Administrator's Record of Decision 1979 Wholesale Power Rate Proposal

Bonneville Power Administration
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I. INTRODUCTION

This document has been prepared to trace the decision-making process that I, as Administrator of the Bonneville Power Administration (Bonneville), employed in overseeing development of new Bonneville wholesale power rate schedules which are scheduled to become effective December 20, 1979. A revised repayment study conducted by Bonneville indicated the need for an 88-percent increase in revenues. The revised wholesale power rates, plus an intended increase in transmission rates (44 FR 30405, May 25, 1979), will produce an estimated 88 percent increase in total revenues throughout the repayment period.

Bonneville's last wholesale power rate increase became effective December 20, 1974. Until recently, Bonneville's power sales contract limited Bonneville to one rate adjustment every 5 years. The contracts have been amended to enable Bonneville to adjust its rates again on July 1, 1981, and each July 1 thereafter. The effect of more frequent rate reviews will permit a series of smaller rate increases rather than infrequent large increases as is currently proposed.

Bonneville's rate revision process began on January 10, 1978, when it announced in the Federal Register its intent to file new wholesale power rate schedules and invited comments. Following completion of a draft environmental impact statement (EIS) and various cost and rate studies, Bonneville's initial wholesale rate proposal was announced in the Federal Register on August 25, 1978. A comment period followed and a revised wholesale rate proposal was announced in the Federal Register on July 17, 1979.

In developing and reviewing each rate proposal, Bonneville followed its published procedures for public involvement (43 FR 62950) as well as those of the President's Council on Environmental Quality regarding environmental review. To this end, Bonneville held 23 public meetings and solicited oral and written comments. During September and November 1978, eight public information forums and eight public comment forums were held throughout the region. There was substantial public interest. After publication of the revised proposal on July 17, 1979, Bonneville held public meetings on July 31, and August 1, 1979, in various locations in the region to receive comments. Bonneville solicited written comments for 30 days after the revised proposal appeared in the Federal Register.

The public involvement process played an important role in formulating the revised proposal of July 1979 and the final rate proposal. Bonneville received many useful comments and suggestions on a variety of topics. Two of the reports prepared as support for the revised and final proposals were the Staff

Evaluation of Official Record, July 1979 (Staff Evaluation), and the Addendum to the Staff Evaluation of Official Record, October 1979 (Addendum). They detail the issues raised in response to the initial and revised proposals and contain Bonneville's assessment of the issues.

In developing the rate proposal, Bonneville considered the six ratemaking standards of the Public Utility Regulatory Policy Act (PURPA), (P.L. 95-617). This Act requires each utility whose total retail sales exceed 500 million kilowatthours in a calendar year to consider ratemaking standards with respect to: (1) conservation of power by the end user of electricity; (2) optimal and efficient use of facilities and resources by electric utilities; and (3) equitable rates for all electric consumers.

Public meetings were held in July 1979 to receive comments on the PURPA standards. Written comments were received until August 20, 1979. The six ratemaking standards were adopted by Bonneville on November 19, 1979, and a copy of Bonneville's order adopting the standards is included in the official record of the wholesale power rate proposal.

To fully comply with Section 111 of PURPA, Bonneville will base its rates (with certain deviations) on a cost-of-service analysis using embedded costs and a long-run incremental cost-of-service analysis. Use of the two cost analyses permits Bonneville to recognize its revenue constraint and at the same time to reflect higher costs of future resources in designing rates. A time-differentiated pricing analysis was conducted, consistent with Section 111 of PURPA, to assist in designing rates which more accurately reflect the cost of providing service. The three remaining studies upon which the final rate proposal is based are the final EIS, the repayment study to determine revenue requirements, and the rate design study which explains the process used in developing the rate schedules. Other factors were also considered in development of rates, including value of service, continuity of rates, ease of administration and understanding, environmental protection, and conservation.

II. LEGAL REQUIREMENTS

A. General Rate Guidelines

Section 6 of the Bonneville Project Act (50 Stat. 735 as amended by 59 Stat. 546) requires that:

> "Schedules of rates and charges for electric energy produced at the Bonneville Project and sold to purchasers as in this Act provided shall be prepared by the administrator and become effective upon confirmation and approval thereof by the Federal Power

Commission; and such rates and charges shall also be applicable to dispositions of electric energy to Federal agencies. Subject to confirmation by the Federal Power Commission, such rate schedules may be modified from time to time by the administrator, and shall be fixed and established with a view to encouraging the widest possible diversified use of electric energy. The said rate schedules may provide for uniform rates or rates uniform throughout the prescribed transmission areas in order to extend the benefits of an integrated transmission system and encourage the equitable distribution of the electric energy developed at the Bonneville Project."

Section 7 of the Bonneville Project Act provides in part:

> "Rate schedules shall be drawn having regard to the recovery (upon the basis of the application of such rates schedules to the capacity of the electric facilities of the Bonneville Project) of the cost of producing and transmitting such electric energy, including the amortization of the capital investment over a reasonable period of years."

Parallel requirements appear in the Federal Columbia River Transmission System Act. For example, Section 9 of that Act provides:

> "Schedules of rates and charges for the sale, including dispositions to Federal agencies, of all electric power made available to the Administrator pursuant to section 8 of this Act or otherwise acquired, and for the transmission of non-Federal electric power over the Federal transmission system, shall become effective upon confirmation and approval thereof by the Federal Power Commission. Such rate schedules may be modified from time to time by the Secretary of the Interior, acting by and through the Administrator, subject to confirmation and approval by the Federal Power Commission, and shall be fixed and established (1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles, (2) having regard to the recovery (upon the basis of the application of such rate schedules to the capacity of the electric facilities of the projects) of the cost of producing and transmitting such electric power, including the amortization of the capital investment allocated to power over a reasonable period of years and payments

provided for in section 11(b)(9), and (3) at levels to produce such additional revenues as may be required, in the aggregate with all other revenues of the Administrator, to pay when due the principal of, premiums, discounts, and expenses in connection with the issuance of and interest on all bonds issued and outstanding pursuant to this Act, and amounts required to establish and maintain reserve and other funds and accounts established in connection therewith."

Section 11(b)(9) of the Transmission System Act enables the Administrator of Bonneville to make:

". . . such payments to the credit of the reclamation fund or other funds as are required by or pursuant to law to be made into such funds in connection with reclamation projects in the Pacific Northwest: Provided, That this clause shall not be construed as permitting the use of revenues for repayment of costs allocated to irrigation at any project except as otherwise expressly authorized by law. . ."

Recognizing that many hydroelectric projects serve other purposes such as navigation, flood control, and irrigation, in addition to the generation of electric power, Section 7 of the Bonneville Project Act further provides that:

"In computing the cost of electric energy developed from water power created as an incident to and a byproduct of the construction of the Bonneville project, the Federal Power Commission may allocate to the costs of electric facilities such a share of the cost of facilities having joint value for the production of electric energy and other purposes as the power development may fairly bear as compared with such other purposes."

B. Repayment Criteria

The mechanism for modifying the Administrator's rates was statutorily mandated by P.L. 89-448 (June 14, 1966, 80 Stat. 200), Section 2 of which provides in pertinent part:

"Sec. 2. The Secretary of the Interior shall prepare, maintain, and present annually to the President and the Congress a consolidated financial statement for all projects heretofore or hereafter authorized, . . . and he shall, if said consolidated statement indicates that the reimbursable construction costs of the projects, or any of the projects, covered thereby which are chargeable to and returnable from the commercial power and energy so marketed are likely not to be returned within the period prescribed by law, take prompt action to adjust the rates charged for such power and energy to the extent necessary to assure such return."

Based upon an opinion of Bonneville's General Counsel dated February 6, 1979, Bonneville has excluded from its repayment study those Federal projects authorized by Congress, but not yet in service. However, Bonneville still includes such uncompleted projects in its annual reports to the President and Congress. The exclusion of projects not yet in service is based upon the fact that the legislative history of P.L. 89-448 indicates that repayment of the Federal projects is scheduled "within 50 years following its being placed into service." (H.R. Rep. No. 1409, 89th Cong., 2d Sess. 7 (1966)) (Emphasis added.)

In addition to this requirement, statutory limitations have been placed upon the extent to which power revenues may subsidize reclamation projects. P.L. 89-561 (September 7, 1966, 80 Stat. 707, et seq.) provides in Section 6:

"(b) It is declared to be the policy of the Congress that reclamation projects hereafter authorized in the Pacific Northwest to receive financial assistance from the Federal Columbia River Power System shall receive such assistance only from the net revenues of that system as provided in this subsection, and that their construction shall be so scheduled that such assistance, together with similar assistance for previously authorized reclamation projects (including projects not now receiving such assistance for which the Congress may hereafter authorize financial assistance) will not cause increases in the rates and charges of the Bonneville Power Administration. It is further declared to be the policy of the Congress that the total assistance to all irrigation projects, both existing and future, in the Pacific Northwest shall not average more than $30,000,000 annually in any period of twenty consecutive years. Any analyses and studies authorized by the Congress for reclamation projects in the Pacific Northwest shall be prepared in accordance with the provisions of this section. As used in this section, the term 'net revenues' means revenues as determined from time to time which are not required for the repayment of (1) all costs allocated to power at projects in the Pacific Northwest then existing or authorized, including the cost of acquiring power by purchase or exchange, and (2) presently authorized assistance from power to irrigation at projects in the Pacific Northwest existing and authorized prior to the date of enactment of this subsection. [16 U.S.C. 835 l] "(c) On December 20, 1974, and thereafter at intervals coinciding with anniversary dates of Federal Power Commission general review of the rates and charges of the Bonneville Power Administration, the Secretary of the Interior shall recommend to the Congress any changes in the dollar limitations herein placed upon financial assistance to Pacific Northwest reclamation projects that he believes justified by changes in the cost-price levels existing on July 1, 1966, or by other relevant changes of circumstances." [16 U.S.C. 835m]

Based upon these requirements, we conducted a repayment study in a manner consistent with that approved by the Congress in its consideration of P.L. 89-448 (See H.R. Rep. No. 1409, 88th Cong., 2d Sess. 7-8 (1966)). The repayment study indicated that existing rates are insufficient to repay the Federal capital investment over a reasonable period of years. Based upon that finding, we developed wholesale power rates in an initial form, then in revised form, and finally in the form appended hereto. I find such rates will be sufficient to meet the statutory requirements of recovering the cost of producing and transmitting electric energy over a reasonable period of years, to pay the principal, premiums, discounts, expenses and interest in connection with bonds issued on behalf of Bonneville, and to make payments to the credit of the reclamation fund required to be paid from electricity sales. Furthermore, I find, as demonstrated by the repayment study, that the rates in Exhibit I are overall the lowest possible consistent with sound business principles. I further find that reclamation projects have been scheduled in such a manner as to assure that the reclamation project assistance required to be paid by Bonneville will not average more than $30,000,000 annually in any period of twenty consecutive years. The rate schedules continue the postage stamp rate policy, a policy which has served to carry out the statutory command to encourage the widest possible diversified use of electric power, and as expressed above, at the lowest possible rates to consumers on a systemwide basis.

C. Equitable Recovery of Transmission Costs

In addition to the requirements relating to wholesale power rates, Section 10 of the Federal Columbia River Transmission System Act provides:

"The said schedules of rates and charges for transmission, the said schedules of rates and charges for the sale of electric power, or both such schedules, may provide, among other things, for uniform rates or rates uniform throughout prescribed transmission areas. The recovery of the cost of the Federal transmission system shall be equitably allocated between Federal and non-Federal power utilizing such system."

As applied to power rates, the costs associated with that portion of the transmission system used for the transmission of Federal power to Bonneville's customers must be recovered from power rates. As explained in the Federal Columbia River Power System Cost of Service Analysis, that portion of the transmission system not used to serve wheeling customers has been segregated from revenue requirements allocated to wheeling services by segmenting the transmission system. I find that the seven segments identified and the resulting allocations of costs will equitably allocate the recovery of the cost of the transmission system of the FCRPS between Federal and non-Federal power utilizing that system.

D. Equitable Sharing of Benefits by Regions

In addition to the general rate guidelines, and those relating to transmission, the Administrator of Bonneville is charged with certain marketing restrictions relating to sales outside the Pacific Northwest by the "Pacific Northwest Regional Preference Act" (P.L. 88-552; August 31, 1964; 78 Stat. 756). Section 5 of the Act, although discussing permissible exchanges of energy between the Pacific Northwest and other regions, contains the statutory mandate that:

> "All benefits from such exchanges, including resulting increases in firm power, shall be shared equitably by the areas involved, having regard to the secondary energy and other contributions made by each."

That statutory charge, together with the language from Section 6 of the Bonneville Project Act and Section 10 of the Transmission System Act which allows for "uniform rates or rates uniform throughout prescribed transmission areas" indicates a congressional acceptance of rates designed for power sales within the Pacific Northwest and rates for power sales outside that region. The Senate and House Committee Reports on the Regional Preference Act and the Congressional Record remarks of individual senators and congressmen indicate rather clearly that in enacting the Regional Preference Act it was contemplated that there should be a continuing and mutual sharing of benefits between the Pacific Northwest and the Pacific Southwest in all power sales, not just exchanges of energy or capacity under Section 5 of the Act. Pursuant to that congressional expression, I have adopted the H-6 rate which I find results in a mutual sharing of the benefits of sales of secondary energy, and at the same time keeps rates to Bonneville's Pacific Northwest regional consumers at the lowest possible cost consistent with sound business principles while equitably sharing the benefits of Bonneville's secondary sales with the Pacific Southwest.

E. Confirmation and Approval

While the Bonneville Project Act and the Federal Columbia River Transmission System Act refer to the confirmation and approval by the Federal Power Commission, that entity was dissolved by the Department of Energy Organization Act (Pub.L. 95-91, August 4, 1977) and the functions of the Federal Power Commission relating to Federal Power Marketing Administration rate approval were transferred to the Secretary of Energy by Section 301(d) of that Act (91 Stat. 578).

Rates which the Secretary of Energy develops, acting by and through the Administrator of the Bonneville Power Administration, are subject to confirmation and approval on an interim basis by the Assistant Secretary for Resource Applications of the Department of Energy pursuant to Secretary of Energy Delegation Order No. 0204-33, (December 28, 1978). That same Delegation Order delegates to the Federal Energy Regulatory Commission the authority to confirm and approve rates on a final basis and to make the allocation of costs for the various purposes of the projects required to be allocated by Section 7 of the Bonneville Project Act and Section 2 of the River and Harbor Act of 1945 (59 Stat. 10, 21, 22).

The following findings and conclusions, related to the individual rate schedules proposed herein, are based upon a review of the staff studies, the Final Environmental Impact Statement, the oral and written public comments, the staff evaluation of the official record and the statutory authorities cited above.

III. NATIONAL ENVIRONMENTAL POLICY ACT

A. The Decision

As the Administrator of the Bonneville Power Administration (Bonneville), I have decided to submit to the Department of Energy a proposal to adjust Bonneville's wholesale power rates in order to achieve a revenue increase of 88-percent. The decisions made are incorporated into the schedules attached to the order as Exhibit A. The proposed rates would permit Bonneville to collect revenues sufficient to meet its Congressionally mandated repayment requirements. The rate adjustment is scheduled to become effective on December 20, 1979.

B. Alternatives Considered

As a part of the process of developing new power rates, Bonneville prepared a Draft and a Final Environmental Impact Statement (EIS). The EIS's focused on various revenue level and rate design alternatives. The objective was to define and analyze a range of alternatives including those which would represent the upper and lower limits of potential environmental impact.

1. Revenue Level Alternatives

Three revenue alternatives which involved lesser increases than that proposed by Bonneville included a "no action" alternative under which Bonneville would maintain its existing rates; a 30-percent increase alternative, which was based on exclusion of any payments for nuclear plants under construction until their dates of commercial operation; and an 83-percent revenue increase, which would require elimination of payment by Bonneville of irrigation assistance and an increase in the amortization period for generation facilities from a 50-year to an 85-year basis. The proposed 88-percent increase is based on Bonneville's current repayment requirement. A 195-percent increase alternative involved inclusion of both fixed and variable costs of authorized facilities in Bonneville's repayment study regardless of when the facilities would become operational, inclusion of funds designed to offset any external costs which Bonneville's action might impose on the environment, and increasing the rate of interest paid by Bonneville on all of its projects to a level equal to the current rate charged by the U.S. Treasury. The final alternative considered involved basing rates on long-run incremental costs. This approach would have resulted in a revenue increase of 895-percent.

The level of physical environmental impact associated with these revenue alternatives would be greatest for that revenue alternative involving the smallest increase and least for that involving the largest increase. This is due to the expectation that increases in the price of electricity would tend to reduce electrical consumption, thereby lowering impacts created by the production and use of electricity. These reductions in impact would be offset to some extent by increases in the use of alternative forms of energy such as oil and natural gas. Some alternative energy sources (e.g., solar or wind) may involve lower levels of environmental impact than those associated with thermal generation.

In contrast to physical environmental impacts, socioeconomic impacts are expected to increase as the revenue level is increased. The impact of a marginal cost revenue level could have substantial adverse financial impact on all users particularly irrigators and low-income residential consumers.

It is my conclusion that the proposed 88-percent revenue alternative represents a reasonable balance between impacts to the physical and socioeconomic aspects of the human environment and is therefore the environmentally preferable alternative. It also permits Bonneville to conform to the statutory guidelines for meeting its repayment requirements.

2. Rate Design Alternatives

Bonneville considered a variety of rate design alternatives in structuring its proposed rates. These design alternatives included various methods for allocating the revenue burden to energy versus capacity, to the summer versus the winter period, and to daily peak versus offpeak periods. Several approaches to industrial availability credits, facility charges, at-site discounts, the pricing of secondary energy, and conservation rate incentives were also considered in designing the proposed rates. The factors of equity, economic efficiency, administrative feasibility, rate and revenue stability, and environmental protection were employed in choosing among the alternatives considered.

a. Cost Recovery - Demand vs. Energy

The final EIS considered the effect of variations in the proportion of Bonneville's costs recovered from demand and/or energy components of the rate structure. The alternatives analyzed included recovery of all costs through (1) a demand charge only, (2) an energy charge only, and (3) demand and energy charges. The use of the first two alternatives is environmentally unacceptable. A rate structure recovering all costs from demand revenues would discourage energy conservation and promote the need for environmentally costly thermal plant development. The recovery of all costs from energy charges could encourage the growth of peak demand which could create greater reliance on the hydro peaking capability of the Federal Columbia River Power System (FCRPS) with consequent strain on the biological systems affected by river fluctuations. The utilization of demand and energy charges would result in the most environmentally acceptable alternative in terms of socioeconomic and physical impacts.

As stated above, of all revenue levels considered, marginal cost pricing has the least physical environmental impact and the greatest socioeconomic impact associated with it. The preferred alternative is to reflect the beneficial aspect of marginal cost pricing in the rate schedules while minimizing its adverse socioeconomic impact. Therefore, the rates which I am proposing are based on an average cost distribution of the revenue burden between capacity and energy modified somewhat to reflect the relationship which exists between the marginal costs of energy and capacity.

b. Time-Differentiation of Rates

Alternative approaches considered by Bonneville regarding time-differentiation of rates included rate differentials reflecting average cost, marginal cost, and constrained marginal cost. Also considered was the option of excluding time-differentiation from the rate structure.

Time-differentiation of rates would enhance environmental quality by reducing the peak demand required to be met by hydroelectric facilities on the Columbia River. Again, in view of the adverse socioeconomic impacts associated with unconstrained marginal cost pricing, constrained marginal cost or an average cost time-differentiated rate structure would be the most environmentally preferable.

For schedules EC-8, IF-2 and MF-2 the proposed peak period rates are based on the results of the time-differentiated pricing analysis whereas the secondary peak and the offpeak capacity charges are founded on both the time-differentiated pricing analysis and the long-run incremental cost analysis.

c. Industrial Availability Credits

In analyzing the impact of granting an availability credit to industrial customers several levels of credit were considered. Bonneville could maintain the credit at its current level of $21 million, increase it to $32 million based on Bonneville's estimate of the cost of replacing capacity restrictions in combination with the cost of purchasing energy in lieu of second quartile interruptions, increase it in proportion to the proposed general revenue increase ($40 million), or base it on the cost of developing alternative generation (estimated by the direct-service industries to be at least $200 million).

The $200 million alternative would significantly increase the cost of power to Bonneville's nonindustrial customers and would contribute significantly to the adverse socioeconomic impact of the proposed rates. The remaining alternatives would be environmentally preferable.

Bonneville's proposed rates include an availability credit based on an estimate of the cost of purchasing power outside the Federal system sufficient to maintain 100-percent availability to the lower three quartiles of the direct-service industrial load and the estimated cost of replacing capacity restrictions.

d. Share-the-Savings Concept

Alternatives considered in the pricing of nonfirm energy for thermal displacement ranged from charging the additional operating costs incurred in producing secondary energy (only a fraction of a mill per kilowatthour) to charging a price equal to the alternative cost of energy to the purchaser. Pricing energy toward the lower end of this range would encourage electricty consumption despite the likelihood of a decrease in the future availability of Northwest nonfirm energy. Alternatively, if nonfirm energy were priced at a level high enough to discourage its purchase, adverse environmental effects would result from the operation of alternative generation resources and from release of water over spillways at FCRPS dams. The environmentally preferable alternative would be to price nonfirm energy at a level which would insure its sale without excessively encouraging increases in the consumption of electrical energy by purchasers of nonfirm energy.

