Office of the Secretary
Service Date
January 31, 1995

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO CUSTOMERS IN THE STATE OF IDAHO.	))))))	CASE NO. IPC-E-94-5 ORDER NO. 25880

ISSUED JANUARY 31, 1995

BOISE, IDAHO

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SUMMARY

This is a final order determining the revenue requirement in Idaho Power Company's (IPCo, Company) general rate case. On June 30, 1994, IPCo filed an Application for authority to increase its rates and charges for electric service in the state of Idaho by $37 million, or approximately 9.09%, effective August 1, 1994. By its Order No. 25635 issued July 12, 1994, the Commission suspended the proposed effective date of IPCo's new schedules of rates and charges pursuant to *Idaho Code* § 61-622 to provide an opportunity for a hearing on the Application. By this Order we authorize IPCo to increase its Idaho rates and charges by $17,177,048 million, or approximately 4.19%.

APPEARANCES

IDAHO POWER COMPANY: LARRY D. RIPLEY, Idaho Power Company, PO Box 70, Boise, ID 83707-0070.

COMMISSION STAFF: BRAD PURDY, Deputy Attorney General, Idaho Public Utilities Commission, PO Box 83720, Boise, ID 83720-0074.

IDAHO IRRIGATION PUMPERS ASSOCIATION, INC.: RANDALL C. BUDGE, Racine, Olson, Nye, Cooper and Budge, PO Box 1391, Pocatello, ID 83204-1391.

MICRON SEMICONDUCTOR, INC.: JOHN J. MCFADDEN, Moore & McFadden, 999 Main Street, Suite 910, Boise, ID 83702.

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INDUSTRIAL CUSTOMERS OF IDAHO POWER: PETER J. RICHARDSON, Davis, Wright, Tremaine, 999 Main Street, Suite 911, Boise, ID 83702.

U.S. DEPARTMENT OF ENERGY: LAWRENCE A. GOLLOMP and MARK D. OLSEN, U.S. Department of Energy, 1000 Independence Avenue., SW, Room 6D-033, Washington, D.C. 20585.

FMC CORPORATION: CONLEY WARD, Givens, Pursley & Huntley, 277 North 6th Street, Suite 200, Boise, ID 83702.

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COMMERCIAL UTILITY CUSTOMERS OF IDAHO POWER COMPANY: RONALD L. WILLIAMS, Eberle, Berlin, Kading, Turnbow & McKlveen, PO Box 1368, Boise, ID 83701-1368.

IDAHO CITIZENS COALITION: AL FOTHERGILL, Idaho Citizens Coalition, 9220 West Wright Street, Boise, ID 83709.

INTRODUCTION

IPCo included in its Application filed June 30, 1994 a request for an interim rate increase of 2.83%, applied uniformly to all classes of customers, pending final resolution of this case. On August 2, 1994, the Commission convened a hearing to consider IPCo's request for interim rate relief. The proposed interim rates were based on IPCo's contention that it should be permitted to immediately add to rate base major improvements to two different hydro electric facilities. The Commission concluded that IPCo had not demonstrated the existence of a financial emergency to justify interim rate relief, and denied IPCo's request for such relief by Order No. 25683 issued August 5, 1994.

The Commission conducted ten days of hearings in Boise on IPCo's Application, commencing on October 10 and December 12, 1994. Public hearings were also held in Pocatello on December 5, and in Caldwell on December 7, 1994. Throughout this proceeding, including during the interim rate hearing, documentary and oral evidence were presented by interested persons or entities that were granted leave to participate as intervenors. Several intervenors did not present evidence or otherwise participate in the hearings in this case. The intervenors that did present evidence are Idaho Irrigation Pumpers Association, Inc. (Irrigators), Micron Semi Conductor, Inc. (Micron), Industrial Customers of Idaho Power (Industrial), U.S. Department of Energy (DOE), FMC Corporation (FMC), Commercial Utility Customers (Commercial), and Idaho Citizens Coalition (Citizens).

By this Order the Commission determines IPCo's Idaho revenue requirement and rate base, authorizes a return on common equity, allocates revenue responsibility among classes and designs rates for Idaho Power's electrical services provided to its Idaho customers.

TEST YEAR

IPCo proposed a 1993 test year and a rate base comprised of the average of 13 monthly balances for the period ending December 31, 1993 rather than a year-end rate base. No party objected to the use of a 1993 test year and an average rate base. Accordingly, we find the use of a 1993 test year and an average rate base to be reasonable and appropriate in this case.

ADJUSTMENTS TO TEST YEAR REVENUES AND EXPENSES

Having selected a 1993 test year, IPCo, and subsequently Staff and intervenors, proposed adjustments to specific booked amounts for revenues, expenses, and rate base. Adjustments to test year revenues and expenses often are necessary to reflect known and measurable changes so that test year totals accurately reflect anticipated amounts for the future period when rates will be in effect. Some of the adjustments to revenues or expenses also affect rate base.

1. Year-End Employee and Depreciation Expenses and Customer Totals.

IPCo adjusted certain expenses to reflect year-end levels, and some intervenors recommended adjusting certain revenues to show year-end levels. The annualizing adjustments proposed by IPCo are an increase in payroll of $132,393, increased operating expenses related to payroll in the amount of $18,185, an increase to Social Security taxes of $9,673, and increased depreciation expense of $996,890. Tr. p. 246. The depreciation expense adjustment also would decrease rate base in the amount of $498,447 for accumulated depreciation. Staff opposed these adjustments, testifying that IPCo's adjustment of these test year expense accounts "is appropriate for matching operating results with a year-end rate base calculation but not to match an average rate base." Staff recommended elimination of these adjustments. Tr. p. 1928-29.

Also citing a mismatch of expenses and revenue, Irrigators and FMC testified that the 1993 test year revenues should be adjusted to reflect year-end customer totals. Tr. p. 1168-70; 2351-53. Irrigators recommended an adjustment to Idaho test year revenues in the amount of $7,532,106. Tr. p. 1171. Admitting its recommendation was based on incomplete information, FMC recommended an adjustment to net Idaho test year revenues of $2.1 million. Tr. p. 2352. In rebuttal, IPCo stated that the proposed adjustments by FMC and Irrigators "would be an improper matching of revenues with expenses and rate base." Tr. p. 2836.

We find all of the proposed adjustments to revenues, expenses and rate base to reflect year-end totals to be inappropriate. The adjustments to expenses proposed by IPCo and the adjustments to revenues proposed by Irrigators and FMC would create a mismatch of revenue, expenses and rate base.

The Company also made known and measurable adjustments for 1993 general wage and payroll-related expense increases totaling $2,135,864, which were generally objected to by Irrigators in its recommendation to use year-end customer totals. This adjustment applies to actual employees and payroll for the test year, not year-end employees. We find it does not result in a mismatch of revenues and expenses and should be allowed.

2. Normalization of Irrigation Revenue.

Because weather conditions during 1993 were wetter and cooler than normal, IPCo in its filing adjusted operating revenue to reflect normal or average weather conditions. Included in its normalizing adjustment is an increase in irrigation revenue, reflecting a 21.6% increase in energy that would be used by irrigators under normal, drier conditions than experienced during the test year.

Irrigators objected to IPCo's calculation of normal irrigation revenue, testifying that normalized irrigation revenue would actually be greater than stated by IPCo because billings and billing demand revenues would increase along with energy revenues. Tr. p. 1176. Irrigators' evidence demonstrated that actual irrigation revenue per kwh in 1993 was approximately 5% above the revenue per kwh derived from the Company normalization adjustment. Irrigators accordingly recommended a $2,744,421 increase in Idaho test year irrigation revenues above the $54.6 million calculated by IPCo. Tr. p. 1179.

The Company on rebuttal responded to Irrigators' proposal, asserting that while energy revenue varies with changing weather conditions, billings and demand revenues do not. It further claimed that the method used by Irrigators to calculate the adjustment inappropriately captured the effect of a temporary surcharge and a PCA surcharge, and also included revenue from sales to Prairie Power and Oregon customers. Tr. p. 2887-88.

We find that an adjustment to test year irrigation revenues to account for billing demand revenues is appropriate to accurately reflect revenues under normalized conditions. However, we also find the corrections made by IPCo to Irrigators' normalized billing demand calculation to be appropriate. If the Irrigators' calculation of irrigation pumping revenues is corrected for the oversights identified by the Company in rebuttal, then actual test year revenue per kwh exceeds normalized test year revenue per kwh by 2.87%. We find, therefore, that it is appropriate to increase Idaho irrigation test year revenue by $1,563,217 to reflect weather normalized billing demand. Accordingly, we have used the billing demand determinate in the calculation of new irrigation rates.

3. Micron Load Adjustment.

The Company in its case used demand and energy data for each month of the test year based on actual monthly usage rather than billed amounts. Staff testified that for Micron, however, IPCo used billed amounts rather than actual monthly usage, and recommended that Micron be treated consistently with other customers in determining test year revenues. Tr. p. 2004. The Company did not dispute this adjustment. Accordingly, we find it reasonable to include Micron demand and energy data in a manner consistent with test year data for other customers. This increases 1993 revenues in the amount of $35,660, increases fuel expense by $9,000, and increases purchased power costs by $17,000.

4. Operation and Maintenance Expenses.

Irrigators witness Yankel noted that the actual amounts of expense included in certain FERC expense accounts were significantly higher in the historical 1993 test year than in the preceding years. Contending the Company should not be allowed to select test years to its advantage, Irrigators proposed to normalize all operation and maintenance (O&M) expenses, except fuel and purchased power, using regression analysis to provide an expense level consistent with general increases experienced during the period 1988-1992. Irrigators proposed a reduction in test year O&M expenses of $10,690,000 for Idaho and $11,498,000 for the total Company. Tr. p. 1167. IPCo on rebuttal claimed the Irrigators proposal would, in effect, result in utilization of a forecasted test year, something the Commission has declined to use in the past. Tr. p. 2802.

Although fair questions were raised by Irrigators regarding the increases in 1993 O&M expenses, no evidence was presented to show these expenses were improperly or artificially inflated, nor was it demonstrated that they would be less in the future. The Commission has traditionally relied on historical test-year data adjusted for specific known and measurable adjustments and has, with the exception of weather and stream-flow sensitive revenue and expenses, rejected adjustments to historical data based strictly on statistical analyses. We find no reason to change that policy in this case. Accordingly, we will not adjust the 1993 O&M expenses.

5. ***Industry Association Dues.***

IPCo reflected in its 1993 expense accounts dues paid to three utility associations—the Edison Electric Institute (EEI), the Electric Power Research Institute (EPRI), and the Pacific Northwest Utilities Conference Committee (PNUCC). Staff and some intervenors questioned the inclusion of association dues in expenses for ratemaking purposes. Staff recommended disallowing all association dues paid by IPCo to EEI, claiming EEI's activities are directed significantly toward lobbying and regulatory advocacy. According to Staff testimony, a National Association of Regulatory Commissioners (NARUC) study indicates 44.2% of EEI's operating expenses are for such activities. Additionally, Staff noted that EEI expenses include payments for technical programs related to nuclear activities and that others duplicate research activities of EPRI. Staff proposed reducing expenses by $186,071, the entire amount of EEI dues included by the Company in test year expenses. Tr. p. 1923-1925. Industrial recommended that, unless the Company identifies the benefits received by customers from its membership in EEI, EPRI and PNUCC, the Commission disallow the $2,157,243 in payments to these organizations. Tr. p. 1356.

