RECEIVED ☒
FILED ☐

2004 MAR 19 PM 4:46

IDAHO PUBLIC
UTILITIES COMMISSION

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 ELECTRIC CUSTOMERS IN THE STATE OF IDAHO.	)	CASE NO. IPC-E-03-13

IDAHO POWER COMPANY

DIRECT REBUTTAL TESTIMONY

OF

MAGGIE BRILZ

Q. Please state your name.
A. My name is Maggie Brilz.
Q. Are you the same Maggie Brilz that has previously presented direct testimony in this case?
A. Yes, I am.
Q. Have you had the opportunity to review the pre-filed direct testimony of Micron Technology, Inc. witness Dr. Peseau, Industrial Customers of Idaho Power witnesses Dr. Reading and Mr. Teinert, Idaho Irrigation Pumpers Association witness Mr. Yankel, Kroger Company witness Mr. Higgins, Federal Executive Agencies witness Dr. Goins, AARP witness Dr. Power, and Commission Staff witnesses Mr. Hessing, Mr. Schunke, and Ms. Parker?
A. Yes, I have.
Q. What is the scope of your rebuttal testimony?
A. My testimony will focus on issues raised by the intervening parties and the Commission Staff regarding the Company's cost-of-service study and rate design proposals as well as several issues raised specifically by the Industrial Customers of Idaho Power. It should be noted that any omission on my part in addressing issues raised by the parties does not indicate my concurrence with those issues.
Q. Are you sponsoring any exhibits with your direct rebuttal testimony?

A. Yes. I am sponsoring Exhibit Nos. 76 and 77.

COST-OF-SERVICE

Weighted 12 CP Methodology

Q. Weighted generation and transmission demand-related allocation factors were derived for use in the cost-of-service study by averaging the actual coincident demands and the coincident demands weighted by marginal costs. Staff witness Mr. Hessing and Federal Executive Agencies witness Dr. Goins recommend the Commission approve this weighted 12 CP methodology. Do any witnesses recommend the Commission adopt a different methodology?

A. Yes. Micron Technology witness Dr. Peseau and Irrigation witness Mr. Yankel do not support this methodology.

Q. What methodology does Dr. Peseau recommend?

A. Dr. Peseau contends that in each of the past three Idaho Power Company general rate cases the Commission has endorsed the weighted 12 CP methodology and not an alternative methodology or some averaging of different methodologies. Dr. Peseau urges the Commission to continue to endorse the weighted 12 CP methodology.

Q. Has the Commission ever approved a variation to the weighted 12 CP methodology?

A. Yes. In Case No. IPC-E-94-5 the Company computed the weighted 12 CP demand allocation factors by multiplying the monthly coincident peaks by the corresponding monthly marginal costs. The Company's analysis indicated no capacity-related marginal costs for the months of September and October resulting in a zero weighting for those two months. In Order No. 25880 issued in Case No. IPC-E-94-5, the Commission found the use of zero weighting factors to be inconsistent with the purpose of spreading cost responsibility on a seasonal basis and assigned weighting factors to the months of September and October equal to the weighting factors for the months of April and May.

Q. Do you believe the Commission should approve the weighted 12 CP methodology used by the Company in this case?

A. Yes, I do. The Commission has in the past found a variation in the determination of the weighted 12 CP allocation factors to be reasonable. I believe the variation used by the Company in this case is also reasonable and should be approved by the Commission.

Q. Do you concur with Dr. Peseau's finding that using the weighted 12 CP allocation factors as he recommends rather than the average weighted factors used by the Company results in a lower cost of service for all customer classes other than the irrigation class and a higher cost of service for the irrigation class?

A. Yes, I do.

Q. What methodology does Mr. Yankel recommend?

A. Mr. Yankel recommends the use of the 12 CP methodology instead of the weighted 12 CP methodology.

Q. Has the Commission previously approved the use of the 12 CP methodology in an Idaho Power general rate case proceeding?

A. To my knowledge, the Commission has not previously approved the use of the 12 CP methodology in an Idaho Power proceeding. The weighted 12 CP methodology, or some variation of that weighted methodology, was approved by the Commission for setting Idaho Power's rates in Case No. U-1006-185, Case No. U-1006-265A, and Case No. IPC-E-94-5. In Case No. U-1006-159 the Commission did not approve a specific methodology but did indicate its inclination to use the results of the "positive excess demand" (PED) and 12 CP methods to select rate levels for customer classes. However, in utilizing the results of the PED and 12 CP methods, the Commission stressed the failure of the embedded studies to deal with the phenomenon of time and to address non-historic cost considerations (Order No. 16688).

