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Washington, DC 20585

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IDAHO PUBLIC
UTILITIES COMMISSION

December 3, 2008

VIA OVERNIGHT SERVICE
Ms. Jean Jewell
Commission Secretary
Idaho Public Utilities Commission
472 W Washington
Boise, ID 83720-0074
RE: Case No. IPC-E-08-10

Dear Ms. Jewell:

Enclosed please find:

(1) an original and 10 copies of the Rebuttal Testimony of Dr. Dennis W. Goins on behalf of the United States Department of Energy in the above-captioned proceeding;

(2) an additional copy of this testimony, that I request be date-stamped and returned in the enclosed postage paid envelope;

(3) a disk upon which this testimony is set out in computer searchable form.

If you have any questions concerning this filing, please contact me at (202) 586-3409.

Sincerely yours,

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CERTIFICATE OF SERVICE - IDAHO PUC CASE NO. IPC-E-08-10

I hereby certify that, this 3d day of December, 2008, I have served or caused to be served a true and correct copy of the attached Testimony of Dr. Dennis W. Goins on behalf of the United States Department of Energy upon each of the individuals listed below, by: (1) placing the same in the United States Mail, addressed to each of the persons listed below at the street address set out below; (2) electronically transmitting the same to each of the persons named below at the email address set out below; (3) sending an original and ten (10) copies of the same via Federal Express to the Secretary of the Commission.

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STATE OF IDAHO
BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-08-10

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

REBUTTAL TESTIMONY OF
DR. DENNIS W. GOINS
ON BEHALF OF THE
U.S. DEPARTMENT OF ENERGY

December 3, 2008

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INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Dennis W. Goins. I operate Potomac Management Group, an economic and management consulting firm. My business address is 5801 Westchester Street, Alexandria, Virginia 22310.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS CASE ON OCTOBER 28, 2008?

A. Yes.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the U.S. Department of Energy (DOE) representing the Federal Executive Agencies (FEA), which is comprised of all Federal facilities served by Idaho Power Company (IPC). Two of the larger FEA facilities are the Department of Energy's Idaho National Laboratory (DOE) and Mountain Home Air Force Base. IPC serves DOE under a special contract, and serves the bulk of Mountain Home AFB's load under Schedule 19 Large Power Service.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to certain conclusions and recommendations made in direct testimony filed by Anthony Yankel on behalf of the Idaho Irrigation Pumpers Association, Inc. (IIPA) and Keith Hessing on behalf of the Staff of the Idaho Public Utilities Commission. In particular, I will respond to:

1. IIPA witness Yankel's attempt to recognize the impact of load growth in IPC's cost-of-service analysis. As I discuss later, witness Yankel's effort

is essentially a roundabout way to argue for vintage pricing of IPC's assets—that is, assigning entitlement to older, lower-cost assets to existing loads and then charging new loads for the higher marginal cost of capacity additions. Vintage pricing is both arbitrary and economically inefficient, and should be rejected. Witness Yankel's vintage pricing adjustments to IPC's cost-of-service methodology suffer from the same deficiencies and should be rejected.

2. Staff witness Hessing's uncritical adoption of IPC's 3CP/12CP cost-of-service methodology. He relies on results from IPC's cost study to develop his recommended revenue spread based on the Staff's proposed revenue requirement. However, the cost study on which he relies ignores numerous deficiencies in IPC's costing methodology that I identified in my direct testimony. Because witness Hessing relies on an improper and unreasonable allocation of IPC's costs, his recommended revenue spread does not properly track IPC's actual cost of serving retail customers in Idaho. His recommended higher-than-average rate increases for higher load factor[1] classes and special contract customers should be rejected.

