Office of the Secretary
Service Date
September 28, 2001

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE IDAHO POWER COMPANY APPLICATION FOR A REFUNDABLE EMERGENCY ENERGY CHARGE FOR THE RECOVERY OF EXTRAORDINARY POWER SUPPLY EXPENSES.	**CASE NO. IPC-E-01-7**
IN THE MATTER OF THE IDAHO POWER COMPANY APPLICATION FOR AUTHORITY TO IMPLEMENT A POWER COST ADJUSTMENT (PCA) RATE FOR ELECTRIC SERVICE FROM MAY 1, 2001 THROUGH MAY 15, 2002.	**CASE NO. IPC-E-01-11** **ORDER NO. 28852**

BACKGROUND

A. Procedural History

In Order No. 28722 issued May 1, 2001, the Commission partially granted Idaho Power's Power Cost Adjustment (PCA) Applications and allowed the Company to immediately recover approximately $168.3 million through the PCA mechanism. The Commission deferred recovery of $59,211,603 pending further investigation of the trading practices used to purchase power for the regulated Company, including hedging against market volatility, transmission and wheeling charges, Mid-C pricing, and the use of weighted average pricing. Order No. 28722 also identified "the November trading event" for further investigation to determine whether the purchasing entity failed to execute a timely purchase of power when requested to do so. On August 28-30, 2001, the Commission conducted an evidentiary hearing on these issues.

After reviewing the record in this matter, the Commission has determined that the Company should be allowed to recover $48,856,748 ($47,665,120 plus interest of $1,191,628) by imposing a uniform 0.3826¢ per kilowatt hour charge for all non-residential customers over a one-year period. The first two blocks of the residential rate will increase by 0.430¢ per kilowatt hour over a one-year period. The Commission's findings are set out in greater detail below.

B. Parties

In these consolidated cases, the Commission granted intervention to: Astaris LLC, Irrigation Pumpers Association, Inc., U.S. Department of Energy, Land and Water Fund of the

Rockies, Mary McGown, Idaho Rivers United, Idaho Rural Council and the Industrial Customers of Idaho Power. The Land and Water Fund, Mary McGown, Idaho Rivers United and the Idaho Rural Counsel later withdrew their submitted comments and participation in this phase of the consolidated cases.

Prefiled testimony was submitted by the Commission Staff, Idaho Power, and the Irrigation Pumpers Association. Although the Irrigation Pumpers Association submitted prefiled testimony, it subsequently withdrew from the proceeding. Consequently, our record in this case does not include the Association's prefiled testimony. Although the Industrial Customers of Idaho Power (ICIP) did not prefile testimony, it was the only intervenor to enter an appearance at the evidentiary hearing and participated by cross-examining witnesses.

ISSUES IN DISPUTE

In Order No. 28722, the Commission specifically identified the November Trading Event and Idaho Power's trading practices, which include hedging, use of weighted average pricing for real-time transactions, use of Mid-C pricing for day-ahead transaction pricing, and its transmission and wheeling charges for further investigation. These issues are discussed at length below.

A. November Trading Event

During the PCA audit, Staff identified a 75 MW term transaction (the "November Trading Event") for the regulated system for January 2001 that was ordered by the Risk Management Committee (RMC) in its November 21, 2000 meeting minutes, but was never completed by the trading entity. When a purchase was subsequently made to meet this need, the market price of power had substantially increased.

Staff witness Carlock argued that the Company should not be allowed to recover the additional $8 million for higher-priced replacement power because the need for the power had been identified but the Company failed to follow through on the purchase. Tr. at 344. Idaho Power witness Gale maintained that the apparent oversight in the RMC minutes is "a record keeping issue and not one of execution." Tr. at 599. Idaho Power argued the transaction was not completed because the RMC changed its decision later during the same meeting. However, this change was not recorded in the meeting minutes because of a "clerical error." Tr. at 144. Furthermore, Company witness Anderson testified that the system did not need to purchase power for January 2001 because it had a net long position of 1,300 MW through the balance of the 2000-2001 PCA year despite net short positions of 80 MW in December 2000 and 63 MW in January 2001. Tr. at 125.

