INTERGOVERNMENTAL AGREEMENT

BETWEEN

ENERGY NORTHWEST

AND

IDAHO WATER RESOURCE BOARD

TO PROVIDE SERVICES AS REQUESTED

Idaho Water Resource Board Agreement No. CON01469
INTERGOVERNMENTAL AGREEMENT
BETWEEN
ENERGY NORTHWEST AND
IDAHO WATER RESOURCE BOARD
TO PROVIDE SERVICES AS REQUESTED

1. DEFINITIONS ..................................................................................................................................... 2
2. SERVICES TO BE PROVIDED BY ENERGY NORTHWEST ........................................................ 4
3. TERMS AND CONDITIONS OF ENERGY NORTHWEST’S SERVICES ......................................... 6
4. OBLIGATIONS OF WATER BOARD .................................................................................................. 10
5. CHANGE REQUESTS .......................................................................................................................... 11
6. COMPENSATION AND BILLING PROCEDURES ........................................................................ 12
7. STANDARD OF CARE .......................................................................................................................... 12
8. REPRESENTATIONS AND WARRANTIES, PRE-EXISTING CONDITIONS ..................................... 13
9. LIABILITY, INSURANCE AND INDEMNITY .................................................................................... 13
10. TERM AND TERMINATION ............................................................................................................. 15
11. MISCELLANEOUS ............................................................................................................................... 16

EXHIBITS

Exhibit A Work Release Order
Exhibit B Insurance Coverage
Exhibit C Compensation for Project Maintenance Services and Additional Services Cost
Exhibit D Pre-existing Conditions
Exhibit E Applicable Project Documents
Exhibit F Applicable Permits
Exhibit G Project Site
Exhibit H Water Board’s Standard Operating Procedures
Exhibit I Project Supplies and Project Tools
Exhibit J Party Representative Information
Exhibit K Memorandum of Understanding between the Water Board and the United States Fish and Wildlife Service, dated June 5, 2000
Exhibit L Settlement and Contingent Power Purchase Agreement, dated April 30, 1990
Exhibit M Electric Power Wheeling and Maintenance Agreement, dated January 19, 2000
Exhibit N Travel Reimbursement
RECITALS

This Intergovernmental Agreement (hereinafter referred to as the “Agreement”) is by and between the Idaho Water Resource Board, a constitutional state agency in the State of Idaho, with its principal offices at 322 E Front St, PO Box 83720, Boise, ID 83720-0098, (hereinafter “Water Board”), and Energy Northwest, a municipal corporation and joint operating agency of the State of Washington, with its principal office at PO Box 968 Richland, WA 99352, by and through its Business Development Fund (hereinafter “EN”), as the parties (each, a “Party,” and collectively, the “Parties”) to the Agreement. This Agreement is authorized pursuant to the Interlocal Cooperation Act (Act), Chapter 39.34.030 Revised Code of Washington (RCW), whereupon “public agencies” as defined by the Act, inclusive of EN and Water Board, may engage in joint and cooperative undertakings.

WHEREAS, EN is authorized, under Revised Code of Washington (RCW) Chapters 43.52.300(2), to maintain, operate, and regulate plants, works, and facilities for the generation and/or transmission of electric energy, which are “Services” sought by the Water Board for the “Project” as hereinafter defined in this Agreement; and

WHEREAS, Water Board owns a hydroelectric facility and needs operation and maintenance Services provided to continue its operation; and

WHEREAS, Water Board finds that EN is willing to perform certain Services on the Project hereinafter described in accordance with the provisions of this Agreement; and

WHEREAS, Water Board is authorized to contract with EN pursuant to Idaho Code § 42-1734(10).

WHEREAS, EN is willing to perform the Services, all relevant factors considered.

NOW, THEREFORE, in consideration of the mutual covenants set forth herein and intending to be legally bound, the Parties hereto agree as follows:

1. DEFINITIONS

1.1 “Additional Services” is defined in Section 2.2.

1.2 “Agreement” means this Intergovernmental Agreement between EN and the Water Board including all Exhibits referenced herein which are hereby incorporated by reference, and as the same may be modified, amended, supplemented or replaced from time to time in accordance with the provisions hereof.

1.3 “Applicable Law(s)” means all applicable and obligatory laws, statutes, ordinances, codes, judgments, decrees, injunctions, writs, orders, permits, approvals, standards, rules, regulations and interpretations (as may be amended, modified or repealed from time to time) of or by any Governmental Authority having jurisdiction over the Project under this Agreement.

1.4 “Applicable Permits” means any federal, state, local or other license, consent, appraisal, authorization, ruling, exemption, variance, order, judgment, decree, declaration, regulation, certification, filing, recording, waiver, permit or other approval listed in Exhibit F.

1.5 “Applicable Project Documents” means reference materials set forth in Exhibit E.

1.6 “Business Development Fund” means the EN account entitled as such as of the date of the Effective Date of this Agreement.
1.7 “Capital Improvement” means any work intended to boost an asset’s condition beyond its original or current state. A Capital Improvement increases an asset’s useful function or service capacity, extends its useful life, reduces future operating costs, or upgrades essential parts of the asset. Examples include replacement of governors, or any other major, value-adding improvement and may be described in a Capital Improvement Plan.

1.8 “Change Request” shall have the meaning given in Section 5.2.

1.9 “Water Board Representative” means one or more persons designated in Exhibit J (as may be revised from time to time) by Water Board as the primary point of contact for EN in its performance of this Agreement.

1.10 “Effective Date” has the meaning given in Section 11.1.

1.11 “EN Personnel” has the meaning given in Section 3.12.

1.12 “Emergent Event” means an event requiring immediate action to prevent or mitigate harm to human life, property, or the environment.

1.13 “Excluded Work” is defined in Section 2.5.

1.14 “Fish Hatchery MOU” means the Memorandum of Understanding for the Use of the Clearwater Fish Hatchery Water Supply Lines for the Operation of the Dworshak Small Hydroelectric Project, dated June 5, 2000, between the Water Board and the United States Fish and Wildlife Service ("FWS"). A copy of which is attached as Exhibit K.

1.15 “Governmental Authority” means any federal, state or local government body having jurisdiction over the Project.

1.16 “Hazardous Materials” means any material that by reason of its composition or characteristics is hazardous material, including hazardous or toxic substances, hazardous waste, petroleum products (including crude oil or any fraction thereof), or has hazardous constituents, defined or regulated as such in or under Applicable Laws or regulations, relating to or imposing liability or standards of conduct concerning the protection of human health or the environment.

1.17 “Incidental Costs” means costs incidental but separate from costs to Operating the Project, including fees for utilities, licenses, permits, consumable supplies, etc., but excluding costs of Capital Improvements.

1.18 “Monthly Operating Report” means a written summary of: (1) all tasks engaged in or executed during the month including a brief description, completion or projected completion status, any additional work required to complete the task, and effectiveness of the task; (2) the general status of all parts ordered or received during the month; (3) a detailed summary of any Project outage that occurred during the month, including all actions taken or coordinated to restore the Project to service, the specific timeframe during which the Project was mechanically unavailable to produce power, and noticeable trends or correlational observations in relation to the cause of the outage.

1.19 “Operate the Project” is defined in Section 2.1.

1.20 “Operational Breach” shall have the meaning given in Section 11.2.

1.21 “Power Agreement” means the Settlement and Contingent Power Purchase Agreement, dated April 30, 1990, between the Water Board and Bonneville Power Administration. A copy of which is attached as Exhibit L.

1.22 “Pre-existing Conditions” shall have the meaning given in Section 9 and Exhibit D.
1.23 “Project” means, Dworshak Small Hydroelectric Project located approximately one mile downstream of Dworshak Dam on the North Fork of the Clearwater River in Clearwater County, Idaho. The Project is licensed by the Federal Energy Regulatory Commission (FERC) as project no. 10819-002.

1.24 “Project Costs” means all costs expended on the Project under this Agreement including, but not limited to, sums payable to EN for Services and sums payable to 3rd parties.

1.25 “Project Site” means, and is limited to, the area depicted in Exhibit G.

1.26 “Prudent Utility Practice” means any of the practices, methods, and acts at a particular time which, in the exercise of reasonable judgment in the light of the facts, including but not limited to, the practices, methods, and acts engaged in or approved by a significant portion of the electrical utility industry prior thereto, known at the time the decision was made, would have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition.

1.27 “Qualified Person” means an EN employee, agent, or subcontractor possessing appropriate licensures and/or certifications), experienced and trained in the duties to which they are assigned.

1.28 “Repair and Maintain” means both routine and preventative maintenance performed to restore the Project’s physical condition and/or operation to a specified standard, prevent further deterioration, replace or substitute a component at the end of its useful life, serve as an immediate but temporary repair, or assess ongoing maintenance requirements but does not include “Excluded Work.”

1.29 “Services” means work as allowed service and/or goods provided by EN under this Agreement and approved by a fully executed Work Release Order(s).

1.30 “Term” means the period of time given in Section 11.1.

1.31 “Unsafe Condition” means a condition at the Project Site or affecting the Project Site that would appear to a reasonable plant operator to unreasonably compromise safety of persons at the Site or unreasonably endanger the Project or other property located at the Project Site.

1.32 “Wheeling Agreement” means the Electric Power Wheeling and Maintenance Agreement, dated January 19, 2000, between the Water Board and Clearwater Power Company. A copy of which is attached as Exhibit M.

1.33 “Work Release Order” or “WRO” means the form or document used to authorize Services, amend Services or add Additional Services. A WRO shall include the scope, schedule (including any operational outage or curtailment periods), budget and outside contractor’s estimate (where applicable), for the Services or Additional Services to be completed. WRO shall also include the payment terms for the Services or Additional Services authorized within the WRO.

2. SERVICES TO BE PROVIDED BY ENERGY NORTHWEST

2.1. **Project Operation.** EN shall operate and maintain the Project on Water Board’s behalf. “Operate the Project” means doing all things (directly or with contracted services) required to ensure the safe and reliable operation of the Project, in accordance with requirements and limitations set forth herein, subject to Applicable Laws including but not limited to the Clean Water Act, Applicable Permits, Prudent Utility Practices and, when EN Operates the Project with contracted services, in compliance with applicable procurement requirements. The Parties herein agree permits and licenses applicable to the Project include those identified in Exhibit F as of the date of this Agreement and shall be referred to as “Applicable Permits.” EN’s provision of Services or Additional Services herein shall not knowingly or intentionally violate such Applicable
Permits. Operate the Project includes all activities typically undertaken to Repair and Maintain a hydroelectric project similar to the Project including, but not necessarily limited to, the tasks and responsibilities set forth in each WRO. Operate the Project does not include performing Capital Improvements or Excluded Work. EN shall utilize Prudent Utility Practices and the “Applicable Projects Documents” as a guide, to provide only the Services described on Exhibit A, or as may be requested by the Water Board, as budget and schedule allow, subject to the terms and conditions of this Agreement. The Services provided by EN shall not conflict or interfere with work conducted by employees of the Clearwater Fish Hatchery related to the Project. Pursuant to the Fish Hatchery MOU (Exhibit K), the USFWS has the right to inspect the Project. Timely written notice of inspections will be provided to EN.

2.2. Additional Services. Upon prior approval of the Water Board’s representative, EN may provide Additional Services to the Water Board. EN’s Additional Services shall be priced in accordance with rates and terms in the WRO for the identified services. Work not performed by EN will be performed by third parties under contract directly to Water Board (prepared and administered by EN in accordance with Section 2.1).

2.3. Work Release Orders. Except as otherwise provided herein, Water Board will use WROs to authorize all EN Services. Concurrent with the execution of this Agreement, the Water Board will execute (and EN shall acknowledge) WRO(s) in the form substantially in accordance with the attached Exhibit A. Future EN work authorizations will occur through additional WROs. The Water Board’s and EN’s authorized representatives shall approve and sign all WRO’s associated with this Agreement.

2.4. Unauthorized Services; Emergent Events. In the event EN provides Services that are required by Prudent Utility Practice (e.g. to prevent an Emergent Event) but are not part of Operating the Project, EN shall perform such Services and, if performing such Services materially increases EN’s costs to provide Services, shall invoice Water Board for EN’s additional costs, in accordance with Exhibit C, invoice shall include a justification for the incurred costs; provided, that EN shall to the extent it is reasonable promptly notify Water Board prior to incurring such costs so that Water Board shall have the ability to explore alternatives that will not cause EN to incur additional costs.

2.5. Excluded Work. For the avoidance of doubt, the following areas and tasks are not within the scope of EN’s authority or responsibility under this Agreement:

2.5.1. Capital improvements;
2.5.2. Water quality testing;
2.5.3. The distribution box located under the hydropower facility which is owned by Clearwater Fish Hatchery.
2.5.4. The gallery located in the dam which houses the Project flow meter. The gallery is owned by the U.S. Army Corps of Engineers. The flow meter is owed by the Water Board and not part of Excluded Work.
2.5.5. Costs arising from contracts between the Water Board and a professional engineer, consultant, or other contractor providing service to the Water Board in connection with the Project;
2.5.6. Costs for materials procured by Water Board to be applied or consumed at the Project (except as otherwise included in Exhibit A);
2.5.7. Identification or abatement of asbestos or lead paint conditions, if any;
2.5.8. Creating or incurring any liability or obligation on behalf of Water Board except as expressly authorized by Water Board or as expressly set forth herein;
2.5.9. Settling, compromising, assigning, releasing or transferring any claim, suit or demand, whether brought by or against Water Board or otherwise involving the Project; or

2.5.10. Taking any action on behalf of the Project that would result in a pledge, mortgage, license, conveyance or other transfer or disposition of any property or assets of the Project except for actions in the ordinary course of business.

3. **TERMS AND CONDITIONS OF EN’s SERVICES**

3.1. **Procurement Procedures.** EN shall comply with all applicable state and federal laws in the procurement of goods or services or professional services.

3.2. **Emergency Notification.** EN shall provide Water Board with 24/7 contact information such that a designated Water Board Representative can reach EN if needed at all times.

3.3. **EN and Water Board Coordination.** The Water Board shall notify EN in advance of planned activities to be conducted by the Water Board related to the Project. EN shall not unreasonably interfere with activity conducted by Water Board related to the Project. EN shall provide Water Board reasonable notice, including by electronic mail, of any plans to limit access within the Project Site or undertake activities that may affect normal operation of the Project.

3.4. **Applicable Project Documents.** EN shall familiarize itself with Applicable Project Documents set forth in Exhibit E so as to improve its working knowledge of the Project and to avoid unnecessary loss of Project knowledge or re-creation of existing information.

3.5. **Water Board Security Standards.** EN’s employees, agents, and subcontractors shall obtain security clearance prior to working at the Project Site and shall comply with Water Board security standards, provided by the Water Board Representative to EN in writing prior to commencement of the Services.

3.6. **Non-Hazardous Waste Management.** EN shall be responsible for supervising the Project Site solid waste management collection and deposit into Water Board-furnished receptacles all solid waste materials generated in the performance of Services herein. When EN supervised work at the Project will result in substantial added solid waste disposal charges, EN shall submit a Change Request. The Water Board shall be responsible for the provision of waste management containers and the disposal, and costs thereto, of all waste materials generated by or in connection with the performance of the Services herein.

3.7. **Security.** To prevent theft and vandalism at and within the Project Site EN shall utilize physical security measures accessible to EN and the Water Board at the Project Site including the securing of locks, doors, and gates when at the Project Site. Water Board approved security standards and measures in place at the Project shall be provided to EN prior to the commencement of Services.

3.8. **Emergency Action Plans.** EN’s employees, agents, and subcontractors shall be familiar and comply with the Water Board’s Emergency Action Plan, as such plans may be created or modified from time to time. The Water Board will provide copies of new and revised plans as they become available.

3.9. **Emergency Call-out.** EN shall ensure that a Qualified Person reports to the Project Site within 3 hours of being notified by Water Board, Clearwater Fish Hatchery or local law enforcement of a condition requiring immediate attention.

3.10. **EN Personnel.** EN shall provide and make available, as necessary, all such labor, supervisory and managerial personnel as required to perform the Services (the “EN Personnel”). Such EN Personnel shall be a Qualified Person. EN shall retain sole authority, control and responsibility with respect to labor matters in connection with the performance of the Services. If Water Board
reasonably deems any EN Personnel as under-qualified, disruptive or non-cooperative, Water Board may, by prior written notice, require the removal of such EN Personnel and the replacement of such EN Personnel with a different employee meeting the requirements of this Agreement. In addition, EN shall also consult and confer with Water Board and reasonably cooperate to address any concerns raised by Water Board with respect to any EN Personnel performing Services under this Agreement. If any person employed by EN appears to Water Board to be incompetent or to act in a disorderly or improper manner or who fails to perform the Services in accordance with the terms and conditions of this Agreement, then upon written notice of Water Board, EN shall promptly replace, but in any event not later than five (5) days after such written notice, such person at the Project and such person shall not again be allowed to perform any of the Services at the Project. EN shall be allowed to use qualified, competent subcontractors to perform Services under the supervision of EN Personnel; provided, that EN shall deliver prior written notice to Water Board of such subcontractors and such notice shall include the identity of the subcontractors; the services to be rendered by such subcontractors; the dates during which such services are to be rendered; and a statement that the subcontractor’s insurance meets the same insurance requirements as EN, set forth in Exhibit B, and that the subcontractor named the Water Board as an additional insured. EN is responsible for actions taken by subcontractors used to perform Services under contract to EN for the Project, pursuant to Section 10 of this Agreement.

3.11. Communications With Agencies. Operating the Project requires periodic communication with various city, state, and federal agencies, including without limitation the Federal Energy Regulatory Commission, the Department of Fish and Wildlife, the Clearwater Fish Hatchery, the Bonneville Power Administration, and any insurance carrier that issued a policy related to the Project. Project operations is a shared task between the Clearwater Fish Hatchery and the Water Board. The Water Board authorizes EN to communicate directly with Clearwater Fish Hatchery regarding Services and emergency tasks. However, communication for work authorizations outside of the scope of a Work Release Order and communications regarding Project costs, shall be between EN and the Water Board. EN will communicate with agencies regarding day to day operations/maintenance tasks and emergent conditions. EN will provide updates to the Water Board regarding the agency communications in their regular reporting. Specific emergency communications between the parties will be outlined in the emergency action plan. The Water Board may require that it be present at and be provided with copies of all communications with EN and these agencies except as to any oral communications pertaining to an Emergent Event or other matter if required by Prudent Utility Practices referred to above. Upon request by EN the Water Board shall provide EN with copies of all written communications between the Water Board and these agencies.

3.12. Recordkeeping and Public Records Requests for EN and Water Board. This Section 3.12 applies equally to EN and the Water Board in order to provide a consistent plan for recordkeeping and the handling of public records requests (PRR) in Idaho and Washington that is both consistent with the public records law in the state in which the PRR is made and to provide each Party the maximum amount of control over what is released, as dictated by the state law in which the PRR is made.

3.12.1. Recordkeeping. Each Party shall create and maintain complete and accurate records of all activities the Party is responsible for under the Agreement. EN shall keep its records at the Project with digital copies available upon request by the Water Board, in a format acceptable to the Water Board.

3.12.2. Public Records Requests. Each Party shall be responsible for the processing of PRRs directed to it, and for all costs, fees and penalties associated with the processing of such or errors thereto.

(a) Idaho PRRs.
3.12.2.a.a.1. **Presumed Public.** The Idaho Public Records Act, Idaho Code § 74-101, et seq., presumes all records in Idaho are open for inspection unless expressly exempted by statute. Information or documents received from EN may be open to public inspection and copying unless exempt from disclosure. When providing the Water Board with documents that contain exemptions, EN shall clearly designate each portion as “exempt” on each page of such documents and shall indicate the basis for such exemption. Water Board will not accept the marking of an entire document as exempt. In addition, Water Board will not accept a legend or statement on one page that all, or substantially all, of the document is exempt from disclosure.

3.12.2.a.a.2. **Response Time.** Pursuant to Idaho Code § 74-103, Water Board must respond to a PRR within three (3) business days of the request. Water Board may take an extension, up to ten (10) working days from the request, to provide records.

(b) **Washington PRRs.**

3.12.2.b.a.1. **Releasability.** EN may only release records specifically prepared, used or retained by EN. Access does not equate to use or retention.

3.12.2.b.a.2. **Expediency.** If the requestor is seeking records held by the Water Board, EN will recommend the requestor deal directly with the Water Board in the interest of expediency. If the requestor maintains they would like their request completed by EN, the Parties will work together to determine what is releasable and what is not.

3.12.2.b.a.3. **Acknowledgement.** Upon receipt of a PRR, EN will respond to the requestor within 5 (five) business days and acknowledge receipt of the request while providing an estimated deadline by which the records requested will be produced. If the requestor is seeking records held by the Water Board, EN will contact the Water Board to determine the time needed to review the records and respond to the request.

3.12.2.b.a.4. **Notification.** Upon discovery that records sought include records created or held by the Water Board, EN will notify the Water Board of the request and initial estimated deadline. EN will also advise the Water Board of a deadline by which a response is required to avoid EN violating RCW 42.56.

3.12.2.b.a.5. **Impasse.** If the Water Board and EN reach an impasse as to what can be released, the Water Board will advise EN whether it intends to challenge the disclosure and, if so, whether the Water Board seeks additional time beyond the initial estimated deadline to seek a protective order relating to the materials. EN shall extend the time estimate for disclosure via notification to the requestor, to allow the Water Board additional time to respond under this subsection if the extension is reasonable under existing law defining reasonableness of disclosure timelines under RCW 42.56. Seven (7) judicial days shall be deemed a sufficiently reasonable period of time to seek injunctive relief until a court can make a final determination as to releasability.
3.12.2.b.a.6. Amendment. This procedure may be amended from time to time as deemed necessary by the Parties without requiring renegotiation of the Agreement.

3.13. Suspension of Services. EN shall have the right to suspend performance due to:

3.13.1. Unsafe Conditions. EN shall have the right to suspend all or part of Services as warranted to avoid Unsafe Conditions. Upon encountering a condition necessitating the suspension of Services, EN shall immediately notify Water Board and not resume performance of such until the condition is rectified to the satisfaction of the Parties. In the event of an unsafe condition EN shall be permitted to take action in an effort to prevent, or mitigate as much as practicable, threatened damage, injury, or loss. If EN’s provision of Services or Additional Services conforms to the Standard of Care set forth in Section 7 herein, EN shall be entitled to a WRO for any increased costs reasonably incurred and scheduling delays resulting from its action in responding to an unsafe condition.

3.13.2. Adverse Change to an Applicable Permit. Should any Applicable Permit(s) necessary to the lawful operation of the Project become suspended or revoked, the Water Board shall notify EN within two (2) calendar days in accordance with Section 12.8 herein. To the extent the aforementioned prohibits or limits by operation of law or regulation EN’s provision of Services the Parties hereby agree that EN may in its sole discretion cease the provision of such without any liability until such legal or regulatory prohibition or limitation is negated. In the event Water Board determines it will no longer sell electric power generated by the Project, the Parties agree to the process identified in Section 11.2 herein.

3.14. Threatened Release of Hazardous Materials. In the event EN encounters any threatened release of, or threatened exposure to, Hazardous Materials at the Project or Project Site (including but not limited to asbestos and lead paint), EN may immediately stop any work likely to result in a release of or exposure to such materials and shall not be obligated to resume work in the area affected until the condition is removed or abated by the Water Board. EN shall where reasonable notify the Water Board and receive direction, and if such direction is not provided or cannot be provided in a timely fashion, shall take action in an effort to prevent, or mitigate as much as practicable, threatened damage, injury, or loss in accordance with Prudent Utility Practices.

3.15. Accounting, Audit Rights. EN shall keep and maintain books, records, accounts and other documents sufficient to reflect accurately and completely all Project Costs incurred pursuant to this Agreement and any other costs which are the basis of a payment hereunder. Such records shall include receipts, memoranda, vouchers, inventories, and accounts of every kind and nature pertaining to the goods and services, as well as complete copies of all contracts, purchase orders, service agreements and other such agreements entered into in connection therewith. The Water Board, its designees, and any independent auditor appointed by Water Board, State of Idaho Auditor, and State of Washington Auditor, shall have access, upon reasonable advance notice in writing, to all such records maintained by EN, for the purposes of auditing and verifying Project Costs or any other costs or expenses claimed to be due and payable hereunder. Such Parties shall have the right to reproduce any such records at their expense, and EN shall keep and preserve all such records for a period of at least three (3) years from and after the expiration or termination of this Agreement. EN shall keep records of partial releases of mechanics liens and materialman liens, if any.
4. **OBLIGATIONS OF WATER BOARD**

4.1. **Payment for Services.** The Water Board shall pay EN all sums to which it is entitled under the terms and conditions of this Agreement, including Additional Services, if any, which are: (a) agreed to in advance; or (b) otherwise authorized in this Agreement or WRO. In no event shall Water Board pay for Services or Additional Services unless such services have been performed.

4.2. **Emergency Notification.** The Water Board shall provide EN with 24/7 contact information such that a designated Water Board Representative can be reached by EN if needed at all times.

4.3. **EN and Water Board Coordination.** The Water Board shall not unreasonably interfere with work conducted by EN related to the Project. The Water Board shall provide EN reasonable notice, including by electronic mail, of any plans to limit access within the Project Site or undertake activities that may affect normal operation of the Project.

4.4. **Project Tools and Supplies.** The Water Board shall provide the Project supplies and Project tools set forth in Exhibit I, which shall remain the property of Water Board.

4.5. **Project Site Fuel Storage and Use.** The Water Board shall be responsible for the provision, maintenance and control of storage facilities including containments for gasoline and diesel fuels, oils, or other liquid or combustible fuels on the Project Site. EN’s use of such fuels for Services shall be limited to instances of written permission from the Water Board.

4.6. **Procuring Applicable Permits.** Unless otherwise required by Applicable Law, the Water Board (with the “cooperation and support of EN” where necessary) shall be solely responsible for renewing all Project required Applicable Permits. For purposes of this Agreement, the term “cooperation and support of EN” shall only mean provision of information and records required to maintain or renew Applicable Permits.

4.7. **Regulatory and Governmental Fees.** The Water Board shall pay any regulatory fees chargeable to the owner of the Project, except in the case of negligence or misconduct directly attributable to EN, in which case EN shall pay any regulatory fees or fines.

4.8. **Project Site Safety Matters.** To the extent either Party observes or becomes aware of a condition or information that could reasonably be interpreted as a risk to the safety of persons or property within the Project Site each Party shall immediately notify the other of such.

4.9. **Funding of Services.** The Water Board shall provide funding for Project maintenance and repairs including emergency repairs, or other changes to the Project in amounts sufficient to maintain compliance with all Applicable Permits or as may be required by Applicable Laws or meet industry safety standards. EN shall have no obligation to provide funds for any repairs, improvements or other changes to the Project, including emergency repairs, and shall be entitled to suspend performance of the Services to be provided hereunder (upon reasonable notice and subject to EN’s obligations under Section 7 of this Agreement) without liability of any kind in the event Water Board fails to provide funding for any such repairs, improvements or other changes to the Project including emergency repairs.

4.10. **Utilities.** The Water Board shall pay directly for electricity, internet and telephone services, refilling the propane tank, and on-site security service for the Project.

4.11. **Taxes.** The Water Board shall pay all taxes applicable to its receipt of goods and services from EN under this Agreement and all property, value added and transactional taxes. EN shall include sales tax charges, separately identified, in the EN invoices to Water Board if applicable. EN shall
only be responsible for taxes applicable to its provision of Services herein which may include, state and federal employment taxes, State excise taxes and payroll taxes relative only to Services in the State of Idaho, and State of Washington business and occupation taxes.

4.12. Emergency Action Plan. The current emergency action plan is provided in Exhibit E.

5. AMENDMENT/CHANGE REQUESTS

5.1. Amendments to the Agreement. The Water Board and EN may amend this Agreement at any time only by written amendment executed by the Water Board and EN. Any amendment to the Agreement shall require the signature of both parties’ authorized representatives.

5.2. Change Requests to WRO. The Water Board may, with the agreement of EN, issue written directions for changes to Services or Additional Services ordered through an approved WRO. Such changes shall be the subject of a written change request which will result in an amendment to a WRO signed by the Water Board’s and EN’s approving authority.

EN shall submit in writing to the Water Board claims for changes to the Services or Additional services, associated to a WRO, but no change shall be authorized unless agreed to by Water Board in writing unless said change is related to EN’s recovery of costs specifically provided for elsewhere in this Agreement. Claims of changes to the Services or Additional services must be made and agreed to with the Water Board prior to the performance of the Services. Changes that both Parties have agreed to shall be documented in a WRO amendment.

Notwithstanding the conditions in the previous paragraph, so long as EN’s provision of Services conforms to the Standard of Care set forth in Section 7, EN shall be entitled to a WRO amendment for EN’s materially increased reasonable costs resulting from:

(a) Unforeseeable regulatory burdens (including but not limited to audits, investigations, and remedial actions) materially increasing EN’s costs to operate the Project;
(b) After-hours operations required by Water Board or by Prudent Utility Practice and not accounted for in Exhibit A;
(c) Suspension of Services under Section 3.15; and
(d) Unauthorized Services necessary to prevent or minimize Emergent Events per Section 2.4.

6. COMPENSATION AND BILLING PROCEDURES

6.1. Audits. The Parties have the authority to audit the others records associated with this Agreement. The Parties shall fully cooperate with the other’s audit of the records at any time. The Water Board reserves the right to request additional documentation to support EN's expenditure of funds in compliance with the Agreement and on the progress of work, Services, or actions required from EN.

EN shall also fully cooperate with an audit to account for all expenses if necessary.

In the event this Agreement is terminated all unexpended Water Board funds shall be returned to the Water Board within sixty (60) days of said termination.

If applicable, EN shall keep vendor receipts and evidence of payment for materials and services, time records, payment for program wages/salaries and benefits. All receipts and evidence of payments shall be promptly made available to the Water Board Project Manager or other
designated persons, upon request. At a minimum, such records shall be made available and may be reviewed as part of the annual monitoring process.

6.2. **Total Amount of Agreement.** The total not to exceed amount for the Term of the Agreement is one hundred thousand dollars ($100,000).

6.3. **Invoicing.** EN shall submit a signed, itemized monthly invoice to the Water Board.  

6.3.1. **Invoice Content.** Each invoice must include:

(a) Detailed descriptions including a breakdown of work performed with associated staff hours and rates, any materials used, or expenses incurred in the fulfillment of this Agreement. The work descriptions must be in a manner that is accountable, transparent and efficient in order to effectively achieve the objects of this Agreement,

(b) Contract number from Page 1 of the Agreement,

(c) EN’s name, address, and telephone number,

(d) Amount of the billing,

(e) Receipts from subcontractors, and

(f) Timeframe covered by the invoice.

6.3.2. **Submission.** Submit invoices to IDWR Payable, PO Box 83720, Boise ID 83720-0098 or email idwrpayable@idwr.idaho.gov.

6.4. **Payment Processing.** Payment from the Water Board will be made pursuant to Idaho Code § 67-2302. Any portion of the invoice in dispute shall be resolved in accordance with Section 12.10 of this Agreement within thirty (30) days of the receipt by EN of the notice from the Water Board it is disputing charges. Any court costs or other reasonable costs incurred by EN in collection of delinquent accounts, excluding any attorney fees, shall be paid by the Water Board only to the extent that such outstanding amounts are determined to be due EN by a final, non-appealable decision of a court of competent jurisdiction.

7. **STANDARD OF CARE**

EN warrants that all Services and Additional Services shall be performed consistent and in accordance with applicable Prudent Utility Practices relating to operation and maintenance of hydroelectric facilities. If EN believes compliance with a requirement or a direction given by the Water Board will result in violation of any laws or regulations, EN shall so notify the Water Board in writing immediately and shall not proceed pursuant to that requirement or direction until the Water Board directs EN to proceed. To the extent of its authority, EN will transfer to Water Board its rights to any manufacturer’s warranties associated with goods or services EN procures in performing Services or Additional Services. No other representation, express or implied, and no warranty or guarantee is included or intended in this Agreement, or in any report, opinion, deliverable, work product, document or otherwise.

THIS SECTION 7 SETS FORTH THE ONLY WARRANTIES PROVIDED BY EN CONCERNING THE SERVICES AND RELATED WORK PRODUCT. THIS WARRANTY IS MADE EXPRESSLY IN LIEU OF ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, INCLUDING WITHOUT LIMITATION, ANY IMPLIED WARRANTIES OF FITNESS FOR A PARTICULAR PURPOSE, MERCHANTABILITY OR OTHERWISE.
8. REPRESENTATIONS AND WARRANTIES

8.1. The Water Board represents that it has no knowledge of any hazardous materials on site including lead paint and asbestos at the Project Site.

8.2. The Water Board represents that it is not aware of any union having a claim to any of the work to be performed under this Agreement. In the event that prior to or during the time EN performs work under this Agreement any union asserts that the work: (a) must be performed by members of that union, or (b) that EN must recognize the union as the representative of employees that will perform the work, then EN may terminate this Agreement in accordance with Section 11.2.

8.3. C.F. Malm previously maintained and operated the Project on Water Board’s behalf. To assist Project maintenance and operations, C.F. Malm used Programmable Logic Controller Code Information related to a Supervisory Control and Data Acquisition system (SCADA Information). C.F. Malm provided the SCADA Information to Water Board and Water Board has, in turn, provided the SCADA Information to EN. Water Board makes no representation as to the accuracy or efficacy of the SCADA Information. Both Parties waive any and all liability against the other Party for any damage either Party may incur due to its reliance upon the SCADA Information.

9. PRE-EXISTING CONDITIONS

To Water Board’s knowledge, the Project is in good working order, properly maintained in accordance with all manufacturers’ maintenance requirements and Prudent Utility Practices applicable to the Project, and in compliance with all Applicable Laws and Applicable Permits, in each case, in all material respects, except for Pre-existing Conditions as described herein this Section 9 and as disclosed in Exhibit D. EN has been afforded the opportunity to review Water Board’s documentation of all Pre-existing Conditions listed in Exhibit D. Notwithstanding any other term or condition of this Agreement, EN shall have no liability of any kind or nature (subject to EN’s obligations under Section 7 of this Agreement), whether in contract or in tort, at law or in equity, arising out of or relating to any condition of the Project or Project Site that existed prior to the date EN commenced providing Services, whether known or unknown, knowable or unknowable, or for any violation of any Applicable Law or Applicable Permit (each, a “Pre-existing Condition”). Within ninety (90) days of execution of this Agreement, Water Board and EN shall jointly conduct a pre-existing condition inspection, Project Site survey and review of the Project and Project Site to identify any Pre-existing Conditions, and shall update Exhibit D. If following this inspection, the Water Board and EN become aware of any violation of Applicable Law or Applicable Permit, both Parties agree to undertake a mutual investigation and resolution at the sole cost and expense of the Water Board.

10. LIABILITY, INSURANCE AND INDEMNITY

10.1. Limitation. Under no circumstances, with the limited exception of gross negligence or willful misconduct, shall EN or Water Board be liable to the other for any special, indirect, consequential damages, loss of power or profits, or punitive damages. The limitation of liability set forth in this Section 10.1 is for any and all matters for which EN or Water Board may otherwise have liability arising out of or in connection with this Agreement, whether the claim arises in contract, or in tort resulting from general negligence, strict liability or otherwise and is limited to the established limits defined by the respective State’s Tort Claim limits. Nor shall EN or Water Board be liable to the other for any claims or damages to the Project facilities or equipment caused by a third-party, or criminal act or security breach of a third party.
10.2. **Indemnity.**

10.2.1. **Energy Northwest.** To the fullest extent allowed under applicable law, and subject only to the limitations provided herein, EN shall defend, indemnify and hold harmless Water Board and its officers, and employees, against all claims, demands, losses and liabilities to or by third parties arising from, resulting from or connected with the Services performed or to be performed under this Agreement by EN or EN’s agents or employees, for bodily injury or wrongful death to persons and damage to property. This indemnification is expressly limited to the amount of insurance set forth in Exhibit B hereto.

10.2.2. **Water Board.** To the extent allowed by the Idaho Tort Claims Act, Title 6, Chapter 9, Idaho Code, and as limited by Article VII, Section 11 of the Idaho Constitution and Idaho Code §§ 59-1015, -1016, and -1017, Water Board recognizes and agrees that it is liable to EN and its officers and employees, for damage to life or property resulting from or connected with acts or omissions by the Water Board or the Water Board’s agents or employees while providing the Services performed or to be performed under this Agreement.

10.2.3. Each Party further agrees that its defense, indemnity and hold harmless obligations shall apply to claims made by its own employees against an Indemnitee, but in that instance only to the extent of the Indemnitor’s own negligence or fault in whole or in part causing the claimant’s damages.

10.3. **Insurance.** EN shall at its own expense maintain during the Term of this Agreement without interruption the coverages of insurance, with limits of no lesser amounts, as set forth in Exhibit B. EN acknowledges that Water Board is self-insured and will not obtain a separate insurance policy for this Agreement. Water Board’s self-insurance is subject to the conditions and limitations of the Constitution, and the Tort Claims Act.

10.4. **Survival.** Sections 7 through 10 shall survive the expiration or termination of this Agreement for all purposes.

10.5. **Hold Harmless.** Water Board recognizes and agrees that it is liable to EN, in accordance with the Idaho Tort Claims Act and as limited by Article VII, Section 11 of the Idaho Constitution and Idaho Code §§ 59-1015, -1016, and -1017 for damages arising from the following:

(a) The presence or occurrence of any conditions or substances foreign to the River, its surrounding environment, the Water Board water supplies or properties including but not limited to the Dams, unless the presence or occurrence of such through independent investigation at the equally-shared expense of the Water Board and EN is determined to be the direct result of EN’s negligence whereupon EN’s liability shall be limited as set forth in Section 10.1 herein. The results of the independent investigation shall determine whether the Water Board or EN, without relying on the limitations set forth in Section 10.1 herein, shall be responsible for abating the condition or foreign substances, communicating with Governmental Authorities, resolving any fines, penalties or other enforcement action, all in accordance with Applicable Laws.

(b) The presence of any pre-existing Hazardous Materials at the Project, Project Site or Hazardous Materials introduced to the Project or upon the Project Site by a person or entity other than EN, unless the presence or occurrence of such through independent investigation at the equally-shared expense of the Water Board and EN is determined to be the direct result of EN’s negligence whereupon EN’s liability shall be limited as set forth in Section 10.1 herein.
The Project and Project Site properties and equipment failures and damages, including normal wear and tear, if EN’s provision of Services complied with the Standard of Care set forth in Section 7 herein.

11. **TERM AND TERMINATION**

11.1. **Term.** This Agreement commences on the Effective Date and ends on March 31, 2021 (the “Term”). The “Effective Date” means the last date on which either Water Board or EN executes this Agreement and it is filed with the Benton County Auditor and/or posting an electronic copy of the Agreement on EN’s website in compliance with RCW 39.34.040.

11.2. **Termination for Cause.** Either Party shall be entitled to terminate this Agreement in the event that the other Party: (a) is in breach of its obligations that affect the operations of the Project (an “Operational Breach”) and such Operational Breach is not cured within ten (10) days of written notice setting forth the basis for the alleged breach; (b) is in breach of an obligation that is not an Operational Breach and such breach is not cured within thirty (30) days of written notice setting forth the basis for the alleged breach; (c) makes a voluntary commencement of any proceeding seeking relief under any bankruptcy, insolvency, reorganization or similar law; or (d) becomes insolvent or is subject to an involuntary petition or any involuntary filing under any bankruptcy, insolvency, reorganization or similar law. The Water Board shall be entitled to terminate this Agreement in the event the Water Board determines it will no longer sell electric power generated by the Project; in that event EN will continue to complete Services as authorized by any WROs until the Water Board surrenders the Project’s FERC license and FERC accepts the Water Board’s surrendered license. The Water Board’s right to terminate based on its decision to no longer sell electric power generated by the Project does not include circumstances where a change in Project ownership results in the Water Board no longer selling electrical power. In the event of change in Project ownership the Water Board shall assign the Agreement, to the extent the Water Board has authority to do so, to the new Project owner subject to Section 12.9 herein.

Termination requires written notice to the other Party. The Agreement shall terminate ninety (90) days from the date of receipt of notice or at another mutually acceptable Termination Date. Unless otherwise agreed, EN shall wind down operation of the Project in accordance with Prudent Utility Practices, including but not limited to:

(a) Place no further orders or subcontracts for materials, equipment, services or facilities, except as may be necessary for completion of such portion of the Services as is not terminated;

(b) If requested by Water Board in writing, cancel all orders and subcontracts, upon terms acceptable to the Water Board, to the extent that they relate to the performance of Services terminated;

(c) Take such action as may be necessary or as directed by Water Board to preserve and protect the Project, Project Site, and any other property related to this Project in the possession of EN in which the Water Board has an interest; and

(d) Submit within fifteen (15) days to the Water Board a written termination settlement proposal and enclosed invoice for costs, fees, and expenses owing to EN; and

(e) Stop performing Services on the date specified in the written notice of termination; and

(f) Surrender to the Water Board all tools, supplies, and inventory of the Water Board relating to the Project.

11.3. **Termination Payment.** The Water Board shall review any termination settlement proposal or proposal for final Change Request(s) submitted by EN within thirty (30) days of receipt. The
Water Board may request additional information or documentation from EN in support of any such proposal submitted and EN shall have fifteen (15) days to provide a response. The Water Board shall pay the undisputed amount of any settlement proposal or proposal for final Change Request(s) submitted by EN within fifteen (15) days after the receipt of any information or documentation it has requested from EN, or within forty-five (45) days of the receipt of the proposal, whichever is earlier. Any amounts not paid by the Water Board shall be subject to Section 12.10 of this Agreement.

11.4. Funding Approval. The Water Board cannot obligate funds prior to obtaining funding approval. The Water Board certifies that state or federal funds are presently available and authorized for expenditure to pay the portion of costs which will accrue during the current Idaho state or federal fiscal year or applicable grant period. EN agrees that all obligations of the Board, including the continuance of payments under this Agreement, are contingent upon the availability and continued appropriation of funds. In the event state or federal funds become unavailable as determined by the Water Board, the Water Board may immediately terminate this Agreement or amend it accordingly; provided, however, Energy Northwest may request a Termination Payment as provided by Section 11.3 above. In no event shall the Water Board be liable for any payments in excess of approved or appropriated funds available for this project. Energy Northwest shall not commence work without receiving prior written certification from the Water Board that it has approved or appropriated funds available for the project and/or pending WRO.

12. MISCELLANEOUS

12.1. License for EN to access Project Site. Without expense to EN, the Water Board grants EN, its employees, agents, contractors, and subcontractors physical access to the Project Site and all therein on a twenty-four (24) hours a day, seven (7) days a week basis, including rights of way and easements required for unconditional and safe access of such persons and equipment, as necessary to permit EN or its designee to perform the Services. Water Board may impose reasonable restrictions on access to the Project Site so long as such restrictions do not interfere with or delay EN’s or its designee’s performance of obligations hereunder. Any limitation or restriction on access to the Project Site which causes a material increase of the cost, materially impacts the schedule of Services, or otherwise materially affects the performance of EN’s obligations under this Agreement shall entitle EN to a WRO to recover said costs.

12.2. Project Liens. Except as expressly directed by Water Board in writing, EN shall not assume, create or suffer to exist or be created any lien on the Project or any portion thereof.

12.3. Headings. The headings contained in this Agreement are for convenience and reference only, do not form part of this Agreement, and in no way define, describe, extend or limit the scope or intent of this Agreement or the intent of any provision contained herein.

12.4. Insecurity and Adequate Assurances. If Water Board’s long-term credit rating drops below Investment Grade, EN may demand in writing adequate assurances of Water Board’s ability to meet its payment obligations under this Agreement. Unless Water Board provides the assurances in a reasonable time and manner acceptable to EN, in addition to any other rights and remedies available, upon at least seven (7) calendar days’ notice to the Water Board Representative, EN may partially or totally suspend its performance while awaiting assurances, without liability to EN.

12.5. Severability. Should any part of this Agreement for any reason be declared invalid, such decision shall not affect the validity of any remaining provisions, which remaining provisions shall remain in full force and effect as if this Agreement had been executed with the invalid portion thereof
eliminated, and it is hereby declared the intention of the Parties that they would have executed the remaining portion of this Agreement without including any such part, parts, or portions which may, for any reason, be hereafter declared invalid. Any provision shall nevertheless remain in full force and effect in all other circumstances.

12.6. **Waiver.** Waiver of any breach of this Agreement by either Party shall not be considered a waiver of any other subsequent breach or any other term, covenant or condition contained in this Agreement, whether of the same or different character.

12.7. **Independent Contractor.** EN is an independent contractor to Water Board and, except as set forth in this Agreement including related Work Release Orders, has no authority to act on behalf of, or to represent itself as having such authority on behalf of the Water Board. This Agreement does not establish any partnership or joint venture relationship between the Parties.

12.8. **Notices.** All notices or other communications hereunder shall be in writing or written electronic format and shall be deemed given when delivered to the address (including electronic mail address with confirmation) specified in Exhibit J (as may be revised from time to time) or such other address as may be specified in a written notice in accordance with this Section. Either Party may, by sending a revised and dated Exhibit J to the other Party, revise their addresses and/or persons designated for receipt of notices. For purposes of RCW 39.34.030(4)(a), both the EN Procurement Specialist and the Water Board’s Contract Manager identified in Exhibit J will serve as their party’s administrators to this Agreement.

12.9. **Assignment.** This Agreement is not assignable or transferable by either Party without the written consent of the other Party, which consent shall not be unreasonably withheld or delayed.

12.10. **Disputes; Costs to Prevailing Party.** EN and Water Board recognize that disputes arising under this Agreement are best resolved at the working level by the Parties directly involved. Both Parties are encouraged to be imaginative in designing mechanisms and procedures to resolve disputes at this level. Such efforts shall include the referral of any remaining issues in dispute to a higher authority within each participating Party’s organization for resolution. To the extent such discussions do not resolve such dispute, the Parties agree to submit all claims, disputes or other matters in question between the Parties arising out of or relating to this Agreement or breach thereof to mediation prior to the institution of any litigation. Failing resolution of conflicts at the organizational level, then the Parties may take other appropriate action subject to the other terms of this Agreement. In the event of litigation, the prevailing Party in such action shall be entitled to its reasonable expenses and fees, including its expert fees and costs excluding its attorneys’ fees.