<u>Classification and Allocation of Distribution Plant</u>

Q. In his direct testimony Irrigation witness Mr. Yankel recommends that 16.86 percent of the Company's investment recorded in FERC Account 364 be classified as secondary-related. This recommendation would increase the amount of FERC Account 364 investment classified as Secondary by $14,273,651 for a total investment classified as Secondary of $28,305,647. Is Mr. Yankel's recommendation reasonable?

A. No. Mr. Yankel asserts that simply because the amount of investment in FERC Account 364 classified as Secondary is 8.4 percent and the amount of investment in FERC Account 365 classified as Secondary is 16.9 percent, the investment in FERC Account 364 classified as Secondary is incorrect. Mr. Yankel's recommendation to reclassify over $14 million of the investment in FERC Account 364 to Secondary based on the percentage of investment in FERC Account 365 classified as Secondary is arbitrary.

Q. What would be the effect of reclassifying over $14 million in FERC Account 364 investment from Primary to Secondary?

A. The revenue requirement for customer classes that utilize the secondary distribution system, such as residential, small commercial, and Schedule 9 Secondary Service Level customers, would increase while the revenue requirement for customer classes that do not utilize the secondary distribution system, such as Schedules 9 and 19 Primary and Transmission Service Level customers and irrigation customers, would decrease.

Q. Irrigation witness Mr. Yankel also recommends that no costs associated with the Company's investment in underground facilities recorded in FERC Accounts 366 and 367 be allocated to the irrigation class. Do you agree with Mr. Yankel's recommendation?

A. No. Mr. Yankel has proposed a one-sided adjustment to the factors used to allocate distribution plant to the various customer classes. I believe this adjustment is inappropriate.

Q. Please explain.

A. Since the Company began preparing class cost-of-service studies, the demand-related investment in distribution plant has been allocated to the various customer classes based on the non-coincident peak demands of each customer class. This methodology recognizes that local area loads are the major factors in sizing distribution facilities. Consequently, no class-specific characteristics or demographics, such as rural versus urban location, average number of distribution line miles per customer in each class, or customer density per feeder, are utilized in the derivation of the class non-coincident peak demand allocation factors. Rather, the methodology relies entirely on the class non-coincident peak demands for assigning costs. All demand-related distribution plant, including both overhead and underground facilities, is allocated based on the class non-coincident peak demands. All customer-related distribution plant is allocated based on the number of customers in each class. While this allocation method is not flawless, I believe it is a reasonable methodology for allocating distribution costs.

Q. Why do you believe Mr. Yankel's recommended adjustment is inappropriate?

A. Mr. Yankel recommends that the allocation factors used to assign underground facilities costs be set to zero for the irrigation class since irrigation customers utilize very few underground facilities. However, he does not recommend a corresponding adjustment to the allocation factors used to assign overhead facilities cost to the irrigation class in recognition of the fact that irrigation customers are rural and tend to have fewer customers served per line mile. Mr. Yankel's adjustment is one-sided and should not be adopted.

Q. What effect would Mr. Yankel's adjustment have on the revenue requirement of the various customer classes?

A. Mr. Yankel's adjustment would decrease the revenue requirement for the irrigation class and increase the revenue requirement for all other standard tariff customer classes.

Q. What methodology do you recommend the

Commission approve for allocating distribution costs to customer classes?

A. I recommend the Commission approve the methodology used by the Company in the cost-of-service study filed in this case.

Normalized Peak Demand

Q. Industrial witness Dr. Reading and Irrigation witness Mr. Yankel suggest that the Company utilize normalized peak demands in developing its cost-of-service analysis. What is the Company's response to this suggestion?

A. The Company's load research experts believe that the present method using actual peak data is sufficient to accurately assign costs and has several advantages including the fact that it is a simple, straightforward, and transparent analysis.

