Final Firm Power Products and Services Rate Adjustment Proposal (FPS-96R)

Final Study FPS-96R-FS-BPA-01

PROPOSED FIRM POWER PRODUCTS AND SERVICES (FPS-96R)
RATE ADJUSTMENT STUDY

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COMMONLY USED ACRONYMS

BPA	Bonneville Power Administration
C&R	Cost and Revenue
CCCT	Combined-Cycle Combustion Turbine
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
Fourth Power Plan	NWPPC's Fourth Northwest Conservation and Electric Power Plan
FPS	Firm Power Products and Services (rate)
kW	Kilowatt (1000 watts)
MW	Megawatt (1 million watts)
NWPPC	Northwest Power Planning Council
NYMEX	New York Mercantile Exchange
O&M	Operation and Maintenance

1. DETERMINING THE RATES FOR CAPACITY WITHOUT ENERGY

This section contains two subsections. Section 1.1 describes the purpose for the proposed adjustments to FPS-96. Section 1.2 presents the method and proposed new rates for a capacity without energy product.

1.1 Purpose of the Proposed Adjustments

The purpose of the proposed adjustments to the Firm Power Products and Services (FPS-96) rate schedule is to clarify and establish the rates that apply to the capacity without energy product.

The FPS-96 rate schedule includes a Contract Rate demand charge section, which contains a rate of $0.87/kilowatts (KW)/month. The demand charge in this section was designed and priced to be used exclusively in conjunction with the purchase of the separate energy product included in the same section of FPS-96. The Contract Rate demand charge was not intended to apply to capacity without energy.

The FPS-96 rate schedule is a successor to the Surplus Firm Power (SP-93) rate schedule. However, prior to the product unbundling in the FPS-96 rate schedule, the Contract Rate demand charge in Bonneville Power Administration's (BPA) Surplus Firm Power rate schedules (SP-93, SP-91, SP-89, and SP-86) was priced to provide capacity without energy. The Contract Rate demand charge in each of these Surplus Firm Power rate schedules included: (1) firm energy; (2) firm capacity without energy; and (3) firm power.

Pursuant to BPA's product unbundling in the 1996 rate case, separate sections for the capacity without energy product were included in the Priority Firm Power (PF-96) and New Resource Power (NR-96) rate schedules. Consistent with this product unbundling, the FPS-96 rate schedule was also designed to unbundle capacity and energy products. Although clarifying language was mistakenly omitted from the FPS-96 rate schedule, it was BPA's stated intent that the capacity without energy product would be sold at a negotiated price, not under the Contract Rate demand charge. This is established by BPA's Final 1996 Wholesale Power Rate Development Study (WPRDS), WP-96-FS-BPA-01. Section 4.7 of the WPRDS states in pertinent part that: "Firm capacity without energy is available under PF-96 and NR-96 rate schedules for Computed Requirements customers purchasing under the 1981 Contract. Firm capacity without energy is also available under the FPS-96 rate schedule, at negotiated prices and terms that may vary from those in the PF and NR rate schedules."

BPA entered into some contracts prior to the establishment of the FPS-96 rate schedule that provide for BPA to supply, under specified circumstances, capacity without energy, and further provide that such product should be priced under the Contract Rate demand charge section of the then applicable Surplus Firm Power rate schedule. As noted previously, the FPS-96 rate schedule is the successor to all prior Surplus Firm Power rate schedules. BPA erred in the FPS-96 rate schedule when it failed to expressly state in that schedule that contracts providing for capacity without energy would no longer be sold at the Contract Rate demand charge, but rather would be priced at a negotiated rate, and that the demand charge in the Contract Rate section in FPS-96 was for a firm power sale product. The fact that an error was made is reflected in the above quoted language from the WPRDS, and in the fact that the $0.87/kW/month price is below the rates posted for capacity without energy in both the PF-96 and NR-96 rate schedules.

Because some contracts may require a posted, as opposed to a negotiated, rate for capacity without energy, BPA is proposing to post seasonally adjusted rates, using the same seasons as are currently contained in the FPS-96 rate schedules and which are also used for capacity without energy rates in the PF-96 and NR-96 rate schedules, that may be used instead of a negotiated rate. The posted rates shall be available for those contracts in effect on or before October 1, 1996, that provide for capacity without energy to be priced at the Contract Rate demand charge in the then applicable Surplus Firm Power rate schedule. These rates may also be applied to contracts for capacity without energy which require posted rates and are entered into on or after June 1, 2000.

Pursuant to 18 CFR §300.11 and 18 CFR §300.12, BPA is required to perform a rate study demonstrating the technical support for BPA's proposed rates. A rate study was performed in conjunction with BPA's 1996 Wholesale Power rate case. Federal Energy Regulatory Commission (FERC) accepted the study and approved BPA's Wholesale Power rates for a five year period and approved the FPS-96 rates for a 10 year period. On September 25, 1996, FERC granted interim approval of the proposed rates effective October 1, 1996. United States Dept. of Energy-Bonneville Power Administration, 76 FERC ¶ 61,314 (1996). On July 30, 1996, FERC issued an order granting final confirmation and approval of BPA's rates, including the FPS-96 rate schedule. United States Dept. of Energy-Bonneville Power Administration, 80 FERC ¶ 61,118 (1997).

The proposed modification to the FPS-96 rate schedule does not impact the rate test study preformed in conjunction with the original FPS-96 rate case because BPA is not anticipating that the change will have any impact on the total revenues earned from the FPS rate schedule during the 10-year period it is in effect.

1.2 Results

The intent of this method is to derive a seasonal capacity without energy charge that reflects the market-based costs of this product.

