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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.	)	CASE NO. IPC-E-08-10

IDAHO POWER COMPANY

DIRECT REBUTTAL TESTIMONY

OF

TIMOTHY E. TATUM

1 Q. Please state your name.

2 A. My name is Timothy E. Tatum.

3 Q. Are you the same Timothy E. Tatum that

4 previously presented direct testimony?

5 A. Yes, I am.

6 Q. Have you had the opportunity to review the

7 pre-filed direct testimony of Idaho Irrigation Pumpers

8 Association's witness Mr. Yankel; Micron Technology, Inc.'s

9 witness Dr. Peseau; Industrial Customers of Idaho Power's

10 witness Dr. Reading; and the U.S. Department of Energy's

11 witness Dr. Goins?

12 A. Yes, I have.

13 Q. What is the scope of your rebuttal

14 testimony?

15 A. My testimony will focus on the issues raised

16 by the intervening parties regarding the Company's cost-of-

17 service study. It should be noted that any omission on my

18 part in addressing issues raised by the parties does not

19 indicate my concurrence with those issues.

20 Q. What cost-of-service methodology does Mr.

21 Yankel recommend?

22 A. Mr. Yankel recommends an alternative cost-

23 of-service methodology that introduces a "Growth Corrected"

1 component into the derivation of the allocation factors for
2 generation and transmission related costs.
3 Q. Do you agree with Mr. Yankel's
4 recommendation?
5 A. No. Mr. Yankel's methodology does not
6 reasonably apportion costs among customer classes. Mr.
7 Yankel proposes to inject an additional growth-related
8 weighting factor into the existing weighted twelve
9 coincident peak demand method ("W12CP"). His growth-
10 related weighting factors are based on the energy sales
11 growth forecast from the Company's Sales and Load Forecast
12 for the 2006 Integrated Resource Plan ("IRP"). This method
13 results in an allocation of costs that is predominately
14 driven by forecasted energy sales growth and fails to give
15 adequate recognition to the impact that existing loads have
16 on costs.
17 Q. Is Mr. Yankel's use of forecasted energy
18 sales growth to weight the class coincident peak demands
19 reasonable?
20 A. No. Mr. Yankel's use of forecasted energy
21 sales growth to weight the class coincident peak demands is
22 not reasonable in either the derivation of the weighting
23 factors or in the manner in which the resulting weighting
24 factors are applied.

1 Q. What is the problem with the way in which
2 Mr. Yankel derives the "growth-adjusted" weighting factors
3 to be applied to the class coincident peak demands?
4 A. Mr. Yankel's method incorrectly assumes that
5 energy sales by class will grow at the same or close to the
6 same rate as class coincident peak demands. This has not
7 been the case in recent history and is not expected to be
8 the case over the next several years.
9 Historically, peak demand has grown at a faster rate
10 than energy usage. Mr. Yankel illustrates this point quite
11 well on page 10 of his direct testimony where he presents
12 the percentage change in annual system peak demand and
13 annual energy levels between the 1993 test year and the
14 2008 test year. As can be seen on page 10 of Mr. Yankel's
15 testimony, the irrigation class's contribution to the
16 annual system peak grew by approximately 6.7 percent over
17 the 15 year period while the class's annual energy
18 consumption declined by 4.4 percent.
19 Prospectively, Mr. Yankel's assumption is also
20 incorrect according to the Company's 2006 IRP analysis,
21 which anticipates that system peak demands will grow at a
22 faster rate than average demands or energy sales.