IPCo in rebuttal testified that the portion of its EEI dues relating to political activities had been moved to a non-ratemaking account, and testified that customers benefited from Company membership in EEI by, for example, EEI's efforts to defeat the proposed BTU tax.

While it is clear that membership in EEI is beneficial to stockholders, its benefit to customers is less obvious. Although the Company testified that it removed the portion of EEI dues relating to political activities, the 1% amount removed is small compared to the 44.2% identified by Staff as related to activities that would not be allowed in revenue requirement if the Company were to incur them directly. We find that disallowing EEI dues in their entirety as Staff recommended goes too far. We find that one-fourth of the dues, or $46,987, should be allowed in test year expenses. This allowance relating to EEI non-political and non-nuclear programs reasonably reflects the benefit to the Company's customers of its EEI involvement.

With respect to PNUCC and EPRI, the Commission finds that benefits are received by customers of member utilities. These expenditures fund PNUCC representation of Northwest interests on power and environmental issues, and EPRI research and development provide benefits to customers. Dues paid by IPCo to PNUCC and EPRI are appropriately included in the Company's 1993 test year expenses.

6. Out of Period Adjustments.

In its audit of IPCo's accounting records supporting test year expenses, Staff identified a number of expenses that were inappropriately recorded on the Company's books during the test period, and Staff proposed adjustments accordingly. These include a 1992 expense of $577,591 to write-off obsolete fuel inventory at the Bridger generating plant, $181,188 of general 1992 expenses identified in IPCo's outside auditor's workpapers as being booked incorrectly in 1993, $141,194 identified in the outside auditor's workpapers as being a likely misstatement, and $248,288 also identified in the auditor's workpapers as being omitted in 1993 postings. Tr. p. 1782-1784. Staff also made an adjustment of $351,277 for excess expense transferred from the Company's transportation clearing account. Tr. p. 1785.

On rebuttal, IPCo agreed with the Bridger fuel adjustment, the $141,194 identified as a likely misstatement, and the $248,288 that should have been posted in 1993; it also corrected the $181,188 inappropriately booked in 1992 to $101,188. Tr. p. 2785. IPCo stressed, however, that these are estimates used by the external auditors in expressing an opinion on the financial statements of the Company and have not been related to any specific items on the Company's books.

We find these adjustments, as agreed to and corrected by the Company, are reasonable and should be adopted. Not all these adjustments affect the test year for ratemaking purposes, and thus these changes result in a net reduction to test year expenses of $5,906.

With respect to Staff's adjustment for the excess transportation clearing account expense, IPCo argued that any excess resulted from its use of logical and prudent estimates in accordance with generally accepted accounting principles, and that Staff's adjustment of only one of the many expenses that are based on estimates is unfair. Tr. p. 2790. However, evidence concerning the transportation clearing account showed that costs from this account charged to expense, in fact, exceeded actual transportation expenses incurred. We find, therefore, that the Staff-proposed adjustment, resulting in a reduction in expenses of $351,277, is appropriate.

7. Pacific Hide Clean-Up.

Included in IPCo's test year expenses is $376,172 relating to hazardous waste clean-up activities at the Pacific Hide and Fur Co. in Pocatello. Staff proposed removal of this expense from the test year as a nonrecurring expense. Tr. p. 1923-1924.

IPCo agreed that the Pacific Hide clean-up has been completed, and thus the expenses associated with that project are nonrecurring. IPCo argued, however, that it is appropriately included to reflect expected average annual expenses for environmental clean-up because under current environmental laws IPCo will likely incur such costs in the future. Tr. p. 2786. In the alternative, IPCo argued that because it spent over $7 million during 1986-93 on clean-up at Pacific Hide, it should be allowed to amortize the full $7 million over five years, resulting in an annual amortization expense of $1,841,962. Tr. p. 2787.

Test year adjustments to expenses are intended to represent costs the Company will likely incur in the future when new rates are in effect. It is undisputed IPCo will not incur further expenses associated with the Pacific Hide clean-up, and thus that particular expense is nonrecurring and cannot be allowed.

Although the Company's assertion that it may incur similar expenses in the future may prove to be true, no evidence was provided to show with any degree of certainty how much those expenses will be. We believe the Company probably does have some level of annual expenses associated with various types of environmental clean-ups. Those expenses may be reflected in various other accounts and not separately identified. Without substantial evidence of what the actual annual level of expense is, and without a demonstration that it is not currently reflected in other accounts, it is inappropriate to include this level of expense with other test year expenses.

The alternative the Company proposed to recover the $7 million cost of the clean-up, recouping the amount through rates over the next five years, would violate the principle that rates must be prospective and may not be used to recoup past losses. The proscription against retroactive ratemaking means the Pacific Hide amounts spent by IPCo in the past are not recoverable through future rates unless they were preserved for that purpose by deferral or other regulatory action. When it became aware the clean-up costs would be substantial, the Company had the opportunity to request rate relief or deferral of these costs for future recovery. It did neither. Had the Company requested deferral of these costs and the Commission had approved it, we could now amortize this expenditure. However, that is not the case and we are without a means to provide recovery of this expense retroactively.

8. Amortization of FAS-106 and FAS-112 Expenses.

This issue relates to two changes in accounting standards required by Statement of Financial Accounting Standard No. 106, Employers' Accounting for Post-Retirement Benefits Other Than Pensions (FAS-106) and Statement of Financial Accounting Standard No. 112, Employers' Accounting for Post-employment Benefits (FAS-112). Order No. 24831 issued in Case No. IPC-E-92-28 approved IPCo's use of accrual accounting for post-retirement benefits other than pensions in accordance with FAS-106. The Order also allowed IPCo to defer the difference in expense between cash and accrual basis accounting, up to a maximum of $6,000,000, for up to two years. The Company's request in Case No. IPC-E-94-16 to defer and amortize over ten years its FAS-112 transition obligation was made subject to resolution in this case.

Both FAS-106 and FAS-112 include the recognition of previously unrecognized obligations on the books of the Company. FAS-106 allows the post-retirement "transition" obligation to be expensed over a period of up to twenty years. FAS-112 generally requires the post-employment obligation to be expensed in the year FAS-112 is adopted.

Included in the Company's test year results of operations are expenses associated with the amortization of the FAS-106 obligation. For financial statement purposes, the Company is amortizing its FAS-106 transition obligation over twenty years, and that amortization was included as a known and measurable adjustment to test year expenses. It also adjusted test year expenses to provide for a ten-year amortization of the previously approved $6,000,000 deferral. Staff included the amortization of the FAS-112 transition obligation over a twenty year period, saying it should be consistent with the twenty-year amortization of the FAS-106 transition obligation. Tr. p. 1788.

We find the appropriate amortization period for the FAS-106 transition obligation to be the twenty years used by IPCo and accepted by Staff. We also accept the Company's proposed ten-year amortization of the FAS-112 transition obligation. Although the nature of the expenses for FAS-106 and FAS-112 may be similar, the amounts of the two obligations differ dramatically. The FAS-112 obligation is roughly one-tenth the FAS-106 transition obligation. A shorter amortization period for FAS-112 will allow the Company to recover this cost and eliminate the regulatory asset in a timely manner.

We also agree with the Company that ten years is an appropriate period to amortize the $6,000,000 deferral of the difference between cash and accrual basis accounting for the FAS-106 expense accumulated over the last two years. A ten-year amortization will appropriately limit the life of this regulatory asset.

9. Tax Credits.

Staff adjusted test year actual income tax expense by a total of $75,221 to reflect State gasoline and special fuels tax credits, and Federal research and fuels tax credits actually received by the Company. IPCo agreed with these adjustments. Tr. p. 2779. Accordingly, we find that test year income tax expenses should be decreased by $75,221.

10. FERC Contract Customer Revenues.

In its Jurisdictional Separation Study (Exhibit No. 20), IPCo allocated its total system rate base, expenses and revenues among four regulatory jurisdictions—the Idaho Public Utilities Commission, the Oregon Public Utilities Commission, the Public Service Commission of Nevada and the Federal Energy Regulatory Commission (FERC). The Idaho, Oregon and Nevada commissions all regulate electrical retail sales by IPCo within the borders of their respective states. FERC regulates IPCo's wholesale electrical sales or sales of electricity to resale customers. Tr. p. 2833. Two of the seven FERC customers are full requirements customers, i.e., IPCo will provide service on an on-going basis, including by constructing additional generating plant if necessary to meet the customer's demand. The other FERC sales are not for requirements service, but instead are opportunity sales IPCo can obtain because it has excess generating capacity. The sales are firm—IPCo is required to provide a specific amount of energy—and long-term, i.e., for five years or more. The energy rates are determined by negotiation and agreement of the parties and must be approved by FERC.

IPCo treated the resale sales as if the FERC jurisdiction is a separate geographic entity in its Jurisdictional Separation Study. The Separation Study assigned a portion of rate base and expenses to correspond to the revenues generated by FERC sales, just as it did for its Idaho, Nevada and Oregon retail sales. Tr. p. 2834. Contending each jurisdiction has its own requirements to determine a utility's cost-based rates, IPCo testified, "it is not appropriate to look at results for FERC jurisdictional customers . . . in determining rates set by the IPUC." Tr. p. 2835.

FMC and Irrigators testified regarding consideration of the FERC customer revenues. Noting that different methods are used to set the FERC rates than to determine Idaho retail rates, Irrigators testified that IPCo's jurisdictional allocation of FERC sales was inappropriate. Tr. p. 1153. Irrigators testified that, because the FERC sales "were essentially opportunity sales that could be made firm because of the excess capacity on the Idaho Power system, they should be treated in a similar manner to the short-term economy sales or short-term firm sales, i.e., allocated to the full requirements customers in the various jurisdictions." Tr. p. 1157-59. If the FERC sales revenues and associated rate base and expenses are allocated to the various retail jurisdictions rather than treated as a separate jurisdiction, the net result according to Irrigators is an increase in Idaho revenues of $7,043,602. Tr. p. 1160.

FMC presented similar testimony, claiming IPCo's Separation Study "denies Idaho customers revenue credits they deserve as a result of paying for rate base subsequently used to make [FERC] sales for resale." Tr. p. 2338. According to FMC's testimony, if FERC sales revenues, expenses and rate base are distributed to the retail sales jurisdictions, the Idaho revenue requirement is reduced by $6.7 million. Tr. p. 2340-41.

The Commission previously considered wholesale sales revenues as a credit or reduction in IPCo's Idaho jurisdictional revenue requirements. In *Idaho Power Company v. IPUC*, 99 Idaho 374, 582 P.2d 720 (1978), the Idaho Supreme Court reviewed the Commission's allocation of $1,686,000 for revenue requirement to resale sale revenues, thereby reducing by that amount the Idaho jurisdictional revenue requirement. IPCo contended on appeal that the Commission may not consider interstate facilities and revenues in determining intrastate rates.

The Supreme Court approved the Commission's treatment of wholesale sales revenues as a reduction in Idaho jurisdiction revenues:

> In the instant case, the effect of the IPUC's action was to disallow a portion of an overall state gross revenue deficiency because part of the Idaho operations sold power in interstate commerce as sales for resale. In order to prevent subsidizing interstate sales for resale by Idaho retail customers, the IPUC was correct in discounting this portion of the utility's operations in determining intrastate rates *assuming that these sales had not previously been discounted* in Idaho Power's original rate increase application.