Staff argues that the Company's record keeping error explanation is not persuasive because the Company's operating plans showed that under nearly every scenario the system would be short in January and thus a term transaction was supported. Tr. at 343. Absent additional documentation of its rationale, Staff contends the Company's alleged subsequent decision to rescind the term transaction was contrary to the prudent decision originally made. Tr. at 419-20. Consequently, Staff advocated that these additional costs should be absorbed by the non-system operations rather than recovered from customers. Tr. at 344.

Commission Findings: After reviewing the testimony of Staff witness Carlock and Company witness Anderson, the Commission must evaluate the reasonableness of the situation based on the information known at the time of the transaction. To assist us in that exercise, the Company must keep detailed and accurate records so that the Commission can correctly assess issues in dispute. Idaho Power's minutes and supporting documents were the primary source of information regarding its contemplation of long-term transactions. Company witness Darrel Anderson testified that Idaho Power was short 63 MW for the month of January 2001 and the RMC decided unanimously to make a term purchase to cover this shortfall. Tr. at 125, 142. According to his testimony, the RMC reversed its original decision later during the same November 21, 2000 meeting. Tr. at 126. However, the Company's record keeping does not support the testimony of the Company's witness. Mr. Anderson also testified that Idaho Power has since changed its handling of RMC minutes to prevent such mistakes from occurring in the future, but that is neither helpful nor applicable to our review of November 2000. Tr. at 127.

Given the operating plans, water forecasts and scenario analyses considered by the RMC on November 21, 2000, the documented decision to purchase the 75 MW hedge was a reasonable and prudent determination that guaranteed adequate power during a peak winter month. Any decision to the contrary was not recorded in the minutes and is unsupported by any other documentation. Moreover, Mr. Anderson testified that if the RMC failed to send a written authorization to the trading entity, the decision to purchase the 75 MW would not have occurred. Tr. at 156. Without evidence of the written authorization or other documents to support the testimony of the Company's witnesses, the Commission finds that the Company has failed to adequately demonstrate that its failure to complete the RMC approved November transaction was reasonable and prudent.

Ratepayers will not be held financially responsible for Idaho Power's poor record keeping in this instance. If the RMC minutes were fully accurate (and the decision to buy was not later rescinded but merely was not carried out by the RMC or traders), the Commission cannot in good faith require ratepayers to pay for a similar transaction in late December that cost significantly more than the approved but uncompleted November transaction. Idaho Power did not properly document that its RMC changed its decision to carry out the approved transaction. Because the Commission finds that Idaho Power has not demonstrated that it acted reasonably in failing to execute the November transaction, the Company will not recover the $7,976,701 in question.

B. Real-Time Transaction Pricing

During the 2000-2001 PCA year, the Company changed the way the real-time transactions were priced. In prior PCA periods, the transactions flowed through the system at their actual cost. Now, however, the transactions are priced based on the weighted average of all real-time transactions that touch the Idaho Power system on an hourly basis. Tr. at 222-23, 341.

According to Staff's analysis, this weighted average price resulted in significant overcharges and underpayments. Tr. at 341. Consequently, the purchases and sales should be kept separate to calculate the cost. Tr. at 341-42. To account for these disparities, Staff recommended that the real time purchase transactions for the months of December 2000 through February 2001 be repriced to the lower of the non-system's cost or market price. *Id.* Staff also recommended repricing the real time sale transactions for the same months using the higher of sales price or market. *Id.* In doing so, the system would receive the benefit of the best price, which Staff believed to be appropriate since the non-operating system had not yet become a separate trading entity. Tr. at 342.

Idaho Power justified implementing this change in real-time pricing because Commission Order No. 28596 approving the IDACORP Energy Solutions (IES)[1] and Idaho Power Service Agreement was "technically in effect" even if the Agreement was not yet effective by its own terms. Tr. at 233. Moreover, the Company believed using the weighted average of all real-time transactions that touch the Idaho Power system on an hourly basis was

[1] IDACORP Energy Solution (IES) is now known as IDACORP Energy (IE).

the best representation of the real-time market prices and the risks associated with the real-time business. *Id.*

<u>*Commission Findings:*</u> In Order No. 28596 issued December 19, 2000, the Commission approved the Agreement between IES and Idaho Power.[2] Terms of the Agreement provide that it does not become effective until the state regulatory commissions of Idaho, Oregon, and Nevada all approve the Agreement in addition to the Federal Energy Regulatory Commission (FERC). Agreement at ¶ 6. The Agreement provides that it "shall not become effective until the commissions have issued their respective final orders approving the Agreement or any future amendments." *Id.* at ¶ 9.