12.11. **Representations; Counterparts.** Each Party hereto represents that such person is duly and validly authorized to do so, on behalf of such Party, with full right and authority to execute this Agreement and to bind such Party with respect to all of its obligations hereunder. Each Party hereto represents that this Agreement constitutes its legally, valid and binding obligation, enforceable against it in accordance with its terms, except as enforceability may be limited by bankruptcy, insolvency, reorganization, moratorium or other similar laws relating to creditors’ rights generally, and general equitable principles whether considered in a proceeding in equity or at law. This Agreement may be signed in counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

12.12. **Residuals.** Subject to Section 12.18, EN and Water Board may use ideas, concepts, know-how, methods, models, data, techniques, skill, knowledge and experience that were used or developed by EN or Water Board in connection with this Agreement.
12.13. **Non-solicitation of Employees.** During and for one (1) year after the Term of this Agreement, Water Board will not affirmatively solicit the employment of, or employ EN’s personnel, without EN’s prior written consent.

12.14. **Cooperation.** The Water Board will cooperate with EN in taking actions and executing documents, as appropriate, to achieve the objectives of this Agreement. The Water Board agrees that EN’s performance is dependent on Water Board’s timely and effective cooperation with EN. Accordingly, Water Board acknowledges that any material delay by Water Board may result in EN being released from a scheduled deadline or in Water Board having to pay extra fees for EN’s agreement to meet a specific obligation or deadline to the extent such delay by Water Board demonstrably causes EN to be delayed and suffer additional costs.

12.15. **Suits.** Any suit brought with regard to this Agreement can be filed in any court of competent jurisdiction.

12.16. **Entire Agreement; Survival.** This Agreement, including any Exhibits, states the entire Agreement between the Parties and supersedes all previous contracts, proposals, oral or written, and all other communications between the Parties respecting the subject matter hereof, and supersedes any and all prior understandings, representations, warranties, agreements or contracts (whether oral or written) between Water Board and EN respecting the subject matter hereof. This Agreement may only be amended by an agreement in writing executed by the Parties hereto.

12.17. **Force Majeure.** Neither Party shall be responsible for any failure in performance due to Force Majeure. “Force Majeure” means an event which is not within the reasonable control of the Party claiming Force Majeure (the “Claiming Party”), and not due to the fault or negligence of such Party and which, by the exercise of due diligence, the Claiming Party is unable to overcome or avoid or cause to be avoided. Subject to the foregoing, Force Majeure may include, but is not restricted to: acts of God; fire; flood; drought; civil disturbance; material shortage; sabotage; pandemic; action or restraint by court order to public or governmental authority (so long as the Claiming Party has not applied for or assisted in the application for such government action).

12.18. **Use by Third Parties; Confidentiality.** Services performed by EN pursuant to this Agreement are only for the purpose intended and may be misleading if used in another context. Neither EN nor the Water Board shall use any documents produced under this Agreement for anything other than the intended purpose without written permission of the other Party. This Agreement shall, therefore, not create any rights in or benefits to Parties other than the Water Board and EN. EN may be granted access to information that is exempt from disclosure to the public and may contain “trade secrets” when it is necessary for EN to perform its obligations pursuant to this Agreement. If EN is granted such access to confidential information, EN shall be considered to be acting as an agent of the Water Board. EN shall not disclose, publish, or authorize others to disclose or publish, design data, drawings, specifications, reports, monitoring results or any other non-public information pertaining to the Services assigned to EN by Water Board or other Project information to which EN has had access during the Term of this Agreement, unless required by operation of applicable law, including but not limited to the Washington State Public Record Act, or court order of a court of competent jurisdiction, after following the process set forth in Section 3.12 herein.
IN WITNESS WHEREOF, the Parties hereto have executed this Agreement as of the day and year last below written:

State of Idaho
Idaho Water Resource Board

[Signature]
Brian Patton
Executive Officer
7/14/2020

Energy Northwest

[Signature]
Sherri Schwartz
Procurement Specialist III
7/9/2020

[Signature]
Richard Shaff
Contracts Supervisor
Exhibit A

Work Release Order (WRO)

This Exhibit A contains the initial Work Release Order, WRO 001 – Scope of Services.
1. **STATEMENT OF WORK**

Energy Northwest (EN) shall provide the necessary resources in accordance with the terms and conditions of the Intergovernmental Agreement (IGA) X-40690, IWRB Contract No. CON01469. The purpose of this WRO is to provide the Idaho Water Resource Board (IWRB) the budgetary estimate for a cost-based plus fixed margin that identifies the costs in support of operations and maintenance (O&M) services at the Dworshak Hydroelectric Project for 9 months and in accordance with Exhibit A, WRO 001 Scope of Services.

This WRO shall be administered in accordance with IGA Section 6, Compensation and Billing Procedures, 6.3.3 Cost Based WROs.

The following identifies the budget for this WRO:

<table>
<thead>
<tr>
<th>Item Description</th>
<th>Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>Consumables &amp; Small Component Replacements</td>
<td>$5,000</td>
</tr>
<tr>
<td>Insurance</td>
<td>$10,000</td>
</tr>
<tr>
<td>Hydro &amp; Wind Supervisor</td>
<td>$13,638</td>
</tr>
<tr>
<td>Project Specialist</td>
<td>$8,391</td>
</tr>
<tr>
<td>Hydro Mechanic/Operator</td>
<td>$16,538</td>
</tr>
<tr>
<td>Hydro Mechanic/Operator – Call Out</td>
<td>$6,891</td>
</tr>
<tr>
<td>Engineer/Technical Support/Project Management</td>
<td>$26,779</td>
</tr>
<tr>
<td>EN Travel</td>
<td>$7,000</td>
</tr>
<tr>
<td><strong>O&amp;M Total</strong></td>
<td><strong>$94,236</strong></td>
</tr>
</tbody>
</table>

Note: This WRO does not include major maintenance or large broke-fix items over $750 per occurrence. Large broke-fix items shall be addressed with an amended WRO or new WRO to cover that work scope.
2. PERIOD OF PERFORMANCE

Estimated Start Date: July 1, 2020

Estimated Completion Date: March 31, 2021

3. CONSIDERATION

Compensation for the services provided shall be in accordance with terms of the Intergovernmental Agreement. The Not to Exceed Cost for this WRO is $94,236.00. Payment for satisfactory performance of the services shall not exceed this amount unless the parties mutually agree to a greater amount prior to the commencement of the services.

The Water Board certifies that it has approved and appropriated funds available to compensate Energy Northwest completely for the performance of this WRO.

The Water Board certifies that it has approved and appropriated funds available to compensate Energy Northwest completely for the performance of this WRO.

4. ENERGY NORTHWEST ADMINISTRATION

Procurement Specialist; Sherri Schwartz, (509) 372-5072, SLSchwartz@energy-northwest.com

Technical Representative; Scott Urban, (509) 377-4453, SJuUrban@energy-northwest.com

5. EXECUTION

All other terms, covenants and conditions of the above referenced Agreement and WRO documents, except as duly modified by this and previous amendments, if any, remain in full force and effect.

IN WITNESS WHEREOF, IWRB and Energy Northwest have executed this WRO No. 001 to be included as part of Intergovernmental Agreement No X-40690 each by its proper respective officers and officials thereunto duly authorized the date written below.

State of Idaho
IDAHO WATER RESOURCE BOARD

[Signature]
Brian Patton
Executive Officer
7/14/2020

[Signature] For Sherri Schwartz
Sherri Schwartz
Procurement Specialist III
7/9/2020

[Signature] Richard Shaff
Richard Shaff
Contracts Supervisor

Date
A. **Operations Support**: EN shall manage all the processes, people, tools, and assets that are required for the Project to fully perform as it is supposed to, and maintain the effectiveness or efficiency of the Project. Operations support will also include the day-to-day operations of the Project.

1. Project operations are associated with the hydropower facility located near Ahsaka, ID and is licensed with the Federal Energy Regulatory Commission (FERC) in accordance with license# 10819-002.

2. **Project Coordination**
   i. EN shall co-operate the Project with Clearwater Fish Hatchery (CFH)
   ii. EN shall assist and coordinate with Clearwater Power Company (CPC) and the Clearwater Fish Hatchery (CFH) with their operations and maintenance activities that affect the Project operations, such as scheduled shut downs, unscheduled shutdowns, response to alarms, and restarting of the Project as necessary.
   iii. In the event the Corps of Engineers (“COE”), BPA, CPC, or Idaho Department of Fish and Game (“IDFG”) proposes any changes to the operation of the Project, EN shall provide technical advice and written recommendations to the Water Board concerning the proposed change.
   iv. EN shall keep the Contract Manager aware of all activities occurring at the Project.
   v. EN will coordinate with the Water Board’s Contractor (KME Specialties LLC) to develop their understanding of the Project.
   vi. EN will coordinate with Contract Manager to have a kickoff meeting with the CFH, Water Board’s Contractor, and the US Fish & Wildlife Hatchery Staff. The purpose of the meeting is to introduce the parties to each other, discuss authorities, and identify critical operations between the parties and how to work on the Project.

3. **Access to Project**
   The Contract Manager and EN shall provide access to the CFH consistent with the terms in the Water MOU attached as Attachment F to the IGA and incorporated by this reference.

4. **Training-Collaborative**
   i. EN may select, train, and supervise qualified employees, subcontractors, or the Water Board’s Contractor in the local area, in the operation and maintenance of the Project. EN may delegate duties to such employees and agents, but no such delegation shall relieve the EN of its obligation to perform such duties, and the delegations of duties is subject to approval of the Contract Manager.
   ii. EN shall collaborate with CFH personnel, the Water Board’s Contractor, and Contract Manager to learn and identify any training protocols for the Project, such as addressing how to respond in an emergency shutdown of the Project. Any training protocols identified will conform to 29 CFR 1910.269; Occupational Safety and Health Standards – Electrical Power Generation, Transmission and Distribution.
   iii. If training is required due to staff turnover at the CFH, the training shall be considered additional services beyond the scheduled annual refresher course.

5. **Compliance Requirements**
   i. EN agrees to provide the Services for the Project in accordance with Prudent Utility Practice as defined in the IGA.
   ii. EN shall operate and maintain the Project, and perform all duties in this IGA, in compliance with the applicable laws, rules, regulations, and orders of any court or other governmental authority, including standards of the United States Environmental Protection Agency, the Occupational Safety and Health Administration, the United States Federal Energy Regulatory Commission, the Corps of Engineers, the
Idaho Public Utilities Commission, the Idaho Division of Building Safety, and any and all other local, state, or federal regulatory agencies having jurisdiction over the Project. EN shall not permit the Project to be used or operated in material violation of any law, rule, regulation or order.

iii. EN shall meet with State of Idaho Safety and Machinery Regulatory officials as directed by the Contract Manager.

iv. EN shall maintain the Project in a safe operating condition in accordance with Prudent Utility Practice. EN will develop a Project Safety Manual, which must be submitted to the Contract Manager for review and approval no later than 90 days after the execution date of this IGA. Reclamation Safety and Health Standards (“RSHS”) shall be incorporated by references in the Project Safety Manual and a copy shall be maintained in the powerhouse at all times. EN is responsible for keeping the Project Safety Manual current with applicable safety standards.

v. EN shall operate and maintain the Project in accordance with the terms in the Wheeling Agreement attached as Attachment E to the IGA and incorporated by this reference.

vi. EN shall operate and maintain the Project in accordance with FERC license 10819-002, which is incorporated by this reference.

vii. EN shall be present to provide a tour of the facilities for State of Idaho Department of Administration Risk Management.

viii. EN will comply with all other applicable terms of the Power Agreement in Attachment C of the IGA.

6. Transition Coordination with New Operator: EN shall assist Contract Manager with transition planning for the new operator to maintain the Project. Services include an on-site transition meeting, telephone conferences, and correspondence to assist the Contract Manager. The on-site transition meeting shall occur no later than 45 days after the Water Board has issued a notice to proceed to the New Operator.

B. Project Operations

1. Flow control for the facility is managed and controlled by the CFH. EN is not authorized to adjust flows at the Project unless CFH has been contacted and CFH has authorized any adjustments to the flows at the Project.

2. Operations associated with turbine, generator, switches, breakers, batteries, and other electrical componentry shall be operated by EN.

C. Project Maintenance: EN shall provide maintenance activities and services including keeping spaces, structures and infrastructure in proper operating condition in a routine, scheduled, or anticipated fashion to prevent failure and/or degradation. Excluded Work (see Section 2.5 of the IGA) is not within the scope of this WRO. Materials to support routine maintenance activities include lubricating oil, cleaning supplies, software updates/upgrades, paint, light bulbs, and any materials routinely used during the term of this IGA.

1. EN shall use a Supervisory Control and Data Acquisition (“SCADA”) system and autodialer to be in continuous remote communication at the site in order to monitor the plant and to communicate with the autodialer in case of a shutdown or other notification.

i. EN shall make reasonable efforts to respond to such notification and take appropriate action within one (1) to three (3) hours.

a. If an emergent situation occurs requiring less than 3 hours for EN to be on site, EN may call the Water Board’s Contractor to address and report on the situation. EN shall notify the Contract Manager immediately if EN intends to use the Water Board’s Contractor.
b. The autodialer will send an alarm directly to EN for water delivery issues and to a local security service during an intrusion or fire at the Project.

ii. EN will maintain the SCADA system to ensure system data can be stored and available for reporting. Data includes control actions, alarms, and door openings.

2. EN shall routinely lubricate, clean and service Project equipment and facilities with consumable maintenance materials such as lubricants, oils, packing, miscellaneous hardware, light bulbs, and gaskets.

3. Software Updates & Upgrades for Team Viewer Software will be in the Water Board’s name, and EN will be authorized to have access to the SCADA system through this software for the term set forth in the IGA.

4. EN shall perform cleaning of powerhouse, intake louver screens, and maintain grounds as needed and provide the cleaning supplies to perform these services. EN shall provide time stamped photos on the day the work occurred.

5. EN shall perform such other routine services as are necessary or customary for the proper operation and maintenance of the Project such as grounds keeping during the fall, spring, and summer months as well as clearing snow during the winter months.

6. EN shall conduct routine biweekly maintenance inspections of the Project’s facilities, including all component parts of the flow control valves and turbines. EN acknowledges that it may become necessary to conduct routine inspections more often than every two weeks due to unforeseen operational problems.

7. There may be instances when it is reasonable for EN to use the Water Board’s Contractor, so long as EN receives prior authorization from the Contract Manager. If authorization to use the Water Board’s Contractor is not granted by the Contract Manager, it shall be EN’s responsibility to maintain the Project in accordance with the IGA.

D. **Documentation, Record Keeping, and Reporting**

1. Document and report daily logs for all outages or failures and corrective actions taken.

2. EN shall generate a SCADA report three times per day documenting and recording the discrete alarms, primary unit details, secondary unit details, and plant details.

3. EN shall submit a monthly Operation Report to the Water Board for the Project, which will include all status reports, inspection reports, trip reports, alarm reports, maintenance and repair records, correspondence relative to the Project, no later than ten (10) days after end of the month.

4. EN shall submit meeting minutes from annual trainings or on-site transition meetings and additional trainings no later than 10 days after the month in which training was conducted.

5. EN shall prepare, maintain, and distribute to all parties a current emergency contact list twice per year.

6. EN shall update the Emergency Action Plan (EAP) as required by FERC in conjunction with the Water Board.

7. EN shall prepare and maintain a Health and Safety Manual.

8. EN shall prepare and submit a weekly power generation preschedule to the Bonneville Power Association (BPA) by Friday at noon each week via fax or email (fax: (503) 230-5061; email: 3shift@bpa.gov)

9. EN shall provide a Project correspondence file for each quarter.
Exhibit B

Insurance Coverage

Without limiting any liabilities or any other obligations of EN, EN shall, prior to commencing Services, secure and continuously carry with insurers having an A.M. Best Insurance Reports rating of A- or better such insurance as will protect EN from liability and claims for injuries and damages which may arise out of or result from EN’s actions under the Agreement and for which EN may be legally liable, whether such operations are by EN or a Subcontractor or by anyone directly employed by any of them, or by anyone for whose acts any of them may be liable. EN shall insure the risks associated with the Services and this Agreement with minimum coverages and limits as set forth below. EN shall maintain such claims-made policies for a period of at least three (3) years after the expiration or termination of this Agreement. Limits may be met through the combination of primary and excess policies.

To the extent the Parties agree any insurance coverage(s) beyond those required in this Agreement are necessary, such coverage(s) will be secured via the terms of a WRO agreed to by the Parties.

EN grants to Water Board a waiver of any right to subrogation which any insurer of EN may acquire against the Water Board by the payment of any loss by any insurer except as respects Workers Compensation in the state of Washington and Professional Liability; and where not allowed by law. EN agrees to obtain any endorsement that may be necessary to waive an insurer’s right of subrogation, but this provision applies regardless of whether the Water Board has received a waiver of subrogation endorsement from the insurer.

Workers’ Compensation. EN shall comply with all applicable workers’ compensation laws as it may be amended from time to time. Coverage should also provide applicable federal regulations (including, without limitation, FELA, USL&H and the Jones Act).

Employers’ Liability. EN shall maintain employers’ liability insurance with a minimum single limit of $1,000,000 each accident, $1,000,000 disease each employee, and $1,000,000 disease policy limit.

Commercial General Liability. EN shall maintain commercial general liability insurance on the most recently approved ISO policy form, or its equivalent, with limits not less than $1,000,000 per occurrence/$5,000,000 general aggregate and shall include the following coverages:

   a. Premises and operations coverage
   b. Independent contractor’s coverage
   c. Contractual liability
   d. Products and completed operations coverage
   e. Coverage for explosion, collapse, and underground property damage
   f. Broad form property damage liability

Business Automobile Liability. EN shall maintain business automobile liability insurance on the most recently approved ISO policy form, or its equivalent, with a minimum single limit of $1,000,000 each accident for bodily injury and property damage, with respect to EN’s vehicles whether owned, hired or non-owned, in the performance of the Services.

Umbrella or Excess Liability. EN shall maintain umbrella or excess liability insurance with a minimum limit of $5,000,000 each occurrence/aggregate where applicable on a following form basis to be excess of the insurance coverage and limits required in employers’ liability insurance, commercial general liability insurance and business automobile liability insurance above.
Contractors’ Pollution Legal Liability. EN shall require its contractors’, excluding its contractors who only provide personnel staffing services or only provide materials for the Project, maintain pollution liability coverage with a minimum limit of $5,000,000 to apply to sudden pollution conditions including the discharge, dispersal, release or escape of smoke, vapors, soot, fumes, acids, alkalis, toxic chemicals, liquids or gases, waste materials or other irritants, contaminant or pollution into or above land, the atmosphere or any watercourse or body of water, which results in bodily injury or property damage with limits as follows:

a. Coverage for bodily injury, sickness, disease, mental anguish or shock sustained by any person, including death;

b. Coverage for property damage including physical injury to or destruction of tangible property including the resulting loss of use thereof, cleanup costs, and the loss of use of tangible property that has not been physically insured or destroyed; and

c. Coverage for defense costs including costs, charges and expenses incurred in the investigation, adjustment or defense of claims for such compensatory damages.

Water Board does not represent that the insurance coverages specified herein (whether in scope of coverage or amounts of coverage) are adequate to protect the obligations of EN, and EN shall be solely responsible for any deficiencies thereof.

Except for workers’ compensation, the policies required herein shall include provisions or endorsements naming Water Board of, its officers, agents and employees as additional insureds. The Commercial General Liability additional insured endorsement shall be ISO Form CG 20 10 or its equivalent.

To the extent of EN’s negligent acts or omissions, all policies required by this Agreement shall include: (i) provisions that such insurance is primary insurance with respect to the interests of Water Board and that any other insurance maintained by Water Board is excess and not contributory insurance with the insurance required hereunder, (ii) provisions that the policy contain a cross liability or severability of interest clause or endorsement in the commercial general liability and automobile liability coverage except for the limits of insurance; and (iii) provisions that such policies are not be canceled: (a) ten (10) calendar days prior written notice to Water Board if canceled for nonpayment of premium; or (b) thirty (30) calendar days prior written notice to Water Board if canceled for any other reason. Unless prohibited by applicable law, all required insurance policies shall contain provisions that the insurer will have no right of recovery or subrogation against the Water Board, its parent, divisions, affiliates, subsidiary companies, co-lessees, or co-venturers, agents, directors, officers, employees, servants, and insurers, it being the intention of the parties that the insurance as effected shall protect all of the above-referenced entities evidenced by waiver of subrogation wording except for Workers Compensation.

EN acknowledges that Water Board is self-insured and will not obtain a separate insurance policy for this Agreement. Water Board’s self-insurance is subject to the conditions and limitations of the Constitution, Article XI, Section 9, and the Tort Claims Act.
EN shall invoice the Water Board in accordance Section 6 “Compensation and Billing Procedures” and as defined in the approved WROs.

“Additional Services Costs”

Any services in support of this Agreement requested by the Water Board that are outside those described in Exhibit A shall be Additional Services for reimbursement by the Water Board upon invoicing based on actual costs incurred from the preceding month. Costs of Additional Services will fluctuate based on the operations and maintenance needs of the Project and by direction given by the Water Board. Additional Services’ costs subject to Water Board reimbursement include but are not limited to, EN direct labor, travel costs, use of approved subcontractors, materials (subcontractors’ and materials costs include the suppliers’ invoiced cost to Energy Northwest), plus any applicable Energy Northwest overheads, costs of additional insurance specifically required for performance of Additional Services, and delivery costs that are attributable to the Additional Services.

“Additional Costs” for Services and Additional Services intended for full cost recovery include but are not limited to: i) payroll, payroll taxes, at risk compensation and fringe benefits; ii) per diem and travel expenses; iii) all reproduction and printing costs including electronic media; iv) communications costs including all phones, faxes, internet, postage, shipping, delivery, couriers; v) computer, software, printers, scanners, office machines and related costs of operations including consumables; vi) insurance costs; vii) indirect and overhead burden; viii) handling service charges; and ix) Profit will be included as a part of these additional costs as indicated as a percentage of overall revenue and applied at 15%. Note: Additional costs may be in the form of an allocation for those specific costs noted above.

Travel - Travel shall be allowed only when the travel is essential to the discharge of EN’s responsibilities under the Agreement. All travel and lodging shall be conducted in the most efficient and cost-effective manner resulting in the best value to the Water Board. Reimbursable direct costs include pre-approved travel beyond a 225-mile radius from the Project. Personal expenses shall not be authorized at any time. Alcohol is not an authorized purchase under this Agreement. Travel costs shall be reimbursed in accordance with the Water Board’s Travel Reimbursement Guidelines. Refer to Exhibit N, Travel Reimbursement. Upon submitting invoices which indicate travel, EN shall provide all travel receipts for any items being requested for reimbursement (other than on a per diem basis). All receipts shall indicate the company that payment was made to, detail describing the type of services purchased and the total amount paid initially by EN. All requests shall be in accordance with the limits of travel reimbursement. When submitting invoices, and travel has been authorized and conducted by EN, a separate line item shall be identified on the invoice.
Exhibit D

Pre-existing Conditions

Following the Water Board and EN inspection referenced in Section 9, within ninety (90) days of execution of this Agreement, Water Board and EN shall jointly conduct a pre-existing condition inspection, Project Site survey and review of the Project and Project Site to identify any Pre-existing Conditions, and shall update this Exhibit D with the identified pre-existing Project and Project Site conditions of the Agreement.
Exhibit E

Applicable Project Documents

The “Applicable Project Documents” mean and include only the following:

1. Emergency Action Plan (EAP), this document is subject to the Critical Energy Infrastructure Information and must be requested from FERC under 18 C.F.R. 388.113. The EAP is provided as a confidential attachment to this Agreement.
EXHIBIT E

CF MALM ENGINEERS LLC
DWORSHAK SMALL HYDRO
EMERGENCY ACTION PLAN

SCOPE:

A. This Emergency Action Plan (EAP) sets out emergency responses to foreseeable emergencies within the Dworshak Small Hydro Powerhouse (DSH). This document has no authority for dealing with catastrophic events outside the powerhouse arising from earthquake, flood, structural damage to powerhouse, or pipelines, or any problem related to road traffic. As requested and able to; support will be provided to assist with emergencies within the system yet outside of the confines of the powerhouse.

B. The prime operational priority is maintenance of required water flow to the Dworshak National Fish Hatchery (DNFH) and Clearwater Fish Hatchery (CFH). The highest priority emergency response is personal safety, and then maintenance of flow. Loss of power generation does not require an emergency response.

EMERGENCY CATEGORIES:

A. Emergencies within the scope of this plan are:
   1. Operational water level alarms
   2. System failure water level alarms
   3. Powerhouse flood arising from structural failure of piping or turbine case.
   4. Fire.
   5. Incomplete turbine generator shutdown

B. Foreseeable emergency events could arise from one of the following causes:
   1. Equipment catastrophic failure.
   2. Equipment malfunction.
   3. Operational errors leading to equipment failure or malfunction.
   4. Operation errors leading to low flow, high flow, turbine generator overspeed or fire.
INTERESTED PARTIES:

Idaho Water Resource Board (IWRB) – Facility Owner

IWRB Operators – CF Malm Engineers LLC (CFME) – Facility engineer and plant contract operators for the IWRB. CFME supervises and monitors plant operation and maintenance.

Clearwater Fish Hatchery (CFH) – State of Idaho Fish Hatchery served by water from the facility. In addition CFH has a SCADA node for plant monitoring and control. CFH adjusts the turbine generators or sleeve valves for water flow as necessary

Dworshak National Fish Hatchery (DNFH) – Federal Fish Hatchery served by water from the facility.

Army Corps of Engineers – Dworshak Dam (USACE) – Operator of the Dworshak Dam and water supply for the facility

Clearwater Power – Local electrical utility facility is connected to

Clearwater County Sheriff & Emergency Services – Local law enforcement & emergency services including Medical and Orofino Rural Fire

Federal Energy Regulatory Commission (FERC) – Federal licensing agency

COOPERATION BETWEEN AGENCIES:

In the event of an emergency anywhere within the system – Dam to Hatcheries – it is expected each organization will work together and share critical information to bring the situation to the best resolution possible.

Dworshak Small Hydro personnel have no specific responsibilities in the USACE Dworshak Dam EAP other than evacuation if anyone happens to be in the facility. We will however to the best of our ability provide assistance as requested.

RESPONSE HIERARCHY:

The first authorized person on the scene shall be designated as Site Commander. As higher-ranking officials arrive on scene, the Site Commander shall hand over responsibility and the first site commander shall then function as Recorder. The Recorder shall record initial observations, record subsequent actions, and perform other duties as directed by the Site Commander.

A. The response hierarchy shall be as follows in descending order or rank:

1. Clearwater County Sheriff or Deputies in event of personal injury, imminent personal hazard, or property damaged to non-Federal, or non-State property.
2. CFM Manager
3. Trained CFH Staff*
4. CFME

*Trained staff in the context of Dworshak Small Hydro Operations

RESPONSE NOTIFICATION:

The DSH primary alarm notification method is via a telephone autodialer emergency alert system (autodialer). The autodialer is programmed with dialing sequences for various categories of alarms. Upon the initial alarm notification it is up to the individual receiving the notification to investigate the cause of alarm then correct if the alarm is operational in nature or notify additional agencies for response support and to initiate their own emergency response protocol if necessary. Refer to the “Dworshak Small Hydro Emergency Phone List” for agency contact numbers.

A. Autodialer first notification categories:
   1. Water level alarms – CFH
   2. Generation alarms – CFME
   3. Transformer alarms – Clearwater Power first, followed by CFME

B. Response notification according to the type of alarm:
   1. Water Level (Low/High) Alarm – Operational:
      Autodialer: CFH
      Notification: Internal only with CFME as backup support as necessary
   2. Water Level Alarm – System Failure:
      Autodialer: CFH
      Notification: Varies according to type of system failure
      a. Internal to the DSH powerhouse – ie. Low/High water level due to inability to adjust nozzles or sleeve valves to regulate water supply
         - CFH Manager – initiate CFH EAP
         - DNFH – initiate DNFH EAP
         - CFME – To be notified by CFH Manager/Staff
b. External to the DSH powerhouse – ie. Low water level due to penstock failure - partial or complete

- CFH Manager – initiate CFH EAP
- DNFH – initiate DNFH EAP
- USACE –initiate USACE EAP
- Clearwater County Sheriff
- CFME – To be notified by CFH Manager/Staff
- IWRB – To be notified by CFME
- FERC – To be notified by CFME

c. Penstock/supply emergency as discovered by USACE. USACE is lead agency for emergency response. As part of the USACE EAP there is an agreement for notification to:

- CFH Manager – initiate CFH EAP.
- DNFH – initiate DNFH EAP
- DSH – the plant is un-manned but personnel may be there at any time so the attempt to call will still be made

- Additional notifications:
  - CFME – To be notified by CFH Manager/Staff
  - IWRB – To be notified by CFME
  - FERC – To be notified by CFME

3. Powerhouse Flood

   Autodialer: CFH

   Notification: - CFH Manager – initiate CFH EAP
               - DNFH – initiate DNFH EAP
               - Clearwater Power – open substation recloser
               - CFME – To be notified by CFH Manager/Staff
4. Fire

Autodialer: CFH

Notification: - Clearwater County Sheriff & Orofino Rural Fire
- CFH Manager – initiate CFH EAP
- DNFH – initiate DNFH EAP
- Clearwater Power – open substation recloser
- CFME – To be notified by CFH Manager/Staff
- USACE – advise a situation is active
- IWRB – To be notified by CFME
- FERC – To be notified by CFME

5. Incomplete turbine generator shutdown

Autodialer: CFME

Notification: - CFH Manager / Staff for local support

NOTIFICATION CONTACT LIST:

A. The “Dworshak Small Hydro Emergency Phone List” is maintained by CFME. The list is an attachment to this document.

1. In September CFME will contact each organization on the list to verify their information. CFME will then update and redistributed the document to all organizations.

2. Additional updates maybe issued throughout the year if necessary. It is the responsibility of each organization to notify CFME of any interim changes that require list updates.

3. Each agency contact is responsible for phone list distribution to the appropriate personnel within their organization.
OPERATIONAL WATER LEVEL EMERGENCY RESPONSE

Water level alarms require the utmost urgency. At the rated maximum flows the tanks can drain in a matter of minutes

- Primary Tank @ 80 cfs: 3 minutes
- Secondary Tank @ 18 cfs: 11 minutes

During normal operation it is desirable to maintain the tank levels from approximately 15.9 to 16.2 ft. This is just below to just above the tank overflow level. Alarm level setpoints:

- Low Level Alarm: 14.5 ft.
- High Level Shutdown: 17.1 ft

Water Level Alarm notification is initiated by an autodialer call to the CFH contact list. The autodialer call will specify which tank is in alarm – Primary or Secondary.

LOW WATER LEVEL – Operational Error

The turbine nozzles (or sleeve valves) are not supplying the flow required by the combined hatchery demand.

From the SCADA computer in the CFH office open the associated unit nozzles (or sleeve valve) to supply more water to the system. Observe the flow for that unit to verify it does not exceed the maximum allowable flow for the penstock.

- Primary: 80 cfs
- Secondary: 18 cfs

If the flow required to maintain the tank level exceeds the maximum allowable for that penstock, the combined hatchery demand must be reduced or there is a penstock problem below the powerhouse.

Further investigation: Review the Historical Charts for the tank level of the unit in alarm.

- If there is a relatively slow decline to the alarm level then just increasing the flow slightly is probably sufficient
- If the decline is fairly rapid further investigation is warranted.

- Did either Hatchery increase their flow recently without adjusting the unit?
- If not contact CFME for additional support troubleshooting
INTERNAL FAILURE WATER LEVEL EMERGENCY RESPONSE

LOW WATER LEVEL – Internal Failure

Inability to adjust nozzles

There are several conditions that could prevent the adjustment of the nozzles but if the tank level is low the first priority is to increase the flow into the low tank.

- Initial responses:

1. Notify managers at both hatcheries there is a problem with the hydro that might require the hatchery low water EAP be initiated.

2. Make a quick attempt to adjust the nozzle setpoints on the SCADA screen in the Powerhouse in case of a communication problem with the Hatchery.

3. Slowly open one of the sleeve valves for the low tank to supplement the water provided by the generator. Be aware of the maximum allowable penstock flow. Also, if the generator is online and operating without any other problem, leave it online. In emergency situations we recommend the sleeve valve is initially operated locally at the valve using the valve control pushbuttons.

- Follow up actions:

1. Contact CFME for additional support to get the situation under control.

2. Check HPU operation. A pump should be running and the pressure should be in the 1900-2100 psi range. If that is the case attempt to adjust the nozzle manually at the HPU/Nozzle Local Control Panel (HPULCP):
   a. Switch the 43NZ-x (x = P or S) control switch into HAND
   b. Attempt to adjust the nozzles using the 65NZ1-x and 65NZ2-x manual control switches. If they adjust manually complete a flow transfer/shutdown.

3. If the HPU is not functioning or the nozzles will not close manually and it is imperative the water is transferred soon, allow the Turbine Shutoff Valves (TSV) to close while opening the sleeve valves. Closing the TSV’s under flowing conditions can be done but should not be the first response.
   a. Open the TSV lock valves (Yellow Tape on handles) on the hydraulic manifolds
b. At the HPU Local Control Panel place the 43TSV1-x and 43TSV2-x control switches to OFF.

c. Verify the TSV’s start to close (they are VERY slow moving) then press the E-STOP pushbutton on the MCB to trip the generator offline.

d. As the TSV’s close, bump open the sleeve valve to try to maintain a consistent flow. Again be aware of max flow.

**Failure of water level transmitter**

It may be possible the tank level is not actually low but that the level transmitter has failed. The tank water level is measured by an ultra-sonic level sensor/transmitter that sends a 4-20mA analog signal to the PLC for conversion and display on the SCADA screens. The transmitters are the blue devices mounted on the river side Powerhouse wall at the top of the stairs.

- **Initial Responses:**

  1. Notify managers at both hatcheries there is a problem with the hydro that might require the hatchery low water EAP be initiated.

  2. Check the display on the Level Transmitters to determine if it is a complete device failure or an analog signal problem.

  3. Make a visual inspection through the vent grates at the bottom of the stairs – lapping at the top of the wall to a slight overflow is normal.

  4. Make a visual inspection of the tank water level through the access hatch.
      a. Primary Unit Tank – 10 ½ rungs exposed normal level
      b. Secondary Unit Tank – 10 rungs exposed normal level

  5. Adjust nozzle setpoints on the SCADA computer as necessary.

- **Follow up actions:**

  1. Contact CFME for additional support to resolve the situation.
HIGH WATER LEVEL EMERGENCY RESPONSE

HIGH WATER LEVEL – Internal Failure

Inability to adjust nozzles

- Initial responses:

1. Notify managers at both hatcheries there is a problem with the hydro.

2. Make a quick attempt to adjust the nozzle setpoints on the SCADA screen in the Powerhouse in case of a communication problem with the Hatchery.

3. If the generator floor has started to flood hit the MCB E-STOP pushbuttons

4. From either SCADA screen open the sub-station recloser.

5. If there are only a couple of inches of water on the floor and the HPU is operating, close the nozzles manually while opening a sleeve valve.
   a. Switch the 43NZ-x (x = P or S) control switch into HAND
   b. Attempt to CLOSE the nozzles using the 65NZ1-x and 65NZ2-x manual control switches. If they close manually complete a flow transfer to a sleeve valve.

6. If the HPU is not functioning or the nozzles will not close manually, allow the Turbine Shutoff Valves (TSV) to close while opening the sleeve valves.
   a. Open the TSV lock valves (Yellow Tape on handles) on the hydraulic manifolds
   b. At the HPU Local Control Panel place the 43TSV1-x and 43TSV2-x control switches to OFF.
   c. Verify the TSV’s start to close (they are VERY slow moving). As the TSV’s close, bump open the sleeve valve to try to maintain a consistent flow. Again be aware of max flow.

7. If the generator floor cannot be safely accessed follow the Powerhouse Flood procedure.

8. Contact CFME for additional support to get the situation under control.

9. Notify Clearwater Power the recloser was purposely tripped.
HIGH WATER LEVEL EMERGENCY RESPONSE

POWERHOUSE FLOOD

A powerhouse flood maybe due to a nozzle problem but more likely caused by an inlet piping or turbine case rupture.

- Initial Response:

1. Notify managers at both hatcheries the hydro is flooded.
2. Notify the USACE the small hydro is flooded.
3. Hit the MCB E-STOP pushbuttons
4. From either SCADA screen open the sub-station recloser.
5. Assess which unit has the problem then go outside and close the turbine plug valve for that unit. See drawing opposite page.
6. When the water level subsides to where it is safe to access the turbine floor, open a sleeve valve for the effected unit to maintain tank water level. Try to keep the tank overflowing the weir wall an inch or so to flush any surface contaminates that may have gotten into the tank out.
7. Contact CFME for additional support to get the situation under control.
8. Notify Clearwater Power the recloser was purposely tripped.
EXTERNAL FAILURE WATER LEVEL EMERGENCY RESPONSE

LOW WATER LEVEL

Penstock Partial or Complete Failure

- Initial response:

1. Notify managers at both hatcheries there is a penstock failure that requires the hatchery low water EAP be initiated.

2. Notify the USACE that there has been a penstock failure.

3. Notify the Clearwater County Sheriff there has been a penstock failure.

4. Hit the MCB E-STOP pushbutton for the effected unit(s).

5. Close the associated TSV’s to prevent possibly contaminated water from entering the system
   a. Open the TSV lock valves (Yellow Tape on handles) on the hydraulic manifold
   b. At the HPU Local Control Panel place the 43TSV1-x and 43TSV2-x control switches to OFF.

6. If only one penstock has failed consider opening the tank cross-connect valve to supply at least some water to the opposite line.

7. If opening the nozzles or sleeve valve on the non-effected unit to support the other; continue to be aware of the maximum allowable penstock flow.
FIRE EMERGENCY RESPONSE

Powerhouse Fire

Most likely a powerhouse fire is electrical in origin but may ignite materials that can give off toxic gases or particles. Human life safety is always paramount over anything else.

DO NOT ENTER the powerhouse!

Transformer Building or Metal Clad Switchgear Fire or Arcing

The transformer is filled with fire retardant coolant and the switchgear has very little combustible material so a fire in either is unlikely. Arcing may occur from insulation flashover due to lightning or other surges. The protective relays should trip the Ahsahka Substation Hydro Recloser and shutdown the generators.

- Initial Response:

1. For a powerhouse fire, the alarm system should notify the local fire department directly. The autodialer should notify the CFH list.
2. Go the Hatchery SCADA computer and attempt to open the Ahsahka Substation Hydro Recloser
3. Call to verify the alarm system indeed notified the fire department.
4. Notify both Hatchery managers of the current situation.
5. Contact Clearwater Power to verify the Ahsahka Substation Hydro Recloser opened if not have them open.
6. When it is safe to enter the powerhouse, assess the water level situation. Transfer water flow to the sleeve valves and close the TSV’s. In the worst case, close the turbine plug valves and hand crank open the sleeve valves.
7. Notify CFME of the current situation.

- Follow up actions:

1. Monitor the tank water levels
INCOMPLETE TURBINE GENERATOR SHUTDOWN

GENERATOR BREAKER WON’T OPEN

If the Generator Breaker does not open properly but the deflector drops the unit will continue to run as a motor. If the unit indicates “Stopped,” but the breaker does not indicate open and the unit is not starting to slow.

- Initial response:
  1. If operating, stop the other unit
  2. From either SCADA computer open the Ahsahka Substation Hydro Recloser.
  3. Press both MCB E-STOP pushbuttons.
  4. Transfer water to the sleeve valves.
  5. Notify CFME of the current situation.
  6. Notify Clearwater Power the recloser was purposely tripped.

TURBINE GENERATOR OVERSPEED

The turbine generator is designed to 200% overspeed for two hours but it is desirable to stop the unit as soon as possible. Even under a trip situation the overspeed should be slight and for only a few seconds. If the overspeed lasts longer or above even 120%:

- Initial response:
  1. Press the MCB E-STOP pushbutton.
  2. If the deflector still does not drop in order of priority until the deflector drops or water stops
     a. Switch the 43DEF toggle switch on the MCB to MANUAL
     b. Close the nozzles
     c. Close the TSV’s
     d. Close the turbine plug valve
  3. Open a sleeve valve and monitor water level
  4. Notify CFME of the current situation.

END OF EMERGENCY ACTION PLAN
CF MALM ENGINEERS LLC
5511 6th Ave. S.
Seattle, WA 98108
206 270 0450 – Fax 270 0449
cfme@cfmalm.com
# EMERGENCY PHONE LIST

**C F MALM ENGINEERS**

**DWORSHAK SMALL HYDRO**

<table>
<thead>
<tr>
<th>PHONE NUMBERS:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>C F MALM ENGINEERS</td>
<td>Office</td>
</tr>
<tr>
<td>CLIFF MALM</td>
<td>Office</td>
</tr>
<tr>
<td>STEVE SPAULDING</td>
<td>Home</td>
</tr>
<tr>
<td>STROM ELECTRIC</td>
<td>Office</td>
</tr>
<tr>
<td>ON CALL</td>
<td>Pager</td>
</tr>
<tr>
<td>PHIL STRADLEY</td>
<td>Home</td>
</tr>
<tr>
<td>MIKE STRADLEY</td>
<td>Home</td>
</tr>
<tr>
<td>JEFF CARLSON</td>
<td>Home</td>
</tr>
<tr>
<td>CLEARWATER FISH HATCHERY</td>
<td>Office</td>
</tr>
<tr>
<td>TONY FOLSOM</td>
<td>Home</td>
</tr>
<tr>
<td>CHRIS SHOCKMAN</td>
<td>Home</td>
</tr>
<tr>
<td>DAN DILLON</td>
<td>Home</td>
</tr>
<tr>
<td>ANDREW NIEBUHR</td>
<td>Home</td>
</tr>
<tr>
<td>STEVE STOWELL</td>
<td>Home</td>
</tr>
<tr>
<td>LeANDRA SMITH</td>
<td>Home</td>
</tr>
<tr>
<td>JOHN ELLIOTT</td>
<td>Home</td>
</tr>
<tr>
<td>CLEARWATER POWER</td>
<td>Dispatch</td>
</tr>
<tr>
<td>LEWISTON</td>
<td>After Hours</td>
</tr>
<tr>
<td>AHSAHKA</td>
<td>Office</td>
</tr>
<tr>
<td>DOUG PFAFF</td>
<td>Yard</td>
</tr>
<tr>
<td>DWORSHAK FISH HATCHERY</td>
<td>Office</td>
</tr>
<tr>
<td>MARK DROBISH</td>
<td>Home</td>
</tr>
<tr>
<td>STEVE RODGERS</td>
<td>Home</td>
</tr>
<tr>
<td>ADAM IZBICKI</td>
<td>Home</td>
</tr>
<tr>
<td>JEREMY SOMMER</td>
<td>Home</td>
</tr>
<tr>
<td>SCOTT KOEHLER</td>
<td>Home</td>
</tr>
<tr>
<td>DWORSHAK DAM</td>
<td>Control Room</td>
</tr>
<tr>
<td>GREG PARKER</td>
<td>Office</td>
</tr>
<tr>
<td>LUCIAN STEWART</td>
<td>Office</td>
</tr>
<tr>
<td>DWORSHAK SMALL HYDRO</td>
<td>Powerhouse</td>
</tr>
<tr>
<td>FERC</td>
<td></td>
</tr>
<tr>
<td>DOUGLAS JOHNSON</td>
<td>Office</td>
</tr>
<tr>
<td>ELISABETH MATT</td>
<td>Office</td>
</tr>
<tr>
<td>IDAHO WATER RESOURCES BOARD</td>
<td>Office</td>
</tr>
</tbody>
</table>

**END OF EMERGENCY PHONE LIST**
Exhibit F

Applicable Permits

“Applicable Permits” mean and specifically include the following:

1. Federal Energy Regulatory Commission license No. 10819-002
Exhibit G

Project Site

This document is subject to the Critical Energy Infrastructure Information and must be requested from FERC under 18 C.F.R. 388.113. The document is provided as a confidential attachment to this Agreement.
Confidential
Exhibit H

Water Board’s Standard Operating Procedures

This document is provided as an attachment to this Agreement.
DWORSKAH SMALL HYDROELECTRIC PLANT

STANDARD OPERATION PROCEDURES
FOR
PROJECT OPERATOR
and
IDAHO WATER RESOURCE BOARD

December – 2019
# Table of Contents

1.0 Introduction ..........................................................................................................................3  
1.1 General Introduction ...........................................................................................................3  
1.2 Background .........................................................................................................................4  
2.0 Objectives ............................................................................................................................4  
3.0 Project Overview  
3.1 Project Facilities...............................................................................................................5  
   3.1.1 Water Supply and Power Generation Facilities .......................................................5  
   3.1.2 Equipment and Controls .........................................................................................5  
4.0 Roles and Responsibilities ...................................................................................................5  
4.1 Operator Roles and Responsibilities ..................................................................................5
1.1 General Introduction

The Idaho Water Resource Board (IWRB) is the owner and operator of the Dworshak Small Hydroelectric Plant (Project). The Project is located at 4125 Ahsahka Road in Ahsahka, Idaho, near the North Fork of the Clearwater River. The Project was constructed within the Nez Perce Indian Reservation on land owned by the US Army Corps of Engineers, the US Fish and Wildlife Service, and the Bureau of Land Management. The Project was issued a FERC license in August, 1997, and the Project was completed in 2000 and commissioned into service in June, 2000.

The Project is approximately one mile downstream of Dworshak Dam on the south side of the North Fork of the Clearwater River. The Project was constructed on an existing fish hatchery flow regulating tank. Two pipelines/penstocks, 36” and 18”, convey water from Dworshak Reservoir to the Project for power generation and to supply water to the Clearwater Fish Hatchery and the Dworshak National Fish Hatchery. The Project is comprised of two hydroelectric units, a 2.5 MW and a 0.5 MW Gilkes Turgo turbines, control equipment with power grid connection, pipeline appurtenances, backup generator, and power substation.