Idaho Power Company v. IPUC, 99 Idaho at 397. The Court reversed the Commission decision only because the rate base associated with the resale sales had not been properly considered by the Commission. The effect was to "twice deduct sales for resale", requiring reversal of the Commission's decision. 99 Idaho at 381.

Although it is proper and legal for the Commission to allocate resale sales revenues to the Idaho jurisdiction, we are reluctant to do so in this case without reviewing additional alternatives to equitably share such revenues between IPCo's shareholders and retail customers. The record in this case contains testimony of increasing competition in the electric energy industry, and of IPCo's strong position to participate in a more competitive industry. The rate of return IPCo earns on its FERC accounts demonstrates an ability to market excess energy to wholesale customers. We are concerned that allocating the entire FERC revenues and costs to the retail jurisdictions, as recommended by FMC and Irrigators, would create too great a disincentive to IPCo to continue its efforts to obtain advantageous wholesale contracts. However, we are also convinced that Idaho ratepayers should receive some benefit from IPCo's ability to provide low-cost energy to customers in the wholesale market, because that ability results in large measure from IPCo's ownership of hydro facilities included in rate base supported by Idaho customers. The Commission finds that this issue needs to be explored more fully and we welcome sound proposals from IPCo and/or interested intervenors, both on the alternative approaches available to the Commission and a procedure by which to review and implement them.

RATE BASE

IPCo initially presented evidence of a rate base amount totalling $1,418,350,108. Based on evidence presented by Staff, IPCo accepted adjustments to rate base resulting in a reduction of approximately $3.3 million. Having reviewed the evidence presented, the Commission finds a rate base in the amount of $1,416,547,976 to be just and reasonable. The Idaho jurisdiction rate base is $1,221,624,208. The adjustments to rate base are discussed below.

1. Swan Falls.

Swan Falls is a hydroelectric facility located on the Snake River in south Ada County. In 1990, IPCo began the process to substantially rebuild its Swan Falls facility. The Commission previously approved the rebuild by Order No. 23520 issued in January 1991 in Case No. IPC-E-90-2.

In its direct case, because the actual costs were still undetermined, IPCo proposed an estimated amount for the Swan Falls rate base component in the amount of $60,542,500. Staff recommended that the estimate be updated and that the rate base reflect the actual costs incurred in the Swan Falls project. IPCo in rebuttal testimony also recommended using actual amounts, stating that actual costs totalled $54,819,571 as of November 30, 1994. Tr. p. 2780-81. This evidence is undisputed.

Staff also recommended other adjustments to the Swan Falls rate base amount related to AFUDC (allowance for funds used during construction), and related accumulated depreciation and property taxes. Staff testified that engineering costs and other expenses incurred prior to 1991 when IPCo commenced the Swan Falls improvement were improperly carried forward, and that adjustments should be made because unnecessary construction delays increased costs. Staff recommended disallowances related to Swan Falls' AFUDC totaling approximately $655,000. Tr. p. 1913-15.

Idaho Code § 61-502(a) requires the Commission to allow a "just, fair and reasonable allowance for funds used during construction or similar account to be accumulated, computed in accordance with generally accepted accounting principals" when construction work is in progress. Staff testified that AFUDC normally "does not commence until actual on-site construction begins," Tr. p. 1913, but no evidence was presented that AFUDC accrual was not computed in accordance with applicable accounting principles. IPCo testified that the Company's accrual account for AFUDC followed proper accounting principles. Tr. p. 2782-83. Based on this record, we find IPCo's accrual of AFUDC related to Swan Falls to be proper, and thus no adjustment to Swan Falls rate base related to AFUDC will be made.

Finally in regard to the Swan Falls rate base amount, IPCo seeks inclusion of approximately $1 million for construction of a planned museum at the Swan Falls facility. IPCo testified that museum construction would be completed in June 1995. Tr. p. 2781. IPCo also testified the museum would add nothing to the energy producing capacity of Swan Falls. *Id.* We find that the amount for museum construction is properly excluded from rate base. The museum is at best a budget estimate for future construction and is not short-term construction work in progress. *See Idaho Code* § 61-502(a). Under these circumstances, the amount related to construction of the Swan Falls museum will not be included in rate base.

The proper rate base amount for the Swan Falls project is $54,819,571, the amount of actual expenditures as demonstrated by IPCo. No adjustments will be made for the accrued AFUDC or for construction of the museum. This adjustment to recognize the actual Swan Falls investment at November 30, 1994 requires several adjustments to operating expenses to maintain the proper matching of rate base with operating results. Depreciation expense is decreased by $109,326, property tax expense is decreased by $47,694, and deferred tax expense is increased by $2,134. The increase in deferred tax expense results in an increase in accumulated depreciation of $1,067 (one-half the deferred tax expense of $2,134), thus decreasing rate base by the $1,067.

2. Amortization Expenses.

IPCo proposed adjustments to expenses for the amortization of intervenor funding and start-up costs of IPCo's Pilot Photovoltaic Energy Program. Expenses for intervenor funding were accumulated during a five-year period (1989-93) in five different cases. In its case in chief, IPCo showed the entire intervenor funding amount ($62,421.55) as an expense item with no effect on rate base. Staff recommended a three-year amortization period, resulting in an increase to rate base of $41,614 and a corresponding decrease to expenses. Tr. p. 1930. Staff testified that expensing the intervenor costs accumulated during five years was premised on a faulty assumption that the entire expense amount would occur each year in the future. Tr. p. 1930.

We adopt a two-year amortization period for the intervenor costs accumulated during 1989-93. It is unlikely that the intervenor costs accumulated during five years will occur each year in the future, and thus a reasonable amortization period is warranted. However, we believe the three-year period proposed by Staff is too long, and thus find reasonable a two-year amortization period. Amortizing the accumulated intervenor expenses over two years results in an increase to rate base, and a corresponding decrease to 1993 operating expenses, of $31,211.

Staff also recommended an increase in rate base for accumulated costs associated with IPCo's Pilot Photovoltaic Program. IPCo proposed a three-year amortization period, but the Commission previously prescribed a ten-year amortization period in Order No. 24473, issued September 4, 1992 in Case No. IPC-E-92-17. IPCo in rebuttal recognized the previously ordered ten-year amortization period, but recommended a change to a three-year period to reduce the administrative burden of the longer amortization period. Tr. p. 2794.

We find the ten-year amortization period is appropriate in this case, as it is consistent with the previous Order of the Commission. This adjustment for accumulated photovoltaic expense increases rate base and reduces expenses by $66,222.

3. Conservation Program Expenses.

A. Accumulated Expenses. Staff and intervenors recommended changes to IPCo's accounting treatment of Demand Side Management (DSM) or conservation programs. IPCo has accumulated $21,213,694 of expenses for DSM programs since 1989. Exhibit No. 13, p. 25. DSM programs include Low Income Weatherization Assistance, Good Cents, Design Excellence Assistance, and Zero Interest Weatherization. IPCo and other utilities have been strongly encouraged by the Commission to aggressively pursue DSM programs to alleviate pressure that energy demands create to construct new generating facilities. See, e.g., Order No. 22299. Before commencing the individual programs, IPCo requested and obtained authorization from the Commission to implement each program.

One adjustment to account for accrued DSM expenses was not disputed by IPCo. In its initial exhibits, IPCo apparently inadvertently eliminated $1,954,204, the amount for weatherization grants prior to 1985, in its DSM rate base calculation. Staff identified the elimination, and IPCo accepted the adjustment. Exhibit No. 53. Accordingly, we find this adjustment to rate base to be just and reasonable.

Staff initially presented evidence to reduce DSM related rate base by approximately $8,000,000. After it withdrew one of its initial recommendations, Staff recommended reductions in rate base related to conservation research ($267,347), the Good Cents Program ($6,621,249) and the Design Excellence Award Program ($498,518). Tr. p. 1826, 1831, 1835, 1837-38. Staff's recommendations were based on its testimony that IPCo mismanaged DSM programs by failing to adequately evaluate energy savings to determine the effectiveness of the programs, to respond quickly enough to available data and implement quality control programs, and to cease programs when information indicated they no longer were effective or necessary. Tr. p. 1818-35.

In rebuttal testimony, IPCo testified that it had initiated its DSM programs in response to Commission Order No. 22299 to identify and aggressively implement specific programs. As the result, IPCo submitted a conservation plan to the Commission in April 1989, and in each subsequent year. Tr. p. 2655. IPCo also presented testimony of subsequent Commission orders relating to specific DSM programs, and testified that IPCo in each case implemented the program as approved. Additionally, where the Commission specified accounting treatment, such as the directive in Order No. 22856 to commence deferral of Good Cents Program expenditures, IPCo responded to the Commission's instruction. Tr. p. 2657-58.

We are not persuaded the DSM related rate base amount should be reduced. The evidence demonstrates that IPCo pursued DSM programs pursuant to the Commission's instructions, seeking approval for implementation of specific programs. Of course, the Commission's prior approval of DSM programs is not approval of particular expenditures for ratemaking purposes. However, there is not sufficient evidence demonstrating IPCo failed in its responsibility to properly manage its DSM programs to disallow such significant expenditures.

B. Amortization of DSM Program Costs. IPCo proposed in its Application to amortize all DSM program expenditures over seven years. Staff recommended that the program expenditures be amortized over a period equal to the approximate effective life of each program, as set forth in Staff's Exhibit No. 119. Tr. p. 1842. Similarly, FMC recommended an amortization period of 24 years for the accumulated DSM program expenditures, which is the average effective life projected for the DSM programs. Tr. p. 2346. Under IPCo's proposal,

$16,468,740 is included in rate base for accumulated DSM costs. Amortizing the expense over the average useful life, a 24-year period, adds $1,894,387 to IPCo's proposed DSM related rate base. The corresponding amortization expense is also reduced by the $1,894,387.

As Staff testified, the Commission previously has indicated it expects expenditures for DSM programs to be amortized over the expected useful life of the program. See, e.g., Order Nos. 22299 and 22893. Such an amortization properly spreads program costs over the expected useful life. For the DSM programs that have resulted in deferred expenses of approximately $18.5 million in this case, the program average useful life is 24 years. We find a 24-year amortization period for the existing deferred DSM costs to be just and reasonable. The total DSM related rate base amount adopted in this Order is $20,317,331, correcting for the Company error of $1,954,204 and amortizing the deferred amount over 24 years.

C. Ongoing DSM Program Expenditures. IPCo also proposed a modification to the usual accounting process for some DSM program expenses. Although this proposal does not affect rate base in this case, it is properly discussed with the other DSM accounting issues presented.

Historically, all DSM expenses have been deferred and then recouped through amortization over a period of time. IPCo proposes to cease deferring and instead expense DSM administrative expenses, including some customer service costs, information costs, and direct in-house labor for DSM programs. IPCo also proposes to expense all costs associated with the Low Income Weatherization Program. Staff did not oppose IPCo's proposal to begin expensing administrative costs and the Low Income Weatherization Program costs. Tr. p. 1917. The effect of IPCo's proposal is to add $1,113,387 to the 1993 test year revenue requirement.

Additionally, Staff recommended that IPCo begin amortization of DSM program expenses as they are incurred. In the past, DSM costs have accumulated until a rate case, and amortization does not commence until the conclusion of the rate case. Under Staff's proposal, IPCo would begin amortization of the costs as they are incurred, although the investment would not be recognized in rates until a subsequent rate case is completed. Tr. p. 1918.