Upon reviewing the Electric Supply and Management Services Agreement (Agreement), we find that the negotiations and the documents contemplated that the Agreement would go into effect when all four commissions approved the Agreement. Because the Agreement was not effective under the express language of the Agreement until July 3, 2001 when the Oregon Commission provided the last requisite approval, the Company was not authorized to implement real-time pricing before that date. The Agreement contemplated several customer benefits and safeguards that were not yet in place when Idaho Power implemented the real-time weighted average pricing for purchases and sales. It is also inappropriate for the Company to implement some provisions of the Agreement but not others. Because the Agreement was not effective, the Commission finds that the $3,569,782 in disputed real-time transactions are disallowed. We also find it is appropriate to calculate the average cost for purchases and sales separately.

Moreover, the Company's change in real-time pricing was a change to the PCA mechanism. Company witness Gale testified that not changing the real-time pricing method in light of Order No. 28596 seemed "a precarious position to take." Tr. at 277. When asked if the Company discussed seeking Commission approval to implement the real-time pricing change prior to the entire Agreement being approved by all the necessary regulators, Company witness Gale responded in the negative because "it was clearly the right thing to do . . . at that time." Tr. at 282. The Company should know that it must file an Application to formally change the PCA's structures or implement Commission Orders outside of their effective dates. Utilities that unilaterally change the implementation terms of major accounting mechanisms without seeking

[2] This Agreement has been included in the record as Idaho Power Exhibit 13 and Staff Exhibit 117.

prior Commission approval run the risk of disallowances. We now turn to day-ahead and intra-month transaction pricing, which comprised the bulk of the monetary amount in dispute.

C. Day-Ahead Transaction Pricing

During its audit of the PCA period, Staff did not find the index market price to be reflective of a reasonable price surrogate between the system and non-system purchases because the non-operating system obtained substantially greater margins on similar transactions than did the regulated system. Tr. at 339-40. According to Staff witness Carlock, the lower of cost or market for purchases and the higher of cost or market for sales is the appropriate transfer pricing mechanism between affiliates to assure that customers are not harmed by affiliate abuse until the requisite safeguards are in place. Tr. at 363.

Company witnesses testified that the day-ahead transfer pricing procedures had been in place without Staff objection since January 1999. Tr. at 572, 599, 609. Moreover, Idaho Power believes that the Mid-C index continues to be representative of the day-ahead pricing in the Idaho regional power markets. Tr. at 571. Company witness Hoyd further indicated that Staff's methodology does not accurately price transactions between operating and non-operating books because it excluded ancillary transaction charges and included irrelevant transactions. Tr. at 568-69.

Commission Findings: Based upon the evidence presented at the hearing, the Commission finds that Idaho Power's day-ahead transfer pricing practices were neither imprudent nor unreasonable for several reasons. First, Mid-C day-ahead pricing has been used in prior PCA periods reviewed by Staff and accepted by the Commission. As Company witness Hoyd testified, Idaho Power has applied the same procedures for pricing day-ahead transfers between the operating and non-operating systems since January 1999. Tr. at 572. Second, Staff agrees that Mid-C is the proper index to reflect market price transfer costs once proper safeguards are in place. Tr. at 407. Staff's testimony identified potential areas of abuse or inequity, and while the transfer mechanism produced significant increases in the PCA deferral that were not actively monitored by Idaho Power, the mechanism itself was not shown to be imprudent. Given our review of the record, we do not find that use of the Mid-C pricing mechanism for day-ahead transactions was unreasonable. However, the market volatility present during the 2000-2001 PCA should have alerted the Company to do further analysis of the impact on the PCA results. Nevertheless, the Commission authorizes Idaho Power to collect the $47,665,120 associated with day-ahead transactions from the 2000-2001 PCA period.