Bonneville's proposed nonfirm energy rate for direct thermal displacement amounts to half the decremental cost to the purchaser of the displaced resource with the provision that the rate may be lowered to 4.5 mills per kilowatthour during offpeak hours or 6.5 mills per kilowatthour during the peak period if, due to water or market conditions, the energy would otherwise be unsaleable. For pass-through sales to the Southwest the rate charged by Bonneville would be one-third of the price at which a Northwest utility sells the output of its thermal resource, thereby encouraging Northwest utilities to maintain operation of their thermal facilities allowing displacement of oil-fired generation in the Southwest. This is intended to prevent the adverse environmental consequences of operating oil-fired generation in lieu of Northwest baseload plants.

A share-the-savings rate concept was also used in the contract season and variable charge portions of the proposed firm capacity rate. Incorporation of the share-the-savings principle in these two rates does not result in significant environmental impacts.

e. Facilities Charge

Bonneville has considered two approaches to the recovery of costs associated with transformation of power from transmission to distribution voltages. A separate facilities charge based on service costs could make electrical service to small rural customers very expensive. Recovering facility costs through the demand charge would distribute these costs among all Bonneville customers. The latter alternative is environmentally preferable since it spreads the economic impact of transformation costs among all of Bonneville's customers rather than concentrating it on a limited number of customers who could be severely affected.

f. At-Site Discount

Bonneville considered both elimination and retention of its at-site discount and is proposing retention in modified form. Neither of these alternatives is judged to have a potential for environmental impact.

g. Baseline Power Rate

Bonneville's existing and proposed rates are based on a melded rate concept which makes no distinction between hydro and thermal power costs. A baseline rate which distinguishes between these costs was also analyzed. Two baseline approaches were considered. Under one approach a baseline rate would be designed to recover the average cost of power generated at all hydroelectric facilities comprising the Bonneville system. Under the second approach, a baseline rate would recover the costs of the least costly of Bonneville's resources required to serve the needs of a given group of "baseline customers."

The impact of an average cost baseline rate would currently differ little from that associated with melded rates. A lowest cost resource baseline rate might significantly reduce the impact of the proposed rate increase on limited groups of Bonneville's customers and could therefore be environmentally preferable to either a melded rate or an average cost hydro baseline rate. However, Bonneville chose to base its proposed rates on a melded rate concept in order to conform to statutory guidelines and historical precedent.

h. Special Irrigation Rate

Bonneville considered a special rate to irrigators to insure that the percentage increase in their power costs under the proposed rates would not exceed the average increase for all Bonneville's customers. Bonneville chose not to implement such a rate because the seasonal differentials in the proposed rates would benefit irrigators sufficiently to insure that increases in their costs during the irrigation season would not differ substantially from the annual increase in the power costs of other customers.

Neither of these alternatives is significantly more environmentally preferable than the other.

i. Rate Incentives for Conservation

Alternative rate design features relating to conservation of energy were considered in developing the proposed rates. Time-differentiated pricing may encourage increased efficiency in the use of power generating facilities. It may also serve to encourage the use of solar energy systems by offering power for recharging such systems at low offpeak rates. The use of seasonal differentials designed to reduce seasonal peak demand can be viewed as a conservation technique.

The above alternatives would be expected to promote environmental quality through limiting the need for the construction and operation of conventional electrical generating facilities. Bonneville's rates include both time-of-day and seasonal price differentials.

C. Avoidance of Impact

All practicable means to avoid or minimize environmental harm have been adopted in selecting the alternatives which make up Bonneville's rate proposal. The selection of the proposed 88-percent revenue alternative will insure that neither physical nor socioeconomic impacts will be extreme. Furthermore, Bonneville has sought to incorporate into the structure of its rates both diurnal and seasonal rate differentials which will further minimize the adverse effects of its proposed rate increase. In addition to being cost justified, the seasonal differentials in the demand and energy components of Bonneville's firm power rates will soften somewhat the impact of the proposed rate increase on irrigators by lessening the proportion of the revenue increase collected during that portion of the year when irrigation loads are at their peak. Furthermore, both the seasonal and diurnal rate differentials in the proposed rates should provide price signals to electricity users which would encourage more efficient use of electrical power, thereby limiting environmental impacts associated with power production. The emphasis on proportionally greater increases in energy costs relative to capacity costs as reflected in the proposed rates could slow the rate at which new thermal power facilities must be added to the regional power system to meet increasing energy requirements, thereby limiting impacts from the construction and operation of such facilities.

In addition to the features in its proposed rates which minimize the impact of the proposed rates, Bonneville is also engaged in program areas such as energy conservation and renewable resource assessments and promotions which will ultimately aid in mitigating the unavoidable adverse impacts associated with increases in the cost of electricity. Also, although not included in the current rate proposal, Bonneville has completed preliminary investigation of a baseline rate alternative which could ease the burden of increasing power rates for specific classes of customers. Further investigation of this alternative is planned for future rate adjustments.

D. Monitoring and Enforcement Programs

No monitoring or enforcement programs beyond those inherent in the processes of metering and billing customers are applicable for mitigation of the proposed action and none have been adopted.

IV. REPAYMENT STUDY

A. Allocation of Costs of Federal Multipurpose Dams

As indicated above, Bonneville is required to set its wholesale power rates so as to recover the cost to the Government of producing, purchasing, and transmitting electric energy.

Under the Bonneville Project Act, the FPC (and now FERC) is charged with allocating the costs of the Bonneville Project. Project authorizing legislation also makes the FPC (FERC) responsible for preparing cost allocations at the McNary project and the four projects on the Lower Snake River (Ice Harbor, Little Goose, Lower Monumental, and Lower Granite). Other project authorizations make the Secretary of the Army responsible for developing cost allocations for the Corps of Engineers projects other than those where this responsibility has been assigned to the FPC (FERC). The Secretary of the Interior is responsible for approving cost allocations for projects constructed by the Water and Power Resources Service, formerly the Bureau of Reclamation. Bonneville usually participates in the development of the cost allocations and reviews and comments upon proposed allocations.

The cost allocation methods used generally allocate the specific cost of each feature to the purpose it serves. For example, the cost of powerhouses, penstocks, and the like are allocated to power and the cost of navigation locks is allocated to navigation. The joint-use costs which remain unallocated after the specific costs have been allocated are generally divided among the various purposes served by various formulas which take into account the relative benefits produced by each function to assure that such allocations are made in an equitable manner.

With respect to the recovery of the cost of the transmission system, the Federal Columbia River Transmission Act recognizes that the transmission system is used both for transmitting Federal power marketed by Bonneville and for wheeling non-Federal power. The Act requires that the recovery of the cost of the transmission system be "equitably allocated between the Federal and non-Federal power utilizing such system." This is to be done by appropriately balancing the wheeling rates with the transmission cost component included in the power rates.

Other statutory provisions concerning the repayment of power costs and the establishment of power rate levels are found in the Reclamation Project Act of 1939; P.L. 89-448, approved June 14, 1966, which authorized construction of the Grand Coulee Third Powerplant; and P.L. 89-561, approved September 7, 1966, which amended P.L. 89-448 in certain respects.

B. Power Rate Level Objectives

Based on the foregoing statutory provisions Bonneville has a dual objective in establishing the level of its power rates; i.e., on the one hand rate levels must be set sufficiently high so as to produce revenues adequate to recover power costs (Section 7 of Bonneville Project Act), but at the same time set sufficiently low to provide the lowest possible rates to consumers (Section 5 of Flood Control Act of 1944). A further proviso, of course, is that this dual objective be accomplished "consistent with sound business principles" (Section 5 of Flood Control Act of 1944 and Section 9 of the Transmission System Act).

C. Administrative Development of Repayment Policy

The statutes, however, are not specific on many points. For instance, what is meant by a "reasonable period of years" is not specifically defined, nor are "sound business principles" described. Neither is there any general requirement for the payment of interest on the investment in power facilities financed with appropriated funds, although the authorizations of several individual power projects provide for the payment of interest. Consequently, the details of the repayment policy have had to be established through administrative interpretation of the basic statutory requirements.

Bonneville's repayment criteria were refined and spelled out in detail in the material submitted to the Secretary and the Federal Power Commission in support of Bonneville's rate increase in December 1965. The repayment policy was also presented to Congress in conjunction with its consideration of the authorization of the Grand Coulee Third Powerplant, and the repayment policy was incorporated into the legislative history of P.L. 89-448, which authorized construction of the Grand Coulee Third Powerplant in June 1966.

The Secretary of the Interior has developed general principles, subsequently set forth in the Department of the Interior Manual, Part 730, Chapter 1, to guide repayment.

"A. Hydroelectric power, although not a primary objective, will be proposed to the Congress and supported for inclusion in multiple-purpose Federal projects when . . . it is capable of repaying its share of the Federal investment, including operating and maintenance costs and interest, in accordance with the law.

"B. Electric power generated at Federal projects will be marketed at the lowest rates consistent with sound financial management. Rates for the sale of Federal electric power will be reviewed periodically to assure their sufficiency to repay operating and maintenance costs and the capital investment within 50 years with interest that more accurately reflects the cost of money."

To achieve a greater degree of uniformity in the application of the repayment policy by all of the Department of the Interior power marketing agencies, the Deputy Assistant Secretary for Water and Power Resources issued a memo on August 2, 1972, spelling out (1) a uniform definition of when the repayment period for projects commences; (2) how to include future replacement costs in repayment studies; and (3) providing that, to the extent possible, while still complying with the repayment period established for each increment of investment, the investment bearing the highest interest rate shall be amortized first.

A further clarification of the repayment policy was enunciated in a joint memo of January 7, 1974, from the Assistant Secretaries for Land and Water Resources and Energy and Minerals. This memo states that in addition to meeting the overall objective of repaying the capital investment within the prescribed repayment periods, revenues shall be adequate, except in unusual circumstances, to repay annually all costs for operation and maintenance, purchased power, and interest.

The most recent expression of the intent of Congress regarding Bonneville's obligation to recover costs is the Federal Columbia River Transmission System Act (approved in October 1974), which restates the rate and cost recovery language of the Bonneville Project Act of 1937 and the Flood Control Act of 1944 with the further proviso that rate levels be adequate to cover the interest and amortization on the bonds that Act authorizes Bonneville to sell to the Treasury.

On March 22, 1976, the Department of the Interior issued Chapter 4 of Part 730 of the Departmental Manual to codify financial reporting requirements for the Interior Department power marketing agencies. Included therein are standard policies and procedures for preparing power system repayment studies.

The DOE has adopted the policies set forth in Part 730 of the Department of the Interior Manual by issuing Interim Management Directive No. 1701 on September 28, 1977, which subsequently was replaced by Order Number RA 6120.2 on September 20, 1979.

D. Repayment Criteria

In brief, the repayment policy as currently in effect provides, based on all of the foregoing, that Bonneville's total revenues from all sources be sufficient to:

1. Pay all costs annually of operating and maintaining the Federal power system.

2. Pay the cost each fiscal year of obtaining power through purchase and exchange agreements.

3. Pay when due the interest and amortization on outstanding bonds sold to the Treasury.

4. Pay interest each year on the unamortized portion of the commercial power investment financed with appropriated funds at the interest rates established for each generating project and for each annual increment of such investment in the Bonneville transmission system.

5. Repay:

   (a) each dollar of the power investment in the Federal generating projects within 50 years after it becomes revenue producing (50 years has been deemed a "reasonable period" as intended by Congress)
   (b) each annual increment of transmission investment previously financed with appropriated funds within 35 years after it is placed in service (35 years is the approximate average service life of the transmission facilities, and hence a "reasonable period")
   (c) the investment in each replacement of a power-generating facility within its service life up to a maximum of 50 years.

   In accomplishing such repayment, the investment bearing the highest interest rate will be amortized first, to the extent possible, while still completing repayment of each increment of investment within its prescribed repayment period.

6. Repay the portion of construction costs at Federal reclamation projects which is beyond the repayment ability of the irrigators, and which is assigned for repayment from commercial power revenues, within the same overall period available to the irrigation water users for making their payments on construction costs. These repayment periods range from 40 years to 66 years with 60 years being applicable to most of the irrigation projects. Irrigation costs are repaid without interest. (P.L. 89-448 authorizes the payment of irrigation costs from revenues of the entire power system. This is the so-called "Basin Account" concept. P.L. 89-561, approved on September 7, 1966, amended P.L. 89-448 to provide several limitations on the repayment of irrigation costs from power revenues recited above.)

7. If revenues are not adequate to recover all amounts due in a given year, repayment of some costs must be deferred. The order in which the deferrals will be made is as follows:

   (a) Amortization of the irrigation repayment assistance is deferred until the last year of its repayment period in all cases,
   (b) Amortization of power investment financed with appropriated funds,
   (c) Interest on power investment financed with appropriated funds,
   (d) Hydroelectric generating project operation and maintenance costs.

If further deferrals were imminent, Bonneville probably would have to request appropriations to continue its operations.

The repayment criteria provide that if interest and/or O&M payments are deferred, the amount deferred must be capitalized and amortized with interest prior to the amortization of any other investment. Such deferrals are permitted by the DOE repayment policy only in unusual circumstances and for a short period of time.

E. Power System Repayment Study

The adequacy of revenues from existing power and wheeling rates to meet the repayment criteria is determined by preparing a power system repayment study. This study projects estimated revenues and costs over the remainder of the repayment period for the entire power system to determine whether there will be enough revenue to recover all costs.

In the repayment study, the estimated revenues are applied to cover each year's expense for (1) purchased power, (2) operation and maintenance, (3) interest, and (4) amortization of Bonneville's bonds. All remaining revenues are applied to the amortization of the power investment financed with appropriations and, in the years in which irrigation repayment assistance is due, to the amortization of the irrigation costs assigned for repayment from power revenues. The adequacy of the revenues to cover all of the repayment obligation is then determined by comparing the unamortized amount of each investment during each year of the study with what is called the "allowable unamortized investment."

The allowable unamortized investment for any given year is the maximum investment that can remain unamortized in that year if the repayment periods established for each power facility are observed; i.e., 50 years for each generating project, 35 years for the transmission system, and the service life for each replacement. Each year there is added to the allowable unamortized investment the amount of new power investment made that year. That same amount is also subtracted from the allowable unamortized investment at the end of its repayment period. The resulting total for each year thus represents the maximum amount of power investment that can remain unamortized while still complying with the established repayment periods.

The repayment study thus determines whether the repayment criteria are met by comparing the estimated future unamortized power investment with the allowable unamortized investment. If the unamortized investment exceeds the allowable amount for any investment for any year, this indicates that the repayment criteria are not being met and that an increase in revenues will be necessary to assure complete recovery of all power costs within the expected repayment periods.

F. Need for 88-Percent Revenue Increase

In compliance with the foregoing statutory requirement and Department of Energy policy, the Bonneville staff prepared a Current Repayment Study to test the adequacy of the revenues from the existing rates. That study demonstrated that the revenues from the existing rates are insufficient to fully recover all costs as required. (See Federal Columbia River Power System Repayment Study for proposed Power Rate Increase, Exhibit 2, Current Repayment Study)

The reason the present revenues are inadequate is that the present rates were established in 1974. Since that time there have been significant increases in the costs of operating and maintaining the Federal power projects and in constructing new projects and additions to the Bonneville transmission system. These cost increases have not been matched by revenue increases, which have been limited to increases resulting from an increase in the volume of sales.

Another significant change is that enactment of the Federal Columbia River Transmission System Act in October 1974 placed Bonneville on a self-financing basis under which it must finance the construction of new transmission facilities through the sale of bonds to the U. S. Treasury. Pursuant to the requirements of the Transmission System Act and the criteria established by the Treasury, Bonneville must pay a rate of interest on the bonds comparable to the current market rate for bonds of comparable quality sold in the money market. This has resulted in increased interest costs to Bonneville compared to the rates of interest previously paid the Treasury on appropriated funds. For example, the interest rate paid by Bonneville on the last appropriated funds enacted for FY 1975 is 6-1/8 percent, whereas the rate established by the Treasury on the most recent long-term bond sold by Bonneville is 9.9 percent.

There have also been substantial increases in the costs of the nuclear power plants of which Bonneville has acquired a share of the capability. These costs increases have been due to a combination of factors, including inflation, higher interest rates, changes in regulatory requirements, construction delays, labor disputes, etc. In addition, Bonneville must now include in its repayment study for the first time the costs for its acquisition of the capability of the WPPSS Nuclear Plant No. 1.

G. Repayment Issues

There were a number of issues raised in the comments submitted in response to Bonneville's preliminary and revised wholesale power rate increase proposals which dealt with how Bonneville had prepared the repayment study and interpreted the repayment criteria. The major issues raised and the disposition made of each are as follows:

1. WPPSS Costs. There were numerous objections to including the costs of the WPPSS plants in the repayment study as these plants will not be in service during the period from December 20, 1979, through June 30, 1981, during which the proposed rates will be in effect. From the standpoint of Bonneville's revenue requirements, however, Bonneville is obligated to pay its share of the costs of the WPPSS plants commencing as of fixed dates which either precede or fall within the rate period. These funds must be generated from Bonneville's revenues.

Bonneville supported a proposal that WPPSS be authorized to issue additional bonds to finance the costs to be paid by Bonneville (primarily interest and amortization on WPPSS construction bonds) until the plants are placed in service. This would have relieved Bonneville of the obligation to pay any further costs of the WPPSS plants during the rate period and would have resulted in a significantly reduced revenue requirement. (This was calculated at the time to be approximately a 40 percent increase.) However, the financing proposal, which had to have the approval of all 104 participants in the WPPSS plants, was not approved unanimously and could not be implemented. Bonneville did make an adjustment in the repayment study, however, which consisted of omitting the operating costs and the revenues of the WPPSS plants and including only the fixed costs for interest and amortization which Bonneville is committed to pay regardless of whether or not the plants are completed and operating. This action minimized the impact of the WPPSS costs on Bonneville's revenue requirements because the operating costs that were excluded exceeded the revenues that were excluded.

2. Future Federal Project Costs. The repayment study used as a basis for the preliminary rate proposal included the costs and revenues associated with all authorized Federal power projects, even though some of the authorized projects would not be completed and placed in service during the rate period. Objections were raised to this practice based on the concept that the rates should be based on only the costs of those power projects which will be in service during the rate period.

This issue was resolved by omitting the costs and revenues from the repayment study of all Federal projects which will not be in service during the rate period. It was determined based upon a legal opinion of the Bonneville General Counsel that, even though there is a statutory requirement (PL 89-448) for including all authorized projects in an annual financial report to the Congress, only those power projects that will be in service during the rate period need to be included in the repayment study for rate-setting purposes.

3. Repayment Study Surplus. The repayment study that was used as a basis for the preliminary rate proposal included surplus revenues from the standpoint of the repayment criteria. The proposed revenue level was sufficient to repay some of the investment in the Federal projects ahead of the time the investments had to be repaid in accordance with the repayment criteria. There were objections to the surplus revenue on the grounds that such a revenue level would be more than the minimum required to meet statutory requirements.

This issue was resolved by refining the repayment study to the point where any decrease in the proposed revenue level, such as to 87 percent, would result in some investment not being repaid within the required repayment period. This demonstrates that, as nearly as can be calculated, the proposed 88 percent increase is the minimum that will assure compliance with the repayment criteria.

4. Cost Escalation. It was pointed out in some comments that Bonneville did not escalate all costs in the repayment study uniformly with respect to the amount of escalation included in the estimates for future years. This issue was resolved in the final repayment study by uniformly escalating all cost estimates to the FY 1980 level, which is the approximate mid-point of the rate period, at escalation rates consistent with the President's price control policy.

5. Replacements. It was pointed out in some comments that the calculations of estimated replacements of power facilities expected to occur within the repayment period were not appropriate with respect to the assumptions used as to cost levels and the useful lives of the facilities subject to replacement. This issue was resolved by basing the calculation of replacements upon the estimated FY 1980 price level consistent with all other cost estimates and by basing the estimates of future transmission system replacements upon the most current estimates of the physical life expectancy of the various transmission facilities.

6. Current Cost Data and Interest Rates. The repayment study used as the basis for the preliminary rate proposal was based on cost estimates developed in 1977. It was pointed out in the comments that more current cost estimates should be used. This issue was resolved by developing new cost estimates based upon the latest information available at the time the studies were prepared and by using the most current interest rates.

7. Transmission System Repayment Period. The repayment study supporting the initial power rate proposal used a 35-year repayment period for the Bonneville transmission system. In revised repayment studies subsequently prepared, Bonneville

proposed to adopt a 50-year repayment period for the transmission facilities. Objection was raised to the 50-year repayment period by the Federal Energy Regulatory Commission staff based on the fact that Bonneville's depreciation study demonstrates that the average service life of the transmission facilities is approximately 35 years. This issue was resolved by reverting to the 35-year repayment period for the transmission system in the final repayment study.

8. Levelization of Revenue and Cost Estimates. The revenue and cost estimates utilized in the repayment study fluctuate over the repayment period in response to presumed changes in conditions. The staff of the Assistant Secretary for Resource Applications questioned whether the revenue and cost estimates should fluctuate over the entire repayment period or whether they should be levelized as of an appropriate time frame reflecting conditions during the proposed rate period. This issue was resolved by continuing the practice of estimating both costs and revenues to reflect changes in conditions over the repayment period which are believed likely to occur.

9. Peaking Capacity Limitations. The revenue estimate used in the repayment study supporting the preliminary rate proposal included revenues from the sale of a greater amount of peaking capacity than subsequent Bonneville studies indicated actually could be produced within the operating constraints of the power system. This issue was resolved by adjusting the revenue forecast to recognize the limitations on peaking capacity.