Based on the record presented, we find it prudent and just for IPCo to expense administrative costs associated with the DSM programs, as well as the Low Income Weatherization Program costs. According to the testimony, this amounts to an addition of $1,113,387 to the 1993 test year revenue requirement.

We also are concerned with the length of time that DSM program expenses were allowed to accumulate prior to the filing of this rate case, resulting in accrued expenses in excess of $20 million. We decline to adopt Staff's proposal to order immediate amortization of DSM costs. We find it reasonable to require that commencement of amortization begin after no more than three years. In the future, IPCo must begin amortization of accumulated DSM costs after a three year period.

4. Other Rate Base Adjustments.

Various other adjustments to the rate base were proposed by Staff and intervenors, some of which were agreed to by IPCo. Recommendations were made regarding adjustments to customer deposits, fuel inventory, and the Voluntary Employee's Beneficiary Association (VEBA) trust account. Regarding customer deposits, Staff recommended reducing rate base by $244,887, the amount of the customer deposits. Tr. p. 1926-27. IPCo opposed the recommended adjustment, stating that customer deposits have no relation to electric plant in service or rate base. Tr. p. 2790.

Irrigators recommended an adjustment to the 45-day fuel inventory allowance. Tr. p. 1172-73. IPCo agreed the fuel inventory amount should be reduced by $891,905. Tr. p. 2841.

Finally, Staff identified a data entry error regarding the VEBA trust account, resulting in a $300,000 error in the rate base amount. In its rebuttal testimony, IPCo agreed the error needed to be corrected. Tr. p. 2779.

On this record, we find the rate base amount should be reduced by $891,905, relating to fuel inventories, and increased by $300,000 relating to the VEBA trust account. We find that a reduction for customer deposits is not just and reasonable. Customer deposits on which IPCo pays interest do not represent cost-free capital to the Company, as do other rate base deductions such as customer contributions and deferred income taxes.

5. Summary of Adjustments to Test Year Revenues, Expenses and Rate Base.

Considering all the evidence presented, and including all adjustments, we find reasonable and just total operating expenses for the 1993 test year in the amount of $402,850,697, and total operating revenues in the amount of $520,490,238. After all adjustments, we find a 1993 total rate base amount of $1,416,547,976 to be just and reasonable. The Idaho jurisdiction rate base is $1,221,624,208; Idaho operating expenses total $348,622,215, and operating revenues total $445,178,729 for the 1993 test year. Appendix 1 to this Order shows the Commission's findings on rate base and operating results for the test year.

CAPITAL STRUCTURE AND RATE OF RETURN

IPCo proposed that its actual capital structure at December 31, 1993, adjusted for the American Falls Bond Guarantee and the Milner Dam Note Guarantee, be used to ascertain the overall rate of return on rate base. The 1993 capital structure consisting of 45.475% long-term debt, 9.103% preferred equity, and 45.422% common equity was specifically agreed to by Staff and DOE, and received no objection from other intervenors. Thus, we find IPCo's actual capital structure at December 31, 1993 to be appropriate for calculating the Company's overall rate of return.

The Company calculated its rates for costs of debt and preferred equity associated with the December 31, 1993 capital structure to be 8.024% and 6.083%, respectively. Tr. p. 729-730. No party disagreed with the Company calculation, and thus we find the 8.024% cost of debt and the 6.083% cost of preferred equity to be just and reasonable.

It remains for the Commission to determine the appropriate cost of common equity capital. The cost of common equity capital, stated as a rate of return on common equity, is a function of several variables, and is primarily an attempt to quantify a rate of return required by investors for that particular investment. IPCo requested a rate of return of 12.5% on the common equity portion of its capital structure.

Different methodologies exist to analyze and ascertain a fair rate of return on common equity capital, including discounted cash flow (DCF) method, risk premium analysis, and comparable earnings method. Each method attempts to ascertain a rate of return on common equity at a point sufficiently attractive that free-market investors will consider purchasing common equity shares in a company. As with other analytical tools used in the ratemaking process, the methods to evaluate a common equity rate of return are imperfect predictors of future performance. Additionally, the rate of return on equity specified by a regulatory agency is but one factor considered by prudent investors when evaluating a utility's stock. A utility's stock performance in the market-place is determined by many variables, including management decisions, weather and stream-flow conditions, and a host of separate economic factors.

The Commission in previous cases has relied on the DCF and comparable earnings methods to determine an appropriate rate of return on common equity. The DCF analysis utilizes the dividend rate, stock price and expected growth rate of a company to quantify the return required by the investor. The comparable earnings method evaluates returns earned by other companies, including utilities, to quantify an investor's expected return, taking into account the risk associated with the particular investment. A third methodology to determine a required rate of return on common equity is the risk premium analysis. The risk premium method starts with a rate of return for a low risk investment, such as government or utility bonds, and adds a premium based on the relative risk associated with a utility's stock.

Using DCF and risk premium analyses, IPCo witness Avera recommended a range of 12% to 13% as a required rate of return on equity for IPCo. Avera presented two DCF methods—the first, using the traditional constant growth method, was applied to IPCo directly and to a proxy group of twelve other electric utilities of comparable investment risk. When applied by Avera to IPCo specific data, the constant growth DCF yielded a rate of return range from 11.85-12.35%. Tr. p. 863. When applied to the selected proxy group, this DCF method produced a return between 10.75% and 11.75%. Tr. p. 865. Avera's second DCF method used growth rates developed for IPCo and the proxy group of electric utilities based on near-term growth rates for the period ending 1998, followed by long-term rates based on projected growth in the gross domestic product (GDP). Combining these projected growth rates with dividend yields used in the standard constant growth DCF analyses, Avera produced a cost of common equity of 13.1% for IPCo and 11.6% for the proxy group. Tr. p. 871.

In his constant growth DCF analyses, Avera used a dividend yield of 8.1% for IPCo, although the average dividend yield for 1993 was 6.1%. Tr. p. 856. Avera affirmed on cross-examination that the most recent time the average yield for IPCo was near 8.1% occurred in 1988, when the average yield was 8.0%. Tr. p. 983. Avera also testified on cross-examination that in determining a growth rate of 3.75% to 4.25% for IPCo he was looking for a return on equity range of 10.4% to 14%. Tr. p. 998. Avera discarded 17 of 24 growth rate observations that produced a cost of equity less than 10.4% when combined with a dividend yield of 8.1%. Tr. p. 993. Avera also testified that he gave little or no weight to extreme values. However, included in his constant growth DCF analysis of the proxy group was a 33.92% growth rate for

General Public Utilities (GPU), which had a "large effect" on the calculated average. Tr. p. 916. Eliminating GPU reduced average earnings growth from 11.91% to 9.9% in the proxy group.

Avera also presented a risk premium analysis to determine the required rate of return on common equity for IPCo. Relying on leading studies adjusted for present capital market conditions and risk differences, Avera presented nine different risk premium studies to arrive at an implied range for IPCo of 12.25% to 13.25%. Tr. p. 893. Avera conceded that none of the risk premium studies provides a precise measure of the cost of equity for IPCo. Tr. p. 935.

DOE witness Kahal also performed DCF and risk premium analyses. Kahal applied his DCF analysis to IPCo, obtaining a rate of return range of 10.4% to 11.4%. In the proxy group of utility companies used by Avera, Kahal obtained a range of 10.4% to 10.9% for a rate of return on common equity, and in his own proxy group of 17 electric utilities, Kahal obtained a rate of return range of 10.9% to 11.4% for common equity. Tr. p. 1437. Kahal attributed the primary differences between his constant growth DCF results and Avera's results to different assumptions of growth rates, asserting that Avera was too selective in the data used. Tr. p. 1473. Elimination of earnings growth for GPU, as well as the lowest growth rate figure, reduced the calculated growth rate from 5.3% to 3.7%, implying a DCF return on common equity result of 10.1% for Avera's proxy group. Tr. p. 1475.

Kahal's risk premium study compared FERC benchmark returns for the period 1985 through 1991 to treasury bond yields and single A-rated utility bond yields. This method produced risk premiums of 3.7% and cost of equity estimates of 11.2%, when compared to treasury bond yields, and 2.2% and 10.7%, respectively, when compared to single A-rated utility bond yields. Tr. p. 1491. Kahal also criticized Avera's risk premium studies as being too reliant on the DCF analysis, thus not providing an independent analysis to determine the required rate of return on common equity. Kahal testified the use of historical market conditions 10 to 20 years old in Avera's risk premium study was inappropriate. Tr. p. 1487-88.

Industrial also presented testimony regarding IPCo's analysis of its required rate of return on common equity. Of the various methods used by IPCo, Industrial preferred the constant-growth DCF method but like DOE, criticized Avera's selective rejection of data used to calculate the growth rate. Inclusion of the data rejected by Avera, according to Industrial, reduced the recommended return on equity range from 11.85 - 12.35% to 9 - 11% for IPCo. Tr. p. 1349.

Staff witness Carlock presented DCF and comparable earnings analyses. Carlock estimated near-future equity rates of return for industrial companies to be in the range of 12% to 13%. Tr. p. 2112 Using this estimate, current utility returns and risk differentials between IPCo and other utilities, Carlock utilized a comparable earnings analysis to estimate the current rate of return on common equity for IPCo to be in the range of 10.5% to 11.5%. Tr. p. 2117. Using price data in the DCF model from May through October, 1994 Carlock calculated a DCF rate of return recommendation of 10.2 to 11.2% for IPCo. Tr. p. 2119-2212. Considering the results of the various studies, Staff recommended a rate of return of 10% to 11% on common equity for IPCo.

Because risk is relevant to an investor's decision to purchase stock and a determination of the required return on equity, considerable testimony was presented on the overall operating and business risks faced by IPCo, as well as its relative risks compared to other electric utilities. IPCo identified risks associated with financing new construction, industry restructuring, CSPP purchases, hydro plant relicensing, and environmental concerns, especially with respect to anadromous fish runs. Staff testified that IPCo is less risky and thus a safer investment than most electric utilities and industrials because of its low-cost power, customer mix, stable demand, and capital structure. Staff also testified that IPCo's risks have been reduced by drought surcharges, the PCA, and rate base assurances for the Swan Falls and Milner projects. Tr. p. 2113-2114. Regarding risks for IPCo associated with a competitive market, Industrial claimed that neither retail wheeling nor increased competition are being actively promoted in Idaho and, in any event, IPCo is in a favorable position to meet competition. Industrial claimed that the PCA reduces the Company's risk and therefore its required rate of return on common equity. Tr. p. 1351-1353. Similarly, DOE recommended that the Commission's findings in this case should take into account the risk-reducing benefit of moving to a 90% reconciliation of power supply cost variation through the PCA. Tr. p. 1447.

The evidence in this case supports a required rate of return on common equity anywhere between 9% and 13.25%. We find IPCo's reasonable required rate of return on common equity to be 11%. When this rate is included in the calculation of IPCo's cost of capital, it results in an overall rate of return of 9.199%. See Appendix 2. A return on common equity of 11% falls within the ranges recommended by Staff, Industrials, and DOE. Although it falls below the recommended range of IPCo's witness, sufficient doubt was cast on IPCo's

DCF analyses to limit its usefulness to the lower end of its recommended range. The testimony revealed that including the growth rate data IPCo rejected in the DCF analysis produces a required rate of return in a range of 9% to 11% for IPCo. The return we authorize is within that range and takes into account the factors IPCo asked us to consider in our adoption of an equity return.

