STATE OF IDAHO
OFFICE OF THE ATTORNEY GENERAL
LAWRENCE G. WASDEN

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IDAHO PUBLIC
UTILITIES COMMISSION

June 29, 2005

VIA HAND DELIVERY

Jean D. Jewell
Commission Secretary
Idaho Public Utilities Commission
PO Box 83720
Boise, ID 83720-0074

RE: The Parties' Final Report in Case No. IPC-E-04-23

Dear Ms. Jewell:

On behalf of the parties in the above referenced case, the Staff is filing an original and seven copies of the Final Report to the Commission. In Order No. 29505 the Commission initiated a proceeding following Idaho Power Company's 2004 rate case to allow interested parties to examine the Company's cost-of-service model. The attached Final Report outlines the issues examined by the parties and lists those cost-of-service issues where the parties reached consensus.

Please contact me if you have any questions.

Sincerely,

Donald L. Howell, II
Deputy Attorney General

Enclosures

cc: Parties of Record (Electronic)

bls/L_Jewell_IPCE0423_dh

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE INVESTIGATION CONCERNING ISSUES RELATED TO IDAHO POWER COMPANY'S COST OF SERVICE STUDY.	)))))	**CASE NO. IPC-E-04-23** **THE PARTIES' FINAL REPORT**

On May 25, 2004, the Commission issued Order No. 29505 addressing substantive cost of service issues raised in Idaho Power Company's (Idaho Power; Company) 2004 general rate case, No. IPC-E-03-13. While the Commission found that Idaho Power's cost of service study was appropriate for allocating costs in that case, the Commission noted that several parties raised legitimate questions regarding the cost of service components that deserve additional investigation before Idaho Power's next general rate case. Order No. 29505 at 47. Therefore, the Commission opened docket IPC-E-04-23 for the purpose of evaluating cost of service issues raised in the general rate proceeding. In Order No. 29505 the Commission wrote:

> Specifically, we direct Staff and interested parties to evaluate appropriate issues through a series of workshops (as needed), including: **(1) how best to determine and weigh monthly generation and transmission allocators, (2) how to most accurately capture coincident peak demand responsibility, and (3) whether new growth is properly covering its cost of service. We expect consensus investigation results and recommendations** to be documented in final report and submitted to the Commission no later than [June 30, 2005].[1] With respect to the issue of new growth and how its cost flows through the cost of service study, we also expect the parties to **submit recommendations regarding any needed changes in Idaho Power's line extension rules** that are identified by the investigation. Once the cost of service investigative report is received, the Commission can then determine how best to proceed addressing any recommended line extension tariff changes.

THE INVESTIGATION

The parties have held three workshops on November 3, 2004, December 14, 2004 and on February 25, 2005. The minutes from those three workshops are attached to this report.

[1] In Order No. 29744 the Commission extended the deadline for the report to April 29, 2005, and in Staff Motion dated April 29, 2005, Staff requested an additional extension of the deadline to June 30, 2005.

1. The first workshop began with a discussion of the scope of issues to be covered in the workshops. It was agreed that the workshop should be confined to the issues defined in the Commission Order and to making the cost of service model and model inputs (load research data) more transparent. Idaho Power then provided an overview of their cost of service model along with a description of the Company's load research methodology to determine coincident peak responsibility. A summary of the legal constraints related to allocating incremental investment costs to new load growth was also given.

2. At the second workshop IPC distributed a spreadsheet showing "2003 Contribution in Aid of Construction (CIAC) Analysis". The analysis pointed out that the Schedule 19 CIAC percentage of investment was larger than the other schedules (64%). This is partly because there is a smaller allowance for that rate schedule. Irrigators (Schedule 24) and Small Commercial (Schedule 7) had the lowest CIAC amount at 28%.

As an example of a marginal cost of service approach, the Company distributed and explained a two-page spreadsheet showing the marginal cost methodology used in Oregon to determine class specific revenue requirement and rate design. Additionally, the Company explained that maintenance of numerous thermal plants in the region occurs in March in order to take advantage of typically lower loads. The larger number of plants down for maintenance tends to drive the marginal cost of generation up in the month of March. Even though loads are down in that month, supply is down sufficiently to drive the price up.