Q. Do you support Mr. Yankel's development of normalized demand values as detailed on his Exhibit Nos. 307 through 311?

A. No. While Mr. Yankel's methodology for computing normalized peak demands may be conceptually reasonable for a quick and simple analysis, his actual development of normalized demand values has several errors. As a starting point in his analysis, Mr. Yankel attempts to adjust energy data into calendar months. He then uses the adjusted data in his computation of normalized peaks. However, the energy data that he uses has already been adjusted into calendar months. As a result, his analysis uses data that is distorted due to this "double" adjustment. Second, Mr. Yankel includes in his analysis several months of customer level irrigation data that is greater than the monthly generation level irrigation data. Generation level data is simply the customer level data adjusted for losses. It is not possible for the customer level usage to be greater than the generation level usage. And third, Mr. Yankel uses an incorrect loss factor in his analysis for the Schedule 9 Primary Service Level normalized peak demands. As a result of these errors, Mr. Yankel's analysis produces incorrect results and his recommended adjustments to the peak demand values are not appropriate.

RATE DESIGN

Service Charge

Q. AARP witness Dr. Power states in his direct testimony that the Company is seeking to collect distribution costs that are not demand-related through a monthly service charge. Please clarify the Company's intent regarding the costs included in the proposed monthly service charge?

A. It is the Company's intent to include in the service charge a portion of the investment in distribution facilities, the investment in meters and service drops, and meter reading, billing, and other customer service related expenses. For customer classes that are billed demand charges, the portion of the distribution system classified as demand-related is included in the demand charge while the portion of the distribution system classified as customer-related is included in the service charge. For residential and small commercial classes, all of the costs associated with the distribution system are classified for inclusion in the service charge. The Company has not stated that only "customer-related" costs be included in the service charge.

Blocked Rates

Q. Both Staff witness Mr. Schunke and AARP witness Dr. Power recommend the Commission approve a blocked rate structure, although each witness recommends a slightly different version. Does the Company support the implementation of blocked rates?

A. No. The Company believes that the proposed blocked rates have no cost basis, penalize customers who utilize electric energy for space heating, and provide an artificially low price signal to customers who use less than the second-block threshold amount.

Q. Please explain your assertion that blocked rates have no cost basis.

A. The cost of energy is based on several variables, including the time of day and time of year during which it is produced or purchased, the balance between supply and demand, and the availability of transmission capacity. The total quantity of energy consumed by an individual customer does not determine the total cost incurred to provide that energy. Rather, it is a combination of variables, such as those previously mentioned, that determines the total cost. The cost to serve a customer who consumes 400 kWh a month but whose consumption occurs mainly during the peak hours can be greater than the cost to serve a customer who consumes 1,000 kWh a month but whose consumption occurs mainly during the off-peak hours. There simply is no cost basis for establishing variable energy prices based solely on the quantity of energy consumed by a customer.

Q. How do blocked rates unfairly penalize customers who utilize electric energy for space heating?

A. Although some customers with electric space heat may have the ability to conserve some energy without endangering their health by lowering their thermostats, they do not necessarily have more ability to conserve electricity than do other customers who use other fuel sources for space heating. Blocked rates simply cause customers with electric space heat, many of whom do not have an alternative form of space heating available, to pay higher bills while other customers with other forms of space heat receive an artificially low price signal.

Q. Dr. Power has recommended an initial block of 400 kWh with all usage above 400 kWh priced at a rate 33 percent higher than the initial block rate. Does this block structure provide a benefit to electric space heat customers?

A. No. The blocked rate structure proposed by Dr. Power, compared to the flat rate structure proposed by the Company, provides a benefit to customers who consume less than 876 kWh a month during the non-summer months (reference Power, Direct, p. 35). Most customers who utilize electricity for space heating consume more than 876 kWh per month during the winter heating season.

Q. How does a blocked rate structure provide an artificially low price signal to customers who use less than the initial block threshold level?

A. A blocked rate structure implies that the energy consumed by high-use customers is more valuable than energy consumed by low-use customers and, therefore, provides more emphasis on energy conservation by high-use customers than by low-use customers. I believe all customers should receive the same price signal to conserve energy. The flat, seasonal rates proposed by the Company for residential and small commercial customers conveys to all customers that each kilowatt-hour of energy that is conserved has value without placing the onus for conservation on customers with usage above the threshold level.

Q. In his testimony, Mr. Schunke recommends the implementation of blocked rates only during the summer months. He proposes an initial block of 800 kilowatt-hours with all usage above 800 kWh charged a rate that is 20 percent higher than the initial block rate. Does Mr. Schunke's proposal convey the same price signal to customers during the summer months as does the Company's proposal?