The Commission believes that the Company should have re-examined its day-ahead transaction pricing in light of the market volatility present during the 2000-2001 PCA period. During the hearing, Company witness Hoyd testified the transfers between the non-operating and operating systems were "quite mechanical." Tr. at 588. The Commission finds this hands-off attitude to be troublesome and a weak justification to explain why the Company did not take action to minimize ratepayer costs in the face of large day-ahead price fluctuations. Although the Company points to the 90/10 power procurement cost sharing in Idaho as incentive to seek low market prices, we question if it is adequate motivation to prompt appropriate Company action. Tr. at 177-79. While the Commission does not presently find the Company's reliance on and compliance with past practices to be imprudent, it is always appropriate to re-examine existing policies and improve them if possible. Consequently, the Commission believes it is appropriate for the parties to discuss a greater sharing of PCA purchased power cost components or other incentive mechanisms within the context of the IPC-E-01-16 case currently in progress.

D. Hedging

Staff asserted that the Company substantially limited system long-term or hedging contracts after November 2000, which created higher customer costs because the power purchases were shifted to intra-month and priced at the market index. Tr. at 322-23. Staff argued that while the non-system operation may execute additional and potentially more risky deals, the direction and the existence of system transactions should be consistent but on a more conservative scale. Tr. at 323. Because the non-system operation executed term transactions, the system (serving native load) should also have had some corresponding transactions within its risk bands. *Id.*

Company witness Anderson testified that the power supply activities of the Company were reasonable and prudent in light of unprecedented high regional energy prices and an uncertain water situation. Tr. at 130. Moreover, the Company implemented both supply and demand side measures to reduce the Company's power supply costs once it knew in February 2001 that the snow pack would be low and that prices for power were not going to decline. Tr. at 131.

Commission Findings: As we have previously seen in California and noted in our Orders, reducing the use of long-term contracts places over-reliance on the spot market and exposes utilities to possible exercise of market power by wholesale power sellers during periods of short supply. Order No. 28722 at 13 *citing California PX v. FERC*, 245 F.2d 1110 (9th Cir. 2001). Long-term power purchases have traditionally mitigated spot market price volatility but can produce higher costs if prices later fall below the purchase price of the hedge.

During Commissioner Hansen's cross-examination of Company witness Darrel Anderson, Mr. Anderson stated that the Company "actively managed the system and monitored the surplus deficits all the way through November, December and January" but "did not take any specific actions" such as tying up long-term contracts that benefited the customer. Tr. at 186.

Upon reviewing the evidence presented, the Commission finds that the Idaho Power Company's actions in regard to hedging have not been shown to be imprudent given the information it had at the time the decisions were being made. Company witness Anderson testified that the Company did not have reliable indication of how poor water conditions would be that winter and was faced with unprecedented price spikes on the spot market. Tr. at 129-30, 184-85, 190. We will not examine the evidence using hindsight, but rather make our findings based upon the circumstances at the time hedging decisions were made by the Company.

The decisions to make or not to make long-term transactions were calls that needed to be made by risk managers trained in such areas. Although the Company's failure to secure long-term transactions proved costly in retrospect, no evidence was presented that definitively proved that the Company's inaction was unreasonable under the circumstances present at that time. Consequently, the Commission will not penalize the Company for the hedging or lack of hedging decisions it made during the 2000-2001 PCA period.

E. Transmission and Wheeling Charges

Staff witness Lord testified that a strong possibility exists that the non-system speculative arm of Idaho Power utilized the Company's transmission facilities without proper benefit or compensation to the regulated utility and its customers. Tr. at 451. Transmission arbitrage occurs where a discrepancy between two pricing points exists such that the transaction can be entered into to capture the difference as profit with little or no risk. *Id.* Transmission services are transferred to the non-system speculative arm of Idaho Power at cost. *Id.* The entity then transfers power purchased for Idaho Power at the Idaho border based on the Mid-C index price – not the border price. *Id.* Because the transportation price is known, the speculative arm can determine whether Idaho border prices are less than the representative market price plus transmission. *Id.* If there is a differential, the speculative arm collects that differential as a profit. This profit is risk-free and is not shared with ratepayers. *Id.*

Commission Findings: The Commission finds that although transmission and wheeling activities are not accounts included in the PCA and their benefits may be difficult to quantify, Idaho Power's non-operating system likely received significant benefits from use of system assets during the 2000-2001 PCA year. On August 30, Company witness Gale testified that it is renegotiating its Agreement with IE to account for "the use of system transmission and system capacity services, as well as other potential intangible benefits" on a prospective basis. Case No. IPC-E-01-16, Tr. at 224.