10. Power Purchases to Cover Shortages. Staff review of the repayment study supporting the preliminary rate proposal brought out that Bonneville does not have sufficient generation resources to meet all contractually committed load requirements up to June 30, 1983, at which time it is contemplated that all customers will be placed on power allocations. This issue was resolved by including in the repayment study estimated costs for additional power purchases that appear to be necessary during the rate period to assure sufficient resources to meet all firm power requirements.

11. Audit Findings. To better assure the accuracy of the repayment study, Bonneville retained the firm of Coopers & Lybrand to perform an independent review of the repayment study. The Bonneville internal audit staff participated in this review. The auditors found some errors and inconsistencies in the preliminary versions of the repayment study which were corrected in the final repayment study.

12. 10-15-Percent Reduction of Revenue Level. It was suggested that Bonneville reduce its required revenue level by 10-15 percent in order to more closely relate it to Bonneville's costs during the rate period as measured on a cost accounting basis, and thus reduce the amount that the ratepayers would be charged during the rate period for construction work in progress for the WPPSS projects. This proposal recognized that one of the effects of reducing the revenue level would be to reduce substantially the amount of revenues that Bonneville would have available during FY's 1980 and 1981 for application to amortization of the Federal investment in power facilities. The argument was made that the repayment policy does not require any specified amount of amortization in any year, and the deferral of amortization during the rate period could be made up through future rate adjustments after the WPPSS plants are in service.

The proposed 10-15 percent reduction was not adopted because, as previously stated, revenue requirements are based upon the repayment policy rather than financial results as measured on a cost accounting basis. Even if the cost accounting basis were used to establish revenue requirements, the payments to WPPSS in advance of completion of the WPPSS plants would have to be included in revenue requirements because Bonneville has to finance these payments from revenues. Bonneville does not have legal authority to borrow for this purpose.

In addition, amortization of the Federal investment is a statutory requirement. Section 7 of the Bonneville Project Act requires Bonneville to recover the cost of producing and transmitting electric energy including the amortization of the capital investment over a reasonable period of years. Similar provisions are found in Section 5 of the Flood Control Act of 1944 and Section 9 of the Federal Columbia River Transmission System Act. Adopting the position that an adequate provision for amortization would be provided in future rate proposals, but not in the current proposal, would not comply with these statutory directives or with Department of Energy policy that the repayment study demonstrate that all the Federal investment in power facilities will be amortized within a period not to exceed 50 years from the time each facility is placed in service, or the service life of each facility , whichever is less. Staff analysis has demonstrated that even a minute reduction in the proposed revenue level would cause the maximum repayment periods for amortizing the Federal investment in power facilities to be exceeded.

13. Theoretical Zero Inflation Interest Rate. It was suggested that a theoretical zero inflation interest rate be used in the repayment study for application to the investments in replacements estimated to be necessary over the repayment

period. It was argued that the repayment study is based on the assumption that there will be no inflation after FY 1980 because the cost estimates used in the repayment study were escalated only through FY 1980. Therefore, an interest rate with zero inflation should be used in the replacement analysis.

This suggestion was not adopted because it is inconsistent with Department of Energy policy on interest rates for use in repayment studies as set forth in Order Number RA 6120.2.

14. Determination of Fixed Costs of WPPSS Projects. It was suggested that the fixed costs of the WPPSS plants included in the repayment study should be calculated on the amount of bonds expected to be outstanding at the close of the rate period, rather than on the total construction costs expected on completion of the plants.

This comment was not adopted because BPA is committed by contracts to pay its full share of the costs of the WPPSS plants from the dates certain.

15. President's Guidelines on Wage and Price Stability. Another issue related to the repayment study concerns the magnitude of the rate increase that Bonneville has proposed. Bonneville has received comments stating that the rate increase would be in conflict to the President's guidelines on Wage and Price Stability.

Bonneville is obligated by statute to recover costs sufficient to meet repayment obligations. Bonneville has reviewed the relationship between the statutory obligations and the President's guidelines on Wage and Price Stability and has determined that the statutory provisions take precedence. This conclusion is based on a notice which appeared in the Federal Register on March 23, 1979, in which the council on Wage and Price Stability states that "while the price standard is intended to apply to all 'government enterprise,' any statute mandating a particular price policy will, of course, take precedence." Furthermore, by letter to the Secretary of Energy dated August 28, 1979, the acting Director of the Council on Wage and Price Stability wrote: "Because PMA's are subject to price setting requirements that were established by law, such statutory requirements take precedence over the voluntary price standard".

V. Cost of Service Analysis

The objective of the cost-of-service analysis was to determine the cost of serving each class of service. This study provided a starting point for development of rates and was one of several studies which were used to prepare the rate proposal. In addition, the cost-of-service analysis was designed to respond to the requirements in Section 10 of the Federal Columbia River Transmission Act that "the recovery of the cost of the Federal Transmission System shall be equitably allocated between Federal and non-Federal power utilizing such system."

In developing the analysis, Bonneville attempted to follow generally accepted procedures for this type of study as much as possible, though modifications were made to reflect the repayment method used by Federal power marketing agencies to determine revenue requirements. Test years were selected (fiscal years 1978-1981) and cost data were collected. Fiscal year 1980 was used as the basis for the proposed rates because it most closely matches the period during which the rates are to be effective.

A. Functionalization

The first step of the cost analysis was to identify investment costs and annual costs according to functions performed by the power system. In the case of the FCRPS, these functions were defined as generation, transmission, and metering and billing. All costs were assigned to one of these functions.

A major concern regarding the cost of service analysis involved the degree of segmentation or separation of transmission system costs. In the initial proposal, Bonneville chose the rolled-in method. With that approach, all transmission facilities were considered part of the integrated system except for the Pacific Northwest-Pacific Southwest Intertie facilities, some portions of facilities included in use-of-facilities wheeling arrangements, and leased facilities.

Although some comments received by Bonneville on the proposal indicated agreement with the separation of transmission costs into four segments, others indicated disagreement. Those who disagreed suggested that Bonneville expand the number of segments to allow clear identification of the costs incurred to provide service within each customer category or major service category. The concern was that Bonneville does not provide uniform service to all users and, therefore, should not allocate a portion of total costs to each user.

As a result of all comments received and statutory requirements which Bonneville must follow, transmission costs were separated into seven segments for the revised and final FCRPS Cost-of-Service Analyses. Segments include: (1) generation integration, (2) transmission system, (3) intertie, (4) fringe area, (5) preference customer delivery, (6) direct-service industrial delivery, and (7) investor-owned utility delivery. These segments were selected primarily to comply with the requirements of the Transmission System Act and to allocate equitably Federal system cost between Federal and non-Federal power. It should be noted that Bonneville did not propose wholesale power rate distinctions based on these cost distinctions.

The direct-service industrial customers (DSI) and Northwest Irrigation Utilities (NIU) felt that the segmentation in the revised proposal was inadequate and should be carried a step further. The DSI's suggested that the transmission system costs be further divided between the facilities located on the east and west side of the Cascade mountains. The NIU's suggested that the transmission system be segmented on a mileage basis.

No explicit proposals were presented as to how Bonneville could further segment the transmission system or how the costs associated with additional segmentation could be allocated among the classes of service. The merits of the proposal for further segmentation of the transmission system were difficult to analyze because the proposals were not specific. The Bonneville staff has not been able to devise a feasible and equitable means of segmentating transmission costs on a mileage or zone basis.

B. Classification

The costs functionalized to generation were then classified to the two subfunctions of generation capacity and energy production. Transmission costs were classified entirely to capacity. The classification of generation costs was based on the principle of cost causation. This method appropriately apportions generation costs between capacity and energy in relation to the causes underlying the construction and operation of various generating plants; i.e., the cost of facilities constructed to meet peaking capacity were classified entirely to capacity and the costs of facilities which provide both capacity and energy were apportioned between the two functions.

Comments on classification of costs between capacity and energy were directed at the appropriateness of the method Bonneville used. Some argued for use of a fixed-variable method which classifies fixed costs to capacity and variable costs to energy. Others suggested some modification to the Bonneville hydro and thermal classification methods. Another suggestion was that Bonneville use the National Association of Regulatory Utility Commissioners' (NARUC) method for classifying hydro costs.

Bonneville examined many different classification methods when preparing its cost-of-service analysis. Exhibit 2, Classification of Generation Costs, in the FCRPS Cost-of-Service Analysis details the other methods that were considered.

The traditional method of classifying costs in a cost-of-service study is to place all costs associated with investment in the capacity costs column and all costs associated with operating the plant in the energy costs column. This method is called the fixed-variable cost approach. In the short run, all the costs which do not vary as output varies are fixed costs and all costs which vary as output varies are variable costs. This approach might be appropriate for a system which is primarily thermal, or for systems with a large thermal base and hydro peaking. However, Bonneville rejected the fixed variable approach because it did not reflect the capacity and energy relationship which was developed during the planning of a total hydro system such as the Federal Columbia River Power System.

During the planning and development of the FCRPS, it has been acknowledged that this system produces both energy and capacity. During early development of the system, the projects were run of the river plants and produced significant amounts of energy. As the region has grown and the hydro sites have been developed, thermal generation is being constructed to produce significant amounts of base load energy, while peaking requirements are being met primarily with the construction of additional units at existing hydro projects. For Bonneville, new energy requirements are being met primarily from purchases of the output of thermal plants, although these plants also provide capacity.

Given how the Federal system costs have been and are being incurred, I concurred with the Bonneville staff conclusion that the traditional method of classifying fixed costs to capacity and variable costs to energy was not appropriate for the FCRPS. I reached this conclusion, even though the Federal Energy Regulatory Commission (FERC) has accepted the fixed-variable method as appropriate in a number of cases, and Bonneville direct service industrial customers have recommended its use for classification of thermal costs. The problem with the approach is that it considers classification of capacity and energy strictly from an operational standpoint and completely disregards a cost causation or planning approach.

Hydro projects provide both capacity and energy. FERC recognizes this when providing guidance for calculation of the benefits for project justification in the FPC P-35 Manual for the Corps and Bureau projects. In the benefit analysis for all FCRPS generating projects a capacity component and an energy component is included. A value is then applied to the capacity and energy components based on alternative costs of generation. It is inconsistent that when planning the construction of hydro projects it is recognized that there are costs and benefits associated with both energy and capacity, but after the project is constructed, costs associated with energy nearly disappear because the variable costs of hydro plants are near zero.

Bonneville also examined the method in the NARUC cost allocation manual for classifying hydro costs. An implicit assumption underlying this method is that average megawatts produced under critical water conditions represents the allocation for capacity while the difference in average megawatts between this output and output under median water conditions represent the allocation for energy. While the rationale for the method is not explained in the NARUC cost allocation manual, it appears average megawatts under critical water conditions represent dependable capacity and the difference between that figure and average megawatts under average water conditions represents energy. Bonneville hydro resource planning is based on the premise that sufficient resources must be available under critical water conditions to meet firm loads. Consequently, both capacity and energy requirements must be met from the resources which are available to meet those loads under critical water conditions. The method referenced in the NARUC cost allocation manual treats the cost of the megawatts which meet firm load requirements as capacity only and the cost of the remaining resource up to the output under average water conditions as energy only. I do not believe that the method described by NARUC is appropriate for the FCRPS.

The classification method which I approved for use in each proposal involves separating costs of hydro plants defined as baseload from costs of additional units. These additional units would not have been needed had capacity requirements not increased. These additional units produce no incremental energy under average water conditions. The fact that once the additional units are installed they may be operated before older units does not negate the fact that they were installed to meet capacity requirements.

It has been argued that the additional units should not be separated from the baseload units because their costs do not include the sunk costs of the original project. An adjustment in the costs of the additional units has been made to include a portion of the costs which are associated with the original project, but which were incurred in anticipation of including additional units in the project.

The method for classifying hydro costs defined as base units has been modified during the rate development process to incorporate the latest cost data, the energy-related operation and maintenance costs, an adjustment to reflect 10-hour peaking capacity rather than instantaneous peaking, and an adjustment in the hydro classification formula.

As a result of these modifications, 72-percent of the base system costs were classified to capacity and 28-percent were classified to energy.

An additional modification in the revised proposal was not included in the final proposal. An expected available portion of the DSI top quartile was added to the average megawatts under critical water conditions to maintain consistency with the method of allocating costs to the DSI service category. Several comments were received noting the inappropriateness of the adjustment because the formula is based on critical water conditions and the adjustment was based on average water conditions. Therefore, the modification was deleted from the final proposal.

Bonneville has proposed a thermal classification method which recognizes that the net-billed thermal plants from which Bonneville purchases power produce both capacity and energy, but that the primary reason for their construction was to provide baseload energy. While BPA recognizes that the plants provide capacity, the least costly alternative for meeting capacity requirements is not a baseload nuclear plant. In fact, additional units are being added at existing FCRPS hydro projects to provide capacity. Other utilities construct plants for capacity only, primarily combustion turbines, pumped-storage hydro plants, or combined cycle plants. Investment costs for these plants are considerably less than investment costs for coal or nuclear plants.

Bonneville has classified that portion of net-billed nuclear plant costs equal to the least expensive alternative cost of capacity to capacity. These are the costs of additional hydro peaking units at existing hydro plants. However, the cost of this capacity has been modified from the August 1978 proposal. Bonneville has completed additional studies and has developed an alternative cost of capacity for all the units which have been defined as peaking units at FCRPS projects including adjustments for sunk costs, with all costs at a 1980 price level. This differs from the August proposal where only a limited number of plants were used.

Inclusion of all the additional units with an adjustment for some of the sunk costs of the original projects, adjusted to a 1980 price level, is in response to comments received concerning the approach used by Bonneville to classify thermal costs. Inclusion of all units provides a better representation of Bonneville's alternative costs of capacity. Units are included which can provide capacity for 10 to 12-hours a day as well as the units which can be operated for fewer hours because of water limitations. As a result, the thermal credit reflects both short-term and intermediate capacity costs. Some commentors have suggested that the capacity credit be a combination of the cost of combustion turbines for short peaking requirements and the costs of pumped storage units for intermediate peaking requirements. This would be an alternative for some utilities in the Northwest and would produce reasonable results. However, the additional hydro units on the Federal system produce both short and intermediate peaking capacity and the costs of these units provide a more representative indication of the alternative cost of capacity for the FCRPS.

Another modification to the original method of classifying thermal costs concerns the choice of thermal project costs. The new thermal classification percentages are based on the costs in 1980 dollars of WPPSS Plants Nos. 1, 2, and 3. In the August proposal, the classification was based on a 1977 estimate of WPPSS Plants Nos. 1 and 2, and Trojan costs. This change reflects the most recent cost estimates and provides comparability between the hydro and thermal costs.

The difference between the average annual costs of the hydro capacity credit and the average annual thermal cost per kilowatt represents the energy component of the ratio, while the hydro capacity credit represents the capacity portion. This approach results in classification of 21-percent of thermal plants costs to capacity and 79-percent to energy. All fuel and variable operation and maintenance costs of thermal plants are classified to energy.

C. Allocation

The final major step in the cost-of-service analysis was to allocate the functionalized and classified costs to service classes. The service classes for the revised and final proposals include power rates, wheeling rates, other services, and miscellaneous services and revenues. The power rate category was further divided into subcategories. They are Firm Power, Reserve Power, Industrial Firm Power, Modified Firm Power, Firm Capacity, Firm Energy, and Nonfirm Energy. In the initial proposal, classes were based on the type of customer served. Federal Energy Regulatory Commission (FERC) staff and others recommended that these customer categories were inappropriate and that they should be based on service offered.

Costs classified to energy were allocated among the classes of service based on the kilowatthours of energy associated with each class. Three classes of service were allocated firm energy costs: Firm Power, Industrial Firm Power, and Firm Energy. The energy allocation amounts were obtained by totaling the number of kilowatthours sold or forecasted to be sold to the respective classes of service. Downstream benefits are also related to energy, but as explained later, energy costs for this class of service were identified via revenue credits.

The method adopted for allocating generation capacity costs and the costs associated with the seven segments of the transmission system was the average of the 12 monthly coincidental peak demands (12CP). Because the power system is designed to provide capacity to meet coincidental peak demands over the full course of the operating year, this method reflects the contribution of each customer class in relation to the need for total system capacity. When it was not feasible to develop allocation factors, costs were assigned using the revenue credit method. The amount of costs assigned was equal to the revenue derived from the existing charges. Less than 2-percent of the annual revenue requirements were assigned in this way.

The DSI's contend that the 12CP method is valid only when all customers have similar load characteristics and, therefore, high load factor customers like the DSI's are at a disadvantage under this method. In addition, DSI's advocate the use of the single noncoincidental peak (1NCP) to allocate transmission costs and the use of single coincidental peak (1CP) to allocate generation costs.

Bonneville, in selecting a method for allocation of demand costs which reflects system design factors, gave the greatest weight to the overall level of system loads, not the load characteristics of any particular customer class.

The relationship between the annual coincidental peak and the average of the 12 monthly coincidental peaks for those classes of service comprising the greatest portion of the total system load, namely Firm Power (EC-8) and Industrial Firm Power (IF-2), is not significantly different. Using the projected coincidental load data contained in Exhibit 3, Table 5 of the FCRPS Cost-of-Service Analysis, the 12 CP value calculated for the industrial firm class is approximately 92-percent of the annual class coincidental peak, while the comparable figure for the firm power class is 86-percent, or 85-percent excluding the load of generating public utilities. While it is clear that the DSI's are high load factor customers on the basis of average load (energy) compared to peak load, the DSI's and other customer classes are similar with respect to load characteristics that directly bear upon capacity cost allocation.

Use of allocation factors reflecting coincidence of loads is not as clearly justified for the transmission system as for the generation system. The reason for this is that the transmission system serves loads in widely divergent regions from resources in widely divergent areas. To the extent that any system deviates from a system serving a single point load from a single point resource, that system must be concerned more with serving noncoincidental peak loads and less with serving coincidental peak loads. However, use of allocation factors reflecting only noncoincidental loads implies either there is no coincidence to be reflected in the transmission peakloads or the flows in every line segment do not contribute to the loads in areas served directly by other segments.

Although the total network may be needed during the peakload hour, very substantial portions of the network are also needed during many other hours. For example, Bonneville provides firm capacity deliveries to California during 5 summer months under a long term contract. Allocation of network cost by the 1NCP method would result in allocation of no costs to this service. Because Bonneville absorbs the risk of not providing this service and must incur additional cost, if necessary, to reduce the risk to an acceptable level, some cost must be assigned to that service.

The transmission system was constructed at least in part to move large amounts of energy from resource to load. This argument is based on speculation that if capacity were needed for only 1-hour at the load center then combustion turbines would have been installed instead of constructing the Federal transmission (and generation) system. Because this transmission of energy is required all year, cost allocation factors should reflect an energy component. The 12CP allocation method does reflect energy components while the 1NCP does not.

Another issue which has been raised concerning Bonneville's use of the 12CP method is whether its use is consistent with Bonneville's seasonal rates. The 12CP method is not inconsistent with seasonal rates. Allocating costs by the 12CP method is based in part on the fact that the cost of supplying generation capacity for Bonneville is fairly uniform throughout the year. The time-differentiated pricing study based on embedded costs demonstrates this fact. It shows that there are not large capacity cost differences among periods. Nevertheless, relatively small differences in costs did appear and they are reflected in the proposed rates.

D. Results

The FCRPS Cost-of-Service Analysis shows that the total annual costs allocated to each class of service generally exceeded the revenues derived from the present rates and that the amount of the revenue deficiencies varied over a wide range. Exceptions include: (1) those services for which the revenue credit allocations method was used, in which case revenues equal allocated cost; (2) nonfirm energy sales to which no generation costs were allocated; (3) firm energy sales for which present revenue slightly exceeded the allocated revenue requirement; and (4) such services as reserve power and modified firm power for which no sales are anticipated. In addition, the analysis revealed that the percentage rate of the net repayment requirement for the different classes of power sales would vary somewhat under the new rates. This variation arises primarily from three factors: (1) contractually fixed rates stemming from the Canadian Treaty; (2) generation reserves provided by the curtailment of the industrial power deliveries; and (3) revenues in excess of costs resulting from the nonfirm energy sales and capacity sales rates which are based on a share-the-savings principle.

VI. TIME-DIFFERENTIATED PRICING ANALYSIS

As part of the process for development of proposed rates a separate study on time differentiation based on average cost was prepared. Time-differentiated pricing is a rate design concept which has evolved because demand for electricity varies over the day and over the year. To the extent that rates of electricity consumption over different time periods result in differences in cost, time-differentiated pricing deals with the problem by addressing these variations within the framework of a pricing structure.

Time-differentiated pricing is based on the concept of cost causation. In the short run, demand for power must be met from existing capacity, if it is available. In the long run, the variable nature of consumption over different time periods may require additional capacity to meet peak load demands. Because additional capacity and energy are required during peak periods, the cost of supplying that energy and capacity may be higher during peak periods.

Bonneville's Time-Differentiated Pricing Analysis is based on FY 1980 costs from the FCRPS Cost-of-Service Analysis. An attempt was made to incorporate the best available data and reasonable methods given Bonneville's physical, operational, and financial system. The general method for determining Bonneville's time-differentiated costs of capacity relies on a procedure developed by EBASCO Services, Inc., for the series of Electric Power Research Institute (EPRI) Rate Design Studies. However, Bonneville modified the approach significantly to reflect FCRPS conditions.

Bonneville employed a method for measuring energy cost differences that is different from that used for capacity. Reservoir storage costs formed the basis for the seasonal energy differential.