A. The blocked rate proposal recommended by Mr. Schunke would provide the price signal that energy consumption during the summer becomes more expensive as more is used. However, it would only convey this message to customers who use more than 800 kWh. Customers who routinely use less than 800 kWh would receive no price signal during the summer to encourage reduced consumption. Exhibit No. 76, which utilizes the residential bill frequency data provided in the Company's Response to Request No. 76 of Staff's Third Production Request, demonstrates that almost 45 percent of customers would see no increase in price over the course of the three-month summer period under Mr. Schunke's proposal. Under the Company's proposal, all customers would receive a price signal during the three-month summer period.

Q. Do you still recommend the implementation of flat, seasonal rates for residential and small commercial customers?

A. Yes, I do.

Proration of Bills on Customer Statements

Q. Staff witness Ms. Parker raises concerns regarding the appearance of customer bills in regards to seasonal rates that would take effect on June 1 and then again on September 1. Ms. Parker recommends that in order to avoid the prorating of charges on customer bills, and therefore customer confusion over understanding their bills, the seasonal rates become effective on a rolling basis coincident with each customer's meter reading date. As an acceptable alternative to implementing seasonal rates on a rolling basis, Ms. Parker has suggested the Company alter its billing system so that any fixed charges or credits not affected by the seasonal change are not prorated due to seasonal rates. What are your thoughts regarding Ms. Parker's recommendations?

A. Ms. Parker has raised legitimate issues regarding the Company's prorated bills and customers' difficulty in understanding them. As Ms. Parker noted, the Company's current billing setup will result in prorated bills when the Power Cost Adjustment (PCA) rate goes into effect. Since the PCA rate will become effective on June 1 coincident with the effective date of the summer rates, customers' bills will be prorated each June. However, this proration will occur only once a year when the PCA changes. At the end of the summer season when the non-summer rates as proposed by the Company become effective, only the seasonal components will prorate. For example, for residential customers, the bill prepared when the non-summer rates become effective will not include prorated fixed charges or credits; only the seasonal components will be prorated in this situation. I have included as Exhibit No. 77 a sample residential bill that illustrates how seasonal charges will appear when the non-summer rates become effective. As stated by Ms. Fullen in her direct rebuttal testimony, the Company is exploring ways to address the issues identified by Ms. Parker regarding prorated bills.

Q. Does the bill presentation you have just described match the option Ms. Parker has suggested as an acceptable alternative to Staff's recommendation to implement seasonal rates on a rolling basis?

A. Generally, yes. I believe Ms. Parker's alternative option is met for the bills that are prepared when the non-summer rates become effective. However, under the Company's current billing process, the bills that are prepared when the PCA rate changes, which will be coincident with when the summer rates become effective, will still show the proration for all components.

Q. Do you believe Staff's proposal to make seasonal rates effective on each customer's meter reading date would be less confusing to customers than the alternative option you have just described?

A. No. I believe it would be very confusing to customers to have to track their meter reading schedule in order to know when the seasonal rates become effective.

<u>Time-of-Use Rates</u>

Q. Witnesses Dr. Power, Mr. Higgins, and Staff support the Company's proposal to adopt mandatory time-of-use rates for all Schedule 19 customers. ICIP witness Mr. Teinert opposes the adoption of time-of-use rates for Schedule 19 customers and instead recommends the continuation of the flat, non-seasonal rate structure currently in place. Mr. Teinert's rationale for a continued flat rate is that the Schedule 19 customers contribute very little seasonal variance to the Company's load shape. Do you agree with Mr. Teinert's rationale?

A. No. Time-of-use rates are intended to more closely match the price of energy with the cost of energy throughout the periods of the day and across the different seasons. Matching the price charged for energy during a particular period of the day with the cost of energy for that same period better matches the cost to serve an individual customer, based on that customer's usage pattern, with the prices charged an individual customer. Time-of-use rates simply better match price with cost. The fact that a customer class's load shape is fairly constant throughout the year does not mean that the costs to serve that class are constant across the day or across seasons.

Q. In his direct testimony, Mr. Teinert states that the proposed mandatory time-of-use rates proposed for Schedule 19 are radically different from those currently in place. Do you believe this difference is a valid reason to reject the Company's time-of-use proposal?

A. No. I agree with Mr. Teinert that the proposed rate design is different from that in place today. I believe, however, that Schedule 19 customers are able to understand the pricing. It is not uncommon for customers taking service under Schedule 19 to have staff devoted to managing energy consumption. In addition, several Schedule 19 customers have facilities in other states where time-of-use rates are already in place. Given the sophistication and experience of the Schedule 19 customers, I do not believe a change in rate structure is a valid reason to reject the proposal.