1.2 Background

In the 1980’s, the federal government commenced planning for the proposed Clearwater Fish Hatchery in Ahsahka, Idaho. Two pipelines from the Dworshak Reservoir Dam will convey water from Dworshak Reservoir to the proposed Clearwater Fish Hatchery, the existing Dworshak National Fish Hatchery, and the Project. The decision to convey water from Dworshak Reservoir to the hatcheries was a result of water quality problems experienced by the Dworshak National Fish Hatchery. A main component of the Clearwater Fish Hatchery project was the design of a concrete flow regulating tank for energy dissipation and for delivery of water to the two fish hatcheries.

Due to the significant potential for hydropower development identified by the US Army Corps of Engineers (Corps), the Corps commenced a search for non-Federal entities that were interested in pursuing hydropower development. The City of Orofino received a Preliminary Permit for Study from the Federal Energy Regulatory Commission (FERC) for the development of hydropower. However, due to legal and financial reasons, the City withdrew from the Project. After the City’s withdrawal from the Project, the IWRB was invited to pursue development of the Project. In 1989, the IWRB funded a feasibility study for the Project on the engineering, environmental, and financial feasibility of the Project for presentation to the Governor and Legislature, as required under Section 42-1734, Idaho Code.

In 1990, the Idaho Legislature authorized the development of the Project by the IWRB in conjunction with the development of a water supply system for the existing Dworshak National Fish Hatchery and the proposed Clearwater Fish Hatchery. Under Section 42-1732, Idaho Code, the Idaho Water Resource Board is authorized to take all actions necessary in accordance with the existing laws to plan, finance, construct, acquire, operate, own and maintain the Project, enter into contracts for the wholesale of hydroelectric power, acquire all necessary real and personal property, and to issue and sell revenue bonds for financing projects.

In 1991, the construction of the Clearwater Fish Hatchery and the concrete distribution tank were completed. In 1992, the installation of the 36-inch and 18-inch supply pipelines from the Dworshak Reservoir Dam were completed and the Clearwater Fish Hatchery commenced operations.
In 1994, the IWRB applied for a FERC license to construct and operate the Project. In 1997, a FERC license was issued to the IWRB. Construction of the Project began in 1999, and the Project was commissioned in June, 2000.

2.0 Objectives

The long-term objective is to maintain efficient operation of the power plant and implement improvements to increase efficiency, reduce maintenance costs, and achieve maximum useful life of the Project.

3.0 Project Overview

3.1 Project Facilities

3.1.1 Water Supply and Power Generation Facilities

Water from Dworshak Reservoir is conveyed from the Dworshak Dam to the Project by a 36” pipeline to the primary turbine and an 18” pipeline to the secondary turbine. Water is deflected through the turbines into a concrete flow regulating tank which delivers water to the Clearwater Fish Hatchery and Dworshak National Fish Hatchery. During Project shutdowns, water supply to the fish hatcheries is uninterrupted. Clearwater Fish Hatchery controls discharge rates from Dworshak Reservoir to both fish hatcheries.

The power generation capacity for the Project is 3.0MW. Power is generated by a 2.5MW Gilkes Turgo turbine (Primary Unit) and a 0.50MW Gilkes Turgo turbine (Secondary Unit). The Project generates approximately 19-million Kilo-Watt hours per year.

3.1.2 Equipment and Controls

Equipment and controls at the Project include control equipment for operation of each turbine by a System Control and Data Acquisition (SCADA) system and autodialer. The SCADA system and autodialer allows remote operation and monitoring by the Contractor and the Clearwater Fish Hatchery. Additional Project equipment includes a power substation with a power grid connection, and a propane fueled backup generator.
4.0 Operator Roles and Responsibilities

4.1 Roles and Responsibilities

The Project Contractor will perform all required engineering, operation, and maintenance duties for the Project over a 5-year Contract Term. The Contractor’s engineering, operation, and maintenance responsibilities shall include, but are not limited to:

- Provide all labor and materials necessary for the engineering services and operation and maintenance of the Project
- Provide information documenting the annual energy generated
- Maintain the SCADA system and autodialer to enable remote monitoring of the Project
- Operator shall conduct routine biweekly inspections of the Project’s facilities, including all components of the water controlling and power producing equipment
- Perform periodic adjustments and routine repairs as necessary to the Project’s water controlling and power producing equipment to minimize interruptions of service and to maximize power output and operational efficiency
- Perform routine and preventative maintenance to the water controlling and power producing equipment in order to maintain the equipment in good condition and to maximize its useful life
- Lubricate and service the equipment and provide consumable maintenance materials such as lubricants, oils, packing, miscellaneous hardware, gaskets, etc.
- Select, train, and supervise capable employees, including a representative in the local area (within a 60-mile radius), to perform the operation and maintenance duties of the Project
- Provide training for designated US Corps of Engineers and Idaho Fish & Game personnel that will respond to an emergency shutdown of the Project
- Maintain the Project in a safe and reliable operating condition in accordance with good utility practices
- Obtain project status reports three times per day
- Perform all routine services as necessary or customary for the proper operation and maintenance of the Project
- Operate and maintain the Project, and perform all duties, in compliance with applicable laws, rules, regulation, and orders
- Perform cleaning operations of the power plant and site
- Prepare Monthly Operation Reports for the Project
- Prepare annual reports of energy generation
- Prepare updated Emergency Action Plan as required by FERC
- Prepare maintenance schedules and procedures
- Prepare daily logs for all system outages or failures and corrective action
- Provide technical advice and written recommendations concerning proposed changes to operation of the Project
5.0 IWRB Roles and Responsibilities

5.1 Roles and Responsibilities

The IWRB Project Coordinator will perform all required contractor coordination, contract management, construction management, and review and processing of all invoices and billings. The Project Coordinator’s responsibilities shall include, but are not limited to:

- Contractor coordination issues
  - Engineering – Proposals for Project enhancements and improvements, study’s
  - Operation – Plant shutdowns, alarms
  - Maintenance – Equipment lubrication, repairs, and replacement
  - Inspections – Bi-weekly on-site inspections/maintenance
- Contract management issues
  - Contract preparation and negotiations (5-year term)
  - Processing of contractor invoices/pay requests
  - Processing of contractor quarterly O & M invoice
- Construction management issues
  - Inspection and monitoring of Project improvements and/or equipment repairs or replacements
- Monthly invoices/billings
  - Bonneville Power Administration – Power production invoicing to BPA (30-year energy sales agreement)
  - Clearwater Power Company – Two invoices (O&M and Project power usage)
  - Frontier Communications – Telephone/security
  - AmeriGas – Propane for backup generator
- Quarterly invoices/billings
  - Johnson Controls - Security
- Annual billings
  - Federal Energy Regulatory Commission (FERC) – Hydropower annual fee
  - Federal Energy Regulatory Commission (FERC) – Land use fee
  - Nez Perce Systems – Wireless internet
- Repair & Replacement Fund
  - Monitor annual fund balance and coordination with finance manager to implement changes to monthly funding transfers from power generation revenue
Exhibit I

Project Supplies and Project Tools

Following the Water Board and EN inspection referenced in Section 9, the following are the Project Supplies and Project Tools:
### Exhibit J

**Party Representative Information**

<table>
<thead>
<tr>
<th>Organization</th>
<th>Name</th>
<th>Title</th>
<th>Contact Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy Northwest</td>
<td>Scott Urban</td>
<td>O&amp;M Professional Services Manager</td>
<td><a href="mailto:sjurban@energy-northwest.com">sjurban@energy-northwest.com</a>  (509) 377-4453</td>
</tr>
<tr>
<td></td>
<td>Kristine Cavanah</td>
<td>Project Specialist</td>
<td><a href="mailto:kdcavanah@energy-northeast.com">kdcavanah@energy-northeast.com</a> (509) 377-4225</td>
</tr>
<tr>
<td></td>
<td>Sherri Schwartz</td>
<td>Procurement Specialist</td>
<td><a href="mailto:slschwartz@energy-northwest.com">slschwartz@energy-northwest.com</a> (509)372-5072</td>
</tr>
<tr>
<td>Idaho Department of Water Resources</td>
<td>Randy Broesch</td>
<td>Staff Engineer</td>
<td><a href="mailto:randall.broesch@idwr.idaho.gov">randall.broesch@idwr.idaho.gov</a> (208) 287-4879</td>
</tr>
<tr>
<td>Idaho Fish and Game</td>
<td>Joel Patterson</td>
<td>Fish Hatchery Manager</td>
<td><a href="mailto:joel.patterson@idfg.idaho.gov">joel.patterson@idfg.idaho.gov</a> (208) 315-0754</td>
</tr>
<tr>
<td>KME Specialties, LLC</td>
<td>Phil Stradley</td>
<td>Owner</td>
<td><a href="mailto:pstradley@kmespecialties.com">pstradley@kmespecialties.com</a> (208) 835-3270</td>
</tr>
</tbody>
</table>
Exhibit K

Memorandum of Understanding between the Water Board and the United States Fish and Wildlife Service, dated June 5, 2000

This document is provided as an attachment to this Agreement.
MEMORANDUM OF UNDERSTANDING

FOR THE USE OF THE
CLEARWATER FISH HATCHERY WATER SUPPLY LINES
FOR THE OPERATION OF THE
DWORSHAK SMALL HYDROELECTRIC PROJECT

BETWEEN

U. S. FISH AND WILDLIFE SERVICE
Lower Snake River Compensation Plan Office

AND

IDAHO WATER RESOURCE BOARD
# TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>Article</th>
<th>Title</th>
<th>Page No.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Purpose</td>
<td>2</td>
</tr>
<tr>
<td>2</td>
<td>Ownership</td>
<td>3</td>
</tr>
<tr>
<td>3</td>
<td>Access</td>
<td>3</td>
</tr>
<tr>
<td>4</td>
<td>Operations</td>
<td>4</td>
</tr>
<tr>
<td>5</td>
<td>Interruption of Water Releases</td>
<td>5</td>
</tr>
<tr>
<td>6</td>
<td>Maintenance</td>
<td>6</td>
</tr>
<tr>
<td>7</td>
<td>Project Modifications</td>
<td>7</td>
</tr>
<tr>
<td>8</td>
<td>Inspection by the Corps after Construction</td>
<td>7</td>
</tr>
<tr>
<td>9</td>
<td>Training</td>
<td>8</td>
</tr>
<tr>
<td>10</td>
<td>Liability</td>
<td>8</td>
</tr>
<tr>
<td>11</td>
<td>Disagreements</td>
<td>8</td>
</tr>
<tr>
<td>12</td>
<td>Assignment</td>
<td>9</td>
</tr>
<tr>
<td>13</td>
<td>Term</td>
<td>9</td>
</tr>
<tr>
<td>14</td>
<td>Exhibits</td>
<td>9</td>
</tr>
<tr>
<td>15</td>
<td>Notices</td>
<td>9</td>
</tr>
<tr>
<td>EXHIBITS</td>
<td>Page</td>
<td></td>
</tr>
<tr>
<td>-------------------------------------------------------------------------</td>
<td>------</td>
<td></td>
</tr>
<tr>
<td>A. Areas of Responsibility</td>
<td>11</td>
<td></td>
</tr>
<tr>
<td>B. Project Operation Procedures</td>
<td>12</td>
<td></td>
</tr>
<tr>
<td>C. Clearance Procedure Summary</td>
<td>13</td>
<td></td>
</tr>
<tr>
<td>D. Memorandum of Understanding between Clearwater Fish Hatchery, Dworshak National Fish Hatchery, and the U.S. Army Corps of Engineer's Dworshak Project for the Operation and Entrance Requirements for the Hatchery Water Supply System</td>
<td>14</td>
<td></td>
</tr>
</tbody>
</table>
PREAMBLE

This Memorandum of Understanding (MOU) is entered into this 5th day of July, 2000, by and between the United States of America acting through the Department of the Interior, Fish and Wildlife Service (Service), and the Idaho Water Resource Board (Board) also referred to as the Licensee.

RECITALS

1. The Department of the Army, Corps of Engineers (Corps), constructed the Clearwater Fish Hatchery (CFH) together with water supply lines for the CFH and water supply lines for the adjacent Dworshak National Fish Hatchery (DNFH) for fish production and other purposes of the Lower Snake River Compensation Plan, which was authorized by Water Resources Act of 1976 (Public Law 94-587). The water supply lines include a distribution box to the two hatcheries. The distribution box provides the base for the main portion of the Dworshak Small Hydroelectric Project (Project).

2. The ownership of CFH including the water supply line from the intake to CFH and the distribution box was transferred from the Corps to the Department of the Interior, Fish and Wildlife Service, on April 10, 2000.

3. The Service administers and funds the Lower Snake River Compensation Plan's fish propagation facilities to offset losses associated with the construction and operation of the four Lower Snake River dams. The Idaho Department of Fish and Game (IDFG) operates CFH under a cooperative agreement with the Service. The Service/IDFG agreement provides that the CFH manager, an IDFG employee, shall operate the water supply lines, which are facilities of CFH, from Dworshak Dam to the distribution box to meet the needs of both CFH and DNFH.

4. The Federal Energy Regulatory Commission (FERC), in accordance with the Federal Power Act, issued License No. 10819-002, dated August 4, 1998, to the Idaho Water Resource Board for the construction, operation and maintenance of the Project. Article 305 of the License required the Licensee to enter into an operating Memorandum of Agreement with the Corps (who owned the pipeline at the time) to protect the interests of the Federal Government and to insure the continuity of the CFH and the DNFH operations.

5. The Corps and Board entered into a Memorandum of Agreement (MOA) executed on September 13, 1993, which described the rights and responsibilities of the Corps and Board in the design and construction of the Project. Article 2 (10) of the MOA required the
parties enter into a subsequent agreement addressing operation and maintenance of the Project.

6. The Board and Bonneville Power Administration (BPA) entered into a Settlement and Contingent Power Purchase Agreement on April 30, 1990 establishing terms for the purchase of the Project's electricity.

7. The Service operates the DNFH under agreement with the Corps. The DNFH takes a portion of its water supply from the distribution box upon which the project largely will be built.

8. The authority of the Service to operate the CFH water supply which is the subject of this MOU, as well as its authority to permit Idaho Water Resources to use the water supply, is subject to a preexisting obligation to provide specific flows to the Corps for operation and maintenance of DNFH. No agreement contained or referenced in this MOU may interfere in any way with the existing Service obligation to provide the required flows to DNFH and any express or implied agreement to the contrary is hereby declared null and void and shall not bind the parties to performance.

9. The Board plans to substantially complete the Project and undertake operation by August 4, 2000, and intends to use the water controlled by the CFH manager for the generation of electrical energy.

10. The Board intends to enter into an agreement with others to operate and maintain the Project.

The Service and Licensee agree to the operation and maintenance of the Project subject to the terms of the License and the conditions hereinafter set forth:

ARTICLE 1

PURPOSE

The purpose of this MOU is to set out the requirements for the operation, maintenance and use of certain facilities owned by the U. S. Government (Government) and needed by the Licensee for the operation of the Project. Additionally, this MOU serves to meet certain requirements and contractual obligations of the Board under Article 305 of FERC License 10819-002, the MOA with the Corps dated September 13, 1993.
ARTICLE 2

OWNERSHIP

A. Existing appurtenances and equipment for the CFH and DNFH including appurtenances and equipment at the water distribution box are presently owned by the Government and shall remain the property of the Government. The Service has jurisdiction of the property. (See U.S. Army Corps of Engineer, Walla Walla, Washington District, original contract drawings Inv. No. 90-B-32 for the Clearwater Fish Hatchery Water Supply and related change orders.)

B. Licensee shall retain ownership of all equipment installed by Licensee to operate the Project. Licensee shall retain ownership to the Project including the powerhouse superstructure above the powerhouse floor, the turbine and generator, the power transformer and turbine intake piping and valves, and all other appurtenant features (hereafter referred to as Project Structures).

C. However, in the event that the Project is abandoned or removed by Licensee, the powerhouse superstructure and floor shall remain an integral part of the existing facilities and title shall pass to the Government by virtue of said action. The Licensee shall remove all other Project Structures and restore the premises to the satisfaction of the Service in accordance with Article 30 of the Terms and Conditions for FERC license 10819-002. If the Licensee fails or neglects to remove said property or restore the premises, then at the option of the Service, the property shall either become the property of the Government without compensation therefore, or the Service may cause the property to be removed and no claim for damages against the Government or its officers or agents shall be created by or made due to such removal or restoration. The Licensee shall also pay the Service on demand any sum which may be expended by the Service in restoring the premises.

ARTICLE 3

ACCESS

A. The Service, its agents, contractors and those employees designated by the CFH manager shall at all times have free and unrestricted access to, through, and across all Project lands and appurtenances wherever access is required for performance of normal operation and maintenance duties as well as during times when such access would be required to protect health and safety. In order to assure safety to persons and property, the Service and CFH hatchery personnel shall attempt to provide the Board prior notification of access and security during periods of access.
B. Access onto CFH and DNFH by Licensee personnel, or its representatives, must be approved by the operating manager of the respective fish hatchery.

C. Access to the distribution box exit pipelines or inlet pipelines located above the inlet plug valves, must be authorized by the CFH manager and, for the DNFH exit pipeline, by DNFH or Corps personnel.

ARTICLE 4

OPERATIONS

A. Project water flows from Dworshak Dam will be determined and controlled by the CFH manager (acting as an agent of the Service) based on the fish production needs of CFH and DNFH. Primary communications shall be provided by the System Control and Data Acquisition (SCADA) equipment to the control equipment with notification to the operator of the Project as mutually agreed upon by the CFH manager and the Licensee. Secondary communications shall be through a computer telephone modem to the control equipment.

B. An emergency, as referred to in this section, is defined as an event that could reasonably lead to the sudden or catastrophic loss of life, property or fish resources. The CFH manager or a designated representative shall determine when an emergency situation exists and will advise the Licensee, DNFH manager, Corps, and Service of the emergency as soon as possible. An emergency situation shall include, but is not limited to, an earthquake, flash flood, tornado, or mechanical failure of gates or valves. In response to an emergency, the CFH manager may take appropriate action, as provided in Exhibit B, including terminating Project operations, provided that any action taken directly by the CFH manager to change the Project operating status will be communicated to the Licensee or its designated representative as soon as possible. The CFH manager, the Service, or the Corps will not be held liable for damage to Licensee's facilities during emergency situations.

C. After construction is complete, a testing program of control features shall be accomplished to determine the actual normal and emergency operating features. The testing program's emergency operating features will be included as a part of the Emergency Action Plan described in Exhibit B of this MOU.

D. The Project will be operated locally and will be visited and monitored on a regular basis by the Licensee's operation and maintenance personnel. The Licensee will monitor the Project status and alarm indicators as provided in Exhibit B.
E. The Licensee will be responsible for operating the turbines and the bypass system in cooperation with the CFH manager. In the event of a load rejection, turbine deflector blades shall automatically move to deflect the incoming water away from the turbine runners allowing the turbine-generator to roll to a stop and flow to the hatcheries to continue.

F. The Licensee shall obtain written consent from the Service and Corps before any modifications are made to the Project Structures or to the Project operations which might affect operations of CFH or DNFH.

G. The Licensee shall be responsible for pollution caused by it and its agents. The Licensee shall not unlawfully pollute the air, ground or water or create a public nuisance. The Licensee shall at no cost to the Government, promptly comply with present and future federal, state and local laws, ordinances, regulations, or instructions controlling the quality of the environment. Nothing in this section shall affect the Licensee’s right to challenge the validity of any law or seek injunctive relief.

H. The Licensee shall be responsible for, and have sole operating responsibility for, equipment as outlined in Exhibit A.

I. The Licensee shall adhere to all provisions of the current Occupational Safety Health Administration (OSHA) requirements and the Idaho General Safety and Health Standards (see Idaho Division of Building Safety).

ARTICLE 5

INTERRUPTION OF WATER FLOW

Flow of water in the CFH pipeline to and from the Project shall be in accordance with schedules established by the CFH manager. Interruptions of flow of more than short durations may be necessary at times for hatchery operations, maintenance, or repair. This MOU does not guarantee flows beyond those needed to safely and properly operate CFH and DNFH. Flow of water from the Project to CFH and DNFH shall not be interrupted by the operation or maintenance of the Project unless approved in advance by the CFH manager or in case of emergency as described in Article 4.B and Exhibit B.
ARTICLE 6

MAINTENANCE

A. All costs necessary for the maintenance, repair, replacement, and proper operation of the following facilities shall be the sole responsibility of the Licensee. These facilities include, but are not limited to:

(1) The Project Structures as defined under Article 2.B. of this MOU.

(2) Grounds care and security measures of established areas of Project Structures known as the “compound.”

(3) Remote status and alarm equipment.

(4) Distribution box lights, panelboards. and project valves and piping other than the Bailey polyjet ported sleeve valves and associated piping.

(5) Powerhouse floor.

B. Limitations and controls on maintenance and post project actions by the Licensee.

(1) The Licensee shall coordinate its operation and maintenance activities so as not to interfere with the maintenance crews and the maintenance programs of the CFH manager.

(2) The distribution structure and all appurtenant facilities including the equipment in the pre-license Government structure, shall not be altered, replaced, or removed without the express written consent of the Service.

C. All costs necessary for the maintenance, repair, replacement, and proper operation of non-Project facilities shall be the sole responsibility of the following parties:

(1) The valves and pipeline from the intake to the distribution structure and the distribution box interior structures below the powerhouse floor and the overflow piping will be the responsibility of CFH (under agreement with the Service).

(2) Routine maintenance, repair, replacement, and proper operation of the valves and pipeline from the distribution box to DNFH will be the responsibility of DNFH (under agreement with the Corps). The Corps will assist with non-routine maintenance, if required.)
D. The CFH manager will provide as much notice as possible of any maintenance activity that might affect the Project.

ARTICLE 7

PROJECT MODIFICATIONS

The Licensee shall undertake no change to the Project, which in the opinion of the Service may affect the structural integrity of the CFH distribution box, inlet piping, outlet piping, or related items or their operation, without first obtaining the written consent of the Service, whose response shall not be unreasonably withheld or delayed.

ARTICLE 8

INSPECTION BY THE GOVERNMENT AFTER CONSTRUCTION

A. The Service shall have the right to inspect the Project Structures to ensure that the Project is being operated and maintained in a manner that will not endanger the structural integrity or operation of the CFH and DNFH water supply lines and appurtenances. Each party shall furnish such plans, drawings, specifications, documentation and information pertaining to its equipment, facilities, or requirements as may reasonably be requested by the other party to perform or exercise its rights or obligations under this MOU. During inspections, the Licensee may be required to de-water the Project Structures to facilitate inspection. Timely written notice of these scheduled inspections shall be given to the Licensee by the Service and shall be scheduled, to the extent practicable, so as to minimize interruption to Project generation. The Service shall provide copies of all inspection reports to the Licensee and the FERC. The Licensee shall only reimburse the Service for costs of inspections pertaining to the Project Structures. The Licensee shall not be required to reimburse the Service for the cost of routine inspections of the CFH water supply line or to the Corps for inspections of the DNFH water supply line.

B. The Licensee will promptly correct all deficiencies associated with the Project Structures identified by the Service, to the extent such deficiencies pertain to the operations or the structural integrity of the CFH water supply line and associated facilities. Should the Licensee fail to make such necessary repairs in a timely and acceptable manner, the repairs will be made by the Service and the Licensee will reimburse the Service for the actual costs of said repairs, including engineering and administrative costs. If the Service makes such repairs to Project Structures, the Licensee shall have the right to review the Service’s books and records to verify the accuracy and appropriateness of such reimbursement of costs.
ARTICLE 9

TRAINING

The Licensee will provide training for designated CFH, DNFH, Service, and Corps personnel expected to respond in the emergency shut down of the Project system. The Licensee shall conduct a refresher course each year for the designated personnel to ensure familiarity with the Project installation and operation. The CFH, DNFH, Service, and Corps shall each pay their own salary costs associated with the training. Other costs, such as travel and supplies, shall be paid by the Licensee. (Training will conform to 29 CFR 1910.269; Occupational Safety and Health Standards -Electrical Power Generation, Transmission and Distribution.)

ARTICLE 10

LIABILITY

A. The Licensee hereby agrees that all claims, personal injury, death, property damage, arising solely out of the Licensee's activities under this MOU are the liability of the Licensee. In the event that a claim, personal injury, death or property damage is caused by joint negligence of the Licensee and Service (or its agents), the parties will attempt to resolve liability.

B. The responsibility for repairing any damage to the CFH water supply lines and its appurtenances as a result of the Licensee's deviation from the requirements of this MOU will be the responsibility of the Licensee.

C. Licensee is not liable for any environmental mitigation or control that may be required as a result of any previous Service action or on any previously installed or maintained Service property associated with this MOU.

ARTICLE 11

DISAGREEMENTS

Differences between the Licensee and the Service will be settled at the LSRCP Office and Regional Office levels if at all possible. Lacking resolution, the Service, Licensee and FERC staff will meet to resolve the dispute.
ARTICLE 12

ASSIGNMENT

The Parties shall not delegate any duties under this MOU or assign any benefits without the prior written consent of the other party. In the event a delegation of duties or an assignment of benefits is approved by the other Party, the Parties agree to bind every such delegate or assignee with the terms and conditions of this MOU.

ARTICLE 13

TERM

This MOU shall become effective on the day of execution by all signatories. The terms of this MOU will be reviewed at least once every five years and may be modified by written amendment as necessary. The term shall be concurrent with that of the License and upon termination of the License, this MOU shall also terminate.

ARTICLE 14

EXHIBITS

The following Exhibits are incorporated into the MOU by this reference:

Exhibit A: Areas of Responsibility
Exhibit B: Project Operation Procedures
Exhibit C: Clearance Procedure Summary
Exhibit D: Memorandum of Understanding between Clearwater Fish Hatchery, Dworshak National Fish Hatchery, and the U.S. Army Corps of Engineer's Dworshak Project for the Operation and Entrance Requirements for the Hatchery Water Supply System

ARTICLE 15

NOTICES

Any notice, demand or request authorized or required by this MOU shall be deemed to have been given on behalf of the Licensee when hand delivered or three days after mailed, postage prepaid, to each of the following:
LSRCP Coordinator
Fish and Wildlife Service
1387 South Vinnell Way, Suite 343
Boise, Idaho 83702

and on behalf of the Service, when hand delivered or three days after mailed, postage prepaid, to:

Chairman
Idaho Water Resource Board
1301 North Orchard St
P.O. Box 83720
Boise, ID 83720-0098

The designation of the addressee or the address may be changed by notice given in the manner as provided in this article for other notices.

The Parties of this MOU have executed this MOU in duplicate.

U. S. FISH AND WILDLIFE SERVICE
Lower Snake River Compensation Plan
By: (Name) Dan Herrig
    (Title) LSRCP Coordinator

IDAHO WATER RESOURCE BOARD
By: (Name) Clarence Parr
    (Title) Chairman

Concurring:
Tom Rogers
Idaho Department of Fish and Game
Fisheries Bureau, Anadromous Hatchery Supervisor
Exhibit A

AREAS OF RESPONSIBILITY

The Licensee will provide for operation and maintenance for all the equipment installed by the Licensee at the Service’s CFH with its water supply line including those facilities identified in Article 6(A) of this MOU. Licensee’s area of responsibility include the following:

1. All equipment installed or retrofitted for use by Licensee including:
   a. The 24.9 kV power line from the Licensee’s transformer to and including the revenue meter at the 24.9 kV side of Clearwater Power Company’s (CPC) Ahsahka Substation.
   b. All associated water passages installed by the Licensee from the exit-flange face of the distribution structure’s outside-the-building inlet plug valves V-29 and V-8, through the turbines to the distribution box. Except that the Licensee shall have no responsibility for water passages in existence prior to construction of this Project including the Bailey polyjet ported sleeve valves.
   c. All incoming power supply lines from Clearwater Power Company to the Licensee’s emergency electrical supply system, which includes the power supply for the Service’s equipment at the distribution structure. This equipment includes the four Bailey polyjet ported sleeve valves owned by the Service.
   d. SCADA - System Control and Data Acquisition System components and communication links.

2. The Licensee and CFH manager shall cooperatively manage and operate all equipment that controls the generator and water supply for the Project.
Exhibit B

PROJECT OPERATION PROCEDURES

1. In the event equipment should fail at the Project, an automatic dialing device located in the powerhouse will first call the Licensee’s operator, and if necessary the numbers listed in the Emergency Action Plan in sequence until there is a response with a key code acknowledgment. At the same time the SCADA monitor at the Clearwater Fish Hatchery will also alert the manager who will take appropriate control action to mitigate any impact to personnel, property or hatchery operations.

2. After receiving a call, the Licensee’s operator will call the manager at the Clearwater Fish Hatchery to confirm contact and advise as to the estimated time of arrival at the project.

3. Failure of the Licensee’s personnel to respond to the call or delayed arrival at the project may require action by CFH personnel.

   a. If the Licensee’s personnel do not advise CFH manager of call receipt within ten minutes, CFH manager shall have back up phone numbers to contact for instructions.

   b. If the Licensee’s personnel are unable to respond within the critical time, IDFG operators should proceed with the actions outlined in Step 4 below.

4. Licensee shall prepare an Emergency Action Plan subject to the approval from the Service and Corps, which describes the prescribed response to foreseeable emergencies.
Exhibit C

CLEARANCE PROCEDURE SUMMARY

1. Clearances, Lock-Out/Tag-Outs will be used at all locations. All equipment will be cleared to its least energized state. If equipment cannot be totally de-energized, the appropriate supervisor and craftsmen will be consulted to decide cooperatively how best to work on the equipment.

2. Qualified personnel will submit Clearance, Lock-Out/Tag-Out requests to the Licensee’s operator on duty (Operator). The Operator will process the request and perform or direct the required switching or clearance operations.

3. The clearance requester will verify proper placement of the clearance cards or Lock-Out devices and the proper positioning of equipment energy source devices (breakers open, valve closed, etc.)

4. The clearance requester will install any personal grounds required for safety. This ground will be noted on the clearance form.

5. No one may remove a clearance card or lock without authorization of the issuing Operator.

6. No one may operate any equipment that has a clearance card or lock attached.

7. When the equipment is ready for service, the Operator shall inspect the equipment, remove the clearance cards and/or locks and return the equipment to normal operating condition. The Operator will then check the clearance form to insure all points of clearance were released and required to normal operating position.

8. Any Contractor, employee of a Contractor, or Subcontractor employed by the Licensee to provide services at the Project shall be required to undergo training in regards to all requirements of this Clearance Procedure.
Exhibit D

MEMORANDUM OF UNDERSTANDING

BETWEEN THE CLEARWATER FISH HATCHERY, DWORSHAK NATIONAL FISH HATCHERY AND THE U.S. ARMY OF CORPS OF ENGINEERS DWORSHAK PROJECT FOR THE OPERATION AND ENTRANCE REQUIREMENTS FOR THE HATCHERY WATER SUPPLY SYSTEM.

Definition
Clearwater Fish Hatchery will be referred to as “Clearwater FH” or “CFH”. Dworshak National Fish Hatchery will be referred to as the “Dworshak Hatchery” or “DNFH”. The Dworshak project of the U.S. Army Corps of Engineers will be referred to as the “Dworshak project” or “project”.

Purpose
This Memorandum of Understanding (MOU) describes the roles, responsibilities and safety requirements of the signatory parties for the operation, maintenance and emergency procedures related to the water supply line from Dworshak Reservoir to the Clearwater Fish Hatchery and Dworshak National Fish Hatchery. All parties agree to the responsibilities and procedures outlined in this MOU.

PART I
PROJECT DESCRIPTION

I Authorization and Location

The Clearwater Fish Hatchery Water Supply System is part of the Lower Snake River Compensation Plan (LSRCP) Program. The LSRCP was established by the Water Resources Development Act of 1976 (Public Law 94-587) to compensate for losses caused by the lower Snake River dams. The Clearwater Fish Hatchery water supply system delivers water from Dworshak Reservoir to the CFH and DNFH. The hatcheries are located near the confluence of the North Fork and the main stem of the Clearwater rivers near Ahsahka, Idaho.

II Brief Description of Project

The CFH water supply system consists of primary and secondary pipelines. The primary pipeline is equipped with a selective withdraw intake screen that allows water at selectable temperatures to be withdrawn when available. A floating platform allows the intake screen to be adjusted from 5 to 50 feet below the water surface. The secondary pipeline has a fixed low level intake that provides water at a temperature that is consistently near 40°F. Both pipelines are routed through Dworshak Dam and then down the face of the dam along the spillway training wall. The pipelines are then buried and follow the left bank of the North Fork Clearwater River to the distribution structure. The distribution structure is the transition between the incoming high pressure piping and outgoing low pressure piping. The distribution structure provides stilling wells for energy dissipation valves and distributes flow between the two fish hatcheries. Two
lines from the distribution structure supply the DNFH with supplemental water. The distribution structure also provides a connection to the secondary pipeline for a potential future municipal and industrial (M&I) hookup for the City of Orofino.

III Construction History

The Clearwater Fish Hatchery Water Supply System was constructed under one contract let by the U.S. Army corps of Engineers. A copy of the construction report is on file at the Walla Walla District Corps of Engineers library in Walla Walla, Washington. The construction contract number, contractor, construction start date, and beneficial occupancy date are shown below:

Project Title: Clearwater Fish Hatchery Water Supply
Contract No.: DACW687-90-C-0030
Contractor: Harcon Inc. and S.A. Gonzales Construction, Inc.
A Joint Venture
P.O. Box 2661
Pocatello, Idaho 83201
Construction Start Date: 28 August 1990
Beneficial Occupancy Date: 15 April 1992

PART II
METHOD OF OPERATION
CLEARWATER FISH HATCHERY PIPELINE

I PRIMARY INTAKE STRUCTURE

Adjustments to the level of the primary intake screen will be determined by locating the seasonal thermocline in the reservoir of 56 to 58°F water temperature. The screen will be raised or lowered to this thermocline. These adjustments will be done by CFH staff.

The primary intake is located inside the log boom security area on the face of Dworshak Dam. Prior to entrance of this security area a 24 hour minimum notice is to be given to the operator at the Dworshak Dam. On the day of entry into the security area, prior to entrance, Clearwater FH staff will notify the on duty operator at Dworshak Dam. After the adjustments or cleaning has been performed on the primary intake screen and the boat has left the security area Dworshak Dam operator will be notified they have left the area.

The intake was modified under the following contracts.

<table>
<thead>
<tr>
<th>Contract Number</th>
<th>Project</th>
<th>Contractor</th>
<th>Start Date</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>DACW68-95-C-0011</td>
<td>Clearwater Hatchery</td>
<td>Knight Construction &amp; Supply Company</td>
<td>12/94</td>
<td>5/30/95</td>
</tr>
<tr>
<td>DACW68-97-C-0017</td>
<td>Clearwater Hatchery</td>
<td>Advanced America</td>
<td>3/97</td>
<td>9/30/97</td>
</tr>
<tr>
<td></td>
<td>Emergency Isolation Valve</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Water Supply Modifications</td>
<td>Diving Service, Inc.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
The CFH manager will schedule a diver to inspect the primary intake screen when determined to be necessary. (The screen was designed so that it would not clog but our experience shows that the algae in the reservoir will completely plug the primary intake screen).

II PIPELINES FROM INTAKE TO CLEARWATER FISH HATCHERY

Routine inspections and maintenance of the pipelines will be the responsibility of the CFH. This approach has resulted from design review meetings conducted by the COE.

   A. Maintenance

   All maintenance of valves and pipeline from the intake to the distribution structure will be the responsibility of CFH.

III DISTRIBUTION STRUCTURE

Any adjustments to the ported sleeve valves on the primary and secondary pipelines will be accomplished by the manager or CFH staff. Each supply line is equipped with two ported sleeve valves. Never at any time will more than one ported sleeve valve be operated unless it is during the switch over process from one valve to another. The manager of CFH will notify the manager of DNFH of any adjustments or maintenance work which may impact distribution to DNFH.

IV DISTRIBUTION TO DWORSHAK NFH

The supply valves on the secondary and primary lines from distribution structure to the DNFH will remain at preadjusted levels. The amount of flow will be controlled by DNFH manager or his staff. Prior to any adjustments, requiring more or less water from either pipeline, notification will be given to the CFH manager. This is to protect from damage to the distribution structure and pipelines resulting from either hatchery calling for more water than available and causing cavitation in the supply pipelines.

   A. Maintenance

   All routine maintenance of valves and pipeline from the distribution structure to DNFH will be the responsibility of DNFH. The COE will assist with non-routine maintenance, if required.

V. DISTRIBUTION TO CLEARWATER FH

All adjustments for water flowing from the distribution structure to CFH will have prior approval from CFH manager or a designated representative and will be accomplished by the CFH staff under the managers direction.
PART III
OPERATION AND MAINTENANCE

I. GENERAL

A. Scope

This section describes the equipment and routine operation and maintenance procedures for the water supply system. It also describes procedures for various emergency situations. The value of this manual is dependent upon how it is used. For this reason, additional reference data and revised procedures and parameters should be inserted into the manual as dictated by changing conditions and operator experience with this particular facility.

B. Responsibility

The operation and maintenance of the Clearwater Fish Hatchery Water Supply System from Dworshak Dam to the distribution structure, including the intake screens and energy dissipation valves, is the responsibility of the CFH personnel. The CFH personnel are also responsible for the system from the distribution structure to the CFH. The DNFH personnel, with COE assistance, when required, are responsible for the system from the distribution structure to DNFH. The Dworshak Dam operator shall be notified when problems arise with the water supply system, and specifically during emergency situations.

C. Dworshak Project Entrance Requirement

Hatchery personnel shall abide by the Dworshak Project entrance requirement and safe clearance procedure while working in the secure project area. The secure project area includes the forebay protected intake area; the main dam and powerhouse; and the south abutment, hillside, and stilling basin wall.

II CLEARWATER HATCHERY WATER SUPPLY

A. Annual Valve Exercise

This exercise will occur after steelhead are completely transported and released from DNFH and CFH in the spring of the year. Coordination and scheduling of exercises will be the responsibility of CFH Manager. CFH will provide six personnel, DNFH a maximum of 2 personnel and electric operator wrench. 1) All rearing areas will be converted to secondary pipeline water only. 2) Pipeline shutdown will start a CFH and DNFH on primary pipeline and proceed upstream to valves inside the dam. Once emergency closure valves are exercised, energizing of the pipeline will begin at emergency closure valves and proceed downstream to both hatcheries. 3) Both hatcheries will then convert to primary pipeline water only and proceed with shutdown of secondary pipeline at each hatchery and proceed upstream to emergency shutdown valve. When exercise is complete, energizing of pipeline will begin at emergency valve and proceed downstream to both hatcheries. Annual exercise is now completed and both pipelines are back in operation.
PART IV
INTAKE FACILITIES

I. GENERAL

A. General Description

The primary intake consists of a tee-screen suspended on a cable from a floating platform. The cable is attached to a winch that allows the depth of the intake screen to be adjusted. The screen is attached to a 48-inch polyethylene pipe. The polyethylene pipe connects to a 24-inch steel pipe at the face of the dam. The secondary intake consists of a drum screen mounted on the face of the dam at Elevation 1361.5 msl. The screen is connected to a 14-inch steel pipe. The 24-inch-diameter and 14-inch-diameter steel pipes pass through the upstream face of the dam and into the maintenance gallery in monolith 14. Inside the maintenance gallery, intake valves are installed to serve as emergency shutoff valves and pressure gauges are installed to measure the pressure differential on the intake screens.

B. Primary Intake Screen

(1) Description

The primary intake screen is a 7.5-foot-diameter by 23-foot-long Johnson tee-screen. The screen is suspended from a floating platform that is anchored to the upstream face of the dam (see Sheet 57.1 of the contract drawing). Access to the floating platform is by use of a boat stored at the CFH. The primary intake screen can be adjusted from 5 to 50 feet below the water surface using the winch on the floating platform. The water surface can vary between a maximum pool level of 1,605 msl and minimum pool level of 1,455 msl. The proper depth to provide the desired temperature is determined by taking temperature measurements from the platform with a portable, hand-held temperature gauge.

(2) Operation and Maintenance

The intake screen is required to have a minimum submergence of 4 feet. A physical restraint is attached to the screen to prevent it from inadvertently being raised to less than 4 feet of submergence. The primary pipeline intake valve (V-1) must be closed before raising the primary screen out of the water for any maintenance procedures. Raising the screen out of the water prior to closing V-1 could cause failure of the pipeline. CAUTION! Follow the procedure described under Intake Valve for closing V-1. To avoid potential freezing problems at the water surface, the primary screen should be lowered to at least 20 feet below the water surface each fall when the temperature is approximately uniform in the top 20 feet of the reservoir, which is typically from about October to March. The wedge wire design of the screen is nonclogging and somewhat self-cleaning; therefore, additional means of cleaning were not considered necessary during the original design. However, experience to date indicates that some cleaning may be required. The screen has air backflushing connections so that backflushing equipment can be added in the future if necessary. The pressure gauge should be checked every two weeks and the screen should be inspected by a diver, if the differential pressure is rising.
and approaching 60 inches, or at least twice a year to determine if cleaning or other maintenance is required. See next Section Pressure Gauge.

(3) Pressure Gauge

An ILT Barton differential pressure gauge is installed inside the maintenance gallery to measure the pressure differential across the primary intake screen. The pressure gauge is calibrated in inches of water and has a range between 0 and 60 inches. The maximum pressure differential allowed is 60 inches. Caution! Allowing more than 60 inches pressure differential could cause damage to the intake pipe and screen.

(4) Emergency Procedures

If the head differential across the primary screen exceeds 60 inches, perform the following procedures:

1. Contact CFH manager.
2. Contact DNFH manager.
3. Contact Dworshak Dam operator.
4. Throttle back the operating primary energy dissipation valve (V-9 or V-10) while monitoring the intake pressure differential to ensure that the pressure differential reduces to less than 60 inches. This will require personnel stationed at both locations with two-way radios to communicate.
5. Determine and correct the problem. Large pressure differentials could be caused by a plugged intake screen or pipeline flows greater than design capacity.

C. Secondary Intake Screen

(1) Description

The secondary intake screen is a 6.5 foot-diameter by 7.5 foot-long Johnson drum screen. The screen is wedge wire type having inwardly enlarging openings. The secondary screen is not adjustable and is mounted at Elevation 1361.5 msl.

(2) Operation and Maintenance

The wedge wire design of the screen is nonclogging and somewhat self-cleaning. Therefore, additional means of cleaning were not considered necessary during the original design. However, experience to date indicates that some cleaning may be required. The screen has air backflushing connections so that backflushing equipment can be added in the future, if necessary. The pressure gauge should be checked every two weeks and the screen should be inspected by a diver, if the differential pressure is rising and approaching 60 inches. See Section Pressure Gauge.
PART V

ENTRANCE REQUIREMENTS AND SAFE CLEARANCE
PROCEDURE FOR NORMAL OPERATION AND MAINTENANCE
AND EMERGENCY CONDITIONS FOR THE CLEARWATER FH

I WATER SUPPLY SYSTEM

A. Purpose

The purpose of this section is to provide an understanding of the entrance requirements, Safe Clearance Procedure, and project personnel interaction with CFH and DNFH personnel during normal O&M and emergency conditions within the secure area of Dworshak Project. The secure project area includes the forebay protected intake area, the main dam and powerhouse, south abutment dam face, hillside, and stilling basin wall.

B. Conditions

(1) General

Activity requiring either CFH or DNFH personnel to enter Dworshak Project secure area will be coordinated with the powerhouse control room operator prior to entry into the secure area. Work requiring access to the floating platform in the intake area will require the requesting and issuance of a safe clearance on spillway machinery (safe clearance on regulating outlet machinery is not required unless diving operations are necessary). A clearance will be issued to the shift operator and then an identical clearance will be issued to an authorized hatchery person who has been trained in the Dworshak Project Hazardous Energy Control Program. A notice of intent will be provided to the control room operator a minimum of a day prior to issuing the clearances. Hatchery personnel will verify the safe clearances have been placed on the machinery before accessing the platform. Hatchery personnel that have been working in the secure area will immediately communicate to the shift operator the completion of their work and confirmation of exiting the secure area. They will then coordinate the release of their safe clearance.

(2) Normal operation and maintenance:

Scheduled inspections and adjustments of equipment within the secure area will be made entirely by hatchery personnel. Results of the inspections will be communicated to the Dworshak Operations and Maintenance Manager.

(3) Emergency Situation:

The shift operator will not normally be available to assist in operations outside the control room such as closing the intake valves, etc. Hatchery personnel will immediately notify the shift operator of the emergency condition and describe any potential effect on the dam or powerhouse. If the emergency requires a boat to go into the protected intake
forebay area, a safe clearance on the spillway must still be requested and implemented before entering the area. If hatchery personnel are required to go to the pipe penetration area they must notify the shift operator just prior to their entrance and immediately after their exit. The COE shift operator will contact supervisory personnel who will direct or make further communication as required. Under an acute emergency condition, COE personnel would be made available to assist hatchery personnel.

PART VI
RESPONSIBILITIES

I  Corps of Engineers

A. To report to the CFH and DNFH managers any problems or suspected problems.
B. To provide to CFH personnel two project entrance keys.
C. To inform CFH personnel (and provide copy) of safe clearance procedures.
D. To provide available help as allowable during an acute emergency.
E. To provide an adequate access to the 1385 gallery and the 1360 pipe penetration gallery.
F. To maintain lighting in these areas and reliable power to the control valves.

II  Clearwater Fish Hatchery

A. Hatchery personnel will inform the shift operator before entering the project secure areas and renotify when leaving.
B. The hatchery will provide Dworshak Project a copy of their inspection reports.
C. The hatchery personnel will abide by the Dworshak Project Hazardous Energy Control Program while working in the secure project area.
D. Hatchery personnel will secure Dworshak Project access keys and immediately report if lost or stolen. They will also ensure Dworshak Project security by keeping all doors, used for their access, secure.
E. The hatchery will inform DNFH manager of any problems which could impact flow to DNFH.