IPCo requested that it receive a higher rate of return than it otherwise would were it not for its efforts in conservation programs, customer relations, and in regard to small power producers (CSPP). Specifically, IPCo requested an adder or bonus of .5% be added by the Commission in determining IPCo's reasonable return on equity. The Company's recommended return of 12.5% includes the proposed bonus. Tr. p. 56-57, 797-798. IPCo's request for a bonus is grounded in its interpretation of the Commission's direction to utilities in Order No. 22299, issued January 26, 1989 in Case No. U-1500-165, to move aggressively to pursue DSM programs. IPCo cites the following language from that Order as the basis for its request for an equity rate of return bonus:

> Accordingly, we take this opportunity to notify our regulated electric utilities that in future rate cases we will take into account the utility's commitment to energy conservation in determining the allowed rate of return. A utility that aggressively addresses the issues and concerns found in this Order, all other things being equal, may expect the allowance of higher returns that might otherwise be allowed.

Order No. 22299, p. 19. Tr. p. 36-37.

Staff and several intervenors addressed the possible bonus to return on equity. Staff witness Hart testified that IPCo's efforts in the areas of customer relations and DSM programs have improved significantly since its last rate case. According to Hart, the Company, by implementing programs to improve customer relations, has achieved an overall satisfactory performance in that area. Tr. p. 1843-44. Hart also testified of IPCo's improved efforts to pursue DSM programs. Tr. p. 1848. Staff recommended that IPCo receive recognition not as a reward for past exemplary performance, because IPCo's efforts are not yet exemplary, but as an incentive to continue improvements that have been made. Tr. p. 1850-51. Staff recommended a temporary two year bonus incentive of .15% be added to the required rate of return on equity. Tr. p. 2126-27.

Industrial witness Saleba testified that IPCo should receive no bonus for its efforts regarding DSM, CSPP and debt refinancing. Saleba testified that it was not necessary to reward a utility for what is merely prudent business decisions. Tr. p. 1354. Similarly, FMC witness Peseau testified that no bonus is justified because IPCo management, in making needed improvements and prudent business decisions, "was only doing its job." Tr. p. 2356. Commercial witness Eberle also testified that IPCo should not receive a bonus "for doing the job they are expected to do." Tr. p. 1630.

We find IPCo has significantly improved its efforts in customer relations since its last rate case, and has responded appropriately to the Commission's earlier directive to increase DSM efforts and programs. The decrease in customer complaints over the past few years demonstrates a serious commitment by IPCo to improve its handling of customer service issues. Particularly noteworthy is the Company's efforts to improve communications with Hispanic customers. We also note that the intervenors complimented the Company on its cooperation during this case and we appreciate those efforts.

We also are generally satisfied with the efforts made by IPCo since 1989 to develop and implement DSM programs. IPCo's conservation efforts have helped it maintain its energy surplus and delay the construction of costly new generating facilities.

Finally, we believe certain management decisions made by IPCo demonstrate sound business judgment and are worthy of recognition. During the late 1970s and early 1980s many electric utilities nationwide committed themselves to nuclear energy production, which for some has turned to disaster in the 1990s. IPCo was able to avoid the push for nuclear production and still meet increased energy demands, and as a result remains a solid, low-cost energy provider.

IPCo is to be commended for these and other appropriate actions and, as the Commission stated in Order No. 22299, is entitled to a higher rate of return on equity than might otherwise be allowed. However, we decline to state a specific, quantified bonus added to the rate of return to recognize such efforts. The Commission reviewed all the evidence bearing on the determination of a reasonable rate of return, including the commendable decisions and efforts made by IPCo. The rate of return determined by the Commission includes consideration of the Company's efforts in conservation, customer relations, and other areas, and is higher than it would have been if such efforts had not been made.

CALCULATION OF REVENUE DEFICIENCY

Having determined the Idaho rate base, revenue requirement and return on common equity, we proceed to determine the Idaho revenue requirement with the following calculation:

Rate base	$1,221,624,208
Rate of Return	9.199%
Revenue Requirement	$112,377,211
Operating Income	$101,916,158
Income Deficiency	$10,461,053
Incremental Tax Multiplier	1.642
Revenue Deficiency	$17,177,048

Appendix 2 to this Order shows the calculation of cost of capital and calculation of revenue deficiency for IPCo.

COST-OF-SERVICE STUDY AND FMC INTERRUPTIBILITY CREDIT

1. Adjustments to the Cost-of-Service Study.

In IPCo's two previous rate cases, the Commission was presented with numerous cost-of-service studies based on IPCo's own loads and resources. In each case, the Commission selected a weighted 12 coincident peak (W12CP) method to allocate costs among customer classes. The Commission determined that a cost-of-service study based on the W12CP method best met the objectives to reasonably distribute the costs of providing electrical service among the customer classes. See e.g., Order No. 21365, p. 15.

In this case, the Commission was presented with only one cost-of-service study, a study based on the W12CP method prepared by the Company, and the IPCo study as modified by Staff. The testimony in this case almost universally supports the use of a W12CP methodology, and thus we find it appropriate and reasonable to once again utilize the W12CP methodology to establish revenue requirement for the customer classes. However, we are aware of the limitations of any cost-of-service study, keeping in mind, as stated by IPCo, that "the preparation of a cost-of-service study is still a combination of art and science with the results hinging on key assumptions and allocation methods." Tr. p. 2990. The dynamic nature of a cost-of-service study is reflected in the fact that the results of the W12CP study in this case vary widely from the results of the same study in IPCo's last rate case. Tr. p. 1524-25. As we stated in an order issued in IPCo's last rate case, "cost-of-service studies provide a useful starting point for allocating revenues, but in the end we must, and do, consider other factors such as rate continuity, equity and proportionality." Order No. 21365, p. 13.

Although there was agreement on the use of the particular cost-of-service study, Staff and several intervenors testified regarding adjustments to the study that affect the end results.

A. Production Plant. IPCo's method of classifying production plant is based on a system load factor of 67.57%, thus 67.57% of production plant costs are classified as energy related. IPCo's system load factor is up from approximately 60% in its past case to almost 68% in this case, which places more weight on the energy component of production. The balance of production costs, 32.43%, are classified to the demand function.

Noting that certain conditions for IPCo have changed since the last case, Micron recommended placing less emphasis on energy and a correspondingly greater emphasis on demand to classify production plant. While use of the system load factor method of classifying production plant costs between demand and energy may have been appropriate in the past, Micron contended that changed conditions justified use of a different classification method in this case. Micron identified a change in IPCo's load and resource balance and the implementation of a PCA as the changed circumstances. Micron recommended giving equal weight to both energy and demand functions by classifying production plant costs evenly between demand and energy. Tr. p. 1286.

Staff in rebuttal responded to Micron's proposal, testifying that IPCo's method of classifying production plant is not arbitrary, but is based on a system load factor of 67.57%. Staff contended Micron's proposal to classify production plant as 50% demand and 50% energy is much more arbitrary. Tr. p. 2037-38. Citizens testified that IPCo's use of the system load factors is appropriate and is consistent with guidelines prepared by the National Association of Regulatory Utility Commissioners (NARUC). Tr. p. 2165-67.

We find: Use of a system load factor to classify production plant between energy and demand is appropriate.

B. Allocation of Transmission and Distribution Costs. IPCo classified transmission plant related to remotely sited plant or other power supply in the same way it does generation plant and classified the remainder of the transmission system based on peak loads. Citizens recommended a change in the classification of part of the transmission system costs, noting that the transmission system provides more than peak load services and costs of transmission do not rise proportionately with peak load, and therefore should be allocated at least in part based on average demand. Tr. p. 2167-71. Citizens recommended allocating 66.7% of distribution plant investment to the various classes on the basis of distribution system peak load and 33.3% on the basis of average loads. Micron contended that peak loads should not dictate how fixed costs are allocated. Industrial opposed Citizens' suggestion to reclassify transmission costs, noting that cost causation is recognized as a fundamental criterion in assigning costs to various customers. Industrial contended that where facilities are used to meet multiple needs, the system load factor is perhaps the best way to allocate common costs to the different cost causers or consumers. Tr. p. 1383-85. IPCo also responded to Citizens' recommendation, testifying that it is not appropriate to assign responsibility for transmission costs based on average demand.

We find: The method used by the Company to allocate transmission and distribution costs is appropriate in this case. We do not believe that average demand is more appropriate than peak demand or number of customers in the allocation of these costs.

C. Allocation of Administrative and General Costs. In its cost-of-service study, IPCo allocated administrative and general (A&G) costs based on the classification of wage and salary expenses. Noting that only 38% of these expenses are labor related costs, Citizens contended that the remaining 62% of A&G expenses should be allocated based on something other than labor related allocators. Tr. p. 2195-97.

We find: The allocation of administrative and general costs in IPCo's cost-of-service study should not be modified.

D. Allocation of Operation and Maintenance Expenses. For purposes of the cost-of-service study, IPCo separates the charges in each operation and maintenance (O&M) account into "labor" and "other." O&M labor costs related to a particular function are allocated based on that function. For example, O&M labor costs classified as production plant related are allocated on the same basis as other production plant costs–in this case, about 68% to energy and 32% to demand. Tr. p. 1360. Industrial recommended classifying the "other" portion of the O&M

accounts in the same manner in which the production accounts are classified. Industrial contended a general ratemaking practice is to classify expense accounts associated with generating resources on the same basis as the plant accounts of the generating resources being operated and maintained. IPCo in rebuttal testified that it generally followed NARUC guidelines in classifying the O&M expenses. IPCo cited the general NARUC guideline to classify the variable costs as energy related and the fixed costs as demand related. IPCo considers the "labor" costs associated with the accounts to be fixed costs. The expenses included in the "other" portion of the accounts are variable costs associated with the amount of energy produced, and thus are appropriately classified as energy related. Tr. p. 2880-81.

We find: IPCo's allocation of its non-labor power generation O&M expenses in its cost-of-service study is appropriate.

E. Marginal Cost Weighting Factors. IPCo used the marginal cost study to derive the weighted demand and energy allocators used in the class cost-of-service study. IPCo testified that when using costs contained in the marginal cost study to develop demand and energy weighting factors that are applied to individual cost components in the class model, it is appropriate for such weighting factors to reflect the seasonal cost responsibility of each of the individual cost components. Tr. p. 2896. According to IPCo, use of marginal costs to derive demand and energy allocators in the class cost-of-service study results in the allocation of costs to the classes which reflects seasonal cost responsibility. The marginal generation capacity costs in IPCo's cost-of-service study receive a zero weighting in September and October. Tr. p. 1203.

Arguing that marginal cost factors are inconsistent and counterintuitive, Irrigators recommended that marginal cost factors not be used at all in the class cost-of-service study. Tr. p. 1200-06. Staff testified that marginal cost factors with a value of zero are inconsistent with the purpose of spreading cost responsibility on a seasonal basis. Staff recommended replacing the zeros in the September and October months with the weighting factors used in the spring months when loads are similar.

We find: The use of marginal cost weighting factors in the cost-of-service study appropriately assigns cost responsibility. However, we agree with Staff that the use of zero weighting factors is inconsistent. Accordingly, we assign weighting factors to the month of September and October with the same weighting factors used for the spring months of April and May.