Q. Given Mr. Teinert's opposition to mandatory time-of-use pricing, do you believe it would be appropriate to make time-of-use pricing available to Schedule 19 customers on a voluntary basis?

A. No. Voluntary time-of-use programs generally attract participation from customers whose electric bills would be lower without any change in consumption. Although the lower electric bills reflect the fact that the customers' usage patterns are less expensive to serve than the class average, the result is a reduction in revenue for the Company without any corresponding benefit. Mandatory time-of-use rates match the price of energy with the cost of energy for all customers in the class. Those customers whose cost to serve is lower due to their patterns of energy consumption pay less. Those customers whose cost to serve is higher due to their patterns of energy consumption either pay more or have an incentive to shift their usage patterns in order to reduce their bills.

Q. Are mandatory time-of-use rates fairly common for customers of comparable size to Schedule 19 in other western states?

A. Yes. In Table KCH-1 included at page 10 of his direct testimony, Mr. Higgins identified several utilities that require time-of-use rates for customers with loads greater than 500 kW. In addition to the numerous California utilities listed by Mr. Higgins, other neighboring utilities that require time-of-use pricing for customers with loads of 1,000 kW or more are Sierra Pacific Power in Nevada and Pacific Power & Light in Washington and Wyoming.

Q. Mr. Teinert has indicated that the Company has not met with its customers to fully explain its proposed time-of-use rates and the potential financial impact of that proposal. Do you agree with Mr. Teinert's assertion?

A. No. Members of Idaho Power's management, including Mr. Gale and myself, met with the Industrial Customers of Idaho Power at their September 2, 2003 meeting. At that meeting, the time-of-use proposal for Schedule 19 was discussed in detail. Several members of the organization shared their thoughts and concerns with the Company regarding the proposal. In addition, following the filing of this case, the Company's Delivery Services Representatives provided detailed information on the time-of-use proposal to over 70 percent of the Schedule 19 customers through a direct mailing or a personal visit. In addition, customers were informed that a detailed spreadsheet showing the potential financial impact of the proposal on their specific facility was available. Over 35 percent of the Company's Schedule 19 customers requested and received the spreadsheet detailing the potential financial impact of the proposal.

Q. Mr. Higgins recommends voluntary time-of-use rates be made available as part of this proceeding for Schedule 9 customers. Do you support Mr. Higgins' recommendation?

A. No. I believe the implementation of time-of-use rates should be taken in steps. While the Company is fully prepared to implement time-of-use rates for Schedule 19 customers, I appreciate that any new rate design creates the need for increased customer communication and assistance as well as potential system issues that cannot be identified until implementation occurs. I recommend time-of-use rates for Schedule 19 customers be implemented and evaluated prior to offering time-of-use rates to Schedule 9 customers.

Q. If the Commission were to decide that time-of-use rates should be made available to Schedule 9 customers as part of this proceeding, are there any issues which you believe should be considered?

A. Yes. Time-of-use pricing requires that metering equipment be in place to correctly record the amount of usage consumed during the various periods of the day. Customers taking service under Schedule 9 Primary and Transmission Service Levels currently have the metering in place to facilitate time-of-use pricing. Should the Commission decide time-of-use rates should be made available to Schedule 9 customers as part of this proceeding, I recommend it be limited to Primary and Transmission Service

Level customers.

Relationship Between Schedule 9 and Schedule 19 Rates

Q. In its proposal for Schedule 9 and Schedule 19 rates, the Company attempted to maintain the relationship between the Service, Basic, and Demand Charges for the corresponding Service Levels on each schedule. For example, the Company proposed a $0.65 Basic Charge for Primary Service for both Schedule 9 and Schedule 19. Staff's proposed rates for Schedules 9 and 19 do not maintain this relationship. Does this proposal cause you any concerns?

A. In order to respond I believe it is necessary to provide some background. Service levels were first implemented in May 1995 as a result of the outcome of the Company's last general rate case, Case No. IPC-E-94-5. Prior to May 1995 all customers on Schedule 9 were charged the same rates as were all customers taking service under Schedule 19. Service levels were added to more accurately match prices to the costs associated with taking service at various voltage levels, to facilitate the movement of customers between Schedule 9 and Schedule 19, and to reduce the discrepancy in prices between Schedule 9 and Schedule 19 so there was limited incentive for a customer to use additional energy in order to qualify for Schedule 19. Experience over the past nine years has shown that the service level pricing strategy has been successful. The

Company's proposed rates for Schedules 9 and 19 attempt to maintain the service level relationships between Schedules 9 and 19, specifically for the Service and Basic Charges. The introduction of time-of-use rates for Schedule 19 has made it more difficult to maintain the service level relationships for the Energy and Demand Charges.