A. Costing/Pricing Periods

From an analysis of Bonneville loads for the FY 1975-1978, FCRPS generation data, and probability of negative margin data, Bonneville determined that the peak season should be defined as December through May, Monday through Saturday, 7 a.m. to 10 p.m. The secondary peak season should be June through November, Monday through Saturday, 7 a.m. to 10 p.m. The offpeak capacity hours should be all other hours of the year.

Many comments have been received regarding the time-differentiated elements of Bonneville's rate proposals. Some of the comments received were directed at the use of probability of negative margins (PONM) analysis to determine seasonal periods. Commentors said that the maintenance schedule is an integral part of the analysis and negative margins can be shown during high scheduled maintenance months even though capacity requirements are much less during these months than during other months of the pricing period. It was stated that monthly peakload generation data for firm capacity sales imply that October through March should be considered the peak capacity period.

Bonneville does not support the argument that monthly peak load generation data should be used for selecting the seasonal capacity periods. These data reflect only the demand side of the issue. Probability of negative margins reflect both the demand for and supply of capacity. That is, PONM's take into account both projected demand for capacity and the monthly availability of resources considering hydrological conditions, hydro and thermal capacity, and maintenance. Though the PONM's are influenced to a certain degree by maintenance schedules, but Bonneville believes that they are a preferable method for selecting seasonal capacity periods. The Pacific Northwest Coordination Agreement states: "The critical peaking period shall comprise those periods for which the probability of a load loss is greater than or equal to one hundredth of the highest probability of load loss in any period of the contract year." Utilizing the above definition of peaking period and the relevant PONM's, December through May was chosen as the peak period.

Comments have been received concerning the use of daily time-differentiation of capacity. Some customers and customer groups have argued that the proposed daily peak period is too long to allow effective shifting of loads to the offpeak period.

The selection of the diurnal periods in the initial proposal was based primarily on the analysis of total Federal generation and the assumption that the probabilities of negative margin (PONM's) were equal to zero for all hours with average ratios of hourly generation to daily peak generation at less than 90-percent. This resulted in the 15-hour period which begins at 7 a.m. and ends at 10 p.m.

Firm load data were available for the new study. An analysis of firm loads and probability of negative margin data indicated that 99.9-percent of PONM occurs for those hours during the day in which loads are 90-percent of daily peakloads or greater. Use of 90-percent criteria results in a 15-hour daily peak period, 7 a.m. to 10 p.m.

In the case of energy costs, characteristics of both thermal and hydro generation were considered. Thermal plants are regarded as baseload and are designed to operate throughout the year except for planned maintenance, refueling, and forced outages. The cost of providing energy from baseload thermal plants is the same for each hour of the year, regardless of operating characteristics, and therefore, was not time-differentiated. Costs associated with hydro generation were found to vary seasonally with respect to water storage to meet peak season energy requirements. This reason was identified in the initial proposal but was not adopted due to its relatively small impact on the energy rate. However, the differential was included in the revised and final proposals following receipt of comments from utilities with large irrigation loads and their customers suggesting that the differential should be included.

Data which show monthly energy production from storage under adverse flow conditions and the respective ratios of monthly energy production from storage to yearly total production were bases for determining seasonal energy periods. The two seasonal periods for hydro energy are April through August and September through March.

The Northwest Irrigation Utilities argued that in addition to hydro storage costs the following seasonal energy cost variations should be included: $26.0 million of availability credits, $4.6 million of thermal fuel costs, $20.0 million of outside energy purchases, and $20.0 million of Hanford energy purchases.

Bonneville examined the issue of time differentiaiton of energy costs and could not support the arguments that have been presented for inclusion of the above costs as a basis for a larger seasonal energy differential.

It was argued that the availability credit dollars should be collected from the winter energy rate. The average total availability credit has been increased to $32.3 million in the final proposal. Of this amount, $5.0 million is for capacity reserves provided by the DSI's. The remaining $27.3 million is the estimated cost of "firming-up" the DSI's second quartile energy load. The second quartile of the DSI's load can be restricted to offset the loss of power to the system due to delays in construction or inability to operate new generating projects. Restriction will occur to protect the system's ability to develop its firm energy capability over a 42 1/2 month critical period, the planning criterion for critical water conditions.

Actual compensation of the $27.3 million can be accomplished in a number of ways, but past practice and the concern for revenue stability constrained the choice to a form that was directly related to top quartile restrictions. That is, the amount of availability credit is based on second quartile restrictions and is only related to the top quartile because Bonneville has chosen to refund the money in that manner. Therefore, the cost to Bonneville of the availability credit is related more closely to the 42 1/2 month critical period than to any given season.

Another comment was directed at the application of thermal fuel costs to the winter period. Baseload thermal plants are designed to be operated throughout the year except for planned maintenance, refueling outages, and forced outages. These outages are dependent upon many factors including fuel life, equipment failure, demand for energy, and the availability of alternative resources, and thus may occur throughout the year. These resources have been added to the FCRPS to supply needed energy on an annual basis under critical water conditions, Bonneville's planning criteria. From a planning perspective, increases in demand for energy at any hour of the year require baseload thermal additions. Thus, the costs of providing energy from baseload thermal plants are the same for each hour of the year, regardless of operating characteristics.

The remaining comments were directed at the application of costs of Hanford purchases and outside energy purchases to the winter period. If Hanford energy is recalled and/or outside energy is purchased during a year, it is in order to protect the system's ability to develop its firm energy capability in future years given the planning criterion of critical water conditions. This is not a seasonal issue, but one that is related to the 42 1/2 month critical period.

The approach used by Bonneville in the Time-Differentiated Pricing Analysis did not time differentiate transmission costs which were classified entirely to capacity. Though most transmission investments have been directly related to winter peak loads, Bonneville recognizes that other factors influenced transmission investments. Further analysis of seasonal transmission cost characteristics is required to formulate a method that can appropriately time differentiate embedded transmission costs.

B. Assignment of Costs

Capacity costs for FY 1980 in the cost-of-service analysis were assigned to each period using an analysis of load duration curves of Federal firm loads for FY 1975-1978. Of the total revenue required, 37.8 percent was apportioned to the peak season, 26 percent to the secondary peak season, and 36.2 percent to the offpeak period.

Energy costs for FY 1980 were assigned to each energy period using analysis of projected energy load generation from reservoir storage. Unadjusted unit costs were then developed from energy costs and projected energy load in each costing/pricing period.

The final step in the analysis was the allocation of time-differentiated costs to service classes based on the allocation factors developed in the FCRPS Cost-of-Service Analysis.

VII. LONG-RUN INCREMENTAL COST OF SERVICE AND RATE STUDY

Bonneville's long-run incremental cost study (LRIC) is a cost-of-service analysis which focuses on the incremental cost incurred to meet load growth requirements or the cost saved by not consuming additional increments. This analysis differs from the average cost-of-service analysis whose primary function is to reflect the book cost which Bonneville is required to recover based on particular accounting practices. Since the foundation of LRIC Analysis is cost causation, an added dimension of time-differentiation of costs is included with the LRIC analysis.

The first step of the LRIC analysis consisted of determining how the system would react to changes in loads, and then collecting the necessary data to measure the corresponding effect on total cost in the resulting LRIC. This process involved analysis of expected additional demands upon Bonneville's system and plans for additional generation plant and transmission facilities to meet these demands.

The LRIC of generation is divided between capacity costs and energy costs. The LRIC of capacity was based on additional resources added to the system to meet peaking requirements. For the FCRPS, peaking requirements will be met by additions of peaking units and existing hydro plants (a total of 11 projects with 7,273 megawatts of generation capacity to be added through 1986). Annual investment costs, annual operation and maintenance expenses and annual replacement costs (all expressed in 1980 dollars) divided by the nameplate capacity adjusted for a reserve factor produces a dollars per kilowatt LRIC of capacity. The long-run incremental cost of capacity for Bonneville is $36.02 per kilowatt.

Firm energy development for the near term will consist primariy of coal and nuclear thermal plants. There are few suitable sites for further hydraulic development for production of energy and thermal plants are the most suitable alternative for serving constant loads. Thus, thermal plants are planned for the region's future baseload energy needs. Federal thermal power supplies are derived solely from power purchases under net billing agreements. Bonneville's LRIC of energy is based in part on Washington Public Power Supply System plants Nos. 1, 2, and 3. A capacity credit method similar to the method used for classification in the FCRPS Cost-of-Service Analysis was used to determine the thermal portion of the LRIC of energy. In addition, a portion of the cost of the Bonneville Dam second powerhouse is included in the LRIC of energy. The weighted average LRIC is 26.68 mills per kilowatthour.

Once generation costs were identified, costing/pricing periods reflecting common cost characteristics were established based on load data, operational characteristics, and probabilities of negative margin. Costing/pricing periods were established for capacity costs to reflect the differences in LRIC over the load cycle (seasonal and diurnal), given limitations on the number of periods for which rates can be set. The peak season is defined as December through May, Monday through Saturday, 7 a.m. to 10 p.m. All other hours are off-peak.

Capacity costs were then assigned to the costing/pricing periods according to the relative probability of negative margin of each period. Probability of negative margin data indicate that all costs should be assigned to the peak period.

Baseload thermal plants are designed to operate throughout the year except for planned maintenance, refueling and forced outages. When critical water conditions exist, increases in the demand for energy at any time require additional baseload thermal generation. Therefore, baseload thermal plant energy costs are the same throughout the year, and are not time-differentiated. Since there are no fuel costs associated with Bonneville second powerhouse, and variable costs are near zero, its costs do not vary by time period.

The LRIC of transmission is based on transmission investment through 1986 plus annual operation and maintenance expenses associated with new transmission facilities. The incremental annual transmission investment cost per kilowatt of added peak for the period 1978-1986 is $15.10. The annual transmission operation and maintenance expense is $7.16 per kilowatt. Since the primary consideration for design of transmission capacity is the winter peak season, transmission capacity costs were assigned on the same basis as generation capacity costs.

Through an analysis of appropriate allocation factors and billing determinants, illustrative LRIC rates were developed. The LRIC demand charge is $9.79 per kilowatt during the peak season and zero for all other hours. The energy rate is 26.68 mills per kilowatthour.

The results of the LRIC study demonstrate that the cost relationship between capacity and energy is changing as Bonneville begins to purchase the output of new thermal plants. By comparing the results of the FCRPS Cost-of-Service Analysis with those of the LRIC Study, this changing relationship becomes evident. These studies show that though all costs are increasing, the cost of supplying energy is increasing at a faster rate. Non-time-differentiated results from the LRIC study indicate a demand rate of $4.96 per kilowatt per month and an energy rate of 26.7 mills per kilowatthour. Unadjusted results from the FCRPS Cost-of-Service Analysis indicate a demand cost of $2.44 per kilowatt per month and an energy cost of 3.12 mills per kilowatthour. The ratio of the LRIC demand cost to the average demand cost is 2.0 to 1 while the ratio of LRIC energy cost to average energy cost is 8.6 to 1.

VIII. SUMMARY RATE DESIGN STUDY

The purpose of the Summary Rate Design Study is to combine the results of the Cost of Service Analysis, Time-Differentiated Pricing Analysis, and Bonneville Long-Run Incremental Cost and Rate Study to develop a set of final rate schedules. The study details each step followed in developing the rate proposal. Following is a list of the Rate Schedules that have been developed and included in the study.

(1) Wholesale Firm Power Rate Schedule, EC-8.

(2) Reserve Power Rate Schedule, EC-9.

(3) Wholesale Power Rate Schedules for Industrial Firm and Modified Firm Power, IF-2 and MF-2.

(4) Wholesale Firm Capacity Rate Schedule, F-7.

(5) Wholesale Emergency Capacity Rate Schedule, F-8.

(6) Wholesale Firm Energy Rate Schedule, J-2.

(7) Wholesale Nonfirm Energy Rate Schedule, H-6.

The process of electric utility ratemaking involves consideration of several rate design objectives. A Federal power marketing agency like Bonneville is non-profit and, as such, has different rate objectives than investor-owned or consumer-owned utilities. Bonneville is obligated to receive sufficient revenues to cover all its costs and is mandated to seek the lowest possible rates to consumers consistent with sound business principles.

The basic rate design objectives Bonneville has followed in designing its wholesale power rates include: (1) revenues must be adequate to meet its repayment obligation; (2) in meeting the revenue requirements, the burden should be distributed in an equitable manner among recipients of the service; (3) rates should be designed to encourage conservation and minimize environmental impact; and (4) rates should be designed to encourage efficient use of the Federal Columbia River Power System by reflecting costs incurred and benefits received. Additionally, consideration was given to rate continuity, ease of administration, revenue stability, and ease of understanding.

A. Adjustment of Cost Data

In developing individual schedules, Bonneville made several adjustments to the cost of service analysis results based on the findings of the other rate design studies and the rate design objectives which were adopted.

1. Fixed Contracts

Bonneville provides services to certain customers at rates which by contract cannot be changed. Because the costs, including those for repayment, allocated to these services in the FCRPS Cost-of-Service Analysis exceed the corresponding revenues, Bonneville could not meet its repayment obligation without adjusting the cost of other services. Therefore, Bonneville has proposed that the differences between allocated costs and expected revenues under the fixed contracts be functionalized, classified, and assigned to the classes of service for which rates can be changed.

By virtue of the ratification of the "Treaty between the United States of America and Canada Relating to the Cooperative Development of the Water Resources of the Columbia River Basin," Bonneville entered into certain obligations to generate capacity and to transmit capacity and energy. Contracts resulting from this treaty obligate Bonneville to generate Supplemental and Entitlement Capacity at a fixed rate and to transmit Supplemental Capacity and Columbia Storage Power Exchange (CSPE) power at a fixed rate. Although the rates are fixed, the amounts of power to which they apply gradually decline until April 1, 2003, at which time the contracts expire. The revenue deficiency associated with all CSPE transactions for FY 1980 is functionalized to generation and classified to both capacity and energy in the same manner as baseload hydro plants (see Table 3, Summary Rate Design Study, (SRDS)). The revenue deficiency is proportioned to the seasonal rate periods on a pro rata basis relative to the billing determinants in each period, and then allocated to class of service on the basis of the appropriate allocation factors (Table 4, SRDS). Ultimately this process results in allocating a portion of the Canadian Treaty revenue deficiencies to virtually all capacity and energy sales customers. Bonneville has developed these functionalization and classification procedures because the Canadian Treaty results in an increase in the firm capacity and energy capability of the Federal System and because all power sales customers receive benefits from this increased capability. Transmission customers do not receive any direct benefits from the Canadian Treaty and, therefore, are not allocated a share of the deficiency.

2. Capacity/Energy Exchange

The capacity/energy exchange contracts obligate Bonneville to provide a service for which there is not always a direct payment. Instead, the contracting party provides a reciprocal service. In these contracts, Bonneville is obligated to generate capacity when requested by a contracting customer and that customer is obligated to return the energy delivered as capacity and to deliver extra energy as payment for the capacity. When Bonneville does not require the return of the energy (for example, when energy is available because of good water conditions), a contracting customer is allowed to meet its obligation by paying cash at the secondary energy sales rate. In an average water year, as is used in the FCRPS Cost-of-Service Analysis, a portion of the contracting customer's obligation is required to be returned while the remaining portion must be paid for at the secondary energy sales rate. Because the firm energy resources provided by the capacity/energy exchange contracts benefit energy sales customers, it is appropriate to classify those capacity costs which were incurred to realize energy benefits as energy-related expenses (Table 3, SRDS). In this manner the revenues from virtually all energy sales are affected. The expenses classified to energy in Table 3 (SRDS) were apportioned between the winter and summer periods and then allocated to the classes of service on the basis of the energy allocation factors (Table 4, SRDS).

3. Availability Credit

The IF-2 rate schedule for firm power sales to direct-service industrial customers (DSIs) contains an availability credit designed to compensate these customers for power delivery restrictions. The expected average annual cost to Bonneville for granting availability credits is approximately $32.3 million. This amount is the sum of: (1) the cost of replacing expected restrictions of second quartile energy deliveries; (2) the cost of expected top and second quartile capacity restrictions; and (3) an adjustment for power purchases which are already included in the repayment study.

The amount of availability credit associated with energy restrictions is recovered through the energy component of the rates and that associated with capacity restrictions is recovered through the capacity component of the rates. Table 5 (SRDS) shows the effect these adjustments have on the unit costs of energy and capacity for each service category.

4. Nonfirm Revenues

The revised wholesale power rate proposal contains a value of service or share-the-savings rate for sales of nonfirm energy (H-6 rate). In addition, the capacity rate (F-7) produces revenues in excess of costs. These two rate schedules produce revenues in excess of allocated costs of $106.165 million in FY 1980, (Table 6, SRDS).

In the cost-of-service analysis, a portion of the costs associated with the intertie have been allocated to nonfirm energy sales and seasonal firm capacity sales. Revenues derived from the H-6 and F-7 seasonal rates will recover the intertie costs allocated to them. Therefore, in determining excess revenues, the intertie costs have been subtracted from revenues received under these rates (Table 6, SRDS).

The $106.165 million of excess revenues was first applied as a credit to the total offpeak capacity costs of $73.544 million, adjusted for revenue deficiencies. The remaining $32.621 million was applied as a credit against summer capacity costs (Table 7, SRDS). The primary reason for applying the credits in this way was to reflect the incremental cost relationship between capacity and energy which was developed in the LRIC study. Additionally, elimination of the offpeak capacity charge will simplify the application of the demand charge during the billing process.

Nonfirm revenues were treated differently in the initial and revised proposals. The initial proposal contained a value of service or share-the-savings rate for sales of nonfirm energy which is consumed outside the Pacific Northwest. It was estimated that the rate would produce revenues in excess of costs that average $49.6 million annually. The revenues from this rate were applied as a credit against the offpeak demand costs of $59.5 million. The remaining cost of $9.9 million associated with the offpeak demand costs was transferred to the energy charge.

The adjustments made for the July 1979 proposal differ from the adjustments in the August 1978 proposal. The initial cost-of-service analysis allocated costs to nonfirm energy sales. In the revised and final cost-of-service analyses, only intertie costs were allocated to nonfirm energy. Further analysis indicated that Bonneville has not incurred any additional costs for the production of nonfirm energy. Therefore, all revenues from nonfirm hydro energy sales were credited to capacity costs, first to the offpeak period and then to the two seasonal peak periods.

Schedule F-7 contains an additional charge for capacity sales that exceed 6 hours per day. Development of this charge is also based on value of service principle. In developing the initial proposal, Bonneville assumed that no customer would purchase capacity for more than 6 hours. Further analysis indicated that sales will be made beyond 6 hours and revenues will exceed allocated costs. The excess revenues from this rate have also been credited to capacity costs. The contract season capacity charge is also based on value of service principle. The revenues in excess of costs from this rate have been credited to capacity.

Bonneville received many comments concerning the rate adjustments intended to reflect the results of the long-run incremental cost pricing study. In summary they are: (1) because nonfirm revenues are from energy sales, they should be credited to energy costs; (2) the appropriate price signals were produced in the FCRPS Cost-of-Service Analysis, and therefore, Bonneville should not try to amplify these signals; (3) because Bonneville chose to implement the results of its Time-Differentiated Pricing Analysis, offpeak capacity costs should not be altered; (4) the removal of offpeak capacity costs results in undervalued capacity.

One comment on the capacity rate adjustment in the revised July 1979 proposal differed from comments received on the August 1978 proposal. The Northwest Irrigation Utilities recommended that the credit should be applied first to offpeak capacity costs and next to secondary peak capacity costs to maintain price signal consistency.

All comments were considered in developing the revised rates. However, Bonneville believes that it was important to reflect the results of the LRIC study in the proposal. Bonneville agrees with the comment that revenues from Schedule H-6 are derived from sales of energy. However, use of nonfirm revenues to eliminate the offpeak demand charge and to adjust secondary peak capacity costs incorporates the proper price signal that future energy costs will increase at a much faster rate than future capacity costs. Furthermore, to the extent that the increase in the energy rate encourages conservation of energy, the environmental impacts associated with construction and operation of baseload thermal plants will be reduced.

Bonneville agrees with the comment submitted by the NIU's. Based on the LRIC study, all incremental capacity costs should be assigned to the period December through May, Monday through Saturday, 7 a.m. to 10 p.m. Therefore, Bonneville credited excess revenues first to offpeak capacity, and then credited the remaining excess revenues to secondary peak capacity to reflect more closely the LRIC study results.

5. Equalization of Demand

An adjustment was made to equalize the demand charge for purchases of wholesale firm power (EC-8), industrial firm power (IF-2), modified firm power (MF-2), and firm capacity (F-7). Table 8 (SRDS) summarizes the cost adjustment information for all cost components, including winter and summer capacity costs. The information shown in Table 8 indicates a slightly higher unit demand cost for direct-service industrial customers which is due in part to their constant load level and the use of the 12CP allocation factor in the FCRPS Cost-of-Service Analysis. However, as shown in Table 9 (SRDS), an adjustment was made to equalize the demand charge for all four rate schedules in an attempt to recognize the operational benefits the FCRPS derives from delivering energy during offpeak hours to high load factor industrial customers. These offpeak deliveries enable Bonneville to accept return energy during offpeak hours and also to purchase the output of baseload thermal plants which produce the same level of output during both peak and offpeak hours.

The rates which are shown in Table 9 (SRDS) (i.e., the peak season demand charge of $1.95 per kilowatt per month and the secondary season demand charge of $1.19 per kilowatt per month) appear in the wholesale firm power rate schedule (EC-8), the industrial firm power rate schedule (IF-2), and the modified firm power rate schedules (MF-2). In addition, the equalized demand charge forms the basis for the firm capacity, contract year service rate schedule (F-7).