Because neither Staff nor the Company quantified the transmission benefits experienced by the non-operating system during the 2000-2001 PCA period, the Commission makes no adjustment for the 2000-2001 PCA period even though some benefits were probably derived by the non-operating system. Moreover, these items are not accounts that flow through the PCA. Even so, we expect this issue should be addressed prospectively in Phase II of the IPC-E-01-16 case.

RATE DESIGN

A. Carrying Charge

Although the Commission conducted its investigation of the above issues as expeditiously as possible while still fully developing the record, five months have passed since we issued Order No. 28722 deferring recovery of the disputed $59 million. This deferral was not without cost; $1,191628 of interest is attributable to the $47,665,120 allowed for recovery during this time at the 6% annual interest rate previously approved by this Commission. Order No. 28575.

Commission Findings: Because this Order authorizes Idaho Power to recover $47,665,120 of the disputed $59 million, the Commission finds it reasonable to award the carrying charge associated with the amount of their authorized recovery. Consequently, Idaho Power shall recover $1,191,628 in carrying charges.

B. Surcharge Amount

Because the Commission has determined that Idaho Power should collect $48,856,748, the issue remains of what recovery method should be used. Company witness Gale testified that the Commission should authorize a rate to collect the additional amount over one year with implementation occurring shortly after the issuance of the Order. Tr. at 269. In the alternative, Mr. Gale testified that the Commission could defer the additional amount for recovery until the next rate action in the form of next year's PCA filing or a securitization filing submitted prior to the next PCA rate change. Tr. at 270.

Commission Findings: The Commission considered amortizing the increase and/or deferring it until the Company files its PCA request next spring. However, the Commission declines to delay recovery of this PCA amount any further. As with any requested rate increase, the Commission must balance the needs of the Company to maintain its financial viability with customer concerns of fair rates and rate stability. In this case, the Commission is confronted with extraordinary conditions that resulted in large purchase power costs and a low forecast of reservoir water levels. Given the amount of purchases the Company has already made, it is reasonable and appropriate for the Company to recover these costs as near as possible to the time period in which they were incurred.

This is not to say that amortization is never a viable option. We noted in the original PCA Order that when the PCA results in large rate increases, it may be appropriate to defer a percentage of that year's power supply costs. Order No. 24806 at 20. However, the Commission will not mortgage the collective future of ratepayers without considerable justification. Given that the costs of several large demand-side initiatives undertaken in the last year will likely be included in Idaho Power's next PCA recovery request, the Commission declines to delay recovery of this amount any longer for fear of exacerbating potential power rate increases next spring. Such a delay would also incur additional carrying charges of approximately $2 million.

To recover the $48.9 million, the rate increase is a uniform 0.3826¢ per kWh surcharge imposed on all energy consumed by non-residential customer classes over a 12-month period. The first two rate blocks of the residential class will increase by 0.430¢ per kWh over a 12-month period. Recovery over a one-year period will ensure that all customers will bear their proportionate share of the rate increase. Imposing a uniform cent per kWh surcharge for non-residential customers is reasonable and consistent with past PCA surcharges. This rate design produces a PCA rate of 0.3826¢ per kWh above existing rates. The Attachment shows Idaho Power's affected schedules and the associated average rates and increases. The table below is a simplified version of the Attachment.

CUSTOMER GROUP	EXISTING AVERAGE RATE	APPROVED AVERAGE RATE	PERCENTAGE INCREASE
Residential			
* 0 – 800 kWh	5.7 cents per kWh	6.2 cents per kWh	7.50 %
* 801 – 2000 kWh	6.5 cents per kWh	7.0 cents per kWh	6.57 %
* over 2000 kWh	8.4 cents per kWh	8.4 cents per kWh	0 %
Irrigation	5.1 cents per kWh	5.4 cents per kWh	7.5 %
Small Commercial	7.6 cents per kWh	8.0 cents per kWh	5.0 %
Large Commercial	4.9 cents per kWh	5.2 cents per kWh	7.8 %
Industrial	4.1 cents per kWh	4.4 cents per kWh	9.3 %

Although the surcharge will be applied to the first two residential rate tiers, the Commission declines to extend it to the third tier with the highest energy consumption. In doing so, the Commission continues to encourage energy conservation but recognizes that a further increase in the over 2000 kWh tier is not warranted at this time.