III  Dworshak National Fish Hatchery

A. Hatchery personnel will coordinate any flow adjustments which may impact CFH with the CFH manager.
B. Hatchery will provide available help to CFH manager when requested in emergency, maintenance or water flow adjustments.
HATCHERY MANAGERS

Jerry McGeehe 10/21/98
Manager, Clearwater FH
Idaho Department of Fish and Game

Gregory A. Parker 11/2/98
Operations & Maintenance Manager
Dworshak Project

Bill Miller 10/31/98
Manager, Dworshak NFH
U.S. Fish and Wildlife Service

Operations Manager
Eastern Operating Projects
Dworshak Project
Exhibit L

Settlement and Contingent Power Purchase Agreement, dated April 30, 1990

This document is provided as an attachment to this Agreement.
EXHIBIT L

Contract No. DE-MS79-908P92888

SETTLEMENT AND CONTINGENT POWER PURCHASE AGREEMENT
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION

and the

STATE OF IDAHO
acting by and through the
IDAHO WATER RESOURCE BOARD

Index to Sections

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>A. GENERAL PROVISIONS</td>
<td></td>
</tr>
<tr>
<td>1. Effective Date</td>
<td>4</td>
</tr>
<tr>
<td>2. Term</td>
<td>4</td>
</tr>
<tr>
<td>3. Early Termination</td>
<td>5</td>
</tr>
<tr>
<td>4. Definitions</td>
<td>6</td>
</tr>
<tr>
<td>5. Exhibits</td>
<td>8</td>
</tr>
<tr>
<td>B. SETTLEMENT PROVISIONS</td>
<td></td>
</tr>
<tr>
<td>6. Ratification of the Letter of Intent</td>
<td>8</td>
</tr>
<tr>
<td>7. Project Design and Construction</td>
<td>9</td>
</tr>
<tr>
<td>8. IWRB Withdraws Opposition to Government Development</td>
<td>9</td>
</tr>
<tr>
<td>9. IWRB's Notification of FERC</td>
<td>9</td>
</tr>
<tr>
<td>10. IWRB's Releases the Government From Claims</td>
<td>10</td>
</tr>
<tr>
<td>11. Development of the Project</td>
<td>10</td>
</tr>
</tbody>
</table>
### C. CONTINGENT POWER PURCHASE PROVISIONS

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>12. Implementation of the Contingent Power Purchase Provisions</td>
<td>12</td>
</tr>
<tr>
<td>13. IWRB Development of the Project</td>
<td>12</td>
</tr>
<tr>
<td>14. Point of Delivery</td>
<td>13</td>
</tr>
<tr>
<td>15. IWRB Coordinated System Operation Obligations</td>
<td>14</td>
</tr>
<tr>
<td>16. Project Electric Power Output</td>
<td>15</td>
</tr>
<tr>
<td>17. Bonneville Request for a Section 9(f) Ruling</td>
<td>15</td>
</tr>
<tr>
<td>18. Insurance</td>
<td>16</td>
</tr>
<tr>
<td>19. Bonneville Payments to IWRB for the Project's Power Output</td>
<td>17</td>
</tr>
</tbody>
</table>

### D. GENERAL PROVISIONS

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>20. Payment Procedures</td>
<td>19</td>
</tr>
<tr>
<td>21. Environmental Compliance</td>
<td>20</td>
</tr>
<tr>
<td>22. Uncontrollable Force</td>
<td>20</td>
</tr>
<tr>
<td>23. Assignment of Agreement</td>
<td>21</td>
</tr>
<tr>
<td>24. Notices</td>
<td>21</td>
</tr>
<tr>
<td>25. Suspension of Payments</td>
<td>22</td>
</tr>
<tr>
<td>26. Disputes</td>
<td>22</td>
</tr>
<tr>
<td>27. Audits</td>
<td>23</td>
</tr>
<tr>
<td>28. Governing Law</td>
<td>24</td>
</tr>
<tr>
<td>29. Waivers</td>
<td>24</td>
</tr>
<tr>
<td>30. Headings Not Binding</td>
<td>25</td>
</tr>
<tr>
<td>31. Agreement of the Parties</td>
<td>25</td>
</tr>
<tr>
<td>32. Interpretation of Agreement</td>
<td>25</td>
</tr>
<tr>
<td>33. Signature Clause</td>
<td>25</td>
</tr>
<tr>
<td>34. Execution by Counterpart</td>
<td>25</td>
</tr>
</tbody>
</table>

Exhibit A (Letter of Intent) 
Exhibit B (Plan of Delivery) 
Exhibit C (Operating Procedures) 
Exhibit D (Trial Technical Standards for Interconnection of Small Generating Resources to the BPA) 
Exhibit E (Bonneville Wholesale General Rate Schedule Provisions) 
Exhibit F (General Contract Provisions)

This SETTLEMENT AND CONTINGENT POWER PURCHASE AGREEMENT (Agreement), executed as of April 30, 1970, by the UNITED STATES OF AMERICA (the Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and the STATE OF IDAHO (the State), acting by and through the IDAHO WATER RESOURCE BOARD (IWRB); Bonneville and IWRB hereinafter sometimes are referred to individually as "Party" and collectively as "Parties."
WHEREAS the Clearwater Fish Hatchery (CFH) located near Orofino, Idaho will be constructed beginning in the spring of 1990; and

WHEREAS water will be taken for the operation of CFH from the nearby Government-owned Dworshak Dam and Reservoir, which will result in a net electric power generation loss to the Federal Columbia River Power System (FCRPS); and

WHEREAS electricity hydrogeneration facilities can be designed for and constructed in the water supply system of CFH (which as defined in subsection 4(h) constitutes the "Project") to offset part of such net electric power generation loss to FCRPS; and

WHEREAS Bonneville believes that only the Government may develop and own the Project; and

WHEREAS IWRB believes the Project is available for non-Federal development, and has filed an application with the Federal Energy Regulatory Commission (FERC) for a preliminary permit to develop the Project; and

WHEREAS Bonneville and IWRB conducted settlement discussions during the autumn of 1989 and winter of 1989-1990 which resulted in the Parties signing a Letter of Intent, attached as Exhibit A to this Agreement; and

WHEREAS this Agreement implements the Letter of Intent; and

WHEREAS the State is authorized to obtain funds for the purposes set forth below in the Agreement pursuant to the provisions of Article 15, section 7 of the Idaho Constitution, Section 42-1734 of the Idaho Code, and 1990 Idaho Session Laws, Chapter 363; and
WHEREAS Bonneville acknowledges the record of involvement in the Project by IWRB, which enabled the development of minimum facilities for in-line power generation, including design and development work on the Project, submittal of a request for a FERC preliminary permit, and preparation to obtain legislative approval for revenue bonds to fund design and construction of the Project;

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

A. GENERAL PROVISIONS

1. **Effective Date.**

   This Agreement becomes effective at 2400 hours on the last date the Parties have signed (Effective Date).

2. **Term.**

   (a) In the event that neither the Government nor the State is allowed to develop the Project, after all appellate rights, if exercised by either or both Parties, are exhausted, the Agreement shall terminate at 2400 hours on the last date all such appellate rights terminate.

   (b) In the event the Government is allowed to develop the Project, after all appellate rights are exhausted as is described in paragraph 11(b)(1), the Agreement shall terminate at 2400 hours on the date Bonneville pays IWRB under section 20 below.

   (c) In the event IWRB's permit application and license for the Project are upheld, after all appellate rights, if exercised by the Government, are exhausted, the Agreement shall terminate at 2400 hours on the date Bonneville makes its final payment to IWRB for energy and capacity under section 20 below.
(d) All obligations incurred under this Agreement shall be preserved until satisfied.

3. Early Termination.

The provisions of this section 3 shall apply only in the event the State receives a preliminary permit from FERC to develop the Project.

(a) Bonneville shall have the right, but not the obligation to terminate the Agreement, effective at 2400 hours on the date IWRB receives Bonneville's notice of termination, if any one or more of the following events occurs:

(1) Once IWRB has received a preliminary permit to develop the Project, IWRB subsequently loses its right to develop the Project; or

(2) IWRB fails to make timely application to the Corps for all agreements necessary to develop the Project; or

(3) IWRB fails to secure funding for the development of the Project no later than the latter of: (i) 90 days after IWRB receives the FERC license to develop the Project; or (ii) 90 days after the Parties receive the Government Department of the Treasury's final response to a request made under section 9(f) of the Pacific Northwest Electric Power Planning and Conservation Act for a ruling on whether the State may use Tax Exempt Bonds (as described in section 17 of the Agreement) to finance the Project; or

(4) IWRB fails to diligently pursue the design, construction, and testing of the Project as follows:
(A) IWRB fails to obtain a preliminary design for the Project during the preliminary permit stage; or

(B) IWRB fails to let a contract for the construction of the Project no later than 12 months after IWRB receives a FERC license to develop the Project; or

(C) IWRB fails to interconnect the Project to the FCRPS and begin deliveries to Bonneville of the Project's electric capacity and energy no later than 2 years after IWRB receives the FERC license to develop the Project; or

(5) IWRB fails to provide all of the capacity and energy output of the Project to Bonneville under section 16 below; or

(6) The Project is unable to generate due to a discontinuance of the water supply to the Project which is planned to last more than 24 consecutive months, or

(7) The Project is unable to generate due to the permanent cessation of CFH operations; or

(8) The Project at any time becomes infeasible for IWRB to either develop or operate.

(b) If the Agreement terminates pursuant to subsection 3(a), IWRB agrees that no damages or liability shall be claimed, assessed, or imposed against Bonneville as a result of such termination.
4. **Definitions.**

The following terms, when used in this Agreement with initial capitalization, whether singular or plural, shall have the meanings specified.

(a) "Calendar Week" means the week beginning at 2400 hours on Saturday, and ending at 2400 hours on the following Saturday.

(b) "CFH" means the Clearwater Fish Hatchery.

(c) "Corps" means the United States of America, Department of Defense, Department of the Army, Corps of Engineers.

(d) "FCRPS" means the Federal Columbia River Power System, as that term is defined in subsection 1(a) of Exhibit F.

(e) "FERC" means the Federal Energy Regulatory Commission, or its successor.

(f) "Letter of Intent" means the letter executed by Bonneville and IWRB on January 31, 1990 concerning the settlement of the dispute over the development of the Project.

(g) "Orofino" means the City of Orofino, Idaho.

(h) "Project" means: (i) provisions within the CFH water supply system to accommodate development of hydroelectric power; and (ii) a powerhouse containing the necessary turbine(s)/generator(s) and appurtenant facilities; and (iii) transmission line with an interconnection into the FCRPS; and (iv) provisions within the CFH water supply system to provide for the future development of municipal and industrial water for Orofino, not to exceed 6 cubic feet per second.
(i) "Uncontrollable Force" means any act or event beyond the control of a Party which impairs the ability of the Party to perform, which by exercise of due diligence such Party could not reasonably have been expected to avoid, and which by exercise of due diligence it shall be unable to avoid. Uncontrollable Force includes, but it is not limited to, failure of or threat of failure of facilities, flood, earthquake, storm, fire, lightning and other natural catastrophes, epidemic, war, labor or material shortage, strike or labor dispute, or sabotage; and also includes restraint by an order of a court of competent jurisdiction or by regulatory authorities, against an action taken or not taken by a Party, after a good faith effort by the appropriate Party (i) to obtain relief from such order, or (ii) to obtain any necessary authorizations or approvals from any governmental agency or regulatory authority.

(j) "Workday" means each day which both Bonneville and IWRB observe as a regular day of work.

5. Exhibits.

Letter of Intent (Exhibit A), Project Plan of Delivery (Exhibit B), Operating Procedures (Exhibit C), Bonneville's Trial Technical Standards for Interconnection of Small Generating Resources to the BPA, as may be amended or replaced (Exhibit D), Bonneville Wholesale General Rate Schedule Provisions, or successor (Exhibit E), and General Contract Provisions (Exhibit F) are attached hereto and hereby made a part of this Agreement.

B. SETTLEMENT PROVISIONS


The Parties hereby ratify the Letter of Intent, attached to this Agreement as Exhibit A; provided, however, when a provision in the
Letter of Intent conflicts with a provision found in the body of this Agreement, the latter shall prevail.

7. **Project Design and Construction.**

The Parties agree that the Project shall be designed and constructed either by the Corps, or by another entity to standards which would allow the Project to be interconnected with the FCRPS. The Parties also agree that the water supply serving CFH shall include sufficient water pipeline capacity to allow Orofino to take up to 6 cubic feet of water per second from the secondary pipeline for Orofino's municipal and industrial purposes, subject to a subsequent agreement between the Corps and any necessary party for costs related to the provision of water under the Water Supply Act of 1958 and other appropriate statutory authority applying to the Corps, and other matters between the Corps and Orofino.

8. **IWRB Withdraws Opposition to Federal Development.**

IWRB hereby agrees not to oppose Federal development of the Project. IWRB hereby agrees to make this position known in all relevant legislative, administrative, judicial and other proceedings, including, but not limited to FERC. The Parties agree to use their best efforts to obtain a FERC ruling on the issue of FERC jurisdiction over the Project. The Parties understand that IWRB will notify FERC that pending FERC's determination of FERC jurisdiction over the Project, IWRB assumes FERC has jurisdiction and, accordingly, IWRB will continue to pursue its application for a preliminary permit for the development of the Project.

9. **IWRB's Notification of FERC.**

IWRB shall submit a written notice to FERC precisely as follows:
Whereas applications have been filed for the right to develop the subject property; and whereas Bonneville has filed a motion that FERC lacks jurisdiction over the proposed Project;

Now therefore, IWRB hereby notifies FERC that IWRB does not oppose Bonneville's motion and claim that the Government's authorization to develop the Project withdraws FERC jurisdiction. Nevertheless, pending FERC's determination that it lacks jurisdiction over this Project, IWRB assumes FERC has jurisdiction and, accordingly, continues to diligently pursue its application for a preliminary permit and development of the Project. Nothing in this response by IWRB is intended to be a waiver of priority by IWRB in favor of any competing application for a preliminary permit for the Project.

10. IWRB's Releases the Government From Claims.

IWRB releases and forever discharges the Government, its agencies, employees, agents and assigns from any and all claims which have been, could have been, or might in the future be asserted against the Government, its agencies, employees, agents and assigns arising from or in any manner directly or indirectly connected with the rights to the development of the Project which forms the subject matter of this Agreement and claims of whatsoever nature directly or indirectly connected with IWRB's efforts to date for the planning and design of the Project.

11. Development of the Project.

Subsections 11(a), 11(b), and 11(c) are alternative scenarios. Therefore, each of the subsections of this section 11 shall operate to the mutual exclusion of the other two subsections.
(a) **Neither Party Allowed to Develop the Project.**

In the event that neither the Government nor the State is allowed to develop the Project, after all appellate rights, if exercised by either or both Parties, are exhausted, then this Agreement shall terminate as is specified above in subsection 2(a).

(b) **Federal Development of the Project.**

(1) If Federal development of the Project is upheld, after all appellate rights, if exercised, are exhausted, Bonneville agrees to compensate the State through IWRB in the amount of $750,000, upon receipt of an invoice from IWRB, pursuant to the terms and conditions of section 20. Notwithstanding the provisions of Exhibit A, IWRB shall not appeal FERC's decision that the Project has been withdrawn for Federal development except to the extent necessary to preserve IWRB's priority in favor of any competing application for a preliminary permit for the Project. The Parties agree such payment is in recognition of IWRB's prior participation in the Project, including the expenditure of funds therefor, and for IWRB not opposing the Government's development of the Project, and for IWRB's satisfactory completion of its obligations under sections 8, 9, and 10 of this Agreement. Contingent upon IWRB fulfilling its obligations as specified above and in sections 8, 9, and 10, Bonneville shall pay IWRB pursuant to section 20 regardless of whether the Government ultimately develops the Project.

(2) The Parties agree Bonneville shall be the marketing agent for the Project's electric power as part of the FCRPS pursuant to BPA's enabling legislation including the

(c) State Development of the Project.

If the State's right to develop the Project is upheld, after all appellate rights, if exercised by the Government, are exhausted, then IWRB agrees to sell, and Bonneville agrees to purchase the Project's entire electric capacity and energy output (Power Output) from IWRB pursuant to the Contingent Power Purchase Provisions below. The Parties agree that once Bonneville has received the Project's Power Output, Bonneville shall be the marketing agent for such power as part of the FCRPS pursuant to BPA's enabling legislation, as is specified above in paragraph 11(b)(2).

C. CONTINGENT POWER PURCHASE PROVISIONS


Sections 12 through 19 of this Agreement shall be implemented and shall operate only in the event that the State's right to develop the Project is upheld, as is described above in subsection 11(c).

13. IWRB Development of the Project.

(a) IWRB agrees to diligently pursue the development of the Project. To that end, IWRB agrees to make timely application to FERC for any necessary permit or license, and to take all other
actions necessary to obtain and keep alive both (i) the FERC permit and (ii) the later FERC license to develop the Project.

(b) IWRB also agrees that the design, construction, testing, operation, and integration of the Project into the FCRPS shall be to standards acceptable to both: (i) the Corps; and (ii) Bonneville, consistent with both the provisions of Exhibit D, and similar electricity hydrogeneration projects integrated into the FCRPS.

14. **Point of Delivery.**

(a) **Location.**

The point in the vicinity of the Government's Dworshak Dam where the 115 kV facilities of the Corps and Bonneville are connected, or at another point to be mutually agreed upon by IWRB and Bonneville.

(b) **Voltage.**

In the event the State develops the Project, the Parties agree to provide for interconnection at a voltage to be mutually agreed upon during the Project's design phase, consistent with the provisions of Exhibit D.

(c) **Metering.**

(1) In the event the State develops the Project, the Parties agree to provide for metering in IWRB's Project powerhouse, in the 13.2 kV circuit over which such electric power flows (Point of Metering). The Parties further agree to provide for metering equipment and other necessary provisions, to
be developed and mutually agreed upon during the Project's design phase, consistent with the provisions of Exhibit D.

(2) **Exception.**

Bonneville and IWRB shall make an adjustment for losses between the Point of Metering and the Point of Delivery.

15. **IWRB Coordinated System Operation Obligations.**

(a) Not later than January 1 every year, IWRB shall submit to Bonneville annual amounts of Project energy it plans to deliver, in the format presented in Exhibit B.

(b) Consistent with the provisions of Exhibit D, IWRB shall make best efforts to conclude an agreement with the Corps, acceptable to Bonneville, which will allow the Corps to approve the operation and integration of the Project into the FCRPS. IWRB shall make best efforts to enter into such agreement with the Corps no later than 6 months after the execution of this Agreement. Bonneville shall not unreasonably withhold its acceptance of the IWRB/Corps agreement. IWRB further agrees it shall make best efforts to conclude one or more agreements, acceptable to Bonneville, to provide for: (i) procedures during periods of transmission outages; (ii) the maintenance and calibration of metering equipment; (iii) the maintenance of hydrgeneration equipment and appurtenant facilities; and (iv) the maintenance of transmission and interconnection equipment and facilities. Bonneville shall not unreasonably withhold its acceptance of such agreement(s).
16. **Project Electric Power Output.**

Bonneville shall receive all of the Project's Power Output, both electric capacity and electric energy: (i) during the testing phase; and (ii) for 30 years after Bonneville accepts the Project for integration into the FCRPS, beginning at 2400 hours on the date IWRB receives Bonneville's notice accepting the Project as integrated into the FCRPS. The Parties agree that none of the Project's Power Output shall be used for station service, or to provide electric power service to CFH. Bonneville shall receive at no cost all of the Project's inadvertent power flow during the testing phase. After Bonneville accepts the Project as integrated into the FCRPS, Bonneville shall pay IWRB at the applicable rate specified below in section 19 for the Project's Power Output beginning at 2400 hours on the date Bonneville accepts the Project as integrated into the FCRPS. The Parties agree that once the Project's power enters the FCRPS, Bonneville alone shall determine how the Project's Power Output shall be used during both the test phase and the term for which Bonneville purchases the Power Output.

17. **Bonneville Request for a Section 9(f) Ruling.**

Notwithstanding the provisions of section 7(b) of Exhibit A and of section 6 of this Agreement, no later than 20 Workdays after the State receives a license from FERC to develop the Project, the Parties agree to develop mutually acceptable provisions concerning if and how a request shall be made to the Government's Department of the Treasury under section 9(f) of the Pacific Northwest Electric Power Planning and Conservation Act to assist the State to obtain Project financing through revenue bonds, the interest on which shall be exempt from Federal taxes (Tax Exempt Bonds).
18. **Insurance.**

(a) **Mechanical Disabling Event or Transmission Interruption.**

IWRB agrees to maintain insurance during the term of this Agreement to ensure that the proceeds of such insurance together with funds set aside by IWRB for Project maintenance and replacement costs shall be adequate to provide necessary Project repairs or replacement in case of (i) a mechanical disabling event which causes the hydropower facility to cease generating and supplying power for a reason unrelated to a discontinuance of the water supply to the CFH; or (ii) in case of a transmission outage or reduction in transmission capacity on the transmission portion of the Project extending more than 24 consecutive hours. IWRB further agrees to effect such repairs or replacement in a timely manner and to produce no less than the rated generation and transmission capacity which existed prior to the disabling event.

(b) **Discontinuance of Water Supply.**

The Parties agree that in the event IWRB is unable to generate electrical power from the Project because of a discontinuance of the water supply to the CFH, IWRB shall not be required during any such period of discontinued water supply to provide any electrical power to Bonneville for purchase under this Agreement, and Bonneville shall not be obligated to pay for power which it has not received. Once Bonneville has made its payment to IWRB pursuant to subsection 19(a) below, the Parties further agree that in the event the Project is later unable to generate electrical power because of a discontinuance of the water supply to the CFH, IWRB may keep the entire $750,000 payment made by Bonneville for the right to receive the Project's Power Output pursuant to subsection 19(a) below.
19. **Bonneville Payments to IWRB for the Project's Power Output.**

(a) **Bonneville One-Time Payment.**

After Bonneville has accepted the Project as integrated into the FCRPS, Bonneville shall pay IWRB a one-time payment of $750,000 for the right to receive the Project's Power Output for the 30 year term specified in section 16, which term begins at 2400 hours on the date IWRB receives written notice from Bonneville that Bonneville accepts the Project as integrated into the FCRPS. Acceptance of the Project as provided herein is an essential consideration of Bonneville's obligation both to make any payments for the right to receive the Project's Power Output and for such Power Output.

(b) **Bonneville Payment for Project Power.**

After Bonneville accepts the Project as integrated into the FCRPS, Bonneville shall pay IWRB for the Project's Power Output which Bonneville receives and meters at the point of interconnection during the 30 year term of the power purchase, which term begins at 2400 hours on the date IWRB receives written notice from Bonneville that Bonneville accepts the Project's output. Bonneville shall pay for the Project's Power Output based on measured Project energy which it receives, adjusted for losses between the Point of Metering and the Point of Delivery. The following rates are expressed in mills per kilowatthour (kWh), and comprise melded capacity and energy rates. Rates shall be calculated to the nearest tenth of a mill.

The Parties assume that the Project will not be able to deliver power to Bonneville prior to calendar year 1992. However, if the Project does deliver power to Bonneville prior to calendar year 1992, the Parties agree to use 97 percent of the applicable
rate indicated below in paragraphs 19(b)(1) and 19(b)(2) for
calendar year 1991, and 97 percent of the applicable 1991 rate
for calendar year 1990.

(1) **Tax Exempt Bonds Energy Rate.**

The provisions of this paragraph 19(b)(1) apply only in the
event the State is able to finance the Project through Tax
Exempt Bonds. The energy rate for metered power IWRB
delivers to Bonneville at the point of interconnection
during calendar year 1992 is 28.1 mills/kWh.

(2) **Non-Tax Exempt Bonds Energy Rate.**

The provisions of this paragraph 19(b)(2) apply only in the
event the State is not able to finance the Project through
Tax Exempt Bonds. The energy rate for metered power IWRB
delivers to Bonneville at the point of interconnection
during calendar year 1992 is 30.7 mills/kWh.

(3) **Annual Adjustments Beginning January 1, 1993.**

Beginning January 1, 1993, the energy rates specified in
paragraphs 19(b)(1) and 19(b)(2) shall be adjusted as
follows:

\[
P_{\text{new}} = P_{\text{init}} \times (1.03)^n
\]

where

- \( P_{\text{new}} \) = The energy rates, as adjusted hereunder,
to be effective each January 1 beginning
with January 1, 1993;
\[ P_{\text{init}} = \begin{cases} 28.1 \text{ mills/kWh} & \text{if the Project is financed with Tax Exempt Bonds;} \\ 30.7 \text{ mills/kWh} & \text{if the Project is not financed with Tax Exempt Bonds;} \end{cases} \]

and \( n = \) the number of calendar years after 1992. Therefore, \( n = 1 \) for calendar year 1993; \( n = 2 \) for calendar year 1994; etc.

D. GENERAL PROVISIONS

20. Payment Procedures.

(a) IWRB Invoices.

IWRB shall request the payments described in paragraph 11(b)(1), and in subsections 19(a) and 19(b) by submitting monthly invoices in a form acceptable to Bonneville. Bonneville shall pay IWRB by the close of business on the thirtieth (30th) day after the date Bonneville receives each such invoice. Should the thirtieth (30th) day be a Saturday, Sunday, or holiday as observed by Bonneville, then the due date shall be the next following business day. Other provisions relating to the payment of bills specified in the General Rate Schedule Provisions attached to this Agreement as Exhibit E, or its successor General Rate Schedule Provisions, shall apply.

(b) Payment by Wire Transfer.

Payments in excess of $25,000 shall be made by direct wire transfer of funds from the United States Treasury to IWRB's bank account, or to the account of IWRB's trustee bank. On the
initial such invoice, IWRB shall include the name and address of the bank, IWRB's bank account number or trustee bank account number, and the American Bankers Association 9-digit routing number. IWRB shall provide similar information on a subsequent invoice only if IWRB changes the bank account to which it wants payment to be made.


The Parties agree that the payment of any sum under this Agreement shall be contingent on the completion of the environmental review work as required by all applicable Federal and state environmental laws and regulations. The Government shall conduct the final review, including an analysis of the environmental review conducted by the State. The Parties further agree that any payment under the scenario described in subsection 11(c) shall be contingent on the Government's determination that the Project may be developed without violating the provisions of the National Environmental Protection Act.

22. Uncontrollable Force.

(a) Obligations of the Parties.

Obligations of the Parties, other than those to pay money, shall be excused when failure to perform such obligations is due to an Uncontrollable Force; provided, however, that if either Party is unable to perform due to an Uncontrollable Force, such Party shall exercise due diligence to remove such inability with reasonable dispatch. Nothing in this subsection 22(a) shall be construed to require either Party to settle any strike or labor dispute in which it may be involved.
(b) **Notice.**

Each Party shall notify the other as soon as possible of any Uncontrollable Force which may impair performance under this Agreement. Failure to give notice shall not be deemed a waiver of such Uncontrollable Force.

23. **Assignment of Agreement.**

Neither Party shall have the right to transfer or assign this Agreement or any part hereof without the prior written consent of the other Party; provided, IWRB may pledge or assign this Agreement, and all or a portion of the payments to be made thereunder by Bonneville, for the benefit of the holders of bonds issued by IWRB to finance the Project. Such prior written consent shall not be unreasonably withheld.

24. **Notices.**

(a) **Notice.**

Each Party shall notify the other as soon as possible if the Party believes the Project at any time becomes infeasible for the IWRB to either develop or operate.

(b) 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 deemed properly served, given, or made if delivered in person or sent by telegraph, or sent by telephone facsimile with a confirmed reception, or by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons specified below:
To IWRB: Director
Idaho Department of Water Resources and
for the Idaho Water Resource Board
1301 North Orchard
Boise, Idaho 83720

To Bonneville: The Administrator
United States Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

(c) Either Party may, by written notice to the other Party, change
the designations or address of the person so specified as the
one to receive notices pursuant to this Agreement.

25. Suspension of Payments.

Bonneville shall have the right to immediately suspend any payment
due IWRB under this Agreement after notice to IWRB only in the event
IWRB fails to deliver all of the Project's Power Output to Bonneville
under the Contingent Power Purchase Provisions.

26. Disputes.

Pending resolution of a disputed matter, the Parties shall continue
performance of their respective obligations pursuant to this
Agreement. For a period not to exceed 6 months unless otherwise
mutually agreed, the Parties shall discuss disputes regarding any
matter relating to this Agreement, and shall use their best efforts
to amicably and promptly resolve each such dispute. If the Parties
have been unable to resolve a disputed matter as specified above,
then each Party has the right to adopt any other remedies available
under law.
27. Audits.

(a) With regard to this Agreement and payments made under it, each Party shall reserve the right to audit and to examine any cost, payment, settlement or supporting documentation, including, but not limited to, audit reports resulting from any items set forth in this Agreement. Any such 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 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 first billing for such cost under this Agreement. The Parties agree to retain all records and documentation related to this Agreement prepared in the normal course of business for the entire length of this audit period. The Parties agree that all Project accounting and records shall be maintained in accordance with Generally Accepted Accounting Principles.

(b) The Party being audited shall be notified in writing of any exception taken as a result of an audit promptly after completion of the audit. The Party being audited shall have 30 days to review the notice of exception.

(1) 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) to the other Party, with interest calculated in the same manner as in Bonneville's Wholesale Power Rate Schedules and General Rate Schedule Provisions, or its successor (Exhibit E) within 10 days after agreement is reached.

(2) If the Parties dispute any exception(s) taken as a result of the audit, the owing Party shall so notify the other
Party in writing promptly after its receipt of the written notification of exception. Such dispute shall then be subject to the provisions set forth in section 26. If upon resolution of the dispute, it is determined that a Party shall make payment to the other Party, such payment shall be made within 10 days of resolution of the dispute, with interest calculated in the same manner as set forth in Bonneville's Wholesale Power Rate Schedules and General Rate Schedule Provisions, or its successor, attached as Exhibit E.

28. **Governing Law.**

This Agreement shall be interpreted, governed by, and construed under Federal law.

29. **Waivers.**

Except as otherwise provided herein or as agreed by the Parties, no provision of this Agreement may be waived except as documented or confirmed in writing. Any waiver at any time by a Party of its right with respect to a default under this Agreement, or with any other matter arising in connection therewith, shall not be deemed a waiver with respect to any subsequent default or matter. Either Party may waive any notice or agree to accept a shorter notice than specified in this Agreement. Such waiver of notice or acceptance of shorter notice by a Party at any time regarding a notice shall not be considered a waiver with respect to any subsequent notice required under this Agreement.
30. **Headings Not Binding.**

The headings and captions in this Agreement are for convenience only and in no way define, limit, or describe the scope or intent of any provisions or sections of this Agreement.

31. **Agreement of the Parties.**

This Agreement represents the entirety of the agreement between the Parties, and the Agreement supersedes any prior written or oral agreements between the Parties.

32. **Interpretation of Agreement.**

The Parties agree that both Parties drafted this Agreement, and that if any ambiguities arise in the later interpretation of the Agreement, such ambiguities shall not be construed against either Party as the sole drafter of the Agreement.

33. **Signature Clause.**

Each Party hereto represents that it has the authority to execute this Agreement and that it has been duly authorized to enter into this Agreement.

34. **Execution by Counterpart.**

This Agreement shall be executed in several counterparts, and shall be deemed to constitute a single document with the same force and effect as if both Parties hereto, having signed a single counterpart, had signed all counterparts. IWRB shall deliver an executed
counterpart to Bonneville, and Bonneville shall prepare a conformed copy of this Agreement and deliver it to IWRB.

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

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By __________________________
Administrator

Date _________________________

THE STATE OF IDAHO
Idaho Water Resource Board

By __________________________
Title Director

Date 4/30/90

(VS6-PMCE-4332c)
counterpart to Bonneville, and Bonneville shall prepare a conformed copy of this Agreement and deliver it to IWRB.

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

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By _____________________________
Administrator

Date _____________________________

THE STATE OF IDAHO
Idaho Water Resource Board

By _____________________________
Title _____________________________

Date _____________________________

(V56-PMCE-4332c)
January 29, 1990

Keith Higginson
Director
Idaho Department of Water Resources and
for the Idaho Water Resource Board
1301 North Orchard
Boise, ID 83720

Dear Mr. Higginson:

Subject: Letter of Intent for Construction of Clearwater and Dworshak Fish Hatcheries Generating Project and Related Matters

This letter is intended to serve as a Letter of Intent (the "Letter") to set out certain terms and conditions which were verbally agreed to with Wayne T. Haas and which will be more fully set out in a final agreement and supplemental documentation. It is understood that the increased capacity in the water supply line to allow the City of Orofino ("City") the option to acquire a future water supply will be provided for the City.

1. The project (the "Project") consists of a hydropower generation facility located in a water supply line serving the Clearwater Fish Hatchery. The Project will also provide and include sufficient water pipeline capacity to allow the City of Orofino to take, at a future date, up to 6 cubic feet per second from the secondary pipeline for its municipal purposes, subject to an agreement between the City and the Corps of Engineers (the "Corps") for costs related to the provision for water under the Water Supply Act of 1958 and other appropriate statutory authority applying to the Corps, and other matters between the Corps and the City. The generating facility will be designed and constructed by the Corps.

2. Bonneville Power Administration (BPA) acknowledges the record of involvement in this project by the Idaho Water Resource Board (IWRB) which enabled the development of minimum facilities for in-line power generation, including design and development work on the Project, submittal of a request for a Federal Energy Regulatory Commission (FERC) permit, and preparation to obtain legislative approval for revenue bonds to fund design and construction of the Project.

3. Subsequent to IWRB's permit application, BPA issued a formal determination to the Secretary of Army that the facility, which will mitigate the loss of generating capacity from the water diversion for the Clearwater and Dworshak Fish Hatcheries, is needed to meet the Federal Columbia River Power System (FCRPS) market requirements.
4. IWRB agrees not to oppose Federal development of the Project and to make this position known in all relevant legislative, administrative, court and other proceeding, including, but not limited to, the FERC. IWRB and BPA agree to use their best efforts to obtain a ruling by FERC on the issue of FERC jurisdiction over the proposed project. IWRB will notify FERC that pending FERC's determination of its jurisdiction over this project, IWRB assumes FERC has jurisdiction and, accordingly, continues to pursue its application for a preliminary permit for development of the project.

5. IWRB, upon execution of a final agreement implementing this letter of intent, will notify FERC in writing, at a future date to be coordinated with BPA, to the following effect:

Whereas applications have been filed for the development of the subject property; and whereas BPA has filed a motion that FERC lacks jurisdiction over the proposed project;

Now therefore, IWRB hereby notifies FERC that IWRB does not oppose BPA's motion and claim that the Federal government's authorization to develop the project withdraws FERC jurisdiction. Nevertheless, pending FERC's determination that it lacks jurisdiction over this project, IWRB assumes FERC has jurisdiction and, accordingly, continues to diligently pursue its application for a preliminary permit and development of the project.

6. IWRB releases and forever discharges the United States, its agencies, employees, agents and assigns from any and all claims which have been, could have been, or might in the future be asserted against the United States, its agencies, employees, agents and assigns arising from or in any manner directly or indirectly connected with the rights to the development of the Project which forms the subject matter of this agreement and claims of whatsoever nature directly or indirectly connected with IWRB's efforts to date for the planning and design of the Project.

7a. In recognition of IWRB's participation in the project, including the expenditure of funds therefore and for IWRB not opposing Federal development of the Project; if Federal development of the Project is upheld (after all appellate rights, if exercised by the State of Idaho, are exhausted), BPA agrees to compensate the State of Idaho through IWRB in the amount of $750,000 subject to the terms and conditions to be agreed to in the final agreement implementing this letter of intent. The IWRB will receive payment under these terms whether the project is ultimately built by the Federal Government. BPA will be the marketing agent for the electric power as part of the FCRTPS pursuant to BPA's enabling legislation including the Federal Columbia River Transmission System Act (FCRTSA), the Bonneville Project Act, the Pacific Northwest Preference Act and the Pacific Northwest Electric Power Planning and Conservation Act.
7b. As an alternative to paragraph 7a, if IWRB's permit application and license for the Project is upheld (after all appellate rights, if exercised by BPA, are exhausted), the State of Idaho agrees to sell the Project's entire capacity and energy output to BPA for a period of 30 years for 28.1 mills during calendar year 1992 and annually escalated on January 1 at a 3 percent rate. BPA agrees to pay the State of Idaho through the IWRB $750,000 for this right contingent upon, and billable after BPA's acceptance of the Project's power for inclusion into the FCRPS and subject to additional terms and conditions to be agreed to in the final agreement implementing this letter of intent.

The terms provided under this paragraph are subject to IWRB being able to issue Federal tax-exempt revenue bonds. BPA agrees to request a ruling under Section 9(f) of the Northwest Power Act pursuant to the 9(f) methodology approved by the Treasury on February 26, 1984.

7c. In the event that IWRB is unable to issue Federal tax-exempt revenue bonds, the State of Idaho agrees to sell the Project's entire capacity and energy output to BPA for a period of 30 years for 30.7 mills during calendar year 1992 and annually escalated at a 3 percent rate. BPA agrees to pay the State of Idaho through the IWRB $750,000 for this right contingent upon, and billable after BPA's acceptance of the Project's power for inclusion into the FCRPS and subject to additional terms and conditions to be agreed to in the final agreement implementing this letter of intent.

7d. In the event that Federal development is denied by FERC and a preliminary permit and/or license is granted to a party other than IWRB, no payment shall be made.

8. It is the position of BPA that it is authorized under the Bonneville Project Act and subsequent legislation to enter into this Letter and the final agreement with IWRB. IWRB is authorized to enter into this letter and the final agreement with BPA. The Director of the Idaho Department of Water Resources is authorized to execute the Letter on behalf of IWRB.

9. This letter of intent shall be null and void if terms and conditions are not agreed to in the final agreement implementing the letter of intent. BPA and IWRB are prepared to develop and execute the final agreement within 45 days of the acceptance of the terms and conditions of this letter of intent.

10. The parties agree to support and implement all the provisions of the final agreement.
Assuming that the foregoing provisions are acceptable, please sign the two copies of this Letter in the space provided below and return one copy in the envelope provided. If you have any questions regarding these matters, please call me at (503) 230-5121.

Sincerely,

Richard L. Perlas
Project Manager

Agreed to and accepted this 31\textsuperscript{st} day of January, 1990.

Idaho Water Resources Board

By: J. Keith Higginson
Director, Idaho Department of
Water Resources
PROJECT PLAN OF DELIVERY


<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Month</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>August</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>September</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>October</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>November</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>December</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>January</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>February</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>March</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>April</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>May</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>June</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>July</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

This Exhibit will be revised each year upon IWRB's submission of new data.


Upon IWRB's submittal of plans of delivery each year in accordance with subsection 15(a), Bonneville shall use such plans in its PNW Coordination Agreement planning. That is, the information from such submittals shall be included in initial, modified, and final coordinated system regulations.

At 2400 hours on July 31, 1995, or shortly thereafter, parties to the PNW Coordination Agreement determine reservoir elevations corresponding to the level of refill. If the system refills, Bonneville will use the most recent plan of delivery submitted by IWRB. If the system does not refill, the parties to the PNW Coordination Agreement will use the system capability associated with actual elevations to most closely match planning done in previous years (earlier 'Critical Periods'). This can be shown as follows:

<table>
<thead>
<tr>
<th>Critical Period</th>
<th>IWRB Plan of Delivery</th>
</tr>
</thead>
<tbody>
<tr>
<td>1993 - 1996</td>
<td>year 1995 from 1993 submittal</td>
</tr>
</tbody>
</table>

If less than a 4 year Critical Period is ever used, there may be fewer than 4 alternatives to be considered.

(VS6-PMCE-4332c)
Both Parties realize that not all of the operating procedures which will be required to implement this transaction have been established as of the Effective Date. During the term of the Agreement, the Parties agree to develop operating procedures as necessary to assist the implementation of the Agreement. Such procedures may include, but are not limited to, determination and verification of costs, additional operating procedures under various water conditions, additional scheduling procedures on a daily prescheduled, Calendar Week, and 10 day planning estimate basis, additional scheduling procedures in the event of transmission outages, establishing and exchanging information on Workdays, and operating procedures as may be necessary during periods of total and partial transmission outages.

These procedures shall be inserted into this Exhibit and shall in no way alter the substance or intent of any language contained in the body of the Agreement.
TRIAL TECHNICAL STANDARDS FOR INTERCONNECTION OF
SMALL GENERATING RESOURCES TO THE BPA
TRANSMISSION SYSTEM

December 27, 1989
# TRIAL TECHNICAL STANDARDS FOR INTERCONNECTION OF SMALL GENERATING RESOURCES TO THE BPA TRANSMISSION SYSTEM

## TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Introduction</td>
<td>1</td>
</tr>
<tr>
<td>Scope</td>
<td>1</td>
</tr>
<tr>
<td>Performance Standards</td>
<td>2</td>
</tr>
<tr>
<td>General Requirements</td>
<td>4</td>
</tr>
<tr>
<td>Protection Guidelines</td>
<td>8</td>
</tr>
<tr>
<td>Appendix A</td>
<td></td>
</tr>
<tr>
<td>Typical Example of Protection Requirements for a SGR (Figure 1)</td>
<td></td>
</tr>
</tbody>
</table>
INTRODUCTION

The Bonneville Power Administration (BPA) has prepared standards for the integration of small generating resources directly or indirectly connected to the BPA system. The purpose of these standards is to ensure the safe operation, integrity, and reliability of the BPA electrical system and of the facilities with which it is interconnected.

These standards are not intended as a design specification or an instruction manual. Many requirements, particularly the protective equipment and relaying, will need to be considered on a case-by-case basis because the BPA system is so varied.

It is important to remember that the physical laws which govern the behavior of electric systems do not recognize defined lines of electric facility ownership. Thus, for a well engineered interconnection, it is mandatory that the systems be studied and analyzed critically without regard to ownership. BPA will review the interconnection plans with the owner/operator of the small generating resource and any interconnected utility. Factors such as short circuit currents, transient voltages, stability requirements, prudent utility practices, safety, operations, and maintenance will be considered.

I. SCOPE

These standards cover small generating resources directly connected to the BPA system or to another utility's system which is directly connected to BPA's system. Based on these standards, the small generating resource and the interconnected utilities must demonstrate that generation on, or connected to, their system will not degrade the reliability and safe operation of the BPA system or another utility's system directly connected to BPA.

A. Definition

A small generating resource (SGR) is a generating resource which has a production capacity of 50 Megawatts or less of electric power.

B. Application of Codes, Policies and Laws

Installations shall be in compliance with the National Electrical Code (ANSI C1), National Electrical Safety Code (ANSI C2), Western Systems Coordinating Council and Northwest Power Pool minimum operating reliability criteria, State and local electrical codes, BPA Reliability Criteria, and the General Contract Provisions of the agreement between BPA and the SGR or interconnected utility, as applicable.
BPA will not interconnect a SGR until completing an appropriate decisionmaking process, which may include preparation of an environmental document under the National Environmental Policy Act (42 U.S.C. & 4321 et seq.). The owner of the SGR may be asked to prepare the environmental document for BPA, or to submit relevant environmental information, before BPA will decide whether to offer a connection.

BPA, in cooperation with the interconnected utility and the SGR, shall determine that the BPA system is properly protected from any problems or disturbances that occur on the SGR's system and that the operation of the SGR is safe and reliable with respect to the BPA system before an interconnection is closed and interconnected operation may begin. At its discretion, BPA may waive those requirements which can be met by equivalent measures to maintain the reliability and safe operation of the BPA system.

Each of the parties involved in a direct or indirect connection of an SGR to the BPA System is responsible for the design, construction, reliability, protection, and safe operation of its own system.

Design of the SGR facilities should be supervised by a Registered Professional Engineer.

C. Interconnection Point

The interconnection point is that point on the BPA system where the facilities of the SGR or the transferring utility are connected with BPA. (The nominal voltage at the interconnection point will normally be at the lowest voltage available at that point.)

The term "interconnection point" is used in a general sense in these standards. The term is used somewhat differently in small resource wheeling agreements. The wheeling agreements define the "Point of Integration" as the point where the project output is made available to BPA, while the "Point of Interconnection" is the point where the developer makes the project output available to a third party utility so it can be wheeled to BPA.

II. PERFORMANCE STANDARDS

The SGR (owner) shall mitigate complaints such as audible noise, radio, television and telephone interference and voltage fluctuations caused by the SGR.

Each party involved in the connection of the SGR shall design, construct, operate, maintain, and use its facilities in conformance with prudent utility practices.
A. **Electric Disturbances**

Each party shall:

1. Minimize the effect of all electric disturbances such as, but not limited to:
   
   a. an abnormal flow of power which may interfere with the interconnected electric systems;
   
   b. the transient overvoltages that occur during ground faults.

2. Minimize the degradation of the reliability of the interconnected electrical system.

B. **Voltage Regulation and Power Factor**

1. The nominal high-side voltage of the SGR's step-up transformer shall be the same as the nominal or agreed upon voltage of the Interconnection Point for SGR’s directly connected to the BPA system.

2. The SGR shall impose no restrictions on BPA's capability to operate within a system voltage range of five percent above or below nominal for voltages equal to or less than 25-kV, and 10 percent above or below nominal for voltages greater than 25-kV.

3. Synchronous generators shall:
   
   a. Be rated at 0.95 power factor or lower, lagging and leading.
   
   b. Coordinate with voltages as scheduled by BPA within the reactive capability of the machine. Design and operation of voltage regulators shall be coordinated with other voltage and reactive control equipment on the system.

4. Induction generators or groups of induction generators shall have a suitable reactive power supply to maintain a power factor that is acceptable to BPA and the other interconnected utilities. If the SGR induction generators can be self-excited during fault conditions, the SGR must provide protective relaying to promptly trip the generator.

5. Inverters or groups of inverters shall have a suitable reactive power supply to maintain unity power factor, or other power factor that may be acceptable to BPA and other interconnected utilities.

C. **Voltage Flicker**

The SGR shall limit to acceptable levels the production of voltage fluctuations (flicker) at the interconnection point.
D. Harmonics Requirements

The SGR shall limit to acceptable levels the production of total harmonic current distortion (THCD) and individual harmonic current distortion injected or coupled into the interconnected system. Harmonic current distortion is defined as the ratio of the rms value of the harmonic current to the rms value of the fundamental alternating current.

The harmonic current distortion of the SGR supplied power shall be limited to the levels indicated below:

<table>
<thead>
<tr>
<th>Individual Harmonic (h) Current Distortion, %</th>
<th>THCD, %</th>
</tr>
</thead>
<tbody>
<tr>
<td>h&lt;9</td>
<td>4.0</td>
</tr>
<tr>
<td>9&lt;h&lt;23</td>
<td>1.5</td>
</tr>
<tr>
<td>23&lt;h&lt;35</td>
<td>1.0</td>
</tr>
<tr>
<td>35&lt;h</td>
<td>0.5</td>
</tr>
<tr>
<td>50</td>
<td>5.0</td>
</tr>
</tbody>
</table>

These values are for long term operation. For short term testing, and startup, these values may be exceeded. A level of 50% higher current distortion will be allowed for up to one hour.