The Irrigators distributed a 39-page document titled, "Irrigator Comments". Their first point was that energy and revenue are normalized and demand should also be "normalized". Using the average of five or ten years of monthly peak demand numbers may reduce the effect of any anomalies that exist in a test year due to extreme conditions. The Irrigators presented their proposal for normalization of the monthly demand in the final workshop. Although the parties did not come to consensus on a demand normalization methodology during the workshop, further discussion between the Irrigators and Idaho Power following the final workshop has resulted in a proposal to which the parties agree. The proposal agreed upon by the parties would simply use the median demand ratios over the most recent five-year period to determine normalized demands for allocation purposes.

Irrigators then discussed growth issues, which they believe are principally driven by a 200% increase in distribution plant over the last 23 years. They suggested that distribution plant, which is related to growth by other customers, not be allocated to the Irrigation class. At the final workshop the Irrigators made a growth allocation proposal for distribution plant, which distinguished between new/growth and old/non-growth. New/growth costs would be defined as the increase in distribution plant over the last 20 years and would be allocated on the basis of the percentage of new energy consumption by class over the last 20 years. Old/non-growth costs would be allocated on energy usage 20 years ago. In the discussion that followed it was suggested that the number of customers or the non-coincident peak might be better than energy for allocation of distribution plant. There was also concern that this methodology might not comply with Supreme Court precedent. This proposal was not accepted by all the parties.

3. In the final workshop, the Company provided a report on the experience of other utilities in dealing with growth issues. It reported that Con-Edison had a similar issue but no solution and other utilities had no experience in dealing with this specific growth issue. Staff reported that several utilities referenced line extension contributions, hookup fees and rate design as tools to deal with increasing costs associated with growth.

Allocation of underground distribution plant was the next point of discussion. The Irrigator's presentation showed that underground plant had increased 600% in the last 23 years. It proposed that underground plant not be allocated to Schedule 19 or to the Irrigation Schedule 24, because they use no significant amount of it. They also suggested charging customers that use underground facilities more for that service. In the discussion it was asserted that most of the additional cost of underground plant is contributed through the over-head/underground differential. It was also suggested by others that if underground distribution plant was not allocated to Irrigators perhaps they should have a greater portion of overhead distribution plant allocated to them because typically irrigators are more spread-out than other customer classes and typically have more distribution per customer. There was no consensus reached on this issue.

The Irrigator's presentation discussed weighting factors for generation and transmission related demand and energy costs. At present, the Company develops these weighting factors based upon its latest Integrated Resource Plan. The Irrigators proposed that a cost-based method be developed for weighting these costs. The method could be based on actual wholesale transactions. There was little discussion on this issue and no agreement.

At the second workshop, the Irrigators suggested that the Company should develop a procedure by which the basic load research data is incorporated into an Excel or Access format. They also recommended that the conversion of billing cycle data should employ a formula that separates base and temperature sensitive load. The temperature sensitive load would then be adjusted by heating degree days (HDD) or cooling degree days (CDD) and assigned to the appropriate month. At the final workshop, Idaho Power made a proposal to capture the effects of weather on energy consumption by using actual load research data to develop daily usage patterns rather than using simple linear interpolation to spread billed energy evenly across each billing cycle. This proposal was acceptable to all the parties. The Company also stated that they could provide load research data used in a rate case, but needed to protect the identity of the individual customers.

CONCLUSIONS

The responses from the workshop parties to each of the questions asked by the Commission are as follows:

(1) How best to determine and weight monthly generation and transmission allocators.

The parties agreed that no consensus could be reached on this issue - primarily because each party represents a different customer or customer group, and any change in the allocators would produce winners and losers. The parties recommend that this issue should remain an issue to be resolved in rate proceedings before the Commission.

(2) How to most accurately capture coincident peak demand responsibility.