Q. Given this background, do you have concerns regarding Staff's proposed rates for Schedules 9 and 19?

A. While I would prefer to keep the existing service level relationships between the Service and Basic Charges on Schedules 9 and 19, I do not believe the relationships between Staff's proposed rates are inappropriate, particularly in conjunction with the adoption of mandatory time-of-use pricing for Schedule 19. My main concern regarding the relationship in the rates between Schedule 9 and Schedule 19 is that the service level objectives be kept in mind so that the issues that existed prior to the adoption of service levels do not reappear.

Q. Would your view of the relationships between Staff's proposed rates for Schedule 9 and Schedule 19 change if the Commission were to decide not to approve mandatory time-of-use rates for Schedule 19?

A. Yes, it would. The introduction of mandatory time-of-use rates for Schedule 19 creates a fundamental difference between the service offered under Schedule 9 and the service offered under Schedule 19. This difference makes it difficult to evaluate any uneconomic incentive to move from one rate schedule to another. However, if mandatory time-of-use rates are not approved for Schedule 19, the evaluation becomes quite simple. In that situation I would recommend the service level relationship between the Service, Basic, and Demand Charges currently in place between Schedules 9 and 19 be maintained with any difference in revenue requirement balanced on the Energy Charge.

<u>Tariff Language Changes</u>

Q. Staff witness Ms. Parker has recommended several language changes to the tariffs proposed by the Company. Would you please identify the recommended changes?

A. Yes. First, Staff recommends that the Company's proposed "Service Reconnection Charge" be renamed "Service Connection Charge". Second, Staff recommends that the sentence "The Company reserves the right to modify meter reading schedules as required by changing conditions" not be added to Rule D. And third, Staff suggests some alternative language to the Company's proposed Rule L as detailed in Staff's Exhibit No. 141.

Q. Does the Company agree with Staff's recommendations?

A. Yes. The Company agrees with all three of Staff's recommendations.

Miscellaneous

Q. ICIP witness Mr. Teinert states that he disagrees with the Company's line extension provisions included in the proposed Schedule 19. Is the Company proposing any changes to its line extension policy as part of this general rate case?

A. No. The specific language in Schedule 19 referring to additional facilities was first approved in January 1993. No changes have been made or proposed since that time.

Q. In his direct testimony Mr. Teinert concludes that transformer capacity for Schedule 19 customers is 96 percent greater than Schedule 19 peak demand. Is Mr. Teinert's conclusion based on sound analysis?

A. No. Mr. Teinert has used the system coincident peak for Schedule 19 for the month of July, which measures the total load of the Schedule 19 class at the time of the system coincident peak, as the measure of total distribution transformer capacity requirements. He then divides this value into the total capacity of Company-owned transformers installed at each customer's service location. Transformers installed at the customer's location are sized to meet the specific needs of the customer at that location. In order for Mr. Teinert's analysis to be conceptually correct, he would need to divide the total capacity of transformers installed at each customer's location by the sum of each customer's peak billing demand.

Q. Mr. Teinert relies on his conclusion that transformer capacity for Schedule 19 customers far exceeds the capacity needed in asserting that Schedule 19 customers are overcharged for transformer capacity through Contribution in Aid of Construction (CIAC) charges and inflated distribution rate base. Is Mr. Teinert's assertion correct?

A. No. First, the transformer capacity Mr. Teinert refers to is the capacity of the transformers installed on the customers' property to serve the specific needs of each customer. Customers do not make CIAC payments for these transformers; rather, they pay monthly facilities charges based on the total investment in the facilities. Second, the investment in transformers installed on Schedule 19 customers' property is directly assigned to the Schedule 19 customer class along with the revenue derived from the monthly facilities charges. The direct assignment of the specific investment in transformers to the Schedule 19 class results in a matching of the rate base attributed to the Schedule 19 customer class with the facilities used by the Schedule 19 customer class and does not result in an inflated distribution rate base as Mr. Teinert asserts.

Q. Mr. Teinert disagrees with the Company's proposal to increase the power factor requirement from 85 percent to 90 percent and states that since the Company has offered no evidence that its delivery system is capacity constrained due to power factor, the change is not warranted. Do you agree with Mr. Teinert?