IIPA WITNESS YANKEL

Q. PLEASE DESCRIBE WITNESS YANKEL'S PRIMARY CRITICISM OF IPC'S COST-OF-SERVICE METHODOLOGY.

A. Witness Yankel presents data showing that loads for the irrigation class have grown very little in the past 25 years relative to load growth for other classes. He

[1] Load factor refers to the ratio of a customer's average demand to peak demand during a specified period. For example, if a customer uses 2,190 kWh per month, the customer's average demand is 3 kW in a typical month (2,190 kWh divided by 730 hours per month). If the customer's maximum monthly peak demand is 10 kW, the customer's monthly load factor is 30 percent (3 kW divided by 10 kW). We generally classify low load factor customers as those with load factors below the system average load factor, and high load factor customers as those with load factors above the system average load factor. IPC's annual system load factor typically falls between 55 and 60 percent.

also shows that during this 25-year period, IPC's plant-in-service has more than doubled to meet load growth, leading to significant rate increases to pay for the additional costs of IPC's expanding asset base. He then concludes that customers whose load growth caused the need for additional capacity should pay for the resulting higher cost of service. According to witness Yankel, because irrigation loads have grown little in 25 years, irrigation customers should bear little if any of the higher cost of new capacity (generation, transmission, and distribution) to meet load growth. He criticizes IPC's costing methodology because, in his opinion:

> ...the Company's cost of service study inappropriately allocates a significant portion of this growth to the Irrigation class. Given the obvious fact that growth and the cost of growth are not being fueled by the Irrigators, the allocation of significant portions of the cost of this growth to the Irrigators is on its face counter-intuitive.[2]

Q. HOW DOES WITNESS YANKEL PROPOSE TO FIX THIS ALLEGED PROBLEM?

A. He proposes modifying IPC's cost-of-service methodology to address what he calls ***backward-looking costs*** and ***forward-looking costs***. His direct testimony addresses his proposed solution using these two cost concepts:

[2] *See* the direct testimony of IIPA witness Anthony J. Yankel at 9:9-12.

The simplest way to correct the Company's Base Case study would be to continue to define "backward-looking" costs base on test year usage levels and "forward-looking costs" at the anticipated <u>increase</u> in usage levels in the Company IRP. The "backward-looking costs" would simply be costs as they exist today and allocated on the basis of today's energy or 12-CP as is presently done in the Company's "base" cost of service study. The "forward looking costs" would be developed using the same weighting factors used by the Company associated with the cost of the anticipated growth, but would be allocated on the basis of <u>only the growth</u> that is anticipated from each rate schedule over a future ten year period. The relative share of historic costs and anticipated costs related to growth would then be averaged using the Company's existing procedures in order to develop a composite allocation factor for use in spreading test year costs for allocation purposes. In this manner, the methodology would be exactly the same as the Company's Base Case, but the marginal costs would be tied to the marginal/new usage and not to the present level (status quo) of usage.[3] (Emphasis in original.)

Q. DOES IPC'S COSTING METHODOLOGY FAIL TO ASSIGN COSTS PROPERLY TO REFLECT FACTORS DRIVING ITS NEED FOR NEW CAPACITY?

A. Yes. However, witness Yankel does not correctly identify deficiencies in IPC's costing methodology that cause the problem with respect to the allocation of production costs, nor does he propose a reasonable and proper solution. I agree

[3] *Ibid.* at 19:13 – 20:2.

with him that IPC's recommended costing methodology is seriously deficient. But I disagree regarding how to fix IPC's methodology.

Q. IS WITNESS YANKEL'S CRITICISM OF IPC'S COST STUDY BASED ON A VALID PREMISE?

A. No. Witness Yankel implicitly assumes that if a class has little or no load growth, then it also should have little if any growth in costs assigned to it. This assumption ignores a fundamental tenet of cost of service—namely, costs should be assigned using allocation factors that reasonably link costs and cost-drivers. Consider IPC's production costs. As I noted in my direct testimony, the key driver underlying IPC's need for new production resources (both new capacity and expensive purchased power) is peak demand in summer months. As a result, a reasonable cost-of-service methodology should ensure that the allocation of these higher summer-related costs should be linked to summer peak demands. That is, customer classes that use electricity primarily in summer peak months—regardless whether their loads have grown or remained stable in the past 25 years—should expect to see significantly higher rates as IPC adds production resources. Instead, as my direct testimony shows, IPC's classification and allocation of production costs focuses on year-round average demands and energy usage, not summer peak demands. Not surprisingly—albeit incorrectly, IPC's costing methodology implies huge rate increases for high load factor classes, yet little if any increase for most lower load factor classes that contribute heavily to summer peak demands relative to their demands in off-peak months.