Exception to these requirements will be considered on an individual basis.

E. Phase Unbalance

Generators shall not cause phase current unbalance greater than 10 percent.

F. Speed/Frequency Control/Damping

1. Speed governors shall be provided when the SGR is to be used to supply loads while operating in isolation from a power system synchronizing source.

2. Speed governors shall be designed and adjusted:
   a. so that they do not react to cause frequency and power swings to develop during normal system conditions, and
   b. so that any swings that do occur during system disturbances are well damped.

III. GENERAL REQUIREMENTS

A. Safety and Operation

All BPA and customer switchgear that could be opened, leaving equipment energized by the SGR, must be visibly marked so that all maintenance crews are aware of the potential hazard.
A switch shall be provided that physically and visibly opens the integrating circuit to the SGR. The device:

1. Must simultaneously open all phases to the SGR.

2. Must be accessible by BPA personnel at any time without notice to the SGR and without restricted access.

3. Must be lockable in the open position by BPA.

BPA personnel may lock the switch in the open position:

1. If it is necessary for the protection of maintenance crew personnel when working on de-energized circuits.

2. If the SGR's equipment presents a hazardous condition.

3. If the SGR's generating equipment interferes with the operation of the BPA transmission system.

B. Inspection, Test, Calibration, and Maintenance

The SGR owner has full responsibility for the inspection, testing, calibration and maintenance of the SGR generating and protection equipment.

Drawings, specifications, maintenance records and test records of SGR equipment pertinent to interconnected operation shall be made available to BPA and any interconnecting utility. In some instances, certain tests may be required by BPA. The type of test and required results will be determined by BPA on an individual basis.

Inspection, test, and calibration of the SGR generating and protection equipment shall be completed before initial operational acceptance and subsequently on a periodic basis. Maintenance intervals shall be based on prudent utility practice.

C. Grounding

Grounding requirements shall be in compliance with the National Electrical Code and any applicable State and local codes. Adequate station grounding shall be provided by the SGR.

If there is any possibility during normal or outage conditions of the SGR energizing an ungrounded system in the event of a disturbance on the connected BPA transmission line, the SGR must provide a grounding current source to the BPA system. In some instances, a fault detection scheme using three potential transformers may be substituted for the grounding current source, subject to approval by BPA.

5

December 27, 1989
In all cases the protection schemes and equipment necessary for the protection of the BPA system shall be approved by BPA. (See Section IV Protection Guidelines.)

D. Metering and Telemetering

The following revenue metering requirements apply to an SGR with which BPA has a contract to purchase or wheel its generated power.

1. The revenue metering shall be specified by BPA.

2. Specific revenue metering requirements will depend on contractual constraints, wheeling arrangements, designated point of delivery, scheduling requirements, and other factors (see Section F).

3. Metering requirements for an SGR will be the same as for any similarly sized BPA point of interconnection. This includes the overall metering scheme, the type of equipment used, and the overall metering accuracy for metering purposes. Required metering could include: recording three-phase kw-hours, kVAR-hours, KW demand and an RMS (Revenue Metering System) remote, complete with a surge-protected telephone line. Potential transformers and current transformers shall be 0.3% accurate metering class accuracy for the burden of the metering circuit. It may also include automatic data acquisition (telemetering) for scheduling, operating reserve responsibilities and/or billing requirements, Automatic Generation Control (AGC) and two-way metering.

4. At BPA's election, these devices may be owned, operated, and maintained by BPA.

5. Calibration of metering shall occur periodically. All parties may witness calibration.

E. Isolating and Synchronizing

The SGR shall not energize a BPA line that is de-energized unless the energization is specifically approved by the BPA dispatcher.

Whenever a disturbance occurs on the BPA system, interconnecting utility, or the SGR system, the disturbance must be isolated before equipment damage occurs.

If, for any reason, the system source is disconnected from the SGR (fault conditions, line switching, etc.), the switching device connecting the SGR to the system must open and not reclose until approved by the BPA dispatcher.

The SGR shall synchronize its equipment to the BPA and/or interconnected utilities' system.

December 27, 1989
The SGR shall clear its generator before the normal system reclosing time. The SGR shall not reclose out of synchronization with the BPA and/or interconnected utilities' system.

F. Scheduling

BPA's Power Supply and Scheduling Division will define scheduling requirements on an individual basis. The SGR operators shall adhere to these requirements.

G. Underfrequency/Voltage Relays

Relays must not trip the SGR for major system disturbances but must allow the generator to ride through system frequency and voltage transients.

In order to meet these requirements, the following relay settings are required.

<table>
<thead>
<tr>
<th>Relay Type</th>
<th>Setting/Delay</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Undervoltage</td>
<td>0.8 pu or above – 2 second delay minimum</td>
</tr>
<tr>
<td></td>
<td>0.75 pu – 0.8 sec. delay minimum</td>
</tr>
<tr>
<td></td>
<td>0.7 pu – 0.25 sec. minimum</td>
</tr>
<tr>
<td>Below 0.7 pu</td>
<td>no restrictions on setting or delay</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>2. Overvoltage</td>
<td>1.2 or below – 2 second delay minimum</td>
</tr>
<tr>
<td></td>
<td>1.25</td>
</tr>
<tr>
<td></td>
<td>1.3</td>
</tr>
<tr>
<td></td>
<td>above 1.3 – no restrictions on setting or delay</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>3. Underfrequency</td>
<td>59.5 Hz or above, 10 minutes min. trip</td>
</tr>
<tr>
<td></td>
<td>59.0 Hz – 4 minutes minimum trip</td>
</tr>
<tr>
<td></td>
<td>58.5 Hz – 1.2 minutes minimum trip</td>
</tr>
<tr>
<td></td>
<td>58.0 Hz – 0.3 minutes minimum trip</td>
</tr>
<tr>
<td></td>
<td>57.5 Hz – 0.06 minutes minimum trip</td>
</tr>
<tr>
<td></td>
<td>57.0 Hz or below – no restrictions</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>4. Overfrequency</td>
<td>60.5 Hz or below – 10 minutes</td>
</tr>
<tr>
<td></td>
<td>61.0 Hz – 4 minutes</td>
</tr>
<tr>
<td></td>
<td>61.5 Hz – 1.2 minutes</td>
</tr>
<tr>
<td></td>
<td>62.0 Hz – 0.3 minutes</td>
</tr>
<tr>
<td></td>
<td>62.5 Hz – 0.06 minutes</td>
</tr>
<tr>
<td></td>
<td>63.0 Hz or above – no restrictions</td>
</tr>
</tbody>
</table>

December 27, 1989
IV. PROTECTION GUIDELINES

The protective devices (relays, instrument transformers, circuit breakers, etc.) required to protect BPA's or an interconnected utility equipment shall be specified by BPA, the SGR, and the interconnecting utility. At BPA's election, these devices may be owned, operated, and maintained by BPA. The settings of the protective devices shall be jointly agreed to by BPA, the SGR, and the interconnecting utility. The interconnecting utility is fully responsible for the protection of all of its own equipment associated with the interconnection. The SGR shall protect its generator and all of its associated equipment from any and all disturbances or malfunctions.

The BPA system is so varied that there is no one single plan of service typical of all cases. The complexity of the protection required must be determined for each project. The following factors will influence the protection scheme:

1. The output (MVA) and the machine characteristics of the generator.

2. The electrical size of the SGR with respect to the load served by the transformer connected to the BPA system.

3. System protection requirements at the interconnection point and elsewhere on the system as a result of the interconnection configuration (both normal and alternate configurations).

4. The type of transformer electrical connections used to integrate the SGR.

5. The insulation level of the system served by the SGR.

Typical protection requirements for a 4 MW SGR connected to a BPA utility customer system with an 8 MW minimum load are shown in figure 1. Additional equipment such as a grounding transformer may be required in this example if the output of the generation approximately matches or exceeds the load.

In all cases, the protection schemes and equipment required for the protection of the BPA system shall be approved by BPA.
APPENDIX A

APPLICABLE STANDARDS

ANSI

C1 National Electrical Code
C2 National Electrical Safety Code
C37.4 Definitions...AC High Voltage Circuit Breakers
C37.16 Requirements...AC Low Voltage Circuit Breakers
C37.30 Definitions...Air Switches, Insulation, and Bus Supports
C37.48 Guide...Cutouts, Fuse Links, Secondary Fuses
C37.90 Relays...Electric Power Apparatus
C37.91 Relays...Transformers
C37.95 Relays...Utility Consumer Interconnections
C57.12.00 Distribution, Power Transformers...General Requirements
C57.12.01 Distribution, Power Transformers...Dry Type
C62.1 Surge Arrestors
C57.13 Instrument Transformers

WSCC Minimum Operating Criteria

NW Power Pool

National Environmental Policy Act

Pacific Northwest Regional Power Act

IEEE Guide 80 Guideline to Substation Grounding

Cogeneration and Small Power Production Guidelines for Public Power Systems, November 1980, American Public Power Association


December 27, 1989
Minimum Requirements:
115 KV Fault Detection
Scheme to Trip Lowside Breaker (3-115 KV PTS Needed)

NOTE:
SURGE ARRESTOR MUST BE CAPABLE OF
WITHSTANDING OVERTURES UNTIL ONE LINE
TO GROUND HIGH SIDE FAULTS ARE CLEARED.

Minimum Trip Requirements:
1. Phase and Ground Overcurrent
2. Under/Over Voltage
3. Hot Bus/Dead Line Detector if Auto Reclosing
1989 Wholesale Power Rate Schedules
and General Rate Schedule Provisions

Bonneville
POWER ADMINISTRATION
Bonneville Power Administration's 1989 Wholesale Power Rate Schedules and General Rate Schedule Provisions, contained herein, were approved on an interim basis effective October 1, 1989. These rate schedules and provisions were approved by the Federal Energy Regulatory Commission, United States Department of Energy, in a Commission Order issued September 29, 1989 (Docket No. EF89-2011-000).

These rate schedules and provisions supersede in their entirety the Administration's Wholesale Power Rate Schedules and General Rate Schedule Provisions effective July 1, 1987.
## TABLE OF CONTENTS

### Wholesale Power Rate Schedules

- **PF-89**  Priority Firm Power Rate ................................................................. 1
- **IP-89**  Industrial Firm Power Rate ................................................................. 4
- **VI-87**  Variable Industrial Power Rate .............................................................. 6
- **SI-89**  Special Industrial Power Rate ............................................................... 10
- **CF-89**  Firm Capacity Rate .................................................................................. 13
- **CE-89**  Emergency Capacity Rate ........................................................................ 14
- **NR-89**  New Resource Firm Power Rate .............................................................. 15
- **SP-89**  Short-Term Surplus Firm Power Rate ....................................................... 18
- **MSL-87**  Modified Long-Term Surplus Firm Power Rate ...................................... 19
- **NF-89**  Nonfirm Energy Rate ................................................................................ 21
- **SS-89**  Share-the-Savings Energy Rate ............................................................... 24
- **RP-89**  Reserve Power Rate .................................................................................. 25

### General Rate Schedule Provisions

- **Section I**  Adoption of Revised Rate Schedules and General Rate Schedule Provisions ................................................................. 29
- **Section II**  Types of BPA Service ......................................................................... 29
- **Section III**  Billing Factors and Billing Adjustments ............................................. 30
- **Section IV**  Other Definitions ............................................................................... 39
- **Section V**  Application of Rates under Special Circumstances ............................ 42
- **Section VI**  Billing Information ........................................................................... 43
- **Section VII**  Variable Industrial Rate Parameters and Adjustments ................... 45
SECTION I. AVAILABILITY

This schedule is available for the contract purchase of firm power or capacity to be used within the Pacific Northwest. Priority Firm Power may be purchased by public bodies, cooperatives, and Federal agencies for resale to ultimate consumers, for direct consumption, construction, test and start-up, and station service.

Utilities participating in the exchange under section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) may purchase Priority Firm Power pursuant to their Residential Purchase and Sale Agreements.

In addition, Bonneville Power Administration (BPA) may make power available to those parties participating in exchange agreements which use this rate schedule as the basis for determining the amount or value of power to be exchanged.

This schedule supersedes Schedule PF-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA’s General Rate Schedule Provisions.

SECTION II. RATE

This rate schedule includes the Preference rate and the Exchange rate. The Preference rate is available for the general requirements of public body, cooperative and Federal agency customers and includes credit attributed to the provision of section 7(b)(2) of the Northwest Power Act. The Exchange rate is available for all purchases of residential and small farm exchange power pursuant to the Residential Purchase and Sale Agreements.

A. Preference Rate

1. Demand Charge
   a. $3.46 per kilowatt of billing demand occurring during all Peak Period hours.
   b. No demand charge during Offpeak Period hours.

2. Energy Charge
   a. 18.4 mills per kilowatthour of billing energy for the billing months September through March;
   b. 14.4 mills per kilowatthour of billing energy for the billing months April through August.

B. Exchange Rate

1. Demand Charge
   a. $3.56 per kilowatt of billing demand occurring during all Peak Period hours.
   b. No demand charge during Offpeak Period hours.

2. Energy Charge
   a. 19.1 mills per kilowatthour of billing energy for the billing months September through March;
   b. 15.1 mills per kilowatthour of billing energy for the billing months April through August.

SECTION III. BILLING FACTORS

In this section, billing factors are listed for each of the following types of purchasers: computed requirements purchasers (section III.A), purchasers of residential exchange power pursuant to the Residential Purchase and Sale Agreements (section III.B), and metered requirements purchasers and those Priority Firm Power purchasers not covered by sections III.A and III.B (section III.C).

A. Computed Requirements Purchasers

Purchasers designated by BPA as computed requirements purchasers pursuant to power sales contracts shall be billed in accordance with the provisions of this subsection.

1. Billing Demand

The billing demand for actual, planned, and contracted computed requirements purchasers shall be the higher of the billing factors “a” and “b,” below:

a. the lower of:
   (1) the larger of the Computed Peak Requirement or the Computed Average Energy Requirement; or
   (2) the Measured Demand, before adjustment for power factor.

b. the lower of:
   (1) the Computed Peak Requirement, or
   (2) 60 percent of the highest Computed Peak Requirement during the previous 11 billing months (Ratchet Demand).

2. Billing Energy

The billing energy for actual, planned, and contracted computed requirements purchasers shall be:
a. for the months September through March, the sum of:
   (1) 78 percent of the Measured Energy (excluding unauthorized increase), and
   (2) 22 percent of the Computed Energy Maximum;

b. for the months April through August, the sum of:
   (1) 57 percent of the Measured Energy (excluding unauthorized increase), and
   (2) 43 percent of the Computed Energy Maximum.

B. Purchasers of Residential Exchange Power
Purchasers buying Priority Firm Power under the terms of a Residential Purchase and Sale Agreement shall be billed as follows:

1. Billing Demand
   The billing demand shall be the demand calculated by applying the load factor, determined as specified in the Residential Purchase and Sale Agreement, to the billing energy for each billing period.

2. Billing Energy
   The billing energy shall be the energy associated with the utility's residential load for each billing period. Residential load shall be computed in accordance with the provisions of the purchaser's Residential Purchase and Sale Agreement.

C. Metered Requirements Purchasers, Other Purchasers Not Covered by Sections III.A and III.B, Above
Purchasers designated as metered requirements customers and purchasers taking or exchanging power under this rate schedule who are not otherwise covered by sections III.A and III.B shall be billed as follows:

1. Billing Demand
   The billing demand shall be the Measured Demand as adjusted for power factor, unless otherwise specified in the power sales contract.

2. Billing Energy
   The billing energy shall be the Measured Energy, unless otherwise specified in the power sales contract.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Power Factor Adjustment
   The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSPs). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

   To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

B. Low Density Discount (LDD)
BPA shall apply a discount to the charges for all Priority Firm Power sold to purchasers who are eligible for an LDD. Eligibility for the LDD and the amount of the discount (3, 5, or 7 percent) shall be determined pursuant to section III.C.3 of the GRSPs.

C. Irrigation Discount
BPA shall apply an irrigation discount, equal to 4.6 mills per kilowatthour, to the charges for qualifying energy purchased under this rate schedule. The irrigation discount shall be applied after calculation of the Low Density Discount. The discount shall apply only to energy purchased during the billing months of April through October. Eligibility for the irrigation discount and reporting requirements shall be determined pursuant to section III.C.4 of the GRSPs.

D. Conservation Surcharge
The Northwest Power Planning Council has recommended that a conservation surcharge be imposed on those customers subject to such surcharge as determined by the Administrator in accordance with BPA's Policy to Implement the Council-Recommended Conservation Surcharge. The Conservation Surcharge shall be applied pursuant to section III.C.7 of the GRSPs and subsequent to any other rate adjustments.

E. Cost Recovery Adjustment Clause
The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all purchases and exchanges under this rate schedule. The percentage increase calculated in section III.C.5.c of the GRSPs shall be applied uniformly to the demand and energy charges contained in sections II.A and II.B and the irrigation discount contained in section IV.C of this rate schedule. An additional increase of .046 mills per kilowatthour shall be made to the irrigation discount for each percentage increase in the PF rates due to the Cost Recovery Adjustment Clause.

F. Outage Credit
Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any purchaser for
those hours for which BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Priority Firm Power. Such credit shall not be provided if BPA is able to serve the purchaser's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

G. Unauthorized Increase

BPA shall apply the charge for Unauthorized Increase to any purchaser of Priority Firm Power taking demand and energy in excess of its contractual entitlement.

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Calculation of the Amount of Unauthorized Increase

Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount that may be considered an unauthorized increase. BPA first shall determine the amount of unauthorized increase related to demand and shall treat any remaining unauthorized increase as energy-related.

a. Unauthorized Increase in Demand

That portion of any Measured Demand during Peak Period hours, before adjustment for power factor, which exceeds the demand that the purchaser is contractually entitled to take during the billing month and which cannot be assigned:

(1) to a class of power that BPA delivers on such hour pursuant to contracts between BPA and the purchaser; or

(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month,

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or

(2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

b. Unauthorized Increase in Energy

The amount of Measured Energy during a billing month which exceeds the amount of energy which the purchaser is contractually entitled to take during that month and which cannot be assigned:

(1) to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser; or

(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month,

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or

(2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

H. Coincidental Billing Adjustment

Purchasers of Priority Firm Power who are billed on a coincidental basis and who have diversity charges or diversity factors specified in their power sales contracts shall have their charges for billing demand adjusted according to the provisions of section III.C.6 of the GRSPs. Computed requirements purchasers are not subject to the Coincidental Billing Adjustment for scheduled power.

I. Energy Return Surcharge

Any purchaser who preschedules in accordance with sections 2(a)(4) and 2(c)(2) of Exhibit E of the power sales contract and who returns, during a single offpeak hour, more than 60 percent of the difference between that purchaser's computed peak requirement and computed average energy requirement for the billing month shall be subject to the following surcharge for each additional kilowatthour so returned:

1. 3.49 mills per kilowatthour for the months of April through October;

2. 1.48 mills per kilowatthour for the months of November through March.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the PF-89 rate is 78.5 percent FBS and 21.5 percent Exchange.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.
SECTION I. AVAILABILITY

This schedule is available to direct-service industrial (DSI) customers for both the contract purchase of Industrial Firm Power and the purchase of Auxiliary Power if requested by the DSI customer and made available by BPA. If a DSI customer purchasing power under this rate schedule requests and BPA makes available power under another applicable wholesale rate schedule the IP-89 rate schedule is available for that portion of power purchased not covered under the alternative rate schedule. This rate schedule supersedes Schedule IP-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA’s General Rate Schedule Provisions.

SECTION II. RATE

The following rates shall be applied when first quartile service is provided under this rate schedule in accordance with the terms of a purchaser’s Power Sales Contract dated August 25, 1981. A separate billing adjustment for the reserves provided by the purchasers of Industrial Firm Power is not contained in this rate schedule; the value of reserves credit has been included in the determination of the demand and energy charges.

Any contractual reference to the IP Premium Rate shall be deemed to refer to the demand and energy charges set forth below. Any reference to the IP Standard Rate shall be deemed to refer to the same demand and energy charges minus the Discount for Quality of Service.

A. Demand Charge

1. $4.14 per kilowatt of billing demand occurring during all Peak Period hours.
2. No demand charge during Offpeak Period hours.

B. Energy Charge

1. 19.5 mills per kilowatthour of billing energy for the billing months September through March;
2. 15.6 mills per kilowatthour of billing energy for the billing months April through August.

SECTION III. BILLING FACTORS

A. Billing Demand

The billing demand shall be the BPA Operating Level during the Peak Period as adjusted for power factor. If there is more than one BPA Operating Level during the Peak Period within a billing month, the billing demand shall be a weighted average of the BPA Operating Levels during the Peak Period for the billing month. The BPA Operating Level is defined in section III.A.10 of the General Rate Schedule Provisions (GRSPs). If BPA has agreed to serve a portion of a DSI load under an alternative rate schedule, the billing demand under the IP-89 rate schedule shall be specified in the contract initiating such arrangement.

However, if BPA has agreed, pursuant to section 4 of the direct-service industrial power sales contract, to sell Industrial Firm Power on a daily demand basis (transitional service), this section of the rate schedule shall not apply, and BPA shall bill the purchaser in accordance with the provisions of section V.C.3 of the GRSPs.

B. Billing Energy

The billing energy shall be the Measured Energy for the billing month, minus any kilowatthours on which BPA assesses the charge for unauthorized increase.

However, if BPA has agreed to serve only a portion of the DSI’s load under the IP rate schedule, the billing energy for the power purchased under the IP rate shall be specified in the contract initiating such arrangement.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Discount for Quality of First Quartile Service

1. Application and Amount of First Quartile Discount

If a purchaser requests discounted rate service, a discount of 0.6 mills per kilowatthour of billing energy shall be granted. This billing credit shall be applied to the monthly billing energy under section III.B for all power purchased under this rate schedule. No credit shall be applied to those purchases subject to unauthorized increase charges under section IV.D of this rate schedule.

2. Eligibility Requirements for First Quartile Discount

To qualify for the First Quartile Discount the purchaser must request discounted rate service in writing by April 2 of each calendar year. By virtue of making such request, the Purchaser is agreeing to accept the level and quality of First Quartile service described in section 6 of the Variable Industrial Rate contract. Such acceptance includes the waiver of contract rights provided in section 6.a(2)(a) of said cont
B. Curtailments

BPA shall charge the DSI for curtailments of the lower three quartiles in accordance with the provisions of section 9 of the power sales contract. BPA shall apply the demand charge in effect at the time of the curtailment in the computation of the amount of the curtailment charge. In the event that a purchaser is found to be eligible to have a portion of their load served under an alternative rate schedule, application of the curtailment charge shall be specified in the contract instituting such arrangement.

C. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all power purchases under this rate schedule.

Application of the Cost Recovery Adjustment Clause shall result in a uniform adjustment applied to the demand and energy charges, contained in sections II.A and II.B of this rate schedule, and the first quartile discount, if applicable, contained in section IV.A.1 of this rate schedule.

The uniform percentage (CRAC%) determined in Section III.C.5.c. of the GRSPs shall be applied in the following manner:

\[(1 + \frac{\text{CRAC} \%}{100}) \times 22.8 \times \text{demand, energy, and first quartile discount charges.}\]

where: 22.8 represents the average IP-89 margin-based rate in mills per kilowatthour, and 23.5 represents the average IP-89 floor rate in mills per kilowatthour.

D. Unauthorized Increase

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Application of the Charge

During any billing month, BPA may assess the unauthorized increase charge on the number of kilowatthours associated with the DSI Measured Demand in any one 60-minute clock-hour, before adjustment for power factor, that exceed the BPA Operating Level for that clock-hour, regardless of whether such Measured Demand occurs during the Peak or Offpeak Period.

E. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the GRSPs. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

F. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any DSI for those hours for which BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Industrial Firm Power. Such credit shall not be provided if BPA is able to serve the DSI's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the IP-89 rate is 99.3 percent Exchange and 0.7 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.
SCHEDULE VI-87
VARIABLE INDUSTRIAL POWER RATE

SECTION I. AVAILABILITY

This schedule is available to direct-service industrial (DSI) customers for purchases under the Power Sales Contract implementing the Variable Industrial Power rate schedule (Variable Rate Contract) of: (1) Industrial Firm Power and (2) Auxiliary Power if requested by the DSI customer and made available by BPA. This schedule is available only for that portion of a DSI's load used in primary aluminum reduction including associated administrative facilities, if any. By virtue of incorporation of this rate schedule and associated General Rate Schedule Provisions (GRSPs) in the Variable Rate Contract, DSI's electing to purchase power under this rate schedule contractually agree to the terms and conditions of this rate schedule. A DSI further agrees to waive for that portion of their load designated to purchase power at the VI rate, all rights they might otherwise have to purchase power at the Industrial Firm Power Rate Schedule for the duration of the Variable Rate Contract. Section VI.J. supplements schedule VI-86. GRSPs effective July 1, 1985, as revised effective August 1, 1986, and as revised in the 1987 rate case and in subsequent wholesale rate filings are applicable to this rate schedule. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. TERM OF THE RATE

This rate schedule shall take effect on August 1, 1986, and shall terminate on midnight June 30, 1993, unless BPA elects to exercise its unilateral option to terminate the rate at midnight June 30, 1991. This termination right is described in section VI.E. of this rate schedule. Actions to invoke an early termination shall comply with section VI.E. of this rate schedule and with the provisions and stipulations set forth in the Variable Rate Contract.

SECTION III. RATE

A. Revised Rate Charges Subject to Rate Case Adjustments

The following rates shall apply to Industrial customers that meet the eligibility requirements and elect to purchase power under the Variable Industrial Power Rate Schedule. These rates shall remain in effect until the next Rate Adjustment Date, at which point the rates shall be adjusted following the procedures set forth in section VI.C. of this rate schedule, unless the Cost Recovery Adjustment Clause triggers, at which point the rates shall be adjusted following the procedures set forth in section VI.J. of this rate schedule. In addition, the Lower Rate Limit also will be subject to a biennial adjustment pursuant to section VI.B. of this rate schedule. The formula to be used in the calculation of the monthly power bill is contained in section IV. A separate billing adjustment for the value of the reserves provided by purchasers of Industrial Firm Power is not contained in this rate schedule; the value of reserves credit has been included in the determination of the Plateau Energy Charge.

1. Base Variable Industrial Rate
   a. Demand Charge
      $5.33 per kilowatt of billing demand occurring during the Peak Period. No demand charge is applied during Offpeak Period hours.
   b. Plateau Energy Charge
      16.1 mills per kilowatthour of billing energy.

2. First Quartile Service Discount
   0.5 mills per kilowatthour of billing energy.

3. Lower Rate Limit
   8.3 mills per kilowatthour of billing energy.

4. Upper Rate Limit
   21.9 mills per kilowatthour of billing energy.

B. Initial Rate Parameters Subject to Annual Adjustments

The following rate parameters shall be used in determining the power bills for customers electing to purchase power under the Variable Industrial Power rate schedule. These parameters will be adjusted annually starting on July 1, 1987, and every July 1 thereafter, in accordance with the procedures contained in section VII.B. of the GRSPs.

1. Lower Pivot Aluminum Price
   60.8 cents per pound.

2. Upper Pivot Aluminum Price
   73.4 cents per pound.

SECTION IV. FORMULA

The Variable Industrial Power rate is a formula rate tied to the U.S. market price of aluminum. Under this rate schedule, the monthly energy charge varies in response to changes in the average price of aluminum in U.S. markets.
A. Demand Charge

1. The Demand Charge, as stated in section III.A.1.a. of this rate schedule, remains constant over all aluminum prices. The demand charge is applied to billing demand occurring during all Peak Period hours for all billing months.

2. No demand charge during Offpeak Period hours.

B. Energy Charge

1. Plateau Energy Charge

When the monthly billing aluminum price (described in section VII.A. of the GRSPs) is between the Lower Pivot Aluminum Price and the Upper Pivot Aluminum Price inclusive (as stated in sections III.B.1. and III.B.2. of this rate schedule), the monthly energy charge shall be the Plateau Energy Charge as stated in section III.A.1.b. of this rate schedule.

2. Reductions to Plateau Energy Charge

When the monthly billing aluminum price is less than the Lower Pivot Aluminum Price, the monthly energy charge shall be the greater of:

a. The Plateau Energy Charge - (LP - MAP) * (LS)

where:

\[ LP = \text{the Lower Pivot Aluminum Price as stated in section III.B.1. of this rate schedule.} \]

\[ MAP = \text{the monthly billing aluminum price in cents per pound determined pursuant to section VII.A. of the GRSPs} \]

\[ LS = \text{lower slope} = \frac{1 \text{ mill per kilowatthour}}{1 \text{ cent per pound}} \]

or

b. the Lower Rate Limit as stated in section III.A.3. of this rate schedule.

3. Increases to Plateau Energy Charge

When the monthly billing aluminum price is greater than the Upper Pivot Aluminum Price, the monthly energy charge shall be the lesser of:

a. The Plateau Energy Charge + (MAP - UP) * (US)

where:

\[ MAP = \text{the monthly billing aluminum price in cents per pound, as determined according to section VII.A. of the GRSPs} \]

\[ UP = \text{the Upper Pivot Aluminum Price as stated in section III.B.2. of this rate schedule.} \]

US \quad = \quad \text{upper slope} = \frac{0.75 \text{ mills per kilowatthour}}{1 \text{ cent per pound}}

or

b. the Upper Rate Limit, as stated in section III.A.4. of this rate schedule.

SECTION V. BILLING FACTORS

A. Billing Demand

1. Billing Demand for Customers Whose Entire BPA Load is Served at the Variable Industrial Power Rate

The billing demand for power purchased shall be the BPA Operating Level during the Peak Period as adjusted for power factor. If there is more than one BPA Operating Level during the Peak Period within a billing month, the billing demand shall be a weighted average of the BPA Operating Levels during the Peak Period for the billing month. The BPA Operating Level is defined in section III.A.10. of the GRSPs.

2. Billing Demand for Customers When Only a Portion of Their Total BPA Load is Served at the Variable Rate

The Billing Demand shall be the portion of the BPA Operating Level attributable to the VI rate as determined by the method specified in the Variable Rate Contract.

3. Billing Demand During Periods of Transitional Service

If BPA has agreed, pursuant to section 4 of the direct-service industrial power sales contract, to sell Industrial Firm Power on a daily demand basis (transitional service), this section of the rate schedule shall not apply, and BPA shall bill the purchaser in accordance with the provisions of section V.C. of the GRSPs.

B. Billing Energy

The billing energy for power purchased shall be the Measured Energy for the billing month, minus any kilowatthours on which BPA assesses the charge for unauthorized increase.

SECTION VI. OTHER ADJUSTMENTS AND SPECIAL PROVISIONS

A. Lower and Upper Pivot Aluminum Prices

Effective July 1, 1987, and every July 1 thereafter, the Lower and Upper Pivot Aluminum Prices set forth in section III.B. of the rate schedule shall be adjusted following the procedures set forth in section VII.B. of the GRSPs. The adjusted Lower and Upper Pivot Aluminum Prices shall supersede the Lower and Upper Pivot Aluminum Prices contained in section III.B. of the rate
schedule. The revised Lower and Upper Pivot Aluminum Prices shall be used for billing purposes and subsequent adjustments to the Lower and Upper Pivot Aluminum Prices.

B. Lower Rate Limit

Beginning with the July 1, 1988, annual adjustment date and every second July 1 thereafter, the Lower Rate Limit as stated in section III.A.3. shall be increased by 1 mill per kilowatthour. The revised Lower Rate Limit shall supersede the Lower Rate Limit as stated in section III.A.3. of the rate schedule. This increase is in addition to rate adjustment increases in the Lower Rate Limit described in section VI.C. of this rate schedule. In the event that a rate adjustment date and the annual adjustment date occur simultaneously, the Lower Rate Limit shall be adjusted first for changes in the Plateau Energy Charge pursuant to section VI.C. of this rate schedule, and then increased by 1 mill per kilowatthour. The revised Lower Rate Limit shall be used for billing purposes and subsequent rate adjustments.

C. Rate Adjustments

The overall rate level of this rate shall be subject to adjustment in BPA’s general wholesale power rate case following the procedures and directives of the Northwest Power Act. The overall rate level consists of the Demand Charge, Plateau Energy Charge, and First Quartile Service Adjustment contained in sections III.A.1. and III.A.2.; these shall be adjusted by a uniform percentage based on the percentage change in the overall rate level. The Lower and Upper Rate Limits as stated in sections III.A.3. and III.A.4. of this rate schedule shall be adjusted by an amount equal to the change, in mills per kilowatthour, in the Plateau Energy Charge. The Lower and Upper Pivot Aluminum Prices shall not be adjusted in the rate case; rather, they shall be adjusted pursuant to the procedures described in section VII.B. of the GRSPs. The lower and upper slopes shall not be adjusted. The rate for unauthorized increase shall be separately determined in each rate case.

D. Discount for Quality of First Quartile Service

If a purchaser requests First Quartile service with other than Surplus FELCC, a discount contained in section III.A.2. of this rate schedule shall be granted. This billing credit shall be applied to the monthly billing energy under section V.B. for all power purchased under this rate schedule. No credit shall be applied to those purchases subject to unauthorized increase charges under section VI.C. of this rate schedule. To qualify for the First Quartile Discount, the purchaser must request discounted rate service in writing by April 2 of each calendar year. By virtue of making such request, the Purchaser is agreeing to accept the level and quality of First Quartile service described in section 6 of the Variable Industrial Rate contract. Such acceptance includes the waiver of contract rights provided in section 6.a(2)(a) of said contract.

E. Termination Provision

The Administrator may terminate the Variable Industrial Power rate effective midnight June 30, 1991, upon a determination that significant changes in the conditions and expectations under which this rate was or will be rendered the continuation of the Variable Industrial rate inconsistent with BPA’s stated goals and objectives. BPA shall provide notification of such a determination pursuant to the provisions of the Variable Rate Contract. As part of the notification procedures, BPA shall provide a reasonable opportunity for interested parties to comment on BPA’s determination, as well as to examine the comments submitted by other parties, prior to BPA taking final action to cancel the rate. If BPA determines that the Variable Industrial rate will remain in place until midnight June 30, 1993, BPA shall provide notice that so states and no additional action by BPA will be required.

F. Curtailments

BPA shall charge the customer for curtailments of the lower three quartiles in accordance with the provisions of section 9 of the power sales contract and the provisions contained in the Variable Rate Contract.

G. Unauthorized Increase

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Application of the Charge

During any billing month, BPA may assess an unauthorized increase charge on the number of kilowatthours associated with the DSIMeasured Demand in any one 60-minute clock-hour, before adjustment for power factor, that exceed the BPA Operating Level for that clock-hour, regardless of whether such Measured Demand occurs during the Peak or Offpeak Period.

H. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1. of the GRSPs. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the BPA Operating Level by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

I. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any BPA customer who has suffered an outage of 99% or more of the customer's average demand during the month and who meets the conditions specified in section VII.C. of this rate schedule.
to whom BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Industrial Firm Power. Such credit shall not be provided if BPA is able to serve the DSL’s load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2. of the GRSPs.

J. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5. of the GRSPs shall be applied to all power purchases under this rate schedule consistent with the procedures to adjust the Variable Industrial rate and the provisions of the Variable Rate Contract. A uniform adjustment will be made only if it causes demand and Plateau Energy charges and the First Quartile Service Discount to increase.

The uniform percentage (CRAC%) determined in section III.C.5.c. of the GRSPs shall be applied in the following manner:

\[
(1 + \frac{\text{CRAC\%}}{100}) \times \frac{22.4}{23.0}
\]

\[
\times \text{the demand and Plateau Energy charges contained in section III.A.1. of this rate schedule and to the First Quartile Service Discount specified in section III.A.2. of this rate schedule.}
\]

where: 22.4 represents the average VI-89 margin-based plateau rate in mills per kilowatthour, and 23.0 represents the average VI-89 floor rate in mills per kilowatthour.

The Lower and Upper Rate Limits stated in sections III.A.3. and III.A.4. of this rate schedule shall be adjusted by an amount equal to the change, in mills per kilowatthour, to the Plateau Energy charge due to application of the Cost Recovery Adjustment Clause. The adjusted rate parameters shall be used for billing purposes and supersede the rate charges subject to the adjustment contained in section III.A. of this rate schedule. The adjusted rate parameters shall also be used in subsequent rate adjustments pursuant to section III.B. of this rate schedule and to subsequent biennial adjustments to the lower rate limit pursuant to section VI.B. of this rate schedule.

SECTION VII. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the VI-87 rate is 99.3 percent Exchange and 0.7 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.
SECTION I. AVAILABILITY

This rate schedule is available to any DSI purchaser using raw minerals indigenous to the region as its primary resource and qualifying for this special power pursuant to the procedures established in section 7(d)(2) of the Northwest Power Act. This schedule is available for the contract purchase of this special class of industrial power and also for the purchase of Auxiliary Power if requested by the DSI and made available by BPA. The Special Industrial Offpeak rate available for Hanna Nickel Smelting Company pursuant to the Amendatory Agreement executed July 1, 1985, remains in force and is retained herein. Except for the Special Industrial Offpeak rate, schedule SI-89 supersedes schedule SI-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA’s General Rate Schedule Provisions.

SECTION II. RATE

This rate schedule contains the Standard Special Industrial Power Rate and the Special Industrial Offpeak Rate. The Standard Special Industrial Power Rate is available to any qualifying DSI for full service provided during all hours of the day. The Special Industrial Offpeak Rate is a lower rate available to the Hanna Nickel Smelting Company (Hanna) for service during periods specified by BPA. A separate billing adjustment for the value of the reserves provided by purchasers of this special class of Industrial Power is not contained in the rate schedule; the adjustment is reflected in the Standard Special Industrial Power Rate.

A. Standard Special Industrial Power Rate

1. Demand Charge
   a. $3.08 per kilowattmonth of billing demand occurring during all Peak Period hours.
   b. No demand charge during Offpeak Period hours.

2. Energy Charge
   a. 16.9 mills per kilowatthour of billing energy for the billing months September through March;
   b. 12.9 mills per kilowatthour of billing energy for the billing months April through August.

B. Special Industrial Offpeak Rate

1. Demand Charge
   No demand charge in any hour of the day.

2. Energy Charge
   7.0 mills per kilowatthour of billing energy during all billing months.

SECTION III. BILLING FACTORS

A. Billing Demand

1. Standard Special Industrial Power Rate

   The billing demand for power purchased under the Standard Special Industrial Power Rate shall be the BPA Operating Level during the Peak Period as adjusted for power factor. If there is more than one BPA Operating Level during the Peak Period within a billing month, the billing demand shall be a weighted average of the Peak Period BPA Operating Levels for the billing month. The BPA Operating Level is defined in section III.A.10 of the General Rate Schedule Provisions (GRSPs).

   However, if BPA has agreed, pursuant to section 4 of the direct-service industrial power sales contract, to sell Special Industrial Power on a daily demand basis (transitional service), this section of the rate schedule shall not apply, and BPA shall bill the purchaser in accordance with the provisions of section V.C of the GRSPs.

2. Special Industrial Offpeak Rate

   There is no billing demand for purchases under the Special Industrial Offpeak rate.

B. Billing Energy

   The billing energy under both the Standard Special Industrial and Special Industrial Offpeak Rates shall be the Measured Energy for the billing month, minus any kilowatthours on which BPA assesses the charge for unauthorized increase.

   The kilowatthours of billing energy shall be prorated among the respective billing demands for the billing month.

SECTION IV. SELECTION OF THE SI-89 RATE FOR THE HANNA NICKEL SMELTING COMPANY

All purchasers, except for Hanna, shall purchase power under the Standard Special Industrial Power rate. Hanna shall have the option to select one of two types of serv
standard service or offpeak service. In this case, BPA will provide standard service under the Standard Special Industrial Power Rate and offpeak service under the Special Industrial Offpeak Rate. Unless BPA receives a formal request from Hanna for service under the Special Industrial Offpeak Rate, all service will be standard service provided under the Standard Special Industrial Power Rate. To change the type of service provided and the associated rate, Hanna shall submit a formal request for service under the preferred rate option in accordance with the terms of the power sales contract providing for purchases under this rate schedule. Once Hanna has elected to purchase under one of the two options, all purchases of Special Industrial Power shall be subject to the terms and conditions of that rate option until such time that Hanna requests the other type of service.

SECTION V. SERVICE UNDER THE SPECIAL INDUSTRIAL OFFPEAK RATE

BPA shall designate the hours during which offpeak service will be available, and shall provide at least 2 weeks’ notice before changing those designated hours. BPA shall identify at least 10 and up to 13 hours on each day Monday through Friday, 15 hours on Saturday, and 24 hours on Sunday, during which offpeak service will be available to the purchaser.

If Hanna has elected to be served under the Special Industrial Offpeak Rate, Hanna may request, during the designated offpeak periods, service in an amount not to exceed the purchaser’s Contract Demand. During all other hours Hanna shall curtail service to a level not to exceed 15 percent of Contract Demand.

SECTION VI. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Curtailments

BPA shall charge the DSI for curtailments in accordance with the provisions of the DSI’s power sales contract. Any curtailment charge levied shall be computed using the Standard Special Industrial Power Rate.

B. Unauthorized Increase Charge

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Application of the Charge

During any billing month, BPA may assess the unauthorized increase charge on the number of kilowatthours associated with the DSI Measured Demand in any one 60-minute clock-hour, before adjustment for power factor, that exceed the BPA Operating Level for that clock-hour, regardless of

whether such Measured Demand occurs during the Peak or Offpeak Period.

If BPA is providing service to Hanna under the Special Industrial Offpeak Rate, the amount by which Hanna’s Measured Demand exceeds 15 percent of its Contract Demand during any hour other than the specified special hours shall be considered unauthorized increase.

C. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the GRSPs. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment for service under the Standard Special Industrial Power Rate, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. For service under the Special Industrial Offpeak Rate, BPA shall increase the billing energy by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

D. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any purchaser for those hours for which BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Special Industrial Power. Such credit shall not be provided if BPA is able to serve the purchaser’s load through the use of alternative facilities or if the outage is for less than 30 minutes. In addition, no credit shall be applied to purchases under the Special Industrial Offpeak Rate. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

E. Extended Service Provision

The terms of this rate schedule may be extended for a period not to exceed June 30, 1990, in accordance with the Amendatory Agreement effective July 1, 1985, with the Hanna Nickel Smelting Company (Hanna). The Amendatory Agreement contains Hanna’s agreement to make certain investments in a wet screening process at its Riddle facility.
SECTION VII. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The SI-89 rate is not based on the cost of resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.
SCHEDULE CF-89
FIRM CAPACITY RATE

SECTION I. AVAILABILITY
This schedule is available for the purchase of Firm Capacity without energy on a Contract Demand basis. This schedule is available only to those purchasers holding Firm Capacity contracts executed prior to July 1, 1985. It supersedes Schedule CF-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE
$42.48 per kilowatt per year of Contract Demand, billed monthly at the rate of $3.54 per kilowatt-month of Contract Demand.

SECTION III. BILLING FACTORS
The billing demand shall be the Contract Demand.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS
A. Conservation Surcharge
The Conservation Surcharge shall be applied in accordance with section III.C.7 of the General Rate Schedule Provisions (GRSPs) and subsequent to any other rate adjustments.

B. Extended Peaking Surcharge
The monthly capacity rate specified in section II above shall be increased by the following extended peaking surcharge to compensate BPA for each hour that the purchaser’s monthly demand duration exceeds 8 hours:
1. $0.0908 per kilowatt per hour of extended peaking for the months April through October;
2. $0.0512 per kilowatt per hour of extended peaking for the months November through March.
The charge shall be adjusted pro rata for each portion of an hour of extended peaking supplied to the purchaser. The purchaser’s monthly demand duration shall be determined by dividing:
1. the kilowatthours supplied to the purchaser under this rate schedule between the hours of 7 a.m. and 10 p.m. on the day of maximum kilowatthour use during those hours, provided such day is not a Sunday, by
2. the purchaser’s Contract Demand for such month.
The purchaser’s extended peaking shall be the amount by which the purchaser’s monthly demand duration exceeds 8 hours. The extended peaking surcharge shall not be applied during periods when BPA does not require the delivery of peaking replacement energy by the purchaser.

C. Energy Return Surcharge
The energy associated with the delivery of Firm Capacity must be returned to BPA in accordance with the terms of the purchaser’s Firm Capacity Contract. Unless waived by BPA, any purchaser whose energy returns during any single hour exceed 60 percent of the purchaser’s Contract Demand during any single hour shall be subject to the following surcharge for each additional kilowatthour so returned:
1. 3.49 mills per kilowatthour for the months April through October, and
2. 1.48 mills per kilowatthour for the months November through March.

D. Cost Recovery Adjustment Clause
The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all purchases under this rate schedule. The percentage increase calculated in sections III.C.5.c of the GRSPs shall be applied to the demand charges contained in section II of this rate schedule.

SECTION V. RESOURCE COST CONTRIBUTION
BPA has made the following determinations:
A. The approximate cost contribution of different resource categories to the CF-89 rate is 75.1 percent FBS and 24.9 percent Exchange for contract year service.
B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.
C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.
SCHEDULE CE-89
EMERGENCY CAPACITY RATE

SECTION I. AVAILABILITY
This schedule is available for the purchase of capacity:
A. when an emergency exists on the purchaser’s system, or
B. when the purchaser wishes to displace higher-cost firm capacity resources which are otherwise available to meet the purchaser’s load, provided the purchaser requests such capacity and BPA has capacity available for such purpose.

This schedule supersedes Schedule CE-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA’s General Rate Schedule Provisions.

SECTION II. RATE
A. Demand Charge
   $1.06 per kilowatt of demand per calendar week or portion thereof.
B. Intertie Charge
   The demand charge specified above shall be increased by $0.15 per kilowatt per week for capacity made available at the Oregon-California or Oregon-Nevada border for delivery over the Pacific Northwest-Pacific Southwest (Southern) Intertie.