This issue is similar to the previous one. The parties agreed that no consensus could be reached on this issue – primarily because each party represents a different customer or customer group, and any change in the allocation of peak demand responsibility would produce winners and losers. The parties recommend that this issue should remain an issue to be resolved in rate proceedings before the Commission.

(3) Whether new growth is properly covering its cost of service.

Most of the workshop time was devoted to discussion of this issue. The parties agreed that there was something inherently troubling with the way costs, associated with growth, were allocated. This is evidenced by the relatively large increase in revenue requirement allocated to customers whose load and energy requirements were unchanged or grew only slightly. While there was agreement that the cost of growth did not necessarily get allocated to the customers and customer classes that grew, we were unable to devise a technical remedy to the allocation procedure that would also satisfy the courts. The parties were unable to devise and agree to a cost-of-service allocation methodology that would properly allocate the cost of growth, without making a distinction between new and old customers. Even a search of what others, around the country, were doing produced little in the way of an acceptable solution. Therefore, it was concluded that the only remedy is a policy solution. The parties were not willing to agree to the particulars of such a policy and recommend that the Commission formulate such a policy in the next rate proceeding.

(4) Recommendations regarding any needed changes in Idaho Power's line extension rules.

The majority of the parties agreed (all except Pike Teinert) that the line extension rules should require new customers to pay the full incremental cost of new distribution plant, to the extent the courts would allow. The existing line extension rules are designed to do this; therefore there was no further discussion on this issue.

(5) Other issues where the parties reached consensus.

In accordance with the issues raised by the Irrigators during the workshop discussions, Idaho Power has offered to take several actions as part of its next general rate case filing.

- Idaho Power will provide customer load research data in computer-readable files so that it will be easier for other parties to review the development of the coincident peak demand responsibility factors and to propose alternative methods for determining coincident peak demand responsibility if they wish.

- Idaho Power will implement a more sophisticated nonlinear method of converting billing month energy data to calendar month energy data. The new method will capture the effects of weather on energy consumption by using actual load research data to develop daily usage patterns rather than using simple linear interpolation to spread billed energy evenly across each billing cycle. Accordingly, the new method will improve the process of determining coincident peak demand responsibility.

- Based on the proposal put forth by the Irrigators and agreed to by the parties, Idaho Power will prepare and include a surrogate for a demand normalization method, along with a traditional method, for the determination of coincident peak demand responsibility in its next general rate case filing. As agreed following the final workshop, the normalization surrogate would be the 5-year median demand ratios from load research samples applied to normalized monthly class energy values.

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IDAHO PUBLIC
UTILITIES COMMISSION

MINUTES
IPC-E-04-23
COST OF SERVICE WORKSHOP #2
Tuesday December 14, 2004

1. Minutes and Participants

The workshop began at 9 AM Wednesday December 14, 2004 in the Idaho Power office building. A list of the attendees is attached (see Attachment No.1). The minutes from the first workshop were distributed and no corrections or additions were offered (see Attachment No. 2).

2. CIAC

Greg Said of IPC distributed a spreadsheet showing "2003 Contribution in Aid of Construction (CIAC) Analysis" (see Attachment No. 3). Greg pointed out that the Schedule 19 CIAC % Investment was larger than the other schedules (64%) because there is a smaller allowance to that rate schedule. Irrigators, Schedule 24,and Small Commercial Schedule 7 had the lowest amount at 28%.

3. Line Extension Issues

Pike Teinert distributed a summary of several related issues that he discussed (see Attachment No. 4). He stated that the Company uses connected load instead of diversified load to design the distribution system. Greg Said assured the group that the Company engineers do consider load diversity in the design of their distribution system. Teinert also felt that a customer's load factor should be considered in setting the CIAC.

*Pike will provide further material on this issue with numerical examples at the next workshop.

4. Marginal Costs

Maggie Brilz distributed a two-page spreadsheet showing the Marginal Cost of Service methodology used by Oregon (see Attachment No. 5). Marginal costs for energy, demand and customer costs by month are calculated for each rate class. These costs are totaled and indexed. The relative index is used to adjust the respective rates for each of the customer classes.