Q. DOES ALL LOAD GROWTH CAUSE IPC TO ADD CAPACITY?

A. No. In trying to link load growth to cost assignment, witness Yankel ignores the link between the timing of electric loads and IPC's need for new production resources. For example, demands in peak periods drive capacity requirements, while load growth in off-peak hours may have little if any effect on IPC's need for new production capacity. In criticizing IPC's costing methodology, witness Yankel never mentions that the bulk of the irrigation class' annual kWh usage and highest class peaks occur in peak hours in peak summer months. In fact, to the extent that IPC's costing methodology understates production costs attributable to summer peak demands, costs assigned to the irrigation class are understated—not overstated at witness Yankel contends. This result was confirmed in the cost-of-service analyses presented in my direct testimony, which indicated that the rate increase for the irrigation class should be significantly greater than the increase proposed by IPC.

Q. IS WITNESS YANKEL'S PROPOSED FIX WORSE THAN THE ALLEGED PROBLEM IT IS DESIGNED TO CURE?

A. Yes. His proposed fix uses an average of growth-adjusted ***forward-looking costs*** and historical ***backward-looking costs*** to allocate ***test-year costs***. This scheme is nothing more than a variant of vintage pricing, which attempts to insulate classes with little or no load growth from any cost responsibility for new capacity—even if their peak demands coincide with other demands that are driving the need for new capacity. Instead of resorting to vintage pricing, the cure for the alleged problem that witness Yankel describes is twofold:

- Properly classify and allocate production costs to emphasize summer peak demands as the driving force behind IPC's recent and planned production resource additions.

- Shift load to off-peak periods to avoid contributing to system peak demands. Simply stated, cost responsibility assigned to irrigators in any properly designed cost-of-service study will decline as irrigators shift more load to off-peak hours.

Q. IS VINTAGE PRICING ECONOMICALLY EFFICIENT?

A. No. Vintage pricing assumes specific customers have entitlement to lower cost assets simply by virtue of when they became market participants. Under witness Yankel's scheme, the higher marginal cost of new capacity additions is assigned primarily to classes with significant load growth, while no-growth classes are primarily assigned much lower historical embedded costs. Charging some customers prices based on marginal capacity costs while charging other customers using the same capacity prices based on historical embedded costs is both economically inefficient and discriminatory. Moreover, vintage pricing encourages no-growth classes to use more energy in high-cost peak periods. Under witness Yankel's scheme, irrigation customers would be encouraged to use more energy in summer peak periods, even while IPC is promoting its Peak Rewards program to encourage irrigation customers to shift loads to off-peak hours.

Q. HAS VINTAGE PRICING BEEN LARGELY DISCREDITED?

A. Yes. Vintage pricing has generally been recognized as bad regulatory policy.[4] For example, in a 1993 report in which it discussed whether new or existing customers should be primarily responsible for the cost of transmission capacity additions, the National Regulatory Research Institute (NRRI) stated:

[4] I do not consider direct cost assignments (for example, directly charging customers for the incremental cost of interconnection upgrades that a utility does not normally provide) as a form of vintage pricing.

> ...In most cases, transmission line upgrades are likely to be constructed not only to serve the current applicant, but also to serve projected future applicants, and to provide more reliable service to existing wholesale, retail, and transmission customers. FERC might choose to protect existing wholesale, retail, and transmission customers at all costs. This would result in a system of vintage pricing, with existing customers paying a depreciated embedded cost of old plant and new customers paying the full incremental cost of new plant. One outcome of such pricing is that the ***old customers would benefit***, enjoying increased reliability and the opportunity to increase their own wholesale or retail purchases or transmission service ***without paying any part of the cost of service of the new plant***. Such ***vintage pricing*** makes for bad economics, whether or not practicable or feasible.[5] (Emphasis added.)

Q. DID WITNESS YANKEL CONDUCT A COST STUDY THAT INCORPORATED HIS PROPOSED FIX?

A. Yes. He prepared a cost study that included growth-adjusted allocation factors for generation and transmission costs but not distribution costs.[6] As expected, his study generally implies rate increases similar to those proposed by IPC except for the irrigation class.