SECTION III. BILLING FACTORS
The billing demand shall be the maximum amount requested by the purchaser and made available by BPA during a calendar week. If BPA is unable to meet subsequent requests by a purchaser for delivery at the demand previously established during such week, the billing demand for that week shall be the lower demand which BPA is able to supply.

SECTION IV. BILLING PERIOD
Bills shall be rendered monthly.

SECTION V. SPECIAL PROVISION
Energy delivered with such capacity shall be returned to BPA within 7 days of the date of delivery and shall be returned at times and rates of delivery agreed to by both the purchaser and BPA prior to delivery. BPA may agree to accept the return energy after the normal 7 day return period provided that such delay has been mutually agreed upon prior to delivery.

SECTION VI. RESOURCE COST CONTRIBUTION
BPA has made the following determinations:
A. The approximate cost contribution of different resource categories to the CE-89 rate is 75.1 percent FBS and 24.9 percent Exchange.
B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.
C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.
SECTION I. AVAILABILITY

This schedule is available for the contract purchase of firm power or capacity to be used within the Pacific Northwest. New Resource Firm Power is available to investor-owned utilities (IOUs) under net requirements contracts for resale to ultimate consumers, direct consumption, or use in construction, test and start up, and station service. New Resource Firm Power also is available to any public body, cooperative, or Federal agency to the extent such power is needed to serve any New Large Single Load. In addition, BPA may make this rate available to those parties participating in exchange agreements that use this rate schedule as the basis for determining the amount or value of power to be exchanged. This schedule supersedes Schedule NR-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA’s General Rate Schedule Provisions.

SECTION II. RATE

A. Demand Charge

1. $4.13 per kilowatt-month of billing demand occurring during all Peak Period hours.
2. No demand charge during Offpeak Period hours.

B. Energy Charge

1. 25.5 mills per kilowatthour of billing energy for the billing months September through March;
2. 21.2 mills per kilowatthour of billing energy for the billing months April through August;

SECTION III. BILLING FACTORS

In this section billing factors are listed for computed requirements purchasers (section III.A) metered requirements purchasers, and those purchasers not covered by section III.A (section III.B.).

A. Computed Requirements Purchasers

Purchasers designated by BPA as computed requirements purchasers pursuant to power sales contracts shall be billed in accordance with the provisions of this section.

1. Billing Demand

The billing demand for actual, planned, and contracted computed requirements purchasers shall be the higher of the billing factors “a” and “b,” below:

\[\begin{align*}
\text{a.} & \quad \text{the lower of:} \\
& \quad \text{(1) the larger of the Computed Peak Requirement or the Computed Average Energy Requirement;} \\
& \quad \text{(2) the Measured Demand, before adjustment for power factor; or} \\
\text{b.} & \quad \text{the lower of:} \\
& \quad \text{(1) the Computed Peak Requirement; or} \\
& \quad \text{(2) 60 percent of the highest Computed Peak Requirement during the previous 11 billing months (Ratchet Demand).}
\end{align*}\]

2. Billing Energy

The billing energy for actual, planned, and contracted computed requirements purchasers shall be:

\[\begin{align*}
\text{a.} & \quad \text{for the months September through March, the sum of:} \\
& \quad \text{(1) 56 percent of the Measured Energy, and} \\
& \quad \text{(2) 44 percent of the Computed Energy Maximum;} \\
\text{b.} & \quad \text{for the months April through August, the sum of:} \\
& \quad \text{(1) 39 percent of the Measured Energy, and} \\
& \quad \text{(2) 61 percent of the Computed Energy Maximum.}
\end{align*}\]

B. Metered Requirements Purchasers and Other Purchasers Not Covered By Section III.A, Above

Purchasers designated as metered requirements customers and purchasers taking power under this rate schedule who are not otherwise covered by section III.A shall be billed as follows:

1. Billing Demand

The billing demand shall be the Measured Demand as adjusted for power factor, unless otherwise specified in the power sales contract. However, purchasers who previously used the Firm Energy rate schedule, FE-2, either in the computation of their power bills or in the determination of the value of an exchange account, shall not be charged for demand under this rate schedule.

2. Billing Energy

The billing energy shall be the Measured Energy, unless otherwise specified in the power sales contract.
SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSPs). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

B. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all purchases and exchanges under this rate schedule. The percentage increase calculated in section III.C.5.c of the GRSPs shall be applied uniformly to the demand and energy charges contained in section II.A and II.B and the irrigation discount contained in section IV.C of this rate schedule. An additional increase of 0.046 mills per kilowatthour shall be made to the irrigation discount for each percentage increase in the NR rates due to the Cost Recovery Adjustment Clause.

C. Irrigation Discount

BPA shall apply an irrigation discount, equal to 4.6 mills per kilowatthour, to the charges for qualifying energy purchased under this rate schedule. The irrigation discount shall be applied after calculation of the Low Density Discount. The discount shall apply only to energy purchased during the billing months of April through October. Eligibility for the irrigation discount and reporting requirements shall be determined pursuant to section III.C.4 of the GRSPs.

D. Conservation Surcharge

The Conservation Surcharge shall be applied in accordance with section III.C.7 of the GRSPs and subsequent to any other rate adjustments.

E. Unauthorized Increase

BPA shall apply the charge for Unauthorized Increase to any purchaser of New Resource Firm Power taking demand and/or energy in excess of its contractual entitlement.

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Calculation of the Unauthorized Increase

Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase. BPA shall first determine the amount of unauthorized increase related to demand and shall then treat any remaining unauthorized increase as energy-related.

a. Unauthorized Increase in Demand

That portion of any Measured Demand during Peak Period hours, before adjustment for power factor, that exceeds the demand which the purchaser is contractually entitled to take during the billing month and that cannot be assigned:

(1) to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser; or

(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour,

shall be billed:

(1) in accordance with the provisions of the “Relief from Overrun” exhibit to the power sales contract; or

(2) if such exhibit does not apply or is not a part of the purchaser’s power sales contract, at a rate for Unauthorized Increase, based on amount of energy associated with the excess demand.

b. Unauthorized Increase in Energy

The amount of Measured Energy during a billing month that exceeds the amount of energy which the purchaser is contractually entitled to take during that month and that cannot be assigned:

(1) to a class of power that BPA delivers during such month pursuant to contracts between BPA and the purchaser; or

(2) to a type of power that the purchaser acquires from sources other than BPA and that BPA delivers during such month,

shall be billed:

(1) in accordance with the provisions of the “Relief from Overrun” exhibit to the power sales contract; or

(2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser’s power sales contract.
F. Coincidental Billing Adjustment

Purchasers of New Resource Firm Power who are billed on a coincidental basis and who have diversity charges or diversity factors specified in their power sales contracts shall have their charges for billing demand adjusted according to the provisions of section III.C.6 of the GRSPs. Computed requirements purchasers are not subject to the Coincidental Billing Adjustment for scheduled power.

G. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any purchaser for those hours for which BPA is unable to deliver the full billing demand during the billing month due to an outage on the facilities used by BPA to deliver New Resource Firm Power. Such credit shall not be provided if BPA is able to serve the purchaser's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

H. Energy Return Surcharge

Any purchaser who preschedules in accordance with sections 2(a)(4) and 2(c)(2) of Exhibit E of the Power Sales contract and who returns, during a single offpeak hour, more than 60 percent of the difference between that purchaser's estimated computed peak requirement and estimated computed average energy requirement for the billing month shall be subject to the following surcharge for each additional kilowatthour so returned:

1. 3.49 mills per kilowatthour for the months of April through October, and
2. 1.48 mills per kilowatthour for the months of November through March.

SECTION V. RESOURCE COST
CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the NR-89 rate is 100.0 percent Exchange.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.
SECTION I. AVAILABILITY

This rate schedule is available for the purchase of Surplus Firm Power for the period ending September 30, 1994, including purchases under the Western Systems Power Pool (WSPP) agreements. BPA is not obligated to make power or energy available under this rate schedule if such power or energy would displace sales under the IP-89, VI-87, PF-89, or NR-89 rate schedules. Schedule SP-89 supersedes schedule SP-87 and associated GRSPs, except in the case of contracts for sales under schedule SP-87 which become effective on or before September 30, 1989. Sales under this schedule are made subject to BPA’s General Rate Schedule Provisions.

SECTION II. RATE

A. Contract Rate

1. Demand Charge

   a. For contracts that specify 12 months of service per year, $51.48 per kilowatt per year of Contract Demand billed monthly at the rate of $4.29 per kilowatt of Contract Demand occurring during all Peak Period hours in each billing month.

   b. For contracts that specify service for fewer than 12 months per year, the monthly demand charge shall be assessed only for the specified service months at the rate of $4.29 per kilowatt of Billing Demand occurring during the Peak Period plus:

   \[
   \frac{4.29 \times (12 - \text{specified service months}) \times 0.25}{\text{specified service months}}
   \]

   c. No demand charge during Offpeak Period hours

2. Energy Charge

   24.3 mills per kilowatthour of Billing Energy.

B. Flexible Rate

Energy charges or demand and energy charges may be specified at a higher or lower average rate as mutually agreed by BPA and the purchaser. In no case shall the rate exceed 100 percent of the fixed and variable unit costs of generation and transmission of BPA’s highest cost resource including exchange resources. No resource cost determination is needed for sales at less than or equal to the Contract rate.

C. Intertie Charge

Rates in sections II.A and II.B that equal or exceed the Contract rate shall be increased by the following charges for transactions over the Pacific Northwest-Pacific Southwest Intertie.

1. $.36 per kilowatt per month of billing demand and
2. 0.69 mills per kilowatthour of billing energy.

Rates in section II.B having an energy-only charge that equals or exceeds 30.2 mills per kilowatthour shall be increased by 1.4 mills per kilowatthour for transactions over the Pacific Northwest-Pacific Southwest Intertie.

SECTION III. BILLING FACTORS

The billing factors shall be the Measured Demand and Measured Energy, unless otherwise specified in the contract.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

Power Factor Adjustment

The adjustment for power factor for BPA customers that are billed for Short-Term Surplus Firm Power on metered amounts when specified in this rate schedule or in the contract, shall be made in accordance with the provisions of section and section III.C.1 of the General Rate Schedule Provisions (GRSPs). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand or energy by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the SP-89 rate is 99.3 percent Exchange and 0.7 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.
SCHEDULE MSL-87
MODIFIED LONG-TERM SURPLUS FIRM POWER RATE

SECTION I. AVAILABILITY

This rate schedule is effective December 1, 1988, and is available for the long-term purchase of Surplus Firm Power for use within the Pacific Northwest Region under BPA contracts executed on or before October 1, 1990. This rate schedule shall be offered for an amount of purchases not to exceed 1,350 MW peak and 572 MW average, less long-term purchases of Surplus Firm Power, exclusive of any surplus firm capacity sales, sold under other rate schedules pursuant to contracts executed after July 1, 1988. This rate schedule shall not be available for contracts that obligate BPA to acquire energy resources to support the sale. Sales of surplus firm energy under this rate schedule will not be included as a firm load in BPA's long-term resource planning. For contracts executed on or before October 1, 1990, this rate schedule shall continue in effect for 20 years from the date of execution of such contract, but in no event later than September 30, 2010. This rate schedule shall not be available for contracts executed after October 1, 1990. Schedule SL-87 supersedes schedule FD-85 and associated GRSP's. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATES

The rate for the long-term purchase of Surplus Firm Power shall be mutually agreed to by BPA and the purchaser, provided that the present value of the forecasted revenue under the contract rate, as projected for the contract term at the date of contract execution, shall be equal to or greater than the forecasted revenue under the Floor projection, specified in subsection A below, and less than or equal to the forecasted revenue under the Ceiling projection, specified in subsection B below. The floor and ceiling projections filed with the Federal Energy Regulatory Commission on September 30, 1988, are incorporated by reference in this rate schedule and shall apply to all contracts executed under this rate schedule.

A. Floor Projection

1. Firm Power Sale

The floor projection shall be the greater of BPA's average Priority Firm rate or BPA's opportunity cost of surplus firm power projected for each year of the contract term. The average PF rate shall be calculated at the load factor of the proposed sale.

2. Firm Capacity Sale

The floor projection shall be the Priority Firm demand charge projected for each year of the contract term.

3. Combination Firm Power and Firm Capacity Sale

The floor projection shall be the sum of:

   a. the floor in section A.1. for each year in which the purchase is a firm power sale; and

   b. the floor in section A.2. for each year in which the purchase is a firm capacity sale.

B. Ceiling Projection

1. Firm Power Sale

The ceiling projection shall be the fully-allocated cost of BPA's highest cost resource including transmission costs projected for each year of the contract term.

2. Firm Capacity Sale

The ceiling projection shall be the demand component of BPA's highest cost resource including transmission costs projected for each year of the contract term.

3. Combination Firm Power and Firm Capacity Sale

The ceiling projection shall be the sum of:

   a. the ceiling in section B.1. for each year in which the purchase is a firm power sale; and

   b. the ceiling in section B.2. for each year in which the purchase is a firm capacity sale.

SECTION III. BILLING FACTORS

The billing factors shall be the Contract Demand and Measured Energy, unless otherwise specified in the contract.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Escalation Requirement

Adjustments to the contract rate shall occur on the dates specified in the contract but the intervals between adjustment dates shall not exceed five years. Each contract shall include an escalation provision specifying the specific formula and index for escalating the contract rate over the term of the contract as mutually agreed to by the parties. In addition each contract shall specify a minimum escalator based on either changes in BPA's Priority Firm Power rate or changes in BPA's Average System Cost.
1. For the first five years, the minimum escalator may be based on:
   (a) the forecasted changes in BPA’s Priority Firm Power rate or in BPA’s Average System Cost at the date of contract execution, filed with the Federal Regulatory Commission on September 30, 1988; or
   (b) actual changes in BPA’s Priority Firm Power rate or in BPA’s Average System Cost determined in accordance with either subsection 3(a) or 3(b) below.

2. For every rate adjustment date after year five, the minimum escalator shall be based on actual changes determined in accordance with either subsection 3(a) or 3(b) below.

3. The minimum escalation for a contract will be calculated as follows:
   (a) Escalation Based on BPA’s Priority Firm Power Rate
       To determine the change in BPA’s Priority Firm Power rate the average Priority Firm Power rate or successors rate(s) in mills per kilowatthour in effect on the rate adjustment date specified in the contract shall be divided by average Priority Firm Power rate or successors rate(s) in mills per kilowatthour in effect on the date contract purchases began under this rate schedule. The average PF rate or successor rate(s) shall be calculated at the load factor of the proposed sale, and assume a uniform demand in all months. If there is more than one PF rate in effect, the PF rate shall be determined by a weighting based on forecasted sales in the relevant rate case.
   (b) Escalation Based on BPA’s Average System Cost
       Changes in BPA’s Average System Cost shall be calculated by dividing BPA’s Average System Cost in effect on the rate adjustment date specified in the contract by BPA’s Average System Cost in effect on the date contract purchases began under this rate schedule. For purposes of this rate schedule, BPA’s Average System Cost shall be determined by dividing BPA’s total system costs by BPA’s total system sales. BPA’s total system costs and total system sales are defined in section IV.D. of the GRSPs.

C. Power Factor Adjustment
   The adjustment for power factor for BPA customers that are billed for the long-term purchase of Surplus Firm Power [and Firm Displacement Power] on metered amounts, when specified in this rate schedule or in the contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSP’s). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.
   To make the power factor adjustment, BPA shall increase the billing demand or energy by one percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:
A. The approximate cost contribution of different resource categories to the MSL-87 rate is 99.3 percent Exchange and 0.7 percent New Resources.
B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.
C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.
SECTION I. AVAILABILITY

This schedule is available for the purchase of nonfirm energy to be used both inside and outside the United States including sales under the Western Systems Power Pool (WSPP) agreements and sales to consumers. This schedule also applies to energy delivered for emergency use under the conditions set forth in section V.A of the General Rate Schedule Provisions (GRSPs). BPA is not obligated to offer nonfirm energy to any purchaser that results in displacement of firm power purchases under BPA’s Power Sales Contracts. The offer of nonfirm energy under this schedule shall be determined by BPA. Schedule NF-89 supersedes Schedule NF-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA’s General Rate Schedule Provisions.

SECTION II. RATES

The average cost of nonfirm energy is 18.0 mills per kilowatthour. The NF-89 rate schedule provides for upward and downward pricing flexibility from this average nonfirm energy cost. All rates and any subsequent adjustments contained in this rate schedule shall not exceed in total the NF Rate Cap defined in section IV.C of the GRSPs.

A. Standard Rate

The Standard rate is any offered rate not to exceed 21.6 mills per kilowatthour.

B. Market Expansion Rate

The Market Expansion rate is any offered rate below the Standard rate in effect. BPA may have one or more Market Expansion rates in effect simultaneously.

C. Incremental Rate

The Incremental rate is the Incremental Cost of energy plus 2.0 mills per kilowatthour, where the Incremental Cost is defined as all identifiable costs (expressed in mills per kilowatthour) that BPA would have avoided had it not produced or purchased the energy being sold under this rate.

D. Contract Rate

The Contract rate is 14.9 mills per kilowatthour of billing energy.

SECTION III. ADJUSTMENTS TO RATES

A. Guaranteed Delivery Surcharge

A surcharge of 2.0 mills per kilowatthour of billing energy is applied to guaranteed delivery of nonfirm energy under the Standard rate and Market Expansion rate.

B. Intertie Charge

Rate offers, under any of the rates specified above, greater than or equal to 18.0 mills per kilowatthour shall be increased by 1.4 mills per kilowatthour for nonfirm energy scheduled for delivery over the Pacific Northwest-Pacific Southwest Intertie.

SECTION IV. BILLING FACTORS

The billing energy for nonfirm energy purchased under this rate schedule shall be the Measured Energy unless otherwise specified by contract.

SECTION V. APPLICATION AND ELIGIBILITY

Any time that BPA has nonfirm energy for sale, the Standard rate, the Market Expansion rate, the Incremental rate, the Contract rate, or a combination of these rates may be in effect.

A. Standard Rate

The Standard rate:

1. is available for all purchases of nonfirm energy; and
2. applies to nonfirm energy purchased pursuant to the Relief from Overrun Exhibit to the power sales contract.

B. Market Expansion Rate

1. Application of the Market Expansion rate

The Market Expansion rate applies when BPA determines that all markets at the Standard rate have been satisfied and BPA offers additional nonfirm energy.

2. Market Expansion Rate Qualification Criteria

In order to purchase nonfirm energy at the Market Expansion rate, a purchaser must:

a. have a displaceable resource, displaceable purchase of electricity, or
b. be an end-user load with a displaceable alternative fuel source.

In addition, a purchaser must demonstrate one of the following:
a. shutdown or reduction of the output of the displaceable resource in an amount equal to the amount of Market Expansion rate energy purchased; or

b. reduction of a displaceable purchase and the output of the resource associated with that purchase, in an amount equal to the amount of Market Expansion rate energy purchased; or

c. shutdown or reduction of the identified output of the resource(s) indirectly in an amount equal to the amount of Market Expansion rate energy purchased (for example, the purchase may be used to run a pumped storage unit); or

d. decrease of an end-user alternate fuel source in an amount equivalent to the amount of Market Expansion rate energy purchased.

3. Eligibility Criteria for Market Expansion rate

a. When only one Market Expansion rate is offered:
Purchasers qualifying under section V.B.2. who purchased nonfirm energy directly from BPA are eligible to purchase power under the Market Expansion rate offered if the decremental cost of the qualifying resource, purchase, or qualifying alternative fuel source is lower than the Standard rate in effect plus 2.0 mills per kilowatthour.
Purchasers qualifying under section V.B.2. who purchase nonfirm energy through a third party are eligible to purchase power under the Market Expansion rate offered if the cost of the qualifying alternative fuel source is lower than the Standard rate in effect plus 4.0 mills per kilowatthour.

b. When more than one Market Expansion rates are offered:
Purchasers qualifying under section V.B.2. who purchased nonfirm energy directly from BPA are eligible to purchase power under the Market Expansion rate if the decremental cost of the qualifying resource, purchase, or qualifying alternative fuel source is lower than the Standard rate in effect plus 2.0 mills per kilowatthour. The rate applicable to a purchaser shall be the highest Market Expansion rate offered that is below the purchaser’s qualifying decremental cost minus 2.0 mills per kilowatthour.
Purchasers qualifying under section V.B.2. who purchase nonfirm energy through a third party are eligible to purchase power under the Market Expansion rate if the decremental cost of the qualifying alternative fuel source is lower than the Standard rate plus 4.0 mills per kilowatthour. The rate applicable to a purchaser shall be the highest Market Expansion rate offered that is below the purchaser’s qualifying decremental cost minus 4.0 mills per kilowatthour.

C. Incremental Rate
The Incremental rate applies to sales of energy:
1. that is produced or purchased by BPA concurrently with the nonfirm energy sale;
2. that BPA may at its option not produce or purchase; and
3. that has an Incremental Cost greater than the Standard rate (plus the Intertie Charge, if applicable) less 2.0 mills per kilowatthour.

D. Contract Rate
The Contract rate applies to contracts (except power sales contracts offered pursuant to sections 5(b), 5(c), and 5(g) of the Northwest Power Act) that refer to the Contract rate:
1. for the sale of nonfirm energy; or
2. for determining the value of energy.

E. Western Systems Power Pool Transactions
BPA may make available nonfirm energy for transactions under the Western Systems Power Pool (WSPP) agreement. WSPP sales shall be subject to the terms and conditions specified in the WSPP agreement and shall be consistent with regional and public preference. The rate for transactions under the WSPP agreement is any within the limits specified by the Standard, Market Expansion, and Incremental rates but may differ from the actual rate offered for non-WSPP transactions in any hour. The rate for WSPP transactions is independent of any other rate offered concurrently under this rate schedule outside that agreement.

F. End-User Rate
BPA may agree to a rate or rate formula for nonfirm energy purchases by end-users. Such rate or rate formula shall be within the limits specified for the Standard and Market Expansion rates but may differ from the actual rates offered during any hour.

SECTION VI. DELIVERY

A. Rate of Delivery
BPA shall determine the amount of nonfirm energy to be made available for each hour. Such determination shall be made for each applicable nonfirm energy rate.

B. Guaranteed Delivery
1. Availability
   BPA will determine the amount and duration of nonfirm energy to be offered on a guaranteed basis.
Such daily or hourly amounts may be as small as zero or as much as all the nonfirm energy that BPA plans to offer for sale on such days.

2. Conditions

Scheduled amounts of guaranteed nonfirm energy may not be changed except:

a. when BPA and the purchaser mutually agree to increase or decrease the scheduled amounts; or

b. when BPA must reduce nonfirm energy deliveries in order to serve firm loads because of unexpected generation or transmission losses.

SECTION VII. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the average cost of nonfirm energy is 99.6 percent FBS and 0.4 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.
SECTION I. AVAILABILITY

This rate schedule is available for the contract purchase of Nonfirm Energy under an experimental rate and is limited to the term of the rate experiment. Nonfirm Energy will be made available under this rate schedule for use both inside and outside the United States for the displacement of a qualifying resource, displaceable purchase of electricity, or end-user load that can be served with alternate fuel sources. This rate schedule is only available to purchasers who execute a contract with BPA specifying use of the Share-the-Savings Rate. BPA is not obligated to offer Nonfirm Energy to any purchaser that results in displacement of firm power purchases under BPA's Power Sales Contracts. Schedule SS-89 supersedes Schedule SS-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

The rate shall be a formula rate based solely or in part on decremental cost information submitted by the purchaser. The rate formula and decremental cost, for purposes of establishing charges under this rate schedule, shall be defined in the applicable contract. The rate formula agreed upon by BPA and the purchaser shall in no event result in a rate higher than the NF Rate Cap defined in section IV.C. of the GRSPs or lower than 1 mill per kilowatthour.

SECTION III. BILLING FACTORS

The billing energy for Nonfirm Energy purchased under this rate schedule shall be the Measured Energy unless otherwise specified in the Share-the-Savings Rate contract.

SECTION IV. APPLICATION AND ELIGIBILITY

A. General Requirements

In order to purchase Nonfirm Energy under the Share-the-Savings Rate, the purchaser must:

1. have executed a contract specifying application of the Share-the-Savings Rate Schedule.

2. have a displaceable resource, displaceable purchase of electricity, or be an end-user load with a displaceable alternate fuel source. End-user loads with alternate fuel sources may not use the Decremental Cost of a displaceable purchase of electricity to qualify for this rate.

B. BPA Service Priority

Offers of Nonfirm Energy under this rate schedule shall be made pursuant to the terms and conditions set forth in the Share-the-Savings rate contract. BPA will sell Nonfirm Energy under this rate schedule consistent with regional and public preference.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The SS-89 rate is not based on the cost of BPA resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.
SECTION I. AVAILABILITY

This schedule is available for the purchase of power:

A. in cases where a purchaser's power sales contract states that the rate for Reserve Power shall be applied;
B. for which BPA determines no other rate schedule is applicable; and
C. to serve a purchaser's firm power load in circumstances where BPA does not have a power sales contract in force with such purchaser, and BPA determines that this rate should be applied.

This rate schedule may be applied to power purchased by entities outside the United States. This rate schedule supersedes Schedule RP-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

A. Demand Charge
   1. $3.64 per kilowatt of billing demand occurring during all Peak Period hours.
   2. No demand charge during Offpeak Period hours.

B. Energy Charge
   25.3 mills per kilowatthour of billing energy.

SECTION III. BILLING FACTORS

The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

A. Billing Demand
   If applicable, the billing demand shall be the Contract Demand as specified in the power sales contract. Otherwise the billing demand shall be the Measured Demand as adjusted for power factor.

B. Billing Energy
   The billing energy shall be the Contract Demand multiplied by the number of hours in the billing month, if use of the Contract Demand for determining billing energy is specified in the power sales contract. Otherwise the billing energy for such purchasers shall be the Measured Energy.

SECTION IV. POWER FACTOR ADJUSTMENT

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSPs). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The RP-89 rate is not based on the cost of resources.
B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.
C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.
I. Adoption of Revised Rate Schedules and General Rate Schedule Provisions ................................................. 29  
   A. Approval of Rates ......................................................... 29  
   B. General Provisions ....................................................... 29  

II. Types of BPA Service .......................................................... 29  
   A. Priority Firm Power ....................................................... 29  
   B. New Resource Firm Power .............................................. 29  
   C. Industrial Firm Power ................................................... 29  
   D. Special Industrial Power ............................................. 29  
   E. Auxiliary Power ........................................................... 30  
   F. Firm Capacity ............................................................. 30  
   G. Surplus Firm Power ..................................................... 30  
   H. Nonfirm Energy ........................................................... 30  
   I. Reserve Power ............................................................. 30  

III. Billing Factors and Billing Adjustments .................................. 30  
   A. Billing Factors for Demand ............................................ 30  
      1. Measured Demand ..................................................... 30  
         a. Metered Demand ................................................... 30  
         b. Scheduled Demand ............................................... 30  
      2. Ratchet Demand .................................................... 31  
      3. Contract Demand ................................................... 31  
      4. Computed Peak Requirement .................................... 31  
      5. Computed Average Energy Requirement ....................... 31  
      6. Operating Demand .................................................. 31  
      7. Curtailed Demand .................................................. 32  
      8. Restricted Demand ................................................ 32  
      9. Auxiliary Demand ................................................ 32  
     10. BPA Operating Level ............................................. 32  
   B. Billing Factors for Energy .......................................... 32  
      1. Measured Energy .................................................... 32  
         a. Metered Energy .................................................. 32  
         b. Scheduled Energy ............................................... 32  
      2. Computed Energy Maximum ...................................... 32  
      3. Contract Energy .................................................. 32  
   C. Billing Adjustments .................................................. 33  
      1. Power Factor Adjustment ....................................... 33  
      2. Outage Credit .................................................... 33  
      3. Low Density Discount ...................................... 33  
         a. Basic LDD Principles ............................................ 33
<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>b. Eligibility Criteria</td>
<td>34</td>
</tr>
<tr>
<td>c. Discounts</td>
<td>34</td>
</tr>
<tr>
<td>4. Irrigation Discount</td>
<td>35</td>
</tr>
<tr>
<td>a. Basic Irrigation Discount Principles</td>
<td>35</td>
</tr>
<tr>
<td>b. Qualifying Energy Purchases</td>
<td>35</td>
</tr>
<tr>
<td>c. Initial Reporting Requirements</td>
<td>35</td>
</tr>
<tr>
<td>d. Annual Report Requirements</td>
<td>35</td>
</tr>
<tr>
<td>5. Cost Recovery Adjustment Clause</td>
<td>35</td>
</tr>
<tr>
<td>a. Applicable Rate Schedules</td>
<td>36</td>
</tr>
<tr>
<td>b. Evaluation and Adjustment Periods</td>
<td>36</td>
</tr>
<tr>
<td>c. Formulas for the Cost Recovery Adjustment Clause</td>
<td>36</td>
</tr>
<tr>
<td>d. Application to Irrigation Discount</td>
<td>37</td>
</tr>
<tr>
<td>e. Cost Recovery Adjustment Clause Implementation Process</td>
<td>37</td>
</tr>
<tr>
<td>6. Coincidental Billing Adjustment</td>
<td>38</td>
</tr>
<tr>
<td>7. Conservation Surcharge</td>
<td>38</td>
</tr>
<tr>
<td>D. Billing-Related Definitions</td>
<td>38</td>
</tr>
<tr>
<td>1. Peak Period</td>
<td>38</td>
</tr>
<tr>
<td>2. Offpeak Period</td>
<td>38</td>
</tr>
<tr>
<td>IV. Other Definitions</td>
<td>39</td>
</tr>
<tr>
<td>A. Computed Requirements Purchasers</td>
<td>39</td>
</tr>
<tr>
<td>1. Designation as a Computed Requirements Purchaser</td>
<td>39</td>
</tr>
<tr>
<td>2. Purpose of the Computed Requirements Designation</td>
<td>39</td>
</tr>
<tr>
<td>B. Definitions Relating to Nonfirm Energy</td>
<td>39</td>
</tr>
<tr>
<td>C. NF Rate Cap</td>
<td>39</td>
</tr>
<tr>
<td>1. Application of the NF Rate Cap</td>
<td>39</td>
</tr>
<tr>
<td>2. Monthly Notification of NF Rate Cap</td>
<td>39</td>
</tr>
<tr>
<td>3. NF Rate Cap Formula</td>
<td>39</td>
</tr>
<tr>
<td>4. Determination of BASC</td>
<td>39</td>
</tr>
<tr>
<td>5. Determination of Decremental Fuel Cost</td>
<td>40</td>
</tr>
<tr>
<td>6. California Gas Price</td>
<td>40</td>
</tr>
<tr>
<td>7. California Petroleum Price</td>
<td>40</td>
</tr>
<tr>
<td>8. Weighting Factors</td>
<td>41</td>
</tr>
<tr>
<td>a. Historical Gas Use in California</td>
<td>41</td>
</tr>
<tr>
<td>b. Historical Petroleum Use in California</td>
<td>41</td>
</tr>
<tr>
<td>D. Determination of BPA's Average System Cost</td>
<td>42</td>
</tr>
<tr>
<td>V. Application of Rates Under Special Circumstances</td>
<td>42</td>
</tr>
<tr>
<td>A. Energy Supplied for Emergency Use</td>
<td>42</td>
</tr>
<tr>
<td>B. Construction, Test and Start-up, and Station Service</td>
<td>42</td>
</tr>
<tr>
<td>C. Application of Rates During Initial Operation Period-Transitional Service</td>
<td>42</td>
</tr>
</tbody>
</table>

27
VII. Variable Industrial Rate Parameters and Adjustments

A. Monthly Average Aluminum Price Determination
   1. Calculation of the Monthly Billing Aluminum Price
   2. Notification of the Monthly Average Aluminum Price
   3. Changes in Aluminum Price Indicators

B. Annual Adjustments to the Lower and Upper Pivot Aluminum Prices
   1. Implementation Procedures
   2. Annual Adjustment Procedures
      a. Annual Adjustment of the Lower Pivot Aluminum Price
      b. Annual Adjustment of the Upper Pivot Aluminum Price
   3. Cost Escalators
   4. Average Historical Aluminum Price
   5. Average Historical Lower Pivot Aluminum Price
   6. Price Deflator Procedures

VI. Billing Information

A. Determination of Estimated Billing Data
B. Load Shift and Outage Reports
C. Billing for New Large Single Loads
D. Determination of Measured Demand
E. Determination of Measured Energy
F. Billing Month
G. Payment of Bills
   1. Computation of Bills
   2. Estimated Bills
   3. Due Date
   4. Late Payment
   5. Disputed Billings
   6. Revised Bills

E. Restriction of Deliveries
D. Changes in a DSIs BPA Operating Level
SECTION I. ADOPTION OF REVISED RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

Approval of Rates
These 1989 rate schedules and General Rate Schedule Provisions (GRSPs) shall become effective upon interim approval or final confirmation and approval by the Federal Energy Regulatory Commission (FERC). BPA will request FERC approval effective October 1, 1989. BPA proposes that the following schedules, and the GRSPs associated with these schedules, be effective for two years: PF-89, IP-89, SI-89, CE-89, CF-89, NR-89, SS-89, NF-89, and RP-89. The VI-87 rate schedule reflects adjustments of and supplements to the rate schedule VI-86 and associated GRSPs (which are to be in effect for 7 years). Sections III.A and VI.J of the VI-87 rate schedule are to be in effect for an additional 2 years. BPA proposes that rate schedule SI-89 be effective 2 years, except for the Special Industrial Offpeak rate provision, which is to remain in effect through June 30, 1990, pursuant to an Amendment Agreement between BPA and Hanna Nickel Smelting Company executed July 1, 1985.

B. General Provisions
These 1989 rate schedules, and the GRSPs associated with these rate schedules, supersede BPA’s 1987 rate schedules (which became effective October 1, 1987) to the extent stated in the Availability section of each 1989 rate schedule. These schedules and GRSPs shall be applicable to all BPA contracts, including contracts executed both prior to and subsequent to enactment of the Northwest Power Act. All sales of power made under these rate schedules are 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 Northwest Power Act.

SECTION II. TYPES OF BPA SERVICE

A. Priority Firm Power
Priority Firm Power is electric power (capacity, energy, or capacity and energy) that BPA will make continuously available for resale to ultimate consumers, or for direct consumption, construction, test and start-up, and station service by public bodies, cooperatives, and Federal agencies. (Construction, test and start-up, and station service are defined in section V.B of these GRSPs.) Utilities participating in the exchange under section 5(c) of the Northwest Power Act may purchase Priority Firm Power pursuant to their Residential Purchase and Sale Agreements.

In addition, BPA may make Priority Firm Power available to those parties participating in exchange agreements specifying use of the Priority Firm rate for determining the amount or value of power to be exchanged. Power purchased under the power rate schedule is to be used to meet the purchaser’s actual firm load within the Pacific Northwest. Such power may be restricted in accordance with the Restriction of Deliveries section of these GRSPs (section V.E). However, BPA shall not restrict Priority Firm Power until Industrial Firm Power has been restricted in accordance with the provisions of section II.C of these GRSPs.

Priority Firm Power is not available to serve New Large Single Loads.

B. New Resource Firm Power
New Resource Firm Power is electric power (capacity, energy, or capacity and energy) that BPA will make continuously available:
1. for any New Large Single Load,
2. for firm power purchased by investor-owned utilities pursuant to power sales contracts with BPA, and
3. for construction, test and start-up, and station service for facilities owned or operated by investor-owned utilities.

New Resource Firm Power is to be used to meet the purchaser’s actual firm load within the Pacific Northwest. Such power may be restricted in accordance with the Restriction of Deliveries section of these GRSPs (section V.E). However, BPA shall not restrict New Resource Firm Power until Industrial Firm Power has been restricted in accordance with the provisions of section II.C of these GRSPs.

C. Industrial Firm Power
Industrial Firm Power is electric power that BPA will make continuously available to a direct-service industrial (DSI) purchaser pursuant to the DSI’s power sales contract and subject to:
1. the restriction applicable to deliveries of all firm power pursuant to the Uncontrollable Forces and Continuity of Service provisions of the General Contract Provisions of the power sales contract, and
2. the restrictions given in the Restriction of Deliveries section of the power sales contract.

D. Special Industrial Power
Special Industrial Power is electric power which BPA will make continuously available to any DSI that quali-
fies for the Special Industrial Power rate pursuant to section 7(d)(2) of the Northwest Power Act. This power is similar in nature to Industrial Firm Power, but is subject to greater restriction by BPA. Special Industrial Power is made available to the qualifying DSI upon adoption of, and subject to, an amendment modifying its power sales contract.

E. Auxiliary Power

Auxiliary Power is that power which a DSI requests and which BPA agrees to make available to serve that portion of the DSI’s load which is in excess of the DSI’s Operating Demand for Industrial Firm Power or Special Industrial Power.

F. Firm Capacity

Firm Capacity is capacity that BPA assures will be available in the amount(s) and during the period(s) specified in the power sales contract. The energy associated with this capacity must be returned to BPA. Firm Capacity may be restricted pursuant to the Restriction of Deliveries section of these GRSPs (section V.E).

G. Surplus Firm Power

Surplus Firm Power is firm energy, firm energy with capacity, and firm capacity (capacity with energy return requirements) in excess of the amount required to meet BPA’s existing contractual obligations to provide firm service. Surplus Firm Power may be used either for resale or direct consumption by purchasers both inside and outside the United States. Such power, however, may be restricted pursuant to the Restriction of Deliveries section of these GRSPs (section V.E).

H. Nonfirm Energy

Nonfirm Energy is supplied or made available by BPA to a purchaser under an arrangement that does not have the guaranteed continuous availability feature of firm power. Nonfirm energy is mostly sold under the Nonfirm Energy rate schedule, NF-89. Nonfirm energy also may be supplied under the Share-the-Savings rate schedule, SS-89, which is available as an experimental rate for contract purchase.

In addition, BPA also can make nonfirm energy available under the Nonfirm Energy rate schedule to the Western Systems Power Pool (WSPP) subject to terms and conditions agreed upon by the members participating in the WSPP and in accordance with BPA policy for such arrangements.

However, Nonfirm Energy that has been purchased under a guarantee provision in the Nonfirm Energy rate schedule shall be provided to the purchaser in accordance with the provisions of that schedule and the power sales contract if applicable. BPA may make Nonfirm Energy available to purchasers both inside and outside the United States.

I. Reserve Power

Reserve Power is firm power sold to a purchaser:

1. in cases where the purchaser’s power sales contract states that the rate for Reserve Power shall be applicable,
2. to provide service when no other type of power is deemed applicable; and
3. to serve the purchaser’s firm power loads under circumstances where BPA does not have a power sales contract in force with the purchaser.

Sales of Reserve Power are subject to the Restriction of Deliveries section of these GRSPs (section V.E).

SECTION III. BILLING FACTORS AND BILLING ADJUSTMENTS

A. Billing Factors for Demand

1. Measured Demand

The purchaser’s Measured Demand shall be determined in the manner described in this section. Measured Demand shall be that portion of the metered or scheduled demand that is purchased from BPA under the applicable rate schedule. For those contracts to which BPA is a party and that provide for delivery of more than one class of electric power to the purchaser at any point of delivery, the portion of each 60-minute clock-hour integrated demand assigned to any class of power shall be determined pursuant to the power sales contract. The portion of the total Measured Demand so assigned shall constitute the Measured Demand for each such class of power.

The Measured Demand shall be determined from the metered demand or the scheduled demand, as hereinafter defined. The Measured Demand shall be determined on either a coincidental or a noncoincident basis, as provided in the purchaser’s power sales contract.

a. Metered Demand

The metered demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands, adjusted as specified in the power sales contract, at which electric energy is delivered to a purchaser:

1. at each point of delivery for which the metered demand is the basis for determination of the Measured Demand,
2. during each time period specified in the applicable rate schedule, and
3. during any billing period.
Such largest integrated demand shall be determined from measurements made either in the manner specified in the power sales contract or as provided in section VI.A herein. In determining the metered demand, BPA shall exclude any abnormal integrated demands due to or resulting from:

1. emergencies or breakdowns on, or maintenance of, the Federal system facilities, and
2. emergencies on the purchaser’s facilities, provided that such facilities have been adequately maintained and prudently operated, as determined by BPA.

b. Scheduled Demand

The scheduled demand in kilowatts shall be the largest of the hourly demands at which electric energy is scheduled for delivery to a purchaser:

1. to each system for which scheduled demand is the basis for determination of the Measured Demand,
2. during each time period specified in the applicable rate schedule, and
3. during any billing period.

Scheduled amounts are deemed delivered for the purpose of determining billing demand.

2. Ratchet Demand

The Ratchet Demand in kilowatts shall be the maximum demand established during a specified period of time either during or prior to the current billing period. The demand on which the ratchet is based is specified in the relevant rate schedule or in these GRSPs. For utilities purchasing under the PF or NR rate schedules, the Ratchet Demand is based on the highest demand during prior billing months. When the Ratchet Demand is used as a billing factor, BPA shall have specified in the appropriate schedules or GRSPs:

a. the period of time over which the ratchet shall be calculated,
b. the type of demand to be used in the calculation, and
c. the percentage (if any) of that demand which will be used to calculate the Ratchet Demand.

3. Contract Demand

The Contract Demand shall be the maximum number of kilowatts that the purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the power sales contract. BPA may agree to make deliveries at a rate in excess of the Contract Demand at the request of the purchaser, but shall not be obligated to continue such excess deliveries. Any contractual or other reference to Contract Demand as expressed in kilowatthours shall be deemed, for the purpose of these GRSPs, to refer to the term “Contract Energy.”

4. Computed Peak Requirement

For purchasers designated to purchase on the basis of computed requirements, the Computed Peak Requirement shall be determined as specified in the purchaser’s power sales contract. That specification is provided in:

a. sections 16, 17(c), and 17(f), as adjusted by other sections of the contract, for actual computed requirements purchasers;
b. sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for planned computed requirements purchasers; and
c. sections 16 and 17(b), as adjusted by other sections of the contract, for contracted computed requirements purchasers.

5. Computed Average Energy Requirement

For computed requirements purchasers, the Computed Average Energy Requirement shall be determined as specified in the purchaser’s power sales contract. That specification is provided in:

a. sections 16, 17(c), and 17(f), as adjusted by other sections of the contract, for actual computed requirements purchasers;
b. sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for planned computed requirements purchasers; and
c. sections 16 and 17(b), as adjusted by other sections of the contract, for contracted computed requirements purchasers.

6. Operating Demand

The Operating Demand is that demand which is established by each DSI in accordance with section 5(b) of the DSI’s power sales contract. Unless the DSI has requested, and BPA has granted, an Auxiliary Demand, the Operating Demand establishes a limit with respect to:

a. the demand which the purchaser may impose on BPA; and
b. the total amount of energy during a billing month which the DSI is entitled to purchase from BPA.
7. Auxiliary Demand

Auxiliary Demand is the number of kilowatts of industrial power (Industrial Firm Power or Special Industrial Power) during the billing month which results from the DSI's request for such power in amounts less than the Operating Demand therefor. Each purchaser of industrial power may curtail its demand according to the terms of its power sales contract (which permits up to three levels of Curtailed Demand each month).

8. Restricted Demand

Restricted Demand is the number of kilowatts of industrial power (either Industrial Firm Power or Special Industrial Power) that results when BPA has restricted delivery of such power for one clock-hour or more. BPA shall make such restrictions according to the terms of the DSI's power sales contract. In a given billing month, there are as many possible levels of Restricted Demand for a DSI as there are number of restrictions.

9. Auxiliary Demand

Auxiliary Demand is the number of kilowatts of Auxiliary Power that a DSI requests and that BPA agrees to make available to serve a portion of the DSI's load during the period specified in the DSI's request. The DSI may request up to three levels of Auxiliary Demand during a billing month.

If BPA agrees to a request for Auxiliary Power but later becomes unable to supply such demand, the Restricted Demand for Auxiliary Power is deemed to be the Auxiliary Demand for such period of restriction. Auxiliary Power may be curtailed by the DSI according to the provisions of section 9(a) of the DSI's power sales contract.

BPA shall make Auxiliary Power available to Industrial Firm Power purchasers under the Industrial Firm Power Rate Schedule at the Standard Industrial Rate. Auxiliary Power sales to DSls electing to purchase under the Variable Industrial Power Rate Schedule (VI-87) shall be made at the rate determined pursuant to section III of the VI-87 rate schedule. Auxiliary Power sales to DSls purchasing under the Special Industrial Rate will be made only at the Standard Special Industrial Power Rate.

10. BPA Operating Level

The BPA Operating Level is, for the purpose of these rate schedules and GRSPs, an hourly amount of industrial power (Industrial Firm Power or Special Industrial Power) for a DSI that is equal to the lowest of the following demands during that hour:

a. Operating Demand plus Auxiliary Demand, if any;

b. Curtailed Demand;

c. Restricted Demand.

The weighted average BPA Operating Level for each DSI can be determined by summing the hourly Operating Levels and dividing by the number of hours in the billing month.

Each DSI must request service from BPA for each billing month in accordance with the terms of the power sales contract. The requested level of service will be the BPA Operating Level, provided BPA does not need to restrict the DSI and provided BPA agrees to supply any requested Auxiliary Demand. Each requested level of service may include a designation for both the Peak Period and the Offpeak Period. A DSI may request and BPA may agree to a level of service for the Offpeak Periods other than that in the Peak Period. If a DSI does not separately designate a requested level of service for the Peak and Offpeak Periods, the BPA Operating Level is the basis for determining if a DSI has incurred an unauthorized increase.

Any DSI whose Measured Demand, before adjustment for power factor, during any 1 hour exceeds the BPA Operating Level for that hour shall be subject to unauthorized increase charges for each kilowatt-hour of unauthorized increase associated with each overrun.

Only the BPA Operating Level applicable during the Peak Period will be used in determining the Billing Demand for power purchased under the Industrial Firm Power rate schedule, the Variable Industrial Power rate schedule, and the Standard Rate under the Special Industrial rate schedule. During the Peak Period the BPA Operating Level may be no greater than the Operating Demand for the billing month unless the customer has requested, and BPA has agreed to supply, the Auxiliary Demand.