1 Q. What is the problem with the way in which
2 Mr. Yankel applies the "growth-adjusted" weighting factors
3 to the class coincident peak demands?
4 A. Mr. Yankel's growth adjustment places too
5 great an emphasis on the growth-related component of the
6 allocation factors. Under Mr. Yankel's methodology, 50
7 percent of the allocation factors used to allocate
8 generation- and transmission-related costs is based solely
9 upon expected load growth. As a result, the averaged
10 allocation factors produced under this method are based
11 upon the invalid assumption that growth-related costs
12 represent 50 percent of the test year generation- and
13 transmission-related costs. Considering the Company's
14 generation- and transmission-related rate base increased by
15 only approximately 11 percent between the 2007 test year
16 and the 2008 test year, the 50 percent growth level assumed
17 under Mr. Yankel's methodology is clearly inappropriate.
18 Q. Does Mr. Yankel's growth-adjusted cost-of-
19 service study properly assign energy-related costs to
20 customer classes?
21 A. No, it does not. The degree at which Mr.
22 Yankel's method fails to properly assign energy-related
23 costs is best illustrated on his Exhibit No. 301. As can
24 be seen on page 5 of Exhibit No. 301, Mr. Yankel derives an

1 energy allocation factor ("E10") that would assign
2 approximately 0.6 percent of the Company's energy-related
3 costs to the irrigation class; a class that represents
4 approximately 11.4 percent of the Company's annual energy
5 supplied. The E10 allocation factor is used to allocate
6 variable costs such as fuel and a portion of purchased
7 power expenses that are tied directly to energy
8 consumption. It is not reasonable to suggest that, because
9 the irrigation class's energy consumption is not growing,
10 they should not be exposed to the rising variable cost of
11 energy.
12 Q. On page 21, lines 17-18 of Mr. Yankel's
13 testimony, he makes the following statement with regard to
14 his proposed methodology: "It does not attempt to separate
15 'old electrons' from 'new electrons' or 'new customers'
16 from 'old customers.'" Do you agree with Mr. Yankel's
17 assessment of his proposal?
18 A. No. Mr. Yankel's methodology does precisely
19 what he claims it does not. In fact, his proposed growth-
20 adjusted cost-of-service study has the effect of turning
21 back the clock by over 15 years with regard to cost
22 assignment for the irrigation class. This effect is best
23 seen by making a comparison similar to that made by Mr.
24 Yankel in his testimony. The Company's cost-of-service

1 study submitted as part of the 1993 general rate case
2 proceeding assigned the irrigation class a share of rate
3 base equal to $192,124,122. Mr. Yankel's proposed growth-
4 adjusted cost-of-service study assigns to the irrigation
5 class a share of rate base equal to $164,908,434. That is
6 a 14 percent decrease in rate base assignment (in nominal
7 dollars) for the irrigation customers even though, as Mr.
8 Yankel points out on page 10 if his testimony, that class's
9 coincident peak demand has grown by 6.7 percent over the
10 same period. Mr. Yankel's results are counterintuitive.
11 Q. If the Commission determines that the
12 growth-related issues that Mr. Yankel identifies have
13 merit, are there any adjustments to his cost-of-service
14 methodology that could be made to produce more reasonable
15 results?
16 A Yes. Although Mr. Yankel's method fails to
17 reasonably apportion costs among customer classes, it could
18 be modified to produce far more reasonable results. This
19 could be accomplished by changing the manner in which the
20 growth factors are derived and how they are subsequently
21 applied. As I pointed out earlier, energy growth is not an
22 appropriate basis for projecting growth in demand. The
23 Company forecasts capacity needs in its IRP process. This

1 process may provide the basis for a more reasonable demand
2 growth projection.
3 Assuming that a more reasonable demand growth
4 projection can be produced, another primary modification
5 that I would make to Mr. Yankel's method relates to how the
6 growth adjustment would be applied. Under Mr. Yankel's
7 proposed methodology, he applies marginal cost weighting to
8 only expected load growth, which corrupts the resulting
9 allocation factors. Instead, if the marginal cost
10 weighting was applied to existing loads that were escalated
11 to include the projected load growth, the resulting
12 allocation factors would include the growth component Mr.
13 Yankel advocates, while producing far more reasonable
14 results. For example, on page 1 of Mr. Yankel's Exhibit
15 No. 301, residential load growth is determined by applying
16 10.65 percent to the existing monthly residential demands.
17 The resulting values are then weighted by the monthly
18 marginal costs. This step should be modified to instead
19 escalate the residential demands by 10.65 percent or by
20 multiplying by 1.1065. The resulting values would then be
21 weighted by the monthly marginal costs as the final step.
22 This modified approach would result in more reasonable cost
23 assignment than the method proposed by Mr. Yankel.

1 Q. Mr. Yankel points out that his growth-
2 adjusted cost-of-service study does not address growth-
3 related costs on the distribution system. Has the Company
4 taken any steps to improve the manner in which it assigns
5 costs associated with growth on the distribution system?
6 A. Yes. On October 30, 2008, the Company filed
7 with the Commission a request to modify its line
8 installation and service attachment policy under Rule H
9 (Case No. IPC-E-08-22). The proposed modifications are
10 designed to place a larger share of the incremental
11 distribution system cost responsibility onto those
12 customers requesting new service. The Company views this
13 approach as an effective way to help alleviate the cost
14 impact that new customer growth has on existing customers.
15 Q. Mr. Yankel proposes a second alternative
16 cost-of-service study that is intended to reflect future
17 load reduction benefits of the Irrigation Peak Rewards
18 Program. Will you please describe your understanding of
19 Mr. Yankel's second alternative methodology?
20 A. As a second alternative, Mr. Yankel proposes
21 a cost-of-service methodology that reduces the coincident
22 peak demand responsibility of the irrigation customers by
23 50 percent to reflect, what Mr. Yankel estimates to be, the

1 load reduction potential of the proposed Irrigation Peak
2 Rewards program in 2009.
3 Q. Do you agree with Mr. Yankel's cost-of-
4 service adjustment to recognize estimated future benefits
5 of the Irrigation Peak Rewards Program?
6 A. No. I do not agree with Mr. Yankel's
7 adjustment on a number of levels. First and foremost, I do
8 not believe that it is appropriate to make an adjustment to
9 the test year loads based upon projected future impacts of
10 demand response programs. Secondly, even if the Commission
11 agrees with Mr. Yankel's rationale for the adjustment, his
12 load reduction projection is based upon the operation of a
13 program that has not yet been approved by the Commission
14 (Case No. IPC-E-08-23). Furthermore, Mr. Yankel
15 optimistically estimates the load reduction potential of
16 the Irrigation Peak Rewards Program in 2009 to be 325
17 megawatts ("MW"). If the Commission approves the proposed
18 Irrigation Peak Rewards Program as detailed in the
19 settlement Stipulation, the Company estimates the program
20 will provide peak load reduction of approximately 112 MW in
21 2009, much lower than the 325 MW estimated by Mr. Yankel.
22 Q. Dr. Reading, Dr. Peseau, and Dr. Goins all
23 recommend that the Company depart from using the Idaho
24 jurisdictional load factor to classify hydro and steam

1 production plant as demand and energy. Has the Commission
2 supported the use of the jurisdictional load factor to
3 classify steam and hydro production plant to demand and
4 energy in past rate case proceedings?
5 A. Yes. The Commission has supported the use
6 of the jurisdictional load factor to classify production
7 plant as demand and energy beginning with its Order No.
8 17856 issued in Case No. U-1006-185 in 1983. Following
9 Order No. 17856, the Company has used this method in all
10 cost-of-service studies filed with this Commission.
11 Q. Do you continue to support the use of the
12 jurisdictional load factor method of classifying production
13 plant as demand and energy?
14 A. Yes. The use of the system load factor to
15 classify production plant as demand and energy has been and
16 continues to be an appropriate method of classification of
17 steam and hydro production plant. This method also aligns
18 quite well with the 3CP/12Cp study, the Company's preferred
19 cost-of-service study. The use of the jurisdictional load
20 factor is based on the premise that the need for hydro and
21 steam generation plant is driven both by customer demand
22 and energy consumption. The system load factor
23 classification method provides a means to identify the
24 percentage of generation plant that is needed to serve

1 average demands (energy) and the percentage that serves
2 peak demands and classifies costs accordingly.
3 Q. What specific classification methodology
4 does Dr. Peseau recommend?
5 A. Dr. Peseau recommends a classification
6 methodology that assigns hydro production plant as 100
7 percent demand-related with 50 percent allocated as peak
8 and 50 percent as base load/intermediate load.
9 Furthermore, Dr. Peseau recommends classifying 100 percent
10 of steam production plant as demand-related, all being
11 allocated as base load.
12 Q. Do you agree with Dr. Peseau's
13 classification recommendation?
14 A. No. As I mentioned earlier in my testimony,
15 a portion of the need for the Company's hydro and steam
16 production plant capacity is driven by average demand or
17 energy. Dr. Peseau recommends a classification approach
18 that ignores this fact and assumes that the Company's hydro
19 and steam production capacity is driven entirely by peak
20 demand.
21 Q. What specific classification methodology
22 does Dr. Reading recommend?

1 A. Dr. Reading recommends that hydro and steam
2 production plant be classified as 75 percent demand and 25
3 percent energy.
4 Q. Do you agree with Dr. Reading's
5 classification recommendation?
6 A. No. Dr. Reading supports his 75/25 demand
7 to energy approach for classifying hydro production plant
8 because it is the same approach used by PacifiCorp. Upon
9 further investigation, PacifiCorp adopted its 75/25
10 classification methodology through negotiations as part of
11 the Multi State Process, also referred to as Revised
12 Protocol. According to PacifiCorp's ("Rocky Mountain
13 Power") cost-of-service witness C. Craig Paice[1], the 75/25
14 classification methodology was accepted by PacifiCorp
15 because it "falls within the middle range of reasonable
16 approaches."
17 Dr. Reading's justification for his classification
18 approach does not provide a sufficient basis for a change
19 of this magnitude. Idaho Power's classification method
20 should be based upon, at least in part, studies and
21 analyses using data specific to Idaho Power's system, not
22 PacifiCorp's.

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[1]Utah Public Service Commission, Docket No. 07-035-93, Rebuttal Testimony of C. Craig Paice, Page 4, Lines 87-88.

1 Q. What specific classification methodology
2 does Dr. Goins recommend?
3 A. Dr. Goins recommends that both hydro and
4 steam production plant be classified as 100 percent demand-
5 related. As an alternative approach, Dr. Goins recommends
6 a classification scheme that classifies both hydro and
7 steam production plant as approximately 57 percent demand
8 and 43 percent energy.
9 Q. What is your opinion of Dr. Goins's
10 classification recommendations?
11 A. I do not support Dr. Goins's 100 percent
12 demand classification approach for the same reasons I
13 covered earlier in my testimony with regard to Dr. Peseau's
14 similar classification recommendation. However, Dr.
15 Goins's alternative 57/43 classification method has some
16 appeal, as it has some relevance to Idaho Power's system.
17 It is my understanding that Dr. Goins's alternative
18 classification method is based on the ratio of the weighted
19 energy allocation factors in the "non-capacity deficit
20 months" to the deficit months. I am not convinced that
21 this method is superior to the Company's historical load
22 factor approach. However, should the Commission wish to
23 consider alternative production plant classification
24 methodologies, Dr. Goins's 57/43 classification method is

1 the most reasonable alternative to the Company's historical
2 load factor approach presented in this general rate case
3 proceeding.
4 Q. Dr. Peseau points out on page 36 of his
5 testimony that the number of months in which the marginal
6 cost weighting factors are applied to the coincident peak
7 demands includes the months May and September. He argues
8 this results in "nonsensical" cost assignment. Has the
9 Company determined the number of months used to seasonalize
10 the coincident peak demands in a manner different from the
11 previously approved methodology?
12 A. No. In the 03-13 Case, the generation and
13 transmission marginal costs were seasonalized according to
14 the projected monthly peak hour capacity deficits
15 identified in the Company's most recent Commission-accepted
16 IRP. In this case, the Commission-accepted 2006 IRP was
17 used in the same way. The 2006 IRP analysis projects
18 additional capacity deficits in May and September which are
19 reflected in the weighting factors.
20 Q. Dr. Peseau argues that including the months
21 of May and September in the marginal cost analysis is
22 erroneous because those months have "typically been low
23 cost months" for Idaho Power's system. Is that a
24 legitimate critique of your approach?

A. No. Whether or not May and September have been "typically two of the lowest cost months" for Idaho Power's system in the past is not relevant in this instance. The inclusion of those months in the marginal cost weighting factor process is consistent with the approved methodology. I explained the reasoning for using marginal cost weightings in the derivation of the demand- and energy-related allocation factors on page 25 of my direct testimony:

> The use of marginal cost weighting is intended to strike a balance between backward-looking costs already incurred and forward-looking costs to be incurred in the future.

The role of the seasonalized marginal cost weighting approach is to provide the forward-looking aspect to the allocation factors. While the historical seasonality of the costs imposed on Idaho Power's system is quite important to consider in the overall assignment of costs, it is not relevant in the context of a forward-looking adjustment factor. According to the 2006 IRP, the Company anticipates a need for additional generation and transmission resources to successfully serve loads in May and September prior to the end of 2012. As a result, the marginal costs have been seasonalized in recognition of this need to serve loads.

1 Q. Dr. Peseau spends a considerable amount of
2 time in his testimony criticizing the Company's methodology
3 used to prepare its preferred cost-of-service study. What
4 cost-of-service methodology does Dr. Peseau ultimately
5 recommend?
6 A. Dr. Peseau accepts the Company's preferred
7 cost-of-service study, the 3CP/12CP Study, modified to
8 incorporate his classification approach discussed earlier.
9 Q. What cost-of-service methodology does Dr.
10 Reading recommend?
11 A. Dr. Reading accepts the Company's preferred
12 cost-of-service study, the 3CP/12CP Study, modified to
13 incorporate his classification approach discussed earlier
14 as well as two additional adjustments. His first
15 additional adjustment relates to the manner in which the
16 coincident peak demands for each class are determined. Dr.
17 Reading proposes to use 2007 load research data to compute
18 the demand factors rather than applying the surrogate for a
19 demand normalization methodology. Dr. Reading's second
20 adjustment is to use full marginal cost weighting on the
21 energy allocation factors rather than an average of
22 weighted and unweighted factors as proposed by the Company.

1 Q. Do you agree with Dr. Reading's
2 recommendation to abandon the surrogate for a demand
3 normalization methodology?
4 A. No. The surrogate for a demand
5 normalization methodology was implemented in accordance
6 with the consensus of the parties involved in the cost-of-
7 service workshops conducted at the Commission's direction
8 in Case No. IPC-E-04-23 ("COS Workshop"). The surrogate
9 for a demand normalization methodology is one of two
10 changes that the Company agreed to as a result of the COS
11 Workshop process. Both changes were related to the
12 preparation of the coincident peak demands used to compute
13 the allocation factors for generation- and transmission-
14 related costs. The changes included (1) a revised
15 methodology to convert billing period data into calendar
16 month data and (2) a surrogate for a demand normalization
17 methodology.
18 Q. Were these two changes incorporated into the
19 cost-of-service studies prepared as part of Case No. IPC-E-
20 05-28 ("05-28 Case") and Case No. IPC-E-07-08 ("07-08
21 Case")?
22 A. Yes.

1 Q. Please explain why you favor the surrogate
2 demand normalization methodology used in this case as
3 opposed to methodology recommended by Dr. Reading.
4 A. Under the methodology recommended by Dr.
5 Reading, the coincident peak demands for each class would
6 be determined based upon demand ratios from the load
7 research data in a single year, 2007. The demand
8 normalization methodology used in this case uses the five-
9 year median demand ratios from the load research sample
10 applied to the normalized monthly energy values for each
11 customer class to determine the coincident peak demands by
12 class. This methodology reduces the effect of any atypical
13 demand ratios that might exist in a given test year due to
14 unusual weather conditions.
15 Q. Do you agree with Dr. Reading's
16 recommendation to use full marginal cost weighting on the
17 energy allocation factors rather than an average of
18 weighted and unweighted factors as proposed by the Company?
19 A. No. My rationale for supporting the
20 averaging of weighted and unweighted factors in the
21 derivation of the energy allocation factors is detailed on
22 page 46 of my direct testimony:
23 The "averaging approach" is consistent
24 with the methodology used in the
25 derivation of the demand-related

allocation factors that receive marginal cost weighting. That is, the D10s, D10NS, and D13 allocation factors used in the Base Case and Modified Base Case are all derived under the same averaging methodology. In the 05-28 Case and the last general rate case proceeding, Case No. IPC-E-07-08, the Company began applying the "averaging approach" as a rate stability measure intended to mitigate any extreme impacts that the marginal costs may have on cost allocation. However, in this case, the relative differences between the factors produced under either method are quite small and, therefore, have little impact on the resulting cost allocation.

Q. What cost-of-service methodology does Dr. Goins recommend?

A. Dr. Goins recommends that the Company be required to allocate costs according to a W12CP method without averaging the weighted and unweighted demand and energy factors.

Q. Do you agree with Dr. Goins's recommendation regarding the use of the W12CP cost-of-service methodology?

A. No. Aside from the use of fully weighted demand and energy allocation factors, the W12CP method proposed by Dr. Goins is quite similar to the Company's Base Case Study prepared in this proceeding. I discuss on pages 20 and 21 of my direct testimony my rationale for selecting the 3CP/12CP Study over the Base Case Study. The

1 3CP/12CP Study is a more effective method for aligning cost
2 causation with cost recovery by isolating the costs
3 associated with peaking resources and allocating those
4 costs according to the loads causing the investment.
5 The 3CP/12CP also reduces the potential that exists
6 under the W12CP method to disproportionately allocate fixed
7 base and intermediate generation costs that do not vary
8 greatly between the summer and non-summer seasons to the
9 higher cost summer months.
10 Q. In discussing his concerns with the
11 Company's preferred cost-of-service study, the 3CP/12CP
12 method, Dr. Goins's makes the following statement:

13 The study is seriously and probably
14 fatally flawed because it fails to
15 align costs allocation with cost
16 responsibility.

17 Do you agree with Dr. Goins's assessment of the Company's
18 preferred cost-of-service study?
19 A. No. The study I have proposed uses a
20 standard ratemaking approach. The 3CP/12CP method
21 incorporates an allocation approach that is quite similar
22 to the Base-Intermediate-Peak ("BIP") method endorsed by
23 the National Association of Regulatory Utility
24 Commissioners ("NARUC") in its most current Electric
25 Utility Cost Allocation Manual dated January 1992. On page

60 of the NARUC manual, the BIP method is presented with the following description:

> The BIP method is a time-differentiated method that assigns production plant costs to three rating periods: (1) peak hours, (2) secondary peak (intermediate, or shoulder hours) and (3) base loading hours. This method is based on the concept that specific utility system generation resources can be assigned in the cost of service analysis as serving different components of load; i.e., base, intermediate, and peak load components.

The Electric Utility Cost Allocation Manual continues on page 61 with the following discussion of the BIP method:

> There are several methods that may be used for allocating these categories of costs to customer classes. One common allocation method is as follows: (1) peak production plant costs are allocated using an appropriate coincident peak allocation factor; (2) intermediate production plant costs are allocated using an allocator based on the classes' contributions to demand in the intermediate or shoulder period; and (3) base load production plant costs are allocated using the classes' average demands for the base or off-peak rating period.

The NARUC BIP method has been around for many years and incorporates much of the same cost of service logic and theory that I applied in the 3CP/12CP method.

Q. Does this conclude your direct rebuttal testimony?

A. Yes, it does.