
• MODs D#5100/8160,5101/8159, 5102/8158	50	100
• Bypass breaker D#5103	50	100
Station General		

6. **BPA/PacifiCorp Dixonville 500 kV Station** (PacifiCorp's one-line diagram PD-40020)

Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299, as revised or amended.

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
For Alvey and Meridian line terminals		
• Breakers 11U1, 11U2, 11U3	50	100
• Isolating MODs 11U701, 11U700/ 11U507, 11U702, 11U703/11U505, 11U704, 11U705/11U506, 11U706, 11U707, 11U708/11U501	50	100
• Two sets of line terminal PTs	50	100
• Two sets of line terminal arresters	50	100

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
	• Series Capacitor Bank in Alvey-Dixonville 500 kV line and associated isolating devices	50	100
	• 180 MVAR Shunt Reactor Bank S664, 665, 666, 667 and associated arresters, PTs, and isolating devices	50	100
	Station General		
7.	**BPA/PacifiCorp Meridian 500 kV Yard** (PacifiCorp's one-line diagram PD-32976)		
	Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299.		
	For Dixonville line terminal		
	• Breakers 11R2, 11R6	50	50
	• Isolating MODs 11R702, 11R703/ 11R501, 11R704, 11R710, 11R711	100	100
	• One set of line PTs	50	100
	• One set of line terminal arresters for the Dixonville line and one set for the Captain Jack line	50	100
	• 180 MVAR Shunt Reactor Bank S690, 691 ,692, 693 and associated arresters, PTs, and isolating devices	50	100
	• Series Capacitor Bank in the Dixonville-Meridian 500 kV line and associated isolating devices.	50	100
	Station General		
8.	**Grizzly 500 kV** (Dispatch one-line diagram No. 103924)		
	John Day No. 1 line terminal		
	• Breaker D#4058	100	100
	• Breaker D#5040	100	100
	• MOD D#4059	100	100
	• MOD D#4057/7848	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4056	100	100
• MOD D#5039	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
John Day No. 2 line terminal		
• Breaker D#4042	100	100
• Breaker D#4046	100	100
• MOD D#4043	100	100
• MOD D#4044/7845	100	100
• MOD D#4045	100	100
• MOD D#4047	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Buckley No. 1 line terminal		
• Breaker D#5031	100	100
• Breaker D#5028	100	100
• MOD D#5032	100	100
• MOD D#5030/8122	100	100
• MOD D#5029	100	100
• MOD D#5027	100	100
• Associated Line PTs	100	100
Captain Jack No. 1 line terminal		
• Breaker D#5037	100	100
• Breaker D#5034	100	100
• MOD D#5038	100	100
• MOD D#5036/8123	100	100
• MOD D#5035	100	100
• MOD D#5033	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Summer Lake line terminal		
• Breaker D#5025	100	100
• MOD D#5026/8121	100	100
• MOD D#5024	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
	180 MVAR Reactor Bank No. 1	100	100
	• Breaker D#4222	100	100
	• Isolating Switch D#4060	100	100
	• Associated Arresters	100	100
	300 MVAR Reactor Bank No. 2	100	100
	• Breaker D#4720	100	100
	• Isolating Switch D#4719	100	100
	• Associated Arresters	100	100
	• 300 MVAR Reactor Bank No. 3 and Neutral Reactor	100	100
	• Breaker D#4038	100	100
	• Isolating Switch D#4062	100	100
	• Neutral isolating switch D#4109/4081	100	100
	• Associated Arresters	100	100
	• Associated PTs	100	100
	• North Main Bus 500 kV PTs	100	100
	• South Main Bus 500 kV PTs	100	100
	Station General		
9.	**Sand Spring 500 kV Compensation Station** (Dispatch one-line diagram No. 142239)		
	Series Cap.Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
	Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
	Station General		
10.	**Fort Rock 500 kV Compensation Station** (Dispatch one-line diagram No. 142237)		
	Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
	Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
	Station General		
11.	**Sycan 500 kV Compensation Station** (Dispatch one-line diagram No. 142238)		

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
	Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
	Series Cap. Bank No. 3 (Summer Lake-Malin line) and associated equipment but **excluding** the bypass MOD D#5065 and transmission tower	65	100
	Station General		
12.	**Summer Lake 500 kV** (Dispatch one-line diagram No. 232667)		
	Grizzly line terminal (formerly Buckley-Ponderosa Tap)		
	• Breaker D#4959	100	57
	• MOD D#4955	100	57
	• MOD D#4956/7309	100	57
	• Associated Terminal Arresters	100	57
	• Associated Line PTs	100	57
	Malin line terminal		
	• Line protective relays	0	100
	Station General		
13.	**Malin 500 kV** (Dispatch one-line diagram No. 103923)		
	Captain Jack No. 1 line terminal		
	• Breaker D#4066	100	100
	• Breaker D#4064	100	100
	• MOD D#4068	100	100
	• MOD D#4067/7849	100	100
	• MOD D#4065	100	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Round Mountain line No. 1 terminal		
	• Breaker D#4186	50	100
	• MOD D#4063/7970	100	100
	• MOD D#4185	50	100
	• MOD D#4187	50	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Round Mountain line No. 2 terminal		

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Breaker D#4582	50	100
• MOD D#4583	50	100
• MOD D#4581	50	100
• MOD D#4074/7856	75	100
Grizzly No. 2/Round Mountain No. 2 line position	-	
• Breaker D#4072	75	100
• MOD D#4073	75	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	50	100
300 MVAR Shunt Reactor Bank No. 1 and associated arresters and isolating devices (D#4327, 4393)	100	100
2-239 MVAR Shunt Cap. Banks and associated isolating devices (D#4183, 4181, 4184, 4182, 8065, 8066)	100	100
Line protective relays for Summer Lake line	0	100
Station General		
14. **Captain Jack 500 kV** (Dispatch one-line diagram No. 248548)		
Series Cap. Bank No. 1 (Captain Jack-Olinda line)	100	100
• MODs D#4974/8101, 4973/8099, 4975/8100	100	100
• Bypass breaker D#4971, 4972		
Grizzly No. 1 line terminal		
• Breaker D#4990	100	100
• Breaker D#4993	100	100
• MOD D#4989	100	100
• MOD D#4991/8104	100	100
• MOD D#4992	100	100
• MOD D#4994/8105	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Malin No. 1 line terminal		
• Breaker D#4996	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4995	100	100
• MOD D#4997	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Olinda No. 1 line terminal		
• Breaker D#4977	100	100
• Breaker D#4980	100	100
• MOD D#4976	100	100
• MOD D#4978	100	100
• MOD D#4979	100	100
• MOD D#4981	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs (2 sets)	100	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	100	100
Station General		
15. **Chief Joseph Substation** (Dispatch one-line diagram No. 124313)		
230 kV, 1400 MW Braking Resistor	100	100
Includes breaker dispatch No. A-594, a high speed vacuum switch and one 230 kV isolating switch in Bay 12		
Station General		

1/ Station General will be allocated to each substation according to Bonneville's standard methodology.

2/ Each substation includes associated relays.

Capacity Owners

CAPACITY OWNER	CONTRACT NUMBER	CAPACITY OWNERSHIP SHARE (MW)	CAPACITY OWNERSHIP PERCENTAGE
PNGC	DE-MS79-94BP94523	50	1.4
Puget	DE-MS79-94BP94521	400	11.6
Seattle	DE-MS79-94BP94522	160	4.6
Snohomish	DE-MS79-94BP94525	42	1.2
Tacoma	DE-MS79-94BP94524	41	1.1

PNGC: Pacific Northwest Generating Cooperative
Puget: Puget Sound Power & Light Company
Seattle: City of Seattle, City Light Department
Snohomish: Public Utility District No. 1 of Snohomish County
Tacoma: Tacoma Public Utilities

Provisions Required by Statute or Executive Order

1. Contract Work Hours and Safety Standards Act (40 U.S.C. & 327, et seq.).

(a) Overtime Requirements.
Puget, contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall not require or permit any such laborers or mechanics in any workweek in which the individual is employed on such work to work in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than 1-1/2 times the basic rate of pay for all hours worked in excess of 40 hours in such workweek.

(b) Violation: liability for unpaid wages; liquidated damages.
In the event of any violation of the provisions set forth in section 1 of this Exhibit H, Puget and any subcontractor responsible therefore shall be liable for the unpaid wages. In addition, Puget and such subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions set forth in section 1 of this Agreement in the sum of $10.00 for each calendar day on which such individual was required or permitted to work in excess of the standard workweek of 40 hours without payment of the overtime wages required by provision set forth in section 1 of this Exhibit.

(c) Withholding for unpaid wages and liquidated damages.
The person designated in writing by Bonneville's Administrator with the Authority to enter into, administer, modify, suspend or terminate this Exhibit, make related determinations and findings and bind Bonneville only to the extent of delegated authority shall upon his or her own action or upon written request of an authorized representative of the Department of Labor withhold or cause to be withheld, from any moneys payable on account of work performed by Puget or its subcontractor, if any, under any such contract

or any other federal contract subject to the Contract Work Hours and Safety Standards Act which is held by the same prime contractor, such sums as may be determined to be necessary to satisfy any liabilities of Puget or such subcontractor for unpaid wages and liquidated damages as provided in section 2 of this Exhibit.

2. Convict Labor (Exec. Order No. 11755, Dec. 29, 1979).
In connection with the performance or work under this Agreement, Puget and any subcontractor, if any agrees not to employ any person undergoing sentence of imprisonment except as otherwise provided by law.

3. Equal Opportunity (Exec. Order No. 11246, Sep. 24, 1965).

(a) If , during any 12-month period (including the 12 months preceding the award of this contract), Puget has been or is awarded nonexempt federal contracts and/or subcontracts that have an aggregate value in excess of $25,000.00, Puget shall comply with sections 3(b)(1) through 3(b)(11) below. Upon request, Puget shall provide information necessary to determine the applicability of this clause.

(b) During performance of this Agreement, Puget agrees as follows:

(1) Puget shall not discriminate against any employee or applicant for employment because of race, color, religion, sex or national origin.

(2) Puget shall take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex or national origin. Such action shall include, but not be limited to: (1) employment; (2) upgrading; (3) demotion; (4) transfer; (5) recruitment or recruitment advertising; (6) layoff or termination; (7) rates of pay or other forms of compensation; and (8) selection for training, including apprenticeship.

(3) Puget shall post in conspicuous places, available to employees and applicants for employment, the notices that explain this clause, such notices to be provided by the person designated in writing by Bonneville's Administrator with the authority to enter into, administer, modify, suspend or terminate this Agreement, make related determinations and findings and bind Bonneville only to the extent of delegated authority (Contracting Officer).

(4) Puget shall, in all solicitations or advertisements for employees placed by or on behalf of Puget, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex or national origin.

(5) Puget shall send, to each labor union or representative or of workers with which it has a collective bargaining agreement or other contract or understanding, the notice provided by the Contracting Officer advising the labor union or workers' representative of Puget's commitments under this clause, and post copies of the notice in conspicuous places available to employees and applicants for employment.

(6) Puget shall comply with Executive Order No. 11246, Sep. 24, 1965 (30 Fed. Reg. 12319), as amended, and the rules, regulations and orders of the Secretary of Labor.

(7) Puget shall furnish to Bonneville all information required by Executive Order No. 11246, as amended, and by the rules, regulations and orders of the Secretary of Labor. Standard Form 100 (EEO-1), or any successor form, is the prescribed form to be filed within 30 days following the award of this contract, unless filed within 12 months preceding the date of the award of this contract.

(8) Puget shall permit access to its books, records and accounts by Bonneville or the Office of Federal Contract Compliance Programs

(OFCCP) for purpose of investigation to ascertain Puget's compliance with such rules, regulations and orders.

(9) If the OFCCP determines that Puget is not in compliance with this clause or any rule, regulation or order of the Secretary of Labor, this Agreement may be canceled, terminated, or suspended in whole or in part and Puget may be declared ineligible for further Government contracts, under the procedures authorized in Executive Order No. 11246, as amended. In addition, sanctions may be imposed and remedies invoked against Puget as provided in Executive Order No. 11246, as amended, the rules, regulations and orders of the Secretary of Labor, or as otherwise provided by law.

(10) Puget shall include the terms and conditions of sections 3(b)(1) through 3(b)(11) of this Exhibit in every subcontract or purchase order that is not exempted by the rules, regulations, or orders of the Secretary of Labor issued under Executive Order No. 11246, as amended, so that these terms and conditions will be binding upon each subcontractor or vendor.

(11) Puget shall take such action with respect to any subcontract or purchase order as may direct as means of enforcing these terms and conditions, including sanctions for noncompliance: Provided, that if Puget becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of any direction, Puget may request the Government to enter into the litigation to protect the interest of the United States.

(c) Notwithstanding any other clause in this Agreement, disputes relative to this clause will be governed by the procedures in 41 CFR § 66-1.1.

4. Certification of Non-segregated Facilities (48 CFR § 22.810).

(a) Puget certifies that it does not and will not maintain or provide for employees any segregated facilities at any of its establishments and that it does not and will not permit its employees to perform their services at any location under its control where segregated facilities are maintained. Puget agrees that a breach of this certification is a violation of section 3 (the Equal Opportunities Clause) of this Exhibit.

(b) Puget agrees that it will (1) obtain identical certifications from proposed subcontractors prior to the award of subcontracts exceeding $10,000.00 which are not exempt from the provisions of the Equal Opportunity Clause; (2) retain such certifications in its files (3) forward the following notice to such proposed subcontractors, except where the proposed subcontractors have submitted identical certifications of specific time periods:

> "Notice to Prospective Subcontractors of Requirement for Certifications of Non-segregated Facilities.
>
> "A Certification of Non-segregated Facilities must be submitted prior to the award of a subcontract under which the subcontractor will be subject to the Equal Opportunity clause. This certification may be submitted either for each subcontract or for all subcontracts during a period (i.e., quarterly, semiannually or annually)."

5. <u>Officials Not to Benefit (41 U.S.C. § 22)</u>.

No member of or delegate to Congress, or resident commissioner, shall be admitted to any share or part of this Agreement or to any benefit arising from it. However, this clause does not apply to this Agreement to the extent that this Agreement is made with a corporation for the corporation's general benefit.

6. <u>Bonneville's Obligations Not General Obligations of the United States (16 U.S.C. § 839(i))</u>.

None of the offerings of obligations, or promotional materials for such obligations, which may be offered by Puget to fund its activities pursuant to this Agreement, shall be construed to be, general obligations of the United States, nor are such obligations intended to be or are they secured by the full faith and credit of the United States.

7. Small Business Act (15 U.S.C. §§ 631 and 637).

(a) It is the policy of the Government that small business concerns owned and controlled by socially and economically disadvantaged individuals shall have the maximum practicable opportunity to participate in the performance of contracts let by any federal agency.

(b) Puget hereby agrees to carry out the policy set forth in 7(a) in awarding subcontracts to the fullest extent consistent with the efficient performance of this Agreement. Puget further agrees to cooperate on any studies or surveys as may be conducted by the United States Small Business Administration or Bonneville as may be necessary to determine the extent of Puget's compliance with this clause.

(c) As used in this agreement the term "small business concern" shall mean a small business as defined in section 3 of Small Business Act (15 U.S.C. § 632) and relevant regulations promulgated pursuant thereto. The term "small business concern owned and controlled by socially and economically disadvantaged individuals" shall mean a small business concern:

(1) which is at least 51 percent owned by one or more socially disadvantaged individuals; or, in the case of any publicly owned business, at least 51 percent of the stock of which is owned by one or more socially or economically disadvantaged individuals; and

(2) whose management and daily business operations are controlled by one or more such individuals.

Puget shall presume that socially and economically disadvantaged individuals include Black Americans, Hispanic Americans, Native Americans, Asian Pacific Americans and other minorities, or any other individual found to be disadvantaged by the United States Small Business Administration pursuant to section 8(a) of the Small Business Act.

(d) Puget acting in good faith may rely on written representations by its subcontractor regarding its status as either a small business concern or a small business concern owned and controlled by socially and economically disadvantaged individuals.

8. <u>Other Statutes, Executive Orders and Regulations</u>.

(a) Puget agrees to comply with the following statutes, executive orders and regulations to the extent applicable:

(1) False Claims Act, 31 U.S.C. § 3729, et seq. Whoever makes or presents to any person or officer in the civil military or naval service of the United States, or to any department or agency thereof, any claim upon or against the United States, or any department or agency thereof, knowing such claim to be false, fictitious or fraudulent, shall be fined not more than $10,000.00 or imprisoned not more than 5 years, or both;

(2) Rehabilitation Act of 1973, 29 U.S.C. §793, as amended, Executive Order No. 11758, Jan. 15, 1974, and the regulations of the Secretary of Labor, 41 CFR Part 60-250, et seq., which concern affirmative action for handicapped workers;

(3) Vietnam Era Veterans Readjustment Assistance Act of 1972, 38 U.S.C. §§ 101, 102, 240, 241, 1502, 1504, 1507, as amended, and the clauses contained in 41 CFR Part 60-250, et

seq., which concern affirmative action for disabled veterans and veterans of the Vietnam Era;

(4) Executive Order No. 11625, Oct. 13, 1971, and implementing regulations which concern utilization of small disadvantaged business concerns;

(5) Anti-Kickback Act, 41 U.S.C. § 51, et seq.; and

(6) Privacy Act of 1974, 5 U.S.C. § 552a.

(b) Puget agrees to comply with requirements deemed necessary by Bonneville in order to implement Bonneville's obligations under the National Historic Preservation Act of 1966, U.S.C. §§ 470, et seq.

Bonneville's PNW AC Intertie Costs

All costs in sections I through VIII of this Exhibit I shall be subject to the following provisions:

PURPOSE

Bonneville shall determine and calculate Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs with respect to Bonneville's PNW AC Intertie in accordance with this Exhibit I. None of Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, and End of Term Costs (each of the foregoing for purposes of this sentence, a Cost) shall include any other Cost.

SOURCE OF INFORMATION AND COSTS

Bonneville shall forecast in accordance with this Exhibit I the costs reflected in any Operating Plan pursuant to Schedules A through H of this Exhibit using the most detailed information available to Bonneville from its budget process at the time the forecast is made. Bonneville shall determine the actual costs reflected in any Operating Plan pursuant to Schedules A through H, using Bonneville's then existing accounting system in accordance with this Exhibit I. All costs reflected in Schedules A through H shall be net of credit.

Bonneville shall determine its overall overhead and overall indirect costs. A portion of Bonneville's overall overhead and indirect costs shall be allocated to such total system operations costs (pursuant to section I below), total system maintenance costs (pursuant to section II below), total capital costs (pursuant to sections III and IV below), Other Costs (pursuant to section V below), Contracts and Rates Costs (pursuant to section VI below), Power Scheduling Costs (pursuant to section VII below), and End of Term Costs (pursuant to section VIII below) using Bonneville's normal allocation or distribution methodologies for such costs, as such methodologies may be changed by Bonneville from time to time. Such allocations or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's PNW AC Intertie than with respect to other transmission facilities.

Bonneville shall record its costs into its accounting systems in accordance with generally accepted accounting principles. For purposes of this Agreement, "generally accepted accounting principles" means the common set of accounting concepts, standards, and procedures that are adopted by entities (such as the utility industry) for purposes of financial statement disclosure.

Whenever Bonneville alters its accounting system or methods to permit costs referred to in this Exhibit I, which were previously allocated to functions and activities, to be directly assigned to function and activities, then in that event Puget and Bonneville shall, in concert with the Capacity Owners other than Puget, in good faith negotiate revisions to this Exhibit I to include such directly assigned costs.

COSTS

I. Operations Costs

A. Operations Costs - Allocation Factor

The allocation factor (Schedule A, line 3) used to determine the Allocated Direct Cost of Operations Cost, Indirect Cost of Operations Cost, and Overhead Cost of Operations Cost is the ratio of major facility units (MFUs) of Bonneville's PNW AC Intertie operated by Bonneville to MFUs of the Federal Columbia River Transmission System.

An MFU (Schedule A, lines 1 and 2) is any of the following major pieces of power system equipment which, at any given time, is installed on and is a part of the Federal Columbia River Transmission System: substation switchgear (such as power circuit breakers; potential devices; disconnects, load interrupters, hot-stick operated bus links; switching devices, circuit switchers, ground switches; and switchyard equipment terminals); protective equipment (such as grounding devices; reactors; arrestors and resistors;

voltage regulators; engine generators and motor generators; and high voltage fuses); transformation equipment (such as power transformers; diesel generators; grounding transformers; regulators and shunt reactors; synchronous condensers; and shunt or series capacitors); station equipment (such as switchyard lighting, batteries and chargers, air compressors, station service equipment, and lightening arrestors); instruments, control, and supervisory equipment (such as switchboards, instruments, and control panels; relay panels, transfer trip, and single-pole relaying; and oscillographs; fault detectors and locators; sequential events recorders, supervisory control, and data acquisition equipment; and indicating meters, instruments, and loggers); and equipment specific to direct current and static var compensator stations (such as mercury arc valves; thyristor systems; air handling packages; water control packages; harmonic filtering systems; motor control centers, such as fans, pumps, and dampening resistors; and valve damping resistors); or devices that perform similar types of functions.

Once each fiscal year, Bonneville shall count the number of MFUs on Bonneville's PNW AC Intertie (exclusive of facilities operated by others) (Schedule A, line 1) and the number of MFUs on the Federal Columbia River Transmission System (Schedule A, line 2). In calculating the forecast Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs, Bonneville shall use the most recent MFU count available at the time of such calculation in developing its initial Operating Plan for a given fiscal year. For each Operating Plan which is for the same fiscal year, Bonneville shall use the same MFU count in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

B. Operations Costs - Operations Functionalization Factor

For each Operating Plan, Bonneville's total system operations direct cost, indirect cost and overhead cost (Schedule A, lines 7, 9, and 11) shall be adjusted by an operations functionalization factor (Schedule A, line 6) so that Capacity Owners pay only transmission-related system operations costs. The operations functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using the costs developed for the last year of the rate period for which Bonneville has developed rates, the operations functionalization factor shall be the ratio of (a) Bonneville's total system operations cost functionalized to transmission (Schedule A, line 4) over (b) Bonneville's total system operations cost (Schedule A, line 5). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

C. Operations Costs - Allocated Direct Costs

For each Operating Plan, Bonneville shall allocate its total system operations direct costs as set forth in Schedule A, lines 7 and 8, to determine Allocated Direct Costs of Operations Cost (Schedule A, line 8).

Schedule A, line 7, shall reflect Bonneville's total system operations direct costs for a fiscal year. Bonneville's total system operations direct costs for a fiscal year shall include all system operations expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: substation operations (which provides for, among other things, making equipment adjustments to maintain loads and voltages within acceptable limits, switching to deenergize lines and equipment during maintenance outages, isolating damaged equipment, restoring service to customers, visually inspecting equipment, and reading meters that record line and equipment loading and voltages), power system control and dispatching (which provides for, among other things, central dispatching, control, and monitoring of the electric operation of the Federal transmission system; load, frequency, and voltage control of

Federal generating plants; the operating of the system control and data computers at the Dittmer and Eastern Control Centers; and modification and maintenance of the operation-related computers), and operations standards and engineering (which provides for, among other things, analyzing system loads, voltage levels, outage information, stability levels, and other data; making policy recommendations for system operations; planning operations' practices, restoration plans and disturbance ports; development of control center requirements for centralized automation of substations and generation; and Bonneville's participation with other utilities in developing utility operating standards and guides); and other system operations activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 8, shall reflect Allocated Direct Cost of Operations Cost.

D. Operations Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system operations indirect costs as set forth in Schedule A, lines 9 and 10, to determine Indirect Costs of Operations Costs.

Schedule A, line 9, shall reflect Bonneville's total system operations indirect costs for a fiscal year. Bonneville's total system operations indirect costs for a fiscal year shall include all system operations indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: general supervision and management, office support, planning, budgeting, training, direction of facilities' operation, and other system operations activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 10, shall reflect Indirect Cost of Operations Cost.

E. Operations Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system operations overhead costs as set forth in Schedule A, lines 11 and 12, to determine Overhead Costs of Operations Costs.

Schedule A, line 11, shall reflect Bonneville's total system operations overhead costs for a fiscal year. Bonneville's total system operations overhead costs for a fiscal year shall include all system operations overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system operations overhead activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule A, line 12, shall reflect Overhead Cost of Operations Cost.

Schedule A, line 13, shall reflect Operations Cost.

II. Maintenance Costs

A. Maintenance Costs - Power System Control Maintenance Functionalization Factor

For each Operating Plan, the Power System Control (PSC) maintenance cost (Schedule B, line 4) shall be adjusted by a PSC maintenance functionalization factor (Schedule B, line 3). PSC maintenance is the testing, repair, and engineering support for Bonneville's communications and control systems. The PSC maintenance functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs for the last year of the rate period for which Bonneville has developed rates, the PSC functionalization factor shall be the ratio of (a) Bonneville's total PSC maintenance cost functionalized to transmission from such general rate case (Schedule B, line 1) over (b) Bonneville's total PSC maintenance cost from such general rate case (Schedule B, line 2).

B. Maintenance Costs - Direct Costs

The Direct Costs of Maintenance Costs for a fiscal year (Schedule B, line 7) shall be Bonneville's direct costs of maintaining Bonneville's PNW AC Intertie and shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities for maintenance of Bonneville's PNW AC Intertie: transmission line maintenance; substation maintenance; power system control maintenance; nonelectric plant maintenance; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of Bonneville's PNW AC Intertie undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

With the exception of PSC maintenance costs, Bonneville shall specifically identify the direct costs of maintaining Bonneville's PNW AC Intertie (Schedule B, line 7). To determine PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6), the total PSC direct maintenance cost (Schedule B, line 4) shall be multiplied by (a) the PSC maintenance functionalization factor (Schedule B, line 3) and (b) the MFU allocation factor (Schedule B, line 5) set forth in Schedule A, line 3. The Direct Costs of Maintenance Costs (Schedule B, line 8) shall be the sum of (a) PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6) and (b) the direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost (Schedule B, line 7).

C. Maintenance Costs - Allocation Factor

The allocation factor (Schedule B, line 10) used to determine Indirect Cost of Maintenance Cost and Overhead Cost of Maintenance Cost shall be the ratio of the Direct Cost of Maintenance Cost (Schedule B, line 8) to Bonneville's total system maintenance direct cost (Schedule B, line 9), as described below.

Schedule B, line 9, shall reflect Bonneville's total system maintenance direct costs for a fiscal year. Bonneville's total system maintenance direct costs for a fiscal year shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: transmission line maintenance; substation maintenance; power system control maintenance; nonelectric plant maintenance; establishing, monitoring, and updating system maintenance standards, policies, and procedures; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of the Federal Columbia River Transmission System undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 10, shall reflect the percentage which shall be used to allocate Bonneville's total system maintenance indirect cost and total system maintenance overhead cost to Bonneville's PNW AC Intertie.

D. Maintenance Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance indirect costs as set forth in Schedule B, lines 11 and 12, to determine Indirect Costs of Maintenance Costs.

Schedule B, line 11, shall reflect Bonneville's total system maintenance indirect costs for a fiscal year. Bonneville's total system maintenance indirect costs for a fiscal year shall include all system maintenance indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance any of the following activities: supervision and management, office support, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other system maintenance activities undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 12, shall reflect Indirect Cost of Maintenance Cost.

E. Maintenance Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance overhead costs as set forth in Schedule B, lines 13 and 14, to determine Overhead Costs of Maintenance Costs.

Schedule B, line 13, shall reflect Bonneville's total system maintenance overhead costs for a fiscal year. Bonneville's total system maintenance overhead costs for a fiscal year shall include all system maintenance overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system maintenance overhead activities undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule B, line 14, shall reflect Overhead Cost of Maintenance Cost.

Schedule B, line 15, shall reflect Maintenance Cost.

III. Replacement Costs and Reinforcement Costs

A. Replacement Costs and Reinforcement Costs - Direct Costs

The Direct Costs for Replacements and Reinforcements for a fiscal year (Schedule C, line 1) shall be Bonneville's direct capital costs for Replacements and Reinforcements for such fiscal year and shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, land, materials and equipment, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of the following activities: planning, environmental analyses and mitigation, survey, design, land, materials and equipment, turnkey contracts, contract construction, force account construction, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council. The Direct Costs for any Replacement or Reinforcement for a fiscal year shall also include the costs of removal and any salvage credits with respect to any PNW AC Intertie facility removed on account of such Replacement or Reinforcement.

B. Replacement Costs and Reinforcement Costs - Indirect Costs and Overhead Costs

For each Replacement and Reinforcement project, the Indirect Costs and Overhead Costs for Replacements and Reinforcements (Schedule C, line 2) shall be allocated or distributed to such Replacements and Reinforcements using the indirect and overhead allocation and distribution methodologies employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Replacements and Reinforcements are under construction. Schedule C, line 2, shall reflect the Indirect Costs and Overhead Costs of Replacements and Reinforcements.

Indirect Costs of Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel expenses, service contracts, consulting contracts, administration of materials, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: supervision, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Overhead Costs for Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other costs, each of which being which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering);

and (c) other replacement and reinforcement activities undertaken by Bonneville that are consistent with replacement and reinforcement activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

C. Replacement Costs and Reinforcement Costs - Allowance for Funds Used During Construction (AFUDC)

Schedule C, line 3, shall reflect AFUDC for Replacements and Reinforcements. At the beginning of each fiscal year, Bonneville shall calculate the AFUDC rate for such fiscal year. Bonneville shall apply such AFUDC rate monthly to the costs in accounts for construction work in progress for Replacements and Reinforcements.

D. Replacement Costs and Reinforcement Costs - Interest

Schedule C, line 4, shall reflect the interest cost payable by Puget pursuant to this Agreement with respect to any Replacement or Reinforcement. Such interest cost for any Replacement or any Reinforcement shall be simple interest calculated at a rate equal to the weighted average interest rate on Bonneville's then outstanding bonds or other debt instruments and such interest shall accrue from the date Bonneville stops accruing AFUDC (approximately the date the work order for such Replacement or such Reinforcement is closed) with respect to such Replacement or such Reinforcement to the due date of the monthly power bill containing the charge for such Replacement or such Reinforcement.

IV. General Plant Costs

For each Operating Plan, Bonneville shall adjust, amortize, and allocate Bonneville's total general plant investment (as described below) and Bonneville's Dittmer control equipment investment as set forth in Schedule D, lines 1 through 11, to determine General Plant Cost.

Schedule D, line 1, shall reflect for a fiscal year Bonneville's total cumulative general plant investment. Bonneville's total general plant investment shall include Bonneville's investments in any of the following: land-general plant, structures/improvements-general plant, office furniture and equipment, transportation equipment, stores equipment, tools/shop/garage equipment, laboratory equipment, power operated equipment, communication equipment, miscellaneous equipment (including equipment or apparatus used in Bonneville's utility operations which are not includable in any other general plant investment category), and other similar investment made by Bonneville that is consistent with general plant investment made by utilities in the Western Systems Coordinating Council.

Schedule D, line 2, shall reflect for a fiscal year Bonneville's cumulative investment in Dittmer control equipment.

Schedule D, line 3, shall reflect Bonneville's total general plant investment and Bonneville's Dittmer control equipment investment functionalized to generation using the methodology for functionalizing general plant as set forth in Bonneville's general rate case most recently approved by FERC on an interim basis.

Schedule D, line 4, shall reflect any general plant investment recovered from all Capacity Owners under the CO-94 rate as such general plant investment is unitized by Bonneville; provided, however, for the first two Operating Plans Bonneville shall estimate the amount of the general plant investment included in the Initial Capacity Ownership Price, which estimate shall be reflected in Schedule D, line 4, and Bonneville shall modify such Operating Plans by December 1995, or as soon as practicable thereafter, to reflect in Schedule D, line 4, the actual general plant investment included in the Adjusted Capacity Ownership Price.

Schedule D, line 5, shall reflect any general plant investment recovered from Capacity Owners pursuant to section 5 for Upgrades. The agreements referred to in subsection 5(d) and subparagraph 5(e)(3)(B) shall specify the portion of costs of an Upgrade that will be considered general plant investment.

Schedule D, line 6, shall reflect Bonneville's adjusted general plant investment functionalized to transmission and shall be calculated by adding line 1 and line 2, and from the sum of line 1 and line 2 subtracting line 3, line 4, and line 5.

Schedule D, line 7, shall reflect Bonneville's annual cost of Bonneville's adjusted general plant investment functionalized to transmission (Schedule D, line 6). Such annual cost shall be the sum of the annual interest and amortization amounts for each category of adjusted general plant investment. The annual interest and amortization amounts for each category shall be calculated by using the investment amounts for each such category, the weighted average interest rate for all Bonneville then outstanding bonds, and the average service lives for each such category from Bonneville's most recent depreciation study. If Bonneville changes its practice of financing general plant investment with bonds, the interest rate used in the calculation referred to in the immediately preceding sentence shall reflect the weighted average interest rate for all of Bonneville's then outstanding debt instruments.

Schedule D, line 8, shall reflect for a fiscal year Bonneville's total cumulative transmission plant-in-service investment (not including general plant investment). Bonneville's total transmission plant-in-service investment shall include Bonneville's investment in any of the following items reflected as total transmission plant-in-service (not including general plant investment) in the Segmentation Study (from Bonneville's general rate case most recently approved by FERC on an interim basis: land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

Schedule D, line 9, shall be the annual cost ratio of Bonneville's PNW AC Intertie transmission-related general plant derived by dividing Schedule D, line 7, by Schedule D, line 8.

Schedule D, line 10, shall reflect Bonneville's PNW AC Intertie investment. Bonneville's PNW AC Intertie investment shall include Bonneville's investment in any of the following items reflected as Bonneville's PNW AC Intertie plant-in-service in the Segmentation Study from Bonneville's general rate case most recently approved by FERC on an interim basis (or the successor to the Segmentation Study, as determined by Bonneville): land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

V. <u>Other Costs</u>

For each Operating Plan, Bonneville shall include Other Costs associated with Bonneville's PNW AC Intertie for a fiscal year. Such Other Costs (Schedule E, line 3) for a fiscal year shall include for such fiscal year any of the following: (1) the costs of operation; maintenance; capital replacements, reinforcements, additions, betterments, renewals; or related costs which Bonneville is obligated to pay pursuant to the Northwest Intertie Agreements or other contracts referred to in subsection 8(b) of this Agreement; and (2) costs paid by Bonneville including monetary judgments, settlements, binding awards, non-contract penalties, contract penalties, liquidated damages, or forfeiture costs, and Bonneville's costs related to such monetary judgments, settlements, binding awards, non-contract penalties, contract penalties, liquidated damages, or forfeiture costs assessed against or incurred by Bonneville as a facilities owner of, or the operator of, the PNW AC Intertie; provided, however, that Puget shall not be obligated to pay a share of any such costs that are not properly allocated to Bonneville's PNW AC Intertie.

Bonneville shall forecast its share of operations, maintenance, capital, and related costs for activities that PacifiCorp performs on Bonneville/PacifiCorp jointly-owned PNW AC Intertie facilities based on forecasts received from PacifiCorp or on actual costs for the most recent 12 consecutive month period prior to preparation of an Operating Plan.

VI. <u>Contracts and Rates Costs</u>

A. Contracts and Rates Costs - Functionalization Factor

For each Operating Plan, Bonneville's total contracts and rates direct costs, indirect costs, and overhead costs (Schedule F, lines 5, 6, and 7) shall be adjusted by a contracts and rates functionalization factor (Schedule F, line 3). The contracts and rates functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the contracts and rates functionalization factor shall be the ratio of (a) Bonneville's total transmission-related contracts and rates cost (Schedule F, line 1) over (b) Bonneville's total contracts and rates cost (Schedule F, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Contracts and Rates Cost.

B. Contracts and Rates Costs - Allocation Factor

The allocation factor (Schedule F, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Contracts and Rates Costs - Total Contracts and Rates Costs

Bonneville's total contracts and rates costs for a fiscal year (Schedule F, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: rate filings with FERC, development of rates customers pay Bonneville for electric power and for wheeling their own power on Bonneville's transmission system; negotiation, administration, and coordination of contracts for power sales, power exchanges, conservation, wheeling and resource services; and analyzing, processing, and issuing all customer power bills; and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule F, line 9, shall reflect Contracts and Rates Cost.

VII. Power Scheduling Costs

For each Operating Plan, Bonneville's total power scheduling direct costs, indirect costs, and overhead costs (Schedule G, lines 5, 6, and 7) shall be adjusted by a power scheduling functionalization factor (Schedule G, line 3). The power scheduling functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the power scheduling functionalization factor shall be the ratio of (a) Bonneville's total transmission-related power scheduling cost (Schedule G, line 1) over (b) Bonneville's total power scheduling cost (Schedule G, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Power Scheduling Cost.

B. Power Scheduling Costs - Allocation Factor

The allocation factor (Schedule G, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Power Scheduling Costs - Total Power Scheduling Costs
Bonneville's total power scheduling costs for a fiscal year (Schedule G, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: scheduling and marketing power to Bonneville customers and interconnected utilities, forecasting the hourly power requirements of Bonneville customers and the interchange of power with the region's interconnected electric utilities and with utilities outside the region, scheduling power to be generated at each Federal plant, weather and streamflow forecasting, controlling the reservoirs, implementing the intertie access policy, coordinating power production with the multi-purpose operation of the Federal power system, seasonal load/resource planning, developing current short-term operating plans, short-term marketing of Bonneville's surplus firm power, exchanges, and nonfirm energy, and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule G, line 9, shall reflect Power Scheduling Cost.

VIII. <u>End of Term Costs</u>
When all facilities of the PNW AC Intertie are determined, in accordance with Northwest Intertie Agreements, to be no longer operable, Bonneville shall include a forecast of all Bonneville's costs associated with

decommissioning the PNW AC Intertie and credits resulting from such decommissioning in the Operating Plan for each fiscal year that such End of Term Costs are to be incurred. Bonneville's End of Term Costs for a fiscal year (Schedule H, line 4) shall include Bonneville's costs (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: decommissioning, razing structures, disposal of debris, site restoration, meeting all requirements of Federal, state, or local applicable law relating to the foregoing activities, and other decommissioning activities undertaken by Bonneville that are consistent with decommissioning activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A for FY XXXX

	Line No.	Forecast	Actual	Difference
I. Operations Costs				
A. Allocation Factor				
MFUs of Bonneville's PNW AC Intertie	1		______	
MFUs of the FCRTS	2		______	
Allocation factor (Line 1/Line 2)	3		______	
B. Operations Functionalization Factor				
Bonneville's total transmission-related systems operations cost from rate case	4		______	
Bonneville's total system operations cost from rate case	5		______	
Operations functionalization factor (Line 4/Line 5)	6		______	
C. Allocated Direct Cost				
Bonneville's total system operations direct cost	7	______	______	______
Allocated Direct Cost of Operations Cost (Line 3 * Line 6 * Line 7)	8	______	______	______

	Line No.	Forecast	Actual	Difference
D. Indirect Cost				
Bonneville's total system operations indirect cost	9	________	________	________
Indirect Cost of Operations Cost (Line 3 * Line 6 * Line 9)	10	________	________	________
E. Overhead Cost				
Bonneville's total system operations overhead cost	11	________	________	________
Overhead Cost of Operations Cost (Line 3 * Line 6 * Line 11)	12	________	________	________
F. Operations Cost (Lines 8 + 10 + 12)	13	________	________	________

Schedule B for FY XXXX

	Line No.	Forecast	Actual	Difference
II. Maintenance Cost				
A. Power System Control (PSC) Maintenance Functionalization Factor				
Bonneville's transmission-related PSC maintenance cost from rate case	1		________	
Bonneville's total PSC maintenance cost from rate case	2		________	
PSC maintenance functionalization factor (Line 1/Line 2)	3		________	
B. Direct Cost				
Total PSC direct maintenance cost	4	________	________	________
MFU Allocation Factor (Schedule A, line 3)	5		________	
PSC direct maintenance cost for Bonneville's PNW AC Intertie (Line 4 * Line 3 * Line 5)	6	________	________	________
Bonneville's direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost	7	________	________	________
Direct Cost of Maintenance Cost (Line 6 + Line 7)	8	________	________	________

C. Allocation Factor

	Line			
Bonneville's total system maintenance direct cost	9	________	________	________
Allocation factor for Indirect Cost and Overhead Cost (Line 8/Line 9)	10	________	________	________

D. Indirect Cost

	Line			
Bonneville's total system maintenance indirect cost	11	________	________	________
Indirect Cost of Maintenance Cost (Line 11 * Line 10)	12	________	________	________

E. Overhead Cost

	Line			
Bonneville's total system maintenance overhead cost	13	________	________	________
Overhead Cost of Maintenance Cost (Line 13 * Line 10)	14	________	________	________

	Line			
F. Maintenance Cost (Lines 8 + 12 + 14)	15	________	________	________

Schedule C

	Line No.	Forecast	Actual	Difference
III. Replacement Costs and Reinforcement Costs				
A. Direct Cost				
Direct Costs of Replacements and Reinforcements	1	______	______	______
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2	______	______	______
C. AFUDC				
AFUDC of Replacements and Reinforcements	3	______	______	______
D. Interest				
Interest Cost of Replacements and Reinforcements	4		______	
E. Total Replacement Costs and Reinforcement Costs (Lines 1 + 2 + 3 + 4)	5	______	______	______

Notes:

A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement.

Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

Schedule D for FY XXXX

	Line No.	Allocated Actual
IV. General Plant Cost		
Bonneville's total general plant investment	1	______
Bonneville's Dittmer control equipment investment	2	______
General plant investment of lines 1 and 2 functionalized to generation	3	______
General plant investment recovered from all Capacity Owners in Adjusted Capacity Ownership Price and Revised Adjusted Capacity Ownership Price	4	______
General plant investment recovered from Capacity Owners for Upgrades	5	______
Adjusted general plant investment functionalized to transmission (Line 1 + Line 2 - Line 3 - Line 4 - Line 5)	6	______
BPA total annual cost of Line 6 general plant investment	7	______
BPA total transmission plant-in-service investment (not including general plant investment) from Segmentation Study	8	______
ACR for Bonneville's PNW AC Intertie (Line 7/Line 8)	9	______
Bonneville's PNW AC Intertie investment from Segmentation Study	10	______
General Plant Cost (Line 9 * Line 10)	11	______

Schedule E for FY XXXX

	Line No.	Forecast	Actual	Difference
V. Other Costs				
A. PacifiCorp and related costs	1	______	______	______
B. Other PNW AC Intertie costs	2	______	______	______
C. Total Other Costs	3	______	______	______

Schedule F for FY XXXX

	Line No.	Forecast	Actual	Difference
VI. Contracts and Rates Costs				
A. Contracts and Rates Functionalization Factor				
Transmission-related contracts and rates cost from rate case	1		______	
Total contracts and rates cost from rate case	2		______	
Contracts and rates cost functionalization factor (Line 1/Line 2)	3		______	
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4		______	
C. Total Contracts and Rates Costs				
Contracts and rates direct costs	5	______	______	______
Contracts and rates indirect costs	6	______	______	______
Contracts and rates overhead costs	7	______	______	______
Bonneville's total contracts and rates costs (Line 5 + Line 6 + Line 7)	8	______	______	______
D. Contracts and Rates Cost (Line 8 * Line 3 * Line 4)	9	______	______	______

Schedule G for FY XXXX

	Line No.	Forecast	Actual	Difference
VII. Power Scheduling Costs				
A. Power Scheduling Functionalization Factor				
Transmission-related power scheduling costs from rate case	1		________	
Total power scheduling cost from rate case	2		________	
Power scheduling cost functionalization factor (Line 1/Line 2)	3		________	
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4		________	
C. Total Power Scheduling Costs				
Power scheduling direct costs	5	________	________	________
Power scheduling indirect costs	6	________	________	________
Power scheduling overhead costs	7	________	________	________
Bonneville's total power scheduling costs (Line 5 + Line 6 + Line 7)	8	________	________	________
D. Power Scheduling Cost (Line 8 * Line 3 * Line 4)	9	________	________	________

Schedule H for FY XXXX

	Line No.	Forecast	Actual	Difference
VIII. End of Term Costs				
A. Direct Cost				
Direct Cost of End of Term Costs	1	______	______	______
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of End of Term Costs	2	______	______	______
C. Credits				
Credits from decommissioning PNW AC Intertie facilities	3	(______)	(______)	(______)
D. End of Term Costs	4	______	______	______

Puget's Initial Transaction with California Utility

Name of parties: Puget / Pacific Gas & Electric Company

Term of Contract: Variable

Date of Execution: October 25, 1991

Amount of Transaction (MW): 300 MW

AUTHENTICATED COPY Contract No. DE-MS79-94BP94521

PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PUGET SOUND POWER & LIGHT COMPANY

Index to Sections

This PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT (Agreement) is entered into as of October 11, 1994, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville or BPA) and PUGET SOUND POWER & LIGHT COMPANY (Puget), a corporation of the state of Washington. Each of Bonneville and Puget is sometimes referred to individually in this Agreement as "Party"; Bonneville and Puget are sometimes referred to together in this Agreement as "Parties."

WITNESSETH:

WHEREAS Bonneville, Portland General Electric Company (Portland), and PacifiCorp Electric Operations (PacifiCorp) planned and constructed improvements and additions to the Northwest portion of the PNW-PSW Intertie; and

WHEREAS such construction was completed in December 1993 resulting in 1600 MW of additional PNW AC Intertie Rated Transfer Capability in a north-to-south direction and 1225 MW of additional PNW AC Intertie Rated Transfer Capability in a south-to-north direction; and

WHEREAS pursuant to the Northwest Intertie Agreements, Bonneville operates the PNW AC Intertie, in coordination with Portland and PacifiCorp, as a single system so as to maximize PNW AC Intertie Rated Transfer Capability and Operational Transfer Capability consistent with Prudent Utility Practice; and

WHEREAS Bonneville has developed a proposal to offer to PNW non-Federal scheduling utilities and joint agencies capacity ownership rights in 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability; and

WHEREAS such proposal has been studied in Bonneville's Final Non-Federal Participation Environmental Impact Statement, dated January 1994, and was the selected alternative in the Administrator's Record of Decision, dated March 25, 1994; and

WHEREAS Bonneville and Puget executed a Memorandum of Understanding, DE-MS79-91BP93466, dated September 18, 1991, which, among other things, sets forth the principles for Puget's capacity ownership rights in Bonneville's PNW AC Intertie; and

WHEREAS interest expressed in capacity ownership by PNW non-Federal scheduling utilities and joint agencies exceeded the 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability offered by Bonneville, and as a result Bonneville developed and applied an allocation methodology selected in the Administrator's Capacity Ownership Record of Decision, dated March 25, 1994; and

WHEREAS concurrent with the execution of this Agreement, Bonneville and Puget are executing Contract No. DE-MS79-94BP93947 to provide Puget with, among other things, network wheeling between the John Day Substation and Puget's transmission system; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power generated at various Federal hydroelectric projects in the PNW, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, Bonneville and Puget agree as follows:

1. **DEFINITIONS**

(a) "Adjusted Capacity Ownership Price" means the price calculated pursuant to column 2, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(b) "Adjusted Lump Sum Payment" means the Adjusted Capacity Ownership Price multiplied by Puget's Capacity Ownership Share (in kilowatts), as described with more particularity in section D of Exhibit D.

(c) "Allocated Direct Costs" means for each fiscal year the Operations Cost as allocated to Bonneville's PNW AC Intertie in accordance with section I.C of Exhibit I for such fiscal year. Allocated Direct Costs are not included in Direct Costs, Indirect Costs, or Overhead Costs.

(d) "Allowance for Funds Used During Construction" or "AFUDC" constitutes interest on the funds used for utility plant under construction. The AFUDC rate approximates the cost of money being used to finance current construction work in progress and is calculated in accordance with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors. AFUDC shall be capitalized in accordance with Bonneville's accounting procedures and practices, and in any event consistent with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors.

(e) "Billing Provisions" means those provisions set forth in Exhibit B, Part B.

(f) "Bonneville's PNW AC Intertie" means facilities of the PNW AC Intertie owned partially or entirely by Bonneville specified in Exhibit F together with the equipment and facilities installed in or connected to such facilities specified in Exhibit F, to the extent such facilities are necessary for the transmission of power on the PNW AC Intertie.

(g) "Bonneville's PNW AC Intertie Operational Transfer Capability" means Bonneville's PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and by operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(h) "Bonneville's PNW AC Intertie Rated Transfer Capability" means Bonneville's share of the PNW AC Intertie Rated Transfer Capability as determined in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(i) "Capacity Owner" means each of the parties listed in Exhibit G to the extent that such party has entered into a Capacity Ownership Agreement.

(j) "Capacity Ownership Agreement" means, in the singular, this Agreement or the agreement, substantially identical to this Agreement, entered into by each Capacity Owner (other than Puget) and Bonneville, and in the plural, this Agreement and all such substantially identical agreements entered into respectively by

Capacity Owners (other than Puget) and Bonneville, as each such agreement may be amended or supplemented from time to time pursuant to the terms of such agreement, concerning (among other things) the rights of such Capacity Owner with respect to the PNW AC Intertie.

(k) "Capacity Ownership Percentage" means, as of the Effective Date, in the singular, the percentage of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Puget pursuant to this Agreement, which percentage is determined by dividing Puget's Capacity Ownership Share as of the Effective Date by Bonneville's PNW AC Intertie Rated Transfer Capability as of the Effective Date (such percentage being subject to change pursuant to the terms of this Agreement), and in the plural, the percentages of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which percentages are set forth in Exhibit G (each of such percentages being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(l) "Capacity Ownership Rights" means the rights of Puget pursuant to this Agreement.

(m) "Capacity Ownership Share" means, except as such term is otherwise used in sections III.A and III.B of the CO-94 rate set forth in Exhibit A on the Effective Date, in the singular, the MW amount of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Puget pursuant to this Agreement, which MW amount is set forth in Exhibit C (such amount being subject to change pursuant to the terms of this Agreement), and in the plural, the MW amounts of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which amounts are set forth in Exhibit G (each of such amounts being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(n) "Committee" has the meaning set forth in subsection 12(a).

(o) "Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

(p) "Direct Costs" means any costs incurred by Bonneville which are readily identifiable, or obviously traceable to, and directly benefit, a specific Bonneville program, project, or other cost objective. Direct Costs are not included in Allocated Direct Costs, Overhead Costs, or Indirect Costs. The methods for determining Direct Costs for Bonneville's PNW AC Intertie are set forth in sections II.B and III.A of Exhibit I.

(q) "Effective Date" means the date as of which this Agreement becomes effective pursuant to section 2.

(r) "End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

(s) "FERC" means the Federal Energy Regulatory Commission or its regulatory successor.

(t) "General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

(u) "GTRSP" or "GTRSPs" means Bonneville's General Transmission Rate Schedule Provisions, set forth in Exhibit A, as such provisions may be revised from time to time.

(v) "Indirect Costs" means any costs incurred by Bonneville which indirectly benefit and are directly charged to a specific Bonneville program, project, or other cost objective for which a Direct Cost or Allocated Direct Cost is charged. Indirect Costs shall not be included in Allocated Direct Costs, Direct Costs, or Overhead Costs. The methods for determining Indirect Costs for Bonneville's PNW AC Intertie are set forth in sections I.D, II.D, and III.B of Exhibit I.

(w) "Initial Capacity Ownership Price" means $215 per kilowatt, the calculation of which charge is set forth in column 1, section B of Exhibit D and in section III.A of the CO-94 rate in Exhibit A.

(x) "Initial Lump Sum Payment" means the Initial Capacity Ownership Price multiplied by Puget's Capacity Ownership Share (in kilowatts), as described with more particularity in section C of Exhibit D.

(y) "Interconnection Agreement" means the "Interim Interconnection Agreement Between Certain California-Oregon Transmission Project Participants and Northwest Participants," Contract No. DE-MS79-91BP93158, as amended or superseded.

(z) "Joint AC Intertie" is as defined in the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(aa) "Joint Intertie Scheduling Office" or "JISO" means the group of Bonneville, Portland, and PacifiCorp schedulers, which, among other things, accepts PNW-PSW Intertie Preschedules.

(bb) "Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

(cc) "MW" means megawatt.

(dd) "Northwest Intertie Agreements" means the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(ee) "Operating Plan" means, subject to subsection 13(o), with respect to any fiscal year commencing on or after the day on which the annual costs rate set forth in Exhibit B has been approved on an interim or final basis by FERC, the written document containing the information described in subsection 13(c), as such document may be amended pursuant to section 13, 14, or 16.

(ff) "Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

(gg) "Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

(hh) "Overhead Cost" means administrative and general costs, support service costs, or other costs similar in nature which are distributed or allocated by Bonneville to Bonneville's PNW AC Intertie. Overhead Costs are not included in Direct Costs, Allocated Direct Costs, or Indirect Costs. The methods for determining Overhead Costs are set forth in sections I.E, II.E, and III.B of Exhibit I.

(ii) "Pacific Northwest" or "PNW" means the area defined as the Pacific Northwest in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. section 839a(14).

(jj) "Pacific Time" means Pacific Standard Time and Pacific Daylight Time as each is in force.

(kk) "PNW AC Intertie" means facilities including, but not limited to, the following: two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's rights in the Meridian-Malin 500 kV transmission line and Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, additions, improvements, or other alterations thereto.

(ll) "PNW AC Intertie Operational Transfer Capability" means the PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(mm) "PNW AC Intertie Rated Transfer Capability" means the north-to-south and south-to-north capability of the PNW AC Intertie to transfer power in a reliable manner as determined consistent with Prudent Utility Practice.

(nn) "Pacific Northwest-Pacific Southwest Intertie" or "PNW-PSW Intertie" means the DC transmission line between the Celilo Converter Station in The Dalles, Oregon, and the Sylmar Converter Station near Los Angeles, California, the PNW AC Intertie, and the AC Intertie in California including, without limitation, the California-Oregon Transmission Project.

(oo) "Pacific Northwest Non-Federal Utility" means any electric utility that serves retail load in the region consisting of (1) the states of Oregon, Washington, and Idaho, the portion of the state of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River Basin drainage basin, and (2) any contiguous areas, not in excess of seventy-five air miles from the area referred to in (1) above, which areas are a part of the service area of a rural electric cooperative power customer served by Bonneville on the effective date of the Pacific Northwest Power Planning and Conservation Act (P.L. 96-501) having a distribution system from which it serves both within and without such region.

(pp) "Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit

I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

(qq) "Preschedule" means the schedule submitted by Puget to the JISO pursuant to paragraph 4(b)(1) for transactions prepared each Working Day for the period beginning 2400 hours of the current Working Day through 2400 hours of the next Working Day.

(rr) "Prudent Utility Practice" means, at any particular time, the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto that would achieve the desired result or, if there are no such practices, methods, and acts, the practices, methods, and acts which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to achieve the desired result consistent with reliability and safety.

(ss) "Real-time Schedule" means a schedule, or change to the Preschedule, submitted during the period which begins when the Preschedule is deemed by the JISO to be complete and concludes at 2400 hours on the day for which the Preschedule is submitted by Puget.

(tt) "Reinforcement" means any transmission plant modification, addition, improvement, or other alteration to the Federal Columbia River Transmission System which is not a Replacement or an Upgrade and which is made pursuant to subsection 7(c).

(uu) "Reinforcement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Puget for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Reinforcement. Reinforcement Costs do not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(vv) "Replacement" means for any transmission plant addition, betterment, renewal and equipment or facility that takes the place of or adds to any existing equipment or facility on Bonneville's PNW AC Intertie that does not increase Bonneville's PNW AC Intertie Rated Transfer Capability.

(ww) "Replacement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Puget for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Replacement. General Plant Cost is not included in Replacement Costs. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(xx) "Revised Adjusted Capacity Ownership Price" means a price calculated pursuant to column 3, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(yy) "Revised Adjusted Lump Sum Payment" means a Revised Adjusted Capacity Ownership Price multiplied by Puget's Capacity Ownership Share (in kilowatts), as described with more particularity in section E of Exhibit D.

(zz) "Scheduler" means the person authorized by a Party to accept or submit schedules pursuant to section 4 and authorized to implement, interpret, and vary the scheduling procedures set forth in such section pursuant to this Agreement.

(aaa) "Scheduling Percentage" means the percentage of the PNW AC Intertie Rated Transfer Capability owned by Puget pursuant to this Agreement, which percentage is determined by dividing Puget's Capacity Ownership Share by the PNW AC Intertie Rated Transfer Capability.

(bbb) "Scheduling Share" means, for any given hour, the MW amount equal to the product of Puget's Scheduling Percentage and the PNW AC Intertie Operational Transfer Capability for such hour.

(ccc) "Scheduling Utility" means either (i) a Pacific Northwest Non-Federal Utility that serves a retail service area and operates a generation control area, or (ii) a Pacific Northwest Non-Federal Utility designated by Bonneville as a "computed requirements customer" or its equivalent.

(ddd) "Term" means the period of effectiveness of this Agreement set forth in subsection 2(a).

(eee) "Third AC Intertie" means the Third AC Intertie Project, which project increased the PNW AC Intertie Rated Transfer Capability by 1600 MW in a north-to-south direction and by 1225 MW in a south-to-north direction.

(fff) "Third AC Intertie Project" means the Third AC Intertie System Reinforcement and the construction of the Alvey-Meridian 500 kV transmission line and of facilities related to such transmission line during the period from July 1984 through December 1993.

(ggg) "Third AC Intertie System Reinforcement" means the improvements, additions and modifications to the PNW AC Intertie constructed during the period from July 1984 through December 1993 plus the construction of the Captain Jack substation and of facilities related to such substation during the period from July 1984 through December 1993.

(hhh) "Upgrade" means any MW increase to Bonneville's PNW AC Intertie Rated Transfer Capability which arises from or is related to an increase to the PNW AC Intertie Rated Transfer Capability.

(iii) "Working Day" means any day other than Saturday, Sunday, and a legal holiday recognized by the Federal government or Puget.

2. **TERM AND TERMINATION**

(a) This Agreement shall become effective as of the later of (1) the date of execution and delivery of this Agreement by both of the Parties, and (2) the date by which this Agreement has, with respect to Puget, been approved, accepted for filing or otherwise permitted to become effective by FERC; provided, that if FERC approves this Agreement for filing or otherwise permits this Agreement to become effective with any change or new condition, this Agreement shall not be or become effective unless both of the Parties have agreed in writing, and until the date by which both of the Parties have so agreed to such change or new condition. To the extent Puget is required to submit this Agreement to FERC, Puget shall submit this Agreement to FERC for approval no later than three Working Days after the date on which this Agreement is executed and delivered by both Parties. Bonneville shall provide Puget with a copy of the executed Agreement on the next Working Day after Bonneville executes the Agreement. Without limiting any of the foregoing, Puget shall use best efforts to obtain from FERC on the earliest possible date (following the date on which Puget is required to submit this Agreement to FERC pursuant to this subsection 2(a)) FERC's acceptance for filing or permission that this Agreement become effective in accordance with this subsection 2(a). This Agreement shall continue in effect so long as any facilities of the PNW AC Intertie are in existence and operable, unless otherwise earlier terminated by written agreement of both of the Parties or unless terminated pursuant to the terms of this Agreement. All liabilities incurred under this Agreement shall be preserved until satisfied.

(b) Notwithstanding subsection 2(a), no Capacity Ownership Rights may be exercised by Puget until payment is made by Puget pursuant to paragraph 9(a)(1) and received by Bonneville.

(c) If Bonneville does not receive the payment from Puget pursuant to paragraph 9(a)(1), then Bonneville shall have the option to terminate this Agreement by delivering to Puget written notice of such termination.

(d) Notwithstanding subsection 2(a), if Bonneville incurs End of Term Costs, the following provisions of this Agreement, and all rights and obligations thereunder, shall continue in full force and effect until Bonneville renders its final bill to Puget pursuant to subsection 9(b), unless this Agreement is earlier terminated by mutual agreement of the Parties: subsections 2(b), 2(c), and 2(d), sections 1, 7, 8, 9, 12, 13, 14, 15, 16, 18, 19, 20, 21, 22, and 23, and Exhibits A, B, C, D, F, G, H, and I. All liabilities incurred under such provisions of this Agreement shall be preserved until satisfied.

(e) If this Agreement has not become effective pursuant to subsection 2(a) within 12 months following the date upon which Bonneville executes and delivers this Agreement to Puget, this Agreement shall be void ab initio and of no force or effect.

3. CAPACITY RIGHTS

(a) Purchase and Sale of Capacity

Pursuant to the terms and conditions of this Agreement, Puget purchases from Bonneville and Bonneville sells to Puget the Capacity Ownership Rights.

(b) **Right to Wheel for Third Parties**

No later than 30 days after the Effective Date, Puget shall notify Bonneville in writing of Puget's decision to utilize its Scheduling Share pursuant to either paragraph 3(b)(1) or paragraph 3(b)(2), and Puget shall have the right to utilize its Scheduling Share pursuant to the paragraph Puget elects. Prior to Bonneville's receipt of such notification, Puget shall utilize its Scheduling Share pursuant to paragraph 3(b)(1). If Puget fails to make an election within the prescribed time period, Puget shall be deemed to have elected the option set forth in paragraph 3(b)(1).

(1) **No Third Party Wheeling**

(A) Except as expressly provided in subparagraph 3(b)(1)(B), Puget shall not use its Scheduling Share to transmit power or energy (except for inadvertent power flows) that Puget does not own at the California-Oregon border or for which transmission Puget receives any revenue that would be reportable in Puget's accounting system where revenues received for wheeling for other entities would be booked.

(B) If Puget's Scheduling Share is not fully utilized by Puget in any hour, Bonneville may schedule for such hour Bonneville's transactions (including, without limitation, Bonneville wheeling for other entities) and wheel such transactions over the unused portion of Puget's Scheduling Share for such hour but no longer than such hour. Puget shall be compensated for such wheeling solely by the payments as described in sections 3(b)(1)(B)(i) and (ii) below. For purposes of this subparagraph 3(b)(1)(B), Puget's Scheduling Share shall be deemed to be not fully utilized in a given hour to the extent that Puget has not scheduled, or does not schedule, on a Preschedule or Real-time Schedule basis, any transaction for such hour on any MW amount of Puget's Scheduling Share. In return for Puget's Scheduling Share being made available to Bonneville pursuant to this subparagraph 3(b)(1)(B), Bonneville shall pay Puget

(i) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a north-to-south direction under the IS-93 rate, section II.A, or its successor to other entities in such hour, and (2) the ratio of Puget's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour, and

(ii) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a south-to-north direction under the IS-93 rate, section II.A or its successor to other entities in such hour, and (2) the ratio of Puget's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour; provided, however, that Bonneville shall not be required to make payments for such south-to-north wheeling pursuant to this section 3(b)(1)(B)(ii) earlier than two years after the Effective Date.

Bonneville shall make payments pursuant to this subparagraph 3(b)(1)(B) in accordance with paragraph 9(f)(1).

(C) During an outage resulting from maintenance activities on the PNW AC Intertie performed by Bonneville other than maintenance activities undertaken due to emergencies or uncontrollable forces, the following shall apply:

(i) When Puget's Scheduling Share for any given hour is reduced as a consequence of such outage which reduces in Bonneville's PNW AC Intertie Operational Transfer Capability such that Puget's Scheduling Share for such hour is less than the MW amount of the aggregate of Puget's net firm transactions identified by Puget to Bonneville pursuant to section 3(b)(1)(C)(iv) for such hour, Bonneville shall, subject only to sections 3(b)(1)(C)(ii) and (iii) and to the immediately succeeding sentence, wheel on a firm basis that portion of Puget's firm transactions that equals the difference between Puget's Scheduling Share for such hour and the MW amount of the aggregate of Puget's firm transactions for such hour up to, but not in excess of, Puget's Capacity Ownership Share. Notwithstanding the foregoing, Bonneville shall only be obligated to provide such wheeling to the extent that each party with whom Puget is conducting such firm transactions has received a sufficient AC Intertie capacity allocation in California to accommodate such transactions. Puget shall pay the IS-93 rate, section II.A, or its successor for such wheeling pursuant to this section 3(b)(1)(C)(i) in accordance with subsection 9(d).

(ii) Bonneville shall not be obligated to provide such wheeling to Puget pursuant to section

3(b)(1)(C)(i) if no PNW AC Intertie Operational Transfer Capability is available to Bonneville after Bonneville has scheduled all of Bonneville's Firm Schedules. For purposes of this section, "Bonneville's Firm Schedules" shall mean schedules for assured delivery or other firm transmission contracts pursuant to the Long-Term Intertie Access Policy, as revised or amended, or its successor, and schedules for Bonneville's firm power and energy sales and exchange transactions.

(iii) Bonneville shall not be obligated to provide such wheeling to Puget pursuant to section 3(b)(1)(C)(i) until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to Puget or until October 1, 1994, whichever occurs sooner.

(iv) No later than ten Working Days prior to the first day of deliveries under a firm transaction, Puget shall identify such firm transaction to Bonneville. Puget shall identify such firm transaction to Bonneville by providing to Bonneville a copy of Puget's contract for such firm transaction (after information considered proprietary by Puget has been redacted by Puget). Bonneville shall review such contract to verify that the transaction is firm. If Puget and its contractor represent or state in writing that the transaction set forth in their contract is firm, Bonneville shall accept that written representation or statement as dispositive of the question of whether such transaction is firm. Implementation of such procedures in this section 3(b)(1)(C)(iv) may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written.

(D) Puget retains any and all rights of access which it would otherwise have to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(2) **Third Party Wheeling**

(A) Puget may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by Puget. Puget shall have no obligation under this Agreement to make available to Bonneville any portion of Puget's Scheduling Share which is unused in any hour, and Bonneville shall not schedule over Puget's Scheduling Share without Puget's prior consent.

(B) Puget hereby waives any and all rights of access to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor; provided, however, that Bonneville may, at its option, provide Puget with access to Bonneville's PNW-PSW Intertie pursuant to any provision of the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(C) Puget shall provide Bonneville with the information set forth in sections 3(b)(2)(C)(i) through 3(b)(2)(C)(iii) when Puget uses its Scheduling Share to export from the Pacific Northwest energy or power received from third parties. Such exports of energy or power on a real-time basis or for durations of less than four months are excluded from this obligation. For exports of four months or longer duration made on behalf of third parties pursuant to paragraph 3(b)(2), such information shall include:

(i) the name and business address of the third party;

(ii) the amount of power or energy and the duration of the transaction; and

(iii) the name of the recipient or purchaser of such power.

Any additional information needed by Bonneville will be obtained from such third party.

4. **SCHEDULING**

(a) Puget (and only Puget) shall be entitled to schedule on the PNW AC Intertie, in any hour, a MW amount up to Puget's Scheduling Share for such hour. The MW amount of Puget's Scheduling Share deemed to be scheduled on the PNW AC Intertie pursuant to this Agreement, in any hour, shall be determined as the net of Puget's north-to-south schedules and south-to-north schedules (net schedules) for such hour.

(b) Puget shall submit all schedules of its Scheduling Share on its own behalf in accordance with the procedures set forth in paragraphs 4(b)(1) and 4(b)(2). Such procedures may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written. All hours referenced in paragraphs 4(b)(1) and 4(b)(2) are Pacific Time.

(1) **Preschedules**

(A) Bonneville shall make available to Puget on each Working Day as soon as practicable after 0800 hours information regarding the PNW AC Intertie Operational Transfer Capability with respect to Preschedules. In the event an emergency or uncontrollable force causes a change in the PNW AC Intertie Operational Transfer Capability, Bonneville shall notify Puget of such change as soon as practicable.

(B) If Long-Term Intertie Access Policy Condition 1 Formula Allocation Procedures or their successor (Condition 1) are expected by Bonneville to become effective, Bonneville shall so notify Puget no later than 0930 hours on the Working Day prior to the day on which Condition 1 is expected to become effective. Bonneville shall notify Puget no later than 0930 hours on the Working Day prior to the day on which Condition 1 ceases to be in effect.

(C) Puget shall submit its Preschedule to the Joint Intertie Scheduling Office no later than 1000 hours on each Working Day if Condition 1 is in effect. If Condition 1 is not in effect, Puget shall submit its Preschedule to the JISO no later than 1430 hours on each Working Day.

(2) **Real-time Scheduling**

(A) Real-time Schedules shall be arranged through Bonneville's real-time scheduling office. Bonneville's real-time Scheduler shall make reasonable efforts to receive Real-time Schedules; provided, however, that Bonneville's real-time Scheduler may, but is not required to, accept Real-time Schedules between 1500 and 2200 hours on the Working Day preceding the day for which such Real-time Schedule is submitted.

(B) Real-time Schedules shall be arranged for a full hour. Arrangements shall be completed no later than 30 minutes prior to that hour.

(C) Puget shall use best efforts to keep schedule changes to a minimum; provided, however, that for purposes of this subparagraph 4(b)(2)(C), "best efforts" shall not be deemed to refer to efforts made regardless of their economic effect.

(D) The requirements set forth in subparagraphs 4(b)(2)(B) and 4(b)(2)(C) do not preclude schedule changes at other times as may be deemed necessary by any control area operators or other entities involved in effectuating such schedule changes. Such control area operators and other entities shall be notified by Bonneville of such schedule changes as soon as practicable in accordance with Prudent Utility Practice for purposes of coordinating ramps and proper accounting. Such schedule changes shall be deemed to occur at mid-ramp. The mid-ramp time and the integrated value for the hour shall be subject to the mutual agreement by such control area operators and other entities.

(E) Subject to compliance with subparagraphs 4(b)(2)(A) through 4(b)(2)(D) and with other applicable PNW AC Intertie scheduling practices then in effect, Bonneville shall make Puget's schedule change.

(c) Bonneville shall make deliveries of power or energy to the California-Oregon border or the John Day Substation, as appropriate, pursuant to schedules submitted in accordance with this section 4; provided, however, that Bonneville shall not be required to make such deliveries in an hour to the extent that Puget's schedule exceeds Puget's Scheduling Share for such hour, except as may be expressly provided pursuant to subparagraph 3(b)(1)(C).

5. **UPGRADES**

(a) Bonneville shall consult with the Committee one time each year regarding any plans for Upgrades.

(b) Prior to the completion of an Upgrade, Bonneville shall provide to Puget information in writing regarding estimated costs and the MW amount of such Upgrade, to the extent that such information is available to Bonneville.

(c) As soon as practicable following the completion of an Upgrade, Bonneville shall notify Puget in writing of the following: (1) the MW amount of such Upgrade; (2) the capital and related costs (less any amount of such costs collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, to Bonneville for completing or implementing such Upgrade; and (3) calculations of (A) Puget's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade and (B) Puget's Capacity Ownership Percentage multiplied by the capital and related costs, if any, to Bonneville for completing or implementing such Upgrade. Puget may elect to acquire a share of such Upgrade in an amount up to Puget's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade. Within 100 days from receipt of such written notice from Bonneville, Puget shall notify Bonneville in writing of Puget's decision regarding such acquisition. If Puget elects to acquire, pursuant to this subsection 5(c), a portion of such Upgrade, Puget's notice to Bonneville shall include the percentage of such Upgrade that Puget elects to acquire (Acquisition Percentage). If

Puget fails to notify Bonneville within such 100-day period, Puget shall be deemed to have elected not to acquire any of such Upgrade.

(d) If Puget elects to acquire a portion of an Upgrade pursuant to subsection 5(c), the cost to Puget shall be Puget's Acquisition Percentage multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such cost collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, incurred by Bonneville for completing or implementing such Upgrade. Puget shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(e) If Puget's Acquisition Percentage with respect to an Upgrade equals its Capacity Ownership Percentage and the Acquisition Percentage of any other Capacity Owner with respect to such Upgrade is less than its Capacity Ownership Percentage, then the following shall apply:

(1) Bonneville shall, in a timely manner, provide written notice simultaneously to Puget and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage) of the MW amount equal to 100 percent of that portion of an Upgrade offered to, but not acquired by, the Capacity Owners pursuant to subsection 5(c) (Unacquired Share). If Puget and each of such other Capacity Owners have agreed in writing to an apportionment as among themselves of the Unacquired Share (Apportionment), Puget may, within 45 days following receipt of such written notice from Bonneville, by written notice request Bonneville to offer in writing to Puget such portion of the Unacquired Share as has been apportioned to Puget pursuant to the Apportionment, and Bonneville shall offer to Puget such portion of the Unacquired Share.

(2) If Bonneville does not receive from Puget and from each Capacity Owner referred to in paragraph 5(e)(1) the requests for offer pursuant to paragraph 5(e)(1) within the 45-day period

specified in such paragraph, Bonneville shall, in a timely manner, offer in writing simultaneously to Puget and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage), respectively, a portion of an Upgrade offered to, but not acquired by, the other Capacity Owners pursuant to paragraph 5(e)(1) (Second Unacquired Share) up to the "Additional Share Offered" determined as follows:

Additional Share Offered = (A + B) x C

where: A = Puget's Capacity Ownership Percentage.

B = Percentage equal to the sum of Capacity Ownership Percentages of Capacity Owners that acquired respectively an Acquisition Percentage equal to their Capacity Ownership Percentage.

C = Second Unacquired Share.