C. Effective Date

According to Company witness Gale's testimony at the evidentiary hearing, Idaho Power prefers that a one-year rate change be implemented as soon as possible due to cash flow and capitalization concerns. Tr. at 270.

<u>*Commission Findings:*</u> We find that the appropriate effective date to implement the PCA rates granted in this Order is October 1, 2001. Because this rate increase will be effective for one year, it will expire on September 30, 2002. The Commission understands that this will cause rates to change more than the once a year we have traditionally experienced. However, this timing will ensure prompt recovery and fairly divide the recovery burden among customer classes.

The Commission recognizes the additional hardship that this increase will place on Idaho Power customers. We also note in the way of rate mitigation that recent approval of a Bonneville Power Administration (BPA) credit will flow through to residential and small farm customers for the next five years. Although the BPA credit will not fully offset the increase approved by this Order, it will help to reduce its impact for those customer classes.

D. Customer Assistance

Because it is necessary to authorize a second rate increase now, the Commission is concerned for the health and safety of ratepayers who struggle to pay their electric bills during the winter heating season. We recognize that some customers may not be able to conserve or reduce their consumption in order to lower their bills. There are programs for eligible residential customers to possibly convert to more efficient space heating appliances or receive assistance for high heating bills. Interested parties should contact the Commission Consumer Assistance Staff at 1-800-432-0369 for more information on programs in their vicinity.

We encourage ratepayers to contact Idaho Power, which offers special payment arrangements to help customers manage their utility payments in extraordinary circumstances. Special payment arrangements can be tailored to the unique needs of each customer and may include spreading payments over several months. To make special payment arrangements, customers should contact Idaho Power's Customer Service Department at (208) 388-2323 or (800) 488-6151.

A budget pay plan is available to Idaho Power customers who are not behind on their bills but merely seek to minimize bill fluctuations. The amount paid is based on the customer's average dollar amount of the previous 12-month history. For those customers who do get behind, a levelized payment arrangement can be made that spreads the past due amount over a number of payments, plus the normal monthly bill.

Customers interested in LIHEAP energy assistance funds must qualify under federal income guidelines. Customers can apply in December to receive a one-time payment made directly to the utility. LIHEAP also provides funding for low-income weatherization programs.

Qualifying customers may also access Idaho Power's Low-Income Weatherization Assistance. The Company provides grants to local non-profit agencies that supplement federal funds supporting weatherization projects for its low-income customers.

Project Share primarily provides funds to qualifying customers for heating assistance from October 1 through the end of April. Applicants may contact organizations like the Salvation Army, American Red Cross, or a local Community Action Agency to apply for Project Share funds. Additional emergency assistance funds may also be available through county welfare offices.

In an effort to help customers improve the energy efficiency of their homes and reduce their electricity bills, Idaho Power has developed an "Energy Planner" or home energy audit packet. The packet contains conservation ideas and ways to improve the energy efficiency of homes, a printed history of the customer's power usage and energy cost calculator. Customers who are interested in receiving an Energy Planner packet or a home energy audit should contact Idaho Power's Customer Service Department at the number given above.

The Commission urges electric customers to conserve energy in an effort to keep electric bills affordable. Customers interested in conserving energy may consult www.eren.doe.gov/buildings/documents/high_heating_bills, the Department of Energy's website. The Commission and Idaho Power also have conservation information available on their respective websites.

Finally, the Commission's winter moratorium rule prohibits any electric or gas utility from terminating or threatening to terminate during the months of December through February the service of any residential customer who declares that he or she is unable to pay in full for utility service and whose household includes children, the elderly, or infirm persons. IDAPA 31.21.01.306.01. However, for families that use this protection, the full amount not paid during the moratorium period becomes due on March 1.

ORDER

IT IS HEREBY ORDERED that the disputed amounts requested by Idaho Power Company's PCA Applications are partially granted. The Company is authorized to implement the surcharge identified in this Order that will generate $48,856,748 in PCA revenues.