B. Billing Factors for Energy

1. Measured Energy

Measured Energy shall be that portion of the metered or scheduled energy that is purchased from BPA under the applicable rate schedule. For those contracts to which BPA is a party and that provide for delivery of more than one class of electric power to the purchaser at any point of delivery, the portion of each 60-minute clock-hour integrated demand assigned to any class of power shall be determined pursuant to the power sales contract. The sum of the portions of the demands so assigned shall constitute the Measured Energy for each such class of power.

The Measured Energy shall be determined from the metered energy or the scheduled energy, as hereafter defined.
a. Metered Energy
The metered energy for a purchaser shall be the number of kilowatthours that are recorded on the appropriate metering equipment, adjusted as specified in the power sales contract, and delivered to a purchaser:

(1) at all points of delivery for which metered energy is the basis for determination of the Measured Energy, and

(2) during any billing period.

The metered energy shall be determined from measurements made either in the manner specified in the power sales contract or as provided in section VI.A herein.

b. Scheduled Energy
The scheduled energy in kilowatthours shall be the sum of the hourly demands at which electric energy is scheduled for delivery to a purchaser:

(1) for each system for which scheduled energy is the basis for determination of the Measured Energy, and

(2) during any billing period.

Scheduled amounts are deemed delivered for the purpose of determining billing energy.

2. Computed Energy Maximum
The Computed Energy Maximum equals the product of the number of hours in the billing month and the Computed Average Energy Requirement.

3. Contract Energy
The Contract Energy shall be the maximum number of kilowatthours that the purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the power sales contract.

C. Billing Adjustments

1. Power Factor Adjustment
The formula for determining average power factor is as follows:

\[
\text{Average Power Factor} = \frac{\text{Average Kilowatthours}}{(\text{Kilowatthours})^2} + \frac{\text{Reactive kilovoltamperehours}}{(\text{Reactive kilovoltamperehours})^2}
\]

The data used in the above formula shall be obtained from meters that are ratcheted to prevent reverse registration. These data then shall be adjusted for losses, if applicable, before determination of the average power factor.

When deliveries to a purchaser at any point of delivery either:

a. include more than one class of power, or

b. are provided under more than one rate schedule and it is impracticable to meter the kilowatthours and reactive kilovoltamperehours for each class or rate schedule separately, the average power factor of the total deliveries for the month will be used, where applicable, as the power factor for all power delivered to such point of delivery.

To maintain acceptable operating conditions on the Federal system, BPA may, unless specifically otherwise agreed, restrict deliveries of power to a purchaser with a low power factor. Such restriction may be made to a point of delivery or to a purchaser’s system 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 75 percent.

2. Outage Credit
To the extent that BPA is unable to provide full service to a purchaser during the billing month as a result of interruptions in service due to reasons cited in the General Contract Provisions, BPA shall adjust the charges for those hours for billing demand for such purchaser to reflect BPA’s inability to provide full service, provided such adjustment is mandated by the purchaser’s power sales contract. The adjustment is provided on a point of delivery basis. To compute the adjustment for noncoincidentally billed systems, BPA shall determine the monthly demand charge(s) for the point(s) of delivery where the outage(s) occurred, multiply by the number of hours of outage, and divide by the total number of hours in the billing month. For coincidentally billed points of delivery, the adjustment shall apply only to those points of delivery at which BPA was unable to provide full service. For partial outages (such as an outage on one feeder in a substation with several feeders), BPA shall determine an equivalent interruption in order to arrive at the number of hours to be used in the calculation of the credit.

3. Low Density Discount (LDD)

a. Basic LDD Principles
A predetermined discount shall be applied each billing month to the charges for all power purchased under the Priority Firm Power rate schedule by eligible purchasers as defined in section b, below. The discount shall be calculated on an annual basis and shall become effective with the first billing period in the calendar year. Retroactive billing for the LDD may be required if the data are
not available by the January billing date. The level of the discount shall be determined from the following ratios:

(1) the purchaser's total electric energy requirements during the previous calendar year (the purchaser's firm sales, nonfirm sales to firm retail loads, sales for resale, and associated losses, but excluding nonfirm sales to nonfirm retail loads, such as boiler loads served under BPA's alternate fuel policy) divided by the value of the purchaser's depreciated electric plant (excluding generation plant) at the end of such year, and

(2) the average number of consumers (annual and seasonal consumers with residential, industrial, commercial, and irrigation accounts, but excluding separately billed services for water heating, electric space heating, and security lights) during the previous calendar year divided by the number of pole miles of distribution line at the end of such year. Distribution lines are defined as those that deliver electric energy from a substation or metering point, at a voltage of 34.5 kV or less, to the point of attachment to the consumer's wiring and include primary, secondary, and service facilities.

These calculations shall be based on data provided in the purchaser's annual financial and operating report. In calculating these ratios, BPA shall use data pertaining to the purchaser's entire electric utility system within the region. Results of the calculations shall not be rounded.

Customers who have not provided BPA with all four requisite pieces of annual data (see a.(1) and a.(2) above) by June 30 of each year shall be declared ineligible for the LDD effective with the June billing period for that year. BPA shall extend a customer's eligibility from the previous year through the June billing period of the following year and shall make any necessary retroactive adjustments once the new data have been processed. If no data have been received by December 31 for the previous calendar year, BPA shall assume that the utility did not qualify for an LDD for that year. Low Density Discounts issued from January 1 to June 30 shall be assumed to have been in error, and the utility shall be billed for any such discounts issued.

Revisions to the data used to calculate the amount of the LDD may be made by the purchaser for a period of up to 2 years from the first day to which the data apply. However, such revisions shall not apply to periods when the customer was ineligible for a discount due to late data submission.

b. Eligibility Criteria

To qualify for a discount, the purchaser must meet all six of the following eligibility criteria:

(1) the purchaser must serve as an electric utility offering power for resale;

(2) the purchaser must agree to pass the benefits of the discount through to the purchaser's consumers within the region served by BPA;

(3) the purchaser's average retail rate for the reporting year must exceed the average Priority Firm Power rate in effect for the qualifying period by 10 percent. For CY 1989, the average Priority Firm Power rate shall be the average of the PF-87 rate for 9 months and the PF-89 Preference rate for 3 months. For CY 1990, the average Priority Firm Power rate shall be the PF-89 Preference rate.

(4) the purchaser's kilowatthour-to-investment ratio (Ratio 3. a.(1)) must be less than 100;

(5) the purchaser's consumers-per-mile ratio (Ratio 3. a.(2)) must be less than 12; and

(6) the purchaser must qualify for a discount based on the criteria in section c, below.

c. Discounts

The purchaser shall be awarded the greatest discount for which that purchaser qualifies. The discounts and the qualifying criteria for those discounts are listed below.

(1) Three percent, for any purchaser for whom:
   (a) the kilowatthour-to-investment ratio is equal to or greater than 25 but less than 35; or
   (b) the consumers-per-mile ratio is equal to or greater than 5 but less than 7.

(2) Five percent, for any purchaser for whom:
   (a) the kilowatthour-to-investment ratio is equal to or greater than 15 but less than 25; or
   (b) the consumers-per-mile ratio is equal to or greater than 3 but less than 5.

(3) Seven percent, for any purchaser for whom:
   (a) the kilowatthour-to-investment ratio is less than 15; or
   (b) the consumers-per-mile ratio is less than
4. Irrigation Discount

a. Basic Irrigation Discount Principles

A discount of 4.6 mills per kilowatthour shall be applied to the charges for qualifying irrigation energy purchased under the Priority Firm Power and New Resource Firm Power rate schedules, during the billing months of April through October. This discount shall be applied subsequent to calculation of the Low Density Discount, if applicable. Any energy on which the irrigation discount is claimed shall be metered separately by the Purchaser, and used exclusively for agricultural irrigation or drainage pumping.

b. Qualifying Energy Purchases

The qualifying irrigation energy shall be determined as follows:

(1) All irrigation energy must be used exclusively for the purpose of irrigation and drainage pumping on agricultural land and be measured at the end-use irrigation customer's meter. The discount shall apply to the measured energy sales at the end-use.

(2) Energy subject to the discount must be purchased during the billing months of April through October.

(3) Purchasers of exchange energy under the Residential Purchase and Sale Agreement (RPSA) are eligible for the irrigation discount for the portion of their irrigation sales qualifying for the exchange under the RPSA contracts.

(4) General requirements customers are eligible for an irrigation discount for a portion of their irrigation sales equal to the share of their total sales served by BPA firm purchases (i.e., total irrigation and drainage pumping sales multiplied by BPA billing energy for Priority Firm or New Resources firm purchases divided by the total firm utility system requirements for the billing month).

c. Initial Reporting Requirements

Requests for the Irrigation Discount must include the following information:

(1) To receive an irrigation discount, a purchaser must file a request for the discount with its local BPA Area or District office by April 1 each year.

(2) In the request, the purchaser must certify that the irrigation energy is sold exclusively for use in irrigation and drainage pumping on agricultural land and that the discount is passed, in its entirety, to the irrigation consumer, regardless of whether the utility has raised its rates. BPA retains the right to verify, in a manner satisfactory to the Administrator, that the discounted energy is used for the sole benefit of the purchaser's irrigation load.

d. Annual Reporting Requirements

Purchasers shall submit an annual irrigation report to their local BPA Area or District office in order to receive the irrigation discount. Purchasers are required to report information related to monthly irrigation energy sales. If a utility does not read its irrigation meters monthly, the utility must estimate its monthly irrigation sales. These estimates shall be reviewed by BPA area and/or district offices. Purchasers must read their meters within 3 working days of the beginning and ending of the irrigation discount period (April-October). In order to qualify for the discount, the purchaser must submit all data to BPA by December 31 of the calendar year in which the sales occurred.第一届 reports to BPA shall include the following monthly information for the reporting period:

(1) utility name and period for which the report is being made;

(2) total irrigation sales and total qualifying irrigation energy sales (in kilowatt-hours) by month;

(3) total qualifying irrigation sales (in kilowatt-hours) by month under 400 horsepower, for exchanging utilities;

(4) total utility firm system requirements for other than full requirement customers by month (in kilowatt-hours);

(5) total energy purchased from BPA under the Priority Firm or New Resource rate by month in kilowatthours; and

(6) the purchaser shall list each irrigation and drainage account number in its annual report and whether each irrigation consumer is billed monthly, bимonthly, or seasonally. If the purchaser is an exchanging utility, the purchaser shall also identify the size (in horsepower) of the connected load for each active account. A utility may submit monthly reports, if it chooses. In that case, the active list of accounts should be included in the last monthly report submitted.

5. Cost Recovery Adjustment Clause

a. Applicable Rate Schedules

The Cost Recovery Adjustment Clause (CRAC) ap-
plies to the Priority Firm Power (Exchange and Preference) (PF-89), Industrial Firm Power (IP-89), Variable Industrial Power (VI-87), Firm Capacity (CF-89), and New Resource Firm Power (NR-89) rate schedules. A percentage adjustment, labeled as CRAC%, is calculated for specific periods and applied to these rates by various formulas.

b. Evaluation and Adjustment Periods

There are two evaluation and adjustment periods for the Cost Recovery Adjustment Clause.

(1) Period 1

Period 1 is comprised of an evaluation period covering FY 1989 (October 1, 1988, through September 30, 1989) and an adjustment period of January 1, 1990, through September 30, 1990.


Any resulting rate adjustment shall be at the Administrator's discretion, shall be upward only, and shall not be greater than 10.0 percent.

If the net revenues are less than zero for the evaluation period (FY 1989) as specified herein, BPA may adjust the applicable rates (PF-89, IP-89, VI-87, CF-89, and NR-89) upward over an adjustment period beginning January 1, 1990, and ending September 30, 1990.

(2) Period 2


Any resulting rate adjustment shall be at the Administrator's discretion, shall be upward only, and shall not be greater than 10.0 percent.


The amount of any CRAC adjustment resulting from Period 1 evaluation shall be subtracted from FY 1990 revenues to obtain the adjusted FY 1990 revenues. The adjusted FY 1990 revenues less FY 1990 expenses equals the adjusted FY 1990 net revenues. If adjusted FY 1990 net revenues are less than zero for Period 2, BPA may adjust the applicable rates (PF-89, IP-89, VI-87, CF-89, and NR-89) upward over an adjustment period beginning January 1, 1991, and ending September 30, 1991.

c. Formulas for the Cost Recovery Adjustment Clause

(1) Adjustment Calculation

BPA shall determine the net revenue for each evaluation period using the following formulas:

(a) Period 1:

\[
NR_1 = \text{revenues} - \text{expenses}
\]

where:

\[
\text{revenues} = \text{total operating revenues (in millions of dollars) from the FCRPS Statements of Revenues and Expenses};
\]

\[
\text{expenses} = \text{sum of total operating expenses, net interest expense, and any litigation settlement expenses or other extraordinary expenses shown separately on the FCRPS Statements of Revenues and Expenses (in millions of dollars));
\]

\[
NR_1 = \text{FY 1989 net revenues (in millions of dollars)};
\]

If \(NR_1\) is zero or greater, then there will be no rate adjustment; and

\[
\text{CR}_1 = 0
\]

If \(NR_1\) is less than zero:

\[
\text{CR}_1 = \text{absolute value of } NR_1, \text{ for Period 1.}
\]

The following formulas apply for the calculation of the percent that the Cost Recovery Adjustment Clause could increase the applicable rates during January 1, 1990, through September 30, 1990:

(i) If \(\text{CR}_1\) is greater than \$29.7 million, then the CRAC\% equals the lesser of:

\[
(A) \frac{(\text{CR}_1 + 12.015)}{13.899}; \text{ or}
\]

\[
(B) \frac{(\text{CR}_1)}{13.899}
\]
(B) 10.0 percent.

(ii) If CR1 is less than or equal to $29.7 million, then, for PF, CF, and NR rate schedules (IP and VI are not adjusted):

\[ \text{CRAC\%} = \frac{\text{CR1}}{9.902} \]

(b) Period 2:

\[ \text{NR2} = (\text{revenues-ACR1}) - \text{expenses} \]

where:

\[ \text{NR2} = \text{Adjusted FY 1990 net revenues (in millions of dollars); and} \]

\[ \text{ACR1} = \text{The lesser of CR1 or $127.0 million; or equals zero if rates were not adjusted, at the discretion of the Administrator, in Period 1.} \]

If NR2 is zero or greater, then there will be no rate adjustment.

If NR2 is less than zero, then:

\[ \text{CR2} = \text{absolute value of NR2 for Period 2.} \]

The following formulas apply for the calculation of the percent that the Cost Recovery Adjustment Clause could increase the applicable rates during January 1, 1991, through September 30, 1991:

(i) If CR2 is greater than $33.1 million, then the CRAC\% equals the lesser of:

(A) \( \frac{\text{CR2}+12.083}{15.056} \); or

(B) 10.0 percent.

(ii) If CR2 is less than or equal to $33.1 million, then, for PF, CF, and NR rate schedules (IP and VI are not adjusted):

\[ \text{CRAC\%} = \frac{\text{CR2}}{11.014} \]

d. Application to Irrigation Discount

In addition to the direct application of the cost recovery adjustment percentage (CRAC\%) to the irrigation discount, an additional adjustment shall be made so that irrigation loads are not disproportionately affected by a 9-month adjustment period as compared to a 12-month adjustment period. The direct and additional adjustments are reflected in the following formula:

\[ \text{Adjusted Irrigation Discount (in mills per kilowatthour)} = 4.6 \ast (1 + \frac{\text{CRAC\%}}{100}) + (0.046 \ast \text{CRAC\%}) \]

where:

\[ 4.6 = \text{Irrigation discount applicable to PF-89 and NR-89, in mills per kilowatthour; and} \]

\[ 0.046 = \text{adjustment to account for the disproportionate impact of CRAC on irrigation loads, in mills per kilowatthour per percentage CRAC adjustment.} \]

e. Cost Recovery Adjustment Clause Implementation Process

(1) Within 30 days after the end of FY 1989 and within 30 days after the end of FY 1990, BPA shall make an initial calculation to identify the preliminary, unaudited net revenues.

(2) On or about November 1 of each of the years 1989 and 1990, BPA shall notify interested persons and the purchasers under each applicable rate schedule of BPA's initial findings concerning the net revenues for the evaluation period.

(a) If no adjustment is required, or if the Administrator waives implementation of an adjustment, BPA shall state in the notice the basis for its decision, and no further process will be required.

(b) If BPA determines that an adjustment to applicable rates is required, BPA shall state in the notice the amount of the adjustment, the calculation of the adjustment, and the resulting level of the adjustment to each applicable rate schedule. The notice shall also contain the data and assumptions prepared and relied upon by BPA, with references to additional documentation, if any, prepared and relied upon by BPA. Such documentation, if nonproprietary and/or nonprivileged, shall be available upon request unless unduly burdensome. The notice shall also contain the tentative schedule for the remainder of the implementation process.

(3) On or about November 6, 1989, and November 5, 1990, BPA shall conduct a public meeting in which interested persons and purchasers under each applicable rate schedule may seek off-the-record clarification, calculation, and application of the adjustment amount to spe-
specific rate schedules. For the purpose of further mailings, a list of the names and addresses of interested persons and purchasers (hereafter referred to as "mailing list") shall be compiled at this meeting.

(4) On or about November 10, 1989, and November 9, 1990, purchasers under each applicable rate schedule may submit information requests to BPA regarding the adjustment. The requests shall also be mailed to all persons on the mailing list. BPA shall respond to the requests within 2 working days of their receipt, or as soon as practicable if 2 days is insufficient time within which to respond.

(5) On or about November 17, 1989, and November 16, 1990, interested persons and purchasers under each applicable rate schedule may submit written comments to BPA regarding the adjustment. The comments shall also be mailed to all persons on the mailing list.

(6) On or about December 1, 1989, and November 30, 1990, commenters may respond to any comments.

(7) On or about December 1, 1989, and November 30, 1990, BPA may release, if available, revised preliminary unaudited net revenues and any resulting revised adjustment to applicable rate schedules.

(8) On or about December 15, 1989, and December 14, 1990, BPA shall conduct an on-the-record public comment forum in which interested persons and purchasers under each applicable rate schedule may present oral comments to BPA.

(9) On or about December 20, 1989, and December 19, 1990, BPA shall notify interested persons and purchasers under each applicable rate schedule of the audited net revenue balance, the amount of the adjustment, the calculation of the adjustment, and the resulting level of the adjustment to each applicable rate schedule. The notice shall also contain the data and assumptions prepared and relied upon by BPA, with references to additional documentation, if any, prepared and relied upon by BPA.

(10) If there is a rate adjustment due the CRAC following the FY 1989 evaluation period, it shall be in effect from January 1, 1991, through September 30, 1991.

6. Coincidental Billing

Purchasers of Priority Firm Power and New Resou. Firm Power shall be billed on a noncoincidental demand basis for power purchased at each point of delivery under the applicable rate schedule(s) unless the power sales contract specifically provides for coincidental demand billing among particular points of delivery. For the purpose of these rate schedules and GRSPs, the purchaser's noncoincidental demand is the sum of the highest hourly peak demands during the billing month for each of the purchaser's points of delivery. The purchaser's coincidental demand is the highest demand for the billing month calculated by summing, for each hour of every day, the purchaser's demands for power purchased under the applicable rate schedule at all coincidentally billed points of delivery. See the Special Provisions Exhibits of the Power Sales Contract, GCP, E, 17.

7. Conservation Surcharge

The Conservation Surcharge shall be applied monthly and shall equal 10 percent of the customer's total monthly charge for all power purchased under each rate schedule subject to the surcharge. The PF, CF, and NR rate schedules are subject to the Conservation Surcharge. If only a portion of the customer's service area is subject to the surcharge, then the amount the surcharge shall equal 10 percent of the total charge for all power purchases multiplied by: (a) the portion of the customer's total retail load that is subject to the surcharge, divided by (b) the customer's total retail load.

D. Billing-Related Definitions

1. Peak Period

The Peak Period includes the hours from 7 a.m. through 10 p.m. on any day Monday through Saturday inclusive. There are no exceptions to this definition; that is, it does not matter whether the day is a normal working day or a holiday. Any charges based on Peak Period hours shall be computed starting with the 8 a.m. meter reading since this reading applies to the 7 o'clock hour (7 a.m. to 8 a.m.). The 10 p.m. meter reading (for the 9 p.m. to 10 p.m. period) is the last meter reading of the day applicable to the Peak Period.

2. Offpeak Period

The Offpeak Period includes all hours which do not occur during the Peak Period. Thus, the Offpeak Period consists of the hours from 10 p.m. to 7 a.m., Monday through Saturday and all hours on Sund. This definition does not apply to the Special Industr Offpeak Rate.
SECTION IV. OTHER DEFINITIONS

A. Computed Requirements Purchasers

1. Designation as a Computed Requirements Purchaser

A purchaser shall be designated as a computed requirements purchaser if it is so designated pursuant to the provisions of its power sales contract.

When a purchaser operates two or more separate systems, only those systems designated by SPA will be covered by this section.

2. Purpose of the Computed Requirements Designation

Use of the computed requirements designation is intended to assure that each purchaser who purchases power from SPA to supplement its own firm resources will purchase amounts of firm capacity and firm energy substantially equal to that which the purchaser would otherwise have to provide on the basis of normal and prudent operations.

The amount of capacity and energy required for normal and prudent operations shall be determined pursuant to the purchaser's power sales contract.

B. Definitions Relating to Nonfirm Energy Decremental Cost

Unless otherwise specified in a contractual arrangement, decremental cost as applied to Nonfirm Energy transactions shall be defined as:

1. All identifiable costs (expressed in mills per kilowatt-hour) associated with the use of a displaceable thermal resource or end-user load with alternate fuel source to serve a purchaser's load that the purchaser is able to avoid by purchasing power from BPA, rather than generating the power itself or using an alternate fuel source; or

2. All identifiable costs (expressed in mills per kilowatt-hour) to serve the load of a displaceable purchase of energy that the purchaser is able to avoid by choosing not to make the alternate energy purchase.

All identifiable costs as used in the above definition may be reduced to reflect costs of purchasing BPA energy such as transmission costs, losses, or loopflow constraints that are agreed to by BPA and the purchaser.

C. NF Rate Cap

1. Application of the NF Rate Cap

The NF Rate Cap defines the maximum nonfirm energy price for general application. At no time shall the total price for nonfirm energy, including any applicable service charges or rate adjustment, sold under any applicable rate schedule exceed the NF Rate Cap. The level of the NF Rate Cap is based on formula tied to BPA's system cost and California fuel costs. The NF Rate Cap applies to all sales of nonfirm energy under any applicable rate schedule for a 12-year period beginning October 1, 1987.

2. Monthly Notification of the NF Rate Cap

Prior to the beginning of a calendar month BPA shall perform the calculations contained in section IV.C.3. of these GRSPs to determine the effective NF Rate Cap for that calendar month. BPA is obligated to provide advance notification of the NF Rate Cap level to purchasers of nonfirm energy. BPA may waive this requirement only if BPA does not intend to offer Nonfirm Energy at prices above BASC at any time during a month. The notification will be given at least 10 calendar days prior to the first day of any calendar month in which the NF Rate Cap applies. BPA shall also maintain, on file for public review, a record of the NF Rate Cap by month throughout the period the cap is in effect.

3. NF Rate Cap Formula

The NF Rate Cap shall be equal to the greater of the following:

a. BASC; or

b. BASC + 0.30(DEC - BASC)

Where:

\[ \text{BASC} = \text{BPA's average system cost, determined by dividing BPA's total system costs by BPA's total system sales. For this rate period BASC has been determined to be 23.2 mills per kilowatthour.} \]

\[ \text{DEC} = \text{The Decremental Fuel Cost as determined in accordance with section IV.C.5. of these GRSPs.} \]

4. Determination of BPA's Average System Cost

For purposes of determining BPA's Average System Cost (BASC), the following definition shall apply:

a. BPA's total system costs shall be the sum of all BPA's costs forecasted in each general rate case for the applicable rate period, including total transmission costs, Federal base system costs, new resource costs, exchange resource costs, and other costs not specifically allocated to a rate pool, such as section 7(g) costs.

b. BPA's total annual system sales shall be the sum of all BPA's system firm and nonfirm sales forecasted each general rate case for the applicable test period.

BASC shall be redetermined in each subsequent period...
general rate case according to the above formula and will be in effect for the entire rate period over which the rates are in effect.

5. Determination of Decremental Fuel Cost

The Decremental Fuel Cost shall be determined monthly by BPA. For purposes of calculating the NF Rate Cap, a weighted average of gas and petroleum prices for California will be used for approximating decremental fuel costs. The monthly decremental fuel cost shall be:

a. the sum of:

(1) the average California price for gas determined by multiplying the monthly gas use (WGU) developed pursuant to section IV.C.8.a. times the monthly California gas price (MGP) determined pursuant to section IV.C.6 rounded to the nearest tenth of a mill; and

(2) the average California price for petroleum determined by multiplying the monthly petroleum use (WOU) developed pursuant to section IV.C.8.b times the monthly California petroleum price (MOP) determined pursuant to section IV.C.7. rounded to the nearest tenth of a mill.

b. divided by the sum of the monthly gas use (WGU) and monthly petroleum use (WOU) developed in section IV.C.8.a. and b. respectively rounded to the nearest tenth of a mill.

6. California Gas Price

The monthly gas price (MGP) for purposes of calculating the decremental cost component of the rate cap shall based on the following formula:

\[ MGP = \frac{AGP \times HGP}{10} \]

Where:

\[ AGP = \text{the average gas price for California electric utility plants expressed in cents per million Btu as reported in the most recent monthly issue of } \text{Electric Power Monthly (EPM)} \]

\[ HGP = \text{the historical relationship between gas prices in the effective month of the NF Rate Cap (month t) and the month in which the gas prices are reported in EPM (month r)} \]

7. California Petroleum Price

The monthly petroleum price (MOP) for purposes of calculating the decremental cost component of the rate cap shall based on the following formula:

\[ MOP = \frac{AOP \times HOP}{10} \]

Where:

\[ AOP = \text{the last available average oil price for California electric utility plants expressed in cents per million Btu reported in Electric Power Monthly (EPM) published by the Energy Information Administration (EIA), U.S. Department of Energy. Prices shall be rounded to the nearest one-tenth of a cent.} \]

\[ HOP = \text{the historical relationship between petroleum prices in the effective month of the NF Rate Cap (month t) and the last month in which the petroleum prices are reported in EPM (month r) using the following procedures:} \]

a. summing all California petroleum prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California petroleum prices shall be divided by the number of years for which month
petroleum prices were reported and rounded to the nearest one-tenth of a cent.

b. summing all California petroleum prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month $r$ for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California petroleum prices shall be divided by the number of years for which monthly petroleum prices were reported and rounded to the nearest one-tenth of a cent.

c. dividing the average monthly California petroleum price in a. above, by the average monthly California petroleum price in b. above, and rounding to the nearest one-tenth of a percent, or three significant places.

10 $= \text{the factor for converting petroleum prices stated in cents per million Btu to mills per kWh. The factor assumes a heat rate of 10,000 Btu per kilowatthour.}$

8. Weighting Factors

For purposes of determining California fuel prices for the month, gas and petroleum prices will be weighted based on California’s historical use of these two alternative fuels.

a. Historical Gas Use in California

The following formula shall be used to determine the weighting factor for gas prices (WGU):

$$WGU = CGU * HGU$$

Where:

$$CGU = \text{the monthly net gas-fired generation, expressed in gigawatthours, for California in the most recent monthly issue of Electric Power Monthly (EPM) published by the Energy Information Administration (EIA), U.S. Department of Energy.}$$

$$HGU = \text{the historical relationship between gas consumptions in the effective month of the NF Rate Cap (month } t \text{) and the month for which gas consumption is reported in EPM (month } r \text{) using the following procedures:}$$

(1) summing the reported net-gas fired generation for California, expressed in gigawatthours, from EPM for month $t$ for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California’s historical monthly consumption shall be divided by the number of years for which gas consumption was reported and rounded to the nearest gigawatthour.

(2) summing the reported net gas-fired generation for California, expressed in gigawatthours, from EPM for month $r$ for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California’s historical monthly consumption shall be divided by the number of years for which gas consumption was reported and rounded to the nearest gigawatthour.

(3) dividing the average consumption of gas in California for the month $t$ as determined in (1) above by the average consumption of gas for the month $r$ as determined in (2) above and rounding to the nearest one-tenth, or three significant places.

b. Historical Petroleum Use in California

The following formula shall be used to determine the weighting factor for petroleum prices (WOU):

$$WOU = COU * HOU$$

Where:

$$COU = \text{the monthly net petroleum-fired generation, expressed in gigawatthours, in California in the most recent monthly issue of Electric Power Monthly (EPM) published by the Energy Information Administration (EIA), U.S. Department of Energy.}$$

$$HOU = \text{the historical relationship between petroleum consumptions in the effective month of the NF Rate Cap (month } t \text{) and the month for which petroleum consumption is reported in EPM (month } r \text{) using the following procedures:}$$

(1) summing the reported net-petroleum generation for California, expressed in gigawatthours, from EPM for month $t$ for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California’s historical monthly consumption shall be divided by the number of years for which petroleum consumption was reported and rounded to the nearest gigawatthour.

(2) summing the reported net-petroleum generation for California, expressed in gigawatthours, from EPM for month $r$ for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California’s historical monthly consumption shall be di-
vided by the number of years for which petroleum consumption was reported and rounded to the nearest gigawatthour.

(3) dividing the average consumption of petroleum in California for the month of as determined in (1) above by the average consumption of petroleum for the month as determined in (2) above and rounding to the nearest one-tenth, or three significant places.

D. Determination of BPA's Average System Cost.

For purposes of determining BPA's Average System Cost (BASC), the following definition shall apply:

1. BPA's total system costs shall be the sum of all BPA's costs forecasted in each general rate case for the applicable rate period, including total transmission costs, Federal base system costs, new resource costs, exchange resource costs, and other costs not specifically allocated to a rate pool, such as section 7(g) costs.

2. BPA's total annual system sales shall be the sum of all BPA's system firm and nonfirm sales forecasted in each general rate case for the applicable test period.

BASC shall be redetermined in each subsequent general rate case according to the above formula and will be in effect for the entire rate period over which the rates are in effect.

SECTION V. APPLICATION OF RATES UNDER SPECIAL CIRCUMSTANCES

A. Energy Supplied for Emergency Use

A purchaser taking Priority Firm or New Resource Firm Power shall pay in accordance with the Nonfirm Energy rate schedule, NF-89, and Emergency Capacity rate schedule, CE-89, for any electric energy or capacity which has been supplied:

1. for use during an emergency on the purchaser's system, or

2. following an emergency to replace energy secured from sources other than BPA during such emergency.

Mutual emergency assistance may, however, be provided and payment therefore settled under exchange agreements.

B. Construction, Test and Start-Up, and Station Service

Power for the purpose of construction, test and start-up, and station service shall be made available to eligible purchasers under the Priority Firm and New Resource Firm Power Rate Schedules. Such power must be used in the manner specified below:

1. Power sold for construction is to be used in the construction of the project.

2. Power sold for test and start-up may be used prior to commercial operation both to bring the project on-line and to ensure that the project is working properly.

3. Power sold for station service may be purchased at any time following commercial operation of the project. Station service power may be used for project start-up, project shut-down, normal plant operations, and operations during a plant shut-down period.

C. Application of Rates During Initial Operation Period—Transitional Service

1. Eligibility for Transitional Service

For an initial operating period, as specified in the power sales contract, beginning with the commencement of operation of a new industrial plant, a major addition to an existing plant, or reactivation of an existing plant or important part thereof, BPA may agree to bill the purchaser in accordance with the provisions of this section. This section shall apply to both:

a. DSIs having new, additional or reactivated plant facilities, and

b. utility purchasers serving industrial purchasers with power purchased from BPA. BPA will provide transitional service to utilities for only those industrial loads for which the demand can be separately metered by the utility and recorded on a daily basis.

2. Calculation of the Daily Demand

If the purchaser requests billing on a Daily Demand basis pursuant to its power sales contract and if BPA agrees to such billing, the billing demand for the billing month shall be the average of the Daily Demands as adjusted for power factor.

Demand for each day shall be defined as 100 percent of the Measured Demand for the day (regardless of whether such Measured Demand occurs during the Peak Period or the Offpeak Period).

3. Billing for Transitional Service

Utilities receiving transitional service shall provide BPA with Daily Demand information for the industrial consumer for whom transitional service is provided. To compute the power bill for the point of delivery which includes the load being served with transitional service, BPA shall, at its discretion, either:

a. determine the demand for the pertinent point of delivery without the industrial load and then add the average daily demand for such industrial load; or
b. bill the entire point of delivery on a daily demand basis.

Daily demand billing shall not affect the level of any curtailment charge or energy charge assessed by BPA.

D. Changes in a DSI's BPA Operating Level

If a DSI requests a waiver regarding the notice requirements specified in the DSI's power sales contract for a voluntary change in its BPA Operating Level, and if BPA does not grant the waiver, or if the DSI fails to give notice of such a change and does not request a waiver, the DSI shall be billed as if no notice has been provided until such time as the number of days in the notice period have passed. If, however, BPA agrees to waive the notice requirement, the power bill shall reflect the requested changes as of the requested effective date specified in the notice or, at BPA's discretion, a date of BPA's choosing within the notice period.

E. Restriction of Deliveries

Deliveries of capacity or energy to any purchaser may be restricted when operation of the facilities used by BPA to serve such purchaser is:

1. suspended,
2. interrupted,
3. interfered with,
4. curtailed, or
5. restricted

by the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service sections of the General Contract Provisions of the power sales contract.

SECTION VI. BILLING INFORMATION

A. Determination of Estimated Billing Data

If the amounts of capacity, energy, or the 60-minute integrated demands for energy purchased from BPA must be estimated from data other than metered or scheduled quantities, historical patterns, and pertinent weather data, BPA and the purchaser will agree on billing data to be used in preparing the bill. If the parties cannot agree on estimated billing quantities, derived by any method, a determination binding on both parties shall be made in accordance with the arbitration provisions of the power sales contract.

B. Load Shift and Outage Reports

Load shift and outage reports must be submitted to BPA within 4 days of the corresponding load shift or outage. Reports may be made by telephone, mail, or other electronic processes where available. If customer reports are not received in a timely manner, BPA has the option to withhold load shift or outage credit.

C. Billing for New Large Single Loads

Any BPA customer whose total load includes one or more New Large Single Loads (NLSL) shall be billed for the NLSL(s) at the New Resource Firm Power Rate. The power requirements associated with the NLSL shall be established in a manner consistent with the provisions of this section.

The purchaser shall warrant to BPA that NLSLs are separately metered. The metering must include provisions for determining:

1. the NLSL demand during BPA's diurnal capacity billing periods,
2. the NLSL energy during BPA's energy billing periods, and
3. the NLSL reactive energy for the billing month.

The design for the metering equipment for the NLSL must be approved by BPA. Testing and inspections of such metering installations shall be as provided in the General Contract Provisions.

On a monthly basis, each purchaser of New Resource Firm Power shall report to BPA the quantity of power used by the NLSL during the purchaser's billing period. Data provided to BPA by the purchaser must be submitted to BPA within 2 normal working days of the date the purchaser reads the meters. BPA may elect to adjust the NLSL data for losses from the point of metering to the closest BPA point of delivery for the purchaser.

D. Determination of Measured Demand

1. For points of delivery with fully operational metering under the Revenue Metering System (RMS), demand shall be measured from 0000 hours on the first day of the billing period through 2400 hours on the last day of the billing period.

2. For points of delivery that do not have RMS metering, demand shall be measured from 0000 hours on the first complete (24 hour) day of the available metering data through 2400 hours on the last complete day of the available metering data. Billing demand will be determined from the period of available metering data that most closely matches the official billing period of the customer.

E. Determination of Measured Energy

1. For points of delivery with fully operational metering under RMS, energy shall be measured from 0000 hours on the first day of the billing period through 2400 hours on the last day of the billing period.

2. For points of delivery that do not have RMS metering, measured energy shall be the quantity of usage recorded on the meter between meter readings.
F. Billing Month

Meters normally will be read and bills computed at intervals of 1 month. A month is defined as the interval between meter-reading dates which normally will be approximately 30 days. If service is for less than or more than the normal billing month, the monthly charges stated in the applicable rate schedule shall be adjusted appropriately.

The calendar month in which the purchaser’s meter is scheduled to be read determines the billing month. (Thus, a bill associated with a meter scheduled to be read on April 10 would be an April bill.) The charges for the winter and summer periods identified in the rate schedules apply to the purchaser’s billing months.

G. Payment of Bills

Bills for power shall be rendered monthly by BPA. Failure to receive a bill shall not release the purchaser from liability for payment. Bills for amounts due BPA 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

Demand and energy billings for power purchased under each rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amount 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 for that month to be followed at a subsequent billing date by a final bill. Such estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). This requirement holds also for revised bills (see section 6 below). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the purchaser), the due date shall be the next following business day.

4. 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 $2.50. 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 purchaser. However, such cancellation shall not affect the purchaser’s liability for any charges accrued prior thereto under such contract.

5. 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 purchaser 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.

6. Revised Bills

As necessary, BPA may render a revised bill. A revised bill shall replace all previous bills issued by BPA that pertain to a specified customer for a specified billing period if the amount of the revised bill is less than the amount of the original bill. If the amount of the revision causes an additional amount to be due BPA beyond the original bill, a revised bill will be issued for the difference.

The date of the revised bill shall be determined as follows:

a. If the amount of the revised bill is equal to or less than the amount of the bill which it is replacing, the revised bill shall have the same date as the replaced bill.

b. If the amount of the revised bill is greater than t
A. Monthly Average Aluminum Price Determination

1. Calculation of the Monthly Billing Aluminum Price
   The monthly billing aluminum price shall be determined by BPA for each billing month. For purposes of this rate schedule, the monthly billing aluminum price shall be based on the average price of aluminum in U.S. markets during the third calendar month prior to the billing month. The average price of aluminum in U.S. markets shall be defined as the average U.S. Transaction Price reported for the month by Metals Week, in cents per pound, rounded to the nearest tenth of a cent.

2. Notification of the Monthly Average Aluminum Price
   BPA shall provide, 45 days prior to the billing month, written notification to purchasers under this rate schedule of the monthly billing aluminum price to be used for billing purposes. Upon written request supporting documentation shall be provided.

3. Changes in Aluminum Price Indicators
   In the event that BPA determines that factors outside its control render the monthly average U.S. Transaction Price unusable as an approximation of U.S. market prices, BPA may develop and substitute another indicator for prices in U.S. markets. BPA shall notify interested parties of its intent to do so at least 120 days prior to the billing month in which the change would become effective. In this notification, BPA shall explain the reason for the substitution and specify the replacement indicator it intends to use. BPA also shall describe the methodology to determine the monthly billing aluminum price to be used for billing purposes under this rate schedule and shall provide the necessary data to be used in the calculation. Interested persons will have until close of business 3 weeks from the date of the notification to provide comments. Consideration of comments and more current information may cause the final methodology and the substitute aluminum price index to differ from those proposed. BPA shall notify all affected parties, and those parties that submitted comments, of its final determination 90 days prior to the billing month the new indicator shall be effective.

Annual Adjustments to the Lower and Upper Pivot Aluminum Prices

On July 1, 1987, and every July 1 thereafter, the Lower and Upper Pivot Aluminum Prices, as stated in section III.B.5 of the rate schedule, shall be subject to change for billing purposes as herein described. The term “annual adjustment date” shall refer to July 1 of each year.

1. Implementation Procedures

Beginning in 1987 and every year thereafter, prior to April 1 of that year, BPA shall provide the purchasers under this rate schedule preliminary written estimates of proposed adjustments to the Lower and Upper Pivot Aluminum Prices. By the last working day of the month of April, BPA shall notify interested parties in writing of BPA’s revised determinations concerning changes to the Lower and Upper Pivot Aluminum Prices. BPA shall describe how the adjustments were determined and provide the data used in the calculations. In addition to written notification, BPA may, but is not obligated to, hold a public comment forum to clarify its determinations and solicit comments. Interested persons may submit comments on the determinations to BPA and other parties. Comments will be accepted until close of business on the last working Friday in May. Consideration of comments and more current information may result in the final adjustment differing from the proposed adjustment. By June 30 of each year, BPA shall notify all VI purchasers, those parties that submitted comments, and parties that requested notification, of the final determination.

2. Annual Adjustment Procedures
   a. Annual Adjustment of the Lower Pivot Aluminum Price
      Beginning with the July 1, 1987, annual adjustment date, for each year that the Variable Industrial rate is in effect, the Lower Pivot Aluminum Price as stated in section III.B.1 of the rate schedule shall be adjusted on the July 1 annual adjustment date. The Lower Pivot Aluminum Price shall be revised by multiplying 59 cents per pound by the Cost Escalation Index described in section VII.B.3.b of these GRSPs and rounded to the nearest tenth of a cent. The revised Lower Pivot Aluminum Price shall replace the Lower Pivot Aluminum Price as stated in section III.B.1 of the rate schedule and shall be used to determine the energy rate in the subsequent 12 billing months.

   b. Annual Adjustment of the Upper Pivot Aluminum Price
      For each year that the Variable Industrial rate is in effect, the Upper Pivot Aluminum Price as stated in section III.B.2 of the rate schedule shall be adjusted on the July 1 annual adjustment date.
(1) Annual adjustment for the period beginning July 1, 1987, and ending June 30, 1991

The Upper Pivot Aluminum Price shall be revised by multiplying 72 cents per pound by the Cost Escalation Index described in section VII.B.3.c of these GRSPs and rounded to the nearest tenth of a cent. The revised Upper Pivot Aluminum Price shall supersede the Upper Pivot Aluminum Price as stated in section III.B.2 of the rate schedule and shall be used to determine the energy rate in the subsequent 12 billing months.

(2) Annual Adjustment for the period beginning July 1, 1991, and ending June 30, 1993

The Upper Pivot Aluminum Price will be adjusted such that the Average Historical Aluminum Price described in section VII.B.4 of these GRSPs is the midpoint between the adjusted Upper Pivot Aluminum Price and the Average Historical Lower Pivot Aluminum Price described in section VII.B.5 below, except as limited to the greater of 65 cents per pound or the adjusted Lower Pivot Point for the year.

The Upper Pivot Aluminum Price shall equal the greater of:

(a) (2)(AAP) - ALP:

where

$AAP = \text{the Average Historical Aluminum Price described in section VII.B.4 of these GRSPs.}$

$ALP = \text{the Average Historical Lower Pivot Aluminum Price described in section VII.B.5 of these GRSPs.}$

(b) 65.0 cents per pound escalated to current dollars using the Cost Escalator for the Upper Pivot Aluminum Price described in section VII.B.3.c of these GRSPs.

or

(c) The adjusted Lower Pivot Aluminum Price for the year.

The revised Upper Pivot Aluminum Price shall supersede the Upper Pivot Aluminum Price as stated in section III.B.2 of the rate schedule and shall be used to determine the energy rate in the subsequent 12 months.

3. Cost Escalators

a. The cost indices described below shall be used in calculating the appropriate cost escalators. Each index shall be rounded to the nearest one-tenth of a percent, or three significant places.

(1) Electricity Cost Index

The average VI-87 rate in mills per kilowatt hour based on the Plateau Energy Charge and the Discount for Quality of First Quartile Service in effect on the April 1 preceding the annual adjustment date and a load factor of 98.5 percent; divided by 22.8 mills per kilowatt hour (the average VI-86 rate assuming the plateau energy charge and the Discount for Quality of First Quartile Service in 1986).

(2) Labor Cost Index

The annual average hourly earnings for the U.S. primary aluminum industry (SIC 3334) over the previous complete calendar year, from the Employment and Earnings, published by the U.S. Department of Labor, Bureau of Labor Statistics (BLS), divided by $14.20 per hour (the value of SIC 3334 earnings reported for 1985).

(3) Alumina Cost Index

The annual average of the monthly billing aluminum prices described in section VII.A of the GRSPs for the previous 1-year period beginning July 1 through June 30 divided by 50.8 cents per pound (the average U.S. Transaction price over the period April 1985 through March 1986).

(4) Other Costs Index

The annual average GNP Implicit Price Deflator for the previous complete calendar year, as published by the U.S. Department of Commerce, Bureau of Economic Analysis, divided by 1.115 (the value of the GNP Implicit Price Deflator for 1985 with 1982 = 1.000).

In the event the indices delineated above are discontinued or revised in a manner that BPA determines renders them unusable for calculating a consistent cost index, BPA will adjust or substitute another similar price index, following advance notification and opportunity for public comment as described in section VII.B.1 of these GRSPs.

b. The Cost Escalator for the Lower Pivot Aluminum Price shall be a weighted average of the four indices contained in section VII.B.3.a above. The following weights shall be assigned each index:
Electricity Cost Index .30
Labor Cost Index .20
Alumina Cost Index .20
Other Costs Index .30
c. The Cost Escalator for the Upper Pivot Aluminum Price shall be a weighted average of the Electricity Cost and Other Cost Escalators as stated in sections VII.B.3.a.(1) and VII.B.3.a.(4) above. The following weights shall be assigned each index:
   Electricity Cost Index .25
   Other Costs Index .75

4. Average Historical Aluminum Price

Prior to the July 1, 1991, annual adjustment date and every annual adjustment date thereafter, an average historical aluminum price shall be calculated for the period the Variable rate has been in effect. The average historical aluminum price shall be determined following the procedures set forth below:

a. Each monthly billing aluminum price determined pursuant to section VII.A of these GRSPs for the period August 1, 1986, through June 30 immediately preceding the annual adjustment date, shall be escalated to the current year dollars using the Price Deflator procedures described in section VII.B.6 below.

b. The sum of the escalated monthly billing aluminum prices shall be divided by the number of months in the period and rounded to the nearest tenth of a cent to obtain the Average Historical Aluminum Price.

5. Average Historical Lower Pivot Aluminum Price

Prior to the July 1, 1991, annual adjustment date and every annual adjustment date thereafter, the average of the Lower Pivot Aluminum Prices for the period the Variable Industrial rate has been in effect shall be calculated following the procedures set forth below:

a. The Lower Pivot Aluminum Price in each month for the period August 1, 1986, through June 30 of the calendar year preceding the annual adjustment date, shall be escalated to the current year’s dollars using the Price Deflator procedures described in section VII.B.6 below.

b. The sum of the escalated monthly Lower Pivot Aluminum Prices shall be divided by the number of months in the period, and rounded to the nearest tenth of a cent to obtain an Average Historical Lower Pivot Aluminum Price.