(3) Within 30 days following Puget's receipt of Bonneville's written offer pursuant to paragraph 5(e)(2), Puget shall notify Bonneville in writing of Puget's decision regarding acquisition of the Additional Share Offered. If Puget fails to notify Bonneville within such 30-day period, Puget shall be deemed to have elected not to acquire any of the Additional Share Offered. If Puget elects pursuant to this paragraph 5(e)(3) to acquire any or all of the Additional Share Offered, then:

(A) Puget shall include in its notice to Bonneville pursuant to this paragraph 5(e)(3) such share (Additional Share Acquired) of the Additional Share Offered as Puget elects to acquire pursuant to this paragraph 5(e)(3), and

(B) the cost to Puget with respect to such acquisition shall be equal to the proportion of the Additional Share Acquired to such Upgrade multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such costs collected by Bonneville through charges other than payments by Puget pursuant to subsection 5(d) or subparagraph 5(e)(3)(B)), if any, to Bonneville for completing or implementing such Upgrade. Puget shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(f) All capacity offered but not acquired pursuant to subsections 5(c) and (e) shall for purposes of this Agreement remain with Bonneville.

(g) After Puget has either accepted or declined all offers of capacity by Bonneville pursuant to subsections 5(c) and (e), Puget's Capacity Ownership Share, Capacity Ownership Percentage, and Scheduling Percentage in Exhibit C shall be revised to reflect changes resulting from Puget's elections pursuant to subsections 5(c) and (e). Revision of Exhibit C shall be pursuant to subsection 19(d). Exhibit G shall be revised accordingly pursuant to subsection 19(i).

6. **SALE OR ASSIGNMENT**

(a) This Agreement or any interest herein shall not be transferred, sold, alienated, or assigned by Puget to any person without Bonneville's prior and express written consent. Such consent shall not be unreasonably withheld. In determining whether to grant its consent under this subsection 6(a), Bonneville shall take into consideration information including, but not limited to, whether the person or entity to whom this Agreement or any interest therein is proposed to be transferred, sold, alienated, or assigned is a person or entity entitled to request and receive transmission services pursuant to section 211 of the Federal Power Act, whether such person or entity can either provide its own scheduling services or has contracted with another entity to provide such scheduling services, whether such person or entity has the financial capability to meet the payment obligations under this Agreement, and whether the person or entity is either electrically interconnected to Bonneville's transmission system or has contractual arrangements for wheeling with others who are electrically interconnected to Bonneville's transmission system. This Agreement shall inure to the benefit of and be binding upon the Parties, their respective legal representatives, permitted assigns, and successors in interest. Any transfer, sale, alienation, or assignment made by Puget in violation of this section 6 shall be void ab initio and without any force or effect whatsoever.

(b) Bonneville hereby consents to the transfer, sale, alienation, or assignment by Puget to any other Capacity Owner of all or part of its Capacity Ownership Share and all of Puget's rights and obligations pursuant to this Agreement with respect thereto. Bonneville hereby further consents to the transfer, sale, alienation, or assignment by Puget of the entire Agreement and of all of Puget's rights and obligations under this Agreement to a Scheduling Utility.

(c) Bonneville hereby consents to the assignment by Puget of this Agreement or of any of Puget's rights under this Agreement as security for any indebtedness, whether present or future, of Puget pursuant to any mortgage, trust, security agreement or similar instrument of indebtedness (each such instrument, a Debt Instrument) made by and between Puget and any mortgagee, trustee, secured party or holder of such instrument of indebtedness, respectively; provided, however, that if Puget has defaulted in the performance of its obligations under any Debt Instrument, such that the mortgagee, trustee, secured party or holder of such Debt Instrument, as the case may be, would be entitled at that time to accelerate the amount of indebtedness under such Debt Instrument, Puget shall give Bonneville prompt written notice in reasonable detail of such default and shall, at Bonneville's election, enter into good faith discussions with Bonneville regarding the cure of such default.

(d) If Puget transfers, sells, alienates, or assigns, with Bonneville's consent, all or any portion of this Agreement and any rights and obligations pursuant to this Agreement to any person or party, Puget shall give Bonneville written notice of such transfer, sale, alienation, or assignment within 10 days after the execution and delivery of the agreement effectuating such transaction by all parties to such transaction.

7. OPERATION, MAINTENANCE, AND MANAGEMENT

(a) Pursuant to the terms and conditions of the Northwest Intertie Agreements, Bonneville is the operator of the PNW AC Intertie. As such, Bonneville is responsible for the dispatch of the PNW AC Intertie in accordance with Prudent Utility Practice. Bonneville's duties as operator of the PNW AC Intertie shall include, but are not limited to, consistent with Prudent Utility Practice and Northwest Intertie Agreements: (1) determining the PNW AC Intertie Operational Transfer Capability; (2) implementing and assisting in rectifying emergency outages on the PNW AC Intertie due to system emergencies or uncontrollable forces; (3) implementing maintenance outages; and (4) giving and receiving switching orders on the PNW AC Intertie. In making any determination or in taking any other action referred to in the immediately preceding sentence, Bonneville shall give fair consideration to Puget's interests to the extent such interests have been expressed to Bonneville in writing. Bonneville shall operate, maintain, and manage Bonneville's PNW AC Intertie, and study, plan, and implement Upgrades, consistent with Prudent Utility Practice.

(b) Bonneville shall determine and revise as necessary the PNW AC Intertie Rated Transfer Capability consistent with Prudent Utility Practice and engineering studies based on then existing reliability criteria developed by the North American Electric Reliability Council, the Western Systems Coordinating Council, the Northwest Power Pool, and Bonneville. In the event the PNW AC Intertie Rated Transfer Capability is changed, Bonneville shall promptly notify Puget in writing of such change and the new PNW AC Intertie Rated Transfer Capability. If and to the extent that the reliability criteria for determining the PNW AC Intertie Rated Transfer Capability change substantially, Bonneville shall notify Puget in writing of such change.

(c) If at any time during the Term, Bonneville's PNW AC Intertie Rated Transfer Capability becomes less than 3450 MW, or if at any time during the Term there is an imminent likelihood that Bonneville's PNW AC Intertie Rated Transfer Capability would become less than 3450 MW, then Bonneville shall reinforce the Federal Columbia River Transmission System so as to raise Bonneville's PNW AC Intertie Rated Transfer Capability to 3450 MW or otherwise to prevent Bonneville's PNW AC Intertie Rated Transfer Capability from becoming less than 3450 MW. Puget's Capacity Ownership Share shall not be decreased on account of any failure by Bonneville to reinforce the Federal Columbia River Transmission System pursuant to this subsection 7(c).

(d) In the event that Bonneville implements a Reinforcement pursuant to subsection 7(c), Bonneville shall equitably allocate the Reinforcement Cost for such Reinforcement between Bonneville and Puget based on factors including, but not limited to, load responsibility, contractual obligation and generation integration responsibility. Any equitable allocation or agreed to allocation (pursuant to the immediately succeeding sentence) of a Reinforcement Cost pursuant to this subsection 7(d) shall be reflected as a Reinforcement Cost in an Operating Plan proposed by Bonneville pursuant to section 13. To the extent that Bonneville and Puget have agreed in writing to an allocation of a Reinforcement Cost incurred by Bonneville pursuant to an agreement or modification referred to in subsection 8(b), the Reinforcement Cost so allocated shall not be subject to arbitration pursuant to section 14 or section 15. Any Reinforcement Cost not allocated to Puget pursuant to this subsection 7(d) shall not be payable by Puget pursuant to this Agreement.

(e) Bonneville shall provide Puget notice of maintenance outages in accordance with the accepted standards for notice on the PNW AC Intertie. Such notice shall include an evaluation of the impact on

Puget's Scheduling Share. In scheduling or planning maintenance on PNW AC Intertie, Bonneville shall give fair consideration to Puget's interests to the extent such interests have been expressed to Bonneville in writing.

8. EXISTING AGREEMENTS

(a) Bonneville shall use good faith efforts to maintain in effect the Interconnection Agreement or its successor.

(b) Bonneville shall use its best efforts to maintain Puget's rights under this Agreement (i) by making no modification to the Northwest Intertie Agreements, (ii) by not entering into any other agreement with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie, and (iii) by making no modification to the agreements referred to in the immediately preceding clause (ii) that would have a substantial negative impact on Puget's rights pursuant to sections 3, 4, 7, or to subsection 9(b), 9(c), or 11(a) without Puget's prior written consent. Without limiting, modifying, or otherwise affecting any of its rights pursuant to sections 9, 13, 14, 15, and 16, Puget hereby consents to Bonneville's modification of the Northwest Intertie Agreements or Bonneville's entering into other agreements or modification to such Agreements with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie to the extent that such modification or such agreement is made or entered into by Bonneville for the purpose of performing Bonneville's obligations pursuant to subsection 7(c).

9. PAYMENT PROVISIONS

As full compensation for their respective payment obligations under this Agreement, Puget shall make payments to Bonneville in accordance with the provisions of this section 9, and Bonneville shall make payments and refunds to Puget in accordance with the provisions of this section 9.

(a) **Lump Sum Payment**

(1) As soon as practicable after the Effective Date, Bonneville shall render a bill to Puget for the Initial Lump Sum Payment (less the negotiation deposit, if any, with applicable interest as described in section C of Exhibit D) and such bill shall include as an attachment and as part of such bill a completed section C of Exhibit D, setting forth the calculation of such Initial Lump Sum Payment due Bonneville in accordance with section IV.A of the CO-94 rate set forth in Exhibit A. Puget shall make such payment pursuant to the CO-94 rate and the applicable GTRSPs set forth in Exhibit A. Each of Bonneville and Puget agrees that section C of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(2) **Calculation and Billing of the Adjusted Capacity Ownership Price**

(A) Approximately December 1995, or as soon as practicable thereafter, Bonneville shall, in accordance with section IV.B of the CO-94 rate set forth in Exhibit A, calculate the Adjusted Capacity Ownership Price to reflect actual construction costs of the facilities listed in section A of Exhibit D and the actual AFUDC with respect to such facilities. Such calculation shall be made in accordance with column 2, section B of Exhibit D.

(B) Promptly after Bonneville has calculated the Adjusted Capacity Ownership Price pursuant to subparagraph 9(a)(2)(A), Bonneville shall render a bill or refund voucher to Puget, and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2), section B of Exhibit D (with a completed column 2), and a completed section D of Exhibit D reflecting the Adjusted Lump Sum Payment. If the

Adjusted Lump Sum Payment is greater than the Initial Lump Sum Payment, Puget shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in such bill, which amount shall be equal to the amount set forth on line 7, section D of Exhibit D (such amount including interest as set forth on line 6, section D of Exhibit D). If the Adjusted Lump Sum Payment is less than the Initial Lump Sum Payment, Bonneville shall pay to Puget, within 30 days after the date of such refund voucher, the amount set forth in such refund voucher, which amount shall be equal to the amount set forth on line 7, section D, of Exhibit D (such amount including interest as set forth on line 6, section D, of Exhibit D). Each of Bonneville and Puget agrees that sections A, B, and D of Exhibit D are consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(3) **Calculation and Billing of the Revised Adjusted Capacity Ownership Price**

(A) After payment is made by Puget pursuant to subparagraph 9(a)(2)(B), or a refund is made by Bonneville to Puget pursuant to subparagraph 9(a)(2)(B), Bonneville may, in accordance with the CO-94 rate set forth in Exhibit A, make one or more adjustments to the Adjusted Capacity Ownership Price; provided, that any such adjustment shall be made by Bonneville within 30 days after the date on which (i) Bonneville receives, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp or any other entity performing work for Bonneville on the Third AC Intertie Project, payment from Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, or (ii) Bonneville pays, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, any amount to Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project; and provided, further, that no adjustment of the Adjusted Capacity Ownership Price or of any Revised Adjusted Capacity Ownership Price shall be made by Bonneville after December 31, 2005.

(B) Promptly after Bonneville has calculated a Revised Adjusted Capacity Ownership Price, Bonneville shall render to Puget a bill or refund voucher with respect to such Revised Adjusted Capacity Ownership Price and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), section B of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), and a completed section E of Exhibit D reflecting the current Revised Adjusted Capacity Ownership Price and the current Revised Adjusted Lump Sum Payment. If the current Revised Adjusted Lump Sum Payment with respect to such Revised Adjusted Capacity Ownership Price is greater than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, then Puget shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in the bill referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E, of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E, of Exhibit D). If the current Revised Adjusted Lump Sum Payment is less than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, Bonneville shall pay to Puget, within 30 days after the date of such refund voucher, the amount set forth in the refund voucher referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E of Exhibit D). Each of Bonneville and Puget agrees that section E of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(4) For purposes of implementing the CO-94 rate, the following shall apply:

(A) the calculations pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the adjustment "to reflect the difference between the actual and the estimated Capacity Ownership Price" required under section IV.B of the CO-94 rate;

(B) the calculations of interest pursuant to footnote 2 of section D of Exhibit D and footnote 2 of section E of Exhibit D shall be deemed to be the computation of "interest using the weighted average interest rate on Bonneville's outstanding bonds" required pursuant to section IV.B of the CO-94 rate;

(C) the calculations of the Adjusted Capacity Ownership Price and of the Revised Adjusted Capacity Ownership Price pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the determination of the "actual Capacity Ownership Price" required pursuant to section IV.B of the CO-94 rate;

(D) as used in the CO-94 rate, the terms "Bonneville's PNW AC Intertie," "PNW AC Intertie," "Third AC Intertie," "Third AC Intertie Project," and "Third AC Intertie System Reinforcement" shall be deemed to have the respective meanings of such terms set forth in section 1;

(E) as used in the CO-94 rate, the term "Capacity Ownership Share" shall be deemed to mean "Capacity Ownership Percentage" as defined in section 1;

(F) the indirect costs and overhead costs described in footnote 5 of section B of Exhibit D shall be deemed to be the indirect costs and overhead costs referred to in section III.A of the CO-94 rate; and

(G) the last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(5) For purposes of application of the CO-94 rate set forth in Exhibit A, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(A) section I;

(B) section III.A;

(C) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(D) subsection 4 of section IV.A;

(E) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A; and

(F) for purposes of subsection 16(e) of this Agreement and as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(b) **Annual Charges**

(1) **Payments Pursuant to AC-93 Rate**

(A) From and after the first Working Day after Bonneville receives payment from Puget pursuant to paragraph 9(a)(1), Bonneville shall bill Puget on the monthly power bill in accordance with the AC-93 rate set forth in Exhibit A. Puget shall pay such bill in accordance with the applicable GTRSPs set forth in Exhibit A.

(B) For purposes of application of the AC-93 rate, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(i) section I;

(ii) section III.A;

(iii) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(iv) the first sentence of subsection 3 of section IV.A;

(v) subsection 4 of section IV.A;

(vi) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A;

(vii) the first paragraph of subsection 6 of section IV.A; and

(viii) as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(C) The last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(D) Bonneville hereby agrees that the provisions of the AC-93 rate shall have no application or effect with respect to the following:

(i) any replacement of the series capacitor banks containing polychlorinated biphenyl at the Sand Springs, Sycan and Fort Rock Substations; and

(ii) any replacement commenced prior to the Effective Date or not completed prior to September 30, 1995.

(E) Upon and after the effective date of the annual costs rate set forth in Exhibit B, Bonneville shall cease billing Puget pursuant to the AC-93 rate.

(2) **Payments Pursuant to Annual Costs Rate**

From and after the date the annual costs rate set forth in Exhibit B becomes effective, the following shall apply:

(A) **Operations Costs, Maintenance Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs**

(i) During each fiscal year during the Term, Bonneville shall bill Puget on the monthly power bill, and Puget shall pay, pursuant to Exhibit B, forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for such fiscal year. Such costs shall be, respectively, the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the fiscal year in which such month occurs.

(ii) Within eight months after the end of each fiscal year during the Term (such fiscal year being hereinafter referred to as a "Fiscal Year"), Bonneville shall determine and calculate, pursuant to Exhibit I, Schedules A, B, D, E, F, G, and H, actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year most recently ended.

(iii) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year is greater than the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year, Bonneville shall refund to Puget the difference between such forecast costs and such actual costs as a lump sum payment, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Bonneville shall, promptly following the date on which the calculation of such difference is made, provide Puget written notice of such refund. Within the 30-day period referred to in the first sentence of this section 9(b)(2)(A)(iii), Bonneville shall provide to Puget an Operating Plan amended in accordance with subsection 13(k) containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(iv) If, based on the calculation performed pursuant to subparagraph 9(b)(2)(A)(ii), the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is equal to or less than 105 percent, but greater than 100 percent, of the sum of the forecast Operations costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and

Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs in the Operating Plan for the Fiscal Year, Bonneville shall bill to Puget on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Puget shall pay such bill in accordance with the Billing Provisions. Within the 30-day period referred to in the immediately preceding sentence, Bonneville shall provide to Puget an amended Operating Plan containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(v) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the actual Operations Cost, actual Maintenance Cost, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is greater than 105 percent of the sum of the forecast Operations Cost, forecast Maintenance Cost, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast

End of Term Costs for the Fiscal Year, Bonneville shall bill to Puget on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Puget shall pay such bill in accordance with the Billing Provisions; provided, however, that Bonneville shall not bill Puget pursuant to this section 9(b)(2)(A)(v) any amount which exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year unless and until such amount which exceeds 100 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year has been included in an Operating Plan amended pursuant to subsection 13(k).

(vi) Simple interest shall be accrued on payments or refunds due pursuant to this paragraph 9(b)(2) with respect to any fiscal year during the Term using the weighted average interest rate on Bonneville's outstanding bonds or other debt instruments then used by Bonneville and such interest shall accrue from (and including) the date of the last day of such fiscal year to (but excluding) the date of refund to Puget or to (but excluding) the due date of a payment due Bonneville.

(B) **Replacement Cost and Reinforcement Cost**

Bonneville shall bill Puget on the monthly power bill Replacement Costs for any Replacement and Reinforcement Costs for any Reinforcement. Bonneville shall render such bill within 15 months following the date on which the project work order for such Replacement or such Reinforcement, as the case may be, is closed. Puget shall pay such bill pursuant to Exhibit B and sections 9(b)(2)(B)(i), 9(b)(2)(B)(ii), 9(b)(2)(B)(iii) and 9(b)(2)(B)(iv).

(i) If the forecast Replacement Cost for a Replacement is greater than the actual Replacement Cost for such Replacement or if the forecast Reinforcement Cost for a Reinforcement is greater than the actual Reinforcement Cost for such Reinforcement, Bonneville shall bill Puget the actual Replacement Cost for such Replacement or the actual Reinforcement Cost for such Reinforcement, as the case may be. Bonneville shall provide to Puget an Operating Plan amended in accordance with subsection 13(k) containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement, as the case may be.

(ii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual

Reinforcement Cost is equal to or less than 105 percent, but greater than 100 percent, of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill Puget such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Puget shall pay such bill pursuant to subparagraph 9(b)(2)(B). Bonneville shall provide to Puget an amended Operating Plan containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the difference between the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement.

(iii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is greater than 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill Puget such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Puget shall pay such bill pursuant to subparagraph 9(b)(2)(B); provided, however, that Bonneville shall not bill Puget pursuant to this subparagraph 9(b)(2)(B) any amount which exceeds 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, as the case may be, unless and until such amount which exceeds 100 percent of such forecast Replacement or such forecast Reinforcement Cost, as the case may be, has been included in an amended Operating Plan pursuant to subsection 13(k).

(iv) Charges pursuant to sections 9(b)(2)(B)(i), (ii) and (iii) for Replacement Costs and Reinforcement Costs shall accrue simple interest pursuant to section III.D of Exhibit I.

(c) **Upgrade Charges**

For purposes of implementing the CO-94 rate, the following shall apply:

(1) as used in the CO-94 rate, the term "upgrade" shall be deemed to mean "Upgrade" as defined in section 1, the term "rated transfer capability" shall be deemed to mean "PNW AC Intertie Rated Transfer Capability" as defined in section 1 and the term "AFUDC" shall be deemed to have the meaning set forth for such term in section 1;

(2) the "Capacity Ownership Share of the capital and related cost of the upgrade," referred to in section III.B of the CO-94 rate shall be deemed to be the costs pursuant to subsection 5(d) and subparagraph 5(e)(3)(B), as applicable; and

(3) "construction costs (including direct, indirect and overhead costs) and AFUDC" referred to in section III.B of the CO-94 rate and "related costs" referred to in section III.B of the CO-94 rate together shall be deemed to be Upgrade costs and shall be determined in the same manner in which Replacement Costs are determined pursuant to section III of Exhibit I; provided, however, that expenses that are properly allocable to an Upgrade (i.e., "related costs" referred to in section III.B of the CO-94 rate) in accordance with generally accepted accounting principles (as defined in Exhibit I) may be included by Bonneville in Upgrade costs for such Upgrade.

(d) **Payments of Charges Pursuant to Section 3(b)(1)(C)(i)**

Bonneville shall bill Puget for wheeling provided pursuant to section 3(b)(1)(C)(i) on Puget's monthly power bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A and Puget shall pay such bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A; provided, however, that under any successor to the IS-93 rate, Puget shall not be obligated to pay any rate or charge greater than the rate or charge payable by any other party to which Bonneville provides nonfirm wheeling services on Bonneville's PNW AC Intertie for such party's nonfirm transaction of a duration similar to Puget's wheeling transaction pursuant to section 3(b)(1)(C)(i).

(e) **Suspension for Failure to Perform**

(1) If at any time during the term of this Agreement Bonneville does not receive payment due and owing to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d), Bonneville shall be entitled to suspend performance of its obligations to Puget pursuant to section 4 without incurring any liability to Puget therefor; provided, that Bonneville shall not be entitled to suspend performance pursuant to this paragraph 9(e)(1) earlier than five Working Days following receipt from Bonneville by Puget of written notice of such suspension. Such suspension shall continue in effect until the next Working Day following the Working Day on which Puget makes payment in full to Bonneville of the balance owed to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d). During the period of such suspension, Puget shall not be entitled to participate through the Committee in any review of an Operating Plan commenced by the Committee pursuant to section 13 during such period of suspension, or to participate in any arbitration commenced by the Committee pursuant to sections 14 and 15 during such period of suspension, or to participate in any audit commenced

by the Committee pursuant to section 16 during such period of suspension.

(2) If during any period in any month Bonneville fails to make deliveries in accordance with subsection 4(c), Puget shall be entitled, without incurring any liability to Bonneville therefor, to delay any payment due and owing to Bonneville by Puget pursuant to subsection 9(b) or 9(d) for a period, equal to the period during which Bonneville failed to make such deliveries, commencing on the date the monthly power bill for such month would otherwise be payable by Puget pursuant to this Agreement; provided, however that Puget's entitlement pursuant to this paragraph 9(e)(2) shall apply only with respect to the amount of such monthly power bill to be paid directly to Bonneville or its agent.

(f) **Payments or Refunds by Bonneville**

(1) Bonneville shall make any payment to Puget pursuant to subparagraph 3(b)(1)(B) within 30 days following the end of the month in which such payment becomes due to Puget pursuant to subparagraph 3(b)(1)(B).

(2) Bonneville shall pay to Puget, in a lump sum, any refund due to Puget pursuant to subsection 16(e) or paragraph 16(f)(2) within 30 days following the date on which such refund becomes due to Puget pursuant to subsection 16(e) or paragraph 16(f)(2), respectively.

(3) Bonneville shall pay any refund, credit, or payment due to Puget under section 18 pursuant to the terms and conditions set forth in section 18.

(4) Each payment, credit or refund due to Puget by Bonneville pursuant to this Agreement shall be made by Bonneville, at Bonneville's option, (A) by check payable to the order of Puget,

(B) by electronic funds transfer of immediately available funds into such account as may be designated in writing by Puget from time to time for such purpose or (C) by crediting the amount of such payment, credit or refund on Puget's power bill.

10. TRANSMISSION LOSSES

(a) To compensate Bonneville for transmission losses incurred by Bonneville in making deliveries scheduled by Puget pursuant to this Agreement, Puget shall make available, or arrange to have made available, to Bonneville, at any point mutually acceptable to the Parties at which the respective electric systems of Puget and Bonneville are interconnected, on the corresponding hour 168 hours later or on another hour to be agreed upon, the amounts of electric power equal to Puget's net PNW AC Intertie schedule multiplied by the appropriate loss factor specified in Exhibit E. Puget's net PNW AC Intertie schedule shall be, for any given hour, the absolute value of the sum of Puget's north-to-south schedules (positive) and south-to-north schedules (negative) for such hour.

(b) Upon the conclusion of any review by Bonneville of the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan provided to the Committee pursuant to section 13. The Committee may make recommendations regarding such results and any revisions to the loss factor in Exhibit E, Part A. Only recommendations regarding assumptions (including, without limitation, data inputs and source of date) made by Bonneville in its review or revision of the loss factor in Exhibit E, Part A, and recommendations regarding the results of such review or revision shall be subject to arbitration pursuant to section 14.

(c) Puget's Scheduling Share shall not be reduced by any amount of losses returned to Bonneville pursuant to subsection 10(a).

11. REMEDIAL ACTIONS

(a) Bonneville's Responsibilities

(1) Within five days after the Effective Date, Bonneville shall notify Puget in writing of the plan for remedial actions required to maintain the PNW AC Intertie Rated Transfer Capability, which plan shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice. If and to the extent that such plan is amended, modified, or replaced, Bonneville shall, promptly following such amendment, modification, or replacement, provide written notice to Puget of such amendment, modification, or replacement, as the case may be. Bonneville shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, required to maintain the portion of Bonneville's PNW AC Intertie Rated Transfer Capability not purchased by Capacity Owners. Such remedial actions shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice.

(2) Bonneville shall be responsible for generating appropriate control signals for transmission to Puget for purposes of effectuating remedial actions pursuant to this section.

(b) Puget's Responsibilities

(1) Puget shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other remedial actions required to maintain Puget's Capacity Ownership Share. Such remedial actions shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1) and Prudent Utility Practice. Bonneville

may perform engineering analyses to confirm Puget's providing capability to arm and having available appropriate remedial actions pursuant to this paragraph 11(b)(1).

(2) In any given hour, Puget shall be responsible for providing sufficient remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, to maintain Puget's schedule on the PNW AC Intertie for such hour. To the extent that load tripping or generator dropping is required as a remedial action by Puget pursuant to this paragraph 11(b)(2) in any given hour, the required amount of such load tripping or such generator dropping shall be determined by dividing the amount of power scheduled by Puget on Puget's Scheduling Share in such hour by the total amount of power scheduled on the PNW AC Intertie in such hour and multiplying the result by the total amount of generation or load (in MW) to be armed for the PNW AC Intertie in such hour.

(3) Puget shall provide, design, operate, and maintain the necessary equipment to accept control signals from Bonneville and to transmit such signals to Puget's generator dropping, load tripping, or other remedial action sites, and to arm and initiate the appropriate control action(s). Such design, operation, and maintenance shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1), and Prudent Utility Practice.

(4) Puget and Bonneville may mutually agree that Bonneville will, pursuant to terms and conditions mutually acceptable to the Parties, provide the remedial actions required of Puget pursuant to subsection 11(b).

12. **CAPACITY OWNERS' COMMITTEE**

(a) **Composition of Committee**

Puget may appoint one representative (and an alternate who may act in the absence of such representative) as a member of the Capacity Owners' Committee (Committee). If during any period Puget fails to appoint a representative to the Committee, Puget waives any and all rights during such period that would otherwise have accrued to it, individually or as a member of the Committee, pursuant to sections 12, 13, 14, 15, and 16 of this Agreement. Puget hereby appoints as its representative pursuant to this subsection the following representative and alternate to the Committee:

Representative: Vice President Power Planning

Alternate: Manager Power Contracts

(b) **Convening Meetings**

(1) Any Capacity Owner that has appointed a representative to the Committee may convene a meeting of the Committee pursuant to the procedures set forth in subsection 12(e). The Capacity Owner convening a Committee meeting shall be responsible for preparing any necessary notices, identifying the subject matter and issues to be discussed, and transmitting notices and relevant documents to the other Committee members and, if appropriate, to Bonneville.

(2) At the written request of any Capacity Owner that has appointed a representative to the Committee, Bonneville shall attend Committee meetings.

(3) The Committee may conduct business only at a properly convened meeting at which a quorum, as defined in subsection 12(c), is present. The Committee shall make or convey any

request, designation, recommendation, notice, appointment, submission, audit report or exception, or statement to which Bonneville is required to respond or which creates or triggers an obligation of Bonneville, pursuant to this Agreement, only upon a decision of the Committee made at a properly convened meeting at which a quorum is present.

(4) Each fiscal year, Bonneville shall convene an annual meeting of the Committee. The purpose of such annual meeting shall be to discuss the Operating Plan delivered, pursuant to subsection 13(b), to each Capacity Owner that has appointed a representative to the Committee. Bonneville shall convene such annual meeting no earlier than 15 days, but no later than 30 days, following the date of such delivery of the Operating Plan.

(5) In addition to the meeting referred to in paragraph 12(b)(4), Bonneville may, at its discretion, convene meetings of the Committee, pursuant to the procedures set forth in subsection 12(e), to present to the Committee any information Bonneville deems relevant.

(c) **Meeting Quorum**

The respective representatives of all of the Capacity Owners that have appointed a representative to the Committee, less one, shall constitute a quorum.

(d) **Meetings by Telephone Conference**

Committee meetings pursuant to the Capacity Ownership Agreements may be conducted by telephone provided all Capacity Owners and, if appropriate, Bonneville, are notified pursuant to the procedures set forth in subsection 12(e) of any such meeting.

(e) **Meeting Notices**

(1) All Committee meeting notices pursuant to the Capacity Ownership Agreements shall be provided in writing no less than 14 days prior to such meeting.

(2) Any Committee meeting notice required by this section shall be deemed properly made if delivered in person, by electronic facsimile, or by mail or other qualified delivery service, postage prepaid, to the person specified below:

If to Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232
Telephone (503) 230-5152
Facsimile (503) 230-5207

If to Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515
Telephone (206) 462-3137
Facsimile (206) 462-3175

If to Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101
Telephone (206) 386-4530
Facsimile (206) 386-4955

If to PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232
Telephone (503) 288-1234
Facsimile (503) 288-2334

If to Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201
Telephone (206) 258-8211
Facsimile (206) 258-8305

If to Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411
Telephone (206) 502-8294
Facsimile (206) 502-8628

Attendance at a meeting by a representative of a Capacity Owner constitutes waiver by such Capacity Owner of notice of such meeting.

(3) Either Party may, by written notice to the other Party and to the Capacity Owners other than Puget, change the designation, address, or facsimile number of the person so specified by it in subsection 12(a) or paragraph 12(e)(2).

13. OPERATING PLAN AND AMENDMENTS TO THE OPERATING PLAN

(a) The provisions of this section shall become effective commencing August 1, 1995; provided, however, that unless and until the annual costs rate set forth in Exhibit B is approved by FERC on an interim basis, Bonneville shall not have any right pursuant to this Agreement to bill or charge to Puget, and Puget shall not have any obligation pursuant to this Agreement to pay to Bonneville, any amount pursuant to any Operating Plan.

(b) **Delivery of Operating Plan**

(1) On or before August 1, 1995, Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1996 and an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1997.

(2) Not later than one year preceding the first day of each fiscal year, other than the fiscal years specified in paragraph 13(b)(1), Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for such fiscal year.

(c) Each Operating Plan delivered pursuant to subsection 13(b) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast costs for the fiscal year to which such Operating Plan pertains, and such Operating Plan may contain such other information as Bonneville may deem relevant; and each amendment of an Operating Plan delivered pursuant to subsection 13(k) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast or actual costs, as appropriate, for the fiscal year to which such Operating Plan pertains, and such amendment may contain such other information as Bonneville may deem relevant:

(1) a forecast of, or the actual, Allocated Direct Cost of Operations Cost (pursuant to section I.C of Exhibit I), Indirect Cost of Operations Cost (pursuant to section I.D of Exhibit I), and Overhead Cost of Operations Cost (pursuant to section I.E of Exhibit I) in the format set forth in Exhibit I, Schedule A;

(2) a forecast of, or the actual, Direct Cost of Maintenance Cost (pursuant to section II.B of Exhibit I), Indirect Cost of Maintenance Cost (pursuant to section II.D of Exhibit I), and Overhead Cost of Maintenance Cost (pursuant to section II.E of Exhibit I) in the format set forth in Exhibit I, Schedule B;

(3) a forecast of, or the actual, Direct Cost of Replacements and Reinforcements (pursuant to section III.A of Exhibit I), Indirect Cost and Overhead Cost of Replacements and Reinforcements (pursuant to section III.B of Exhibit I), and AFUDC of Replacements and Reinforcements (pursuant to section III.C of Exhibit I) in the format set forth in Exhibit I, Schedule C, for each Reinforcement and Replacement which is expected to be, in the fiscal year to which the Operating Plan pertains, a planned new start, construction work in progress on a previously initiated Reinforcement or Replacement, as the case may be, or a closed work order. The forecast shall include for each such Reinforcement or Replacement an estimate of the total cost of construction and the cost to be incurred with respect to such Reinforcement or Replacement during each fiscal year until the work order for such Reinforcement or Replacement has been closed. Bonneville may elect, but shall not be required, to include in any such forecast the information set forth in the immediately preceding sentence regarding any Replacement and Reinforcement which is expected to be planned a new start in any fiscal year following the fiscal year to which the Operating Plan pertains. In the event Bonneville elects to forecast Direct Cost, Indirect Cost, and Overhead Cost of any Reinforcement or Replacement which is expected to be a

planned new start in any fiscal year subsequent to the fiscal year to which the Operating Plan pertains, Bonneville shall provide to the Committee such forecast costs, in the format set forth in Exhibit I, Schedule C (together with additional information pertinent to such forecast costs as required by paragraph 13(c)(9)), 30 days prior to the date such Operating Plan is delivered to the Committee pursuant to subsection 13(b). In addition, Bonneville shall include such forecast costs in the Operating Plan delivered to the Committee pursuant to subsection 13(b);

(4) the General Plant Cost (pursuant to section IV of Exhibit I) in the format set forth in Exhibit I, Schedule D;

(5) a forecast of, or the actual, Other Costs (pursuant to section V of Exhibit I) in the format set forth in Exhibit I, Schedule E;

(6) a forecast of, or the actual, Contracts and Rates Costs (pursuant to section VI of Exhibit I) in the format set forth in Exhibit I, Schedule F;

(7) a forecast of, or the actual, Power Scheduling Costs (pursuant to section VII of Exhibit I) in the format set forth in Exhibit I, Schedule G;

(8) a forecast of, or the actual, End of Term Costs (pursuant to section VIII of Exhibit I) in the format set forth in Exhibit I, Schedule H. Such forecast shall include Bonneville's proposed apportionment of such End of Term Costs among Puget and Capacity Owners other than Puget and Bonneville's rationale for such apportionment;

(9) additional information pertinent to the forecast costs, actual costs, and General Plant Cost provided pursuant to paragraphs 13(c)(1) through 13(c)(8), including, without limitation, descriptions of the activities or projects and explanations of the

costs comprising the Direct Cost components of such forecast costs, actual costs, and General Plant Cost, and explanations of MFU counts; and

(10) if Bonneville has reviewed the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), the Operating Plan shall contain the results of such review, including any revision to the loss factor in Exhibit E, Part A, pursuant to subsection 10(b), and any additional information pertinent to such review.

(d) **Requests by Committee**

(1) No later than 15 days after the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), the Committee may make a single request of Bonneville in writing for:

(A) such supporting documentation, data, and information as may be reasonably necessary to analyze (i) the Operating Plan, or its constituent parts, delivered to the Committee pursuant to subsection 13(b), or (ii) any amendment to an Operating Plan pursuant to subsection 13(k); and

(B) such documentation, data, and information relating to Bonneville's present or past activities or practices concerning Bonneville's PNW AC Intertie and to alternatives considered by Bonneville to costs or activities described in the Operating Plan or any amendment to an Operating Plan as may be reasonably necessary for the Committee to formulate recommendations pursuant to subsection 13(e);

provided, however, that with regard to requests for documentation, data, and information pursuant to this paragraph 13(d)(1), the Committee must designate in such request the specific item in the Operating Plan or in any amendment to an Operating Plan to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information. Such single request may contain multiple parts.

(2) The Committee shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to paragraph 13(d)(1).

(3) Bonneville shall have 20 days from the date it receives any request pursuant to paragraph 13(d)(1) to provide the documentation, data, and information requested; provided, however, that Bonneville shall be under no obligation (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Committee, or (D) to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or any regulation and Executive Order applicable to Bonneville.

(4) The Committee in such request shall designate one of its members to be its representative for the sole purpose of receiving such documentation, data, or information from Bonneville pursuant to this subsection 13(d). Bonneville shall deliver such documentation, data, or information to the representative designated by the Committee to receive such materials.

(5) For purposes of this subsection 13(d) and subsection 13(f), each of Bonneville and the Committee shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests for, documentation, data, and information and responses to such requests.

(e) The Committee shall have 20 days from the date on which it receives documentation, data, or information from Bonneville pursuant to subsection 13(d) or, if none was requested, 50 days from the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), whichever date is later, to recommend to Bonneville in writing a revision or revisions to any forecast cost or General Plant Cost in the Operating Plan. The Committee shall have the time periods set forth in subsection 13(m) to recommend to Bonneville in writing a revision or revisions to a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan. Such recommendation shall set forth, at a minimum, the exact revisions to the forecast cost or General Plant Cost proposed by the Committee and the reasons for such revisions. Failure of the Committee to recommend a revision or revisions to all or any portion of a forecast cost or General Plant Cost in the Operating Plan or a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan within the applicable time limit set forth above shall be deemed to constitute acceptance by the Committee of all portions of the forecast costs and General Plant Cost of the Operating Plan for which the Committee has not recommended a revision.