A. No. The 2002 IRP identified multiple delivery system capacity constraints. Additionally, Idaho Power's distribution system is typically voltage and capacity constrained. The Company's distribution planning engineer has informed me that these constraints require the reactive loads on Idaho Power's distribution system to be fully compensated. In order to minimize losses and maintain system capacity, Idaho Power must install capacitors to correct for loads with less than unity power factors. The increase in the minimum power factor from 85 percent to 90 percent brings the requirement for reactive load for individual customers closer to the system requirement.

Q. Did the Company take the power factor requirements of neighboring utilities into account in making its determination to increase the minimum power factor from 85 percent to 90 percent?

A. Yes. The listing below shows the sample of utilities reviewed.

Utility	Power Factor Requirement
Nevada Power	95%
Utah Power (ID)	85%
Portland General Electric	93%
Pacific Gas & Electric	85%
Sierra Pacific (NV and CA)	90%
San Diego Gas & Electric	90%
Avista	80%
Pacific Power & Light	93%

Q. Mr. Teinert states that Idaho Power does not administer any conservation programs for Schedule 19 customers and therefore should not be required to contribute Energy Efficiency Rider funds. Is Mr. Teinert correct in his understanding of the availability of conservation programs for Schedule 19 customers?

A. No. Idaho Power's Industrial Efficiency program was launched in October 2003. This program is targeted specifically at customers with 500 kW or more of load. This program allows customers to propose energy efficiency measures tailored specifically to their own processes. Currently, two proposals have been approved for implementation and an additional three proposals are undergoing the approval process.

Q. Does this conclude your direct rebuttal testimony?

A. Yes, it does.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-03-13

IDAHO POWER COMPANY

EXHIBIT NO. 76

M. BRILZ

Residential Bill Frequency Analysis

IDAHO POWER COMPANY
Residential Bill Frequency Analysis
June - August 2003

KWH Blocks		June		July		August		Total	
		Bills in Block	Cummulative Percentage	Bills in Block	Cummulative Percentage	Bills in Block	Cummulative Percentage	Bills in Block	Cummulative Percentage
none		0		0		0		0	
.00	100.00	16,411	4.8%	14,672	4.3%	13,825	4.1%	44,908	4.4%
100.00	200.00	15,373	9.4%	13,980	8.4%	12,564	7.7%	41,917	8.5%
200.00	300.00	17,396	14.5%	15,715	13.1%	13,069	11.6%	46,180	13.0%
300.00	400.00	22,067	21.0%	18,542	18.5%	14,862	15.9%	55,471	18.5%
400.00	500.00	25,480	28.5%	20,722	24.6%	16,391	20.7%	62,593	24.6%
500.00	600.00	27,266	36.6%	21,953	31.1%	17,622	25.9%	66,841	31.2%
600.00	700.00	27,770	44.7%	23,031	37.8%	18,699	31.4%	69,500	38.0%
700.00	800.00	26,910	52.7%	23,117	44.7%	19,302	37.0%	69,329	44.8%
800.00	900.00	24,863	60.0%	22,611	51.3%	19,210	42.7%	66,684	51.3%
900.00	1,000.00	22,623	66.7%	21,451	57.6%	19,273	48.3%	63,347	57.5%
1,000.00	1,100.00	19,695	72.5%	19,611	63.4%	18,865	53.9%	58,171	63.2%
1,100.00	1,200.00	16,679	77.4%	17,844	68.6%	18,335	59.2%	52,858	68.4%
1,200.00	1,500.00	34,922	87.7%	41,406	80.8%	46,338	72.8%	122,666	80.4%
1,500.00	2,000.00	26,167	95.4%	37,111	91.7%	49,168	87.3%	112,446	91.5%
2,000.00	2,500.00	9,064	98.1%	15,423	96.3%	23,251	94.1%	47,738	96.1%
2,500.00	3,000.00	3,351	99.1%	6,601	98.2%	10,378	97.1%	20,330	98.1%
3,000.00	4,000.00	2,089	99.7%	4,163	99.5%	6,882	99.1%	13,134	99.4%
4,000.00	5,000.00	586	99.9%	1,124	99.8%	1,801	99.7%	3,511	99.8%
5,000.00	99,999,999,999.99	437	100.0%	727	100.0%	1,151	100.0%	2,315	100.0%
Company Totals:		339,149		339,804		340,986		1,019,939	

Exhibit No. 76
Case No. IPC-E-03-13
M. Brilz, IPCo

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-03-13

IDAHO POWER COMPANY

EXHIBIT NO. 77

M. BRILZ

Sample Bill
Seasonal Proration

IDAHO POWER
An IDACORP Company

www.idahopower.com

Questions? Contact us at:
PO Box 30, Boise, ID 83721.
Or call us at 388-5083 (Treasure Valley)
or (800) 488-6151 Se habla español
For faster service please call
Tuesday through Friday, 7:30 a.m. to 6:30 p.m.