6. Other Adjustments

Three other types of adjustments are included in one or more of the rate schedules. They include an adjustment for power factor, an adjustment for at-site service, and an additional charge for power transmitted over the Pacific Northwest-Pacific Southwest intertie.

The power factor adjustment is the same as that contained in the existing wholesale power rate schedules. An adjustment to the billing factors is included in the EC-8, EC-9, IF-2, MF-2, and J-2 rates for customers that have a 95 percent or lower power factor. It is widely accepted that a power factor correction should be made as close to the load as is practical to allow for the most efficient operation of the transmission system. Therefore, to encourage customers to install capacitors at their load points, Bonneville proposes that billing factors be increased by 1 percent each month for each 1 percent or major fraction thereof by which the average lagging or leading power factor at which energy is supplied during such month is less than 95 percent. This adjustment may be waived if Bonneville determines a power factor of less than 95 percent lagging or 95 percent leading would be beneficial to the Government. Detailed provisions of the power factor adjustment are contained in each of the rate schedules subject to this adjustment.

A rate adjustment for at-site power is included in the EC-8, IF-2, and MF-2 rate schedules for customers that presently purchase power under existing contracts at an at-site rate. The adjustment was derived from the rate which was in effect at the time contracts for at-site power were negotiated. At-site customers are entitled by contract to the adjustment. However, at-site customers do benefit from the transmission system from a reliability standpoint and, therefore, should pay some of the cost associated with the transmission system. The proposed at-site adjustment conforms to contract provisions, while recognizing that some transmission costs should be recovered from at-site customers. Based on results of the FCRPS Cost-of-Service Analysis for FY 1980, an adjustment equal to the total unit transmission cost would be approximately $1.07 per kilowatt per month (Table 1, SRDS). For at-site customers, the adjustment in each of the schedules is $0.257 per kilowatt per month, as provided in the contracts.

Bonneville received comments stating that the full amount of the transmission component of the demand charge should be applied as an adjustment to the rate. Bonneville no longer considers at-site delivery any significant benefit to the transmission system and does not plan on entering into additional agreements for at-site power. However, the existing at-site customers had to install or lease from Bonneville all facilities required to receive the at-site power. Therefore, Bonneville has concluded that these customers should continue to receive the credit contemplated by the contract provisions which is $0.257 per kilowatt per month.

Intertie costs have been allocated to F-7, seasonal capacity, and H-6, nonfirm energy, in the cost of service analysis. There are no separate intertie charges included in these rate schedules because sufficient revenues will be collected to recover intertie costs. No sales are forecast to be made under the F-8 emergency capacity rate schedule in 1980, and, therefore, no costs have been allocated to it. An additional charge for power transmitted over the PNW-PSW intertie is included in the F-8 rate schedule. The charge was calculated by dividing the projected FY 1980 intertie costs allocated to the F-7 seasonal capacity service by the F-7 seasonal billing determinant.

B. Wholesale Firm Power Rate Schedule, EC-8

The EC-8 rate schedule replaces the EC-6 rate schedule. The EC-6 schedule became effective December 20, 1974. It has been available for purchase of firm power for resale or for direct consumption by purchasers other than direct-service industrial customers. The demand and energy charges in EC-6 are time-differentiated on a seasonal basis. The winter period demand and energy charges are in effect from September 1 through March 31. The summer period demand and energy charges are in effect from April 1 through August 31. The EC-6 rate contains a transformation and other substation facilities charge, a power factor adjustment, and a demand charge adjustment for at-site customers.

The EC-8 schedule was derived according to the steps which are described in the preceding sections on time-differentiation and adjustments. The demand charge is time-differentiated on both a daily and seasonal basis. The peak season demand charge is in effect from December through May, Monday through Saturday, 7 a.m. to 10 p.m. The secondary season demand charge is in effect from June through November, Monday through Saturday, 7 a.m. to 10 p.m. There is no demand charge for deliveries during offpeak hours, which are all hours not included in the other two periods. There is a seasonal energy charge based on an analysis of the cost of seasonal hydro storage. The two energy seasonal periods are April through August and September through March.

The rate contains a power factor adjustment and a demand charge adjustment for at-site customers but does not include a transformation charge. The 1974 Wholesale Power Rate Schedules included for the first time a separate charge based on the voltage of the customer's point-of-delivery. This charge was initiated to recognize that some customers take power at higher voltages and require less transformation than others.

Bonneville has received comments for and against a separate charge for lower voltage delivery facilities. The arguments supporting continuation of the transformation charge can be divided into the following two general categories: (1) Continuity of rates; and (2) Incentive for customers to build their own delivery facilities. Similarly, the arguments objecting to the voltage-based transformation charge can be put into two categories: (1) Postage stamp rate concept should be maintained; and (2) Cost differences are not related to voltage only.

Bonneville has examined various rate forms as options to the existing transformaton charge. Although it may seem intuitively obvious that lower voltage delivery facilities must be more expensive than higher voltage delivery facilities, Bonneville found that there is very little correlation between higher costs and lower voltage. Location, size, reserve capacity, chronological date of initial service, and voltage all have some impact on costs. It is inequitable to isolate and develop a separate charge for only one of these cost indicators.

The proposed EC-8 schedule has two sets of billing factors: one for customers designated by Bonneville to purchase on a computed demand basis because operation of their resources can adversely impact the Federal System, and the other for customers that may or may not have resources available to them, but if they do have resources, such resources do not adversely impact the Federal System. In either case, Bonneville is obligated to provide power to meet the utilities' requirements or provide an amount to which the parties agree.

A utility that is designated to purchase on a computed demand basis has an ability and an obligation, due to the coordinated operation of resources by utilities in the Pacific Northwest, to produce an assured resource capability. This assured resource capability is determined based on critical water conditions. Bonneville is obligated to supply firm power to these customers equal to the amount by which each customer's firm load exceeds its assured resource capability (net requirements). The difference is the customer's "computed demand." Bonneville may deliver less than this limit when the customer generates in excess of the assured capability of its firm resources, e.g., during the waterflows in excess of critical waterflows. In these cases, the customer's power bill may be reduced. Alternatively, the customer has the option of selling its excess generation and relying on Bonneville to deliver the computed demand. The computed demand billing factors provide Bonneville with a means of assuring that the amount of firm power delivered to a customer does not exceed the customer's net requirements. Bonneville is thereby assured that the customer is using its own assured resources to meet its load and is selling its own excess resource capability, not Bonneville's.

A computed demand customer's "net requirement" may be different for capacity than for energy. Bonneville, therefore, defines peak computed demand (PCD) and energy computed demand (ECD) and determines the customer's rights to firm power monthly based on these two amounts.

In some cases, a computed demand customer may be billed on quantities involving 60 percent of the highest PCD or ECD determined for the customer during the prior 11 months. Bonneville proposes continuation of this ratchet in the rate schedule to help ensure that the costs of Federal facilities required to serve these fluctuating loads are recovered.

When a computed demand customer receives more Federal firm power than it is entitled to, under certain conditions the excess amount is called an unauthorized increase or overrun.

During the comment period on the August proposal, Bonneville received several comments on computed demand and the overrun penalty, all from computed demand customers. All felt that there should be specific criteria establishing the definition of a computed demand customer in the rate schedule. Several commented that the overrun penalty was inequitable. One customer stated that the overrun penalty should be eliminated. The basis for their criticism was that the overrun penalty impacts only the computed demand customers prior to the date Bonneville has announced it will have insufficient resources to meet projected firm load demands. Due to variations in load, a computed demand customer despite his best efforts might not be able to avoid an overrun. Some also indicated that the overrun penalty is not cost related. Two suggestions were made to aid in avoiding overruns: (1) allowing a margin of error on estimating peak loads; and (2) allowing more flexible load shaping.

A revised proposal was developed after comments on the August proposal were considered. The actual determination of whether or not a utility should be designated as a computed demand customer is not a rate matter. The determination is made by the Administrator based on an assessment of the effect of a utility's resource operations on the Federal system. Therefore, Bonneville has not included specific criteria for establishing the definition of a computed demand customer in the rate schedule. Most of the objections to the overrun penalty have been or are being dealt with through the computed demand customer contracts. Therefore, the computed demand section under "Billing Factors" and the unauthorized increase section of the proposed EC-8 wholesale firm power rate schedule are, in content, the same as the August proposal. The wording in the August proposal could have been interpreted to mean that a customer would be charged twice for an hourly overrun. As a result, the unauthorized increase sections in the revised and final proposals were reworded for clarification.

Bonneville's proposed wholesale power rate schedules presented in August 1978 did not include a rate design reflecting multi-tier rate or baseline rate concepts. Comments were received which suggested that a baseline concept should be investigated by Bonneville. The results were published as "Bonneville Issue Paper: Baseline Rates."

The study considered two baseline rate designs. The first reflected the difference between Bonneville's hydro and thermal generating costs. Hydro generation is, on the average, considerably less costly than thermal generation, and mechanically could be assigned on a priority basis to customers who were designated to receive a baseline amount. The generation cost component of the baseline rate would be determined on the basis of the average generation cost of all hydro generation facilities under Bonneville's marketing jurisdiction. The rate for all other sales would include a melding of both a hydro (assuming Bonneville's hydro resources exceed baseline requirements) and a thermal cost component.

The second baseline rate was derived by assigning the costs of the lowest-cost generation resources to a baseline rate. The amount of baseline power would determine the number of generation facilities required and, hence, the generation cost for baseline power. This method would guarantee the lowest cost-based baseline rate. As with the other baseline method, the generation cost component for non-baseline power would depend on the average generation cost of all facilities not designated as baseline resources.

Each design was tested by an econometric model for potential impacts upon load growth in the Pacific Northwest. Preliminary studies indicate that neither baseline rate design would have significant effects on regional power consumption.

In a legal opinion, Bonneville's General Counsel concluded that a two-tier hydro-thermal rate would be in violation of Bonneville's current statutory authority. The melded rate concept is supported throughout the legislative history associated with Bonneville. Congressional approval would be necessary to change from "melded" rates to a baseline approach. Consequently, Bonneville did not include a baseline rate design for the 1979 wholesale power rate filing. However, Bonneville will continue to research various means of reducing impact on consumers in the future. The baseline rate alternative was included in the Final Rate Environmental Impact Statement.

Two features of the initial EC-8 rate proposal were of special significance to irrigators. Since irrigation loads are substantially larger during the summer than during the winter, elimination of a seasonal energy rate as was proposed in August 1978 would have resulted in higher power costs for utilities serving large irrigation loads. Bonneville reexamined the issue of a seasonal energy rate in response to comments received on our initial proposal and concluded that justification does exist for a seasonal energy rate based on hydro storage costs. The revised proposal includes a seasonal energy rate. In addition the capacity charge is seasonally differentiated, with a higher rate during the winter period. This differential benefits customers with large irrigation loads.

Bonneville has proposed that energy charges be increased significantly more than capacity charges. This also has an important impact on utilities serving large irrigation loads. During the summer, irrigation loads are relatively high and uniform. Therefore, a larger portion of the total cost of serving irrigators is associated with energy charges (as opposed to capacity charges) than is the case for most other customers. This has created a proportionately greater impact on utilities with a large irrigation load than on other firm power customers. Although the final proposal does call for a larger percentage increase in energy charges than in capacity charges, the increase is not as great as that originally proposed in August 1978.

C. Reserve Power Rate Schedule, EC-9

The EC-9 rate schedule replaces the EC-7 rate schedule. The Reserve Power Rate schedule is designed for three different types of service: (1) firm power to meet unanticipated load growth of purchasers with fixed supply contracts; (2) power for which Bonneville determines no other rate schedule is applicable; and (3) power to serve a purchaser's firm power loads when Bonneville does not have a power sales contract in force with the purchaser.

This rate was developed from the LRIC study. The incremental costs of capacity, which are reflected in the rate, are based on the costs of new transmission facilities and hydroelectric peaking facilities at existing FCRPS generating plants. The incremental costs of energy are based on energy costs associated with the net-billed thermal plants and the Bonneville Dam Second Powerplant. The demand rate in this schedule is time differentiated to produce the same ratio that exists between the peak season and secondary season demand charges in EC-8. The capacity charge in EC-9 was not time differentiated in the initial proposal. It has been changed to be more consistent with other capacity charges in the EC-8, IF-2, and MF-2 rate schedules.

D. Wholesale Power Rate Schedules for Industrial Firm and Modified Firm IF-2 and MF-2

The IF-2 and MF-2 rate schedules are for sales of Federal power to Bonneville's direct-service industrial (DSI) customers. They replace schedules IF-1 and MF-1. The loads of these customers differ from typical utility loads in that they can be restricted by Bonneville for various reasons and in various amounts. This feature increases the reliability of service to other firm Federal customers' loads when the Federal system is unable to meet its firm power commitments due to insufficient generation or transmission capability.

The demand charges are time-differentiated on both a daily and a seasonal basis. The peak season demand charge is in effect from December through May, Monday through Saturday, 7 a.m. to 10 p.m. The secondary season demand charge is in effect from June through November, Monday through Saturday, 7 a.m. to 10 p.m. There is no demand charge for deliveries during offpeak hours, which include all hours not included in the other two periods. The energy charge is seasonally differentiated based on an analysis of the cost of seasonal hydro storage. The existing IF-1 and MF-1 rates are not time differentiated.

Bonneville is offering two power rate schedules to DSI customers to allow for billing differences associated with the two types of contracts available to these customers. All DSI customers are currently operating under interim contracts which can be terminated individually by either the customer or by Bonneville with 30-days notice. If the interim contracts are terminated, conditions for power sales revert to those specified under prior contracts. Because of the significant differences between the interim contracts and prior contracts in the quality of power provided to DSI customers, Bonneville is offering the IF-2 rate schedule, with its special provisions, for sales made under the interim contracts and the MF-2 rate schedule for sales made under the prior contracts. Although the IF-2 and MF-2 rate schedules share many common features, significant differences occur in the areas of availability, availability credits, and advance of energy.

An availability credit is included under the IF-2 rate schedule, but not under the MF-2 schedule, because of the difference in the quality of power available under the two rate schedules and associated contracts. Bonneville has less right to restrict load under the MF-2 rate schedule than under the IF-2 schedule. Under the IF-2 schedule, Bonneville can restrict up to one-quarter of the DSI customers' contract demand at any time for any reason. Second quartile restrictions can also be made for delays in completion of construction of hydroelectric and thermal plants. Restrictions also can be made in the event of forced outages and to maintain system stability. These restrictions allow Bonneville to refrain from developing the resources which would otherwise be required to provide unrestricted service to these customers, thereby avoiding the environmental impacts associated with construction and operation of additional power plants. Under the IF-2 schedule, Bonneville compensates industries whose loads are restricted.

The credit given under the current IF-1 rate was designed to bring about an average rate increase to the DSI customer group that would be comparable to the rate increases realized by other customer groups in the 1974 rate filing. The amount of the credit per kilowatt of demand received was in discreet steps corresponding to each 5-percent of restriction. The annual credit under the IF-1 rate schedule for years with average water conditions was calculated to be about $21 million.

The availability credit formula contained in the August 1978 proposal represented an increase in the IF-1 credit corresponding to the magnitude of the overall Bonneville rate increase, while maintaining the same basic form of the IF-1 availability credit function. However, in that proposal the IF-2 rate had a continuous rather than a discrete function, thereby avoiding some of the operational problems which occur because of the discontinuities in the current availability credit formula. The average annual credit which would have been given under the August 1978 proposal was $40 million, which is approximately 90 percent greater than the existing IF-1 annual credit.

The availability credit in the August 1978 proposal had two distinct linear segments designed to adjust for the expected 90-percent revenue increase and to eliminate the problems associated with application of the IF-1 credit. Minor variations in availability under the IF-1 rate schedule can significantly change industrial availability credits under certain conditions because the credit is applied in 5-percent steps.

Comments were received concerning both the average amount of availability credit that would be given under the August proposal and the manner in which the credit would be given.

The $40 million annual credit was criticized by the Public Power Council (PPC) as not being adequately documented. The PPC further suggested that a proper estimate would be the amount of revenues potentially available if the energy which is subject to restriction were instead sold in secondary markets. The industrial customers, on the other hand, suggested that availability credits should be greater than the $40 million, arguing that the cost of building incremental generation equal in size to the restriction rights provided for in the DSI's interim contracts is significantly greater than $40 million.

The design of the availability credit formula for application in the rate also attracted a number of comments from industrial customers. The August formula provided no credits for restrictions of less than 1-percent. The industrial customers commented that even restrictions less than 1-percent deserve compensation. Restrictions greater than 1-percent but less than 10-percent would result in increasing availability credits. Restrictions between 10 and 25-percent would also result in an increase in the credit but at a slower rate. The industrial customers have argued that the entire range of the credit should be linear. Total availability credits reached a maximum at 75-percent availability (a 25-percent restriction) in the August 1978 proposal and the industrial customers argued that this provided Bonneville with an incentive to restrict deliveries beyond this level because the cost to Bonneville would decline as restrictions increased.

The reason for the initial 1-percent limit on restrictions prior to the calculation of availability credits was to maintain consistency with other firm power sales contracts. Under those contracts, interruptions for standard maintenance or service equipment failures are allowed without granting availability credits to firm power customers. Since this did not represent a change in the quality of firm service provided others, it was felt that no adjustment should be allowed for similar restrictions to industries.

The revised proposal of July 1979 incorporated some of the comments and criticisms made regarding the August proposal. First, the magnitude of the expected average total availability credit was reduced from $40 million to $26 million. This revised amount of average credit to be given was based on the estimated cost of purchasing energy to replace expected second quartile energy restrictions. Second, the revised formula was linear throughout the entire range and the 1-percent limitation was removed. However, no availability credit will be given for outages due to scheduled maintenance or forced outages on either the purchaser's sytem or Bonneville's delivery facilities. The Summary Rate Design study of July 1979 shows details of development of the $26 million credit.

While it is true that total availability credit will decrease with each additional restriction beyond 25-percent, this will have no impact on Bonneville's decision to restrict. As indicated above, the amount of the total availability credit is based on the cost of capacity restrictions for the top and second quartiles and the replacement cost of energy due to second quartile energy restrictions. From an analysis based on average water conditions, the average annual replacement cost of these restrictions is expected to be $32.3 million. Although actual compensation for the restrictions could have been accomplished in a number of ways, past practice and the concern for revenue stability constrain the choice to a form that is directly related to top quartile restrictions.

Bonneville's contractual obligations limit its ability to restrict industrial load. In addition to other firm loads, Bonneville is obligated to serve the bottom three quartiles of industrial load. As set forth in the industrial firm contracts, Bonneville can restrict the top quartile of the DSI's contract demand at any time for nearly any reason. Restrictions beyond the top quartile can be made only for delays in construction or inability to operate new generating projects and in the event of forced outages in order to maintain system stability. Regardless of the economic incentive to restrict beyond the top quartile, Bonneville's contractual obligations require that the lower three quartiles of the industries loads be served if resources are available.

The DSI customers commented that the availability credit in the July proposal was inadequate because: (1) it did not recognize the value of capacity reserves, (2) it did not recognize the value of top quartile interruptible energy provided by the DSI's, and (3) it underestimated the cost of purchasing replacement energy. The DSI's commented again that the structure of the credit should be changed because it provides Bonneville with an incentive to restrict because the total availability credit decreases with additional restrictions in excess of 25 percent.

The availability credit for the revised proposal was determined by calculating the cost of replacing energy lost due to second quartile restrictons for each of the operating years 1980 through 1985 and then deriving an average annual cost over the 6-year period. The amount of second quartile restrictions expected in each of the years was determined by the size of the industrial loads, the amount of the firm energy available to meet industrial loads (plant delays reduce the amount of available energy), and the amount of available secondary energy and advance energy. The estimated cost of purchasing energy to replace second quartile restrictions was based on cost of existing resources and planned cogeneration resources.

Bonneville has reexamined the issue concerning the cost of replacement energy and agrees with the comment made by the DSI's concerning the cost of purchasing energy to "firm up" the second quartile. New cost data increases the expected average availability credit to $29.0 million.

Bonneville has also reevaluated the issue of capacity reserves and recognizes that restrictions of DSI load do provide capacity reserves. Therefore, some compensation for these capacity reserves is justifiable. Based on expected top quartile and second quartile capacity restrictions made during an average water year (1944), Bonneville estimated that the availability credit should include $4.9 million for top quartile capacity reserves and $0.1 million for second quartile capacity reserves.

Though capacity and energy costs are allocated to the DSI's based in part on the average availability of top quartile capacity and energy, these two classified costs should be viewed differently with respect to availability credits. Bonneville has incurred the obligation to provide sufficient capacity to meet the industrial loads whenever sufficient energy is available for this purpose. This obligation results in an additional cost to Bonneville. However, whenever Bonneville cannot meet all of its firm capacity loads, it has the contractual option of restricting DSI loads in lieu of restricting other firm loads. If such restrictions are made, the implication is that Bonneville has not acquired enough capacity resource (or transmission capability) and Bonneville's total costs are less than the amount necessary to provide reliable service. Based on these cost distinctions Bonneville believes that it is appropriate to consider such restrictions in determining availability credits. In contrast, Bonneville has not incurred the obligation to meet top quartile energy loads under all conditions (for example under low water flow conditions). The limited obligations contained in the IF and MF contracts reflect the historical development of Bonneville's obligation and ability to supply energy under various conditions. Bonneville has incurred some expense in facilities required to meet top quartile energy loads but only to the extent such energy is available. Given the limited expense and obligation involved, along with the fact that the DSIs only pay for the energy received, Bonneville does not believe that it is appropriate to consider top quartile energy restrictions in determining availability credits.