(f) No later than 15 days after receipt of a Committee recommendation made pursuant to subsection 13(e), Bonneville may make a single request (which may contain multiple parts) in writing of the Committee for such supporting documentation, data, and information as may be reasonably necessary to analyze the Committee's recommendation, including without limitation, any estimated costs or forecast costs contained in such recommendation; provided, however, that the Capacity Owners that have appointed a representative to the Committee shall be under no obligation (1) to create additional documentation, data, or information, (2) to provide documentation, data, or information that is not readily available to the Committee or to any Capacity Owner that has appointed a member to the Committee, (3) to provide to Bonneville documentation, data, or information that the Committee has previously provided to Bonneville; provided, further, that with regard to requests for documentation, data, and information pursuant to this subsection 13(f), (1) Bonneville must designate in such request the specific item in the Committee's recommendation to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information, and (2) Bonneville shall use reasonable efforts, consistent with Bonneville's needs as set forth in this subsection 13(f), to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to this subsection. Such single request shall be made of the Committee by delivering a copy of the request to each Capacity Owner that has appointed a representative to the Committee. The Committee shall have 20 days from the date of its receipt of Bonneville's request to provide a single response containing the documentation, data, and information requested.

(g) If the Committee makes any recommendation in writing pursuant to subsection 13(e), Bonneville shall have the greater of 15 days from the date of receipt of the requested documentation, data, and information requested pursuant to subsection 13(f) or, if none was requested, 30 days from the date of receipt of the Committee's recommendations made pursuant to subsection 13(e) to, by written notice to each Capacity Owner that has appointed a representative to the Committee, accept the recommendation, accept the recommendation in part, reject the recommendation, or propose an action that is responsive to the Committee's recommendation and that is different from Bonneville's proposal contained in the Operating Plan. If Bonneville makes such a proposal, Bonneville shall set forth in such written notice the exact revisions to the Operating Plan. The Committee shall have 7 days from the date of receipt of Bonneville's proposal to make any requests in writing for supporting documentation, data, and information as set forth in subsection 13(d). Bonneville shall have 7 days to respond to those requests as set forth in subsection 13(d). Failure of Bonneville to respond in writing to any recommendation of the Committee within the applicable time period set forth in this subsection 13(g) shall be deemed to constitute rejection of such recommendation.

(h) If Bonneville rejects all or any portion of the Committee's recommendation, or if the Committee elects not to accept a proposal made by Bonneville pursuant to subsection 13(g), then the Committee may

(1) elect by written notice to Bonneville to refer to binding arbitration, pursuant to section 14 and consistent with subsections 13(i) and 14(b), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g); and

(2) elect by written notice to Bonneville to refer to nonbinding arbitration pursuant to section 15 and consistent with subsections 15(a) and 15(d), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g).

Failure of the Committee to elect to refer to arbitration

(A) such portion of any recommendation of the Committee not accepted by Bonneville within 15 days following Bonneville's rejection or acceptance in part of such recommendation of the Committee pursuant to subsection 13(g), or

(B) any proposal made by Bonneville pursuant to subsection 13(g) within 15 days following Bonneville's written notice of such proposal or, if documentation, data, or information was requested by the Committee pursuant to subsection 13(g), within 15 days following receipt by the Committee of such documentation, data, or information pursuant to subsection 13(g),

shall be deemed to constitute acceptance by the Committee of Bonneville's rejection or acceptance in part of the recommendation of the Committee or of Bonneville's proposal and waiver by the Committee of any right pursuant to this section 13 or to section 15 to arbitrate such recommendation or portion thereof.

(i) The Committee may, subject to the immediately succeeding sentence, arbitrate, pursuant to subsection 13(h); any recommendation by the Committee concerning a revision pursuant to this Agreement to a loss factor set forth in any Operating Plan or in any amendment to an Operating Plan or concerning any forecast cost or actual (allocated or otherwise) cost set forth in any Operating Plan or in any amendment to an Operating Plan (including the following costs and related items set forth in any Operating Plan, or in any amendment to an Operating Plan, pursuant to Exhibit I, Schedule A, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12 and 13; Exhibit I, Schedule B, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14 and 15; Exhibit I, Schedule C, lines 1, 2, 3, 4 and 5; Exhibit I, Schedule D, lines 3, 4, 5, 6, 7, 8, 9, 10 and 11; Exhibit I, Schedule E, lines 2 and 3; Exhibit I, Schedule F, lines 1, 2, 3, 4, 5, 6, 7, 8, and 9; Exhibit I, Schedule G, lines 1, 2, 3, 4, 5, 6 7, 8, and 9; and Exhibit I, Schedule H, lines 1, 2, 3, and 4). The Committee's right pursuant to this subsection 13(i) to arbitrate any such recommendation shall be subject to the following limitations:

(1) if such recommendation, or portion thereof, includes a Replacement Cost for a Replacement or a Reinforcement Cost for a Reinforcement, and such Replacement Cost or Reinforcement Cost was included in a previous Operating Plan

(either of such costs, a Previous Operating Plan Cost), the Committee may arbitrate pursuant to this subsection 13(i) such recommendation, or portion thereof, only to the extent that such recommendation, or portion thereof, includes any Replacement Cost or Reinforcement Cost in excess of the Previous Operating Plan Cost;

(2) the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, pertaining to a revision to a loss factor pursuant to this Agreement only to the extent such arbitration is permitted by subsection 10(b);

(3) the Committee may arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning an Other Cost only to the extent that such Other Cost is a cost set forth in an Operating Plan or amendment to an Operating Plan pursuant to Exhibit I, Schedule E, line 2 and such recommendation, or portion thereof pertains to whether such Other Cost is properly allocated to Bonneville's PNW AC Intertie pursuant to Exhibit I, section V;

(4) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in such Operating Plan or in any amendment to an Operating Plan, the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan only to the extent that such actual cost exceeds 105 percent of the forecast cost for such activity or such project; provided, however, that, without limiting any of Puget's rights

and benefits pursuant to subsection 16(c), the Committee may not arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan or in any amendment to an Operating Plan if such actual cost is less than 105 percent of the forecast for such activity or such project;

(5) the Committee may not arbitrate, pursuant to this subsection 13(i), (a) the allocation by Bonneville pursuant to this Agreement of any of its costs to overall overhead costs or to overall indirect costs, or (b) the allocation by Bonneville pursuant to this Agreement of a portion of Bonneville's overall overhead costs and overall indirect costs to its total system operations costs, its total system maintenance costs, its total capital costs or its total indirect and overhead power scheduling costs; provided, however, that nothing in this paragraph (5) shall be deemed to prevent or restrict the Committee from arbitrating pursuant to this subsection 13(i) the level (rather than the allocation) of any of Bonneville's Exhibit I, Schedule A, line 9 total system operations indirect costs and line 11 total system operations overhead costs; Bonneville's Exhibit I, Schedule B, line 11 total system maintenance indirect costs and line 13 total system maintenance overhead costs; Bonneville's total capital costs; Bonneville's Exhibit I, Schedule F, line 6 total indirect contracts and rates costs and Bonneville's Exhibit I, Schedule F, line 7 total overhead contracts and rates costs; or Bonneville's Exhibit I, Schedule G, line 6 total indirect power scheduling costs and Bonneville's Exhibit I, Schedule G, line 7 total overhead power scheduling costs;

(6) the Committee may not arbitrate any recommendation, or any portion thereof, regarding any amendment to an Operating Plan made pursuant to sections 9(b)(2)(A)(iv) and 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2);

(7) the Committee may not arbitrate any such recommendation, or portion thereof, to the extent that in doing so the arbitrators would be required to decide a matter of law in order to render a decision pursuant to subsection 14(h). If, subsequent to the Effective Date, Bonneville is given legal authority to submit to binding arbitration matters of law, Bonneville shall enter into good faith negotiations with Puget and Capacity Owners other than Puget regarding a revision to this paragraph 13(i)(7) enabling arbitration of matters of law pursuant to this subsection 13(i) consistent with such legal authority; and

(8) the Committee may not arbitrate any recommendation, or portion thereof, regarding an allocation of a Reinforcement Cost to the extent prohibited by subsection 7(d).

In arbitrating any recommendation, or portion thereof, pursuant to this subsection 13(i), the Committee may raise in support of such recommendation arguments regarding whether any forecast or actual cost should be based upon activities different in degree, but not in kind, from the activities upon which such forecast or actual cost in the Operating Plan is based.

(j) Each Operating Plan provided pursuant to subsection 13(b) which has completed the Committee review process set forth in subsections 13(d) through 13(g) shall take effect on the first day of the fiscal year to which such Operating Plan pertains and shall remain in effect for the duration of such fiscal year.

(k) At any time during the fiscal year in which an Operating Plan is in effect, or within 8 months after the end of such fiscal year, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast or actual Operations Cost, Maintenance Cost, General Plant Cost, Other Cost, Contracts and Rates Cost, Power Scheduling Cost, or End of Term Cost in such Operating Plan. At any time during the fiscal year an Operating Plan is in effect, or within 30 months after a work order for a Replacement or Reinforcement is closed, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast cost or actual cost component for such Replacement or Reinforcement.

(l) Any amendment made to any Operating Plan pursuant to subsection 13(k) shall be provided by delivery of a copy in writing of such amendment by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(m) Consideration of amendments to the Operating Plan pursuant to subsection 13(l) shall be consistent with the procedures set forth above in subsections 13(c) through 13(k), except that the time limits set forth in such subsections shall be reduced as follows: 15 days shall be 7 days, 20 days shall be 10 days, 30 days shall be 15 days, and 50 days shall be 25 days. For purposes of computing the time limits in this subsection 13(m), the date Bonneville provides the Capacity Owners with a proposed amendment, pursuant to subsection 13(k), shall be deemed to be the date the annual meeting was convened for purposes of paragraph 13(d)(1) and subsection 13(e).

(n) Without limiting any of Puget's rights and benefits pursuant to subsection 13(i) and sections 14 and 15, any Operating Plan amended pursuant to section 9(b)(2)(A)(v) or 9(b)(2)(B)(iii), or subsection 13(k) shall take effect when such amendment is accepted by the Committee pursuant to subsection 13(e) or 13(h). Any Operating Plan amended pursuant to section 9(b)(2)(A)(iii), 9(b)(2)(A)(iv), 9(b)(2)(B)(i), or 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2) shall take effect as soon as such amendment is delivered by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(o) An Operating Plan shall, during the fiscal year in which such Operating Plan is in effect, establish the costs which Puget is obligated to pay pursuant to the terms and conditions of this

Agreement. In no event shall such Operating Plan, or any portion thereof, contain or constitute an obligation of Bonneville to undertake, or to expend funds on, activities described or indicated in such Operating Plan.

14. **ARBITRATION**

(a) During any arbitration process conducted pursuant to this section 14, Puget shall act through the Committee. Each of Bonneville and Puget agrees to be bound by any decision rendered by the arbitrators in any arbitration brought pursuant to subsection 13(i) and this section 14.

(b) The Committee may initiate arbitration pursuant to subsection 13(i) by taking the following actions:

(1) an affirmative vote to initiate arbitration by at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(2) either of the following:

(a) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to subsection 13(i) within the applicable time period established in subsection 13(h); or

(b) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subsection 14(b) shall set forth in detail the matter or matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(c) Bonneville shall, within 10 Working Days after receipt of the notice by the Committee referred to in subsection 14(b), appoint a second arbitrator and provide by written notice to each Capacity Owner that has appointed a representative to the Committee the name, street address and telephone number of the arbitrator appointed by Bonneville. The two arbitrators appointed by the Committee and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville.

(1) If the arbitrators appointed by the Committee and by Bonneville, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville, then within 30 days after the date of the appointment of an arbitrator by Bonneville, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(2) If Bonneville fails to appoint an arbitrator within 15 days after receipt of the notice by the Committee referred to in subsection 14(b), then within 30 days after the date of such notice, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(3) If, pursuant to either paragraph 14(c)(1) or 14(c)(2), the Committee applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Committee shall give Bonneville written notice of such application within 5 days after the date of filing such application.

(d) The three arbitrators appointed pursuant to subsections 14(b) and 14(c) shall select by a majority vote an alternative pursuant to subsection 14(g).

(e) Within 10 days after the appointment of a third arbitrator pursuant to subsection 14(c), the arbitrators shall establish a schedule for submission of written positions by Bonneville and Puget, respectively. The arbitrators must establish a schedule for such submissions pursuant to this subsection 14(e) that will allow the arbitration to be concluded, and the decision of the arbitrators rendered pursuant to subsection 14(g), within 120 days following the date of the appointment of the third arbitrator. A copy of any submission by the Committee to the arbitrators pursuant to this section 14 shall be simultaneously served by the Committee on Bonneville, and a copy of any submission by Bonneville to the arbitrators pursuant to this section 14 shall be simultaneously served by Bonneville on each Capacity Owner that has appointed a representative to the Committee. The Committee shall state, in a letter to the arbitrators, as its proposed alternative to each Bonneville proposal in dispute, the recommendation proposed by the Committee pursuant to subsection 13(g) and rejected in whole or in part by Bonneville pursuant to subsection 13(g). Bonneville shall state its position and proposed resolution of the dispute in a letter to the arbitrators. If Bonneville made a proposal in response to such recommendation of the Committee pursuant to subsection 13(g), then such position and proposed resolution shall set forth such proposal, or if Bonneville made no such proposal, then such position and proposed resolution shall set forth the relevant portion of the Operating Plan. If, however, the arbitration concerns an exception pursuant to paragraph 16(f)(3), then the positions and proposed resolutions of Bonneville and the Committee shall be as established pursuant to such subsection. The Committee may then submit a response to Bonneville's letter, and Bonneville may thereafter submit a reply to the Committee's response. Bonneville and the Committee shall have an equal number of days to prepare and serve their replies.

(f) No submission by either the Committee or Bonneville to the arbitrators pursuant to subsection 14(e) shall be more than 50 pages in length (not including exhibits). If requested in writing by either the

Committee or Bonneville, and for good cause shown, the arbitrators may permit any submission by such Party to exceed 50 pages.

(g) The arbitrators shall select, as between the Committee's recommendation pursuant to subsection 13(e), on the one hand, and the portion of Bonneville's proposed Operating Plan to which the Committee's recommendation pertains or Bonneville's proposal pursuant to subsection 13(g) not accepted by the Committee, on the other, the alternative which

(1) is consistent with the provisions of this Agreement and

(2) (A) in conformity with the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto, would better achieve the desired result consistent with safety, reliability, and cost-benefit or (B) if there are no such generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area, would, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, be reasonably expected to better achieve the desired result consistent with safety, reliability, and cost-benefit.

(h) In applying the standards set forth in subsection 14(g), the arbitrators shall take into consideration, among other things (a) that Bonneville and Puget each have responsibilities for service to customers within and without the Pacific Northwest region in accordance with applicable law, (b) that Bonneville and others jointly own the PNW AC Intertie and Bonneville owes contractual obligations to those parties regarding the PNW AC Intertie, (c) that Bonneville must operate, as a practical matter, the PNW AC Intertie in coordination with the operation of the interconnected intertie facilities in California, and (d) that the PNW AC Intertie is a major import-export facility important to the service of loads in and out of the region.

(i) In any arbitration pursuant to this section 14, the arbitrators shall choose, pursuant to subsection 14(g), only between the alternatives proposed by Bonneville and the Committee and shall have no authority to resolve such arbitration other than by selecting an alternative proposed by either Bonneville or the Committee.

(j) Upon selection by the arbitrators of an alternative pursuant to subsection 14(g), then Bonneville shall amend the Operating Plan to cause it to conform to the decision of the arbitrators.

(k) If the arbitrators have not made a selection of an alternative pursuant to subsection 14(i) before the date on which the Operating Plan becomes effective pursuant to subsection 13(j), then Puget shall make payments of annual charges pursuant to such Operating Plan. If the arbitrators subsequently select the Committee's alternative, then Bonneville shall, subsequent to amending such Operating Plan pursuant to subsection 14(j), refund to or bill Puget its pro rata share of the amount of the incremental difference between the costs set forth in such Operating Plan as amended pursuant to subsection 14(j) and 105 percent of the costs set forth in such Operating Plan, prior to its amendment pursuant to subsection 14(j), to the extent that such costs were incurred during the period from the first day of effectiveness of such Operating Plan pursuant to subsection 13(j) to the date of the arbitrators' decision, such refund to be made pursuant to subsection 9(f) and such payment to be made pursuant to subsection 9(b).

(l) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 14 equal to $1 \div (n + 1)$, where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay its own expenses related to the arbitration proceeding including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(m) Any judgment rendered by a court of competent jurisdiction upon an award made by the arbitrators pursuant to this section 14 may be entered in any court having jurisdiction thereof.

15. **NONBINDING ARBITRATION**

(a) The Initiating Party (as defined in paragraph 15(e)(1)) may, subject to the immediately succeeding sentence, elect by written notice to Responding Party (as defined in paragraph 15(e)(1)) to refer to nonbinding arbitration pursuant to the other provisions of this section 15 the following: (i) if the Initiating Party is the Committee, any recommendation by the Committee, or any portion thereof, concerning any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 and (ii) any other issue, dispute, or controversy regarding the Parties' respective rights and obligations pursuant to this Agreement. The Initiating Party's right pursuant to this subsection 15(a) to arbitrate any recommendation or any issue, dispute or controversy shall be subject to the following limitations:

(1) the Initiating Party may not arbitrate pursuant to this subsection 15(a): (A) any recommendation with respect to an Operating Plan or any amendment to an Operating Plan or (B) any issue, dispute, or controversy, which recommendation, issue, dispute or controversy may be arbitrated pursuant to subsection 13(i) or 16(f);

(2) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation not permitted to be arbitrated pursuant to paragraphs 13(i)(1), 13(i)(3), 13(i)(4), and 13(i)(8);

(3) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or

controversy concerning a loss factor or revision to a loss factor set forth in Exhibit E, Part A or Part B pursuant to this Agreement;

(4) the Committee may not (but the Puget or Bonneville may) arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning any right or obligation of Puget pursuant to this Agreement that is not a right or obligation, as the case may be, of each other Capacity Owner under its respective Capacity Ownership Agreement; or

(5) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operating Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs and forecast End of Term Costs set forth in such Operating Plan, the Committee may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 only to the extent that such actual cost exceeds 105 percent of the forecast for such activity or such project; provided, however, that, without limiting any of Puget's rights and benefits pursuant to section 16(f), no Initiating Party may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B,

lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 if such actual cost is less than 105 percent of the forecast for such activity or such project; and

(6) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any issue, dispute, or controversy (A) concerning matters of ratemaking (for purposes of this subsection 15(a), the term "ratemaking" shall mean the determination of matters appropriately determined pursuant to section 7(i) of the Regional Act, including (i) Bonneville's revenue requirements (including without limitation Bonneville's depreciation and repayment standards and planned net revenues for risk, but excluding program level issues determined in the Federal budget process), (ii) Bonneville's cost of service analysis (including functionalization, segmentation, and allocation of costs contained in such analysis, but excluding any allocation of costs contemplated in Exhibit I), (iii) Bonneville's rate design, and (iv) any related environmental analysis of proposed rates; (B) concerning a final action of Bonneville, which final action is not itself performance of any obligation of Bonneville or Bonneville's Administrator under this Agreement; or (C) concerning, or requiring the decision of, a matter not arising under this Agreement or the other Capacity Ownership Agreements.

(b) Except as otherwise provided in paragraph 15(a)(4), all arbitrations pursuant to this section 15 shall be between Bonneville and the Committee.

(c) A copy of any submission (including, without limitation, any statement of position or any brief) by the Initiating Party or the Responding Party to the arbitrators pursuant to this section 15 shall be simultaneously served by such party on the Responding Party or Initiating Party, respectively. No submission by either the Initiating

Party or the Responding Party to the arbitrators shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Initiating Party or the Responding Party, and for good cause shown, the arbitrators may permit any submission by such party to exceed 50 pages.

(d) With respect to any arbitration pursuant to this section 15 of any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) Only the Committee may initiate arbitration with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7. The Committee may initiate nonbinding arbitration pursuant to this section 15 by taking the following actions:

(A) an affirmative vote to initiate arbitration pursuant to this section 15 by the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(B) either of the following:

(i) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to this section 15 within the applicable time period set forth in subsection 13(h); or

(ii) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subparagraph 15(d)(1)(B) shall (x) indicate that such vote has been taken and (y) set forth in detail the matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(2) The respective rights and obligations of the Committee and of Bonneville with respect to arbitration pursuant to this subsection 15(d), unless otherwise provided in this subsection 15(d), shall be as set forth in subsections 14(d) through 14(l).

(e) With respect to any arbitration pursuant to this section 15 of any issue, dispute, or controversy other than with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) The party (which term, for purposes of this subsection 15(e), shall refer to Bonneville, on the one hand, and to the Committee or Puget, on the other) initiating arbitration (Initiating Party) shall initiate arbitration pursuant to this section 15 by serving written notice on the other party (Responding Party) of its initiation of arbitration. If the Committee is the party initiating arbitration, the Committee, in addition to serving such notice, shall initiate such arbitration by an affirmative vote to do so of at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one.

The Committee shall indicate that such vote has been taken in such notice to Bonneville. Any such notice by an Initiating Party shall set forth in detail the following: (A) the issue, dispute, or controversy to be arbitrated and the Initiating Party's position regarding such issue, dispute, or controversy; (B) the relief sought by the Initiating Party; and (C) the name, street address, and telephone number of the arbitrator appointed by the Initiating Party. The Responding Party shall, within 15 days after receipt of the notice by the Initiating Party referred to in this subsection 15(e), appoint a second arbitrator and provide written notice to the Initiating Party and to the arbitrator appointed by the Initiating Party of the name, street address and telephone number of the arbitrator appointed by the Responding Party. The arbitrators appointed by the Initiating Party and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party.

(A) If the arbitrators appointed by the Initiating Party and by the Responding Party, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party, then within 30 days after the date of the appointment of an arbitrator by the Responding Party the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(B) If the Responding Party fails to appoint an arbitrator within 15 days after receipt of the notice by the Initiating Party referred to in paragraph 15(e)(1), then within 30 days after the date of such notice the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(C) If, pursuant to either subparagraph 15(e)(1)(A) or 15(e)(1)(B), the Initiating Party applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Initiating Party shall give the Responding Party written notice of such application within one day after the date of filing such application.

(2) The three arbitrators appointed pursuant to paragraph 15(e)(1) shall decide any issue, dispute, or controversy by majority vote.

(3) Within 20 days after the appointment of a third arbitrator pursuant to paragraph 15(e)(1) with respect to any arbitration pursuant to this subsection 15(e), the arbitrators shall establish a schedule for the completion of such arbitration. The first day pursuant to such schedule shall be hereafter referred to in this subsection 15(e) as the "Arbitration Commencement Date."

(4) No later than 15 days after the Arbitration Commencement Date, the Initiating Party may make a single request in writing to the Responding Party for documentation, data, and information relevant to or reasonably necessary to support the Initiating Party's position communicated to the Responding Party pursuant to paragraph 15(e)(1). Such single request may contain multiple parts. The Initiating Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information pursuant to this paragraph.

(5) The Responding Party shall have 20 days from the date it receives the request from the Initiating Party pursuant to paragraph 15(e)(4) to provide the documentation, data, and information requested; provided, however, that the Responding Party shall be under no obligation pursuant to this paragraph 15(e)(5) (A) to create additional documentation, data, or

information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Initiating Party or (D) if Bonneville is the Responding Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(6) No later than 15 days after the Arbitration Commencement Date, the Responding Party may make a single request in writing to the Initiating Party for documentation, data and information relevant to Initiating Party's position communicated to the Responding Party pursuant to subsection 15(e)(4). Such single request may contain multiple parts. The Responding Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data and information pursuant to this paragraph.

(7) The Initiating Party shall have 20 days from the date it receives the request from the Responding Party pursuant to paragraph 15(e)(6) to provide the documentation, data and information requested; provided, however, that the Initiating Party shall be under no obligation pursuant to this paragraph 15(e)(7) (A) to create additional documentation, data, or information, (B) to provide documentation, data or information that is not readily available to it, (C) to provide to the Responding Party documentation, data, or information that the Initiating Party has previously provided to the Responding Party or (D) if Bonneville is the Initiating Party, to provide documentation, data, or information that Bonneville would not

otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(8) For purposes of this subsection 15(e), each of the Initiating Party and the Responding Party shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests by it for, documentation, data, and information and responses to such requests.

(9) Within 65 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may state in reasonable detail its position regarding any issue, dispute or controversy to be arbitrated pursuant to this subsection 15(e) in a letter to the arbitrators and to the other party to the arbitration of such issue, dispute, or controversy Within 85 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may submit a letter to the arbitrators and to the other party responding to the letter that the other submitted to the arbitrators pursuant to the immediately preceding sentence.

(10) The arbitrators shall resolve any issue, dispute, or controversy pursuant to this subsection 15(e) by deciding (taking into consideration, among other things, any letter submitted by the Initiating Party or the Responding Party with respect to such issue, dispute, or controversy) whether the position of the Initiating Party or the position of the Responding Party regarding the action taken or proposed to be taken by the Responding Party conforms more closely with the standard for such action set forth in this Agreement. The arbitrators shall have no authority to fashion a resolution of such arbitration other than pursuant to this paragraph 15(e)(10).

(f) Any selection by the arbitrators of an alternative pursuant to subsection 15(d) and any decision by the arbitrators pursuant to subsection 15(e) shall be reported by the Initiating Party to the Bonneville Administrator (Administrator) for review within 30 days after such selection or decision is made. The Administrator shall either accept or reject in writing such selection or decision. If the Administrator fails to either accept or reject such selection or decision, as the case may be, within 90 days after such selection or decision is made, such selection or decision, as the case may be, shall be deemed to be accepted by the Administrator.

(g) If the Administrator accepts any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e), such selection or decision shall become binding upon Puget and Bonneville at the time of its acceptance.

(h) The Administrator may reject any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e) only for one or more of the following reasons:

(1) the arbitrators did not follow the arbitration procedures set forth in this section 15;

(2) the arbitrators decided a matter that is not a matter arising under this Agreement as set forth in paragraph 15(a)(6);

(3) the arbitrators did not completely apply the appropriate standard for arbitration pursuant to this section 15;

(4) the arbitrators granted relief in contravention of this Agreement;

(5) the arbitrators' decision is not supported by substantial, competent evidence; or

(6) implementation of the arbitrators' decision would cause Bonneville to violate a statutory obligation of Bonneville's or would cause Bonneville to breach a contractual obligation not in contravention of this Agreement.

(i) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 15 equal to $1 \div (n + 1)$, where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay for its own expenses related to the arbitration proceeding, including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(j) If the Initiating Party elects to arbitrate any issue, dispute, or controversy pursuant to this section 15, the Initiating Party must initiate arbitration of such issue, dispute, or controversy within one year following the occurrence of the event giving rise to such issue, dispute, or controversy. Failure of the Initiating Party to initiate arbitration of any such issue, dispute, or controversy within such one-year period shall constitute a waiver of the Initiating Party's right to arbitrate such issue, dispute, or controversy pursuant to this section 15.

16. AUDIT RIGHTS

(a) The Committee shall have the right to perform an audit of Bonneville's books, records, and documents used in or relating to the determination of the Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to the Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(2)(B).

(b) The Committee shall have the right to perform an audit of Bonneville's books, records and documents used in or relating to the determination of any Revised Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to any Revised Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(3)(B).

(c) The Committee shall have the right to audit Bonneville's books, records, and documents (i) used in or relating to the determination of any charge (including, without limitation, any MFU count made pursuant to section I.A of Exhibit I) billed to Puget pursuant to paragraph 9(b)(2) and subsection 9(c), or (ii) used in or relating to any billing or refund with respect to any such charge. Such audit shall be performed within 36 months after the date of Bonneville's bill or refund voucher for such charge rendered by Bonneville to Puget pursuant to paragraph 9(b)(2) or subsection 9(c), as the case may be.

(d) Bonneville shall not be responsible to pay any of the expenses incurred by any of the Capacity Owners in performing any audit pursuant to this section 16. Bonneville shall not directly charge Puget or any Capacity Owner other than Puget for Bonneville's costs incurred by Bonneville with respect to any audit pursuant to this section 16 unless Bonneville develops a general practice of charging, through direct charges, each of its customers for such costs incurred by Bonneville in connection with audits undertaken pursuant to those customers' respective contracts with Bonneville.

(e) After completing any audit specified above, the Committee shall promptly provide to Bonneville a written report of the results of such audit. If such audit report includes any exception taken as a result of such audit and Bonneville agrees with such exception, Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such audit exception,

(1) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Puget a revised bill or refund voucher pursuant to paragraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(2) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and either (A) render to Puget a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (B) cause to be refunded to Puget as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Puget's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this subsection 16(e) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such audit report is received by Bonneville to (but excluding) the date on which such amount is refunded to Puget.

(f) If an audit report provided to Bonneville by Puget pursuant to subsection 16(e) includes any exception taken as a result of such audit and Bonneville does not agree with such exception, then the following shall apply:

(1) Bonneville may, within 30 days following its receipt of such audit report, propose to the Committee a resolution of any

inconsistency noted in any exception taken as a result of such audit;

(2) If the Committee accepts such resolution proposed by Bonneville, then Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such resolution,

(A) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Puget a revised bill or refund voucher pursuant to subparagraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(B) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and shall either (i) render to Puget a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (ii) cause to be refunded to Puget as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Puget's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this paragraph 16(f)(2) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such resolution is accepted by the Committee to (but excluding) the date on which such amount is refunded to Puget; and

(3) If the Committee does not accept such resolution, if any, proposed by Bonneville with respect to any such exception, or if Bonneville does not propose any such resolution, then the Committee

(A) shall have the right to arbitrate, pursuant to section 14, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to subsection 13(i); and

(B) shall have the right to arbitrate, pursuant to section 15, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to section 15.

The Committee must refer to arbitration pursuant to subparagraph 16(f)(3)(A) or 16(f)(3)(B) any cost to which exception is taken as a result of any audit within eight months after the date the Committee commences such audit. Failure of the Committee to elect to so refer to arbitration any cost within such eight-month period shall be deemed to constitute waiver by the Committee of any right pursuant to this section 16 to arbitrate such cost.

(g) Puget shall have the right to participate in any audit pursuant to this section 16 only by acting through the Committee. If Puget chooses not to participate in any audit undertaken by the Committee, then Puget shall accept the findings of the Committee with respect to such audit and any resolution by the Committee and Bonneville of any inconsistency noted in any exception taken as a result of such audit.

(h) Any audits undertaken by the Committee shall be upon reasonable notice to Bonneville and at reasonable times and shall commence no more frequently than once in any 24 consecutive months. The audit rights provided in this section shall not be construed to permit a general audit of Bonneville's books, records, and documents. Audits shall be in conformance with generally accepted auditing standards.

Prior to and for the duration of any audit, Bonneville shall retain all pertinent books, records, and documents prepared in the normal course of business. After commencement of an audit pursuant to subsection 16(a), 16(b), or 16(c), the Committee may request and Bonneville shall promptly provide reasonably available supporting documentation for any cost or charge subject to audit. If the Committee fails to commence an audit pursuant to subsection 16(a), 16(b), or 16(c) within the time periods set forth in subsection 16(a), 16(b), or 16(c), such failure shall constitute waiver by Puget of any right pursuant to this section 16 to arbitrate any charge or refund billed or refunded by Bonneville.

(i) If Puget is operating pursuant to paragraph 3(b)(1), Bonneville shall have the right, at its own expense, to review Puget's books, records, and documents that directly pertain to the revenue reportable in Puget's accounting system where revenues received for wheeling for other entities would be booked for the purpose of verifying compliance with paragraph 3(b)(1). Bonneville shall have the right to perform such audit no more frequently than once every 36 months.

17. PROTECTED AREAS

Puget shall not use its Scheduling Share for transmission of power on the PNW AC Intertie from new hydroelectric projects which are constructed in Columbia River Basin Protected Areas after designation thereof by Bonneville unless Puget is required by regulatory authority to purchase or provide transmission for the output of such project or unless Bonneville receives sufficient demonstration that a particular project would provide benefits to Bonneville's existing or planned fish and wildlife investments or the Pacific Northwest Electric Power and Conservation Planning Council's Fish and Wildlife Program. The Parties agree that System Sales shall not be taken into consideration in any determination of whether Puget has used its Scheduling Share for transmission of power on the PNW AC Intertie from the hydroelectric projects referred to in the immediately preceding sentence. For purposes of this section 17, "System Sale" means any sale of power or energy to Puget or by a seller of power or energy, which power or energy is not resource-specific and is delivered to Puget at a point that connects one or more resources or transmission systems.

18. **ESTABLISHMENT AND MAINTENANCE OF RATES AND RELIEF FROM REGULATORY ACTION**

(a) Bonneville shall use good faith efforts to maintain in effect such of the following rates that has been approved by FERC on an interim or final basis, during the rate approval period established by FERC for such rate:

(1) any rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date;

(2) the Initial Successor Rate;

(3) the Alternative Successor Rate; and

(4) the Bonneville Successor Rate.

(b) If Bonneville's Administrator submits to FERC a rate that is different from that set forth in Exhibit B, Part A and Part B, on the Effective Date, as the first rate proposed by Bonneville (Initial Successor Rate) to replace the AC-93 rate set forth in Exhibit A or that is for a rate approval period which is less than the remainder of the Term following the expiration of the AC-93 rate, Puget may, within 90 days after Bonneville submits the Initial Successor Rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Puget may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Puget may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Puget's notification to terminate this Agreement pursuant to this subsection 18(b) except for those rights and obligations set forth in this paragraph 18(b)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Puget has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Puget's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

A - ((B/540) X A) + I = Refunded Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(b).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

I = Interest on A - ((B/540) X A), accruing from (and including) the date of Bonneville's receipt of Puget's Initial Lump Sum Payment to (but excluding) the date on which Bonneville receives Puget' notification to terminate this Agreement pursuant to this subsection 18(a), at the 5-year Treasury note rate in effect on the date on which Bonneville receives Puget's Initial Lump Sum Payment.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(b)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(b)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(b)(2)(B), Bonneville may accelerate payment to Puget of the amount of the Refunded Lump Sum Payment.

If Puget elects to proceed under this paragraph 18(b)(2), Bonneville shall not develop a rate or charge that would inequitably allocate to Puget and Capacity Owners other than Puget, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Puget or any Capacity Owner other than Puget.

(c) If FERC approves the Initial Successor Rate, the Alternative Successor Rate (as defined in subsection 18(d)), or the Bonneville Successor Rate (as defined in subsection 18(d)) for a term less than the remainder of the Term following the expiration of the AC-93 rate, and if Bonneville's Administrator thereafter submits to FERC a rate (Replacement Rate) that is different from the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis) or that is for a rate approval period which is less than the remainder of the Term following the expiration of the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis), Puget may, within 90 days after Bonneville submits such rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Puget may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Puget may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Puget's notification to terminate this Agreement pursuant to this subsection 18(c) except for those rights and obligations set forth in this paragraph 18(c)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Puget has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Puget's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

$$A - ((B/540) \times A) + R = \text{Refunded Lump Sum Payment}$$

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement.

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

R = 2.5 times the amount paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the immediately preceding fiscal year times the ratio of (a) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the first fiscal year during the proposed rate approval period pursuant to the rate submitted by Bonneville to FERC to replace the immediately preceding annual costs rate over (b) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the same fiscal year were the immediately preceding annual costs rate to remain in effect; provided, however, that the ratio of (a) over (b) shall in no event be less than one for purposes of this subsection.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(c)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(c)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(c)(2)(B), Bonneville may accelerate payment to Puget of the amount of Refunded Lump Sum Payment.

If Puget elects to proceed under this paragraph 18(c)(2), Bonneville shall not develop a special rate or charge that would inequitably allocate to Puget and Capacity Owners other than

Puget, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Puget or any Capacity Owner other than Puget.

The terms of this subsection 18(c) shall be effective through December 31, 2040.

(d) If (i) FERC remands or approves a rate which materially differs from the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, or (ii) FERC grants final approval to a rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date, or to the Initial Successor Rate for a rate approval period of less than the remainder of the Term following the expiration of the AC-93 rate, or (iii) FERC remands or disapproves the Initial Successor Rate, then in any such event Bonneville, Puget, and Capacity Owners other than Puget shall use good faith efforts to develop an alternative successor rate (Alternative Successor Rate) which would place Puget in substantially the same position with respect to Puget's rights and obligations under this Agreement as if the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, had been approved by FERC for the remainder of the Term following the expiration of the AC-93 rate. Bonneville, Puget, and Capacity Owners other than Puget shall use good faith efforts to reach agreement on an Alternative Successor Rate within 6 months after the date of the FERC order regarding the Initial Successor Rate contemplated in this subsection 18(d) or within the time period established in such FERC order, whichever is earlier.