IT IS FURTHER ORDERED that the Company shall file tariffs in conformance with a uniform kWh rate increase of 0.3826¢ per kWh for all non-residential customer classes and a 0.430¢ per kWh increase in the first two rate blocks of the residential class.

IT IS FURTHER ORDERED that the PCA rates established in this Order are effective October 1, 2001 for a period of 12 months.

IT IS FURTHER ORDERED that the Commission invites the parties to consider whether a change is warranted in the 90/10 cost sharing mechanism or components included in the PCA. In particular, the Commission invites the parties to comment on the need, if any, to provide additional incentive for Idaho Power to act in the ratepayers' interests within the context of the workshops scheduled in the IPC-E-01-16 case. IDAPA 31.01.01.273.

THIS IS A FINAL ORDER. Any person interested in issues finally decided by this Order or in interlocutory Orders previously issued in these Case Nos. IPC-E-01-7 and IPC-E-01-11 may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter finally decided in this Order or in interlocutory Orders previously issued in these Case Nos. IPC-E-01-7 and IPC-E-01-11. For purposes of filing a petition for reconsideration, this order shall become effective as of the service date. *Idaho Code* § 61-626. 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 27th day of September 2001.

Paul Kjellander

PAUL KJELLANDER, PRESIDENT

Marsha H. Smith

MARSHA H. SMITH, COMMISSIONER

Dennis S. Hansen

DENNIS S. HANSEN, COMMISSIONER

ATTEST:

Jean D. Jewell

Jean D. Jewell
Commission Secretary

O:IPCE017_11_ln

ATTACHMENT
ORDER NO. 28852
CASE NOS. IPC-E-01-7/-11

Commission Decision
IPC-E-01-7 & 11
Summary of Revenue Impact
State of Idaho
Normalized 12-Months Ending December 31, 1999
5/1/01 PCA Rates to 10/1/01 PCA Rates
12 Month Recovery Period

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Tariff Description	Rate Sch. No.	1999 Avg. Number of Customers	1999 Sales Normalized (kWh)	5/1/01 Revenue	Revenue Adjustments	Authorized Total Revenue	Average ¢/kWh	Percent Change
	Uniform Tariff Rates:								
1	Residential Service	1	299,321	4,076,279,049	264,663,185	15,595,844	280,259,029	6.875	5.89%
2	Small General Service	7	30,236	267,798,952	20,504,410	1,024,599	21,529,009	8.039	5.00%
3	Large General Service	9	14,287	2,724,587,690	133,936,626	10,424,273	144,360,899	5.298	7.78%
4	Dusk to Dawn Lighting	15	-	5,950,841	1,600,132	22,768	1,622,900	27.272	1.42%
5	Large Power Service	19	101	1,908,784,165	78,512,596	7,303,008	85,815,604	4.496	9.30%
6	Irrigation Service	24	12,343	1,678,547,071	85,622,698	6,422,121	92,044,819	5.484	7.50%
7	Unmetered General Service	40	806	9,441,291	639,774	36,122	675,896	7.159	5.65%
8	Municipal Street Lighting	41	84	15,816,545	2,024,423	60,514	2,084,937	13.182	2.99%
9	Traffic Control Lighting	42	56	11,968,722	520,680	45,792	566,472	4.733	8.79%
10	Sub-Total		357,234	10,699,174,326	588,024,524	40,935,041	628,959,565	5.879	6.96%
	Special Contracts:								
11	Micron	26	1	536,787,231	21,978,995	2,053,748	24,032,743	4.477	9.34%
12	FMC	28	1	1,051,200,000	37,842,367	4,021,891	41,864,258	3.983	10.63%
13	J R Simplot	29	1	279,696,105	10,337,974	1,070,117	11,408,091	4.079	10.35%
14	DOE	30	1	203,547,709	7,376,739	778,774	8,155,513	4.007	10.56%
15	Sub-Total		4	2,071,231,045	77,536,075	7,924,530	85,460,605	4.126	10.22%
16	Total Annual Idaho Retail Sales		357,238	12,770,405,371	665,560,599	48,859,571	714,420,170	5.594	7.34%

	$	kWh	¢/kWh
Additional PCA True-up Calculation Interest Through 10/1/01	48,856,748	12,770,405,371	0.3826