An additional proposed change in the determination of the annual availability credit reflects power purchases which, in part, are expected to increase the availability of industrial deliveries. This change is expected to reduce the credit by $1.7 million per year. Combining these adjustments, the magnitude of the expected average annual availability credit is $32.3 million, an increase from the $26.0 million in the July 1979 proposal. The Summary Rate Design Study of October 1979 shows details of the development of the $32.3 million credit.

E. Wholesale Nonfirm Energy Rate Schedule, H-6

This rate schedule is for sales of nonfirm energy. It has two basic components, a rate for thermal displacement and a rate for all other sales. The rate for sales other than for thermal displacement is based on the results of the cost-of-service analysis and is time-differentiated on a daily basis. The thermal displacement rate is flexible to allow Bonneville to react to market and water conditions which would permit maximum displacement of thermal resources both inside and outside the Pacific Northwest. The thermal displacement rate is based on both value-of-service (i.e., a share-the-savings concept) and cost-of-service considerations. This share-the-savings concept is meant to bridge the large gap between the value of the secondary energy and its actual costs and, therefore, distribute the substantial savings that accrue to secondary energy customers in an equitable manner among all of Bonneville's customers.

The H-6 rate schedule that I am submitting with the final proposal differs slightly in wording from the H-6 rate schedule included in the EIS. The words "firm" and "thermal" in Section 2.a. were inadvertently included in the rate schedules submitted in the EIS to describe the types of displaced energy purchases. These words have been eliminated from the final proposal. Bonneville's analysis of revenues from schedule H-6 and analysis of its environmental impacts in the EIS were based on a schedule that did not include conditions associated with firm thermal purchases of energy. Therefore, the environmental analysis in the EIS is consistent with the wording contained in the final proposal.

Numerous comments on the proposed H-6 rate have been received from California utilities, state regulatory commissions, and the Northwest investor-owned utilities. The comments can be grouped into the following categories: (1) the rate is a violation of the ratemaking principle and the Congressional intent that rates be based on cost; (2) it is without precedent; (3) it represents a violation of national energy policy because it will result in increased oil consumption; and (4) it is discriminatory.

1. Value of Service as a Basis for Pricing Nonfirm Energy

Value of energy to the purchaser as an upper limit is equal to the purchaser's costs saved (decremental cost) by not operating its highest cost generation resource. In the case of thermal resources, the cost can range from 5 to 6 mills per kilowatthour for nuclear plants to more than 50 mills per kilowatthour for some oil-fired plants. Operational costs which can be saved establish the upper limit for determining value of energy to the purchaser. For Bonneville, the cost of generating nonfirm energy is relatively low. The hydroelectric generation resources included in the Federal system were constructed predominately to serve firm loads and to provide peaking capacity. Availability of energy to meet firm loads is based on critical water conditions and not on average water conditions. Thus, nonfirm energy becomes available when flows are above the critical level and this energy is generated at the hydro facilities with little or no increase in costs. As a result, Bonneville has not allocated any generation costs to the nonfirm energy service category in its cost-of-service analysis. Because the cost of nonfirm energy is near zero, cost of service alone is not an appropriate basis for pricing the energy.

The share-the-savings rate concept is a pricing mechanism which attempts to reconcile the difference between the cost of energy to the seller and the value of energy to the purchaser, by establishing a price somewhere between the two.

The share-the-savings rate concept for Bonneville nonfirm sales has been in effect since the intertie between the Northwest and the Southwest became operational. At that time, oil-fired generation in California had a decremental cost of 3 to 4 mills per kilowatthour. The cost to generate nonfirm energy in the Northwest was less than 1 mill per kilowatthour. Bonneville's rate for nonfirm energy was 2.5 mills per kilowatthour between 1965 and 1974, except when the energy was surplus to the needs of the Northwest and sales could be made to California. When this occurred, the rate was reduced to 2.0 mills per kilowatthour in both regions which resulted in an approximate sharing between the Northwest and the Southwest of the benefits from displacement of oil-fired generation in California. In 1974, when new rates were developed, the nonfirm energy rate was increased to 3.0 mills per kilowatthour in the summer and 3.5 mills per kilowatthour in the winter. At that time oil costs in California had risen to about 15 mills per kilowatthour. As a result, the primary beneficiaries of the nonfirm energy rate were customers in California because they were able to purchase energy at a rate much below their alternative costs. Since 1974 the alternative cost of energy in California from oil-fired generation has risen to between 30 and 40 mills per kilowatthour, and is higher in some cases.

The statutes under which Bonneville operates do not specifically address a share-the-savings rate concept. However, the use of this rate is not precluded and in fact is implied.

Section 5 of the "Northwest Regional Preference Act" (16 U.S.C. 837d, PL 88-552 78 Stat. 756) with reference to sharing of benefits, states:

> "All benefits from such exchanges, including resulting increases in firm power shall be shared equitably by the areas involved, having regard to secondary energy and other contributions made by each."

That statutory charge should be read together with the language from Section 6 of the Bonneville Project Act:

> ". . . Rates may provide for uniform rates or <u>rates uniform throughout prescribed transmission areas</u> in order to extend the benefits of an integrated transmission system and encourage the equitable distribution of the electric energy developed at the Bonneville Project." (Emphasis added)

Section 10 of the Federal Columbia River Transmission System Act provides parallel requirements:

> "The said schedules of rates and charges for transmission, the schedules of rates and charges for the sale of electric power, or both such schedules, may provide, among other things, <u>for uniform rates or rates uniform throughout</u>

> <u>prescribed transmission areas</u>. The recovery of the cost of the Federal transmission system shall be equitably allocated between Federal and non-Federal power utilizing such system." (Emphasis added)

Bonneville interprets these to indicate legislative acceptance of rates designed for power sales within the Pacific Northwest and rates for power sales outside that region. The Senate and House Committee Reports on the Regional Preference Act and the Congressional Record remarks of individual Senators and Congressmen indicate rather clearly that in enacting the Regional Preference Act it was contemplated that there should be a continuing and mutual sharing of benefits between the Pacific Northwest and the Pacific Southwest in <u>all</u> power sales, not just exchanges of energy or capacity under Section 5 of the Act.

Furthermore, Bonneville disagrees with comments that the following cited language from Section 7 of the Bonneville Project Act requires Bonneville to base each rate on cost-of-service principles.

Section 7 provides:

> "Rate schedules shall be drawn having regard to the recovery (upon the basis of the application of such rate schedules to the capacity of the electric facilities of Bonneville project) of the cost of producing and transmitting such electric energy, including the amortization of the capital investment over a reasonable period of years. Rate schedules shall be based upon an allocation of costs made by the Federal Power Commission."

As is evident from a reading of the legislative history of the Bonneville Project Act, Congressional intent in enacting Section 7 was to recover the overall costs allocated to the power production function of the Federal multipurpose dams, plus transmission costs, rather than the intent that individual rates follow costs of providing each of the many services. The fact that Congress was also concerned with establishing programs for social welfare rather than strictly recovering costs of providing various services is well illustrated by the directive that power rates should subsidize agricultural irrigation. This subsidy for irrigation has also been statutorily mandated in the ratemaking provisions of the Transmission System Act. Thus Congress has established a policy of basing prices on considerations other than costs.

Finally, Bonneville has been encouraged by the General Accounting Office to adopt a share-the-saving concept for pricing nonfirm energy. In a letter from John P. Carroll, Regional Manager, U.S. General Accounting Office, to the Administrator, dated September 11, 1976, the question of an appropriate Bonneville nonfirm energy rate was addressed. The General Accounting Office report which accompanies the letter states that:

> "The current Bonneville rate for secondary energy may be inconsistent with sound business principles and with the concept of equitable sharing of benefits because it does not fully reflect the value of the energy it displaces."

2. Precedent for Share-the-Savings Principle for Ratemaking

Share-the-savings or split rates for sales of nonfirm energy are common among utilities throughout the United States. Power pools, investor-owned utilities, and other Federal power marketing administrations employ the share-the-savings rate concept for nonfirm energy sales.

There are many agreements in the United States which incorporate a share-the-savings principle. Three Federal power marketing administrations, Southeastern, Southwestern, and Western Area, all have such charges for the sale of surplus power. Their charges are all based on a percentage of the purchaser's fuel cost savings. These percentages range from 50 percent in the case of Southwestern to 85 percent for some of Western Area's sales. An opinion of the Assistant Solicitor for Power, Department of the Interior, dated May 20, 1976, concluded that an 85 percent share-the-savings rate for the Pick-Sloan Missouri Basin Program was legal because "The power marketing statutes do not require that the price for each category of service must be based on the cost of that service." Thus, share-the-savings rates did not originate with the Department of Energy but rather were a practice of the Department of Interior. Other agreements exist between utilities which establish a rate halfway between the seller's cost and the purchaser's alternative cost. Moreover, one of Bonneville's California customers, the City of Pasadena, contracted to purchase excess energy from Western at 85 percent of displaced fuel costs.

3. Final Proposal and National Energy Policy

The thermal displacement portion of the H-6 rate in the July 1979 proposal was subdivided into two categories, direct and indirect displacement of thermal resources. If the sale of nonfirm energy displaced a purchaser's thermal resource, the proposed rate was 5 mills per kilowatthour or 50 percent of the decremental cost of the displaced thermal resource, whichever was greater, up to a limit of 20 mills per kilowatthour. The upper limit of 20 mills per kilowatthour was based on 50 percent of the anticipated cost of energy from oil-fired generation during the rate period. If the purchaser were a Pacific Northwest utility and that utility did not displace a thermal resource but rather sold to another utility outside the Pacific Northwest as defined in Public Law 88-552, the rate would have been the lesser of (1) 20 mills per kilowatthour, or (2) 50 percent of the sum of the purchaser's rate for sales of nonfirm energy for use outside the Pacific Northwest which would have been generated from the purchaser's own thermal resource during the period that purchases of nonfirm energy were made from Bonneville , and the decremental cost of the purchaser's designated operating resource.

Bonneville has also intended to provide the operators of the Northwest thermal with an economic incentive to purchase nonfirm energy from Bonneville while continuing to operate their low-cost thermal, and thus displace relatively higher cost Southwest oil-fired thermal. Under the H-6 rate in the July 1979 proposal, there was an unintended disincentive for operators of Northwest thermal projects which had a decremental cost in excess of 10 mills per kilowatthour to cointinue to operate these plants and make sales to the Southwest. The sales price to the Southwest would have to be twice the decremental cost of the Northwest utility's operating thermal resource before the utility would export the output of the resource to the Southwest. The final proposal has been corrected to eliminate this problem. The final proposal provides operators of Northwest thermal plants with sufficient economic incentive to purchase nonfirm energy from Bonneville while continuing to operate their low-cost thermal plants and use the output from these resources to displace relatively higher cost Southwest oil-fired thermal.

The nonfirm rate schedule as proposed should provide long-term benefits for the country by encouraging the development of more capital intensive generation plants in the Northwest such as renewable resources, coal generation, and nuclear generation instead of resources, such as oil, with higher variable costs, for example, oil-fired generation. Conversely, low rates for nonfirm energy would encourage utilities in the Pacific Northwest to develop generation plants with low investment costs and high operating costs, such as combustion turbines. Such a plan is contrary to the national policy of encouraging generation that does not use oil as fuel. Nevertheless, the economic feasibility of combustion turbines are being examined by Bonneville and other Northwest utilities. Low rates for nonfirm energy could ultimately lead to greater consumption of oil in both the Northwest and Southwest due to increased oil-fired generation in the Northwest and decreased nonfirm energy sales to the Southwest.

Of a more immediate concern is the potential effect of low nonfirm rates on the operation of the Bonneville system. As more new high cost thermal resources are added in the Northwest, a rate for nonfirm energy which is less than the incremental cost of these thermal resources could provide an incentive to displace these plants rather than oil-fired generation in the Southwest. Additionally, such a low rate could provide an incentive to reevaluate operational and planning criteria to find means for more intensive use of nonfirm energy within the Northwest. The net effect would be a reduction of the availability of nonfirm energy for the displacement of oil-fired generation in the Southwest which would result in higher costs in the Southwest. This would be contrary to National energy policy which is to reduce oil consumption.

4. Equity Aspects of the Nonfirm Energy Rate

Bonneville has changed the proposed H-6 rate to eliminate any provisions or charges that may be viewed as unduly discriminatory. The initial proposal provided separate nonfirm energy rates for sales within the Pacific Northwest region and for sales outside the region. That format was abandoned in the revised proposal for language that was similar to the wording of the final proposal. The final proposal has two parts, one for thermal displacement and one for sales other than for thermal displacement. The thermal displacement rate has two parts; one for direct thermal displacement and the other for indirect thermal displacement. Except for indirect thermal displacement, both the thermal displacement rate and the rate for sales other than for thermal displacement apply equally for all nonfirm sales, both inside and outside the Pacific Northwest. The rate as proposed in July 1979 contained a provision that some viewed as discriminatory. The schedule included a charge for "sales other than thermal displacement" that applied only in the Northwest. Bonneville removed the reference to geographical location.

Bonneville has also received many adverse comments concerning the provision that allows flexibility in the rate:

> "Bonneville may determine that because of water and market conditions a rate of less than 50 percent of decremental cost . . ., but not less than the minimum rates, may be charged."

This provision has been included in the schedule to prevent a situation whereupon Bonneville would spill water because of a lack of a market based on a fixed rate in the schedule. To conform with National energy policy, Bonneville included this flexibility to guarantee that as much oil as possible is displaced. By the time this schedule is effective, Bonneville will have a stated policy assuring that all customers within a class are treated uniformly.

Another concern expressed by some is that the H-6 rate inherently discriminates against the Southwest, despite the fact that the rate is the same for both regions, because the decremental cost of resources is higher, on the average, in the Southwest than in the Northwest. Though it is true that there are more resources having high decremental costs in the Southwest, Bonneville's objective was to design a rate that would ultimately displace oil-fired generation. The fact that the Southwest has traditionally relied on oil-fired generation is beyond Bonneville's control.

The record demonstrates, and I find that California utilities on the average will not be paying more than 1 mill per kilowatthour in excess of Bonneville's average cost of power. The proposed nonfirm rate for direct thermal displacement is based on 50 percent of the decremental cost of the displaced resource limited to a floor of a 4.5 mills per kilowatthour during offpeak hours and 6.5 mills per kilowatthour during peak hours, and a ceiling of 20 mills per kilowatthour. A misconception has arisen as to what the average sales rate to California utilities for thermal displacement would be under this rate. Because the displaceable resources in California are high cost oil-fired thermal, with current decremental costs of about 30 mills per kilowatthour (with the expectation that they may rise to 40 mills per kilowatthour or higher during the period the rate will be in effect), many have assumed that the California utilities would be paying Bonneville, on the average, 15 to 20 mills per kilowatthour (50 percent of decremental cost) for nonfirm energy purchases. In developing an estimate of revenues from nonfirm sales, Bonneville has assumed an average sales rate of 8 mills per kilowatthour for all sales to California under this rate schedule. This estimate is based on the provision in the rate which permits negotiations of the rate downward to a level less than 50 percent of the decremental cost.

The rate that California utilities will be willing to pay Bonneville for nonfirm energy depends upon the availability of other nonfirm energy supplies from the Pacific Northwest (PNW) private utilities and the rate at which the energy is offered. Use of the intertie is determined on a priority basis between

Bonneville and PNW utilities based on the transactions they have negotiated for sales to the Pacific Southwest (PSW). Each PNW entity declares an amount of surplus available at a given price, and negotiates the sale with the PSW utility. As a result, if a PNW utility is willing to sell nonfirm energy to a PSW utility at a rate less than 50 percent of the decremental cost of the PSW utility's displaceable resource, then Bonneville will reduce the price for nonfirm energy in order to remain competitive. Whenever the supply of nonfirm energy in the PNW for export to the PSW is less than the intertie capacity, Bonneville probably would sell energy at the full rate (50 percent of the decremental cost). However, if there is a supply of nonfirm energy in the PNW more than sufficient to load the intertie, the rate at which Bonneville sells nonfirm energy to the PSW will be quickly driven down to the floor rate of 4.5 mills per kilowatthour during off-peak hours and 6.5 mills per kilowatthour during peak hours.

Determination of the 8 mills per kilowatthour average rate for nonfirm energy sold to the PSW is based on an analysis made by Bonneville for 1980. Bonneville has monthly estimates of secondary sales for 1980, based on 40 years of historical water flows. A month by month determination of sales was made for each of these water years. For any month that the available secondary energy was less than 90 percent of the available intertie capacity, a rate of 15 mills per kilowatthour (50 percent of the current decremental cost) was assumed. For any month that the supply of secondary energy was greater than 90 percent of the available intertie capacity, a rate of 5.2 mills per kilowatthour (1/3 at 6.5 mills/kWh, 2/3 at 4.5 mills/kWh) was assumed. The resulting weighted average rate for all sales that would be made for 40 historical water years was 8.6 mills per kilowatthour. Extrapolating the 40 historical water years to 99 water years using appropriate weighting factors yeilds an average sales rate of 8.0 mills per kilowatthour.

F. Wholesale Firm Capacity Rate Schedule, F-7

Bonneville's current F-6 capacity rate schedule is for the sale of peaking capacity. This schedule separately identifies rates for: (a) annual capacity (delivery of capacity throughout the year as requested by the customer) and (b) seasonal capacity (capacity delivered during five summertime months, principally to Pacific Southwest utilities).

The F-7 rate schedule replaces the F-6 rate schedule. The F-7 rate schedule applies to capacity sales to utilities on both a contract year and seasonal basis. Energy associated with the delivery of capacity is returned to Bonneville. The contract year rate is derived by accumulating the monthly demand charges for firm power (e.g., under the EC-8 rate) over 12 consecutive months. In contrast, the rate for contract season service (June 1 through October 31) is derived from an estimate of the value of service provided and an application of alternative cost principles. In this case, the estimated annual cost for a combustion turbine prorated over a 5-month contract season resulted in an estimated resource cost per kilowattseason. Bonneville's resource and transmission costs were computed on a per kilowatt basis (for 5 months). Application of value-of-service principles yielded a rate which was halfway between Bonneville's average cost and the purchaser's alternative cost. An additional charge per kilowattmonth was included for deliveries over the Pacific Northwest-Pacific Southwest intertie.

This rate provides a significant benefit to seasonal capacity customers because the alternative cost of this capacity would be incurred for the entire year and not just for the 5 months that Bonneville has used in calculating the rate. Moreover, the rate is established halfway between Bonneville's summer capacity cost of $5.95 per kilowatt and $13.50 per kilowatt based on the cost of a combustion turbine for 5 months.

To encourage capacity purchasers to limit their usage of Federal generating facilities and maximize use of their own facilities, the capacity rate includes an additional monthly charge for capacity usage in excess of 6 hours per day. The reason for this additional charge is that the Federal hydro peaking system cannot generate as much capacity during sustained daily periods (e.g., in excess of 6 consecutive hours) as it can for shorter periods (e.g., less than 6 hours). When the FCRPS generates capacity for extended periods, the ability of the FCRPS to meet firm commitments is reduced. Moreover, return of significant amounts of energy during offpeak hours at times forces the Federal System to sell the returned energy, thus reducing firm energy capability, or to spill water. The potential for environmental damage related to river fluctuation and nitrogen supersaturation may be reduced if capacity purchasers limit their usage of Federal generating facilities.

Development of this additional charge for sustained peaking was based on an alternative cost principle applied to an estimate of the fuel savings realized by the customer by not having to operate a peaking plant. Annual variable turbine costs in FY 1980 were first reduced to account for the low incremental operating cost resources not needed. The resulting net fuel cost (a savings) per kilowatthour was then reduced by one-half to arrive at a share-the-savings rate. Finally, application of this savings to 1-hour each day for 20 working days per month yielded a charge per kilowattmonth for each additional hour of capacity in excess of 6 hours. A complete explanation of the development of F-7 is in the Summary Rate Design Study.

The InterCompany Pool, the Oregon Public Utility Commission, and others expressed several objections to the proposed F-7 rate. The principal objections were that the cost of purchasing capacity in excess of 6 hours was greater for ICP members purchasing under the F-7 rate schedule than for capacity purchased by firm power customers under the EC-8 rate schedule and that F-7 unilaterally changes the nature of a commodity sold under a fixed contract.

The cost of capacity purchases in excess of 6 hours under the F-7 rate exceeds the cost under the EC-8 rate because the service provided is different. The F-7 rate provides a load-shaping service by allowing for the return of energy during offpeak hours. Raising the cost of this service by lowering the maximum number of hours that capacity purchases can be made without an additional charge does not constitute a unilateral change in the nature of the commodity sold, but rather reflects the fact that the sustained peaking capability of the Federal hydro system is reduced if the time period over which peaking capability must be maintained is increased. The proposed hours reflect that constraint. The additional monthly charge for capacity usage in excess of 6 hours per day is to encourage capacity purchasers to limit their usage of Federal generating facilities.

G. Wholesale Emergency Capacity Rate Schedule, F-8

The F-8 rate covers emergency capacity provided to utilities on a weekly basis when available and for the return of energy associated with the delivery of this capacity. Bonneville will provide short-term capacity sales only when an emergency condition exists as defined by Bonneville's General Contract Provisions (Section 24 "Uncontrollable Forces") and when Bonneville has capacity available. The F-7 contract year rate per kilowatt was divided by the number of weeks in a year and the resultant cost was increased by 15 percent to cover additional administrative and general costs. This results in a rate of $0.42 per kilowattweek for deliveries in the Pacific Northwest. Because costs associated with deliveries over the Pacific Northwest-Pacific Southwest intertie have not been allocated to this service category in the Cost-of-Service analysis, such deliveries are subject to an additional charge of $0.086 per kilowattweek. This was derived by dividing the intertie costs allocated in the COS study to F-7 seasonal capacity by the billing determinant for F-7 seasonal capacity.

H. Wholesale Firm Energy Rate Schedule, J-2

This rate is designed to serve contract purchasers of firm energy in the amounts and during the periods specified in the contracts. The rate is based on the EC-8 rates at 100 percent load factor.

Delivery of energy under this rate is assured during the contract period. However, Bonneville may interrupt the delivery of firm energy, in whole or in part, at any time that it is determined that Bonneville is unable to provide delivery because of system operating conditions.

IX. SUMMARY OF CONCLUSIONS

A. The proposed rates have been designed with a view to encouraging the widest possible diversified use of electric energy, consistent with other statutory requirements, by providing rates for a wide range of services.

B. The rate schedules provided for herein provide uniform rates within a particular customer class and type of service. The value of service based rates (H-6 and F-7) are computed in a uniform manner.

C. The proposed rate schedules will extend the benefits of Bonneville's integrated transmission system by providing a variety of services consistent with Bonneville's need for operating efficiency.

D. The proposed rate schedules encourage the equitable distribution of the electric energy developed at the Bonneville Project by equitably allocating the costs identified in Bonneville's repayment study, its cost of service analysis and its long run incremental cost study as modified by the needs of conservation, efficiency, equity, ease of administration, continuity and legal requirements identified in Bonneville's Summary Rate Design Study.

E. As demonstrated by the Final Repayment Study, the proposed rates recover the cost over a reasonable period of years of producing and transmitting electric energy and capacity, including amortization of the capital investment, interest on such investment, and all annual operating costs associated with the Federal Projects and acquired power, and is sufficient to repay when due, the principal, premiums, discounts, and expenses in connection with the issuance of and interest on all bonds issued and outstanding pursuant to the Federal Columbia River Transmission System Act, and to establish and maintain reserve and other funds connected with such bonds.

F. As demonstrated by the Current, Revised and Final Repayment studies, Bonneville needs a wholesale power rate increase to repay all of its obligations. The proposed rates, as demonstrated by those studies will, overall, provide the lowest possible rates to consumers, allowable by law, consistent with sound business principles.

G. The proposed rates, as demonstrated by the repayment study, will be sufficient to allow the Administrator to make payments to the credit of the reclamation funds required by law to be made, but will not provide for payment beyond the amounts required to be repaid from power revenues for such projects.

H. The proposed rates will provide sufficient revenue to repay the Federal investment in generation within 50 years following each unit's being placed into service.

I. The amortization of reclamation projects which Bonneville is required to repay from net revenues will not average more than $30,000,000 per year for any consecutive 20-year period and such reclamation projects have not been scheduled in a manner which would result in exceeding that 20-year average figure.

J. The recovery of the cost of the transmission system, as demonstrated by the segmented analysis of transmission costs contained in the cost of service analysis, is equitably allocated between Federal and non-Federal power utilizing Bonneville's transmission system.

K. The proposed rates for secondary energy have been established having regard for an equitable sharing of the benefits of such sales between the regions involved in such sales.

Based upon the foregoing, I hereby adopt as Bonneville Power Administration's final rate proposal the attached rate schedules EC-8, EC-9, IF-2, MF-2, H-6, F-7, F-8, and J-2.

Issued at Portland, Oregon this 27th day of November, 1979.

Sterling Munro

Sterling Munro
Administrator

Exhibit A

Proposed Rate Schedules and General Rate Schedule Provisions

A. SCHEDULE EC-8 - WHOLESALE FIRM POWER RATE

Section 1. Availability: This schedule is available for the purchase of firm power for resale or for direct consumption by purchasers other than direct-service industrial purchasers which purchase power under rate Schedules IF-2 or MF-2.

Section 2. Rate:

a. Demand Charge: (1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $1.95 per kilowatt of billing demand; (2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $1.19 per kilowatt of billing demand; and (3) all other hours: No demand charge.

b. Energy Charge: (1) for the billing months September through March: 4.13 mills per kilowatthour of billing energy; (2) for the billing months April through August: 3.76 mills per kilowatthour of billing energy.

Section 3. Billing Factors: The factors to be used in determining the billing for firm power purchased under this schedule are as follows:

a. For any purchaser not designated to purchase under subsection 3b or 3c: (1) the contract demand as specified in the contract; (2) the measured demand for the billing month adjusted for power factor; and (3) the measured energy for the billing month.

b. For any purchaser designated by Bonneville to purchase on a computed demand basis because of such purchaser's potential ability either to sell generation from its resources in such a manner as to increase Bonneville's obligation to deliver firm power to such purchaser in an amount in excess of Bonneville's obligation prior to such sale, or to redistribute the generation from its resources over time in such a manner as to cause losses of power or revenue on the Federal System; provided, however, that when a purchaser operates two or more separate systems, only those systems designated by Bonneville will be covered by this subsection:

(1) the peak computed demand for the billing month; (2) the average energy computed demand for the billing month; (3) 60 percent of the highest peak computed demand during the previous 11 billing months; (4) 60 percent of the highest average energy computed demand for the previous 11 billing months; (5) the measured demand for the billing month adjusted for power factor; (6) the measured energy for the billing month; and (7) the contract demand as specified in an agreement between a purchaser and Bonneville for a specified period of time.

c. For any purchaser contractually limited to an allocation of capacity and/or energy as determined by Bonneville pursuant to the terms of a purchaser's power sales contract: (1) the allocated demand for the billing month, as specified in the contract; (2) the measured demand for the billing month adjusted for power factor; (3) the allocated energy for the billing month, as specified in the contract; (4) the measured energy for the billing month.

Section 4. Determination of Billing Demand and Billing Energy:

a. For a purchaser governed by subsection 3a:

(1) The billing demand for the month shall be factor 3a(1) or 3a(2), as specified in the purchaser's power sales contract, except that at such time as Bonneville determines that the limitation in section 3c is necessary, the billing demand for the month shall be factor 3c(2), provided, however, that billing demand factor 3c(2), before adjustment for power factor, shall not exceed factor 3c(1).

(2) The billing energy for the month shall be factor 3a(3) except that at such time as Bonneville determines that the limitation in section 3c is necessary, the billing energy shall be factor 3c(4), provided, however, that factor 3c(4) shall not exceed factor 3c(3).

b. For a purchaser governed by subsection 3b:

(1) the billing demand for the month shall be the largest of factors 3b(3), 3b(4), and 3b(5), or 3b(7) if applicable. Factor 3b(5), before adjustment for power factor, shall not exceed the largest of factors 3b(1), 3b(2), or 3b(7) if applicable, except that at such time as Bonneville determines that the limitation in section 3c is necessary, the billing demand for the month shall be factor 3c(2), provided, however, that billing demand factor 3c(2), before adjustment for power factor, shall not exceed factor 3c(1).

(2) the billing energy for the month shall be factor 3b(6) except that at such time as Bonneville determines that the limitation in section 3c is necessary, the billing energy shall be factor 3c(4), provided, however, that factor 3c(4) shall not exceed factor 3c(3). Factor 3b(6) shall not exceed factor 3b(2) times the number of hours during such month.

Section 5. Adjustments:

a. Power Factor: The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the measured demand for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95 percent, such average power factor to be computed to the nearest whole percent from the formula given in section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by Bonneville. Unless specifically otherwise agreed, Bonneville may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

b. At-Site Power: At-site power purchased for consumption by a purchaser shall be used within 15 miles of the powerplant specified in the power sales contract. At least 90 percent of any at-site power purchased for resale shall be used within 15 miles of the specified powerplant.

The monthly demand charge for at-site firm power will be the monthly demand charge for firm power reduced by $0.257 per kilowatt of billing demand.

At-site firm power is made available only under existing contracts, providing for at-site firm power, at a Federal hydroelectric generating plant or at a point adjacent thereto, and at a voltage, all as designated by Bonneville. If deliveries are made from an interconnection with the Federal System other than at one of such designated points, the purchaser shall pay an amount adequate to cover the annual cost of the facilities which would have been required to deliver such power to such point from either the generator bus at the generating plant, or from the adjacent point as designated by Bonneville. This use of facilities charge shall be in addition to the charge determined by application of section 2 of the rate schedule as reduced by the provisions of this subsection.

Section 6. Unauthorized Increase: That portion of (a) any 60-minute clock-hour integrated demand or scheduled demand (the total amount of power scheduled to the purchaser from Bonneville) that cannot be assigned to a class of power which Bonneville delivers on such hour pursuant to contracts between Bonneville and the purchaser or to a type of power which the purchaser acquires from sources other than Bonneville which Bonneville delivers during such hour, or (b) the total of a purchaser's 60-minute clock-hour integrated or scheduled demands during a billing month which cannot be assigned to a class of power which Bonneville delivers during such month pursuant to contracts between Bonneville and the purchaser or to a type of power which the purchaser acquires from sources other than Bonneville which Bonneville delivers during such month, may be considered an 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 pursuant to (a) and the total of such amounts which are in fact considered unauthorized increases shall be excluded from the total of the integrated or scheduled demands for such month in determining the amount which may be considered an unauthorized increase under (b).

The charge for an unauthorized increase shall be $0.10 per kilowatthour.

Section 7. General Provisions: Sales of power under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, and to the applicable General Rate Schedule Provisions.

B. SCHEDULE EC-9 - RESERVE POWER RATE

Section 1. Availability: This schedule is available for the purchase of:

a. firm power to meet a purchaser's unanticipated load growth as provided in a purchaser's power sales contract.

b. power for which Bonneville determines no other rate schedule is applicable; or,

c. power to serve a purchaser's firm power loads in circumstances where Bonneville does not have a power sales contract in force with such purchaser, and Bonneville determines that this rate should be applicable.

Section 2. Rate:

a. Demand Charge: (1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $6.16 per kilowatt of billing demand; (2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $3.76 per kilowatt of billing demand; and (3) all other hours: no demand charge.

b. Energy Charge: 26.7 mills per kilowatthour of billing energy.

Section 3. Billing Factors: The factors to be used in determining the billing for power purchased under this schedule are as follows:

a. The contract demand as specified in the contract.

b. The measured demand.

c. The contract amount of energy for the month.

d. The measured energy for the month.

Section 4. Determination of Billing Demand and Billing Energy: The billing demand and billing energy shall be determined as provided in a purchaser's power sales contract. If Bonneville does not have a power sales contract in force with a purchaser, the billing demand and billing energy shall be the measured demand adjusted for power factor and measured energy.

Section 5. Unauthorized Increase: That portion of (a) any 60-minute clock-hour integrated demand or scheduled demand (the total amount of power scheduled to the purchaser from Bonneville) that cannot be assigned to a class of power which Bonneville delivers on such hour pursuant to contracts between Bonneville and the purchaser or to a type of power which the purchaser acquires from sources other than Bonneville which Bonneville delivers during such hour, or (b) the total of a purchaser's 60-minute clock-hour integrated or scheduled demands during a billing month which cannot be assigned to a class of power which Bonneville delivers during such month pursuant to contracts between Bonneville and the purchaser or to a type of power which the purchaser acquires from sources other than Bonneville which Bonneville delivers during such month, may be considered an 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 pursuant to (a) and the total of such amounts which are in fact considered unauthorized increases shall be excluded from the total of the integrated or scheduled demands for such month in determining the amount which may be considered an unauthorized increase under (b).

The charge for an unauthorized increase shall be $0.10 per kilowatthour.

Section 6. Power Factor Adjustment: The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the measured demand for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95 percent, such average power factor to be computed to the nearest whole percent from the formula given in section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by Bonneville. Unless specifically otherwise agreed, Bonneville may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

Section 7. General Provisions: Sales of power under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, and to the applicable General Rate Schedule Provisions.

C. SCHEDULE IF-2 - WHOLESALE POWER RATE FOR INDUSTRIAL FIRM POWER

Section 1. Availability: This schedule is available for the purchase of industrial firm power and/or authorized increase on a contract demand basis and for additional power requested by the purchaser and made available as authorized increase by Bonneville on an intermittent basis.

Section 2. Rate:

a. Demand Charge: (1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $1.95 per kilowatt of billing demand; (2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $1.19 per kilowatt of billing demand; and (3) all other hours: no demand charge.

b. Energy Charge: (1) for the billing months September through March: 4.13 mills per kilowatthour of billing energy; (2) for the billing months April through August: 3.76 mills per kilowatthour of billing energy.

Section 3. Billing Factors: The factors to be used in determining the billing for power purchased under this rate schedule are as follows: (a) contract demand, (b) curtailed demand, (c) restricted demand, and (d) measured energy.

Section 4. Determination of Billing Demand and Billing Energy: The billing demands for industrial firm power and authorized increase, respectively, and for additional power requested by the purchaser and made available by Bonneville as authorized increase on an intermittent basis will be the lowest of the respective contract demand, curtailed demand, or restricted demand after each such demand is adjusted for power factor. The billing energy associated with each of the respective billing demands will be the measured energy distributed porportionately among the respective demands for each hour each such demand is applicable during the billing month.

Section 5. Adjustments:

a. Availability Credit: If Bonneville restricts deliveries to the purchaser for any purpose other than scheduled maintenance or forced outages on either the purchaser's system or Bonneville's delivery facilities, then the purchaser will be entitled to an annual billing credit for such restriction. For periods beginning July 1 and ending June 30 (operating year), such credit will be the product of one-twelfth of the sum of the monthly billing demands and the value of the availability credit factor (determined from the appropriate formula below). An appropriate adjustment shall be made to the purchaser's December wholesale power bill based on calculated availability during the first six months of the operating year. A final adjustment, when appropriate, shall be made to the purchaser's June wholesale power bill for availability credits calculated on an annual basis, giving consideration for those credits granted on the purchaser's December wholesale power bill. For periods which do not correspond to an operating year, the sum of the monthly billing demands during the period will be divided by the number of months in the period and then multiplied by the appropriate availability credit factor calculated for such periods. An appropriate adjustment will be made at the earliest practical time. Availability credits will be separately determined for industrial firm power and authorized increases. Availability credits will not apply to additional power made available as authorized increase on an intermittent basis.

Annual Availability A		Formula for availability credit factor F
greater than	but less than or equal to	
.75	1.00	F = $56 (1-A)
.0	.75	F = $14.00

b. Power Factor: The adjustment for power factor, when specified in this rate schedule or power sales contract, may be made by increasing the appropriate demand (contract, curtailed, or restricted) for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95 percent, such average power factor to be computed to the nearest whole percent from the formula given in section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by Bonneville. Unless specifically otherwise agreed, Bonneville may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

c. At-Site Power: At-site industrial firm power shall be used within 15 miles of the powerplant.

The monthly demand charge for at-site industrial firm power will be the monthly demand charge for industrial firm power reduced by $0.257 per kilowatt of billing demand.

At-site industrial firm power is made available only under existing contracts, providing for at-site industrial firm power at a Federal hydroelectric generating plant or at a point adjacent thereto, and at a voltage, all as designated by Bonneville. If deliveries are made from an interconnection with the Federal System other than at one of such designated points, the purchaser shall pay an amount adequate to cover the annual cost of the facilities which would have been required to deliver such power to such point from either the generator bus at the generating plant, or from the adjacent point as designated by Bonneville. This use of facilities charge shall be in addition to the charge determined by application of section 2 of the rate schedule as reduced by the provisions of this subsection.

Section 6. Unauthorized Increase: Any amount by which any 60-minute clock-hour integrated demand exceeds the sum of the billing demand for such hour before adjustment for power factor, plus any applicable scheduled demands which the purchaser acquires through other contracts for such hour will be assessed a charge of $0.10 per kilowatthour.

Section 7. Special Conditions - Advance of Energy: Bonneville may elect to advance energy under terms and conditions of the purchaser's power sales contract.

Section 8. General Provisions: Sales of power under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, and to the applicable General Rate Schedule Provisions.

D. SCHEDULE MF-2 - WHOLESALE POWER RATE FOR MODIFIED FIRM POWER

Section 1. Availability: This schedule is available for the purchase of modified firm power on a contract demand basis for direct consumption by existing direct-service industrial customers until existing contracts terminate. This schedule is also available for the purchase of authorized increase power on a contract demand basis and for additional power requested by the purchaser and made available by Bonneville as authorized increase on an intermittent basis.

Section 2. Rate:

a. Demand Charge: (1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $1.95 per kilowatt of billing demand; (2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $1.19 per kilowatt of billing demand; and (3) all other hours: no demand charge.

b. Energy Charge: (1) for the billing months September through March: 4.13 mills per kilowatthour of billing energy; (2) for the billing months April through August: 3.76 mills per kilowatthour of billing energy.

Section 3. Billing Factors: The factors to be used in determining the billing for power purchased under this rate schedule are as follows: (a) contract demand, (b) curtailed demand, (c) restricted demand, and (d) measured energy.

Section 4. Determination of Billing Demand and Billing Energy: The billing demand for modified firm power and authorized increase, respectively, and for additional power requested by the purchaser and made available by Bonneville on an intermittent basis will be the lowest of the respective contract demand, curtailed demand, or restricted demand after each such demand is adjusted for power factor. The billing energy associated with each of the respective billing demands will be the measured energy distributed proportionately among the respective demands for each hour each such demand is applicable during the billing month.

Section 5. Adjustments:

a. Power Factor: The adjustment for power factor, when specified in this rate schedule or power sales contract, shall be made by increasing the appropriate demand (contract, curtailed, or restricted) for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95 percent, such average power factor to be computed to the nearest whole percent from the formula given in section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by Bonneville. Unless specifically otherwise agreed, Bonneville may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

b. At-Site Power: At-site modified firm power shall be used within 15 miles of the powerplant.

The monthly demand charge for at-site modified firm power will be the monthly demand charge for modified firm power reduced by $0.257 per kilowatt of billing demand.

At-site modified firm power will be made available under existing contracts, providing for at-site modified firm power at a Federal hydroelectric generating plant or at a point adjacent thereto, and at a voltage, all as designated by Bonneville. If deliveries are made from an interconnection with the Federal System other than at one of such designated points, the purchaser shall pay an amount adequate to cover the annual cost of the facilities which would have been required to deliver such power to such point from either the generator bus at the generating plant, or from the adjacent point as designated by Bonneville. This use of facilities charge shall be in addition to the charge determined by application of section 2 of the rate schedule as reduced by the provisions of this subsection.

Section 6. Unauthorized Increase: Any amounts by which any 60-minute clock-hour integrated demand exceeds the sum of the billing demand for such hour (before adjustment for power factor) plus any applicable scheduled demands which the purchaser acquires through other contracts for such hour will be assessed a charge of $0.10 per kilowatthour.

Section 7. General Provisions: Sales of power under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, and to the applicable General Rate Schedule Provisions.

E. SCHEDULE F-7 - WHOLESALE FIRM CAPACITY RATE

Section 1. Availability: This schedule is available for the purchase of firm capacity without energy on a contract demand basis for supply during a contract year of 12 months, or during a contract season of 5 months, June 1 through October 31.

Section 2. Rate:

a. Contract Year Service: $18.84 per kilowatt per year of contract demand. Interim bills will be rendered monthly at the rate of $1.57 per kilowatt of contract demand.

b. Contract Season Service: $9.73 per kilowatt per season of contract demand. Interim bills will be rendered monthly at the rate of $1.946 per kilowatt of contract demand.

c. The capacity rate specified in subsections a. and b. above shall be increased by $0.265 per kilowattmonth of billing demand for each hour that the purchaser's monthly demand duration exceeds 6 hours. The purchaser's demand duration for the month shall be determined by dividing the kilowatthours supplied under this rate schedule to a purchaser on the day of maximum kilowatthour use between the hours of 7 a.m. and 10 p.m., excluding Sundays, by the purchaser's contract demand effective for such month. If, however, Bonneville does not require the delivery of peaking replacement energy by the purchaser during certain periods, the additional charge above will not be made for such periods.

Section 3. Billing Factors: The billing demand will be the contract demand.

Section 4. Special Provision: Contracts for the purchase of firm capacity under this schedule will include provisions for replacement by the purchaser of energy accompanying the delivery of such capacity.

Section 5. General Provisions: Sales of power under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, and to the applicable General Rate Schedule Provisions.

SCHEDULE F-8 - EMERGENCY CAPACITY RATE

Section 1. Availability: This schedule is available for purchase of emergency capacity requested by a purchaser when Bonneville determines that an emergency condition exists on the purchaser's system and it has capacity available for such purpose.

Section 2. Rate: $0.42 per kilowatt of demand per calendar week or portion thereof. For deliveries over the Pacific Northwest-Pacific Southwest intertie, made available for the account of a purchaser at the Oregon-California or the Oregon-Nevada border, the charge will be increased by $0.086 per kilowatt. Bills will be rendered monthly.

Section 3. Billing Factors: The billing demand will be the maximum amount requested by the purchaser and made available by Bonneville during a calendar week, provided that if Bonneville is unable to meet subsequent requests by a purchaser for delivery at the demand previously established during such week, such billing demand for such week shall be the lower demand which Bonneville is able to supply.

Section 4. Special Provision: Energy delivered with such capacity shall be returned to Bonneville within 7 days of the date of delivery at times and rates of delivery agreed to by the purchaser and Bonneville prior to delivery. Bonneville may agree to accept delay of return energy beyond 7 days if it so agrees prior to the delivery of capacity.

F. SCHEDULE J-2 - WHOLESALE FIRM ENERGY RATE

Section 1. Availability: This schedule is available for contract purchase of firm energy, to be delivered for the uses, in the amounts, and during the period or periods specified in such contract.

Section 2. Rate: 6.1 mills per kilowatthour of billing energy.

Section 3. Billing Factors: The contract energy is the billing factor.

Section 4. Determination of Billing Energy: The billing energy shall be determined as provided in the purchaser's power sales contract.

Section 5. Delivery: Delivery of energy under this rate schedule is assured during the contract period. However, Bonneville may interrupt the delivery of firm energy hereunder, in whole or in part, at any time that Bonneville determines that Bonneville is unable because of system operating conditions, including lack of generation or transmission capacity, to effect such delivery.

Section 6. Power Factor Adjustment: The adjustment for power factor, when specified in this rate schedule or power sales contract, may be made by increasing the contract energy delivered for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95 percent, such average power factor to be computed to the nearest whole percent from the formula given in section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by Bonneville. Unless specifically otherwise agreed, Bonneville may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to the purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

Section 7. General Provisions: Sales of energy under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, and to the applicable General Rate Schedule Provisions.

G. SCHEDULE H-6 - WHOLESALE NONFIRM ENERGY RATE

Section 1. Availability: This schedule is available for the purchase of nonfirm energy both inside and outside the Pacific Northwest. This schedule is also available for energy delivered for emergency use under the conditions set forth in section 5.1 of the General Rate Schedule Provisions. This schedule is not available for the purchase of energy which Bonneville has a firm obligation to supply.

Section 2. Rate:

a. Thermal Displacement - This rate is for nonfirm energy sales to any purchaser for displacement of thermal generation. When Bonneville determines that nonfirm energy is available, such energy shall be offered to displace the thermal generation and purchases of energy, consistent with Public Law 88-552 and other applicable statutes.

(1) For all nonfirm energy sales for thermal displacement not subject to the provisions of a.(2) below the rate is 50 percent of either (a) the decremental cost in mills per kilowatthour of the displaced thermal resource or (b) the rate in mills per kilowatthour associated with the displaced purchase of energy. The maximum charge is 20 mills per kilowatthour. The minimum charge is 6.5 mills per kilowatthour during the period Monday through Saturday, 7:00 a.m. through 10:00 p.m.; and 4.5 mills per kilowatthour for all other hours of the year. Bonneville may determine that because of water and market conditions a rate of less than 50 percent of decremental cost or purchase rate, but not less than the minimum rates, may be charged. The purchaser will furnish Bonneville with either (a) the decremental cost in mills per kilowatthour of the purchaser's displaced thermal resource or (b) the rate in mills per kilowatthour associated with the displaced purchase of energy.

(2) For nonfirm energy sales to any Pacific Northwest utility during the period when that utility is either operating a displaceable thermal resource or is purchasing energy from a resource and is concurrently selling nonfirm energy outside the Pacific Northwest, as defined in Public Law 88-552, the rate is:

Thirty-three percent of the rate in mills per kilowatthour that the purchaser receives for concurrent nonfirm energy sales for use outside the Pacific Northwest. The maximum charge is 20 mills per kilowatthour. The minimum charge is 6.5 mills per kilowatthour during the period Monday through Saturday, 7:00 a.m. through 10:00 p.m.; and 4.5 mills per kilowatthour for all other hours of the year. The purchaser will furnish Bonneville with the amount and rate per kilowatthour for the purchaser's sale of nonfirm energy for use outside the Pacific Northwest for the period when nonfirm energy purchases are made from Bonneville.

b. Sales other than for Thermal Displacement - This rate is for all nonfirm energy sales which are not applicable to the provisions of a. above.

(1) 6.5 mills per kilowatthour during the period Monday through Saturday, 7:00 a.m. through 10:00 p.m.; and

(2) 4.5 mills per kilowatthour for all hours of the year not included in subsection b(1) above.

c. For contracts which refer to this schedule for determining the value of energy, the rate is 5.5 mills per kilowatthour.

Section 3. Delivery: Bonneville shall determine the availability of energy hereunder and the rate of delivery thereof.

Section 4. General Provisions: Sales of energy under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, and to the applicable General Rate Schedule Provisions.

H. GENERAL RATE SCHEDULE PROVISIONS

1.1 Firm Power: Firm power is electric power which Bonneville will make continuously available to a purchaser to meet its load requirements except when restricted because the operation of generation or transmission facilities used by Bonneville to serve such purchaser is suspended, interrupted, interfered with, curtailed, or restricted as the result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract. Such restriction of firm power shall not be made until industrial firm power has been restricted in accordance with section 1.4 and until modified firm power has been restricted in accordance with section 1.2.

1.2 Modified Firm Power: Modified firm power is electric power which Bonneville will make continuously available to a purchaser on a contract demand basis subject to: (a) the restriction applicable to firm power, and (b) the following:

When a restriction is made necessary because the operation of generation or transmission facilities used by Bonneville to serve such purchaser and one or more firm power purchasers is suspended, interrupted, interfered with, curtailed, or restricted as a result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract, Bonneville shall restrict such purchaser's contract demand for modified firm power to the extent necessary to prevent, if possible, or minimize restriction of any firm power, provided, however, that: (1) such restriction of modified firm power shall not exceed at any time 25 percent of the contract demand therefor, and (2) the accumulation of such restrictions of modified firm power during any calendar year, expressed in kilowatthours, shall not exceed 500 times the contract demand therefor. When possible, restrictions of modified firm power will be made ratably with restrictions of industrial firm power based on the proportion that the respective contract demands bear to one another. The extent of such restrictions shall be limited for modified firm power by this subsection and for industrial firm power by the Restriction of Deliveries Section of the General Contract Provisions of the contract.

1.3 Firm Capacity: Firm capacity is capacity which Bonneville assures will be available to a purchaser on a contract demand basis except when operation of generation or transmission facilities used by Bonneville to serve such purchaser is suspended, interrupted, interfered with, curtailed, or restricted as the result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract.

1.4 Industrial Firm Power: Industrial firm power is electric power which Bonneville will make continuously available to a purchaser on a contract demand basis subject to: (a) the restriction applicable to firm power, and (b) the following:

(1) The restrictions given in the Restriction of Deliveries Section of the General Contract Provisions of the contract.

(2) When a restriction is made necessary because of the operation of generation or transmission facilities used by Bonneville to serve such purchaser and one or more firm power purchasers is suspended, interrupted, interfered with, curtailed, or restricted as a result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract, Bonneville shall restrict such purchaser's contract demand for industrial firm power to the extent necessary to prevent, if possible, or minimize restriction of firm power. When possible, restrictions of industrial firm power will be made ratably with restrictions of modified firm power based on the proportion that the respective contract demands bear to one another. The extent of such restrictions shall be limited for modified firm power by section 1.2 (b) of these General Rate Schedule Provisions and for industrial firm power by the Restriction of Deliveries Section of the General Contract Provisions of the contract.

1.5 Authorized Increase: An authorized increase is an amount of electric power specified in the contract in excess of the contract demand for firm power, modified firm power, or industrial firm power that Bonneville may be able to make available to the purchaser upon its request. The purchaser shall make such request in writing stating the amount of increase requested, the purpose for which it will be used, and the period for which it is needed. Such request shall be made prior to the first calendar month beginning such specified period. Bonneville will then determine whether such increase can be made available, but it shall retain the right to restrict the delivery of such increase if it determines at any subsequent time that such increase will no longer be available.

The purchaser may curtail an authorized increase, in whole or in part, at the end of any billing month within the period such authorized increase is to be made available.

1.6 <u>Firm Energy</u>: Firm energy is energy which Bonneville assures will be available to a purchaser during the period or periods specified in the contract except during such hours as specified in the contract and when the operation of the Government's facilities used to serve the purchaser are suspended, interrupted, interfered with, curtailed, or restricted by the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract.

2.1 <u>Contract Demand</u>: The contract demand shall be the number of kilowatts that the purchaser agrees to purchase and Bonneville agrees to make available. Bonneville may agree to make deliveries at a rate in excess of the contract demand at the request of the purchaser (authorized increase), but shall not be obligated to continue such excess deliveries.

2.2 <u>Measured Demand</u>: Except where deliveries are scheduled as hereinafter provided, the measured demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands at which electric energy is delivered to a purchaser at each point of delivery during each time period specified in the applicable rate schedule during any billing period. Such largest 60-minute integrated demand shall be determined from measurements made as specified in the contract, or as determined in section 3.2 herein. Bonneville, in determining the measured demand, will exclude any abnormal 60-minute integrated demands due to or resulting from (a) emergencies or breakdowns on, or maintenance of, the Federal System facilities, and (b) emergencies on the purchaser's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by Bonneville. For those contracts to which Bonneville is a party and which 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 integrated demand assigned to any class of power shall be determined as specified in the contract. The portion of the total measured demand so assigned shall constitute the measured demand for each such class of power.

If the flow of electric energy to a purchaser's system through two or more points of delivery cannot be adequately controlled because such points are interconnected within the purchaser's system, or the purchaser's system is interconnected directly or indirectly with the Federal System, the purchaser's measured demand for each class of power for such system for any billing period shall be the largest of the hourly amounts of such class of power which are scheduled for delivery to the purchaser during each time period specified in the applicable rate schedule.

2.3 Peak Computed Demand and Energy Computed Demand: The purchaser's peak computed demand for each billing month shall be the largest amount during such month by which the purchaser's 60-minute system demand exceeds its assured peaking capability.

The purchaser's average energy computed demand for each billing month shall be the amount during such month by which the purchaser's actual system average load exceeds its assured average energy capability.

a. General Principles:

(1) The assured peaking and average energy capability of each of the purchaser's systems shall be determined and applied separately.

(2) As used in this section, "year" shall mean the 12-month period commencing July 1.

(3) The critical period is that period, determined for the purchaser's system under adverse streamflow conditions adjusted for current water uses, assured storage operation, and appropriate operating agreements, during which the purchaser would have the maximum requirement for peaking or energy after utilizing the firm capability of all resources available to its system in such a manner as to place the least requirement for capacity and energy on Bonneville.

(4) Critical water conditions are those conditions of streamflow based on historical records, adjusted for current water uses, assured storage operation, and appropriate operating agreements, for the year or years which would result in the minimum capability of the purchaser's firm resources during the critical period.

(5) Prior to the beginning of each year the purchaser shall determine the assured capability of each of the purchaser's systems in terms of peaking and average energy for each month of each year or years within the critical period. The firm capability of all resources available to the purchaser's system shall be utilized in such a manner as to place the least requirement for capacity and energy on Bonneville. Such assured capability shall be effective after review and approval by Bonneville.

(6) The purchasers's assured energy capability shall be determined by shaping its firm resources to its firm load in a manner which places a uniform requirement on Bonneville within each year of the critical period with such requirement increasing each year not in excess of the purchaser's annual load growth.

(7) As used herein, the capability of a firm resource shall include only that portion of the total capability of such resource which the purchaser can deliver on a firm basis to its load. The capabilities of all generating facilities which are claimed as part of the purchaser's assured capability shall be determined by test or other substantiating data acceptable to Bonneville. Bonneville may require verification of the capabilities of any or all of the purchaser's generating facilities. Such verification will not be required more often than once each year for operating plants, or more often than once each third year for thermal plants in cold standby status, if Bonneville determines that adequate annual preventive maintenance is performed and the plant is capable of operating at its claimed capability.

(8) In determining assured capability, the aggregate capability of the purchaser's firm resources shall be appropriately reduced to provide adequate reserves.

b. Determination of Assured Capability: The purchaser's assured peaking and energy capabilities shall be the respective sums of the capabilities of its hydroelectric generating plants based on the most critical water conditions on the purchaser's system, the capabilities of its thermal generating plants based on the adverse fuel or other conditions reasonably to be anticipated; and the firm capabilities of other resources made available under contracts prior to the beginning of the year, after deduction of adequate reserves. Assured capabilities shall be determined for each month if the purchaser has seasonal storage. The capabilities of the purchaser's firm resources shall be determined as follows:

(1) Hydroelectric Generating Facilities: The capability of each of the purchaser's hydroelectric generating plants shall be determined in terms of both peaking and average energy using critical water conditions. The average energy capability shall be that capability which would be available under the storage operation necessary to produce the claimed peaking capability.

Seasonal storage shall mean storage sufficient to regulate all the purchaser's hydroelectric resources in such a manner that when combined with the purchaser's thermal generating facilities, if any, and with firm capacity and energy available to the purchaser under contracts, a uniform energy computed demand for a period of 1 month or more would result.

A purchaser having seasonal storage shall, within 10 days after the end of each month in the critical period, notify Bonneville in writing of the assured energy capability to be applied tentatively to the preceding month; such notice shall also specify the purchaser's best estimate of its average system energy load for such month. If such notice is not submitted, or is submitted later than 10 days after the end of the month to which it applies, subject to the limitations stated herein, the assured energy capability determined for such month prior to the beginning of the year shall be applied to such month and may not be changed thereafter.

If notice has been submitted pursuant to the preceding paragraph, the purchaser shall, within 30 days after the end of the month, submit final specification of the assured energy capability to be applied to the preceding month; provided that the assured energy capability so specified shall not differ from the amount shown in the original notice by more than the amount by which the purchaser's actual average system energy load for such month differs from the estimate of that load shown in the original notice. If the assured energy capability for such month differs from that determined prior to the beginning of the year for such month, the purchaser, if required by Bonneville, shall demonstrate by a suitable regulation study based on critical water conditions that such change could actually be accomplished, and that the remaining balance of its total critical period assured energy capability could be developed without adversely affecting the firm capability of other purchaser's resources. The algebraic sum of all such changes in the purchaser's assured energy capability shall be zero at the end of the critical period or year, whichever is earlier. Appropriate adjustments in the assured peaking capability shall be made if required by any change in reservoir operation indicated by such revisions in the monthly distribution of critical period energy capability.

(2) Thermal Generating Facilities: The capability of each of the purchaser's thermal generating plants shall be determined in terms of both peaking and average energy. Such capabilities shall be based on the adverse fuel or other conditions reasonably to be anticipated. The effect of limitations on fuel supply due to war or other extraordinary situations will be evaluated at the time of occurrence.

(3) Other Sources of Power: The assured capability of other resources available to the purchaser on a firm basis under contracts shall be determined prior to each year in terms of both peaking and average energy.

c. Determination of Computed Demand: The purchaser's computed demand for each billing month shall be the greater of:

(1) The largest amount during such month by which the purchaser's actual 60-minute system demand, excluding any loads otherwise provided for in the contract, exceeds its assured peaking capability for such month, or period within such month, or

(2) The largest amount for such month, or period within such month, by which the purchaser's actual system average energy load, excluding the average energy loads otherwise provided for in the contract, exceeds its assured average energy capability.

The use of computed demands as one of the alternatives in determining billing demand is intended to assure that each purchaser who purchases power from Bonneville to supplement its own firm resources will purchase amounts of power substantially equivalent to the additional capacity and energy which the purchaser would otherwise have to provide on the basis of normal and prudent operations, viz, sufficient capacity and energy to carry the load through the most critical water or other conditions reasonably to be anticipated, with an adequate reserve.

Since the computed demand depends on the relationship of capability of resources to system requirements, the computed demand for any month cannot be determined until after the end of the month. As each purchaser must estimate its own load, and is in the best position to follow its development from day to day, it will be the purchaser's responsibility to request scheduling of firm power, including any increase over previously established demands, on the basis estimated by the purchaser to result in the most advantageous purchase of the power to be billed at the end of the month.

Each contract in which computed demand may be a factor in determining the billing demand shall have attached to it as an exhibit a sample calculation of the computed demand of the purchaser for the period having the highest computed demand during the 12 months immediately preceding the effective date of the contract.

2.4 Restricted Demand: A restricted demand shall be the number of kilowatts of firm power, modified firm power, industrial firm power, or authorized increase of any of the preceding classes of power which results when Bonneville has restricted delivery of such power for 1 clock-hour or more. Such restrictions by Bonneville are made pursuant to section 8 of the General Contract Provisions for industrial firm power and pursuant to sections 1.1 and 1.2 of the General Rate Schedule Provisions for firm power and modified firm power, respectively. Such restricted demand shall be determined by Bonneville after the purchaser has made its determination to accept such restriction or to curtail its contract demand for the month in accordance with section 2.5 of the General Rate Schedule Provisions.

2.5 Curtailed Demand: A curtailed demand shall be the number of kilowatts of firm power, modified firm power, industrial firm power, or authorized increase of any of the preceding classes of power which results from the purchaser's request for such power in amounts less than the contract demand therefor. Each purchaser of industrial firm power or modified firm power may curtail its demand in accordance with the section entitled "Curtailment of Deliveries and Payment Therefor" of the General Contract Provisions of the contract. Each purchaser of an authorized increase in excess of firm power, modified firm power, or industrial firm power may curtail its demand in accordance with section 1.5 of the General Rate Schedule Provisions.

3.1 Billing: Unless otherwise provided in the contract, power made available to a purchaser at more than one point of delivery shall be billed separately under the applicable rate schedule or schedules. The contract may provide for combined billing under specified conditions and terms when (a) delivery at more than one point is beneficial to Bonneville, or (b) the flow of power at the several points of delivery is reasonably beyond the control of the purchaser.

If deliveries at more than one point of delivery are billed on a combined basis for the convenience of the customer, a charge will be made for the diversity between the measured demands at the several points of delivery. The charge for the diversity shall be determined in a uniform manner among purchasers and shall be specified in the contract.

3.2 Determination of Estimated Billing Data: If the purchased amounts of capacity, energy, or the 60-minute integrated demands for energy must be estimated from data other than metered or scheduled quantities, Bonneville and the purchaser will agree on billing data to be used in preparing the bill. If the parties cannot agree on the estimated billing quantities, a determination binding on both parties shall be made in accordance with the arbitration provisions of the contract.

4.1 Application of Rates During Initial Operation Period: For an initial operating period, not in excess of 3 months, 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, Bonneville may agree (a) to bill for service to such new or reactivated plant facilities on the basis of the measured demand for each day, adjusted for power factor, or (b) if such facilities are served by a distributor purchasing power therefor from Bonneville, to bill for that portion of such distributor's load which results from service to such facilities on the basis of the measured demand for each day, adjusted for power factor. Any rate schedule provisions regarding contract demand, billing demand, and minimum monthly charge which are inconsistent with this section shall be inoperative during such initial operating period.

The initial operating period and the special billing provisions may, on approval by Bonneville, be extended beyond the initial 3-month period for such additional time as is justified by the developmental character of the operations.

5.1 Energy Supplied For Emergency Use: A purchaser taking firm power shall pay in accordance with Wholesale Nonfirm Energy Rate Schedule H-6 and emergency capacity Schedule F-8 for any electric energy which has been supplied (a) for use during an emergency on the purchaser's system, or (b) following an emergency to replace energy secured from sources other than Bonneville during such emergency, except that mutual emergency assistance may be provided and settled under exchange agreements.

6.1 Billing Month: Meters will normally 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 or more than the normal billing month, the monthly charges stated in the applicable rate schedule will be appropriately adjusted. Winter and summer periods identified in the rate schedules will begin and end with the beginning and ending of the purchaser's billing month having meter-reading dates closest to the periods so identified.

7.1 Payment of Bills: Bills for power shall be rendered monthly and shall be payable at Bonneville's headquarters. Failure to receive a bill shall not release the purchaser from liability for payment. Demand and energy billings under each rate schedule application shall be rounded to whole dollar amounts, by elimination of any amount of less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

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

Bills not paid in full on or before the close of business of the 20th day after the date of the bill shall bear an additional charge which shall be the greater of one-fourth percent (0.25%) of the amount unpaid or $50. Thereafter a charge of one-twentieth percent (0.05%) of the sum of the initial amount remaining unpaid and the additional charge herein described shall be added on each succeeding day until the amount due is paid in full. The provisions of this paragraph shall not apply to bills rendered under contracts with other agencies of the United States.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the 20th day after the date of the bill. If the 20th 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 20th day must bear a postal department cancellation in order to avoid assessment of such further charges.

Bonneville may, whenever a power bill or a portion thereof remains unpaid subsequent to the 20th day after the date of the bill, and after giving 30 days advance notice in writing, cancel the contract for service to the purchaser, but such cancellation shall not affect the purchaser's liability for any charges accrued prior thereto.

8.1 Approval of Rates: Schedules of rates and charges, or modifications thereof, for electric energy sold by Bonneville shall become effective only after confirmation and approval by the entity or entities designated to confirm and approve such rates and charges by the Secretary of Energy.

9.1 Average Power Factor: The formula for determining average power factor is as follows:

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

The data used in the above formula shall be obtained from meters which are ratcheted to prevent reverse registration.

When deliveries to a purchaser at any point of delivery include more than one class of power or are under more than one rate schedule, and it is impracticable to separately meter the kilowatthours and reactive kilovoltamperehours for each class, the average power factor of the total deliveries for the month will be used, where applicable, as the power factor for each of the separate classes of power and rate schedules.

10.1 Temporary Curtailment of Contract Demand: The reduction of charges for power curtailed pursuant to the purchaser's contract and Sections 1.5 and 2.5 hereof shall be applied in a uniform manner.

11.1 General Provisions: The Wholesale Rate Schedules and General Rate Schedule Provisions of the Bonneville Power Administration effective December 20, 1979, supersede in their entirety Bonneville's Wholesale Power Rate Schedules and General Rate Schedule Provisions effective December 20, 1974.