(1) If Bonneville, Puget, and Capacity Owners other than Puget reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, then Bonneville shall, subject

to section 7(i) of the Regional Act, submit such Alternative Successor Rate to FERC for approval and confirmation.

(2) If Bonneville, Puget, and Capacity Owners other than Puget do not reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, Bonneville shall develop a rate, which, among other things, in Bonneville's judgment, protects the rights and obligations of Puget and Capacity Owners other than Puget and, subject to section 7(i) of the Regional Act, shall submit such rate (Bonneville Successor Rate) to FERC for approval and confirmation.

Nothing in this subsection 18(d) shall limit or otherwise affect any provisions of subsection 18(b) or 18(c).

(e) If Bonneville, Puget, and Capacity Owners other than Puget are unable to agree upon an Alternative Successor Rate pursuant to subsection 18(d), or if FERC approves the Alternative Successor Rate for a period of less than 15 years or with terms and conditions that differ from the terms and conditions of the Alternative Successor Rate, or if FERC remands the Alternative Successor Rate, or if FERC approves the Bonneville Successor Rate, Puget may elect, within 6 months of any of the foregoing events, to terminate this Agreement and execute a long-term contract with Bonneville for firm wheeling on the PNW-PSW Intertie for a term not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Puget's Capacity Ownership Share, pursuant to subsection 18(f).

(f) Should Puget elect to proceed pursuant to paragraph 18(b)(1) or 18(c)(1) or subsection 18(e), the Parties shall take the following steps:

(1) Puget shall provide Bonneville with written notification of its election to terminate this Agreement and with a written request for a long-term contract for firm wheeling on the PNW-

PSW Intertie for a period not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Puget's Capacity Ownership Share.

(2) As soon as practicable after receipt by Bonneville of the written notice sent pursuant to paragraph 18(f)(1), Bonneville shall offer to Puget a long-term contract for firm wheeling on the PNW-PSW Intertie of an amount of power equal to the amount of power specified in Puget's written request pursuant to paragraph 18(f)(1), such offered contract to contain other terms and conditions substantially similar to those then being offered by Bonneville to its other firm wheeling customers for transactions on the PNW-PSW Intertie.

The termination date of this Agreement shall be the same date as the effective date of the long-term contract for firm wheeling referred to in this paragraph 18(f)(2), and such date shall in any event be no more than 6 months after Bonneville's receipt of Puget's notification pursuant to paragraph 18(f)(1).

(3) The long-term contract for firm wheeling offered to Puget pursuant to paragraph 18(f)(2) shall also contain provisions which:

(A) Require Bonneville to credit or pay (any such payment to be made pursuant to paragraph 9(f)(4)), in equal monthly amounts during the term of such long-term contract for firm wheeling, against the amount payable by Puget to Bonneville pursuant to such long-term wheeling agreement an amount equal to the "Credited Lump Sum Payment" calculated as follows:

A - ((B/540) X A) = Credited Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(e).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

(B) Require Bonneville, subject to the immediately succeeding sentence, to credit or pay interest on the Credited Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest to be credited or paid pursuant to this provision shall be credited or paid by Bonneville on the amount of each monthly amount of the Credited Lump Sum Payment to be credited or paid by Bonneville pursuant to the provision set forth in subparagraph 18(f)(3)(A).

(C) Permit Bonneville to accelerate payment to Puget of the amount of Credited Lump Sum Payment which remains uncredited at any time during the term of such long-term contract for firm wheeling.

(g) Puget's right to terminate this Agreement pursuant to subsections 18(d) through 18(f) is a one-time only right that must be exercised after FERC action pursuant to subsection 18(d). If Puget fails to terminate the Agreement pursuant to subsection 18(e) as prescribed therein as a result of FERC action, Puget shall have no future rights to terminate the Agreement under this section 18 as a result of FERC action.

(h) Bonneville shall use best efforts to establish and maintain in effect the AC-93 rate, set forth in Exhibit A, during the remainder of the Term, but only until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), that is confirmed and approved by FERC on an interim or final basis, becomes effective. If FERC does not confirm and approve on a final basis the AC-93 rate for a rate approval period of sufficient duration so that the AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or such other rate, becomes effective, then upon expiration of the rate approval period of such AC-93 rate, Bonneville shall submit to FERC a rate based on the methodology used to determine the AC-93 rate (revised AC-93 rate) and shall use best efforts to obtain a rate approval period for the revised AC-93 rate of sufficient duration so that the revised AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), becomes effective. If, at any time during the Term, FERC does not confirm and approve on an interim or final basis the AC-93 rate or revised AC-93 rate for any reason other than the duration of the rate approval period, Bonneville and Puget shall use best efforts to develop a rate that would replace the AC-93 rate or revised AC-93 rate, and Bonneville shall submit such rate to FERC, pursuant to section 7(i) of the Regional Act, for confirmation and approval if such rate is agreed to by Bonneville, Puget and Capacity Owners other than Puget. If Bonneville and Puget do not succeed in developing such rate, Bonneville shall submit to FERC, pursuant to section 7(i) of the Regional Act, a rate which in Bonneville's judgment recovers Bonneville's costs. Bonneville shall bill Puget, and Puget shall pay Bonneville, in accordance with the AC-93 rate or, if FERC does not confirm and approve on an interim or final basis the AC-93 rate, the rate confirmed and approved by FERC on an interim or final basis.

Bonneville shall revise Exhibit A so that it contains, at a given time, the AC-93 or other rate confirmed and approved by FERC on an interim or final basis.

19. **EXHIBITS**

(a) Exhibits A through J attached to this Agreement are by this reference made a part of this Agreement. In the event of a conflict between any provision in Exhibits A through J and the provisions of sections 1 through 23 of this Agreement, the provisions of sections 1 through 23 of this Agreement shall prevail.

(b) Bonneville shall revise Exhibit A pursuant to subsections 18(g) and 18(h) and this subsection 19(b). The rate schedules attached hereto as Exhibit A have been conditionally or finally confirmed by FERC. If the final rate schedules which are approved by FERC are an amendment or modification of the initial rate schedules, the applicable amended or modified rate schedules and associated GTRSPs shall be attached to and made part of this Agreement effective as of the date specified in FERC's approval. The rate schedules and GTRSPs included in Exhibit A shall be replaced by successor rate schedules and provisions in accordance with the provisions of section 7(i) of the Regional Act and FERC rules.

(c) Upon interim or final approval by FERC of any rate submitted to FERC pursuant to subsections 18(a) through 18(g), Bonneville shall revise Exhibit B so that Exhibit B contains such rate approved by FERC as contemplated in this subsection 19(c). For purposes of this Agreement, such rate shall be effective as of the date of effectiveness specified in FERC's approval of such rate. Subject to the provisions of subsections 18(a) through 18(g), the rate schedule set forth in Exhibit B, Part A and Part B, on the Effective Date, shall be replaced by successor rate schedules and provisions pursuant to section 7(i) of the Northwest Power Act and applicable FERC rules.

(d) Bonneville shall revise or modify Exhibit C from time to time to reflect changes hereafter agreed to in writing by the Parties in Puget's Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share.

(e) Bonneville shall revise Exhibit D pursuant to subsection 9(a). Revision or modification of Exhibit D shall not require an executed amendment or revision to this Agreement.

(f) Not more frequently than annually, Bonneville shall review and, as appropriate, revise Exhibit E, Part A, in accordance with Bonneville's standard methodology and formula for calculation of average losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie. Such methodology and formula are intended to forecast average annual actual losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie Operational Transfer Capability. Any changes to the loss methodology or formula, other than numerical values, shall be made only after consultation with the Committee. During such consultation, Bonneville shall provide to the Committee material pertinent to such changes to the loss methodology or formula. Upon conclusion of any review of the loss factor in Exhibit E, Part A, Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan pursuant to section 13. If the Committee pursues arbitration pursuant to subsection 10(b) and section 14, Bonneville shall revise Exhibit E, Part A, to reflect the selection of the arbitrators pursuant to subsection 14(j).

(g) Bonneville shall revise the loss factor in Exhibit E, Part B, as necessary to equal the same factor for average losses as Bonneville generally applies to transmission over Bonneville's share of the PNW-PSW Intertie. Revision of Exhibit E, Part B, shall not require an executed amendment or revision to this Agreement.

(h) Bonneville shall revise Exhibit F as appropriate to reflect the facilities in Bonneville's PNW AC Intertie. Revision or modification of

Exhibit F shall not require an executed amendment or revision to this Agreement.

(i) Bonneville shall revise Exhibit G as appropriate to reflect the complete list of all of the Capacity Owners and their respective Capacity Ownership Shares and Capacity Ownership Percentages from time to time pursuant to this Agreement.

(j) Bonneville shall revise Exhibit H as appropriate to reflect all provisions required by statute or Executive Order. Revision or modification of Exhibit H shall not require an executed amendment or revision to this Agreement.

(k) Bonneville shall revise Exhibit I to reflect changes as agreed to in writing by Puget and Capacity Owners other than Puget.

(l) Bonneville shall revise Exhibit J as mutually agreed to in writing by the Parties.

20. **RULES OF LAW**

(a) Bonneville and Puget agree that each fully participated in the drafting of each provision of this Agreement. The rule of law interpreting ambiguities against the drafting Party shall not be applicable to or utilized in resolving any dispute over the meaning or intent of this Agreement or any of its provisions.

(b) This Agreement shall not be construed to establish a partnership, association, agency relationship, joint venture, or trust. Neither Party shall be under the control of or shall be or represent itself as, the agent of, or have a right or power to bind, the other Party without the other's express written consent, except as provided in this Agreement.

(c) All applicable law is incorporated in and made part of this Agreement.

21. NOTICES

(a) Unless the Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be served, given, or made if delivered in person or sent by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons addressed as set forth below:

To Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232

To Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515

To Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101

To PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232

To Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201

To Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411

(b) Either Party may, by written notice to the other Party pursuant to subsection 21(a), change the address set forth in subsection 21(a) for the notifying Party.

(c) All notices pursuant to this Agreement shall be effective on the date of receipt.

22. WAIVER

Any waiver at any time by a Party of its rights with respect to any matter arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent or other matter. Except as otherwise provided herein or as agreed in writing by the Parties, no provision in this Agreement may be waived except as documented or confirmed in writing.

23. MISCELLANEOUS

(a) Effect of Section Headings

Section headings and subheadings appearing in this Agreement are inserted for convenience only and shall not be construed as interpretations of provisions of this Agreement.

(b) **Amendments**

Except as may be expressly otherwise provided in this Agreement, this Agreement may be amended only with the express written consent of both of the Parties, and no provision of this Agreement shall be varied or contradicted by any oral agreement, course of dealing or performance or any other matter not hereafter set forth in a written agreement signed by both of the Parties.

(c) **Entire Agreement**

This Agreement constitutes, on and as of the date hereof, the entire agreement of the Parties with respect to the subject matter of this Agreement, and all prior understandings or agreements, whether written or oral, between the Parties with respect to the subject matter of this Agreement are hereby superseded in their entireties.

(d) **No Third Party Beneficiaries**

There are no third party beneficiaries of this Agreement. This Agreement shall not be construed to create rights in, or to grant remedies to, any third party as a beneficiary of this Agreement or of any duty, obligation, or undertaking established herein.

(e) **Regulatory Approvals**

Each Party shall use its best efforts to obtain and maintain in effect regulatory approvals that are necessary to permit such Party to perform its obligations under this Agreement in accordance with its terms and conditions. Neither Party shall oppose in any way or seek to alter or amend the terms and conditions of this Agreement by application to or participation in any application of any regulatory authority or court having jurisdiction. Puget shall not oppose in any way or seek to alter or amend the terms or conditions of the annual costs rate set forth in Exhibit B, the CO-94 rate, the AC-93 rate, or any rate described in section 18 that is agreed to by the Parties subsequent to each entering into this Agreement, in any proceeding pursuant to section 7 of the Pacific Northwest Electric Power Planning and Conservation Act before FERC or in any court of competent jurisdiction.

(f) **Other Capacity Ownership Agreements**

If Bonneville offers to enter into (i) a Capacity Ownership Agreement with any other Capacity Owner or (ii) any written amendment of any Capacity Ownership Agreement (other than this Agreement), then Bonneville shall offer to Puget an amendment of this Agreement that contains the terms and conditions of such Capacity Ownership Agreement with such other Capacity Owner or of such written amendment, as the case may be. Bonneville shall advise, and use reasonable efforts to consult with, Puget during the development or consideration of any offer to any Capacity Owner other than Puget to enter into a Capacity Ownership Agreement or any amendment of such agreement.

(g) **Singular and Plural Forms**

For purposes of interpreting and construing this Agreement, the singular form of a word shall include its plural and the plural form of a word shall include its singular, unless otherwise expressly provided by this Agreement.

(h) **Performance Pending Dispute**

Except as otherwise expressly provided in this Agreement, pending resolution of any dispute, issue, or controversy arising under this Agreement, the Parties shall each continue performance of their respective obligations pursuant to this Agreement.

(i) **Time Periods**

For purposes of calculating any time period prescribed by this Agreement, if the last day of the time period falls on a day that is not a Working Day, then the last day of the time period shall be the first Working Day following such day as would otherwise be the last day of the time period.

(j) **Double Counting**

In developing rates or charges under section 7 of the Pacific Northwest Electric Power Planning and Conservation Act for any rate period, Bonneville shall not set rates or charges that recover, more than once, the costs associated with capital projects that are paid or forecast to be paid under the CO-94 rate and the AC-93 rate and annual costs rate set forth in Exhibit B, or the remaining Bonneville's PNW AC Intertie costs forecast to be paid under the AC-93 rate and annual costs rate set forth in Exhibit B. Bonneville's forecast of revenues chargeable under the CO-94 rate, AC-93 rate, and annual costs rate set forth in Exhibit B shall be based on the best available information, including information provided pursuant to section 13 of this Agreement.

In the event Bonneville proposes any wheeling rate for transmission service on Bonneville's main grid that includes costs of the PNW AC Intertie, such proposed rate shall include a credit or other mechanism that ensures that Puget is not charged any of the PNW AC Intertie costs for deliveries of power that utilize up to the Puget's Capacity Ownership Share, as that term is defined in this Agreement.

(k) **Committee Action**

Each of the Parties agrees that to the extent it is provided in sections 13, 14, and 16 that the Committee shall take any action or shall make any decision, such action or decision shall be taken or made, as the case may be, by the Committee, and not by Puget acting individually.

(l) **Fiscal Year**

For purposes of this Agreement, the term "fiscal year" shall mean Bonneville's fiscal year.

(m) **Rights and Remedies Cumulative**

All rights and remedies of either Party under this Agreement and at law and in equity shall be cumulative and not mutually exclusive and the exercise of one right or remedy shall not be deemed a waiver of any other right or remedy. Nothing contained in any provision of this Agreement shall be construed to limit or exclude any right or remedy of either Party (arising on account of the breach or default by the other Party or otherwise) now or hereafter existing under any other provision of this Agreement, at law or in equity.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

/s/ WALTER E. POLLOCK
Group Vice President for Marketing,
Conservation and Production

By Walter E. Pollock
Group Vice President for Marketing, Conservation and Production

Name Walter E. Pollock
(Print/Type)

October 11, 1994

Date October 11, 1994

Puget Sound Power & Light Company

By J R Lauckhart

/s/ J. R. LAUCKHART

Name J. R. Lauckhart
(Print/Type)

Title VP Power Planning

Vice President, Power Planning

Date 9/26/94

September 26, 1994

Effective Date ______________

CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions

Schedule CO-94

CAPACITY OWNERSHIP RATE SCHEDULE

Section I. Availability

This schedule applies to all agreements which provide life-of-facilities capacity rights to non-Federal participants (Capacity Owners) in 725 MW of Bonneville's PNW AC Intertie and any upgrades thereto. Service under this schedule is subject to Bonneville's General Transmission Rate Schedule Provisions.

Section II. Rate

The charge for capital and related costs for non-Federal capacity ownership in Bonneville's PNW AC Intertie shall be determined by the methodologies set out in Section III below.

Section III. Determination of Rate

A. Capacity Ownership Price

The charge for capacity ownership in Bonneville's PNW AC Intertie shall be the Capacity Ownership Share of the actual capital and related costs of facilities as determined by the formula shown below. The Capacity Ownership Share shall be determined pursuant to the Capacity Ownership agreement.

$$\frac{(A - B) + C + D}{E} = \text{Capacity Ownership Price in \$/kW}$$

Capacity Ownership Price in \$/kW x number of kW contracted for by Capacity Owner = Capacity Owner's payment to Bonneville

Where:

A = Bonneville's cost of new facilities for the Third AC Intertie, which increased the ra[illegible] transfer capability of the PNW AC Intertie by approximately 1600 MW, is the construction costs (including direct, indirect and overhead costs) of the facilities associated with the Third AC Intertie System Reinforcements and the Alvey-Merid[illegible]

Transmission Line (also known as Eugene-Medford 500-kV Transmission Line), referred to jointly as the Third AC Intertie Project.

B = Bonneville's cost of new facilities needed for the first 800 MW increment of the 1600 MW Third AC Intertie Project, which includes a portion of the construction costs (including direct, indirect and overhead costs) associated with the Third AC Intertie System Reinforcement.

A-B = The cost of new facilities for the second 800 MW increment of the 1600 MW Third AC Intertie Project (presented in Exhibit C of the Capacity Ownership agreement).

C = Allowance for Funds Used During Construction (AFUDC) constitutes interest on the funds used for the Third AC Intertie Project while it was under construction. AFUDC is calculated and capitalized consistent with FERC requirements as described in FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions, 3.A(17). The AFUDC applies to that amount capitalized on the second 800 MW increment of the 1600 MW Third AC Intertie Project, or A - B.

D = Book value of existing Bonneville support facilities that are dedicated to the PNW AC Intertie equal to $19,100,000.

E = 725,000 kW, which equals Bonneville's share of the second 800 MW of the Third AC Intertie.

B. PNW AC Intertie Upgrade Price

The charge for upgrades to Bonneville's PNW AC Intertie facilities that occur after December 1993, and which result in an increase of rated transfer capability, shall be the Capacity Ownership Share of the capital and related costs of the upgrade. The Capacity Ownership Share of any upgrades shall be determined pursuant to the Capacity Ownership agreement. The capital costs shall consist of the construction costs (including direct, indirect and overhead costs) and AFUDC (as described in Section III.A. above) of the facilities associated with such upgrades.

Section IV. Adjustments and Special Provisions

A. Initial Lump Sum Payment

Capacity Owners shall make an initial, lump sum payment of an estimate of the Capacity Ownership Price equal to $215/kW pursuant to the Capacity Ownership agreement.

B. Adjustment to Reflect Actual Construction Costs

Approximately December 1995 or as soon as practicable thereafter, the Capacity Owner's initial lump sum payment shall be adjusted to reflect the difference between the actual and the estimated Capacity Ownership Price. The actual Capacity Ownership Price shall be determined pursuant to Section III.A. above. There will be no adjustment for the book value of the support facilities dedicated to the PNW AC Intertie. Capacity Owners will either receive a refund, with interest, from Bonneville or make an additional payment, with interest, to Bonneville. Bonneville shall compute interest using the weighted average interest rate on Bonneville's outstanding bonds.

C. PNW AC Intertie Upgrade Payments

Capacity Owners shall pay a share of the upgrades to Bonneville's PNW AC Intertie in the manner and time to be determined when participation in such upgrades are agreed to pursuant to the Capacity Ownership agreement.

Southern Intertie Annual Cost

SECTION I. AVAILABILITY

This schedule is applicable to all parties (New Owners) that execute PNW AC Intertie Capacity Ownership Agreements (Agreements) and will be effective on the date described in the Agreement. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The rate charges reflect the terms of the Memorandum of Understanding (MOU), signed in the Fall of 1991, between BPA and potential New Owners. The MOU provides for the payment by New Owners of their prorated share of: (1) BPA's annual operations, maintenance, and general plant expense (including applicable overheads) properly chargeable to the AC Intertie facilities; and (2) BPA's share of capitalized replacements on the AC Intertie. The monthly charge shall be the sum of the charges specified in sections II.A and II.B.

A. Operations, Maintenance, and General Plant

The monthly charge shall equal $325 per megawatt of billing demand.

B. Replacements

The monthly charge shall equal $0 per megawatt of billing demand.

SECTION III. ADJUSTMENT TO REPLACEMENTS RATE

A. Determination of Billing Adjustment

New Owners will receive a billing adjustment if BPA incurs AC Intertie replacement cost during the rate period. The Replacements Rate Adjustment equals:

$$\frac{\text{AC Intertie work orders (\$000)} * \%}{725 \text{ MW} * \text{\# months}}$$

where:

"# months" equals: (1) the number of months that this rate schedule is in effect during the fiscal year for the Initial Replacements Rate Adjustment; or (2) the number of months in the rate period for the Final Replacements Rate Adjustment; and

"%" equals the New Owners' percentage share of BPA's total AC Intertie Rated Transfer Capability as specified in the Agreements.

B. Initial Replacements Rate Adjustment

New Owners will receive a billing adjustment for each fiscal year that BPA incurs AC Intertie replacement cost. At the end of each fiscal year, the cost associated with AC Intertie capital replacement work orders that have closed during the fiscal year will be determined. The unit rate that would result using these closed work orders is the basis of the Initial Replacements Rate Adjustment.

1. Notice Provisions

Following each fiscal year, BPA shal notify all New Owners by December 1 of the proposed Replacements Rat Adjustment. BPA will provide th calculation of the adjustment and a shor description of the work performed an the associated cost used as the basis fo the billing adjustment. In addition t written notification, BPA may, but is no obligated to, hold a public meeting t clarify its determinations.

Written comments on the Initial Replacements Rate Adjustment will be accepted through the end of January. Consideration of comments submitted by the New Owners may result in the billing adjustment differing from the initially proposed adjustment. BPA shall notify all New Owners of the Initial Replacements Rate Adjustment by the last day of February.

2. **Adjustment of Monthly Bills**

An adjustment will be made on the New Owner's monthly bill prepared during March. The Initial Replacements Rate adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal year (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal year). The Initial Replacements Rate Adjustment will appear as a charge to the New Owner on the monthly bill prepared during March.

C. **Final Replacements Rate Adjustment**

The actual costs associated with the AC Intertie capital replacement work orders that occur during the rate period may change after BPA performs its final analysis of the work orders. BPA shall compare the unit rate for the rate period using the results of the final work order analysis to the weighted average of the unit rates from the Initial Replacements Rate Adjustments.

1. **Notice Provisions**

BPA shall notify all New Owners in May 1998 of the results of the calculations, an explanation of work order change(s), and any resulting billing adjustment. Written comments from New Owners will be accepted through the end of June. BPA shall notify all New Owners of the Final Replacements Rate Adjustment by July 31. Consideration of comments submitted by the New Owners may result in the Final Replacements Rate Adjustment differing from the initially proposed adjustment.

2. **Adjustment of Monthly Bills**

If the absolute value of the Final Replacements Rate Adjustment is greater than or equal to $1 per megawatt per month, an adjustment will be made on the New Owner's monthly bill prepared during August. For each New Owner, the Final Replacements Rate Adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal years (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal years). The Final Replacements Rate Adjustment will appear as a charge or credit to the New Owner on the monthly bill prepared during August. Interest, as determined by BPA's Office of Financial Management, will be included in any adjustment.

SECTION IV. BILLING FACTOR

The billing demand shall be the New Owner's capacity ownership share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability as specified in the Agreement.

Southern Intertie Transmission

SECTION I. AVAILABILITY

This schedule supersedes IS-91 and is available for all transmission on the Southern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. Nonfirm Transmission Rate

The charge for nonfirm transmission of non-BPA power shall be 3.11 mills per kilowatthour of billing energy. This charge applies for both north-to-south and south-to-north transactions.

B. Firm Transmission Rate

The charge for firm transmission service shall be $0.706 per kilowatt per month of billing demand and 1.69 mills per kilowatthour of billing energy. Firm transmission will only be made available to customers under this rate schedule who have executed a contract with BPA specifying use of the Firm Transmission rate for either north-to-south or south-to-north transactions.

SECTION III. BILLING FACTORS

A. For services under Section II.A, the billing energy shall be the monthly sum of the scheduled kilowatthours, plus the monthly sum of kilowatthours allocated but not scheduled. The amount of allocated but not scheduled energy that is subject to billing may be reduced pro rata by BPA due to forced Intertie outages and other uncontrollable forces that may reduce Intertie capacity. The amount of allocated but not scheduled energy that is subject to billing also may be reduced upon mutual agreement between BPA and the customer.

B. For services under Section II.B, the billing demand shall be the Transmission Demand as defined in the Agreement. The billing energy shall be the monthly sum of scheduled kilowatthours, unless otherwise specified in the Agreement.

SECTION I. ADOPTION OF REVISED TRANSMISSION RATE SCHEDULES AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS (GTRSPs)

A. Approval of Rates

These rate schedules and GTRSPs shall become effective upon interim approval or upon final confirmation and approval by FERC. BPA will request FERC approval effective October 1, 1993.

B. General Provisions

These 1993 Transmission Rate Schedules and associated GTRSPs are virtually identical to and supersede BPA's 1991 Transmission Rate Schedules and GTRSPs (which became effective October 1, 1991) but do not supersede prior rate schedules required by agreement to remain in force.

Transmission service provided shall be subject to the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act, and the Energy Policy Act of 1992, Pub. L. 102-486, 106 Stat. 2776 (1992).

The meaning of terms used in the transmission rate schedules shall be as defined in agreements or provisions which are attached to the Agreement or as in any of the above Acts.

C. Interpretation

If a provision in the executed Agreement is in conflict with a provision contained herein, the former shall prevail.

SECTION II. BILLING FACTOR DEFINITIONS AND BILLING ADJUSTMENTS

A. Billing Factors

1. Scheduled Demand

The largest of hourly amounts wheeled which are scheduled by the customer during the time period specified in the rate schedules.

2. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands measured by meters installed at each POD during each time period specified in the applicable rate schedule. Such measurements shall be made as specified in the Agreement. BPA, in determining the Metered Demand, will exclude any abnormal readings due to or resulting from: (a) emergencies or breakdowns on, or maintenance of, the FCRTS; or (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. If more than one class of power is delivered to any POD, the portion of the metered quantities assigned to any class of power shall be as agreed to by the parties. The amount so assigned shall constitute the Metered Demand for such class of power.

3. Transmission Demand

The demand as defined in the Agreement.

4. Total Transmission Demand

The sum of the transmission demands as defined in the Agreement.

5. Ratchet Demand

The maximum demand established during the previous 11 billing months. Exception: If a Transmission Demand or Total Transmission Demand has been decreased pursuant to the terms of the Agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

B. Billing Adjustments

Average Power Factor

The adjustment for average power factor, when specified in a transmission rate schedule or in the Agreement, shall be made in accordance with the average power factor section of the General Wheeling Provisions.

To maintain acceptable operating conditions on the Federal system, BPA may restrict deliveries of power at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 85 percent.

SECTION III. OTHER DEFINITIONS

Definitions of the terms below shall be applied to these provisions and the Transmission Rate Schedules, unless otherwise defined in the Agreement.

A. Agreement

An agreement between BPA and a customer to which these rate schedules and provisions may be applied.

B. Eastern Intertie

The segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment including related terminals at Garrison.

C. Electric Power

Electric peaking capacity (kW) and/or electric energy (kWh).

D. Federal Columbia River Transmission System

The transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

E. Firm Transmission Service

Transmission service which BPA provides for any non-BPA power except for transmission service which is scheduled as nonfirm. If the firm service is provided pursuant to the Agreement, the terms of the Agreement may further define the service.

F. Integrated Network

The segment of the FCRTS for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest, excluding facilities not segmented to the network as shown in the Wholesale Power Rate Development Study used in BPA's rate development.

G. Main Grid

As used in the FPT and IR rate schedules, that portion of the Integrated Network with facilities rated 230 kV and higher.

H. Main Grid Distance

As used in the FPT rate schedules, the distance in airline miles on the Main Grid between the POI and the POD, multiplied by 1.15.

I. Main Grid Interconnection Terminal

As used in the FPT rate schedules, Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

J. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, switching, transformation, and other facilities of the Main Grid not included in other components.

K. Main Grid Terminal

As used in the FPT rate schedules, the Main Grid terminal facilities located at the sending and/or receiving end of a line exclusive of the Interconnection terminals.

L. Nonfirm Transmission Service

Interruptible transmission service which BPA may provide for non-BPA power.

M. Northern Intertie

The segment of the FCRTS for which the transmission facilities consist of two 500 kV lines between Custer Substation and the United States-Canadian border, one 500 kV line between Custer and Monroe Substations, and two 230 kV lines from Boundary Substation to the United States-Canadian border, and the associated substation facilities.

N. Point of Integration (POI)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is made available to BPA for wheeling.

O. Point of Delivery (POD)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is delivered to a customer by BPA.

P. Secondary System

As used in the FPT and IR rate schedules, that portion of the Integrated Network facilities with operating voltage of 115 kV or 69 kV.

Q. Secondary System Distance

As used in the FPT rate schedules, the number of circuit miles of Secondary System transmission lines between the secondary POI and the Main Grid or the secondary POD, or the Main Grid and the secondary POD.

R. Secondary System Interconnection Terminal

As used in the FPT rate schedules, the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

S. Secondary System Intermediate Terminal

As used in the FPT rate schedules, the first and final terminal facilities in the Secondary System transmission path exclusive of the Secondary System Interconnection terminals.

T. Secondary Transformation

As used in the FPT rate schedules, transformation from Main Grid to Secondary System facilities.

U. Southern Intertie

The segment of the FCRTS for which the major transmission facilities consist of two 500 kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation; when completed, the Third AC facilities, which include Captain Jack Substation and the Alvey-Meridian 500 kV AC line; one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border; and associated substation facilities.

V. Transmission Service

As used in the MT rate schedule, Transmission Service is as defined in the Western Systems Power Pool Agreement.

SECTION IV. BILLING INFORMATION

A. Payment of Bills

Bills for transmission service shall be rendered monthly by BPA. Failure to receive a bill shall not release the customer from liability for payment. Bills for amounts due of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

The transmission billing determinant is the electric power quantified by the method specified in the Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

The transmission customer shall provide necessary information to BPA for any computation required to determine the proper charges for use of the FCRTS, and shall cooperate with BPA in the exchange of additional information which may be reasonably useful for respective operations.

Demand and energy billings for transmission service under each applicable rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill to be followed at a subsequent billing date by a final bill. The estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Billing Month

For charges based on scheduled quantities, the billing month is the calendar month. For charges based on metered quantities, the billing month is defined as the interval between scheduled meter-reading dates. The billing month will not exceed 31 days in any case. While it may be necessary to read meters on a day other than the scheduled meter-reading date, for determination of billing demand, the billing month will cease at 2400 hours on the last scheduled meter-reading date. Schedules will be predetermined. The customer must give 30 days notice to request a change to the schedule.

4. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the customer), the due date shall be the next following business day.

5. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid, subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the customer. However, such cancellation shall not affect the customer's liability for any charges accrued prior thereto under such agreement.

6. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the customer is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

7. Revised Bills

As necessary, BPA may render a revised bill.

a. If the amount of the revised bill is less than or equal to the amount of the original bill, the revised bill shall replace all previous bills issued by BPA that pertain to the specified customer for the specified billing period and the revised bill shall have the same date as the replaced bill.

b. If a revision causes an additional amount to be due BPA or the specified customer beyond the amount of the original bill, a revised bill will be issued for the difference and the date of the revised bill shall be its date of issue.

Annual Costs Rate

A. PROPOSED SOUTHERN INTERTIE ANNUAL COST RATE

SECTION I. AVAILABILITY

This schedule is applicable to each party (Capacity Owner) that executes a PNW AC Intertie Capacity Ownership Agreement (Agreement). Billings pursuant to this schedule is subject to the Billing Provisions in Exhibit B of the Agreement. This rate schedule shall be effective on the first day of the fiscal year following the earlier of interim or final FERC approval of this rate schedule. Unless otherwise defined in this rate schedule, capitalized terms used in this rate schedule shall have the respective definitions set forth in section 1 of this Agreement.

SECTION II. RATE

A. Operations

The monthly charge equals:

$$\frac{\text{Operations Cost * Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Operations Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Operations rate shall be calculated using the forecast Operations Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Operations Cost shall be calculated using the forecast Operations Cost less the Operations Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

B. Maintenance

The monthly charge equals:

$$\frac{\text{Maintenance Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Maintenance Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Maintenance rate shall be calculated using the forecast Maintenance Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Maintenance Cost shall be calculated using the forecast Maintenance Cost less the Maintenance Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

C. General Plant

The monthly charge equals:

$$\frac{\text{General Plant Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to General Plant Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the General Plant rate shall be calculated using the General Plant Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for General Plant Cost shall be calculated using the General Plant Cost less the General Plant Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

D. Other Costs

The monthly charge equals:

$$\frac{\text{Other Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Other Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Other Costs rate shall be calculated using the forecast Other Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Other Costs shall be calculated using the forecast Other Costs less the Other Costs already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

E. Contracts and Rates

The monthly charge equals:

$$\frac{\text{Contracts and Rates Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Contracts and Rates Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Contracts and Rates Cost is determined in accordance with section VI of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Contracts and Rates Cost determined in accordance with section VI of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Contracts and Rates rate shall be calculated using the forecast Contracts and Rates Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Contracts and Rates Cost shall be calculated using the forecast Contracts and Rates Cost less the Contracts and Rates Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

F. Power Scheduling

The monthly charge equals:

$$\frac{\text{Power Scheduling Costs * Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Power Scheduling Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Power Scheduling Cost is determined in accordance with section VII of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Power Scheduling Cost determined in accordance with section VII of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Power Scheduling rate shall be calculated using the forecast Power Scheduling Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Power Scheduling Cost shall be calculated using the forecast Power Scheduling Cost less the Power Scheduling Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

G. End of Term

The monthly charge shall equals:

$$\frac{\text{End of Term Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to End of Term Costs, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the End of Term rate shall be calculated using the forecast End of Term Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for End of Term Costs shall be calculated using the forecast End of Term Costs less the End of Term Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

H. Replacements and Reinforcements

1. For each Replacement, the charge equals:

   Replacement Cost * Capacity Ownership Percentage

2. For each Reinforcement, the charge equals:

   Reinforcement Cost * Capacity Ownership Percentage

Where

"Replacement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Replacement Cost does not include capitalized general plant cost. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Reinforcement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Reinforcement Cost does not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The charge for the Replacements and Reinforcements rate shall use the actual Replacement Cost and Reinforcement Cost in the Operating Plan.

SECTION III. ADJUSTMENTS

If an amendment to the Operating Plan results in a net amount that Bonneville owes the Capacity Owners pursuant to sections II.A-G or pursuant to section II.H, Bonneville shall refund such net amount pursuant to paragraph 9(f)(4) of the Agreement.

The monthly charges assessed Capacity Owners under sections II.A-G shall be adjusted, and payment or refund made with interest, pursuant to paragraphs 9(b)(2) or 9(f)(4) of the Agreement, to reflect amendments to the Operating Plan that occur after the year to which such Operating Plan pertains.

A Capacity Owner's share of the adjustment shall be determined using the same Capacity Ownership Percentage used in the billings under sections II.A-G during the fiscal year that such Operating Plan is effective.

B. BILLING PROVISIONS

I. General Provisions

A. Approval of Rates

The annual costs rate shall become effective upon interim approval or upon final confirmation and approval by FERC. Bonneville will request FERC approval of such rate schedule effective on the first day of a Bonneville fiscal year.

B. Application of Billing Provisions

These Billing Provisions shall apply to bills rendered by Bonneville pursuant to the annual costs rate.

C. Definition of Terms

The meaning of terms used in the AC-95 rate shall be as defined in the Agreement or, if no definition is provided by the Agreement, such terms shall be defined according to applicable Federal law.

II Billing Information

Payment of Bills

Charges pursuant to the AC-95 rate shall be included in Bonneville's monthly power bill to Capacity Owner. Failure to receive a power bill shall not release Capacity Owner from liability for payment. Power bills for amounts due of $50,000 or more must be paid by direct wire transfer. If Capacity Owner anticipates special difficulties in meeting this requirement, Capacity Owner may request and Bonneville may approve an exemption from this requirement. Power bills for amounts due Bonneville under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by Bonneville. The procedures to be followed in making direct wire transfers will be provided by Bonneville's Financial Services Group and updated as necessary.

(1) Computation of Bills

(a) Bonneville shall bill Capacity Owner in accordance with the annual costs rate.

(b) Capacity Owner shall provide necessary information to Bonneville for any computation required to determine proper charges pursuant to the Agreement and shall cooperate with Bonneville in the exchange of additional information which may be reasonably useful for respective operations.

(c) Bills rendered pursuant to this Agreement shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents to 99 cents to the next higher whole dollar.

(2) Billing Month

For charges pursuant to the annual costs rate the billing month shall be the same as for the power bill rendered by Bonneville to Capacity Owner.

(3) Due Date

Charges pursuant to the annual costs rate shall be included in the power bill rendered by Bonneville to Capacity Owner and shall be due as part of the power bill when such power bill is due.

(4) Late Payment

The penalties for failure to pay a bill in full on or before close of business on the due date shall be the same as those contained in the late payment provisions in Bonneville's General Transmission Rate Schedule Provisions in effect on the date of the bill; provided, however, that no other provision of any such General Transmission Rate Schedule Provisions, including, but not limited to, provisions regarding cancellation, termination, or suspension of service, shall have application with respect to the payment of any rate or charge pursuant to the annual costs rate set forth in Exhibit B. Bonneville's right to suspend service for late payment under the Agreement shall be pursuant to paragraph 9(e)(1) of this Agreement, which right shall in no way be limited by this section.

(5) Disputed Bills

In the event of a disputed bill, full payment shall be rendered to Bonneville and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified in section II(4) of the Billing Provisions of this Exhibit B. Bonneville shall separately account for the disputed amount. If it is determined that Capacity Owner is entitled to the disputed amount, Bonneville shall refund the disputed amount with interest, such interest to be determined by Bonneville's Financial Services Group. In the event that Bonneville and Capacity Owner do not resolve such dispute, Capacity Owner shall not be prevented by this section II(5)of the Billing Provisions of this Exhibit B from initiating arbitration pursuant to and to the extent allowed by section 15 of this Agreement.

(6) Revised Bills

If Bonneville determines that it has over- or under-charged Capacity Owner due to a computational error or pursuant to an amendment to the Operating Plan in any given billing month, Bonneville may render to Capacity Owner a revised bill.

(i) If the amount of the revised bill is less than or equal to the amount of the original bill for such billing month, the revised bill shall replace the original bill issued by Bonneville. The revised bill shall have the same date as the original bill.

(ii) If the amount of the revised bill is greater than the amount of the original bill for such billing month, a new bill will be issued for the difference between the revised bill and the original bill. The date of the new bill shall be its date of issuance, and Capacity Owner shall make payment to Bonneville as specified in the Billing Provisions of this Exhibit B.

Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share

Capacity Ownership Share	=	400 MW
Capacity Ownership Percentage	=	Capacity Ownership Share ÷ Bonneville's PNW AC Intertie Rated Transfer Capability[1]
Scheduling Percentage	=	Capacity Ownership Share ÷ PNW AC Intertie Rated Transfer Capability
Scheduling Share	=	Scheduling Percentage × PNW AC Intertie Operational Transfer Capability

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1/ As of the Effective Date, Bonneville's PNW AC Intertie Rated Transfer Capability in a north-to-south direction, calculated in accordance with the Northwest Intertie Agreements equals 3450 MW (total PNW AC Intertie Rated Transfer Capability (4800 MW) – Portland's PNW AC Intertie Rated Transfer Capability (950 MW) – PacifiCorp's PNW AC Intertie Rated Transfer Capability (400 MW)).

Lump Sum Payment Calculation

A. SECOND 800 MW COSTS, ESTIMATED[1], ACTUAL[2], AND REVISED ACTUAL[3]

		($ in Thousands)		
		(1)	(2)	
Facilities whose costs will be adjusted using change Between Estimate and Actual		BPA's Costs Estimated	BPA's Costs Actual	BPA's Costs Revised Actual
1.	Alvey (Marion-Alvey Caps)	$5,739		
2.	Slatt (Loop in - Breaker)	3,044		
3.	Grizzly (BPA Breakers)	11,044		
4.	Loop into Slatt	656		
5.	Malin-Meridian loop into Captain Jack	982		
6.	Alvey Substation - BPA	8,168		
7.	Dixonville - PacifiCorp	8,635		
8.	Meridian - PacifiCorp	6,548		
9.	Power System Control	3,575		
10.	Alvey-Spencer - BPA	1,346		
11.	Spencer-Dixonville - PacifiCorp	20,388		
12.	Dixonville-Meridian - PacifiCorp	32,140		
	SUBTOTAL	102,265		
Facilities whose costs will be adjusted using Change Between Estimate and Actual, multiplied by 50 percent				
13.	Captain Jack (BPA Breakers)	$14,335		
14.	Captain Jack (Communication and Control)	5,100		
15.	Captain Jack (Series Capacitors)	722		
16.	Power System Control	5,596		
17.	Captain Jack line to Oregon-Calif. border	5,724		
	SUBTOTAL	$31,477		
	50 PERCENT OF SUBTOTAL	15,739		
	TOTAL	$118,004		

1/ Based on mid-1989 program planning levels.

2/ Actual costs will be available approximately December 1995, or as soon as practicable thereafter. Supporting documentation will be provided including work orders and accounting data for each line item.

3/ For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the revised actual costs of facilities pertaining to each such calculation of the Revised Adjusted Capacity Ownership Price.

B. INITIAL, ADJUSTED, AND REVISED ADJUSTED CAPACITY OWNERSHIP PRICE[1]

($ in Millions)

	Cost Item	(1) Initial Capacity Ownership Price	(2) Adjusted Capacity Ownership Price	Revised Adjusted Capacity Ownership Price[2]
1.	Second 800 MW	$118	$___	$___
2.	AFUDC[3] on Second 800 MW	+ 19	+ ___	+ ___
3.	Existing Support Facilities	+ 19.1	+ 19.1[4]	+ 19.1[4]
4.	Total Cost[5]	$156	$___	$___
5.	PRICE PER KW (CO-94)[6]	$215	$___	$___

1/ Initial, Adjusted, and Revised Adjusted Capacity Ownership Price are determined in accordance with the CO-94 rate in Exhibit A.

2/ Bonneville may make multiple calculations of the Revised Adjusted Capacity Ownership Price pursuant to paragraph 9(a)(3). For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the column pertaining to such calculation and the columns for any previous calculations of the Revised Adjusted Capacity Ownership Price.

3/ AFUDC will be calculated in accordance with the CO-94 rate in Exhibit A.

4/ Not adjusted in calculating the Adjusted Capacity Ownership Price or the Revised Adjusted Capacity Ownership Price.

5/ Bonneville's indirect costs and overhead costs shall be included. Such indirect costs and overhead costs shall be allocated or distributed to the Third AC Intertie Project using the indirect and overhead allocation and distribution methodologies employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Third AC Intertie Project was under construction. Such allocation or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's Third AC Intertie Project than with respect to any other transmission projects under construction at the same time.

6/ Price per kW is derived by dividing the Total Cost by 725 MW.

C. INITIAL LUMP SUM PAYMENT

1.	Puget's Capacity Ownership Share	=	400 MW
2.	Initial Capacity Ownership Price	X	$215 ($215,000/MW)
3.	Initial Lump Sum Payment[1]	=	$86,000,000
4.	Deduction: Negotiation Deposit with Interest[2]	-	
5.	Due to Bonneville:	=	

1/ Initial Lump Sum Payment is calculated in accordance with section IV.A of the CO-94 rate in Exhibit A.

2/ Interest is calculated as specified in Bonneville's April 23, 1993, letter to Puget. The rate of interest for the computation is the interest rate applicable to 3-month Treasury Bills as specified in the FEDERAL RESERVE Statistical Release G.13. The rates are determined for the 3-month yield reported on the first day of the month of receipt of the negotiation deposit and on the first day of each subsequent third month thereafter. Interest is compounded quarterly from May 11, 1993, through the date Bonneville receives payment pursuant to paragraph 9(a)(1).

D. ADJUSTED LUMP SUM PAYMENT

1.	Puget's Capacity Ownership Share	=	400 MW
2.	Adjusted Capacity Ownership Price	X	$
3.	Adjusted Lump Sum Payment[1]	=	
4.	Initial Lump Sum Payment	–	__________
5.	SUBTOTAL due to Bonneville, or Refund Due to Puget	=	
6.	Interest[2]	+	
7.	Due to Bonneville, or Refund due to Puget	=	

1/ Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A.

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from the date Bonneville receives payment pursuant to paragraph 9(a)(1) through the date Bonneville or Puget receives payment pursuant to subparagraph 9(a)(2)(B).

E. REVISED ADJUSTED LUMP SUM PAYMENT

1.	Puget's Capacity Ownership Share	=	400 MW
2.	Current Revised Adjusted Capacity Ownership Price	X	$
3.	Current Revised Adjusted Lump Sum Payment[1]	=	
4.	Adjusted Lump Sum Payment/immediately preceding Revised Adjusted Lump Sum Payment	-	____________
5.	SUBTOTAL due to Bonneville, or Refund Due to Puget	=	
6.	Interest[2]	+	
7.	Due to Bonneville, or Refund due to Puget	=	

1/ Revised Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A. Bonneville will calculate a Revised Adjusted Lump Sum Payment each time a Revised Adjusted Capacity Ownership Price is calculated pursuant to paragraph 9(a)(3).

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from (a) the date Bonneville or Puget receives payment with respect to the Adjusted Lump Sum Payment pursuant to paragraph 9(a)(2)(B) or (b) the date Bonneville or Puget receives payment with respect to the Revised Adjusted Lump Sum Payment immediately preceding the current Revised Adjusted Lump Sum Payment through the date Bonneville or Puget receives payment with respect to the current Revised Adjusted Lump Sum Payment pursuant to subparagraph 9(a)(3)(B).

Transmission Loss Factors

A. The transmission loss factor to be applied to Puget's schedules for transactions transmitted on Puget's Scheduling Share shall be 2.5 percent.

B. The transmission loss factor to be applied to Puget's schedules for transactions transmitted pursuant to subparagraph 3(b)(1)(C) shall be 3.0 percent.

Bonneville's PNW AC Intertie

A. TRANSMISSION LINE FACILITIES

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	McNary-John Day 500 kV Line Loop into Slatt: • McNary-Slatt Str. 108/1 to substation dead end tower, 155 meters • Slatt-John Day Str. 1/1 to substation dead end tower, 194 meters	100	100
2.	John Day-Grizzly No. 1 500 kV	100	100
3.	John Day-Grizzly No. 2 500 kV	100	100
4.	Grizzly-Captain Jack No. 1 500 kV	100	100
5.	Captain Jack-Malin No. 1 500 kV	100	100
6.	Buckley-Grizzly 500 kV	100	57
7.	Grizzly-Summer Lake 500 kV	100	57
8.	500 kV double circuit between Buckley and Marion that supports the Buckley-Marion No. 1 and the Ashe-Marion No. 2 500 kV circuits (Str. No. 1/3 to Marion, 159 km)	100	25
9.	Marion-Alvey 500 kV	100	50
10.	Captain Jack-COB (10 km) 500 kV	100	100
11.	Alvey-Dixonville 500 kV	50	100
12.	Dixonville-Meridian 500 kV	50	100

B. SUBSTATION FACILITIES [1/] [2/]

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	**Slatt 500 kV** (Dispatch one-line diagram No. 228962)		
	John Day line terminal		
	• New Breaker D#5021	100	100
	• Existing 500 kV MOD D#5020/7022	100	100
	• New 500 kV MOD D#5022	100	100
	• Existing 500 kV MOD D#5019	100	50
	• Existing Breaker D#5018	100	50

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	McNary line terminal		
	• 500 kV MOD D#5023/7847	100	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Station General		
2.	**John Day 500 kV** (Dispatch one-line diagram No. 132281)		
	Grizzly No.2 line terminal		
	• Breaker D#4131	100	50
	• Breaker D#4134	100	100
	• MOD D#4132	100	50
	• MOD D#4133/7867	100	100
	• MOD D#4135	100	100
	• Associated Line PTs	100	100
	Grizzly No.1 line terminal		
	• Breaker D#4140	100	50
	• Breaker D#4143	100	100
	• MOD D#4141	100	50
	• MOD D#4142/7869	100	100
	• MOD D#4144	100	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Station General		
3.	**Buckley 500 kV, Gas Insulated Substation** (Dispatch one-line diagram No. 232583)		
	Slatt No. 1 line terminal		
	• Breaker D#4967	100	57
	• Isolating switch D#4966/7328	100	57
	• Isolating switch D#4968/7355	100	57
	• Ground switch D#7415	100	57
	• Associated Terminal Arresters	100	57
	• Associated Line PTs	100	57
	Summer Lake No. 1 line terminal		
	• Breaker D#4961	100	57

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Isolating switch D#4960/7312	100	57
• Isolating switch D#4962/7313	100	57
• Ground switch D#7311	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Marion No. 1 line terminal		
• Breaker D#4964	100	57
• Isolating switch D#4963/7314	100	57
• Isolating switch D#4965/7321	100	57
• Ground switch D#7477	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Station General		
4. **Marion 500 kV** (Dispatch one-line diagram No. 136180)		
Buckley line terminal		
• Breaker D#4389	100	50
• Breaker D#4386	100	25
• MOD D#4387	100	25
• MOD D#4390	100	50
• MOD D#4388/7751	100	50
• Associated Line PTs	100	50
Alvey line terminal		
• Breaker D#4374	100	50
• Breaker D#4377	100	25
• MOD D#4376	100	25
• MOD D#4375/7922	100	50
• MOD D#4373	100	50
• Associated Line PTs	100	50
Station General		
5. **Alvey 500 kV** (Dispatch one-line diagram No. 121424)		
Bank No. 5 terminal		
• Breaker D#5081	50	100
• MOD D#5080	50	100
• MOD D#5082	50	100
• MOD D#5090	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#5089/8157	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Marion No. 1 line terminal		
• Breaker D#5084	50	100
• MOD D#5083/8155	50	100
• MOD D#5085	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Dixonville No. 1 line terminal		
• Breaker D#5087	50	100
• MOD D#5086/8156	50	100
• MOD D#5088	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
500 kV Series Capacitor Bank (Marion-Alvey 500 kV line)	50	100
• MODs D#5100/8160,5101/8159, 5102/8158	50	100
• Bypass breaker D#5103	50	100
Station General		

6. **BPA/PacifiCorp Dixonville 500 kV Station** (PacifiCorp's one-line diagram PD-40020)

Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299, as revised or amended.

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
For Alvey and Meridian line terminals		
• Breakers 11U1, 11U2, 11U3	50	100
• Isolating MODs 11U701, 11U700/ 11U507, 11U702, 11U703/11U505, 11U704, 11U705/11U506, 11U706, 11U707, 11U708/11U501	50	100
• Two sets of line terminal PTs	50	100
• Two sets of line terminal arresters	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Series Capacitor Bank in Alvey-Dixonville 500 kV line and associated isolating devices	50	100
• 180 MVAR Shunt Reactor Bank S664, 665, 666, 667 and associated arresters, PTs, and isolating devices	50	100
Station General		
7. **BPA/PacifiCorp Meridian 500 kV Yard** (PacifiCorp's one-line diagram PD-32976)		
Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299.		
For Dixonville line terminal		
• Breakers 11R2, 11R6	50	50
• Isolating MODs 11R702, 11R703/ 11R501, 11R704, 11R710, 11R711	100	100
• One set of line PTs	50	100
• One set of line terminal arresters for the Dixonville line and one set for the Captain Jack line	50	100
• 180 MVAR Shunt Reactor Bank S690, 691 ,692, 693 and associated arresters, PTs, and isolating devices	50	100
• Series Capacitor Bank in the Dixonville-Meridian 500 kV line and associated isolating devices.	50	100
Station General		
8. **Grizzly 500 kV** (Dispatch one-line diagram No. 103924)		
John Day No. 1 line terminal		
• Breaker D#4058	100	100
• Breaker D#5040	100	100
• MOD D#4059	100	100
• MOD D#4057/7848	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4056	100	100
• MOD D#5039	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
John Day No. 2 line terminal		
• Breaker D#4042	100	100
• Breaker D#4046	100	100
• MOD D#4043	100	100
• MOD D#4044/7845	100	100
• MOD D#4045	100	100
• MOD D#4047	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Buckley No. 1 line terminal		
• Breaker D#5031	100	100
• Breaker D#5028	100	100
• MOD D#5032	100	100
• MOD D#5030/8122	100	100
• MOD D#5029	100	100
• MOD D#5027	100	100
• Associated Line PTs	100	100
Captain Jack No. 1 line terminal		
• Breaker D#5037	100	100
• Breaker D#5034	100	100
• MOD D#5038	100	100
• MOD D#5036/8123	100	100
• MOD D#5035	100	100
• MOD D#5033	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Summer Lake line terminal		
• Breaker D#5025	100	100
• MOD D#5026/8121	100	100
• MOD D#5024	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
180 MVAR Reactor Bank No. 1	100	100
• Breaker D#4222	100	100
• Isolating Switch D#4060	100	100
• Associated Arresters	100	100
300 MVAR Reactor Bank No. 2	100	100
• Breaker D#4720	100	100
• Isolating Switch D#4719	100	100
• Associated Arresters	100	100
• 300 MVAR Reactor Bank No. 3 and Neutral Reactor	100	100
• Breaker D#4038	100	100
• Isolating Switch D#4062	100	100
• Neutral isolating switch D#4109/4081	100	100
• Associated Arresters	100	100
• Associated PTs	100	100
• North Main Bus 500 kV PTs	100	100
• South Main Bus 500 kV PTs	100	100
Station General		
9. **Sand Spring 500 kV Compensation Station** (Dispatch one-line diagram No. 142239)		
Series Cap.Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
Station General		
10. **Fort Rock 500 kV Compensation Station** (Dispatch one-line diagram No. 142237)		
Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
Station General		
11. **Sycan 500 kV Compensation Station** (Dispatch one-line diagram No. 142238)		

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Summer Lake-Malin line) and associated equipment but **excluding** the bypass MOD D#5065 and transmission tower	65	100
Station General		
12. **Summer Lake 500 kV** (Dispatch one-line diagram No. 232667)		
Grizzly line terminal (formerly Buckley-Ponderosa Tap)		
• Breaker D#4959	100	57
• MOD D#4955	100	57
• MOD D#4956/7309	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Malin line terminal		
• Line protective relays	0	100
Station General		
13. **Malin 500 kV** (Dispatch one-line diagram No. 103923)		
Captain Jack No. 1 line terminal		
• Breaker D#4066	100	100
• Breaker D#4064	100	100
• MOD D#4068	100	100
• MOD D#4067/7849	100	100
• MOD D#4065	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Round Mountain line No. 1 terminal		
• Breaker D#4186	50	100
• MOD D#4063/7970	100	100
• MOD D#4185	50	100
• MOD D#4187	50	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Round Mountain line No. 2 terminal		

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Breaker D#4582	50	100
• MOD D#4583	50	100
• MOD D#4581	50	100
• MOD D#4074/7856	75	100
Grizzly No. 2/Round Mountain No. 2 line position	-	
• Breaker D#4072	75	100
• MOD D#4073	75	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	50	100
300 MVAR Shunt Reactor Bank No. 1 and associated arresters and isolating devices (D#4327, 4393)	100	100
2-239 MVAR Shunt Cap. Banks and associated isolating devices (D#4183, 4181, 4184, 4182, 8065, 8066)	100	100
Line protective relays for Summer Lake line	0	100
Station General		
14. **Captain Jack 500 kV** (Dispatch one-line diagram No. 248548)		
Series Cap. Bank No. 1 (Captain Jack-Olinda line)	100	100
• MODs D#4974/8101, 4973/8099, 4975/8100	100	100
• Bypass breaker D#4971, 4972		
Grizzly No. 1 line terminal		
• Breaker D#4990	100	100
• Breaker D#4993	100	100
• MOD D#4989	100	100
• MOD D#4991/8104	100	100
• MOD D#4992	100	100
• MOD D#4994/8105	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Malin No. 1 line terminal		
• Breaker D#4996	100	100

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
	• MOD D#4995	100	100
	• MOD D#4997	100	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Olinda No. 1 line terminal		
	• Breaker D#4977	100	100
	• Breaker D#4980	100	100
	• MOD D#4976	100	100
	• MOD D#4978	100	100
	• MOD D#4979	100	100
	• MOD D#4981	100	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs (2 sets)	100	100
	North Main Bus 500 kV PTs	100	100
	South Main Bus 500 kV PTs	100	100
	Station General		
15.	**Chief Joseph Substation** (Dispatch one-line diagram No. 124313)		
	230 kV, 1400 MW Braking Resistor	100	100
	Includes breaker dispatch No. A-594, a high speed vacuum switch and one 230 kV isolating switch in Bay 12		
	Station General		

1/ Station General will be allocated to each substation according to Bonneville's standard methodology.

2/ Each substation includes associated relays.

Capacity Owners

CAPACITY OWNER	CONTRACT NUMBER	CAPACITY OWNERSHIP SHARE (MW)	CAPACITY OWNERSHIP PERCENTAGE
PNGC	DE-MS79-94BP94523	50	1.4
Puget	DE-MS79-94BP94521	400	11.6
Seattle	DE-MS79-94BP94522	160	4.6
Snohomish	DE-MS79-94BP94525	42	1.2
Tacoma	DE-MS79-94BP94524	41	1.1

PNGC: Pacific Northwest Generating Cooperative
Puget: Puget Sound Power & Light Company
Seattle: City of Seattle, City Light Department
Snohomish: Public Utility District No. 1 of Snohomish County
Tacoma: Tacoma Public Utilities

Provisions Required by Statute or Executive Order

1. Contract Work Hours and Safety Standards Act (40 U.S.C. & 327, et seq.).

(a) Overtime Requirements.
Puget, contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall not require or permit any such laborers or mechanics in any workweek in which the individual is employed on such work to work in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than 1-1/2 times the basic rate of pay for all hours worked in excess of 40 hours in such workweek.

(b) Violation: liability for unpaid wages; liquidated damages.
In the event of any violation of the provisions set forth in section 1 of this Exhibit H, Puget and any subcontractor responsible therefore shall be liable for the unpaid wages. In addition, Puget and such subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions set forth in section 1 of this Agreement in the sum of $10.00 for each calendar day on which such individual was required or permitted to work in excess of the standard workweek of 40 hours without payment of the overtime wages required by provision set forth in section 1 of this Exhibit.

(c) Withholding for unpaid wages and liquidated damages.
The person designated in writing by Bonneville's Administrator with the Authority to enter into, administer, modify, suspend or terminate this Exhibit, make related determinations and findings and bind Bonneville only to the extent of delegated authority shall upon his or her own action or upon written request of an authorized representative of the Department of Labor withhold or cause to be withheld, from any moneys payable on account of work performed by Puget or its subcontractor, if any, under any such contract

or any other federal contract subject to the Contract Work Hours and Safety Standards Act which is held by the same prime contractor, such sums as may be determined to be necessary to satisfy any liabilities of Puget or such subcontractor for unpaid wages and liquidated damages as provided in section 2 of this Exhibit.

2. Convict Labor (Exec. Order No. 11755, Dec. 29, 1979).
In connection with the performance or work under this Agreement, Puget and any subcontractor, if any agrees not to employ any person undergoing sentence of imprisonment except as otherwise provided by law.

3. Equal Opportunity (Exec. Order No. 11246, Sep. 24, 1965).

(a) If, during any 12-month period (including the 12 months preceding the award of this contract), Puget has been or is awarded nonexempt federal contracts and/or subcontracts that have an aggregate value in excess of $25,000.00, Puget shall comply with sections 3(b)(1) through 3(b)(11) below. Upon request, Puget shall provide information necessary to determine the applicability of this clause.

(b) During performance of this Agreement, Puget agrees as follows:

(1) Puget shall not discriminate against any employee or applicant for employment because of race, color, religion, sex or national origin.

(2) Puget shall take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex or national origin. Such action shall include, but not be limited to: (1) employment; (2) upgrading; (3) demotion; (4) transfer; (5) recruitment or recruitment advertising; (6) layoff or termination; (7) rates of pay or other forms of compensation; and (8) selection for training, including apprenticeship.

(3) Puget shall post in conspicuous places, available to employees and applicants for employment, the notices that explain this clause, such notices to be provided by the person designated in writing by Bonneville's Administrator with the authority to enter into, administer, modify, suspend or terminate this Agreement, make related determinations and findings and bind Bonneville only to the extent of delegated authority (Contracting Officer).

(4) Puget shall, in all solicitations or advertisements for employees placed by or on behalf of Puget, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex or national origin.

(5) Puget shall send, to each labor union or representative or of workers with which it has a collective bargaining agreement or other contract or understanding, the notice provided by the Contracting Officer advising the labor union or workers' representative of Puget's commitments under this clause, and post copies of the notice in conspicuous places available to employees and applicants for employment.

(6) Puget shall comply with Executive Order No. 11246, Sep. 24, 1965 (30 Fed. Reg. 12319), as amended, and the rules, regulations and orders of the Secretary of Labor.

(7) Puget shall furnish to Bonneville all information required by Executive Order No. 11246, as amended, and by the rules, regulations and orders of the Secretary of Labor. Standard Form 100 (EEO-1), or any successor form, is the prescribed form to be filed within 30 days following the award of this contract, unless filed within 12 months preceding the date of the award of this contract.

(8) Puget shall permit access to its books, records and accounts by Bonneville or the Office of Federal Contract Compliance Programs

(OFCCP) for purpose of investigation to ascertain Puget's compliance with such rules, regulations and orders.

(9) If the OFCCP determines that Puget is not in compliance with this clause or any rule, regulation or order of the Secretary of Labor, this Agreement may be canceled, terminated, or suspended in whole or in part and Puget may be declared ineligible for further Government contracts, under the procedures authorized in Executive Order No. 11246, as amended. In addition, sanctions may be imposed and remedies invoked against Puget as provided in Executive Order No. 11246, as amended, the rules, regulations and orders of the Secretary of Labor, or as otherwise provided by law.

(10) Puget shall include the terms and conditions of sections 3(b)(1) through 3(b)(11) of this Exhibit in every subcontract or purchase order that is not exempted by the rules, regulations, or orders of the Secretary of Labor issued under Executive Order No. 11246, as amended, so that these terms and conditions will be binding upon each subcontractor or vendor.

(11) Puget shall take such action with respect to any subcontract or purchase order as may direct as means of enforcing these terms and conditions, including sanctions for noncompliance: Provided, that if Puget becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of any direction, Puget may request the Government to enter into the litigation to protect the interest of the United States.

(c) Notwithstanding any other clause in this Agreement, disputes relative to this clause will be governed by the procedures in 41 CFR § 66-1.1.

4. Certification of Non-segregated Facilities (48 CFR § 22.810).

(a) Puget certifies that it does not and will not maintain or provide for employees any segregated facilities at any of its establishments and that it does not and will not permit its employees to perform their services at any location under its control where segregated facilities are maintained. Puget agrees that a breach of this certification is a violation of section 3 (the Equal Opportunities Clause) of this Exhibit.

(b) Puget agrees that it will (1) obtain identical certifications from proposed subcontractors prior to the award of subcontracts exceeding $10,000.00 which are not exempt from the provisions of the Equal Opportunity Clause; (2) retain such certifications in its files (3) forward the following notice to such proposed subcontractors, except where the proposed subcontractors have submitted identical certifications of specific time periods:

> "Notice to Prospective Subcontractors of Requirement for Certifications of Non-segregated Facilities.
>
> "A Certification of Non-segregated Facilities must be submitted prior to the award of a subcontract under which the subcontractor will be subject to the Equal Opportunity clause. This certification may be submitted either for each subcontract or for all subcontracts during a period (i.e., quarterly, semiannually or annually)."

5. Officials Not to Benefit (41 U.S.C. § 22).

No member of or delegate to Congress, or resident commissioner, shall be admitted to any share or part of this Agreement or to any benefit arising from it. However, this clause does not apply to this Agreement to the extent that this Agreement is made with a corporation for the corporation's general benefit.

6. Bonneville's Obligations Not General Obligations of the United States (16 U.S.C. § 839(i)).

None of the offerings of obligations, or promotional materials for such obligations, which may be offered by Puget to fund its activities pursuant to this Agreement, shall be construed to be, general obligations of the United States, nor are such obligations intended to be or are they secured by the full faith and credit of the United States.

7. <u>Small Business Act (15 U.S.C. §§ 631 and 637)</u>.

(a) It is the policy of the Government that small business concerns owned and controlled by socially and economically disadvantaged individuals shall have the maximum practicable opportunity to participate in the performance of contracts let by any federal agency.

(b) Puget hereby agrees to carry out the policy set forth in 7(a) in awarding subcontracts to the fullest extent consistent with the efficient performance of this Agreement. Puget further agrees to cooperate on any studies or surveys as may be conducted by the United States Small Business Administration or Bonneville as may be necessary to determine the extent of Puget's compliance with this clause.

(c) As used in this agreement the term "small business concern" shall mean a small business as defined in section 3 of Small Business Act (15 U.S.C. § 632) and relevant regulations promulgated pursuant thereto. The term "small business concern owned and controlled by socially and economically disadvantaged individuals" shall mean a small business concern:

(1) which is at least 51 percent owned by one or more socially disadvantaged individuals; or, in the case of any publicly owned business, at least 51 percent of the stock of which is owned by one or more socially or economically disadvantaged individuals; and

(2) whose management and daily business operations are controlled by one or more such individuals.

Puget shall presume that socially and economically disadvantaged individuals include Black Americans, Hispanic Americans, Native Americans, Asian Pacific Americans and other minorities, or any other individual found to be disadvantaged by the United States Small Business Administration pursuant to section 8(a) of the Small Business Act.

(d) Puget acting in good faith may rely on written representations by its subcontractor regarding its status as either a small business concern or a small business concern owned and controlled by socially and economically disadvantaged individuals.

8. Other Statutes, Executive Orders and Regulations.

(a) Puget agrees to comply with the following statutes, executive orders and regulations to the extent applicable:

(1) False Claims Act, 31 U.S.C. § 3729, et seq. Whoever makes or presents to any person or officer in the civil military or naval service of the United States, or to any department or agency thereof, any claim upon or against the United States, or any department or agency thereof, knowing such claim to be false, fictitious or fraudulent, shall be fined not more than $10,000.00 or imprisoned not more than 5 years, or both;

(2) Rehabilitation Act of 1973, 29 U.S.C. §793, as amended, Executive Order No. 11758, Jan. 15, 1974, and the regulations of the Secretary of Labor, 41 CFR Part 60-250, et seq., which concern affirmative action for handicapped workers;

(3) Vietnam Era Veterans Readjustment Assistance Act of 1972, 38 U.S.C. §§ 101, 102, 240, 241, 1502, 1504, 1507, as amended, and the clauses contained in 41 CFR Part 60-250, et

seq., which concern affirmative action for disabled veterans and veterans of the Vietnam Era;

(4) Executive Order No. 11625, Oct. 13, 1971, and implementing regulations which concern utilization of small disadvantaged business concerns;

(5) Anti-Kickback Act, 41 U.S.C. § 51, et seq.; and

(6) Privacy Act of 1974, 5 U.S.C. § 552a.

(b) Puget agrees to comply with requirements deemed necessary by Bonneville in order to implement Bonneville's obligations under the National Historic Preservation Act of 1966, U.S.C. §§ 470, et seq.

Bonneville's PNW AC Intertie Costs

All costs in sections I through VIII of this Exhibit I shall be subject to the following provisions:

PURPOSE

Bonneville shall determine and calculate Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs with respect to Bonneville's PNW AC Intertie in accordance with this Exhibit I. None of Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, and End of Term Costs (each of the foregoing for purposes of this sentence, a Cost) shall include any other Cost.

SOURCE OF INFORMATION AND COSTS

Bonneville shall forecast in accordance with this Exhibit I the costs reflected in any Operating Plan pursuant to Schedules A through H of this Exhibit using the most detailed information available to Bonneville from its budget process at the time the forecast is made. Bonneville shall determine the actual costs reflected in any Operating Plan pursuant to Schedules A through H, using Bonneville's then existing accounting system in accordance with this Exhibit I. All costs reflected in Schedules A through H shall be net of credit.

Bonneville shall determine its overall overhead and overall indirect costs. A portion of Bonneville's overall overhead and indirect costs shall be allocated to such total system operations costs (pursuant to section I below), total system maintenance costs (pursuant to section II below), total capital costs (pursuant to sections III and IV below), Other Costs (pursuant to section V below), Contracts and Rates Costs (pursuant to section VI below), Power Scheduling Costs (pursuant to section VII below), and End of Term Costs (pursuant to section VIII below) using Bonneville's normal allocation or distribution methodologies for such costs, as such methodologies may be changed by Bonneville from time to time. Such allocations or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's PNW AC Intertie than with respect to other transmission facilities.

Bonneville shall record its costs into its accounting systems in accordance with generally accepted accounting principles. For purposes of this Agreement, "generally accepted accounting principles" means the common set of accounting concepts, standards, and procedures that are adopted by entities (such as the utility industry) for purposes of financial statement disclosure.

Whenever Bonneville alters its accounting system or methods to permit costs referred to in this Exhibit I, which were previously allocated to functions and activities, to be directly assigned to function and activities, then in that event Puget and Bonneville shall, in concert with the Capacity Owners other than Puget, in good faith negotiate revisions to this Exhibit I to include such directly assigned costs.

COSTS

I. Operations Costs

A. Operations Costs - Allocation Factor

The allocation factor (Schedule A, line 3) used to determine the Allocated Direct Cost of Operations Cost, Indirect Cost of Operations Cost, and Overhead Cost of Operations Cost is the ratio of major facility units (MFUs) of Bonneville's PNW AC Intertie operated by Bonneville to MFUs of the Federal Columbia River Transmission System.

An MFU (Schedule A, lines 1 and 2) is any of the following major pieces of power system equipment which, at any given time, is installed on and is a part of the Federal Columbia River Transmission System: substation switchgear (such as power circuit breakers; potential devices; disconnects, load interrupters, hot-stick operated bus links; switching devices, circuit switchers, ground switches; and switchyard equipment terminals); protective equipment (such as grounding devices; reactors; arrestors and resistors;

voltage regulators; engine generators and motor generators; and high voltage fuses); transformation equipment (such as power transformers; diesel generators; grounding transformers; regulators and shunt reactors; synchronous condensers; and shunt or series capacitors); station equipment (such as switchyard lighting, batteries and chargers, air compressors, station service equipment, and lightening arrestors); instruments, control, and supervisory equipment (such as switchboards, instruments, and control panels; relay panels, transfer trip, and single-pole relaying; and oscillographs; fault detectors and locators; sequential events recorders, supervisory control, and data acquisition equipment; and indicating meters, instruments, and loggers); and equipment specific to direct current and static var compensator stations (such as mercury arc valves; thyristor systems; air handling packages; water control packages; harmonic filtering systems; motor control centers, such as fans, pumps, and dampening resistors; and valve damping resistors); or devices that perform similar types of functions.

Once each fiscal year, Bonneville shall count the number of MFUs on Bonneville's PNW AC Intertie (exclusive of facilities operated by others) (Schedule A, line 1) and the number of MFUs on the Federal Columbia River Transmission System (Schedule A, line 2). In calculating the forecast Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs, Bonneville shall use the most recent MFU count available at the time of such calculation in developing its initial Operating Plan for a given fiscal year. For each Operating Plan which is for the same fiscal year, Bonneville shall use the same MFU count in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

B. Operations Costs - Operations Functionalization Factor

For each Operating Plan, Bonneville's total system operations direct cost, indirect cost and overhead cost (Schedule A, lines 7, 9, and 11) shall be adjusted by an operations functionalization factor (Schedule A, line 6) so that Capacity Owners pay only transmission-related system operations costs. The operations functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using the costs developed for the last year of the rate period for which Bonneville has developed rates, the operations functionalization factor shall be the ratio of (a) Bonneville's total system operations cost functionalized to transmission (Schedule A, line 4) over (b) Bonneville's total system operations cost (Schedule A, line 5). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

C. Operations Costs - Allocated Direct Costs

For each Operating Plan, Bonneville shall allocate its total system operations direct costs as set forth in Schedule A, lines 7 and 8, to determine Allocated Direct Costs of Operations Cost (Schedule A, line 8).

Schedule A, line 7, shall reflect Bonneville's total system operations direct costs for a fiscal year. Bonneville's total system operations direct costs for a fiscal year shall include all system operations expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: substation operations (which provides for, among other things, making equipment adjustments to maintain loads and voltages within acceptable limits, switching to deenergize lines and equipment during maintenance outages, isolating damaged equipment, restoring service to customers, visually inspecting equipment, and reading meters that record line and equipment loading and voltages), power system control and dispatching (which provides for, among other things, central dispatching, control, and monitoring of the electric operation of the Federal transmission system; load, frequency, and voltage control of

Federal generating plants; the operating of the system control and data computers at the Dittmer and Eastern Control Centers; and modification and maintenance of the operation-related computers), and operations standards and engineering (which provides for, among other things, analyzing system loads, voltage levels, outage information, stability levels, and other data; making policy recommendations for system operations; planning operations' practices, restoration plans and disturbance ports; development of control center requirements for centralized automation of substations and generation; and Bonneville's participation with other utilities in developing utility operating standards and guides); and other system operations activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 8, shall reflect Allocated Direct Cost of Operations Cost.

D. Operations Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system operations indirect costs as set forth in Schedule A, lines 9 and 10, to determine Indirect Costs of Operations Costs.

Schedule A, line 9, shall reflect Bonneville's total system operations indirect costs for a fiscal year. Bonneville's total system operations indirect costs for a fiscal year shall include all system operations indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: general supervision and management, office support, planning, budgeting, training, direction of facilities' operation, and other system operations activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 10, shall reflect Indirect Cost of Operations Cost.

E. Operations Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system operations overhead costs as set forth in Schedule A, lines 11 and 12, to determine Overhead Costs of Operations Costs.

Schedule A, line 11, shall reflect Bonneville's total system operations overhead costs for a fiscal year. Bonneville's total system operations overhead costs for a fiscal year shall include all system operations overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system operations overhead activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule A, line 12, shall reflect Overhead Cost of Operations Cost.

Schedule A, line 13, shall reflect Operations Cost.

II. <u>Maintenance Costs</u>

A. Maintenance Costs - Power System Control Maintenance Functionalization Factor

For each Operating Plan, the Power System Control (PSC) maintenance cost (Schedule B, line 4) shall be adjusted by a PSC maintenance functionalization factor (Schedule B, line 3). PSC maintenance is the testing, repair, and engineering support for Bonneville's communications and control systems. The PSC maintenance functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs for the last year of the rate period for which Bonneville has developed rates, the PSC functionalization factor shall be the ratio of (a) Bonneville's total PSC maintenance cost functionalized to transmission from such general rate case (Schedule B, line 1) over (b) Bonneville's total PSC maintenance cost from such general rate case (Schedule B, line 2).

B. Maintenance Costs - Direct Costs

The Direct Costs of Maintenance Costs for a fiscal year (Schedule B, line 7) shall be Bonneville's direct costs of maintaining Bonneville's PNW AC Intertie and shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities for maintenance of Bonneville's PNW AC Intertie: transmission line maintenance; substation maintenance; power system control maintenance; nonelectric plant maintenance; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of Bonneville's PNW AC Intertie undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

With the exception of PSC maintenance costs, Bonneville shall specifically identify the direct costs of maintaining Bonneville's PNW AC Intertie (Schedule B, line 7). To determine PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6), the total PSC direct maintenance cost (Schedule B, line 4) shall be multiplied by (a) the PSC maintenance functionalization factor (Schedule B, line 3) and (b) the MFU allocation factor (Schedule B, line 5) set forth in Schedule A, line 3. The Direct Costs of Maintenance Costs (Schedule B, line 8) shall be the sum of (a) PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6) and (b) the direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost (Schedule B, line 7).

C. Maintenance Costs - Allocation Factor

The allocation factor (Schedule B, line 10) used to determine Indirect Cost of Maintenance Cost and Overhead Cost of Maintenance Cost shall be the ratio of the Direct Cost of Maintenance Cost (Schedule B, line 8) to Bonneville's total system maintenance direct cost (Schedule B, line 9), as described below.

Schedule B, line 9, shall reflect Bonneville's total system maintenance direct costs for a fiscal year. Bonneville's total system maintenance direct costs for a fiscal year shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: transmission line maintenance; substation maintenance; power system control maintenance; nonelectric plant maintenance; establishing, monitoring, and updating system maintenance standards, policies, and procedures; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of the Federal Columbia River Transmission System undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 10, shall reflect the percentage which shall be used to allocate Bonneville's total system maintenance indirect cost and total system maintenance overhead cost to Bonneville's PNW AC Intertie.

D. Maintenance Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance indirect costs as set forth in Schedule B, lines 11 and 12, to determine Indirect Costs of Maintenance Costs.

Schedule B, line 11, shall reflect Bonneville's total system maintenance indirect costs for a fiscal year. Bonneville's total system maintenance indirect costs for a fiscal year shall include all system maintenance indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance any of the following activities: supervision and management, office support, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other system maintenance activities undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 12, shall reflect Indirect Cost of Maintenance Cost.

E. Maintenance Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance overhead costs as set forth in Schedule B, lines 13 and 14, to determine Overhead Costs of Maintenance Costs.

Schedule B, line 13, shall reflect Bonneville's total system maintenance overhead costs for a fiscal year. Bonneville's total system maintenance overhead costs for a fiscal year shall include all system maintenance overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system maintenance overhead activities undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule B, line 14, shall reflect Overhead Cost of Maintenance Cost.

Schedule B, line 15, shall reflect Maintenance Cost.

III. Replacement Costs and Reinforcement Costs

A. Replacement Costs and Reinforcement Costs - Direct Costs

The Direct Costs for Replacements and Reinforcements for a fiscal year (Schedule C, line 1) shall be Bonneville's direct capital costs for Replacements and Reinforcements for such fiscal year and shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, land, materials and equipment, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of the following activities: planning, environmental analyses and mitigation, survey, design, land, materials and equipment, turnkey contracts, contract construction, force account construction, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council. The Direct Costs for any Replacement or Reinforcement for a fiscal year shall also include the costs of removal and any salvage credits with respect to any PNW AC Intertie facility removed on account of such Replacement or Reinforcement.

B. Replacement Costs and Reinforcement Costs - Indirect Costs and Overhead Costs

For each Replacement and Reinforcement project, the Indirect Costs and Overhead Costs for Replacements and Reinforcements (Schedule C, line 2) shall be allocated or distributed to such Replacements and Reinforcements using the indirect and overhead allocation and distribution methodologies employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Replacements and Reinforcements are under construction. Schedule C, line 2, shall reflect the Indirect Costs and Overhead Costs of Replacements and Reinforcements.

Indirect Costs of Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel expenses, service contracts, consulting contracts, administration of materials, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: supervision, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Overhead Costs for Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other costs, each of which being which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering);

and (c) other replacement and reinforcement activities undertaken by Bonneville that are consistent with replacement and reinforcement activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

C. Replacement Costs and Reinforcement Costs - Allowance for Funds Used During Construction (AFUDC)

Schedule C, line 3, shall reflect AFUDC for Replacements and Reinforcements. At the beginning of each fiscal year, Bonneville shall calculate the AFUDC rate for such fiscal year. Bonneville shall apply such AFUDC rate monthly to the costs in accounts for construction work in progress for Replacements and Reinforcements.

D. Replacement Costs and Reinforcement Costs - Interest

Schedule C, line 4, shall reflect the interest cost payable by Puget pursuant to this Agreement with respect to any Replacement or Reinforcement. Such interest cost for any Replacement or any Reinforcement shall be simple interest calculated at a rate equal to the weighted average interest rate on Bonneville's then outstanding bonds or other debt instruments and such interest shall accrue from the date Bonneville stops accruing AFUDC (approximately the date the work order for such Replacement or such Reinforcement is closed) with respect to such Replacement or such Reinforcement to the due date of the monthly power bill containing the charge for such Replacement or such Reinforcement.

IV. <u>General Plant Costs</u>

For each Operating Plan, Bonneville shall adjust, amortize, and allocate Bonneville's total general plant investment (as described below) and Bonneville's Dittmer control equipment investment as set forth in Schedule D, lines 1 through 11, to determine General Plant Cost.

Schedule D, line 1, shall reflect for a fiscal year Bonneville's total cumulative general plant investment. Bonneville's total general plant investment shall include Bonneville's investments in any of the following: land-general plant, structures/improvements-general plant, office furniture and equipment, transportation equipment, stores equipment, tools/shop/garage equipment, laboratory equipment, power operated equipment, communication equipment, miscellaneous equipment (including equipment or apparatus used in Bonneville's utility operations which are not includable in any other general plant investment category), and other similar investment made by Bonneville that is consistent with general plant investment made by utilities in the Western Systems Coordinating Council.

Schedule D, line 2, shall reflect for a fiscal year Bonneville's cumulative investment in Dittmer control equipment.

Schedule D, line 3, shall reflect Bonneville's total general plant investment and Bonneville's Dittmer control equipment investment functionalized to generation using the methodology for functionalizing general plant as set forth in Bonneville's general rate case most recently approved by FERC on an interim basis.

Schedule D, line 4, shall reflect any general plant investment recovered from all Capacity Owners under the CO-94 rate as such general plant investment is unitized by Bonneville; provided, however, for the first two Operating Plans Bonneville shall estimate the amount of the general plant investment included in the Initial Capacity Ownership Price, which estimate shall be reflected in Schedule D, line 4, and Bonneville shall modify such Operating Plans by December 1995, or as soon as practicable thereafter, to reflect in Schedule D, line 4, the actual general plant investment included in the Adjusted Capacity Ownership Price.

Schedule D, line 5, shall reflect any general plant investment recovered from Capacity Owners pursuant to section 5 for Upgrades. The agreements referred to in subsection 5(d) and subparagraph 5(e)(3)(B) shall specify the portion of costs of an Upgrade that will be considered general plant investment.

Schedule D, line 6, shall reflect Bonneville's adjusted general plant investment functionalized to transmission and shall be calculated by adding line 1 and line 2, and from the sum of line 1 and line 2 subtracting line 3, line 4, and line 5.

Schedule D, line 7, shall reflect Bonneville's annual cost of Bonneville's adjusted general plant investment functionalized to transmission (Schedule D, line 6). Such annual cost shall be the sum of the annual interest and amortization amounts for each category of adjusted general plant investment. The annual interest and amortization amounts for each category shall be calculated by using the investment amounts for each such category, the weighted average interest rate for all Bonneville then outstanding bonds, and the average service lives for each such category from Bonneville's most recent depreciation study. If Bonneville changes its practice of financing general plant investment with bonds, the interest rate used in the calculation referred to in the immediately preceding sentence shall reflect the weighted average interest rate for all of Bonneville's then outstanding debt instruments.

Schedule D, line 8, shall reflect for a fiscal year Bonneville's total cumulative transmission plant-in-service investment (not including general plant investment). Bonneville's total transmission plant-in-service investment shall include Bonneville's investment in any of the following items reflected as total transmission plant-in-service (not including general plant investment) in the Segmentation Study (from Bonneville's general rate case most recently approved by FERC on an interim basis: land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

Schedule D, line 9, shall be the annual cost ratio of Bonneville's PNW AC Intertie transmission-related general plant derived by dividing Schedule D, line 7, by Schedule D, line 8.

Schedule D, line 10, shall reflect Bonneville's PNW AC Intertie investment. Bonneville's PNW AC Intertie investment shall include Bonneville's investment in any of the following items reflected as Bonneville's PNW AC Intertie plant-in-service in the Segmentation Study from Bonneville's general rate case most recently approved by FERC on an interim basis (or the successor to the Segmentation Study, as determined by Bonneville): land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

V. Other Costs

For each Operating Plan, Bonneville shall include Other Costs associated with Bonneville's PNW AC Intertie for a fiscal year. Such Other Costs (Schedule E, line 3) for a fiscal year shall include for such fiscal year any of the following: (1) the costs of operation; maintenance; capital replacements, reinforcements, additions, betterments, renewals; or related costs which Bonneville is obligated to pay pursuant to the Northwest Intertie Agreements or other contracts referred to in subsection 8(b) of this Agreement; and (2) costs paid by Bonneville including monetary judgments, settlements, binding awards, non-contract penalties, contract penalties, liquidated damages, or forfeiture costs, and Bonneville's costs related to such monetary judgments, settlements, binding awards, non-contract penalties, contract penalties, liquidated damages, or forfeiture costs assessed against or incurred by Bonneville as a facilities owner of, or the operator of, the PNW AC Intertie; provided, however, that Puget shall not be obligated to pay a share of any such costs that are not properly allocated to Bonneville's PNW AC Intertie.

Bonneville shall forecast its share of operations, maintenance, capital, and related costs for activities that PacifiCorp performs on Bonneville/PacifiCorp jointly-owned PNW AC Intertie facilities based on forecasts received from PacifiCorp or on actual costs for the most recent 12 consecutive month period prior to preparation of an Operating Plan.

VI. <u>Contracts and Rates Costs</u>

A. Contracts and Rates Costs - Functionalization Factor

For each Operating Plan, Bonneville's total contracts and rates direct costs, indirect costs, and overhead costs (Schedule F, lines 5, 6, and 7) shall be adjusted by a contracts and rates functionalization factor (Schedule F, line 3). The contracts and rates functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the contracts and rates functionalization factor shall be the ratio of (a) Bonneville's total transmission-related contracts and rates cost (Schedule F, line 1) over (b) Bonneville's total contracts and rates cost (Schedule F, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Contracts and Rates Cost.

B. Contracts and Rates Costs - Allocation Factor

The allocation factor (Schedule F, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Contracts and Rates Costs - Total Contracts and Rates Costs

Bonneville's total contracts and rates costs for a fiscal year (Schedule F, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: rate filings with FERC, development of rates customers pay Bonneville for electric power and for wheeling their own power on Bonneville's transmission system; negotiation, administration, and coordination of contracts for power sales, power exchanges, conservation, wheeling and resource services; and analyzing, processing, and issuing all customer power bills; and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule F, line 9, shall reflect Contracts and Rates Cost.

VII. <u>Power Scheduling Costs</u>

For each Operating Plan, Bonneville's total power scheduling direct costs, indirect costs, and overhead costs (Schedule G, lines 5, 6, and 7) shall be adjusted by a power scheduling functionalization factor (Schedule G, line 3). The power scheduling functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the power scheduling functionalization factor shall be the ratio of (a) Bonneville's total transmission-related power scheduling cost (Schedule G, line 1) over (b) Bonneville's total power scheduling cost (Schedule G, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Power Scheduling Cost.

B. Power Scheduling Costs - Allocation Factor

The allocation factor (Schedule G, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Power Scheduling Costs - Total Power Scheduling Costs
Bonneville's total power scheduling costs for a fiscal year (Schedule G, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: scheduling and marketing power to Bonneville customers and interconnected utilities, forecasting the hourly power requirements of Bonneville customers and the interchange of power with the region's interconnected electric utilities and with utilities outside the region, scheduling power to be generated at each Federal plant, weather and streamflow forecasting, controlling the reservoirs, implementing the intertie access policy, coordinating power production with the multi-purpose operation of the Federal power system, seasonal load/resource planning, developing current short-term operating plans, short-term marketing of Bonneville's surplus firm power, exchanges, and nonfirm energy, and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule G, line 9, shall reflect Power Scheduling Cost.

VIII. <u>End of Term Costs</u>
When all facilities of the PNW AC Intertie are determined, in accordance with Northwest Intertie Agreements, to be no longer operable, Bonneville shall include a forecast of all Bonneville's costs associated with

decommissioning the PNW AC Intertie and credits resulting from such decommissioning in the Operating Plan for each fiscal year that such End of Term Costs are to be incurred. Bonneville's End of Term Costs for a fiscal year (Schedule H, line 4) shall include Bonneville's costs (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: decommissioning, razing structures, disposal of debris, site restoration, meeting all requirements of Federal, state, or local applicable law relating to the foregoing activities, and other decommissioning activities undertaken by Bonneville that are consistent with decommissioning activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A for FY XXXX

	Line No.	Forecast	Actual	Difference
I. Operations Costs				
A. Allocation Factor				
MFUs of Bonneville's PNW AC Intertie	1		________	
MFUs of the FCRTS	2		________	
Allocation factor (Line 1/Line 2)	3		________	
B. Operations Functionalization Factor				
Bonneville's total transmission-related systems operations cost from rate case	4		________	
Bonneville's total system operations cost from rate case	5		________	
Operations functionalization factor (Line 4/Line 5)	6		________	
C. Allocated Direct Cost				
Bonneville's total system operations direct cost	7	________	________	________
Allocated Direct Cost of Operations Cost (Line 3 * Line 6 * Line 7)	8	________	________	________

	Line No.	Forecast	Actual	Difference
D. Indirect Cost				
Bonneville's total system operations indirect cost	9	________	________	________
Indirect Cost of Operations Cost (Line 3 * Line 6 * Line 9)	10	________	________	________
E. Overhead Cost				
Bonneville's total system operations overhead cost	11	________	________	________
Overhead Cost of Operations Cost (Line 3 * Line 6 * Line 11)	12	________	________	________
F. Operations Cost (Lines 8 + 10 + 12)	13	________	________	________

Schedule B for FY XXXX

	Line No.	Forecast	Actual	Difference
II. Maintenance Cost				
A. Power System Control (PSC) Maintenance Functionalization Factor				
Bonneville's transmission-related PSC maintenance cost from rate case	1		______	
Bonneville's total PSC maintenance cost from rate case	2		______	
PSC maintenance functionalization factor (Line 1/Line 2)	3		______	
B. Direct Cost				
Total PSC direct maintenance cost	4	______	______	______
MFU Allocation Factor (Schedule A, line 3)	5		______	
PSC direct maintenance cost for Bonneville's PNW AC Intertie (Line 4 * Line 3 * Line 5)	6	______	______	______
Bonneville's direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost	7	______	______	______
Direct Cost of Maintenance Cost (Line 6 + Line 7)	8	______	______	______

C. Allocation Factor				
Bonneville's total system maintenance direct cost	9	______	______	______
Allocation factor for Indirect Cost and Overhead Cost (Line 8/Line 9)	10	______	______	______
D. Indirect Cost				
Bonneville's total system maintenance indirect cost	11	______	______	______
Indirect Cost of Maintenance Cost (Line 11 * Line 10)	12	______	______	______
E. Overhead Cost				
Bonneville's total system maintenance overhead cost	13	______	______	______
Overhead Cost of Maintenance Cost (Line 13 * Line 10)	14	______	______	______
F. Maintenance Cost (Lines 8 + 12 + 14)	15	______	______	______

Schedule C

	Line No.	Forecast	Actual	Difference
III. Replacement Costs and Reinforcement Costs				
A. Direct Cost				
Direct Costs of Replacements and Reinforcements	1	______	______	______
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2	______	______	______
C. AFUDC				
AFUDC of Replacements and Reinforcements	3	______	______	______
D. Interest				
Interest Cost of Replacements and Reinforcements	4		______	
E. Total Replacement Costs and Reinforcement Costs (Lines 1 + 2 + 3 + 4)	5	______	______	______

Notes:

A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement.

Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

Schedule D for FY XXXX

	Line No.	Allocated Actual
IV. General Plant Cost		
Bonneville's total general plant investment	1	________
Bonneville's Dittmer control equipment investment	2	________
General plant investment of lines 1 and 2 functionalized to generation	3	________
General plant investment recovered from all Capacity Owners in Adjusted Capacity Ownership Price and Revised Adjusted Capacity Ownership Price	4	________
General plant investment recovered from Capacity Owners for Upgrades	5	________
Adjusted general plant investment functionalized to transmission (Line 1 + Line 2 - Line 3 - Line 4 - Line 5)	6	________
BPA total annual cost of Line 6 general plant investment	7	________
BPA total transmission plant-in-service investment (not including general plant investment) from Segmentation Study	8	________
ACR for Bonneville's PNW AC Intertie (Line 7/Line 8)	9	________
Bonneville's PNW AC Intertie investment from Segmentation Study	10	________
General Plant Cost (Line 9 * Line 10)	11	________

Schedule E for FY XXXX

	Line No.	Forecast	Actual	Difference
V. Other Costs				
A. PacifiCorp and related costs	1	__________	__________	__________
B. Other PNW AC Intertie costs	2	__________	__________	__________
C. Total Other Costs	3	__________	__________	__________

Schedule F for FY XXXX

	Line No.	Forecast	Actual	Difference
VI. Contracts and Rates Costs				
A. Contracts and Rates Functionalization Factor				
Transmission-related contracts and rates cost from rate case	1		______	
Total contracts and rates cost from rate case	2		______	
Contracts and rates cost functionalization factor (Line 1/Line 2)	3		______	
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4		______	
C. Total Contracts and Rates Costs				
Contracts and rates direct costs	5	______	______	______
Contracts and rates indirect costs	6	______	______	______
Contracts and rates overhead costs	7	______	______	______
Bonneville's total contracts and rates costs (Line 5 + Line 6 + Line 7)	8	______	______	______
D. Contracts and Rates Cost (Line 8 * Line 3 * Line 4)	9	______	______	______

Schedule G for FY XXXX

	Line No.	Forecast	Actual	Difference
VII. Power Scheduling Costs				
A. Power Scheduling Functionalization Factor				
Transmission-related power scheduling costs from rate case	1		______	
Total power scheduling cost from rate case	2		______	
Power scheduling cost functionalization factor (Line 1/Line 2)	3		______	
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4		______	
C. Total Power Scheduling Costs				
Power scheduling direct costs	5	______	______	______
Power scheduling indirect costs	6	______	______	______
Power scheduling overhead costs	7	______	______	______
Bonneville's total power scheduling costs (Line 5 + Line 6 + Line 7)	8	______	______	______
D. Power Scheduling Cost (Line 8 * Line 3 * Line 4)	9	______	______	______

Schedule H for FY XXXX

	Line No.	Forecast	Actual	Difference
VIII. End of Term Costs				
A. Direct Cost				
Direct Cost of End of Term Costs	1	______	______	______
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of End of Term Costs	2	______	______	______
C. Credits				
Credits from decommissioning PNW AC Intertie facilities	3	(______)	(______)	(______)
D. End of Term Costs	4	______	______	______

Puget's Initial Transaction with California Utility

Name of parties: Puget / Pacific Gas & Electric Company

Term of Contract: Variable

Date of Execution: October 25, 1991

Amount of Transaction (MW): 300 MW

Capacity Ownership Agreement

FY 2017 Operating Plan
EXHIBIT I
UPDATED

FY 2017 Revised Operating Plan Summary*

Schedule	Forecast	Updated	Difference	
A	$2,537,222	$2,480,440	($56,782)	Operations
B	$3,149,036	$2,999,423	($149,613)	Maintenance
C [1/]	$0	$0	$0	Replacements & Reinforcements
D	$2,485,604	$3,266,580	$780,976	General Plant
E	$146,212	$205,987	$59,775	Other (PacifiCorp)
F	$397,814	$381,573	($16,240)	Contracts & Rates
G	$368,694	$321,058	($47,636)	Transmission Scheduling
H	$0	$0	$0	End of Term
Total	$9,084,581	$9,655,061	$570,480	Total

$9,655,061 / 3450 MW / 12 Months = $233.21 /MW-month

Rounded to $233 for whole-dollar billing

This information is being released externally by BPA on 7/24/2018 as an ad hoc report or analysis generated for a specific purpose. The information provided is based upon data found in Agency Financial Information but may not be found verbatim in an External Standard Financial Report or other Agency Financial Information release.

Notes:

[1/] Schedule C amounts are not included in Totals. Schedule C forecasts are presented separately (attached).

*References to the rate case are from documents that support rate case document BP-16 Final. Budget figures are derived from the IPR documents for 2016/2017.

Capacity Ownership Agreement

FY 2017 Amended Operating Plan

Schedule A for FY 2017

	Line No.	Forecast	Actual	Difference
I. Operations Costs				
A. Allocation Factor				
MFUs of Bonneville's PNW AC Intertie	1	81.0	81.0	
MFUs of the FCRTS	2	3,574	3,574	
MFU Allocation Factor (Line 1/Line 2 calculation rounded to two decimals)	3	2.27%	2.27%	
B. Operations Functionalization Factor				
Bonneville's total transmission-related systems operations cost from the rate case	4	$78,999,106	$79,341,107	
Bonneville's total system operations cost from rate case	5	$78,999,106	$79,341,107	
Operations functionalization factor (Line 4/Line 5)	6	100.00%	100.00%	
C. Allocated Direct Cost				
Bonneville's total system operations direct cost	7	$67,037,127	$72,602,467	$5,565,340
Allocated Direct Cost of Operations Cost (Line 3 * Line 6 * Line 7)	8	$1,519,308	$1,645,439	$126,131
D. Indirect Cost				
Bonneville's total system operations indirect cost	9	$10,939,935	$8,090,268	($2,849,667)
Indirect Cost of Operations Cost (Line 3 * Line 6 * Line 9)	10	$247,939	$183,355	($64,584)
E. Overhead Cost				
Bonneville's total system operations overhead cost	11	$33,973,954	$28,752,841	($5,221,113)
Overhead Cost of Operations Cost (Line 3 * Line 6 * Line 11)	12	$769,975	$651,645	($118,330)
F. Operations Cost (Line 8 + Line 10 + Line 12)	13	$2,537,222	$2,480,440	($56,782)

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Report ID: 0061FY17 | **Run Date/Time: November 07, 2017 06:37**
Requesting BL: TRANSMISSION BUSINESS UNIT | **Data Source: EPM Data Warehouse**
Unit of Measure: $ Thousands | **% of Year Elapsed = 100%**

		A	B	C	D <Note 1	E	F
		FY 2016	FY 2017			FY 2017	FY 2017
		Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals	Actuals per Forecast
	Operating Revenues						
	Sales						
	Network						
1	**Network Integration**	$ 129,695	$ 133,090	$ 131,143	$ 130,617	$ 133,535	102%
2	**Other Network**	436,310	461,684	451,685	442,038	446,492	101%
3	**Intertie**	73,891	78,630	76,368	76,949	76,257	99%
4	**Other Direct Sales**	263,312	270,592	263,557	265,520	265,824	100%
5	**Miscellaneous Revenues**	44,033	39,154	42,431	43,262	41,491	96%
6	**Inter-Business Unit Revenues**	114,459	117,591	112,403	121,945	128,126	105%
7	**Total Operating Revenues**	**1,061,700**	**1,100,742**	**1,077,587**	**1,080,330**	**1,091,725**	**101%**
	Operating Expenses						
	Transmission Operations	2>	2>2>	2>	2>	2>2>	
	System Operations						
8	INFORMATION TECHNOLOGY	9,436	10,558	7,298	10,701	9,903	93%
9	POWER SYSTEM DISPATCHING	13,913	13,671	12,895	13,945	13,722	98%
10	CONTROL CENTER SUPPORT	23,066	18,757	25,178	25,009	23,567	94%
11	TECHNICAL OPERATIONS *<Note 2*	7,750	6,983	14,168	9,979	8,029	80%
12	STRATEGIC INTEGRATION	2,414	7,555	1,607	2,118	2,028	96%
13	SUBSTATION OPERATIONS	23,572	21,817	24,507	24,081	23,444	97%
14	**Sub-Total**	80,151	79,341	85,653	85,833	80,693	94%
	Scheduling						
15	RESERVATIONS	1,167	1,383	1,227	1,044	1,211	116%
16	PRE-SCHEDULING	382	276	284	284	211	74%
17	REAL-TIME SCHEDULING	4,739	5,169	5,789	4,929	5,062	103%
18	SCHEDULING TECHNICAL SUPPORT	3,641	4,259	4,751	4,182	3,656	87%
19	SCHEDULING AFTER-THE-FACT	273	289	277	277	305	110%
20	**Sub-Total**	10,202	11,376	12,328	10,716	10,445	97%
	Marketing and Business Support						
21	TRANSMISSION SALES	2,299	2,775	2,834	2,621	2,524	96%
22	MKTG TRANSMISSION FINANCE	-	-	-	-	-	0%
23	MKTG CONTRACT MANAGEMENT	4,453	4,984	4,946	4,660	4,465	96%
24	MKTG TRANSMISSION BILLING	2,318	3,377	2,433	2,116	2,093	99%
25	MKTG BUSINESS STRAT & ASSESS *<Note 3*	6,836	7,291	6,877	6,651	7,948	119%
26	**Marketing Sub-Total**	15,906	18,426	17,089	16,048	17,030	106%
27	EXECUTIVE AND ADMIN SERVICES	16,630	27,540	28,608	17,753	16,908	95%
28	LEGAL SUPPORT	2,611	3,548	1,641	1,962	2,304	117%
29	TRANS SERVICES INTERNAL GENERAL & ADMINISTRATIVE *<Note 4*	11,047	13,135	14,777	13,522	9,847	73%
30	AIRCRAFT SERVICES	1,094	2,230	2,489	1,839	882	48%
31	LOGISTICS SERVICES	6,685	4,488	4,354	5,151	5,861	114%
32	SECURITY ENHANCEMENTS	889	716	561	561	547	98%
33	**Business Support Sub-Total**	38,957	51,657	52,432	40,789	36,350	89%
34	**Transmission Operations Sub-Total**	**$ 145,216**	**$ 160,800**	**$ 167,501**	**$ 153,386**	**$ 144,518**	**94%**

Pct of Dir & Indirects	Allocation of OH		
24.58%	$ 28,752,841.45	Subtot Programs	$ 328,336,340.61
		Subtot Overhead	$ 116,994,457.86
		Total Costs	$ 445,330,798.47
		$ 3,655,912.96	Scheduling Indirects
		$ 6,788,621.97	Scheduling Directs
3.18%	$ 3,721,649.27	$ 10,444,534.93	Scheduling Total
Included in row 44 (Marketing subtotal) below.			
3.78%	$ 4,423,132.56	$ 12,413,196.18	Subtot Contr &Rates
5.19%	$ 6,068,365.79	$ 17,030,422.24	Marketing
		$ 27,474,957.17	Mktg + Scheduling

Report ID: 0061FY17 — **Run Date/Time: November 07, 2017 06:37**
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Unit of Measure: $ Thousands — **% of Year Elapsed = 100%**

		A	B	C	D <Note 1	E	F
		FY 2016	FY 2017			FY 2017	FY 2017
		Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals	Actuals per Forecast
	Transmission Maintenance						
	System Maintenance						
35	NON-ELECTRIC MAINTENANCE	$ 27,546	$ 31,424	$ 28,233	$ 25,556	$ 28,872	113%
36	SUBSTATION MAINTENANCE	31,125	29,043	32,267	31,353	30,860	98%
37	TRANSMISSION LINE MAINTENANCE	25,564	27,482	31,119	29,851	27,574	92%
38	SYSTEM PROTECTION CONTROL MAINTENANCE	13,222	13,741	14,198	13,837	14,921	108%
39	POWER SYSTEM CONTROL MAINTENANCE	19,095	18,507	19,706	20,706	21,589	104%
40	JOINT COST MAINTENANCE	230	113	8	8	190	2242%
41	SYSTEM MAINTENANCE MANAGEMENT	8,555	9,556	9,495	9,403	8,348	89%
42	ROW MAINTENANCE	7,785	10,162	8,858	8,842	10,401	118%
43	HEAVY MOBILE EQUIP MAINT	312	()	()	-	427	0%
44	TECHNICAL TRAINING	2,719	2,418	2,735	2,735	2,796	102%
45	VEGETATION MANAGEMENT	16,489	17,039	18,480	18,480	16,784	91%
46	**Sub-Total**	152,640	159,485	165,098	160,770	162,762	101%
	Environmental Operations						
47	ENVIRONMENTAL ANALYSIS	6	-	-	-	6	0%
48	POLLUTION PREVENTION AND ABATEMENT	4,808	4,787	4,726	4,121	4,161	101%
49	**Sub-Total**	4,815	4,787	4,726	4,121	4,166	101%
50	**Transmission Maintenance Sub-Total**	**157,455**	**164,272**	**169,824**	**164,891**	**166,929**	**101%**
	Transmission Engineering						
	System Development						
51	RESEARCH & DEVELOPMENT	7,458	9,555	6,961	6,463	8,576	133%
52	TSD PLANNING AND ANALYSIS	18,059	16,738	25,241	21,177	21,601	102%
53	CAPITAL TO EXPENSE TRANSFER	8,951	4,351	4,211	4,227	6,896	163%
54	NERC / WECC COMPLIANCE	14,052	20,422	17,585	16,241	12,684	78%
55	ENVIRONMENTAL POLICY/PLANNING	1,251	1,642	1,633	1,708	1,192	70%
56	ENG RATING AND COMPLIANCE	1,399	2,207	2,298	2,238	2,291	102%
57	**Sub-Total**	51,168	54,915	57,929	52,054	53,240	102%
58	**Transmission Engineering Sub-Total**	**51,168**	**54,915**	**57,929**	**52,054**	**53,240**	**102%**
	Trans. Services Transmission Acquisition and Ancillary Services						
	BBL Acquisition and Ancillary Products and Services						
59	ANCILLARY SERVICES PAYMENTS	103,366	101,027	103,653	102,661	102,947	100%
60	OTHER PAYMENTS TO POWER SERVICES	9,393	9,617	9,395	9,394	9,407	100%
61	STATION SERVICES PAYMENTS	2,595	2,785	2,704	2,704	2,639	98%
62	**Sub-Total**	115,354	113,429	115,752	114,759	114,993	100%
	Non-BBL Acquisition and Ancillary Products and Services						
63	LEASED FACILITIES	7,533	7,447	6,849	6,849	6,128	89%
64	GENERAL TRANSFER AGREEMENTS (SETTLEMENT)	1,344	18	2	2	198	8088%
65	NON-BBL ANCILLARY SERVICES	4,932	18,560	18,865	13,117	11,850	90%
66	OVERSUPPLY DISPLACEMENT COSTS	-	-	-	-	2,239	0%
67	RELIABILITY DEMAND RESPONSE/REDISPATCH	46	1,328	5,155	6,277	5,506	88%
68	**Sub-Total**	13,856	27,353	30,872	26,246	25,921	99%
69	**Trans. Srvcs. Acquisition and Ancillary Services Sub-Total**	**129,210**	**140,782**	**146,623**	**141,005**	**140,914**	**100%**
	Transmission Reimbursables						
	Reimbursables						
70	EXTERNAL REIMBURSABLE SERVICES	13,624	8,615	8,802	8,802	14,459	164%
71	INTERNAL REIMBURSABLE SERVICES	1,752	1,120	1,120	1,121	1,187	106%
72	**Sub-Total**	15,376	9,735	9,922	9,923	15,646	158%
73	**Transmission Reimbursables Sub-Total**	**$ 15,376**	**$ 9,735**	**$ 9,922**	**$ 9,923**	**$ 15,646**	**158%**

TLM ROW VEG
$ 54,759,896
SUB Maint
$ 30,860,406

$ 36,509,900.95 SPC+PSC
$ 11,570,907.11 Mtc. Indirects
$ 155,357,995.65 Dir Mtc less Indirects

50.84% $ 59,480,947.02

16.22% $ 18,970,654.33
8562030295.78% $ 121,417,590.42 Total Allocation incl. Contr. & Rates.
8562030292.00% $ 116,994,457.86 Total Allocations

Report ID: 0061FY17
Requesting BL: TRANSMISSION BUSINESS UNIT
Unit of Measure: $ Thousands

Run Date/Time: November 07, 2017 06:37
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% of Year Elapsed = 100%

		A	B	C	D <Note 1	E	F
		FY 2016	FY 2017			FY 2017	FY 2017
		Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals	Actuals per Forecast
	BPA Internal Support						
74	**Additional Post-Retirement Contribution**	$ 16,440	$ 19,748	$ 17,023	$ 14,672	$ 13,920	95%
75	**Agency Services G & A** (excludes direct project support)	71,144	64,775	73,647	66,825	66,724	100%
76	**BPA Internal Support Subtotal**	**87,584**	**84,523**	**90,670**	**81,497**	**80,644**	**99%**
	Other Income, Expenses, and Adjustments						
77	**Bad Debt Expense**	**10**	**-**	**-**	**10**	**48**	**490%**
78	**Other Income, Expenses, Adjustments**	**(6,737)**	**-**	**-**	**245**	**(1,093)**	**-546%**
79	**Undistributed Reduction**	**-**	**(2,100)**	**(11,688)**	**-**	**-**	**0%**
80	**Depreciation**	**241,985**	**257,416**	**257,416**	**257,866**	**258,767**	**100%**
81	**Amortization**	**2,174**	**2,132**	**2,132**	**2,152**	**2,160**	**100%**
82	**Total Operating Expenses**	**823,440**	**872,475**	**890,328**	**863,029**	**861,773**	**100%**
83	**Net Operating Revenues (Expenses)**	**238,260**	**228,267**	**187,259**	**217,302**	**229,952**	**106%**
	Interest Expense and (Income)						
84	**Federal Appropriation**	14,059	8,954	8,628	8,628	8,628	100%
85	**Capitalization Adjustment**	(18,968)	(18,968)	(18,968)	(18,968)	(18,968)	100%
86	**Borrowings from US Treasury**	91,889	138,723	93,979	95,024	94,921	100%
87	**Debt Service Reassignment**	24,114	15,810	15,601	14,341	14,341	100%
88	**Customer Advances**	5,648	6,041	4,738	4,646	4,454	96%
89	**Lease Financing**	54,614	55,408	69,878	61,024	60,745	100%
90	**AFUDC**	(31,042)	(41,346)	(24,342)	(21,000)	(21,577)	103%
91	**Interest Income**	(3,957)	(16,310)	(3,875)	(3,093)	(3,045)	98%
92	**Net Interest Expense (Income)**	**136,358**	**148,313**	**145,640**	**140,601**	**139,499**	**99%**
93	**Total Expenses**	**959,798**	**1,020,788**	**1,035,968**	**1,003,630**	**1,001,272**	**100%**
94	**Net Revenues (Expenses)**	**$ 101,902**	**$ 79,954**	**$ 41,619**	**$ 76,700**	**$ 90,453**	**118%**

<1 Although the forecasts in this report are presented as point estimates, BPA operates a hydro-based system that encounters much uncertainty regarding water supply and wholesale market prices. These uncertainties, among other factors, may result in large range swings +/- impacting the final results in revenues, expenses, and cash reserves.