(1) To develop this cost estimate, BPA used annual average fixed costs of a Combined-Cycle Combustion Turbine (CCCT) for each year in the 2000-2006 rate period and monthly prices on New York Mercantile Exchange (NYMEX) electricity futures market. These CCCT costs were developed by the Northwest Power Planning Council (NWPPC). The CCCT fixed costs are determined as described in the CCCT cost determination.

(2) These annual average CCCT fixed costs are converted to monthly prices using NYMEX Futures prices. The NYMEX prices are for the period January 2000 through December 2000, as of June 26, 1999, at California-Oregon Border. These monthly prices are determined by multiplying each of the annual CCCT fixed cost by the set of monthly NYMEX Futures prices for each year separately in the 2000-2006 rate period.

(3) Finally, using the estimates in (2), six seasonal capacity rates are determined using the same seasons as are used for the Firm Power product in the FPS-96 rate schedule. The six seasonal rates are in the table below.

Results

Applicable Months	***Rate***
September – December	$12.20/kW-mo.
January – March	$8.95/kW-mo.
April	$8.13/kW-mo.
May – June	$6.68/kW-mo.
July	$10.78/kW-mo.
August	$16.04/kW-mo.

2. NORTHWEST POWER PLANNING COUNCIL COMBINED-CYCLE COMBUSTION TURBINE COST DETERMINATION

2.1 Fixed Costs of Combined-Cycle Combustion Turbines

The data for cost and efficiency on potential new resources was drawn from the NWPPC's Analysis of BPA's Potential Future Cost and Revenues. The source for several of these assumptions was the NWPPC's Fourth Northwest Conservation and Electric Power Plan (Fourth Power Plan).

2.2 Technology

The CCCT powerplant study assumptions are based on 250-megawatt (MW) class industrial units. The 250 MW class unit is the predominant combined-cycle unit currently employed in powerplant development.

2.3 Capital Cost

The Clark Public Utilities River Road powerplant provides the starting point for the capital cost estimates of a new combined-cycle plant. River Road, a 248 MW General Electric 107FA combined-cycle powerplant, entered service in late 1997.

The River Road construction costs were first adjusted by a factor representing the estimated difference between the development cost of a single-unit combined-cycle powerplant at the River Road Vancouver site and the average plant development cost for a large group of potential combined-cycle powerplant sites in the Northwest[1]. This factor normalizes for site-specific development costs and captures possible economies at sites capable of accommodating multiple

[1] The development of this factor is further described in Appendix F of the *Fourth Northwest Conservation and Electric Power Plan*. The factor used here is the difference between the estimated cost of developing a single unit combined-cycle powerplant at a Vancouver, Washington, site (the location of the actual River Road plant) and the average estimated cost of developing units at the "Group 1" set of sites identified in the Fourth Power Plan. The Group 1 sites are those sites for which construction permits were currently held or being sought at the time the Fourth Power Plan was in preparation. Group 1 sites could accommodate from one to four 250 MW class units.

units. The resulting "average Northwest" development cost was then increased by 2.7 percent to represent the estimated average degradation of capacity over the life of the plant. The resulting cost is assumed to be the average cost of developing new combined-cycle plants in the Oregon and Washington area under current market conditions.

However, because of the weak market conditions prevailing for the past several years, the average Northwest cost is assumed to represent a depressed price. The estimate was increased by 10 percent to represent a market equilibrium condition thought more typical of the study period.

2.4 Operation and Maintenance Cost

Fixed operation and maintenance (O&M) cost assumptions are based on those developed for the Fourth Power Plan. The Fourth Power Plan values were adjusted to 1997 dollars, then de-escalated by 2.5 percent per year to reflect the effect of competitive pressure in the generation sector on plant O&M costs. This de-escalator is used by the Energy Information Agency (EIA) in preparing its Annual Energy Outlook.

The fixed O&M costs of future plants are assumed to decline in proportion to the capital cost technology improvement indices. Furthermore, future fixed O&M costs of both new and existing plants are assumed to continue to decline at 2.5 percent per year through 2004 in response to the expected effects of an increasingly competitive wholesale power market.

2.5 Financing

New capacity is assumed to be merchant plants that will not have long-term power sales agreements when built. Developers are assumed to be non-regulated private generating companies. The "Unregulated Independent" financing assumptions of the NWPPC's Analysis of

BPA's Potential Future Cost and Revenues Study were used. These were based on Fourth Power Plan values, modified as described below. Estimated future general inflation rates were reduced from 3.5 percent annually to 2.5 percent annually to reflect continuing low rates of general inflation. Concurrently, nominal debt interest rate and return on equity assumptions were lowered by 1 percent, consistent with the reduction in the general inflation rate. The resulting annual long-term debt interest and return on equity rates are 8.7 percent and 17.3 percent, respectively. The discount rate was adjusted from the 8.5 percent annual "societal" rate (nominal) of the Fourth Power Plan to the after-tax cost of capital rate of 9 percent annual (nominal). This adjustment was made to simulate the expected actual cost of the developing merchant powerplants. Finally, the Fourth Power Plan "Unregulated Independent" debt/equity ratio of 80/20 was adjusted to 70/30, consistent with recent merchant plant financing experience.

2.6 Other Assumptions

Fourth Power Plan assumptions were used for development and construction lead times, plant availability, construction cash flows, and operating life.

2.7 Data Used in Determining Capacity without Energy Prices for FPS-96

The costs used in this analysis reflect the assumptions and methods described above. The specific numbers and estimated rates are shown in FPS-96R-FS-BPA-02.