6. Price Deflator Procedures

For purposes of converting nominal dollars to real dollars in the calculation of the Average Historical Aluminum Price and the Average Historical Lower Pivot Aluminum Price, the following Price Deflator procedures shall be used:

a. Monthly billing aluminum prices and Lower Pivot Aluminum Prices for any calendar months July through December shall be inflated by multiplying the price by the ratio of the GNP Implicit Price Deflator for the calendar year prior to the annual adjustment date divided by the Implicit Price Deflator for the calendar year in which the price occurred.

b. Monthly billing aluminum prices and Lower Pivot Aluminum Prices for any calendar months January through June shall be inflated by multiplying the price by the ratio of the Implicit Price Deflator for the calendar year prior to the annual adjustment date divided by the Implicit Price Deflator for the calendar year prior to the year in which the price occurred.

Each price shall be rounded to the nearest tenth of a cent.
GENERAL CONTRACT PROVISIONS

Index to Sections

Section | Page
---|---
**IN REFERENCE TO MEANING**
1. Definitions | 1
2. Interpretation | 2
**IN REFERENCE TO DELIVERY OF POWER**
3. Character of Service | 2
4. Point(s) of Delivery and Delivery Voltage | 2
5. Metered Quantities | 3
**IN REFERENCE TO PAYMENT FOR POWER**
6. Payment of Bills | 3
7. Determination of Estimated Billing Data | 3
**MISCELLANEOUS PROVISIONS**
8. Additional Provisions | 3
9. Notices and Computation of Time | 4
10. Interest of Member of Congress | 4

**IN REFERENCE TO MEANING**

1. Definitions. The definitions in the body of this contract and the following additional definitions apply to this exhibit.
   (a) "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 United States 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 non-Federal 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 United States and Canada relating to the cooperative development of water resources of the Columbia River Basin, signed in Washington, D.C., on January 17, 1961.

(b) "Integrated Demand" means the number of kilowatts which is equal to the number of kilowatthours delivered at any point during any clock hour.

(c) "Non-Federal Utility" means any utility not owned or controlled by the United States, including any entity (1) which such a utility owns or controls, in whole or in part, or is controlled by; (2) which is controlled by those controlling such utility; or (3) of which such utility is a member.

(d) "Pacific Northwest" means the same as such term is defined in P.L. 96-501.

(e) "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.

(f) "Treaty" means the Treaty between the United States and Canada relating to the cooperative development of water resources of the Columbia River Basin, signed in Washington, D.C., on January 17, 1961.

2. 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 in this exhibit, the former shall prevail.

(b) If a provision in the General Rate Schedule Provisions incorporated in the Wholesale Power Rate Schedules and General Rate Schedule Provisions Exhibit is in conflict with a provision contained 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 hereto of any means of enforcing any remedy, either at law or in equity, for the breach of any of the provisions of this contract which it would otherwise have.

IN REFERENCE TO DELIVERY OF POWER

3. Character of Service. Unless otherwise specifically provided for in the contract, electric power, capacity or energy made available pursuant to this contract shall be in the form of three-phase current, alternating at a nominal frequency of 60 hertz.

4. Point(s) of Delivery and Delivery Voltage. Electric power, capacity or energy shall be delivered to each purchaser at the Point(s) of Delivery and
at such voltage(s) as specified. Unless otherwise agreed, delivery at more than one voltage shall constitute delivery at more than one point.

5. Metered Quantities. The amount(s) of energy, Integrated Demands therefor and amount(s) of reactive energy delivered to the Point(s) of Delivery during each month shall be determined from measurements made by meters installed for such Point(s) of Delivery in the circuit specified.

IN REFERENCE TO PAYMENT FOR POWER

6. Payment of Bills. Each calculated monetary amount in a wholesale power bill shall be rounded to a whole dollar amount, 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 IWRB 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 by the final bill. Such estimated bill, if so issued, shall have the validity of and be subject to the same payment provisions as shall a final bill; however, payment required under the estimated bill shall be adjusted as appropriate in the final bill.

Bills not paid in full on or before the date specified in the Payment of Bills section, or its successor, of the General Rate Schedule Provisions incorporated in the Wholesale Power Rate Schedules and General Rate Schedule Provisions Exhibit shall bear additional charges as specified therein.

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 30th day after the date of the bill. If the 30th day after the date of the bill is a Sunday or other nonbusiness day of the purchaser, the next following business day shall be the last day on which payment may be made to avoid such further charges. Payment made by metered mail and received subsequent to the 30th day must bear a postal department cancellation in order to avoid assessment of such further charges.

7. Determination of Estimated Billing Data. If the amounts of power or energy which have been delivered hereunder must be estimated from data other than metered quantities, scheduled quantities or tabulations of hourly interchange prepared by Bonneville, Bonneville and IWRB shall agree on estimated billing data to be used in preparing the bill.

MISCELLANEOUS PROVISIONS

8. Additional Provisions. IWRB agrees to comply with the clauses for United States 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 Part 60-741.4 (Affirmative Action for Handicapped Workers);
(b) the Vietnam Era Veterans Readjustment Assistance Act of 1972, Public Law 92-540, as amended, and 41 CFR Parts 60-250.4 and 60-250.10 (Affirmative Action for Disabled Veterans and Veterans of the Vietnam Era);
(c) the Small Business Act, as amended;
(d) Executive Order 11246 and 41 CFR Part 60-1.4 (Equal Opportunity). Such clauses, as amended, are incorporated by reference herein as if fully set forth.

9. 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.

10. 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 such contract if made with a corporation for its general benefit.

(VS6-PMCE-4332c)
Exhibit M

Electric Power Wheeling and Maintenance Agreement, dated January 19, 2000

This document is provided as an attachment to this Agreement.
Electric Power Wheeling and Maintenance Agreement

between

Idaho Water Resources Board

and

Clearwater Power Company

for

Use of Electrical Transmission Facilities associated with the Dworshak Small Hydroelectric Project FERC License No. 10819
# TABLE OF CONTENTS

## RECITALS

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>I. Definitions</td>
<td>1</td>
</tr>
<tr>
<td>II. Scope</td>
<td>2</td>
</tr>
<tr>
<td>III. Description of Services</td>
<td>3</td>
</tr>
<tr>
<td>IV. Continuity of Service</td>
<td>4</td>
</tr>
<tr>
<td>V. Payment, Rate and Charges</td>
<td>6</td>
</tr>
<tr>
<td>VI. Term</td>
<td>7</td>
</tr>
<tr>
<td>VII. Audit by IWRB</td>
<td>7</td>
</tr>
<tr>
<td>VIII. Interpretation</td>
<td>8</td>
</tr>
<tr>
<td>IX. Conflicts</td>
<td>8</td>
</tr>
<tr>
<td>X. Attorney's Fees</td>
<td>8</td>
</tr>
<tr>
<td>XI. Assignment of Agreement</td>
<td>8</td>
</tr>
<tr>
<td>XII. Indemnification</td>
<td>8</td>
</tr>
<tr>
<td>XIII. Null and Void Covenants</td>
<td>8</td>
</tr>
<tr>
<td>XIV. Notices</td>
<td>9</td>
</tr>
<tr>
<td>XV. Liability Insurance</td>
<td>9</td>
</tr>
<tr>
<td>XVI. Waiver, Modification or Amendment</td>
<td>9</td>
</tr>
<tr>
<td>XVII. Governing Law</td>
<td>9</td>
</tr>
<tr>
<td>XVIII. Enforceability</td>
<td>10</td>
</tr>
<tr>
<td>XIX. Authorization</td>
<td>10</td>
</tr>
<tr>
<td>XX. Mediation and Arbitration</td>
<td>10</td>
</tr>
<tr>
<td>XXI. Disconnection and Termination</td>
<td>11</td>
</tr>
</tbody>
</table>
AGREEMENT

This Agreement, made this 19th day of January 2000, by and between the Idaho Water Resources Board (IWRB) and the Clearwater Power Company (CPC).

RECITALS

1. IWRB is developing the Dworshak Small Hydroelectric Project “Project” a hydroelectric power plant, having a name-plate generation capacity of approximately 2,900 kW, located approximately one mile downriver of Dworshak Dam on the feedwater lines serving the Clearwater and Dworshak National Fish Hatcheries in Clearwater County.

2. IWRB was issued Federal Power License No. 10819 for the Project on August 4, 1998, by Federal Energy Regulatory Commission (FERC).

3. IWRB desires to deliver the output from the Project to the Bonneville Power Administration’s (BPA) transmission system.

4. CPC owns and operates the Ahsahka Substation, a 115kV to 24.9kV facility located in the vicinity of the Project, and a 115kV transmission line which interconnects the Ahsahka Substation to the BPA Transmission System.

5. CPC has designed, on behalf of IWRB, a protection system satisfactory to CPC for the protection of CPC’s electric distribution system. A copy of the design of the protection system is attached as Exhibit A and incorporated herein by this reference.

6. CPC is willing to make the necessary changes to its facilities in order to wheel the power produced from the Project to the BPA Transmission System.

Now, therefore, in consideration of the promises stated, the parties hereto agree as follows:

I. Definitions

As used in this Agreement:

1. “Good Utility Practice” shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been
expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be a range of acceptable practices, methods or acts.

2. "System" or "Facilities" shall include transmission, transformer, substation, and distribution facilities which are owned by either party or which either party may use under a lease, easement or license.

3. "Point of Interconnection" shall be defined as where the 24.9kV low voltage side of CPC's Ahsahka Substation and IWRB facilities are connected.

4. "Point of Delivery" shall be defined as the junction of the CPC and BPA facilities located approximately one mile northeast up the North Fork of the Clearwater River from the Ahsahka Substation.

5. "Metering Point" shall be in CPC's Ahsahka Substation, in the 24.9 kV circuit over which such electric power and energy flows.

6. "Uncontrollable Forces" may include, but are not restricted to:

   a. Strikes affecting the operation of either party's system or other physical facilities upon which such operation is dependent; or

   b. The following events that either party, by exercise of reasonable diligence and foresight, could not reasonably have been expected to avoid:

      (1) Events, reasonably beyond the control of the party having jurisdiction thereof, causing failure, damage, or destruction of any system or facility. The term "failure" shall include any interruption or interference with the actual operation of such system or facility.

      (2) Acts of God or of the public enemy, acts of the government in its sovereign or contractual capacity, fires, floods, epidemics, quarantine restrictions, strikes or failure or breakdown of transmission, distribution or other facilities.

II. Scope

CPC agrees to furnish wheeling services requested by IWRB to transmit the output from the Project to the Point of Delivery. CPC also agrees to perform the identified construction and maintenance services to facilitate
the delivery of electrical power from the Project to the Point of Interconnection.

III. Description of Services

1. Wheeling Services

   a. CPC agrees to provide wheeling services from the Point of Interconnection located at the 24.9 kV circuit side of the Ahsahka Substation through the substation to the Point of Delivery on the BPA Transmission System located approximately one mile from the Ahsahka Substation.

   b. The premises to be served under this Agreement is the Dworshak Small Hydroelectric Project FERC License No. 10819 located near Ahsahka Idaho. The name-plate generation capacity of the Project is approximately 2,900 kW and the annual energy production is estimated at 23,000,000 kWh.

   c. IWRB shall give reasonable notice to CPC respecting any changes anticipated in the capacity requirements or characteristics of the wheeling service required.

2. Construction and Maintenance Services

   a. CPC agrees to construct and install all necessary electrical facilities identified in Exhibit C incorporated herein by this reference and located between the south side vault of the Ahsahka Bridge and the Point of Interconnection located at the 24.9 kV circuit side of the Ahsahka Substation. Ownership and title to the facilities including the conduits, primary conductors, ground wire and connectors shall remain with IWRB, except that CPC shall own and hold title to the Ahsahka Bridge electrical vaults and bridge cable tray together with other associated facilities attached to the vaults and tray. CPC hereby provides to IWRB a license to jointly use the bridge vaults; cable tray and associated facilities owned by CPC for the life of this Agreement. CPC agrees to be responsible for all loss or damage to its facilities except loss or damage that is caused by the interconnection of IWRB’s facilities to CPC or that arising out of the negligence of IWRB, its agents or employees. All real estate taxes and other charges, together with all liability arising out of the negligence of CPC in the construction and maintenance shall be assumed by CPC.

   b. IWRB shall construct and install the transformer, buried conduit and wire to the Clearwater Bridge. Ownership and title to the transformer, buried conduit and wire shall remain with IWRB and it shall be responsible for all loss and damages to its facilities except that arising
out of the negligence of CPC, its agents or employees. All taxes and other charges, together with all liability arising out of the negligence of IWRB shall be assumed by IWRB.

c. CPC agrees to provide the inspection, maintenance, and periodic replacement of the transformer, buried conduit, and wire owned by IWRB together with electric facilities identified in Exhibit C. CPC agrees to inspect and maintain all the facilities identified under this Agreement to the same standard it maintains its other distribution facilities using Good Utility Practices, and use reasonable diligence to provide a regular uninterrupted wheeling service to the Project. Notwithstanding CPC’s agreement to provide maintenance for the IWRB transformer, CPC shall not have any liability for any damages arising from, but not limited to, any environmental cleanup, fines, or other costs. Except that CPC shall be responsible for damages that arise as the result of negligence on the part of CPC in the performance of its maintenance duties under this Agreement. IWRB shall provide periodic maintenance, testing and repair to all other Project facilities. CPC reserves the exclusive rights to operate, maintain, inspect, update, and/or repair IWRB’s facilities within the boundaries of CPC’s Ahsahka Substation and the North and South vaults located on the Ahsahka Bridge. IWRB reserves the right to accompany CPC personnel during any maintenance, inspections, updates, and/or repairs of IWRB’s facilities.

d. Each party agrees to design, construct, operate, maintain and use its electric facilities in conformance with Good Utility Practices to minimize electrical disturbances such as, but not limited to, the abnormal flow of power which may interfere with the electric system of the other party or any other electric system connected to the party’s system. Nothing in this section shall be construed to create any duty, standard of care, or liability to any person not a party to this Agreement, including but not limited to those who purchase electricity directly from CPC.

IV. Continuity of Service

1. CPC shall not be liable to IWRB for damages, breach of Agreement, or service interrupted by any uncontrollable force or any other event or consequence unless such event or consequence is the result of CPC’s willful misconduct or negligence.

2. CPC may temporarily interrupt or reduce wheeling of electrical power of the Project if it determines that such interruption or reduction is necessary or desirable in case of system emergencies, uncontrollable forces, or in order to make repairs, replacements, investigations,
inspections or install equipment and perform other maintenance work on CPC's system. CPC shall make every effort to perform all repairs and other duties identified in this paragraph with reasonable dispatch to promptly restore wheeling service to the Project. Except in cases of emergency and/or uncontrollable forces, CPC agrees to give IWRB reasonable notice of any anticipated interruption or reduction together with an explanation for the action and an estimate of the duration of the interruption.

3. IWRB shall provide power and energy in conformance with IEEE Standard 519-1992 for harmonic control and IEEE Standard 141-1986 for voltage guidelines. IWRB also shall maintain unity average power factor as nearly as practicable. In the event that the delivered power and energy is not within the standard or the power factor falls below 95% leading or lagging based on an hourly average, CPC, after notification to IWRB, may disconnect the Project from its system until such time as the power quality is corrected at IWRB expense. IWRB shall adhere to Good Utility Practices in the operation and maintenance of the Project, including, but not limited to, system protection and generation output.

4. CPC agrees to notify IWRB as soon as possible of any uncontrollable force that in any way affects transmission of power under this Agreement. In the event the operations of CPC are interrupted or curtailed due to such uncontrollable force, CPC agrees to exercise due diligence to reinstate such operations with reasonable dispatch. In the event CPC is unable to wheel power for any causes identified under this Agreement, for any period, CPC shall not be held responsible for the lost production revenues of the Project.

5. In the event IWRB is unable to operate the Project in whole or in part, IWRB shall not be liable to CPC for damages breach of Agreement or service interrupted by any uncontrollable force or any other event or consequence. CPC agrees to maintain IWRB's facilities as outlined in this Agreement and IWRB shall continue to pay the monthly rate subject to an adjustment pro-rated daily as described in Section V below until such time as IWRB notifies CPC in writing of the termination of this Agreement.

6. The parties shall furnish each other such information as is necessary for making any computation required under this Agreement and the parties further agree to cooperate in the exchange of additional information as may be useful in their respective operations.

7. It is the intent of the parties to create and foster an atmosphere of cooperation over the term of this Agreement.
V. Payment, Rate and Charges

1. IWRB shall pay and CPC shall accept as payment the monthly rate specified in Exhibit B and incorporated herein by this reference. The monthly rate shall include charges for standby, maintenance and inspection and wheeling and joint use for the Project. An adjustment pro-rated daily shall be made to the monthly Wheeling and Joint Use Fee if IWRB is unable to operate the Project for more than thirty (30) consecutive days.

2. The rate schedule may be renegotiated at any time upon request of either party. CPC agrees that the rate will not exceed the rate CPC would charge others under similar conditions of service.

3. CPC agrees to bill and IWRB agrees to pay up to twenty five thousand dollars ($25,000.00) per year for all costs, including but not limited to labor, material, and overhead, plus ten percent (10%), associated with repairs to IWRB equipment and replacement thereof. CPC agrees to, after consultation with IWRB, bill IWRB for any additional amounts that may exceed $25,000.00 in any given year.

4. Upon completion of the facilities, or periodically prior to completion if the parties agree, IWRB shall pay CPC the approximate total sum of one hundred seventy three thousand two hundred dollars ($173,200) for construction and installation of the facilities identified in the attached Cost Estimate of Electric Facilities labeled as Exhibit C. Payment shall be adjusted more or less from the amount identified above to reimburse CPC for the actual costs expended to construct and install the facilities. Upon full payment, CPC agrees to execute a release in favor of IWRB for all claims arising under or by virtue of the installation.

5. The parties agree that actions performed under this Agreement are not intended to cause any detrimental effect on CPC in regards to any agreement CPC has or may have with BPA and/or other power providers. The parties further agree to promptly renegotiate any term of this Agreement to alleviate any dispute or remove any detrimental effect encountered by either party. If the parties are unable to reach agreement to modify this Agreement to remedy a dispute or eliminate a detrimental effect, either party may submit the dispute for Mediation and Arbitration as set out in Section XX of this Agreement. CPC agrees to continue to provide Wheeling and Maintenance services while any matter in this Agreement may be in dispute. IWRB agrees to reimburse CPC for reasonable costs associated with any ongoing maintenance, inspection and detrimental effects attributable to IWRB, as determined by the parties.
VI. Term

1. This Agreement shall become effective upon the execution by the parties. Services provided by CPC described in Exhibit B shall commence at 2400 hours on or before August 3, 2000 and shall continue until the earlier of:

   a. 2400 hours on the date 60 days after written notice from IWRB to CPC of termination of the Power Sales Agreement between IWRB and BPA; or

   b. 2400 hours on the date 60 days after written notice from IWRB to CPC of termination pursuant to section XXI of this Agreement; or

   c. Fifty (50) years from the effective date of this Agreement.

2. This Agreement may be extended or renewed upon agreement of the parties.

VII. Audit by IWRB

   IWRB shall have the right to audit and inspect the records of CPC subject to the following provisions:

1. Examination of Costs. CPC agrees to make available and IWRB shall have the right to examine books, records and documents, and other evidence, accounting procedures and practices, sufficient to reflect properly all direct and indirect costs of whatever nature claimed to have been incurred and anticipated to be incurred for the performance of this Agreement. Such right of examination shall include inspection at all reasonable times of CPC’s plants, or parts thereof, as may be engaged in the performance of this Agreement.

   Any data relied upon by CPC to establish a price shall be made available to IWRB upon request.

2. The materials described in paragraph No. 1 of this section shall be made available at the offices of CPC, at all reasonable times and with reasonable notice, for inspection, audit, or reproduction, until three years after payment under this Agreement. IWRB shall reimburse CPC for costs of providing data and assistance during the audit.
VIII. Interpretation

Nothing in this Agreement shall, in any manner, be construed to abridge, limit or deprive any party hereto of any means of enforcing any remedy, either at law or in equity, for the breach of any provision in this Agreement that either party would otherwise have.

IX. Conflicts

Any inconsistency between the provisions of this Agreement and the provisions of any schedule, rider or exhibit incorporated into this Agreement by reference or otherwise, the provisions of this Agreement shall control.

X. Attorney's Fees

In the event either IWRB or CPC takes action, judicial or otherwise, to enforce or interpret any of the terms of this Agreement, the prevailing party shall be entitled to recover reasonable fees of attorneys, paralegal, accountants and other experts, and all other amounts provided by law, whether incurred in a suit or action or appeal from a judgment or decree therein.

XI. 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 without the written consent of the other, which consent shall not be unreasonably withheld. In the event approval is not given, the non-assigned party must state the reason for withholding approval and list conditions needed for approval.

XII. Indemnification

Each party agrees to indemnify, defend and hold harmless the other party, its assigns, officers, employees and agents from any and all claims, demands, suits, losses, costs and damages of every kind and description, including attorney fees, growing out of or connected with its negligent acts, errors or omissions its employees or agents, provided that neither party shall be relieved hereby from liability for their own negligence and that of its employees.

XIII. Null and Void Covenants

If any part of this Contract is declared invalid or becomes inoperative for any reason, such invalidity or failure shall not affect the validity and enforceability of any other provision.
XIV. Notices

Notices shall be in writing and shall be delivered by means of registered or certified mail, confirmed facsimile transmission, courier or messenger service or personal delivery, and shall be deemed given upon receipt or, in case of the notice by mail, three business days after deposit in the United States mail. Notices shall be addressed as follows, or to such other address as either IWRB or CPC shall provide.

To IWRB: Director
Idaho Department of Water Resources
1301 N. Orchard Street
P.O. Box 83720
Boise, Idaho 83720-0098
Facsimile: (208) 327-7866
Telephone: (208) 327-7900

To CPC: Raymond J. Thayer, P.E.
General Manager
Clearwater Power Company
4230 Hatwai Road
P.O. Box 997
Lewiston, Idaho 83501
Facsimile: (208) 746-3902
Telephone: (208) 743-1501

XV. Liability Insurance

IWRB and CPC agree to obtain and maintain liability insurance with a single limit of coverage of not less than $5,000,000 for each occurrence. A certificate of such insurance shall be provided by IWRB and CPC to the other party prior to operation of the Project. Each party agrees to promptly notify the other of any changes in its liability insurance coverage and policies. The liability of each party is limited to amount of coverage identified herein.

XVI. Waiver, Modification or Amendment

No waiver, modification, or amendment of this Agreement or of any covenants, conditions or limitations herein contained shall be valid unless in writing duly executed by both parties and the parties further agree that the provisions of this section may not be waived, modified, or amended except as herein set forth.

XVII. Governing Law

This Agreement shall be interpreted, construed and enforced in accordance with the laws of the State of Idaho or the law of the United States of America, whichever is applicable.
XVIII. Enforceability

IWRB and CPC each represent and warrant that this Agreement has been duly authorized, executed, and delivered by the party and constitutes a legal and binding obligation of the party, enforceable against the other party in accordance with its terms.

XIX. Authorization

The persons signing this Agreement each represent that they have been appropriately authorized to enter into the Agreement on behalf of the party for which they sign.

XX. Mediation and Arbitration

Except for the right of either party to apply to a court of competent jurisdiction for a temporary restraining order or preliminary injunction to preserve the status quo or to prevent irreparable harm pending the decision of the arbitrator, the parties agree to first attempt to resolve any dispute arising under this Agreement informally through mediation using a mediator mutually agreed upon by the parties. If the parties cannot resolve the dispute through mediation, the parties may agree to submit the dispute to binding arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association.

The arbitration may be conducted by one (1) impartial arbitrator chosen by mutual agreement or by three (3) arbitrators if the parties are unable to agree on a single arbitrator within thirty (30) days of the first demand for arbitration. All arbitrators are to be selected from a panel provided by the American Arbitration Association. The arbitrators should be knowledgeable in electric utility and electric transmission matters. The chair shall be an attorney at law. Upon the request of a party, the arbitrators shall have the authority to permit discovery to the extent they deem appropriate. A court reporter shall record the arbitration hearing and the reporter’s transcript shall be the official transcript of the proceeding. The arbitrators shall have no power to add or detract from the agreement of the parties and may not make any ruling or award that does not conform to the terms and conditions of this Agreement. The arbitrators shall have the authority to grant injunctive relief in a form substantially similar to what could be granted by a court of law. The arbitrators shall have no independent authority to award punitive damages or any other damages not measured by the prevailing party’s actual damages. The arbitrators shall specify the basis for any damage award and the types of damages awarded. The decision of the arbitrators shall be final and binding on the parties and may be entered and enforced in any court of competent jurisdiction by either party.

The prevailing party in the arbitration proceedings shall be awarded reasonable attorneys’ fees, expert witness costs and expenses, and all other expenses incurred directly or indirectly in connection with the proceedings, unless the arbitrators shall for good cause determine otherwise. Nothing in this

AGREEMENT, Page 10
Agreement shall prevent either party from petitioning the Federal Energy Regulatory Commission at its expense to obtain relief under the provisions of the Federal Power Act or the regulations promulgated pursuant thereto.

XXI. Disconnection and Termination

If, in the sole judgment of CPC, IWRB's Project fails to remain in an operating condition that conforms to Good Utility Practices as set forth in this Agreement, CPC shall describe the deficiency and notify IWRB in writing to disconnect the IWRB's Project from CPC's system. In the event IWRB fails to remedy the described deficiency within seven (7) calendar days, CPC may discontinue services under this Agreement until such time as IWRB's Project is restored to an operating condition satisfactory to CPC. This Agreement may be terminated upon the destruction or abandonment of the Project or upon discontinuation of Project operations under a final order issued by a public official having authority to issue such order. Upon termination, IWRB agrees to reimburse CPC for costs associated with the removal of IWRB's facilities located in CPC's Ahsahka Substation and Ahsahka Bridge Vaults including, but not limited to, labor and material.
IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the day and year first above written.

IDAHO WATER RESOURCE BOARD

By  

Title Chairman IWRB

Date 1/27/2000

CLEARWATER POWER COMPANY

By  

Title President

Date 1/19/2000

ATTEST:

By  

Title Secretary

Date ____________________________
Exhibit A

Dworshak Small Hydroelectric Project (FERC License 10819)

Protection System

See Attached Drawing

Clearwater Power Company One-Line Diagram

Ahsahka Substation

File: AS007

Sheet: 007
Exhibit B
Dworshak Small Hydroelectric Project (FERC License 10819)

Rate Schedule

The annual charge for electric power wheeling service and facility maintenance shall be comprised of the following costs:

1. Standby Fee: $5,000

   Standby: CPC agrees to maintain personnel and equipment 24 hours per day 7 days a week to conduct inspections, maintenance, repair, and replacement of IWRB’s transformer, buried conduit and wire and the other facilities identified in Exhibits C. CPC agrees to respond in accordance with Good Utility Practices and shall not give preferential treatment to IWRB.

2. Maintenance and Inspection Fee: $10,000

   Maintenance and Inspection Fee: CPC agrees to inspect and perform maintenance on IWRB facilities and the other facilities identified in Exhibits C according to Good Utility Practice up to $7,500 annually.

3. Wheeling and Joint Use Fee: $7,686

Total Annual Charge: $22,686

The monthly rate shall be determined by dividing the annual charge by twelve. Billing shall be to the nearest whole dollar and shall be rendered by IWRB on a monthly basis to CPC.

Monthly Rate: $1,891
Wheeling and Joint-Use Fees
For
CPC’s Ahsahka Substation and Transmission Line
By
IWRB

Ahsahka Substation Point of Delivery

Location: The point in CPC’s Ahsahka Substation where the 24.9 kV facilities of IWRB and CPC are connected.

- Voltage: 24.9 kV
- IWRB Reserved Capacity: 2,900 kW
- Transformer Peak Load (TPL): 21,000 kW
- Annual Cost Ratio (ACR): .1387
- Diversity Factor: 1.05
- Joint-Use Investment: $377,241

Annual Joint-Use Fee: \[\frac{2,900}{(21,000 \times 1.05)} \times .1387 \times 377,241 = \$7,587\]

Ahsahka Transmission Line

- Transmission Distance: .785 miles
- Transmission Distance Ratio: $0.0436
- Joint-Use Transmission Factor: $.785 \times .0436 = .0342 / \text{kW-yr}
- IWRB Reserved Capacity: 2,900 kW

Annual Wheeling Fee: $0.0342 \times 2,900 = \$99.00

Total Annual Wheeling and Joint-Use: $7,587 + \$99 = \$7,686
**Exhibit C**

Dworshak Small Hydroelectric Project (FERC License 10819)

Cost Estimate and Description of Electric Facilities Provided by CPC

<table>
<thead>
<tr>
<th>Description</th>
<th>Materials</th>
<th>Labor</th>
<th>Overhead</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Ahsahka Substation Modifications</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Structure Modifications</td>
<td>$1,120</td>
<td>$7,060</td>
<td>$1,640</td>
<td>$9,820</td>
</tr>
<tr>
<td>Safety Breaker</td>
<td>15,740</td>
<td>7,000</td>
<td>4,550</td>
<td>27,290</td>
</tr>
<tr>
<td>Controls</td>
<td>4,500</td>
<td>3,500</td>
<td>1,600</td>
<td>9,600</td>
</tr>
<tr>
<td>Switches</td>
<td>3,000</td>
<td>1,350</td>
<td>870</td>
<td>5,220</td>
</tr>
<tr>
<td>Buswork</td>
<td>---</td>
<td>1,200</td>
<td>240</td>
<td>1,440</td>
</tr>
<tr>
<td>Metering (buy from BPA)</td>
<td>20,000</td>
<td>5,000</td>
<td>5,000</td>
<td>30,000</td>
</tr>
<tr>
<td>Underground Riser</td>
<td>---</td>
<td>640</td>
<td>130</td>
<td>780</td>
</tr>
<tr>
<td>Controls</td>
<td>4,500</td>
<td>3,500</td>
<td>1,600</td>
<td>9,600</td>
</tr>
<tr>
<td>Switches</td>
<td>3,000</td>
<td>1,350</td>
<td>870</td>
<td>5,220</td>
</tr>
<tr>
<td>Buswork</td>
<td>---</td>
<td>1,200</td>
<td>240</td>
<td>1,440</td>
</tr>
<tr>
<td>Metering (buy from BPA)</td>
<td>20,000</td>
<td>5,000</td>
<td>5,000</td>
<td>30,000</td>
</tr>
<tr>
<td>Underground Riser</td>
<td>---</td>
<td>640</td>
<td>130</td>
<td>780</td>
</tr>
<tr>
<td>Trenching and Backfill</td>
<td>---</td>
<td>3,750</td>
<td>750</td>
<td>4,500</td>
</tr>
<tr>
<td>Conduit</td>
<td>1,440</td>
<td>1,750</td>
<td>640</td>
<td>3,830</td>
</tr>
<tr>
<td>Conductor</td>
<td>1,450</td>
<td>450</td>
<td>380</td>
<td>2,280</td>
</tr>
<tr>
<td>Oil Containment</td>
<td>---</td>
<td>1,000</td>
<td>200</td>
<td>1,200</td>
</tr>
<tr>
<td>Subtotal Ahsahka Substation</td>
<td>$47,250</td>
<td>$21,220</td>
<td>$13,700</td>
<td>$95,960</td>
</tr>
<tr>
<td><strong>Bridge Crossing</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Conduit</td>
<td>$1,410</td>
<td>$9,360</td>
<td>$2,150</td>
<td>$12,920</td>
</tr>
<tr>
<td>Conductor</td>
<td>3,230</td>
<td>1,670</td>
<td>980</td>
<td>5,880</td>
</tr>
<tr>
<td><strong>Cable Tray (1/3 of cost)(actual)</strong></td>
<td></td>
<td></td>
<td></td>
<td>8,440</td>
</tr>
<tr>
<td>Subtotal Bridge Crossing</td>
<td>$6,840</td>
<td>$13,720</td>
<td>$4,110</td>
<td>$27,240</td>
</tr>
<tr>
<td><strong>Bridge Vaults</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ahsahka Side (1/3 of cost)(actual)</td>
<td></td>
<td></td>
<td></td>
<td>$5,750</td>
</tr>
<tr>
<td>Orofino Side (1/3 of cost)(actual)</td>
<td></td>
<td></td>
<td></td>
<td>$5,750</td>
</tr>
<tr>
<td>Subtotal Bridge Vaults</td>
<td></td>
<td></td>
<td></td>
<td>$11,500</td>
</tr>
</tbody>
</table>

Contract Setup Costs $17,500

CPC Engineering and Coordination $21,000

**TOTAL CPC ESTIMATED CONSTRUCTION COST** $173,200
**U.S. DEPARTMENT OF ENERGY**  
**BONNEVILLE POWER ADMINISTRATION**

**AGREEMENT**

<table>
<thead>
<tr>
<th>1. AGREEMENT NUMBER</th>
<th>2. AGREEMENT EFFECTIVE FROM DATE IN BLOCK 4 UNTIL</th>
<th>3. MODIFICATION NO.</th>
<th>4. EFFECTIVE DATE (MMDDYY)</th>
<th>5. PROCUREMENT REQUEST NUMBER</th>
</tr>
</thead>
<tbody>
<tr>
<td>00TX30375</td>
<td>Completion of Work</td>
<td>-0-</td>
<td>Same as Block 20</td>
<td></td>
</tr>
</tbody>
</table>

**ISSUED TO:**  
Clearwater Power Company  
ATTN: Raymond Thayer, General Manager  
P.O. Box 997  
Lewiston, ID 83501

**TECHNICAL CONTACT**  
Doug Pfaff  
(208) 743-1501

**ADMINISTRATIVE CONTACT**  
Raymond Thayer, General Manager  
(208) 743-1501

**BPA TECHNICAL CONTACT**  
Jeff Hathhorn  
(208) 746-2357

**BPA ADMINISTRATIVE CONTACT**  
Ed Woessner  
(509) 358-7426

**DESCRIPTION OF WORK TO BE PERFORMED UNDER THIS AGREEMENT:**

Bonneville Power Administration (BPA) will, at Clearwater Power Company’s (CPC) expense, install revenue metering in CPC’s Ahsahka Substation to capture generation output from the Idaho Water Resources Board (IWRB) generation facility (also known as the Dworshak Small Hydro Project). Metering is to be located in BPA’s meterhouse.

CPC is acting as the IWRB agent for the purposes of paying for and installing the required metering package. BPA does not have a direct contact with IWRB for this part of the project.

The estimated completion date for this project is April 5, 2000.

The following documents are attached to and become a part of this Agreement:
- Financial Terms and Conditions Statement dated December 1, 1999

The following documents are attached for reference:
- Letter from Ralph Mellin (IWRB) to Thomas Murphy (BPA) and Edward Woessner (BPA) dated November 8, 1999
- BPA Contract #92888, Settlement and Contingent Power Purchase Agreement, signed April 30, 1990
- BPA Preliminary Project Requirements Diagram No. 258573

**AMOUNT TO BE PAID BY BPA $**

**SUBMIT INVOICE TO**

U.S. Department of Energy  
Bonneville Power Administration  
ATTN: Edward A. Peterson - TOC/DITT2  
P.O. Box 491  
Vancouver, WA 98666-0491

**ACCOUNTING INFORMATION**  
Actual Costs (estimated at $21,000)

**SUBMIT INVOICE TO**

Clearwater Power Company  
ATTN: Raymond Thayer, General Manager  
P.O. Box 997  
Lewiston, ID 83501

**PARTICIPANT**

Raymond J. Thayer  
General Manager  
1/25/00

**APPROVED BY (Signature)**

<table>
<thead>
<tr>
<th>NAME AND TITLE</th>
<th>DATE (MMDDYY)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Raymond J. Thayer</td>
<td>1/25/00</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>NAME AND TITLE</th>
<th>DATE (MMDDYY)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Edward A. Peterson</td>
<td>12/21/99</td>
</tr>
</tbody>
</table>

**MANAGER, Customer Service Planning and Engineering**
NOTES:
1. THE PURPOSE OF THIS PROJECT IS TO INTEGRATE THE IDAHO WATER RESOURCES BOARD GENERATION INTO CLEARWATER POWER COMPANY'S ASAHLA SUBSTATION.
2. REAL-TIME AGC TELEMETRY OF GENERATION QUANTITIES FOR THE WMB PROJECT IS NOT REQUIRED. TOTAL NAMEPLATE CAPACITY OF THE WMB GENERATORS IS SLIGHTLY LESS THAN 3 MW. THE TOTAL ELECTRICAL OUTPUT OF THIS PROJECT MAY INTERMITTENTLY EXCEED 3 MW FOR SHORT PERIODS. EXPANSION OF THIS PROJECT IS UNLIKELY DUE TO LIMITATION OF HYDRAULIC CAPACITY AT THIS SITE.
3. BPA TO MODIFY THEIR SINGLE-DIRECTION METERING TO BE BI-DIRECTIONAL.
4. BPA WILL INSTALL A PHONE SWITCH TO UTILIZE TELEPHONE LINE FOR ACCESS TO THE NEW REVENUE METER IN NOTE 5.
5. BPA TO PROVIDE AT CPC'S EXPENSE, RMS REMOTE BI-DIRECTIONAL METERING PACKAGE INCLUDING A JEM METER WITH INTEGRAL DEMAND RECORDER.
6. OVERUNDER FREQUENCY AND VOLTAGE RELAYING FOR THE PROJECT GENERATION SHOULD BE SET TO COMPLY WITH REQUIREMENTS SPECIFIED IN SECTION 6-G (RELAY COORDINATION) OF BPA TECHNICAL REQUIREMENTS FOR THE INTERCONNECTION OF GENERATION RESOURCES.
7. POTENTIAL LIGHT-LOAD FERRO/RESONANCE PROBLEM EXISTS IF THE ASAHLA 24.9 KV BUS IS ISOLATED WITH THE WMB GENERATION IN-SERVICE. THERE MAY BE INSTANCES WHERE THE MINIMUM LOAD AT ASAHLA IS LESS THAN 3 TIMES THE WMB GENERATION.
8. PROTECTIVE RELAYING FOR FAULTS ON THE 115 KV SYSTEM WILL INCLUDE PHASE OVERCURRENT AS WELL AS NEGATIVE SEQUENCE OVERCURRENT PROTECTION PROVIDED BY SEL RELAY.
9. ENGINEERING COORDINATOR: ED WOESSNER (409) 356-7426
TO: JOHN HOMAN, DEPUTY ATTORNEY GENERAL  
WATER RESOURCE UNIT  
FAX NUMBER: 327-7866

FROM: JOAN COMPTON, CPIW  
Risk Management Analyst  
State of Idaho  
Office of Insurance Management/Risk Management  
TELEPHONE NUMBER: (208) 332-1872  
E-mail Address: jcompton@adm.state.id.us  
FAX NUMBER: (208) 334-5315

DATE: 11/19/99 TIME: 3:30 NUMBER OF PAGES (INCLUDING COVER SHEET): 4

RE: EVIDENCE OF FINANCIAL RESPONSIBILITY TO CLEARWATER POWER COMPANY  
REGARDING PROPOSED ELECTRIC POWER WHEELING AND MAINTENANCE AGREEMENT  
(Small Hydroelectric Project)

PER YOUR REQUEST, FOLLOWING ARE TWO CERTIFICATES EVIDENCING THE INSURANCE REQUIREMENTS IN THE AGREEMENT. ONE OF THEM IS FROM THE EXCESS INSURANCE CARRIER COMPLYING WITH THE $5,000,000 LIMIT EXCESS OF THE STATE’S SELF-INSURED LIMIT OF $500,000.

LET ME KNOW IF YOU HAVE QUESTIONS OR I CAN BE OF FURTHER ASSISTANCE.

HAVE A GREAT WEEKEND!

REGARDS,

Joan Compton  
Risk Management Analyst  
Office of Insurance Management  
jcompton@adm.state.id.us  
208-332-1872
State of Idaho
CERTIFICATE OF FINANCIAL RESPONSIBILITY

The State of Idaho and its departments and agencies are self-insured for their public liability exposures. The State of Idaho has created the Retained Risk Fund, administered by the Bureau of Risk Management (Idaho Code § 67-5776), as the method to finance its risks of loss. Self-insurance is not insurance.

NAME OF AGENCY: State of Idaho/DEPARTMENT OF WATER RESOURCES/WATER RESOURCES BOARD

CERTIFICATE HOLDER: CLEARWATER POWER COMPANY
4238 HATWAI ROAD
LEWISTON, IDAHO 83501
ATTN: RAYMOND J. THAYER

DESCRIPTION OF OPERATION: The State of Idaho's Self Retained Risk Liability Fund, subject to the limits of liability specified in Idaho Code 6-901 through 6-929, is in effect on behalf of the State of Idaho including Dept. of Water Resources and the Idaho Water Resources Board but only for the Negligent actions of the Idaho Water Resources Board as respects to the Electric Power Wheeling and Maintenance Agreement between the Clearwater Power Company (CPC) and the Idaho Water Resources Board.

<table>
<thead>
<tr>
<th>TYPE OF COVERAGE</th>
<th>INDEMNIFICATION PROVIDED BY</th>
<th>EFFECTIVE DATES OF CERTIFICATE</th>
<th>LIMITS OF LIABILITY EACH OCCURRENCE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Comprehensive General Liability For:</td>
<td>State of Idaho</td>
<td>Nov. 1999 until cancellation of</td>
<td></td>
</tr>
<tr>
<td>Bodily Injury including</td>
<td>Retained Risk Fund</td>
<td>signed agreement</td>
<td></td>
</tr>
<tr>
<td>Personal Injury</td>
<td></td>
<td>$500,000</td>
<td></td>
</tr>
<tr>
<td>Error &amp; Omission</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Medical Malpractice, if applicable</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Property Damage</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

If applicable:

| Comprehensive Auto Liability For:                     | State of Idaho              | Retained Risk Fund |
| Bodily Injury and                                     |                             |                  |
| Property Damage                                       |                             |                  |

Date Issued: 11-19-99

In the event of any material change in this program, the Office of Insurance Management-Risk Management will give 30 days' written notice to the party to whom this certificate is issued, but failure to give such notice shall impose no obligation upon the State of Idaho and the Office of Insurance Management.
November 18, 1999

Clearwater Power Company
Attn: Raymond J. Thayer P.E.
4230 Hatwai Road
Lewiston, ID 83501

RE: State of Idaho

TO WHOM IT MAY CONCERN:

Attached are the following items per your request:

<table>
<thead>
<tr>
<th></th>
<th>Certificate of Insurance</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Memorandum of Insurance</td>
</tr>
<tr>
<td></td>
<td>Original Policy (as captioned)</td>
</tr>
<tr>
<td></td>
<td>Copy of Policy (as captioned)</td>
</tr>
<tr>
<td></td>
<td>Loss Payable and/or Mortgage Clause</td>
</tr>
<tr>
<td></td>
<td>Contract of Sale Clause</td>
</tr>
<tr>
<td></td>
<td>Cover Note and/or Binder</td>
</tr>
<tr>
<td></td>
<td>Other</td>
</tr>
</tbody>
</table>

The enclosed is issued in connection with:

Evidence of Insurance as respects to the Electric Power Wheeling and Maintenance Agreement between the Clearwater Power Company and the Idaho Water Resources Board.

We trust that you will find the enclosure(s) entirely satisfactory.

By: Connie J. Jones
Connie Jones, CPIW

cc: Joan Compton, State of Idaho

b:\comgrp\genbus\connie\soi\soicert.doc
### Certificate of Liability Insurance

**Producer:** Marsh USA, Inc.  
**Address:** P.O. Box 8688  
Boise, ID 83707  
(208) 342-6573 Fax (208) 338-6436

**Insured:**  
STATE OF IDAHO  
OFFICE OF INSURANCE MGT.  
PO BOX 83720  
BOISE, ID 83720

**Coverages:**

This certificate is issued as a matter of information only and confers no rights upon the certificate holder. This certificate does not amend, extend or alter the coverage afforded by the policies below.

<table>
<thead>
<tr>
<th>CO</th>
<th>TYPE OF INSURANCE</th>
<th>POLICY NUMBER</th>
<th>POLICY EFFECTIVE DATE (MADEUP)</th>
<th>POLICY EXPIRATION DATE (MADEUP)</th>
<th>LIMITS</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>GENERAL LIABILITY</td>
<td>9312254</td>
<td>07/01/99</td>
<td>07/01/00</td>
<td></td>
</tr>
</tbody>
</table>

**Excess Liability - Umbrella Form**

- Other than Umbrella Form

**Workers' Compensation and Employers' Liability**

- The Proprietor
- Partners/Executive Officers

**Other**

- Evidence of insurance as respects to the Electric Power Wheeling and Maintenance Agreement between the Clearwater Power Company (CPC) and the Idaho Water Resources Board.

**Certificate Holder:** Clearwater Power Company  
**Address:** Attn: Raymond J Thayer P.E.  
4230 Hattai Road  
Lewiston, ID 83501

**Cancellation:** Should any of the above described policies be cancelled before the cancellation date thereon, the issuing company will endeavor to mail 30 days written notice to the certificate holder named to the left, but failure to mail such notice shall impose no obligation or liability of any kind upon the company, its agents or representatives.
Travel Reimbursement

All reimbursable travel must be incurred and conducted in the most economical and practical manner for the Water Board.

Allowable travel expenses are those travel expenses which are essential in transacting the Water Board’s business.

TRAVEL CLAIMS AND DOCUMENTATION

Travel claims shall be submitted with invoices. Receipts must be obtained for all expenditures except where it is not practical (meals, tips, etc.). Charge card statements (MasterCard, Visa, American Express, etc.) are not considered proofs of purchase and cannot be used as a receipt. All receipts must be submitted with invoices.

The destination, time, and date of departure and must be included for each trip.

Transportation will be reimbursed at 57.5 cents per mile.

The actual cost of lodging will be reimbursed to EN. Original receipts for all lodging must be attached. Reimbursement will not be made for lodging while staying with friends or relatives.

Expenses for meals, including gratuity, will be paid up to a maximum allowed by the Idaho Board of Examiners. The present full-day reimbursement rate is $49.00.

TRAVEL VOUCHER

Water Board can provide EN with a fillable form to submit travel reimbursement requests if needed. Submit request for the travel voucher form to IDWRpayable@idwr.idaho.gov.