F. Classification of CSPP and Conservation Costs. IPCo's class cost-of-service study classified the costs associated with cogeneration and small power production (CSPP) based on the type of payment made to developers. Thus, capacity payments are classified as capacity related costs and energy payments are classified as energy related costs. Tr. p. 2877-78. Because IPCo cannot call upon the capacity provided by CSPP when needed nor rely upon any given amount of capacity to be available at any point in time, the capacity value for CSPP is small. Accordingly, the methodology used by IPCo to classify CSPP related costs to demand and energy results in the classification of approximately 92% of the costs as energy related. Tr. p. 2878-79. IPCo classified its investment in conservation for DSM programs on the basis of energy.

Industrial and FMC both recommended reclassification of CSPP and conservation program costs. Industrial contended that CSPP resources provide most of their capacity in the summer months when IPCo needs capacity most, and thus their costs should be classified more to demand. Industrial recommended classifying CSPP purchases in the same manner in which IPCo classifies production plant, i.e., approximately 68% to energy and 32% to demand. Tr. p. 1359. FMC made a similar recommendation. Tr. p. 2364.

We find: The CSPP purchases primarily have value to IPCo as energy resources and not capacity resources. Accordingly, IPCo's classification of its CSPP related costs is appropriate. We also find that conservation resources provide both demand and energy benefits and should be classified accordingly. The easiest method to classify conservation program expenses is in the same manner in which generation resources are classified, i.e., on the basis of the system load factor.

G. Irrigation Sector Load Factor. Irrigators made several recommendations relating to the marginal load factors used in the class cost-of-service study and data used in the study relating to irrigation customers. For example, Irrigators recommended adjustments be made to IPCo's load data to reflect that the system peak load occurred on a Sunday during 1993. However, IPCo pointed out in rebuttal that the peak day of June 26, 1993 was a Saturday, rather than a Sunday. Irrigators' recommendations also are based on other assumptions, for example, that the irrigation load follows a specific pattern throughout the summer season.

We decline to adopt any of the additional recommendations made by Irrigators. The data used by IPCo to determine irrigation load factors is appropriate. We could not find a specific pattern of irrigation usage from year to year in this record.

2. FMC Interruptibility Credit.

The determination of a credit to FMC for the interruptible nature of its electric service affects the allocation of revenue requirement among the customer classes. To the extent FMC receives a credit and its revenue requirement is reduced, revenue requirement from other customer classes must be increased. IPCo provides electric service to FMC pursuant to a contract executed by the parties in 1974. The contract divides energy and capacity equally between primary and secondary service, and allows IPCo to interrupt service to FMC's Pocatello plant. The Commission in previous IPCo rate cases has determined that the interruptible service provided to FMC by contract is beneficial to IPCo and its customers. See e.g., Order No. 21365, p. 11 ("FMC interruptibility continues to be of value to the system"). The value of the interruptible contract with FMC is presented again in this case. IPCo did not address the issue in its direct case, but it was raised in the direct testimony of FMC, by Staff in supplemental direct testimony and by several witnesses in rebuttal testimony.

The contract between IPCo and FMC is an agreement to supply interruptible capacity and energy. The contract includes 120 MW of primary power and 120 MW of secondary power. All but 17 MW of the primary portion may be interrupted "when load and capacity condition on [IPCo's] system require." Tr. p. 2452-53. According to the contract, these interruptions cannot exceed 300 kWh per kilowatt of primary power contract amount per year. Secondary power interruptions are available at the discretion of IPCo. Tr. p. 2453. Only two constraints on interruption of secondary power exist—a maximum interruption of 4,380 kWh per kW of average secondary power contract amount per year, and a requirement that not less than 6,720 kWh per kW of average secondary power must be made available during a stated ten-year period. Tr. p. 2453.

The contract provides that when FMC is interrupted, IPCo will at FMC's election attempt to replace the interrupted power if supplies can be obtained from other sources. If FMC purchases replacement power, it must reimburse IPCo for the purchase and pay a standard rate for the service. Tr. p. 2456. The replacement power costs for the past six years total

$19,035,752, an average of $3,172,625 per year. Thus the current interruptibility credit of $1,732,497 was not sufficient to recover the energy value of FMC's actual interruptions during the past six years. Tr. p. 2467. FMC testified that an interruptibility credit must exceed FMC's out-of-pocket costs for interruptions by a substantial margin or there is no incentive to accept interruptible service and the operational problems that arise when power is interrupted. Tr. p. 2469-70.

With the possible exception of Citizen's witness, the expert witnesses in this case agree that FMC interruptibility benefits IPCo and its other customers. We find, as we did in the previous IPCo rate cases, that FMC's interruptibility is of benefit to the IPCo system. The issue regarding the FMC contract is not whether interruptibility has value, the issue is how best to quantify the value in the form of a credit to FMC.

In Case No. U-1006-185 (the -185 case), the Commission established an interruptibility credit in the amount of 2.5 mills to fully recognize the benefits afforded to IPCo. According to FMC, however, the Commission did not establish an identifiable method for quantifying the value of interruptions. Tr. p. 2459. In Case No. U-1006-265 (the -265 case), the Commission decreased the credit to 1.07 mills, resulting in a credit of approximately $1.73 million, because IPCo had ample capacity and energy to serve FMC without interruptions. Interruptions were predicted to occur in only two of 51 water years. Tr. p. 2461.

According to FMC, and contrary to the views expressed in the -265 case, FMC interruptions have been extensive, averaging 179,747 MWh per year over the past six years. Tr. p. 2463. FMC testified that the economic impact on FMC in terms of the average annual incremental additional cost of purchasing replacement power was $1,966,215 per year. Tr. p. 2468. Accordingly, FMC testified that its interruptible rates are higher than rates for firm energy provided to other large contract customers. Tr. p. 2470-71.

Stating that the energy saved by interrupting FMC is far less crucial to IPCo's system integrity than the ability to instantly add 200 MW of capacity, FMC testified that the calculation of an interruptibility credit must rely heavily on the valuation of capacity. FMC provided three methods to value the capacity cost savings resulting from FMC interruptibility. The first, described as the avoided cost of plant method, results in a credit of $12.8 million annually. FMC conceded this method does not produce a realistic result. Tr. p. 2395. The second method proposed by FMC recognizes the interruptibility credit within the cost-of-service model itself, rather than externally calculated as in the cost-of-plant method. Because FMC receives no firm generating capacity, the second method proposed by FMC allocates zero generating capacity costs to FMC. This method still allocates a large portion of generating facility costs to FMC on the basis of energy. By eliminating all but 20 MW of FMC demand from the demand allocator within the cost-of-service study, FMC's allocated costs are reduced by about $8 million, the amount of the annual credit under this proposed method. Tr. p. 2401. The final method proposed by FMC also values the capacity credit within the cost-of-service study by changing capacity allocators in given months to reflect peak demand that otherwise occurs when FMC is interrupted. After normalizing major FMC interruptions over the past six years and adjusting monthly demand allocators to reflect those interruptions, FMC estimates a capacity credit of approximately $5 million. Tr. p. 2405. FMC views this credit as conservative and the floor for the value of FMC's capacity interruptibility. Tr. p. 2406. FMC's evidence thus provides a range of $5-8 million to value an interruptible credit.

Staff also proposed a method to value the interruptibility credit. Staff's valuation method also is "internal" in that it tracks through the cost-of-service study, and the credit is reflected in a reduced cost allocation to FMC. Tr. p. 2030-31. The first step in Staff's approach is to quantify the level of FMC interruptible demand by normalizing or averaging the allowable contract interruptions over a ten-year period. This normalization results in demand interruption of 30.9 aMW and energy interruption of 140,422 MWh on an annual basis. Although the actual demand can be interrupted up to 223 MW and energy interruptions in a single year can total 561,600 MWh, in many years FMC sees little interruption. Tr. p. 2031. According to Staff's testimony, adjusting demand and energy allocators within the cost-of-service study as described results in an annual FMC credit of $4.3 million or 2.71 mills/kWh. Tr. p. 2032. Staff stressed the importance of internalizing the method used to establish the FMC credit so that jurisdictional and class cost-of-service models appropriately allocate the credit. Using Staff's approach, $747,940 is shifted from the Idaho jurisdiction to other jurisdictions. Tr. p. 2034.

IPCo in rebuttal testimony generally agreed with FMC's description of the contract terms. IPCo explained that the Company's cost-of-service study allocated costs to FMC as if it were a firm customer. IPCo did not try to model internally or calculate externally the value of FMC interruptibility because the Company did not propose to move FMC to full cost-of-service according to the results of the cost-of-service study. Tr. p. 2998. In response to Staff's testimony, IPCo testified that Staff's outcome of a $4.3 million credit is high but within a reasonable range when viewed from a historical perspective. The credit has been as high as $4 million in the past. Tr. p. 3005. If Staff's methodology is adopted, FMC's normalized revenues must be adjusted in the cost-of-service studies, according to IPCo, and FMC prices would have to be adjusted based on the new level of energy sales.

IPCo testified that many factors have combined to make a consistent method for valuing FMC interruptibility all but impossible and a determination based on subjective judgment unavoidable. IPCo testified that the reasonable rate to value the credit is between $1.8 million and $5 million. IPCo believes that Staff's approach, if modified to account for a normalized level of energy after interruptions, would be the most reasonable. Tr. p. 3008. The evidence presented establishes a range to value an annual interruptibility credit from $1.8 million, the current credit, to $8 million.

We believe the methodology developed by Staff using normalized FMC interruptions to establish demand and energy allocator reductions for use within the cost-of-service study is appropriate. We also find as reasonable a total FMC annual credit of $4.3 million. We further believe that it is appropriate to adjust only the FMC demand allocator within the cost-of-service study to achieve the FMC credit that would generally result if both demand and energy allocators were adjusted. IPCo expressed concern regarding revenue recovery potential if FMC energy allocators are adjusted in the cost-of-service model. While we generally believe that the method used to calculate the FMC credit within the model is independent of revenue generation, we also believe that it is appropriate to use consistent energy determinates throughout the process. The methodology developed by Staff is not perfect in that it reflects demand interruptions in average megawatts rather than actual demand interruptions. We also recognize that the actual amount of the credit as determined by the cost-of-service study is dependent upon the ultimate revenue requirement as determined by the Commission. However, we believe that the credit value of $4.3 million as calculated by Staff is very close to what would be calculated given the approved revenue requirement and is well within the reasonable range of credit amounts established in this case. Moreover, the methodology developed by Staff can be used in the future to assist the Commission in establishing a reasonable FMC credit.

With respect to allocation of the FMC credit among jurisdictions, we find that a 34.2 MW generation level reduction in Idaho jurisdictional demand is appropriate. This level of demand reduction within the jurisdictional separations study results in a 15% allocation of the FMC credit to other jurisdictions. A 15% allocation is consistent with percentages of other costs currently allocated to other jurisdictions on a total company basis.

CLASS REVENUE ALLOCATION

Having determined the Idaho jurisdictional revenue requirement that includes the FMC interruptibility credit, we must now determine the appropriate revenue requirement for each customer class. Appendix 3 shows the results of the W12CP cost-of-service study, with the adjustments made by the Commission.

We find: Moving all class revenue requirements to the levels shown in Table 1 would be unreasonable. Important interests in rate stability and continuity preclude adopting the extremely large shifts in revenues from one class to another that are depicted. In addition, the results of cost-of-service studies are not so precise that the determination of appropriate revenue shifts is an exact certainty. Nonetheless, the passage of time since the Commission's last examination of IPCo's rates has allowed several classes to drift further away from cost-of-service rates. Recognizing that cost-of-service studies are not precise, we think it important that cross subsidies among customer classes should be minimized. Accordingly, as outlined below we take significant steps to move each class closer to its indicated cost-of-service.

The increases shown in Appendix 3 for the small general service (Schedule 7) and the irrigation service (Schedule 24) should be tempered by important interests in rate stability and continuity for these classes. Increases of 15% and 10.23% respectively in these schedules represent significant moves toward cost-of-service and send an important price signal to customers making consumption decisions within these classes.

We also find that an increase for the residential class of 7.42% reflects a move substantially to cost-of-service. Further, we find that the rates for Schedules 9, 15, 40, 41 and 42 should be reduced by 10%. We believe that this amount of reduction in view of the overall revenue increase and the significant revenue requirement increases in other customer classes is fair and reasonable and represents a significant and balanced move toward cost-of-service rates for these classes.

The remaining classes, Schedule 19, and all special contracts customers are increased to cost-of-service. Schedule 19 is very nearly at cost-of-service and will maintain that status with a small increase. Although some of the special contracts customers will receive significant increases to reach cost-of-service, we believe that it is important to maintain the relative rate differentials among these customers. Failure to move all special contract customers to cost-of-service will result in relative average mills per kWh prices that would be inappropriate.

The final revenue allocation among the customer classes resulting from these findings is shown in Appendix 4. We are concerned that the passage of much time between examinations of cost-of-service and revenue allocation issues prevents an orderly move to cost-of-service rates. Accordingly, if a general rate case has not been filed by IPCo within two years of today's Order, we direct the Company to prepare a cost-of-service study for Staff review on or before April 1, 1997.

RATE DESIGN AND TARIFF ISSUES

IPCo made specific proposals regarding rate design for its various classes of customers. Generally, IPCo's rate design proposals are intended to create a billing structure to reflect cost-based services as derived from the results of the W12CP cost-of-service study. Tr. p. 413-18. IPCo proposed eliminating Schedule 33—Public Water Supply—believing the customers should be placed on service schedules based on their usage and not on their end uses. IPCo proposed moving the dividing line between Schedule 9 and Schedule 19 customers from 750 kw to 1,000 kw. Finally, IPCo proposed three additional changes in rate structures: (1) replace customer minimums with customer charges, (2) implement distribution capacity pricing in the form of a basic charge on all demand metered schedules (Schedules 9, 19 and 24), and (3) implement voltage service levels on Schedules 9, 19 and 24.

Staff generally accepted IPCo's proposal to replace minimum charges with customer charges. Staff also accepted the changes to the basic charge as proposed by IPCo, but would not apply the charge to Schedule 24, the irrigation class. Staff testified that the basic charge is appropriate for Schedules 9 and 19 because these two classes contain more seasonal diversity than does the irrigation class. Tr. p. 2020-22. Irrigators recommend no change in the present rate design for the irrigation class. Tr. p. 1207.

Citizens presented testimony regarding the proposed changes to the residential rate design. Citizens opposed the implementation of a customer charge, contending that a fixed charge would substantially increase the percentage impact of the overall increase on consumers with low usage. Citizens recommended the Commission approve new residential rates consistent with existing rates, an energy charge combined with a minimum monthly bill of $7.50. Tr. p. 2212.

Commercial testified that it generally supports IPCo's effort to publish tariffs that more accurately reflect the costs imposed on its electrical system. Commercial opposed IPCo's proposal to reduce the incentive for a rate schedule cross-over between Schedule 9 and 19 customers by imposing an energy surcharge on the Schedule 9 commercial primary service customers. Commercial contended the proposal is not cost-based, but is merely an attempt to remove the incentive for customers to use additional energy in order to qualify for Schedule 19 rates. Commercial recommended the Commission not allow this adjustment. Tr. p. 1648-49.

We have reviewed each of the rate design proposals presented by IPCo, and the testimony provided by Staff and intervenors. We generally approve of IPCo's effort, as did Staff and most intervenors, to create rate structures that are cost-based. We find IPCo's proposal to eliminate Schedule 33 and to change the threshold level between Schedule 9 and Schedule 19 to 1,000 kWh to be reasonable and appropriate. We also find reasonable and thus approve IPCo's proposed implementation of customer and basic charges, with one exception. The Company proposed a new basic charge of $5.45 for secondary service, Schedule 24 customers. The purpose of the basic charge is to spread cost recovery responsibility among diverse customer types within a given class. When a customer group such as the irrigation class has similar seasonal usage patterns, the basic charge provides increased complexity without improved cost recovery. Staff recommended a basic charge not be included in Schedule 24. We adopt Staff's recommendation and reject the basic charge for Schedule 24. We also adopt a single customer charge of $2.50 for both Schedule 1 and Schedule 7 (residential and small commercial).

Other specific tariff changes proposed by IPCo include changes to Schedule 66 to reflect charges for instrument transformer metering and temporary service return trips, and increasing its maximum metered testing charge for residential customers from $10 to $30. Staff provided testimony supporting the proposed changes to Schedule 66, Tr. p. 1980-81, and the proposed increase in IPCo's maximum metered testing charge to $30. Tr. p. 1982. Staff additionally recommended an amendment to the tariff to provide for one free test every 12 months. Tr. p. 1982. Staff also recommended changes to the proposed Rule H to provide for better communication regarding removal of facilities, and Rule E, to recognize that sub-metering was permitted in master-metered mobile home parks established prior to July 1, 1980. Tr. p. 1982-83. We find that the changes to Schedule 66 and the recommendations by Staff are reasonable and appropriate and we approve them.

IPCo also proposed an increase to the Schedule 45 standby reservation charge from 59¢ per kilowatt month to $1.48 per kilowatt month for primary service. Industrial presented testimony opposing IPCo's proposed increase in the Schedule 45 standby reservation charge. Industrial claimed the proposed charge is above the rate cap prescribed by the Commission in its Order establishing Schedule 45, and that the proposed rate of $1.48 per kilowatt month will result in the loss of the only customer currently purchasing standby service under Schedule 45. Tr. p. 1364-73.

The Commission approved Schedule 45 in Order No. 22887 issued in December 1989, Case No. IPC-E-89-4. The Commission did cap the standby reservation rate at .59/kw in that Order, but did not preclude a raise in the Schedule 45 rates in the future. In fact, noting the experimental nature of the new Schedule 45 and its approved rates, the Commission specifically reserved "the right to reassess its reasonableness and appropriateness as the Commission, the Company and customers gain experience in its application." Order No. 22887, p. 16. To establish rates more closely aligned with embedded costs, the Commission stated it would "require the Company to establish and document all related costs (including generation and transmission) in its next cost-of-service or general ratemaking proceeding." *Id.* at 9. IPCo testified in this case that the rates now proposed for Schedule 45 are based on the results of the W12CP cost-of-service study. Tr. p. 2912. We find the rates proposed by IPCo for Schedule 45 to be reasonably based on the costs of providing the standby service covered by Schedule 45, and thus we approve them.

ADJUSTMENT TO PCA

On March 29, 1993, the Commission in Case No. IPC-E-92-25 issued Order No. 24806 approving a power cost adjustment (PCA) for IPCo. The PCA allows IPCo to adjust its rates as actual production costs vary from year to year in relation to stream flow changes. Each year the PCA is based on annual, forecasted power supply costs. Deviations from the predicted power costs are deferred and then reconciled in the succeeding year. Initially, because it had been many years since IPCo's previous rate case, IPCo was authorized to recover only

60% of the variation between base power supply costs and actual power supply costs through the PCA mechanism. The Commission found that to be reasonable because there had been no recent Commission review of power supply costs and IPCo's allowed return on equity, including the possible risk reducing effect of a PCA. In Order No. 24806 the Commission stated it would permit IPC to recover 90% of variable power supply costs through the PCA "upon completion of any proceeding in which we reexamine Idaho Power's normalized costs and authorized return."

The Commission intended the increase in the PCA mechanism to occur after a final order in a rate case or similar proceeding that establishes new rates based on an examination of the evidence presented. That examination now being completed, it is appropriate for IPCo to recover the allowed variable power costs at the 90% level above or below the power cost base established in this case.

ENERGY COST RATES IN COGENERATION CONTRACTS

Although they did not present evidence or otherwise participate in the hearing in this case, intervenors William Arkoosh (Arkoosh) and Faulkner Brothers Hydro (Faulkner) on December 15, 1994 filed a memorandum at the close of the evidentiary record. Arkoosh and Faulkner are parties to separate Firm Energy Sales Agreements with IPCo wherein the Company agrees to purchase electricity produced by facilities owned by Arkoosh and Faulkner. Discussing in their memorandum a change in IPCo's use of hydro, thermal and purchased power, Arkoosh and Faulkner suggest "it may be appropriate to review whether the variable costs, as a portion of those costs avoided by the ratepayer in receipt of intervenors' power, should include not only fuel costs, but the costs of purchasing power elsewhere." Arkoosh and Faulkner ask the Commission "to comment" on the effect of IPCo's use of different power sources on the variable cost portion of Arkoosh and Faulkner's contract rates.

Pursuant to their contracts and prior Commission orders, the adjustable portion of the rate paid to Arkoosh and Faulkner Brothers is based on the operating costs of Valmy I and is to be adjusted during the course of every IPCo general rate proceeding. Accordingly, the Company is instructed to recalculate the adjustable payments of the Arkoosh and Faulkner contracts, consistent with the terms of the contracts and prior Commission orders, based upon the revised power supply costs approved by this Order. In the event Arkoosh and Faulkner believe that the Company has inappropriately calculated the rate or that there are issues yet to be resolved, they are free to either file for reconsideration of this Order or to file a subsequent pleading in another case for the purpose of resolving those issues.

INTERVENOR FUNDING

The Commission received requests for intervenor funding from Commercial ($50,875), Citizens ($12,925.71), Irrigators ($61,644.49), and Industrial ($139,387.46). *Idaho Code* § 61-617A authorizes an intervenor cost award not to exceed a total of $25,000 for all intervening parties combined. Intervenor awards must be based on findings that participation of the intervenor materially contributed to the Commission's decision, the costs of intervention are reasonable and would be a significant financial hardship for the intervenor, the recommendations made by the intervenor differed materially from Staff's evidence, and the intervenor's participation addressed issues of concern to the general body of users or consumers.

All four of the intervenors requesting funding provided information that materially contributed to the Commission's decisions, even though the Commission did not adopt all the proposals advocated by the intervenors. Also, each of the intervenors offered evidence that differed materially from evidence offered by Staff. Likewise, each intervenor addressed issues of concern to the general body of users or consumers, although this standard was perhaps accomplished more completely by Citizens, who participated in the case solely to represent public consumers rather than a select group of business consumers.

It is in the standard requiring consideration of reasonableness in the costs of intervention and the relative hardship for each intervenor that the findings diverge. Each of the four intervenors fully participated in the case by presenting prefiled testimony, attending the hearings, and cross-examining witnesses. Citizens request of $12,925.71 on its face is more reasonable than any other request. Likewise, compared to the other intervenors, Citizens has the best case for significant financial hardship. Citizens is a non-profit corporation that probably would not be able to participate without intervenor funding. Without Citizens' participation, low income residential consumers would not have separate representation in rate proceedings.

Based on the record and the intervenor funding requests, we find: The policy stated in *Idaho Code* § 61-617A to encourage participation in Commission proceedings "so that all affected customers receive full and fair representation" is best furthered by awarding payment of reasonable out-of-pocket expenses to all intervenors and the balance of the awardable amount to Citizens. We find that the amount of actual expenses of the Irrigators ($6,159.49) is a reasonable expense amount for this proceeding, and we thus award each intervenor its claimed actual expenses up to that amount. Accordingly, Commercial is awarded $1,840 to be recovered from Schedule 7 and Schedule 9 customers; Irrigators is awarded $6,159.49, to be recovered from Schedule 24 customers; and Industrial is awarded $6,159.49, to be recovered from Schedule 19 customers. Citizens is awarded its costs of $1,270.71, plus $9,570.31, the balance of the awardable amount after the awards for costs, to be recovered from Schedule 1 customers.

ULTIMATE FINDINGS OF FACT

Idaho Power Company is an electrical corporation subject to the Commission's regulation under the Idaho Public Utilities Law. The rates of all its tariff customers in the state of Idaho and of its contract customers are subject to this Commission's regulation under the Public Utilities Law.

The Company's present rates do not provide it with an opportunity to earn a fair and reasonable return on its investment. Allowing the Company to increase its rates and charges by $17,177,048 will provide it with the opportunity to earn a fair and reasonable return. The average 1993 test year is the appropriate test year period for use in this proceeding.

The adjusted test year net operating income for Idaho of $101,916,158 is just and reasonable for setting rates. The test year adjusted rate base for Idaho of $1,221,624,208 is just and reasonable for setting rates. Idaho Power's actual capital structure at December 31, 1993 is the appropriate one for this case and an overall rate of return of 9.199% to be applied to all rate base is a fair and reasonable rate of return for the Company.

The revenue allocation shown in Appendix 4 is a just, reasonable and non-discriminatory allocation of the Company's revenue requirement among the various customer classes. It is also fair, just and reasonable to design the customer class rates according to the directives contained in the text of this Order.

The awards of intervenor funding in the amounts of $1,840 to Commercial Utilities' customers, $6,159.49 to Idaho Irrigation Pumpers Association, Inc., $6,159.49 to Industrial Customers of Idaho Power Company, and $10,841.02 to Idaho Citizens Coalition are reasonable.

CONCLUSIONS OF LAW

This Commission has jurisdiction and authority to authorize and require Idaho Power Company to reallocate its revenues among the customer classes, to change its rate components within the customer classes, to address the other issues and to award intervenor funding in the manner set forth in the text of this Order.

ORDER

IT IS HEREBY ORDERED that Idaho Power Company file within seven days from the date of this Order rates and charges authorized by this Order for tariff and contract customers to be effective on February 1, 1995, for service rendered on and after February 1, 1995.

IT IS FURTHER ORDERED that Idaho Power Company comply with all other directives of the text of this Order.

THIS IS A FINAL ORDER. Any person interested in this Order (or in issues finally decided by this Order) or in interlocutory Orders previously issued in this Case No. IPC-E-94-5 may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter decided in this Order or in interlocutory Orders previously issued in this Case No. IPC-E-94-5. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 31st day of January 1995.

MARSHA H. SMITH, PRESIDENT

DEAN J. MILLER, COMMISSIONER

RALPH NELSON, COMMISSIONER

ATTEST:

Myrna J. Walters
Commission Secretary

vld/O-IPC-E-94-5.ws2

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
COMMISSION FINDINGS ON RATE BASE AND OPERATING RESULTS
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 1993

	TOTAL SYSTEM	IDAHO IPUC
*** ***RATE BASE*** ***		
ELECTRIC PLANT IN SERVICE	$2,275,958,733	$1,959,256,661
LESS: ACCUM PROVISION FOR DEPRECIATION	705,906,590	606,417,778
AMORT OF OTHER UTILITY PLANT	2,399,619	2,065,729
NET ELECTRIC PLANT IN SERVICE	1,567,652,524	1,350,773,154
LESS: CUSTOMER ADV FOR CONSTRUCTION	17,353,548	16,945,826
LESS: ACCUM DEFERRED INCOME TAXES	210,365,678	181,093,071
ADD : PLT HLD FOR FUTURE+ACQUIS ADJ	(422,264)	(398,585)
ADD : WORKING CAPITAL	47,311,139	41,662,865
ADD : CONSERVATION+OTHER DEFERRED PROG.	31,506,869	29,149,119
ADD : SUBSIDIARY RATE BASE	(1,781,066)	(1,523,449)
TOTAL COMBINED RATE BASE	$1,416,547,976	$1,221,624,208

	TOTAL SYSTEM	IDAHO IPUC
*** ***OPERATING RESULTS*** ***		
REVENUES		
SALES REVENUES	$493,994,272	$429,573,971
OTHER OPERATING REVENUES	26,495,966	15,604,758
TOTAL OPERATING REVENUES	$520,490,238	$445,178,729
OPERATING EXPENSES		
OPERATION & MAINTENANCE EXPENSES	$272,850,444	$238,884,105
DEPRECIATION EXPENSE	62,745,730	54,311,559
AMORTIZATION OF LIMITED TERM PLANT	(2,962,493)	(2,550,258)
TAXES OTHER THAN INCOME	22,946,025	19,787,625
PROVISION FOR DEFERRED INCOME TAXES	9,949,243	8,564,795
INVESTMENT TAX CREDIT ADJUSTMENT	(590,924)	(508,696)
FEDERAL INCOME TAXES	33,802,675	26,866,449
STATE INCOME TAXES	4,109,997	3,266,635
TOTAL OPERATING EXPENSES	$402,850,697	$348,622,215
OPERATING INCOME	$117,639,541	$96,556,515
ADD: IERCO OPERATING INCOME	6,265,967	5,359,644
CONSOLIDATED OPERATING INCOME	$123,905,508	$101,916,158
RATE OF RETURN UNDER PRESENT RATES	8.747%	8.343%

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
COMMISSION FINDINGS ON RATE OF RETURN AND REVENUE DEFICIENCY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 1993

*** *CALCULATION OF COST OF CAPITAL* ***

CAPITAL COMPONTENT	RATIO	COMPOSITE COST	RATE OF RETURN
LONG TERM DEBT	45.475%	8.024%	3.649%
PREFERRED STOCK	9.103%	6.083%	0.554%
COMMON STOCK	45.422%	11.000%	4.996%
TOTAL	100.000%		9.199%

*** *CALCULATION OF REVENUE DEFICIENCY* ***

	TOTAL SYSTEM	IDAHO IPUC
RATE BASE	$1,416,547,976	$1,221,624,208
RATE OF RETURN REQUIRED	9.199%	9.199%
NET OPERATING INCOME REQUIRED	$130,308,248	$112,377,211
NET OPERATING INCOME REALIZED	123,905,508	101,916,158
EARNINGS DEFICIENCY	$6,402,740	$10,461,053
NET-TO-GROSS TAX MULTIPLIER	1.642	1.642
REVENUE DEFICIENCY	$10,513,300	$17,177,048
PERCENT INCREASE REQUIRED	2.20%	4.19%

ORDER NO. 25880
APPENDIX 3

Idaho Power Company
12W CP Cost-of-Service Study
Idaho Jurisdiction
12 Months Ending December 31, 1993
Proformed Normalized

Line No.	Tariff Description	Rate Schedule No.	Proformed Normalized Revenue	Average Mills Per kWh	W12 CP Revenue Increase	W12 CP Percent Increase	W12 CP Average Mills/KWH
	Uniform Tariff Rates:						
1	Residential Service	1	166,267,206	47.18	13,109,459	7.88%	50.90
2	Small General Service	7	12,211,325	54.03	3,016,762	24.70%	67.38
3	Large general Service	9	77,081,869	39.10	(10,972,720)	-14.24%	33.53
4	Area Lighting	15	1,488,756	282.26	(1,281,287)	-86.06%	39.34
5	Large Power Service	19	42,432,754	26.92	1,034,534	2.44%	27.57
6	Irrigation Service	24	56,030,726	34.56	10,077,978	17.99%	40.78
7	Public Water Supply	33	3,621,786	36.00	64,500	1.78%	36.64
8	Unmetered General Service	40	273,808	60.21	(94,717)	-34.59%	39.38
9	Municipal Street Lighting	41	1,660,885	132.83	(609,567)	-36.70%	84.08
10	Traffic Control Lighting	42	194,598	33.78	(34,662)	-17.81%	27.76
11	Total		361,263,713	39.93	14,310,280	3.96%	41.51
	Special Contracts:						
12	Micron	26	6,442,182	23.17	131,009	2.03%	23.64
13	FMC	28	32,553,763	20.47	1,438,038	4.42%	21.38
14	JR Simplot	29	5,434,627	21.46	673,981	12.40%	24.12
15	DOE	30	3,573,125	20.74	623,739	17.46%	24.36
16	Total		48,003,697	20.93	2,866,767	5.97%	22.18
17	Total Idaho Retail Sales		409,267,410	36.09	17,177,047	4.20%	37.60

ORDER NO. 25880
APPENDIX 4

Idaho Power Company
Final Revenue Allocation to the Customer Classes
Idaho Jurisdiction
12 Months Ending December 31, 1993
Proformed Normalized

Line No.	Tariff Description	Rate Schedule No.	Base Normalized Revenue	Base Average Mills/KWH	Ordered Revenue Increase	Ordered Percent Increase	Ordered Average Mills/KWH
	Uniform Tariff Rates:						
1	Residential Service	1	166,267,206	47.18	12,337,027	7.42%	50.68
2	Small General Service	7	12,211,325	54.03	1,831,699	15.00%	62.14
2a	Sch 7 (Public water supply)	7	234,959	36.00	3,076	1.31%	61.50
3	Large general Service	9	77,081,869	39.10	(6,166,550)	-8.00%	35.97
3a	Sch 9 (Public water supply)	9	3,386,827	36.00	(96,902)	-2.86%	34.01
4	Area Lighting	15	1,488,756	282.26	(148,876)	-10.00%	254.04
5	Large Power Service	19	42,432,754	26.92	1,034,534	2.44%	27.57
6	Irrigation Service	24	56,030,726	34.56	5,731,943	10.23%	38.10
7	Unmetered General Service	40	273,808	60.21	(27,381)	-10.00%	54.19
8	Municipal Street Lighting	41	1,660,885	132.83	(166,089)	-10.00%	119.55
9	Traffic Control Lighting	42	194,598	33.78	(19,460)	-10.00%	30.40
10	Total		361,263,713	39.93	14,313,022	3.96%	41.51
	Special Contracts:						
11	Micron	26	6,442,182	23.17	131,009	2.03%	23.64
12	FMC	28	32,553,763	20.47	1,438,038	4.42%	21.38
13	JR Simplot	29	5,434,627	21.46	673,981	12.40%	24.12
14	DOE	30	3,573,125	20.74	623,739	17.46%	24.36
15	Total		48,003,697	20.93	2,866,767	5.97%	22.18
16	Total Idaho Retail Sales		409,267,410	36.09	17,179,789	4.20%	37.60