Q. DO YOU AGREE WITH THE RESULTS FROM HIS COST STUDY?

A. No. Even if one agreed with the premise of witness Yankel's growth-adjusted cost study, one could not agree with his study's results because of a serious error he introduced in his analysis. Specifically, in developing his growth-adjusted allocation factors, witness Yankel used annual class energy growth instead of

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[5] Kenneth W. Costello *et al.*, *A Synopsis of the Energy Policy Act of 1992: New Tasks for State Public Utility Commissions*, The National Regulatory Research Institute, Columbus, Ohio, June 1993 at 31.
[6] *See* Yankel direct testimony at Exhibit No. 302.

summer peak demand growth—the primary driver underlying IPC's need for additional production resources. Moreover, he did not to correct the classification and allocation errors embodied in IPC's costing methodology, thereby ensuring that his results did not reflect proper links between customer demands and cost allocation. The Commission should reject his growth-adjusted cost-of-service study and associated revenue spread.

Q. SHOULD A COST STUDY ATTEMPT TO ADDRESS THE IMPACT OF LOAD GROWTH ON RISING COSTS?

A. Yes. But such attempts should be direct, transparent, and economically rational. Assigning asset entitlements to specific customers or classes through vintage pricing is not a proper mechanism to address load growth in a cost study. (Neither is the convoluted blending of average and marginal cost concepts as occurs in IPC's 3CP/12CP cost study.) Instead, in an embedded cost analysis, load growth can be properly addressed by linking as closely as possible allocation factors to cost drivers. For example, if summer peak demands are principal drivers behind rising production costs, then fixed production cost should be classified as demand-related costs and allocated using schemes that emphasize summer peak demands—not energy usage (think IPC's 3CP/12CP methodology).

STAFF WITNESS HESSING

Q. DOES STAFF RECOMMEND IPC'S PROPOSED 3CP/12CP COST-OF-SERVICE METHODOLOGY?

A. Yes. Staff witness Hessing recommends that the Commission adopt IPC's 3CP/12CP methodology.[7]

[7] *See* the direct testimony of Staff witness Keith Hessing at 8:25 – 9:1.

Q. WHAT IS THE COMMON THEME BETWEEN COST-OF-SERVICE POSITIONS TAKEN BY WITNESSES YANKEL AND HESSING?

A. Both witnesses—consistent with IPC's witness Tatum—recommend disproportionate allocations of production-related costs to loads occurring in non-summer months and off-peak hours. Their recommendation is premised on support (either explicit or implicit) for effectively allocating steam and hydro production-related costs away from the summer on-peak loads though a combination of classification and allocation techniques that improperly focus on energy usage. While witness Yankel's position is understandable—the irrigation class benefits from disproportionate cost allocations to off-peak loads—I do not understand why Staff supports a costing methodology that fails to emphasize summer peak demands as the principal driver behind IPC's rising production costs. Moreover, the costing methodologies advocated by IIPA and Staff put a completely unreasonable emphasis on energy usage as a principal cost driver.

Q. HOW DOES THIS OVER-EMPHASIS ON ENERGY OCCUR?

A. The problem starts with IPC's (and Staff's) use of load factor to classify steam and hydro production plant. Under this load factor classification scheme, IPC (and Staff) classify almost 60 percent of these fixed costs as energy-related costs. No witness in this case has provided a valid reason why such a high percentage of IPC's fixed production costs should be classified as variable energy costs. That should surprise nobody since the classification cannot be justified on either economic or engineering grounds. As I noted earlier, load factor is simply the relationship between average and peak demands. While system load factor may influence the types and operation of system production resources, it does not reflect the driving force underlying the amount of required production resources—namely peak demands.[8]

IPC's and Staff's over-emphasis on energy as a cost driver is then exacerbated by the use of 12CP factors in the 3CP/12CP methodology to allocate the 40 percent of steam and hydro fixed costs that are classified as demand costs. A 12CP allocation method is a hybrid between strict demand and energy allocation approaches since it diminishes the importance of annual peaks through averaging, thereby indirectly recognizing annual energy usage in assigning cost responsibility for fixed production costs. As a result, the 12CP method shifts cost responsibility to energy-intensive, high load factor customers. More importantly, except for utilities with similar monthly peaks, the 12CP method largely ignores the role of annual system peaks in driving the need for and operation of production capacity.[9] For example, in IPC's case, the 12CP approach almost totally ignores the role that hydro plant in particular plays in serving IPC's summer peak loads. Combining a load factor scheme that improperly classifies 60 percent of IPC's steam and hydro plant costs as energy costs with an allocation method that mutes the importance of summer peak demands in allocating the remaining demand-related 40 percent of these costs results in further unjustified shifts of IPC's production costs to high load factor customers.