Customer Name: James R Customer
Account Number: **6428882444**
Billing Date: 09/15/2004
Print Date: 09/16/2004

Due Date	Please Pay
09/30/04	**$64.43**

Account Activity

Previous Balance	$86.70	
Payments – Thank You	$86.70 CR	
Balance Forward		$0.00
Current Charges		$64.43
Account Balance		$64.43

Please Note: Any unpaid balances will be assessed a monthly charge of one percent (1%) for Idaho customers. Returned checks may be resubmitted electronically for payment. Checks remaining unpaid will be charged a $20 fee.

Please return this portion with your payment and write your account number on your check or money order made payable to Idaho Power.
Please bring in entire bill when paying in person. Thank You!

IDAHO POWER
An IDACORP Company

Please Pay: **$64.43**

Due Date: 09/30/2004

Account Number: 6428882444

Amount Enclosed: ______________

- ☐ Project Share pledge – noted on reverse side
- ☐ Address/phone correction – printed on reverse side

5002 1 AV 0.255 ****AUTO** 5-DIGIT 83204
JAMES R CUSTOMER
1001 MAIN ST
HOMETOWN, ID 80000-0000

Idaho Power
P.O. Box 30
Boise, ID 83721

642888244460000012633 000006670 000012633 0122

Exhibit No. 77
Case No. IPC-E-03-13
M. Brilz, IPCo

IDAHO POWER
An IDACORP Company

www.idahopower.com

Questions? Contact us at:
PO Box 30, Boise, ID 83721.
Or call us at 388-5083 (Treasure Valley)
or (800) 488-6151 Se habla español
For faster service please call
Tuesday through Friday, 7:30 a.m. to 6:30 p.m.

Customer Name: James R Customer
Account Number: **6428882444**
Billing Date: 09/15/2004
Print Date: 09/16/2004

Service Agreement No.: **7044458886**
Service Location: 12 MAR VISTA DR/POCATELLO, ID

Next Read Date: 10/13/2004

Meter Number	Service Period From	To	Number of Days	Reading Type	Meter Readings Previous	Current	Meter Constant	KWh Used
002I60006253	08/12/04	09/13/04	32	Regular	98419	99419	1	1000

Residential Rate Schedule I01

08/12/04 – 09/13/04 32 days	$0.00
Service Charge	$10.00
Non-Summer Energy Charge @ $0.049101 per kWh, 12 days	$18.41
Summer Energy Charge @ $0.061375 per kWh, 20 days	$38.36
Franchise Fee 1%	$0.67
Conservation Program Funding Charge	$0.30
Federal Columbia River Benefits Supplied by BPA	$3.31 CR
Current Charges – Electric Service	**$64.43**

Average Daily Use Comparison

This Month This Year:		This Month Last Year:*	
Days =	32	Days =	32
kWh Billed =	1000	kWh Billed =	1218
kWh per Day =	31.2	kWh per Day =	38.1

CR = Credit
BLC = Basic Load Capacity
kWh = Kilowatt-hour
G = Generation
kW = Kilowatt
* Available after 12 months of service at this location

IDAHO POWER
An IDACORP Company

If writing information below, please check the appropriate box on the reverse side.

Account Number: **6428882444**

NEW CONTACT INFORMATION:

Does Idaho Power have your correct mailing address
And phone number? If not, please write any changes below:

____

____

____

____

New Telephone Number: ________________

PROJECT SHARE PLEDGE

☐ Please add the amount indicated to my monthly bill.

☐$2 ☐$5 ☐$10 $ ______

☐ I would like to make a one-time contribution in the amount of $ ______________.

☐ Please round-up my monthly bill amount to the Nearest dollar and contribute the difference to Project Share.

Thank you and please remember to track your tax-deductible donations.

Exhibit No. 77
Case No. IPC-E-03-13
M. Brilz, IPCo
Page 1 of 2