<2 Technical Operations project reporting includes the 2017 KSI project Commercial Operations.

<3 Marketing Business Strategy and Assessment project reporting includes the three 2017 KSI projects Long-term Finance and Rates, Asset Management and Business Information Systems.

<4 Transmission Services Internal General & Administrative reporting includes the 2017 KSI project Safety and Occupational Health.

Capacity Ownership Agreement

FY 2017 Amended Operating Plan

Schedule B for FY 2017

	Line No.	Forecast	Actual	Difference
II. Maintenance Cost				
A. Power System Control (PSC) Maintenance Functionalization Factor				
Bonneville's transmission-related PSC maintenance cost from rate case	1	$32,248,588	$32,248,588	0
Bonneville's total PSC maintenance cost from rate case	2	$32,248,588	$32,248,588	0
PSC maintenance functionalization factor (Line 1/Line2)	3	100.00%	100.00%	
B. Direct Cost				
Total PSC direct maintenance cost	4	$32,248,588	$36,509,901	$4,261,313
MFU Allocation Factor (Schedule A, Line 3 rounded to two decimals)	5	2.27%	2.27%	
PSC direct maintenance cost Bonneville's PNW AC Intertie (Line 4 * Line 3 * Line 5)	6	$730,872	$827,449	$96,577
Bonneville's direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost	7	$1,328,761	$1,230,696	($98,065)
Direct Cost of Maintenance Cost (Line 6 + Line 7)	8	$2,059,633	$2,058,145	($1,488)
C. Allocation Factor				
Bonneville's total system maintenance direct cost	9	$153,648,714	$155,357,996	$1,709,282
Allocation factor for Indirect Cost and Overhead Cost (Line 8/Line 9)	10	1.34%	1.32%	
D. Indirect Cost				
Bonneville's total system maintenance indirect cost	11	$10,623,459	$11,570,907	$947,448
Indirect Cost of Maintenance Cost (Line 11 * Line 10)	12	$142,406	$153,289	$10,883
E. Overhead Cost				
Bonneville's total system maintenance overhead cost	13	$70,646,056	$59,480,947	($11,165,109)
Overhead Cost of Maintenance Cost (Line 13 * Line 10)	14	$946,997	$787,989	($159,008)
F. Maintenance Cost (Lines 8 + 12 + 14)	**15**	**$3,149,036**	**$2,999,423**	($149,613)

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Capacity Ownership Agreement
FY 2017
Operating Plan
EXHIBIT I
Schedule C Table of Contents

This revision is to: 1) update the former Estimated Energization Date column to read "Work Order Completion Date"; 2) add in a work order status column; 3) update for work orders added (see red font and "Billed"; 4) update for work orders cancelled (see red font and "CANCELLED"); 5) updated work order completion dates; 6) update for work orders BILLED or COMPLETE (see red font); 7) renumbered page numbers (see red font); 8) key and notes added on page 7.

Capacity Ownership Agreement
FY 2017
Operating Plan
EXHIBIT I
Schedule C Table of Contents

Capacity Ownership Agreement
FY 2017
Operating Plan
EXHIBIT I
Schedule C Table of Contents

Below is information about work orders added or removed, acronyms and further information.

Note 1: For Exhibit I Schedule Cs billed, please refer to the letter previously provided per date stated above.

Note 2: The status of TBD Alvey Dix 01 project is determined each individual fiscal year. For FY 2017, the TBD Alvey Dix 01 has been removed from this FY 2017 operating plan.

Key:

Project (BPA) Work Order Status is for BPA project information prior to BPA Active (or Pending) work order status or prior to establishing a BPA work order number

Project (PAC) Work Order Status is for project information provided to BPA in April 2017 and June 2018 prior to establishing a BPA work order number

FY 2017 Schedule C

Project Work Order: **00248443**
Project Short Description: **Install a New Shunt Reactor**
Project Facility: **Alvey Substation**
Exhibit F Section: **B.1. Alvey 500 kV Switchyard**
Percent of Project cost applied to PNW AC Intertie: **100%**
Estimated Energization Date: **2/24/2017**
Status: **COMPLETE**
Contract Section 9(b)(2)(B) Date:

	Line No.	Forecast	Actual	Less General Plant	Adjusted Actuals	Difference
III. Replacement Costs and Reinforcement Costs						
A. Direct Cost						
Direct Costs of Replacements and Reinforcements	1	$9,939,138				
B. Indirect Cost and Overhead Costs						
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2	$4,969,569				
C. AFUDC						
AFUDC of Replacements and Reinforcements	3	$2,618,206				
D. Interest						
Interest Costs of Replacements and Reinforcements (Interest Calculated without plant costs)	4					
E. Total Replacement Costs and Reinforcement Costs (Lines 1 + 2 + 3 + 4)	5	$17,526,913				

Notes:

1/ A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement. The amounts shown above are for the work order; each customer will be billed its pro-rata share of the total adjusted actual.

2/ Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

3/ Allowance for Funds Used During Construction (AFUDC) represents the estimated cost of interest on financing the construction of all BPA capital projects or BPA portion of capital projects. In instances where BPA owns a portion of the asset then BPA will only apply AFUDC to its portion of the asset.

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FY 2017 Schedule C

Project Work Order: **00329379**
Project Short Description: **Access Road Improvements**
Project Facility: **Marion-Alvey No. 1**
Exhibit F Section: **A.11. Marion-Alvey 500 kV**
Percent of Project cost applied to PNW AC Intertie: **50%**
Estimated Energization Date: **12/15/2017**
Status: **COMPLETE**
Contract Section 9(b)(2)(B) Date:

	Line No.	Forecast	Actual	Less General Plant	Adjusted Actuals	Difference
III. Replacement Costs and Reinforcement Costs						
A. Direct Cost						
Direct Costs of Replacements and Reinforcements	1	$728,732				
B. Indirect Cost and Overhead Costs						
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2	$364,366				
C. AFUDC						
AFUDC of Replacements and Reinforcements	3	$126,402				
D. Interest						
Interest Costs of Replacements and Reinforcements (Interest Calculated without plant costs)	4					
E. Total Replacement Costs and Reinforcement Costs (Lines 1 + 2 + 3 + 4)	5	$1,219,500				

Notes:

1/ A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement. The amounts shown above are for the work order; each customer will be billed its pro-rata share of the total adjusted actual.

2/ Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

3/ Allowance for Funds Used During Construction (AFUDC) represents the estimated cost of interest on financing the construction of all BPA capital projects or BPA portion of capital projects. In instances where BPA owns a portion of the asset then BPA will only apply AFUDC to its portion of the asset.

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FY 2017 Schedule C

Project Work Order: **00339242**
Project Short Description: **Replace Remedial Action Scheme, Transfer Trip Equipment and Line Loss Relays on the Dixonville 500 kV line**
Project Facility: **Alvey Substation**
Exhibit F Section: **B.5. Alvey 500 kV**
Percent of Project cost applied to PNW AC Intertie: **100%**
Estimated Energization Date: **8/30/2017**
Status: **COMPLETE**
Contract Section 9(b)(2)(B) Date:

	Line No.	Forecast	Actual	Less General Plant	Adjusted Actuals	Difference
III. Replacement Costs and Reinforcement Costs						
A. Direct Cost						
Direct Costs of Replacements and Reinforcements	1	$1,222,998				
B. Indirect Cost and Overhead Costs						
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2	$611,499				
C. AFUDC						
AFUDC of Replacements and Reinforcements	3	$182,585				
D. Interest						
Interest Costs of Replacements and Reinforcements (Interest Calculated without plant costs)	4					
E. Total Replacement Costs and Reinforcement Costs (Lines 1 + 2 + 3 + 4)	5	$2,017,082				

Notes:

1/ A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement. The amounts shown above are for the work order; each customer will be billed its pro-rata share of the total adjusted actual.

2/ Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

3/ Allowance for Funds Used During Construction (AFUDC) represents the estimated cost of interest on financing the construction of all BPA capital projects or BPA portion of capital projects. In instances where BPA owns a portion of the asset then BPA will only apply AFUDC to its portion of the asset.

4/ Pursuant to Contract No. DE-MS-94BP94332 this Schedule C has had the 50% PacifiCorp costs removed from this work order.

5/ The costs in the Line #1 are from PacifiCorp information provided April 2017 to BPA.

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Schedule D for FY 2017

IV. General Plant Cost

	Line No.	Allocated Actual	Allocated Forecast
Bonneville's total general plant investment ***[From D-1, D-2]***	1	$1,260,992,898	$1,066,479,917
Bonneville's Dittmer control equipment investment ***[From D-4A]***	2	$128,920,000	$128,920,000
General plant investment of lines 1 and 2 functionalized to generation ***[From D-4B]***	3	$262,279,000	$262,279,000
General plant investment recovered from all Capacity Owners in Adjusted Capacity Ownership Price and Revised Adjusted Capacity Ownership Price ***[From D-5]***	4	$1,435,350	$1,435,350
General plant investment recovered from Capacity Owners for Upgrades	5	0	0
Adjusted general plant investment functionalized to transmission ***[From D-3]*** (Line 1 + Line 2 - Line 3 - Line 4 - Line 5)	6	$1,126,198,548	$931,685,567
BPA total annual cost of Line 6 general plant investment ***[From D-3]***	7	$62,692,114	$49,594,573
BPA total transmission plant-in-service investment (not including general plant investment) from Segmentation Study ***[From D-6]***	8	$7,866,227,461	$7,866,227,461
ACR for Bonneville's PNW AC Intertie (Line 7/Line 8 Calculation rounded to two decimals)	9	0.80%	0.63%
Bonneville's PNW AC Intertie investment from Segmentation Study ***[From D-7, D-8]***	10	$408,322,489	$394,540,336
General Plant Cost (Line 9 * Line 10)	**11**	**$3,266,580**	**$2,485,604**

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FY 2017 Schedule C

Project Work Order: **00339242**
Project Short Description: **Replace Remedial Action Scheme, Transfer Trip Equipment and Line Loss Relays on the Dixonville 500 kV line**
Project Facility: **Alvey Substation**
Exhibit F Section: **B.5. Alvey 500 kV**
Percent of Project cost applied to PNW AC Intertie: **100%**
Estimated Energization Date: **8/30/2017**
Status: **COMPLETE**
Contract Section 9(b)(2)(B) Date:

	Line No.	Forecast	Actual	Less General Plant	Adjusted Actuals	Difference
III. Replacement Costs and Reinforcement Costs						
A. Direct Cost						
Direct Costs of Replacements and Reinforcements	1	$1,222,998				
B. Indirect Cost and Overhead Costs						
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2	$611,499				
C. AFUDC						
AFUDC of Replacements and Reinforcements	3	$182,585				
D. Interest						
Interest Costs of Replacements and Reinforcements (Interest Calculated without plant costs)	4					
E. Total Replacement Costs and Reinforcement Costs (Lines 1 + 2 + 3 + 4)	5	$2,017,082				

Notes:

1/ A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement. The amounts shown above are for the work order; each customer will be billed its pro-rata share of the total adjusted actual.

2/ Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

3/ Allowance for Funds Used During Construction (AFUDC) represents the estimated cost of interest on financing the construction of all BPA capital projects or BPA portion of capital projects. In instances where BPA owns a portion of the asset then BPA will only apply AFUDC to its portion of the asset.

4/ Pursuant to Contract No. DE-MS-94BP94332 this Schedule C has had the 50% PacifiCorp costs removed from this work order.

5/ The costs in the Line #1 are from PacifiCorp information provided April 2017 to BPA.

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Description	Investment [1]	Cap Recovery [2]	Amount
Land	879,420	0.0642	56,459
Buildings	262,128,864	0.0178	4,665,894
	263,008,284		4,722,353
M.W./Hydr/Radio/Comm	686,359,076	0.0600	41,181,545
Office Furniture	1,729,500	0.0527	91,145
Data Processing	44,168,694	0.1327	5,861,186
Software	59,164,104	0.1710	10,117,062
Transportation	60,493,993	0.0333	2,014,450
Helicopter	9,234,320	0.0332	306,579
Airplane	8,656,306	0.0630	545,347
Stores Equipment	3,809,093	0.0391	148,936
Tools Shop Garage	13,836,541	0.0410	567,298
Laboratory Equipment	30,935,963	0.0688	2,128,394
Power Operated Equipment	30,234,379	0.0540	1,632,656
Miscellaneous	49,362,645	0.0670	3,307,297
Total General Plant	**1,260,992,898**	***[To Schedule D, Line 1]***	72,624,248

[1] Source: Summary Utility for the period ending 9/30/2017 (Worksheet D-2) from FRP.

[2] Source: Depreciation Study, Calculated Annual Depreciation Accruals Related to Electric Plant at September 30, 2010, pgs III-4 and III-5. This depreciation study was completed February 2012 and was effective March 2012.

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B/L		FERC ACCT	PEOPLESOFT BEG. BALANCE 9/30/2016	ADDITIONS	RETIREMENTS	ADJUSTMENTS	PEOPLESOFT ENDING BALANCE 9/30/2017	
General Plant								To D-1
T	LAND-GENERAL PLANT	3890	667,022	212,399	0	0	879,420	
T	STRUCTURES/IMPROVEMENTS	3900	257,771,240	4,357,624	0	0	262,128,864	
T	OFFICE FURNITURE	3911	1,729,500	0	0	0	1,729,500	
T	DATA PROCESS EQUIPMENT	3912	37,844,323	8,272,935	1,948,564	0	44,168,694	
T	SOFTWARE	3913	54,226,141	16,650,835	11,712,872	0	59,164,104	
T	ROLLING STOCK	3921	56,037,627	5,182,593	726,227	0	60,493,993	
T	HELICOPTERS	3922	9,234,320	0	0	0	9,234,320	
T	AIRPLANES	3923	8,656,306	0	0	0	8,656,306	
T	STORES EQUIPMENT	3930	3,728,800	80,293	0	0	3,809,093	
T	TOOLS/SHOP/GARAGE EQUIP	3940	11,429,857	2,406,684	0	0	13,836,541	
T	LABORATORY EQUIP (PORT)	3950	27,776,612	3,326,336	166,986	0	30,935,963	
T	POWER OPERATED EQUIP	3960	28,927,623	1,953,872	647,115	0	30,234,379	
T	COMMUNICATION EQUIP-PORT	3970	661,795,904	39,145,361	14,445,862	(136,326.73)	686,359,076	
T	MISC EQUIP	3980	46,923,431	3,476,423	1,037,210	0	49,362,645	
Total General Plant				***[To Schedule D, Line 1]***			1,260,992,898	

Source: Plant and ML Rollforward (FRP J. Guillard)
Bonneville Power Administration
Summary Utility
For the period ending September 30, 2017
Peoplesoft Plant Investment

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ADJUSTMENTS TO GENERAL PLANT ANNUAL COST CALCULATION

Schedule D Adjustments	Investment	Cap Recovery	Amount
additions:			
BPA Dittmer control equip investment (FERC 353)	128,920,000	0.0218	2,810,456
[From D-4A To Schedule D, Line 2]			
subtractions:			
Functionalized to Generation			
[Values from D-4A]			
FERC 353	(128,920,000)	0.0218	(2,810,456)
FERC 390	0	0.0178	0
FERC 391.1	0	0.0527	0
FERC 391.2	(13,103,000)	0.1327	(1,738,768)
FERC 391.3	(8,035,000)	0.1710	(1,373,985)
FERC 392.3	0	0.0630	0
FERC 397	(112,221,000)	0.0600	(6,733,260)
[Equals amount on Schedule D-4A]	(262,279,000)		(12,656,469)
General Plant recovered in CO-94 lump sum payment *(Mostly FERC 397)*	(1,435,350)	0.0600	(86,121)
[From D-5]			
Total adjustments	(134,794,350)		(9,932,134)
Total General Plant ***[From D-1, D-2]***	1,260,992,898		72,624,248
Schedule D Total General Plant	1,126,198,548		
[Equals amount on Schedule D, Line 6]			
Schedule D annual cost of Adjusted General Plant			62,692,114
		[To Schedule D, Line 7]	

This is based on the depreciation study that was completed Feburary 2012 and was effective March 2012.
This is the most recent depreciation study.

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ANCILLARY SERVICES
PLANT-IN-SERVICE
($ THOUSANDS)

Totals by Year	**FERC ACCOUNT**				**2014**	**FERC ACCOUNT**				**2015**	**FERC ACCOUNT**				**2016**	**FERC ACCOUNT**				**2017**
	353	**391.2**	**391.3**	**397**	**TOTAL**	**353**	**391.2**	**391.3**	**397**	**TOTAL**	**353**	**391.2**	**391.3**	**397**	**TOTAL**	**353**	**391.2**	**391.3**	**397**	**TOTAL**
Sched, Syst Control, and Disp Serv [1]	77,904	13,103	5,074	51,272	147,353	90,655	13,103	6,288	74,788	184,834	104,953	13,103	7,709	105,245	231,010	128,920	13,103	8,035	112,221	262,279
Total Plant-in-Service	77,904	13,103	5,074	51,272	147,353	90,655	13,103	6,288	74,788	184,834	104,953	13,103	7,709	105,245	231,010	128,920	13,103	8,035	112,221	262,279

ANCILLARY SERVICES
PLANT ADDITIONS [2]
($ THOUSANDS)

Additions included in above totals by year	**FERC ACCOUNT**				**2015**	**FERC ACCOUNT**				**2016**	**FERC ACCOUNT**				**2017**
	353	**391.2**	**391.3**	**397**	**TOTAL**	**353**	**391.2**	**391.3**	**397**	**TOTAL**	**353**	**391.2**	**391.3**	**397**	**TOTAL**
Sched, Syst Control, and Disp Serv [1]	12,751	0	1,214	23,516	37,481	14,298	0	1,421	30,457	46,176	23,967	0	326	6,976	31,269
Total Additions	12,751	0	1,214	23,516	37,481	14,298	0	1,421	30,457	46,176	23,967	0	326	6,976	31,269

[1] Equals Bonneville's Dittmer control equipment investment

[2] Totals shown for Additions for each year are already included in the Totals by Year for that year

From BP-16 Final Proposal provided by M. (Gestrin) McGraw 4/30/18

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CAPACITY OWNERSHIP AGREEMENT
FY 2017 OPERATING PLAN
SCHEDULE D-4B WORKSHEET

BPA GENERAL PLANT
CUMULATIVE PLANT INVESTMENT
($ THOUSANDS)

		FERC ACCT	ANCILL SERV	TRANS	2015 TOTAL	ANCILL SERV	TRANS	2016 TOTAL	ANCILL SERV	TRANS	2017 TOTAL
1	LAND & LAND RIGHTS	389	0	11,920	11,920		20,866	20,866		29,758	29,758
2	STRUCTURES & IMPROVEMENTS	390	0	245,923	245,923		310,421	310,421		350,278	350,278
3	OFFICE FURNITURE & FIXTURES	391.1	0	1,696	1,696		1,696	1,696		1,696	1,696
4	DATA PROCESSING -EQUIPMENT	391.2	13,103	556	13,659	13,103	556	13,659	13,103	556	13,659
5	DATA PROCESSING -SOFTWARE	391.3	6,288	37,795	44,083	7,709	44,478	52,187	8,035	50,662	58,697
6	TRANSPORT EQUIPMENT	392.1	0	62,309	62,309		67,925	67,925		74,040	74,040
7	HELICOPTERS	392.2	0	9,234	9,234		9,234	9,234		9,234	9,234
8	AIRPLANES	392.3	0	8,656	8,656		8,656	8,656		8,656	8,656
9	STORES EQUIPMENT	393	0	3,006	3,006		3,006	3,006		3,006	3,006
10	TOOLS, SHOP & GARAGE EQUIPMENT	394	0	14,107	14,107		17,872	17,872		21,821	21,821
11	LAB EQUIPMENT	395	0	25,593	25,593		25,593	25,593		25,593	25,593
12	POWER OPERATED EQUIPMENT	396	0	27,832	27,832		27,832	27,832		27,832	27,832
13	COMMUNICATIONS EQUIPMENT	397	74,788	470,998	545,786	105,245	489,815	595,060	112,221	525,461	637,682
14	MISC EQUIPMENT	398	0	39,554	39,554		39,554	39,554		39,554	39,554
15	SUBTOTAL GENERAL PLANT		94,179	959,178	1,053,357	126,057	1,067,503	1,193,560	133,359	1,168,146	1,301,505
16	STATION EQUIPMENT	353	90,655	0	90,655	104,953	0	104,953	128,920	0	128,920
17	**TOTAL GENERAL PLANT**		184,834	959,178	1,144,012	231,010	1,067,503	1,298,513	262,279	1,168,146	1,430,425

⇧

[To Schedule D, Line 3]

From BP-16 Final Proposal provided by M. (Gestrin) McGraw 4/30/18

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Capacity Owners - Actual 08/97
BY WORK ORDER

Budget Item	**General Plant**		
Alvey (Marion-Alvey Caps) Total	11,104	100%	11,104
Slatt (Loop in - 1 Breaker) Total	0		
Grizzly (7 BPA Breakers) Total	27,859	100%	27,859
Loop into Slatt Total	0		
Malin-Meridian Loop into Captain Jack Total	0		
Alvey-BPA (Includes Marion Sub work) Total	160,294	100%	160,294
Dixonville- PP&L Total	0		
Meridian-PP&L Total	0		
Power System Control - BPA Total	87,010	100%	87,010
Alvey-Spencer - BPA (Land & Pre Engineering only) Total	0		
Spencer-Dixonville - PP&L Total	0		
Dixonville-Meridian - PP&L Total	0		
Captain Jack Breakers Total	839,370	50%	419,685
Captain Jack (Comm & Control) Total	561,390	50%	280,695
Captain Jack (Series Caps) Total	0		
Power System Control & Misc Total	897,405	50%	448,703
Captain Jack-OR/Cal Border Total	0		
	2,584,432		1,435,350

[To Schedule D, Line 4]

Note: Per Jim Dowty, these are original amounts and do not change.
Source: E. Doyle - 6/12/98

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BONNEVILLE POWER ADMINISTRATION
PROJECTED TRANSMISSION PLANT INVESTMENT
($ THOUSANDS)

	TOTAL 2014 INVEST	2015 ADDITIONS	TOTAL 2015 INVEST	2016 ADDITIONS	TOTAL 2016 INVEST	2017 ADDITIONS	TOTAL 2017 INVEST
GENERATION-INTEGRATION	99,827	0	99,827	0	99,827	0	99,827
NETWORK	5,389,747	308,870	5,698,618	394,218	6,092,835	285,745	6,378,581
SOUTHERN INTERTIE	835,569	26,007	861,576	23,091	884,667	294,633	1,179,300
EASTERN INERTIE	118,197	189	118,386	83	118,469	79	118,548
UTILITY DELIVERY	11,475	49	11,524	58	11,582	41	11,623
DSI DELIVERY	10,333	0	10,333	0	10,333	0	10,333
REGULATORY ASSET	56,083	655	56,738	771	57,509	949	58,458
INTANGIBLE PLANT	9,559		9,559	0	9,559	0	9,559
ANCILLARY SERVICES	147,353	37,481	184,833	46,176	231,009	31,269	262,278
GENERAL PLANT	944,193	122,773	1,066,967	125,322	1,192,288	113,762	1,306,050
TOTAL BPA	7,622,335	496,024	8,118,359	589,718	8,708,077	726,479	9,434,556
GENERAL PLANT/ANC SERV	(1,091,546)		(1,251,800)		(1,423,297)		(1,568,329)
TOTAL LESS GP/ANC SERV	6,530,789		6,866,559		7,284,780		7,866,227

[To Schedule D, Line 8]

From BP-16 Final Proposal provided by M. (Gestrin) McGraw 4/30/18

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SUBSTATION INVESTMENT ($)
As of May 06, 2018
SOUTHERN AC INTERTIE

ID #	Name	Investment
10000656	ROUND MOUNTAIN SUBSTATION	65,046
10000121	CHIEF JOSEPH SUBSTATION	1,283,281
10000477	MARION SUBSTATION	3,493,420
10000776	SUMMER LAKE SUBSTATION	3,969,153
10000737	SLATT SUBSTATION	4,094,898
10000060	BUCKLEY SUBSTATION	6,512,717
10000019	ALVEY SUBSTATION	8,569,823
10000197	DIXONVILLE SUBSTATION	7,837,854
10000499	MERIDIAN SUBSTATION(PACIFICORP)	9,354,973
10000390	JOHN DAY SUBSTATION	13,538,980
10000784	SYCAN COMPENSATION STATION	16,203,749
10000269	FORT ROCK COMPENSATION STATION	17,681,028
10000713	SAND SPRING COMPENSATION STATION	18,401,359
10000033	BAKEOVEN COMPENSATION STATION	22,847,075
10000474	MALIN SUBSTATION	29,043,051
10000314	GRIZZLY SUBSTATION	33,620,708
10000162	CAPTAIN JACK SUBSTATION	42,644,102
Total	Southern AC Intertie	239,161,217

[To Schedule D,
Line 10 (Add with D-8)]

Original Source: Materials prepared by for BP-20 rate case Appendix A
Updated 06/26/2018 by Andrew Loescher

[1] Multi-segment allocation updated per segmentation study analysis as of April 17, 2017.

[2] Metering equipment at Round Mountain added in Fiscal Year 2012.

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TRANSMISSION LINE INVESTMENT ($)
As of May 09, 2018
SOUTHERN AC INTERTIE

ID #	Name of Line	Investment
	Multi-Segment Lines:	
20000095	Buckley-Grizzly No. 1@ 57%	9,961,133
20000096	Buckley-Marion No. 1 @ 50%1	21,425,547
20000249	Grizzly-Summer Lake No. 1 @ 57%[2]	19,480,851
20000351	Marion-Alvey No. 1 @ 50%	6,046,722
20000372	Coyote Springs-Slatt No 1*	328,931
20000529	Slatt-John Day No. 1*[3]	328,108
Total Multi-Segment Lines		57,571,292
20000102	Captain Jack-Malin No. 1	844,154
20000103	Captain Jack-Olinda No. 1	7,393,503
20000248	Grizzly-Captain Jack No. 1[4]	22,226,974
20000289	John Day-Grizzly No. 1[5]	12,099,924
20000290	John Day-Grizzly No. 2[6]	10,521,016
20000615	Alvey-Dixonville No. 1	25,192,398
20000616	Dixonville-Meridian	33,312,011
Total Southern AC Intertie		169,161,272

[To Schedule D,
Line 10 (Add with D-7)]

Original Source: Materials prepared by for BP-20 rate case Appendix A
Updated 06/26/2018 by Andrew Loescher

[1] Also includes IDs# 20001337, 20001338 associated with leased costs for Buckley-Marion No. 1
[2] Also includes IDs# 20000911, 20000912, 20000913 associated with leased costs for Grizzly-Summer Lake No. 1
[3] Also includes IDs# 20000972 & 20000973 associated with leased costs for Slatt-John Day No. 1
[4] Also includes IDs # 20000922 & 2000923 associated with leased costs for Grizzly-Captain Jack No. 1
[5] Also includes IDs # 20000908, 2000909, 2000910 associated with leased costs for John Day-Grizzly No. 1
[6] Also includes IDs # 20000924, 2000925, 2000926 associated with leased costs for John Day-Grizzly No. 2
*The PNW AC Intertie Capacity Ownership Agreement (Exhibit F) provides that the costs of looping the McNary-John Day line into Slatt were to be allocated to the Southern Intertie segment. These costs are now identified as part of the Coyote Springs-Slatt No 1 and Slatt-John Day No 1 lines.

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FY 2017 Amended Operating Plan

Schedule E for FY 2017

	Line No.	Forecast	Actual	Difference
V. Other Costs				
A. PacifiCorp and Related Costs	1	$146,212	$205,987	$59,775
B. Other PNW AC Intertie Costs	2			
C. Total Other Costs	**3**	**$146,212**	**$205,987**	**$59,775**

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FY 2017 Amended Operating Plan

Schedule F for FY 2017

	Line No.	Forecast	Actual	Difference
VI. Contracts and Rates				
A. Contracts and Rates Functionalization Factor				
Transmission-related contracts and rates cost from rate case	1	$12,274,289	$12,274,289	
Total contracts and rates cost from rate case	2	$12,274,289	$12,274,289	
Contracts and rates cost functionalization factor (Line 1/Line 2)	3	100.00%	100.00%	
B. Allocation Factor				
MFU allocation factor (Schedule A, Line 3 rounded to two decimals)	4	2.27%	2.27%	
C. Total Contracts and Rates Costs				
Contracts and rates direct costs	5	$12,274,289	$12,413,196	$138,907
Contracts and rates indirect costs	6			
Contracts and rates overhead costs	7	$5,278,618	$4,423,133	-$855,485
Bonneville's total contracts and rates costs (Line 5 + Line 6 + Line 7)	8	$17,552,907	$16,836,329	-$716,578
D. Contracts and Rates Cost (Line 8 * Line 3 * Line 4)	**9**	**$397,813.51**	**$381,573.21**	**($16,240.30)**

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FY 2017 Amended Operating Plan

Schedule G for FY 2017

	Line No.	Forecast	Actual	Difference
VII. Transmission Scheduling Costs				
A. Transmission Scheduling Functionalization Factor				
Transmission scheduling costs from rate case	1	$11,375,812	$11,375,812	0
Total **transmission** scheduling cost from rate case	2	$11,375,812	$11,375,812	0
Transmission scheduling cost funcionalization factor (Line 1/Line 2)	3	100.00%	100.00%	
B. Allocation Factor				
MFU allocation factor (Schedule A, Line 3 rounded to two decimals)	4	2.27%	2.27%	
C. Total Transmission Scheduling Costs				
Transmission scheduling direct costs	5	$7,116,689	$6,788,622	-$328,067
Transmission scheduling indirect costs	6	$4,259,123	$3,655,913	-$603,210
Transmission scheduling overhead costs	7	$4,892,224	$3,721,649	-$1,170,575
Bonneville's total **transmission** scheduling costs (Line 5 + Line 6 + Line 7)	8	$16,268,036	$14,166,184	-$2,101,852
D. Transmission Scheduling Cost (Line 8 * Line 3 * Line 4)	**9**	**$368,694**	**$321,058**	**($47,636)**

FY 2017 Amended Operating Plan

Schedule H for FY 2017

	Line No.	Forecast	Actual	Difference
VIII. End of Term Costs				
A. Direct Cost				
Direct Cost of End of Term Costs	1	$0		
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of End of Term Costs	2	$0		
C. Credits				
Credits from decommissioning PNW AC Intertie facilities	3	$0		
D. End of Term Costs	4	$0		

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Contract No. DE-MS79-94BP94613

Portland General Electric Company

September 15, 1994

VIA FACSIMILE AND MAIL

Mr. Walter E. Pollock
Group Vice President for
Marketing, Conservation and Production
Transmission Branch - PMT
Bonneville Power Administration
PO Box 3621
Portland OR 97208-3621

Dear Walt:

By letter dated July 7, 1994, Portland General Electric Company (PGE) notified the Bonneville Power Administration (Bonneville) that PGE was withholding its consent to Bonneville's entering into the PNW AC Intertie Capacity Ownership Agreement (Capacity Ownership Agreement). Without agreeing that PGE has withheld consent as required by Section 16 of the BPA-PGE Intertie Agreement, Contract No. DE-MS79-87BP92340 (Intertie Agreement), and without waiving any rights pursuant to Section 16 of the Intertie Agreement, BPA has participated in discussions with PGE regarding the conditions under which PGE would grant its consent to Bonneville's entering into the Capacity Ownership Agreement. PGE and Bonneville agree to the following terms:

1. Pursuant to Section 16 of the Intertie Agreement, PGE consents to Bonneville's execution of the Capacity Ownership Agreement, as provided to PGE for review on June 29, 1994, with various Northwest parties for up to 725 MW.

2. Bonneville represents and warrants that Bonneville's execution of and performance under the Capacity Ownership Agreement and any operating procedures established thereunder will not have any material adverse effect on PGE's rights and benefits and will not materially increase PGE's obligations under the Intertie Agreement. Without limiting the foregoing Bonneville agrees to the following:

   (a) Real Time Scheduling. While real time scheduling is not contemplated specifically in the Intertie Agreement, Bonneville has operated such that PGE enjoys real time scheduling. Bonneville agrees to continue that past scheduling practice with PGE and does not intend that specific relationships with new owners of Bonneville's PNW AC Intertie capacity (New Owners) change in any way the practice with PGE. Bonneville warrants that real time scheduling rights granted the New Owners shall not degrade the reliability of AC Intertie schedules, and Bonneville will accept all responsibility for failures to keep frequencies stable on the Intertie due to failure of any New Owner to honor their schedules.

Bonneville agrees that it will not withhold its consent to PGE's assignment to a Scheduling Utility, as defined in the Capacity Ownership Agreement, pursuant to Section 16 of the Intertie Agreement for the reason that the assignee will be allowed to schedule directly with the Joint Intertie Scheduling Office, as defined in the Intertie Agreement, in a manner similar to that set forth in Section 4(b) of the Capacity Ownership Agreement.

(b) Upgrades. Bonneville warrants that commitments made to the New Owners in Section 5 of the Capacity Ownership Agreement to consult them regarding upgrades will not interfere with the existing rights and obligations of PGE under Section 9 of the Intertie Agreement regarding decisions for upgrades or reinforcements to the AC Intertie. Specifically, plans of service will be developed and approved as specified in the Intertie Agreement with the New Owners having no rights to dictate, initiate, or approve the development of plans of service for modifications of or additions to the PNW AC Intertie facilities, or as such development and approval may be otherwise agreed to by Bonneville and PGE.

(c) Operation and Maintenance. Bonneville warrants that in giving fair consideration to the needs of the New Owners pursuant to Section 7 of the Capacity Ownership Agreement such consideration will not degrade PGE's rights or reduce Bonneville's obligations as set forth in Sections 6(b)(2) and 6(c) of the Intertie Agreement.

(d) Reinforcements. Bonneville has committed in Section 7(c) of the Capacity Ownership Agreement to keep Bonneville's capacity share of the AC Intertie at existing levels. Bonneville warrants that, in keeping such commitment, no additional obligations will be placed on PGE other than PGE's existing obligations under Section 11 of the Intertie Agreement, nor will existing rights and obligations related to planning in Section 9 of the Intertie Agreement be adversely impacted in any way.

(e) Losses. Bonneville warrants that the Capacity Ownership Agreement does not relieve Bonneville of its responsibility under Section 14 of the Intertie Agreement as it relates to losses for its ownership share of the Intertie.

(f) Remedial Actions. All remedial actions shall be jointly developed in accordance with Section 6(d) of the Intertie Agreement. BPA warrants that New Owners' remedial actions shall comply with the remedial action plan developed pursuant to Section 6(d) of the Intertie Agreement. Bonneville and PGE agree to continue the past practices with respect to remedial actions, consistent with the Intertie Agreement. Bonneville does not intend that specific relationships with the New Owners with respect to remedial actions change in any way such practices with PGE.

(g) Binding Arbitration. Bonneville warrants that the results or determinations of binding arbitration under the Capacity Ownership Agreement apply only to Bonneville and the New Owners. Rights and obligations between Bonneville and PGE regarding issues being arbitrated under the Capacity Ownership Agreement will be governed by the Intertie Agreement and related agreements between Bonneville and PGE.

(h) Operating Plan. Upon request by PGE, Bonneville will provide PGE a copy of the operating plan developed in accordance with the Capacity Ownership Agreement to the extent such operating plan is effective according to Sections 13(e), 13(h), 13(n), or 14 of the Capacity Ownership Agreement. Development or implementation of operating plans under the Capacity Ownership Agreement shall not adversely affect PGE's rights under the Intertie Agreement.

(i) Assignment to Other Parties. Bonneville agrees to provide PGE copies of any modifications to the Capacity Ownership Agreement. Bonneville agrees that in giving its consent to any subsequent assignment by a New Owner, where Bonneville's consent is required by the Capacity Ownership Agreement, Bonneville will not give such consent if such assignment would impair or otherwise have any material adverse effect on PGE's rights or obligations pursuant to the Intertie Agreement. Any assignee of the Capacity Ownership Agreement shall be treated as New Owner for purposes of this letter agreement.

3. PGE's consent contained in Section 1 of this letter agreement shall not amend or change any existing contractual arrangements between PGE and Bonneville.

If the terms and conditions of this letter agreement are acceptable to Bonneville, please indicate your acceptance by signing both enclosed copies and returning one copy to PGE. The remaining copy is for your files.

Yours very truly

Richard E. Dyer
Vice President and General Manager
Power Resources and Marketing

ACCEPTED:

BONNEVILLE POWER ADMINISTRATION

By Walter E. Pollock

Name Walter E. Pollock
(Print/Type)

Title Group Vice President for Marketing, Conservation and Production

Date September 15, 1994

IPS-24993