[8] While I support classifying all steam and hydro plant costs as demand-related costs, in my direct testimony I presented a rational alternative to IPC's (and Staff's) load factor classification scheme. My alternative classified IPC's steam and hydro plant costs as 57.10 percent demand and 42.90 percent energy. I offered this alternative simply as an option if the Commission decides that some part of IPC's fixed steam and hydro plant costs should be classified as energy-related costs.

[9] A 12CP allocation method is sometimes justified as a means of reflecting the value of production capacity in all months—including months with maximum demands far below the utility's annual system peak. However, a utility does not plan for and add production capacity to meet the average of its 12 monthly system peaks. Its capacity additions are driven by its need to meet annual system peaks. Capacity used to meet annual system peaks then becomes available to meet peak demands in all other months.

Q. DID STAFF PERFORM A COST-OF-SERVICE STUDY USING THE 3CP/12CP METHODOLOGY?

A. Yes. The cost-of-service analysis that Staff conducted (*see* Staff Exhibit No. 130) was based on a lower jurisdictional revenue requirement than IPC proposed.

Q. DID STAFF CORRECT ANY OF THE DEFICIENCIES IN IPC'S COST STUDY THAT YOU IDENTIFIED IN YOUR DIRECT TESTIMONY?

A. No. Staff witness Hessing made no changes in IPC's cost study with respect to the classification and allocation of IPC's retail costs. Staff's cost-of-service study is simply IPC's cost study with Staff's lower jurisdictional revenue requirement. As a result, Staff's cost study suffers from the same fatal flaws as IPC's cost study—flaws that I discussed in detail in my direct testimony.

Q. DID STAFF PROPOSE A REVENUE SPREAD THAT REFLECTS RESULTS FROM ITS COST-OF-SERVICE ANALYSIS?

A. Yes. Staff's proposed revenue spread is quite similar to IPC's proposed spread although the percentage increases are smaller because of Staff's lower revenue requirement. In particular, Staff's proposed revenue spread calls for increases well above the system average increase for higher load factor customers, including special contract customers.

Q. HOW DOES STAFF JUSTIFY ITS RECOMMENDED HIGHER-THAN-AVERAGE RATE INCREASES FOR HIGHER LOAD FACTOR CUSTOMERS?

A. Staff implies that because average rates (prices) for higher load factor customers (around $30 dollars per MWh) are less than IPC's marginal power supply costs (around $60 per MWh according to witness Hessing), above average increases for higher load factor customers should be expected.[10]

Q. DOES THIS RELATIONSHIP BETWEEN MARGINAL POWER SUPPLY COSTS AND AVERAGE RATES SUPPORT STAFF'S RECOMMENDED REVENUE SPREAD?

A. No. Witness Hessing's cost and rate comparison ignores two key factors:

- IPC's test-year average fuel and purchased power expense is less than $18 per MWh—well below the average price witness Hessing claims that higher load factor customer pay and far below his estimated $60 per MWh marginal power supply cost. Under IPC's rates, customers are charged average power supply costs—not marginal costs. Moreover, marginal power supply costs are not constant—they may vary significantly by hour, day, or month. In many hours of the year, the average price IPC charges for energy may be significantly above its marginal cost of energy.
- In a properly designed cost-of-service study, high load factor customers should receive most of the off-system sales revenue credits resulting from off-peak sales attributable to excess block energy purchases and available system hydro capacity. This does not happen in IPC's cost study—which Staff recommends—because off-system sales revenue credits are allocated without reference to when such sales occur (primarily off-peak months). As I pointed out in my direct testimony, because IPC's costing methodology does not properly link sales revenue credits to off-peak energy usage, a disproportionately ***small*** share of the off-system sales revenue credits is assigned to

[10] *Ibid.* at 11:2-7.

higher load factor customers and a disproportionately ***high*** share is assigned to lower load factor customers whose electricity usage occurs primarily in summer peak months. As a result, IPC's cost of serving higher load factor customers is overstated and understated for low load factor classes.

Q. HAS THE COMMISSION TRADITIONALLY RELIED ON COST STUDIES THAT ALLOCATE A DISPROPORTIONATE AMOUNT OF IPC'S STEAM AND HYDRO PLANT COSTS TO NON-SUMMER, OFF-PEAK LOADS?