Greg Said explained that maintenance of numerous thermal plants in the region tended to drive the marginal cost of generation up in the month of March. Even though loads are down in that month supply is down sufficiently to drive the price up.

5. Irrigators

Tony Yankel distributed "Irrigator Comments", a 39-page document (see Attachment No. 6).

His first point was that energy and revenue are normalized and demand should be "normalized". It was later clarified that the "normalizing" of demand that he was proposing could take the form of an average of 5 or 10 years of monthly peak demand numbers in order to reduce the effect of any anomalies that may exist in a test year due to extreme conditions.

*Yankel will provide a proposal on how this might be done at the next workshop.

Yankel suggested that the Company should develop a procedure by which the basic load research data is incorporated into an Excel or Access format.

*The Company indicated that they thought something like that could be done but will provide a more definitive answer next workshop.

Yankel recommended that the conversion of billing cycle data should employ a formula that separates base and temperature sensitive load. The temperature sensitive load would then be adjusted by HDD or CDD and assigned to the appropriate month.

*Paul Werner agreed to take a look at that and provide a possible methodology to accomplish that for the next workshop.

Yankel then discussed Growth issues, which are principally driven by a 200% increase in distribution plant over the last 23 years. He suggested that distribution plant, which is related to growth by other customers, not be allocated to the Irrigation class.

*Yankel will continue to examine the distribution accounts in order to provide greater detail and understanding on what is behind these cost increases. He will present his findings and a possible solution that would better align the cost of growth with customers causing the growth at the next workshop.

*The Company will research to see if other utilities have employed a mechanism that considers growth in cost allocation.

***Denotes action items**

The next workshop is scheduled for Friday February 25, 2005 from 9 AM to noon, at the Idaho Power Office in Boise.

The meeting adjourned shortly after noon.

AGENDA

IPC-E-04-23
COST OF SERVICE WORKSHOP #2
Tuesday December 14, 2004
Idaho Power Office, Boise, Id.

9:00	Contribution in Aid of Construction (CIAC) by customer class	-Idaho Power
9:20	Marginal Cost use in Oregon	-Idaho Power
9:40	Marginal Cost February vs March	-Idaho Power
10:00	Irrigators Presentation	- Tony Yankel
11:00	Discussion of next steps; agenda and schedule for the next meeting.	- Dave Schunke
11:30	Adjourn	

Attendance at the Cost of Service Workshop No. 2
Case No. IPC-E-04-23

Name	Representing	Phone #
Keith Hessing	IPUC Staff	334-0348
Rick Sterling	IPUC Staff	334-0351
David Schunke	IPUC Staff	334-0355
Michael Fuss	IPUC Staff	334-0366
Donovan Walker	IPUC Deputy Attorney General	334-0357
Don Howell	IPUC Deputy Attorney General	334-0312
Randy Lobb	IPUC Staff	334-0350
Laura Nelson	IPUC Staff	334-0363
Maggie Brilz	Idaho Power	388-2848
Greg Said	Idaho Power	388-2288
Bart Kline	Idaho Power	388-2682
Paul Werner	Idaho Power	388-2669
Pete Pengilly	Idaho Power	388-2281
Irene V. Victory	Electric Heat	853-9216
Conley Ward	Micron	388-1219
Randy Budge	Irrigators (IIPA)	232-6101
Tony Yankel	Irrigators (IIPA)	440-892-1222
Brenda Tominaga	Irrigators (IIPA)	381-0294
Lynn Tominaga	Irrigators (IIPA)	381-0294
Pete Richardson	Industrial Customers	938-7901
Pike Teinert	ESG/Energy Strategy Group	429-0808

By Phone

Larry Gollomp	U.S. Department of Energy
Dennis Goins	U.S. Department of Energy

Attachment No. 1

MINUTES

IPC-E-04-23

COST OF SERVICE WORKSHOP #1

Wednesday November 3, 2004

The workshop began at 9 AM Wednesday November 3,2004 in the Public Utilities Commission Hearing room. A discussion of the scope of issues to be covered in the workshops was lead by David Schunke. It was agreed that the workshop should be confined to the following issues:

- Making the Cost of Service model and model inputs (Load research data) more transparent.
- Determining how to best weight monthly generation and transmission allocators.
- Determining how to most accurately capture coincident peak demand responsibility.
- Determining whether new growth is properly covering its cost of service. If not, determining how to address that issue given the legal constraints that exist.

A summary of the legal constraints was given by Lisa Nordstrom and Bart Kline.

Maggie Brilz provided an overview of Idaho Power's Cost of Service Model and a description of the methodology used by the Company's. A brief discussion followed.

A description of the Company's Load research methodology was given by Paul Werner.

The next workshop was scheduled and the following items were identified for the agenda:

- Contribution in Aid of Construction (CIAC) by customer class -Idaho Power
- Marginal Cost use in Oregon -Idaho Power
- Marginal Cost Feb. vs March -Idaho Power
- Irrigators Presentation to provide a better understanding of their concerns.

The meeting adjourned shortly after noon.

Attachment No. 2

Idaho Power Company

2003 Contribution In Aid of Construction (CIAC) Analysis

4/2/2004

Method: Selected all completed workorders from 2003 for which Rule H applied. Selected a random sample of 100 in order to associate a Rate Schedule with the workorders. Calculated Proportion of total workorder values attributable to each Rate Schedule.

	A	B	C	D	E	F	G	H
	Total Count	CIAC Count	% CAIC Count	Total Invest	IPCo Invest	Total CIAC	CIAC % Invest	% CIAC By rate
Total Workorders	1,156	847	73%	$8,502,520	$5,824,617	$2,677,903	31%	
Random Sample	100	71	71%	$808,382	$574,734	$233,648	29%	
				Sample Breakdown				
Schedule 1	52	35	49%	$478,461	$341,164	$137,297	29%	59%
Schedule 7	16	9	13%	$48,456	$35,913	$12,543	26%	5%
Schedule 9	8	7	10%	$101,709	$68,538	$33,171	33%	14%
Schedule 19	1	1	1%	$12,442	$5,123	$7,319	59%	3%
Schedule 24	23	19	27%	$167,314	$123,996	$43,318	26%	19%
Total	100	71	100%	$808,382	$574,734	$233,648	29%	100%
				Allocation of Totals Based on Sample				
Schedule 1	601	418	49%	$5,032,424	$3,457,507	$1,573,599	31%	59%
Schedule 7	185	107	13%	$509,657	$363,959	$143,758	28%	5%
Schedule 9	92	84	10%	$1,069,775	$694,600	$380,182	36%	14%
Schedule 19	12	12	1%	$130,862	$51,916	$83,885	64%	3%
Schedule 24	266	227	27%	$1,759,802	$1,256,634	$496,479	28%	19%
Total	1,156	847	100%	$8,502,520	$5,824,617	$2,677,903	31%	100%

Attachment No. 3

Line Extension Issues

Case No. IPC-E-04-23

Pike Teinert
esg, energy strategies group
December 14, 2004

Line Extension Issues

- Nonresidential new and added load
  - Connected vs. diversified load
  - Line Extension revenue component

New & Added Load Issues

- Connected vs. Diversified Load
  - The Company's use of connected instead of diversified load, as defined in Rule H, to design service to new and added load for commercial and industrial customers generates higher cost of service for customers.
  - Nonresidential customers pay excessive distribution plant CIAC for new and added loads, based on connected instead of diversified loads.
  - Non-diversified, connected, new and added load for nonresidential customers artificially drives Company project design beyond existing substation and transmission capacity, inflating the need for additional substation and transmission facilities and customer CIAC.
  - The use of diversified load in project design for new and added nonresidential load will reduce the rate of cost of service increases.

New & Added Load Issues

- Nonresidential Customer - Line Extension Revenue Component
  - CIAC calculations for nonresidential customers do not include a revenue component.
  - Nonresidential customers should be credited for revenues from new and added load with average load factors that exceed their rate class average load factor and generate RORs in excess of the average ROR for the rate class.
  - CIAC analysis should include provisions for added or new load with above rate class average load factors thereby reducing or eliminating the CIAC.