A. No. For 25 years the Commission has consistently adopted what is commonly referred to as a weighted 12CP methodology to allocate demand-related steam and hydro production plant costs to rate classes. The weights used to develop class allocation factors are IPC's monthly marginal generation capacity costs. These weighted 12CP allocation factors emphasize peak demands in summer months when IPC's marginal generation capacity costs are highest. As a result, weighted 12CP factors allocate substantially more costs to rate classes that use the IPC system during summer peak hours. Because IPC's growing summer peak demands are driving its need for production resources, the Commission should not support any cost-of-service methodology that does not emphasize the importance of summer on-peak demands in driving the need for capacity resources—for example, the costing methodologies proposed by witnesses Yankel and Hessing. Instead, the Commission should adopt my recommended classification of production costs and my recommended weighted 12CP methodology, which emphasizes summer peak demands, to allocate IPC's production costs to rate classes.

Q. SHOULD THE COMMISSION REJECT STAFF'S RECOMMENDED COST STUDY AND ASSOCIATED REVENUE SPREAD?

A. Yes. Staff's cost study is fatally flawed, and its recommended revenue spread—which is derived from the cost study results—does not reasonably track IPC's cost of serving each customer class.

Q. HAVE YOU CHANGED ANY RECOMMENDATIONS IN YOUR DIRECT TESTIMONY AFTER REVIEWING THE TESTIMONY FILED BY WITNESSES YANKEL AND HESSING?

A. No. I still recommend the following:

1. Reject IPC's 3CP/12CP seriously and probably fatally flawed cost-of-service study.[11]
2. Reject IPC's classification of steam and hydro production plant costs as demand- and energy-related costs. Instead, all steam and hydro production plant costs should be classified as demand-related costs.
3. If the Commission allows IPC to classify steam and hydro plant costs into demand and energy cost components, then system load factor ***should not*** be used to determine the energy cost component. Instead, as an alternative, I recommend classifying 57.10 percent of these plant costs as demand and 42.90 percent as energy. (I described how these percentages are derived in my direct testimony.)
4. Reject IPC's classification of Account 555 purchased power costs. Instead, they should be classified using the same alternative classification

[11] Throughout my direct testimony I focused on IPC's 3CP/12CP cost study since IPC recommends this study. However, IPC's Base Case and Modified Base Case cost studies suffer from deficiencies comparable to those in the 3CP/12CP cost study. As a result, neither the Base Case nor the Modified Base Case studies should be used for setting IPC's rates in this case.

scheme I propose for classifying steam and hydro plant costs (that is, 57.10 percent demand and 42.90 percent energy.)

5. Reject IPC's proposed assignment of all demand-related hydro plant costs to the baseload capacity category. Instead, I recommend assigning 50 percent of demand-related hydro costs to the baseload plant category (which is allocated on the basis of 12CP demands) and 50 percent to the peaking category (which is allocated on the basis of 3CP demands).

6. Reject IPC's proposed assignment of demand-related purchased power costs to baseload and peaking capacity categories on the basis of how it assigns production plant to these categories. Instead, I recommend using the same 50/50 demand and energy split for demand-related Account 555 costs that I recommend for assigning demand-related hydro plant costs.

7 Reject IPC's marginal-cost-weighted allocation of energy costs in its 3CP/12CP study. Instead, an unweighted energy cost allocation should be used to ensure that higher load factor classes are assigned a higher percentage of the lower fuel costs associated with baseload capacity.

8. Require IPC to allocate demand-related production costs using a weighted 12CP method. I presented results from two W12CP cost studies that I performed in Exhibit Nos. 610 and 611.

9. Reject any revenue spread that is based on 3CP/12CP cost study results. Instead, results from my Exhibit No. 611 should be used as a starting point in developing a revenue spread for any rate change the Commission approves in this case.[12] At a minimum, these results support an across-the-board revenue spread instead of the higher-than-average increases for

[12] This includes Staff's proposed revenue requirement.

higher load factor and special contract customers proposed by IPC and Staff.

10. Require IPC to retain the services of a reputable outside firm to examine, evaluate, and recommend necessary changes to its cost-of-service model.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes.