Department of Energy
Washington, DC 20585

RECEIVED
2008 OCT 27 AM 10: 23
IDAHO PUBLIC
UTILITIES COMMISSION

October 24, 2008

VIA OVERNIGHT SERVICE
Ms. Jean Jewell
Commission Secretary
Idaho Public Utilities Commission
472 W Washington
P.O. Box 83720
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 Direct Testimony and Exhibits of Dr. Dennis W. Goins on behalf of the United States Department of Energy in the above-captioned proceeding;

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

(3) a disk upon which each of these items is set out in computer searchable form.

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

Sincerely yours,

Arthur Perry Bruder
Attorney for the United States
Department of Energy
Office of the General Counsel
United States Department of Energy
1000 Independence Avenue SW
Washington, D.C. 20585
Arthur.Bruder@hq.doe.gov
(202) 586-3409

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

I hereby certify that I have, this 24th day of October, 2008, served or caused to be served a true and correct copy of the attached Testimony and Exhibits 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 the street address set out below; (2) electronic transmission of the same to 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.

Ms. Jean Jewell, Secretary
Idaho Public Utilities Commission
472 W. Washington
Boise, ID 83702
jean.jewell@puc.idaho.gov

RECEIVED
2008 OCT 27 AM 10: 23
IDAHO PUBLIC
UTILITIES COMMISSION

Barton L. Kline
Lisa D. Nordstrom
Idaho Power Company
1221 W. Idaho St. (83702)
P.O. Box 70
Boise, ID 83707-0070
bkline@idahopower.com
lnordstrom@idahopower.com

John R. Gale
Vice President, Regulatory Affairs
Idaho Power Company
1221 W. Idaho St. (83702)
P.O. Box 70
Boise, ID 83707-0070
rgale@idahopower.com;

Weldon Stutzman
Neil Price
Deputy Attorneys General
Idaho Public Service Commission
472 W. Washington (83702)
PO Box 83720
Boise, ID 83720-0074
weldon.stutzman@puc.idaho.gov
neil.price@puc.idaho.gov

Peter J. Richardson
Richardson & O'Leary
515 N. 27th St.
P.O. Box 7218
Boise, ID 83702
peter@richardsonandoleary

Dr. Don Reading
Ben Johnson Associates
6070 Hill Road
Boise, ID 83703
dreading@mindspring.com

Randall C. Budge
Eric L. Olsen
Racine, Olson, Nye, Budge &
Bailey, Chartered
P.O. Box 1390
201 E. Center
Pocatello, ID 83204-1391
rcb@racinelaw.net
elo@racinelaw.net

Anthony Yankel
29814 Lake Road
Bay Village, OH 44140
yankel@attbi.com

Michael Kurtz, Esq.
Kurt J. Boehm, Esq.
Boehm, Kurtz & Lowry
36 E. Seventh Street, Suite 1510
Cincinnati, OH 45202
mkurtz@BKLlawfirm.com
kboehm@ BKLlawfirm.com

Conley E. Ward
Michael Creamer
Givens Pursley LLP
601 W. Bannock Street
PO Box 2720
Boise, ID 83701-2720
cew@givenspursley.co

Dennis E. Peseau, Ph.D.
Utility Resources, Inc.
1500 Liberty Street, Suite 250
Salem, OR 97302
dpcseau@cxcitc.com

Brad M. Purdy
Attorney at Law
2019 N.17thSt.
Boise, Idaho 83702
bmpurdy@hotmail.com
Ken Miler
Snake River Alliance
Box 1731
Boise, ID 83701
kmiler@snakeriverallance.org

Kevin Higgins
Energy Strategies LLC
Parkside Towers
215 South State Street
Suite 200
Salt Lake City, UT 84111
khiggins@energystrat.com

Arthur Perry Bruder, Esq.
Office of the General Counsel
United States Department of Energy
Washington, DC 20585
(202) 586-3409

RECEIVED

2008 OCT 27 AM 10: 23

IDAHO PUBLIC
UTILITIES COMMISSION

Arthur Perry Bruder (admitted *pro hac vice*)
1000 Independence Ave. SW
Washington, D.C. 20585
phone: (202) 58603409
FAX: (202) 586-7479
arthur.bruder@hq.doe.gov
Attorney/Representative for the
United States Department of Energy

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

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

October 24, 2008

Table of Contents

Page

INTRODUCTION AND QUALIFICATIONS

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. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Ph.D. degree in economics and a Master of Economics degree from North Carolina State University. I also earned a B.A. degree with honors in economics from Wake Forest University. From 1974 through 1977 I worked as a staff economist at the North Carolina Utilities Commission (NCUC). During my tenure at the NCUC, I testified in numerous cases involving electric, gas, and telephone utilities on such issues as cost of service, rate design, intercorporate transactions, and load forecasting. While at the NCUC, I also served as a member of the Ratemaking Task Force in the national Electric Utility Rate Design Study sponsored by the Electric Power Research Institute (EPRI) and the National Association of Regulatory Utility Commissioners (NARUC).

Since 1978 I have worked as an economic and management consultant to firms and organizations in the private and public sectors. My assignments focus primarily on market structure, policy, planning, and pricing issues involving firms that operate in energy markets. For example, I have conducted detailed analyses of product pricing, cost of service, rate design, and interutility planning, operations, and pricing; prepared analyses related to utility mergers, transmission access and pricing, and the emergence of competitive markets; evaluated and developed regulatory incentive mechanisms applicable to utility operations; and assisted clients in analyzing and negotiating interchange agreements and power and fuel supply contracts. I have also assisted clients on electric power market restructuring issues in Arkansas, New Jersey, New York, South Carolina, Texas, and Virginia.

I have submitted testimony and affidavits and provided technical assistance in more than 100 proceedings before state and federal agencies as an expert in competitive market issues, regulatory policy, utility planning and operating practices, cost of service, and rate design. These agencies include the Federal Energy Regulatory Commission (FERC), the Government Accountability Office, the First Judicial District Court of Montana, the Circuit Court of Kanawha County, West Virginia, and regulatory agencies in Alabama, Arizona, Arkansas, Colorado, Florida, Georgia, Idaho, Illinois, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, and the District of Columbia. Additional details of my educational and professional background are presented in the Appendix.

I have also participated in several cases before this Commission involving Idaho Power Company (IPC). These cases include Docket Nos. IPC-E-03-13, IPC-E-04-23, IPC-E-05-28, and IPC-E-07-08.

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 ASSIGNMENT WERE YOU GIVEN WHEN YOU WERE RETAINED?

A. I was asked to undertake two primary tasks:

1. Review IPC's proposed cost-of-service analyses (including pro forma adjustments) and related rates.
2. Identify any major deficiencies in the cost analyses and proposed rates and suggest recommended changes.

Q. WHAT SPECIFIC INFORMATION DID YOU REVIEW IN CONDUCTING YOUR EVALUATION?

A. I reviewed IPC's application, testimony, exhibits, and responses to requests for information related to cost of service, revenue spread, and rate design issues. I also reviewed documents found on web sites operated by the Commission and by IPC.

CONCLUSIONS

Q. WHAT CONCLUSIONS HAVE YOU REACHED?

A. On the basis of my review and evaluation, I have concluded the following:

1. <u>IPC's Cost of Service</u>. IPC has proposed increasing base revenues by approximately $66.6 million (9.89 percent). In developing proposed rates for its retail electric services, IPC first conducted three (3) cost-of-service (COS) studies for the test year ending December 31, 2008. In these cost analyses, IPC allocated and/or directly assigned its costs to functional

segments of its retail electric business. The return component of IPC's costs reflects a requested 8.55 percent return on its retail jurisdictional rate base (using an 11.25 percent return on common equity). IPC calls the three cost studies the:

- Base Case, which is supposedly similar to the COS methodology IPC presented in Case No. IPC-E-03-13. In the Base Case, IPC classified 59.38 percent of its fixed costs associated with steam (FERC accounts 310-316) and hydro (FERC accounts 330-336) production plant as energy-related costs, and the remainder—40.62 percent—as demand-related costs. The 59.38 percent classification is equal to the IPC jurisdictional load factor. IPC allocated its demand-related production costs to customer classes using a marginal-cost-weighted average of each class' contribution to IPC's 12 monthly coincident peaks. That is, IPC used a version of the weighted 12CP (W12CP) allocation method. In its final order in Case No. IPC-E-03-13, the Commission found that the W12CP methodology reflected a reasonable approximation of class cost responsibility.
- Modified Base Case, which is the Base Case with two modifications. First, IPC classified purchased power expenses (FERC account 555)[1] as demand and energy costs in the same manner as hydro and steam production plant costs are classified—that is, 40.62 percent as demand-related costs and 59.38 percent as energy-related costs. (In the Base Case, IPC classified almost all of its purchased power costs as energy-related costs.) Second, energy cost allocators E10S and

[1] This account include sub-accounts 555.1 (power purchases) and 555.2 (purchases from cogeneration and small power producers—or CSPPs).

E10NS were derived using the average of each class' normalized kWh sales and its marginal-cost-weighted normalized kWh sales.

- 3CP/12CP, which is the Modified Base Case with production plant split into two categories that I call baseload capacity[2] and peaking capacity. IPC assigned all steam (FERC accounts 310-316) and hydro (FERC accounts 330-336) production plant to the baseload capacity category, and combustion turbine (CT) plant costs (FERC accounts 340-346) to the peaking capacity category. IPC allocated plant costs assigned as peaking capacity on the basis of each class' average coincident peak in June, July, and August (that is, a 3CP allocation method). Like the Modified Base Case, hydro and steam production plant costs were allocated using a 12CP allocator. However, the allocation factors were not weighted by IPC's marginal-costs—that is, IPC used an unweighted 12CP allocator.

IPC's preferred cost-of-service methodology is the 3CP/12CP method. According to IPC, the 3CP/12CP method best reflects factors driving IPC's need for capacity to meet growing summer demands as well as year-round demands.

2. Cost-of-Service Problems. In this case, IPC recommends a production cost allocation method that the Commission has never approved. Prior to this case, the Commission's last addressed the allocation of demand-related production costs in Case No. IPC-E-03-13, in which it approved the W12CP method—a method that the Commission had endorsed in several preceding cases. In the current case, IPC recommends a seriously

[2] Includes capacity designed to serve both baseload and intermediate load requirements.

flawed 3CP/12CP allocation method. In particular, the IPC's 3CP/12CP cost-of-service study (COSS):

- Departs from Commission precedent.
- Improperly classifies steam and hydro production plant costs and Account 555 purchased power expenses as demand- and energy-related costs.
- Improperly splits Account 555 costs into baseload and peaking categories. I discuss this in more detail later.
- Fails to track costs accurately. For example, IPC's 3CP/12CP cost study does not reflect the concentration of purchased power costs in the summer peak months, thereby understating costs assigned to summer peak usage. That is, costs that should be allocated primarily to classes with heavy summer electricity usage are instead allocated to classes with high load factor usage in non-summer, off-peak months (for example, special contract and Schedule 19 customers). As a result, low load factor classes with high summer demands are able to avoid responsibility for a large share of purchased power costs they cause IPC to incur.
- Fails to allocate steam and hydro production plant costs; fuel costs, and revenues from off-system sales (Account 447) in a manner that properly aligns class cost responsibility with class loads that underlie these costs and revenues. For example, most of IPC's off-system sales revenue is produced in non-summer, non-peak months when significant excess baseload capacity (steam and hydro capacity) is available. Higher load factor classes are allocated most of IPC's

baseload production costs, and therefore should also be allocated most of its off-system sales revenues. Yet IPC allocates off-system sales revenue on the basis of marginal-cost-weighted energy usage. As a result, lower load factor classes with heavy energy usage in peak months are allocated too large a share of off-system sales revenues—thereby understating their test-year cost responsibility.

3. Revenue Spread. IPC spread its proposed revenue increase among rate classes using the following 4-step sequential approach:

- Identify sales revenue increases (or decreases) necessary to match total revenue from each class with IPC's estimated cost of serving the class as determined in IPC's 3CP/12CP cost study.
- Set a 15-percent limit on rate increases to Special Contracts customers and Schedules 19 Large Power Service, 24 Irrigation Service, and 42 Traffic Control Lighting.
- Hold revenues from Schedules 15, 40, and 41 at test-year levels under present rates instead of decreasing revenues as indicated by the COSS results—that is, give no initial increase to this class.
- Spread the revenue shortfall caused by the 15-percent cap on class increases across all non-capped rate schedules.

RECOMMENDATIONS

Q. WHAT DO YOU RECOMMEND ON THE BASIS OF THESE CONCLUSIONS?

A. I recommend the following:

1. Reject IPC's 3CP/12CP cost-of-service study.[3] The study is seriously and probably fatally flawed because it fails to align cost allocation with cost responsibility.

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. IPC's proposed classification scheme suffers from at least two arbitrary assumptions. First, the classification scheme arbitrarily assumes that IPC's system load factor somehow identifies the portion of generation plant costs that is supposedly energy-related. IPC has provided no empirical analysis to justify or support its choice of system load factor to classify production plant costs.[4] Second, like most capital substitution arguments,[5] the classification scheme implicitly assumes that if all production plant costs were classified as demand-related costs, higher load factor customers would receive a disproportionate share of the cheap energy benefits of baseload and intermediate capacity without paying a proportionate share of the higher capital costs of such capacity—particularly if demand-related capacity costs are allocated on the basis of peak demands. Neither assumption is intuitively obvious or empirically supportable.

[3] Throughout my testimony I focus 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 I describe regarding 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.

[4] IPC witness Timothy Tatum (direct testimony at 29:7-10) says that the load factor methodology used to classify steam and hydro production plant reflects "the methodology preferred by the Commission in prior general rate proceedings."

[5] With respect to system planning analyses that focus on choosing a mix of generation plant that meets expected demand at least cost, *capital substitution* refers generally to trade-offs between production plant with relatively high capital costs but low energy costs (for example, baseload generating units) and production plant with relatively low capital costs but high energy costs (for example, combustion turbines).

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 describe how these percentages are derived later in my testimony.) With respect to the classification of hydro plant, IPC uses hydro plant not only to meet baseload demands, but also to serve peak loads. This operating flexibility is not reflected in a classification scheme based on system load factor.

4. Reject IPC's classification of Account 555 purchased power costs. Instead, they should be classified using the same alternative classification 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. This assignment ignores the role that hydro plant plays in meeting IPC's summer peak demands. 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). My recommended alternative classification scheme falls between the 100-percent demand classification scheme IPC uses for peaking CTs and the approximately 40 percent demand/60 percent energy scheme it uses to classify baseload steam generating costs.[6]

[6] A reasonable argument could also be made that under IPC's 3CP/12CP methodology, some portion of steam production plant should be designated as peaking capacity and allocated on the basis of 3CP demands. I do not address this issue in my direct testimony.

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. IPC's approach assigns far too little of Account 555 costs to the peaking category. 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 present results from two W12CP cost studies that I performed in Exhibit Nos. 610 and 611.

9. Reject IPC's proposed revenue spread, which is based on its 3CP/12CP cost study results. Instead, I recommend that results from my Exhibit No. 611 be used as a starting point in developing a revenue spread for any rate change the Commission approves in this case. At this point, I have not developed a proposed revenue spread for all classes based on results from my W12CP cost study. However, results from my W12CP cost study—combined with the total unreliability of results from IPC's costs studies—support an across-the-board revenue spread. Moreover, in addition to my recommended W12CP cost study, other studies that I prepared clearly show that IPC's proposed 15 percent increases for DOE and Schedule 19 are excessive. IPC's proposed increases for these customers are about 1.5

times the system average increase of 9.89 percent. My analyses indicate that increases to DOE and Schedule 19 should be limited to the system average increase and under no circumstance should exceed 1.10 times the system average increase.

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. More than 5 years have passed since the Commission ordered IPC in Case No. IPC-E-03-13 to work with stakeholders to address cost-of-service issues. The issues have not been resolved. Large customers such as DOE and Mountain Home AFB no longer have confidence that IPC's cost studies properly reflect class cost responsibility. While my recommended changes mitigate some of the more obvious problems in IPC's cost analyses, they do not resolve a fundamental problem. Specifically, classes driving the need for additional capacity to meet summer peak demands are not being assigned a fair share of the costs of meeting those demands.

COST OF SERVICE

Q. DID IPC ESTIMATE ITS COST OF SERVING DIFFERENT CUSTOMER CLASSES?

A. Yes. IPC conducted three detailed cost-of-service studies using data (adjusted in many cases) for the test year ending December 31, 2008. In these cost analyses, IPC classified and then allocated and/or directly assigned its costs to functional segments of its retail electric business. The return component of IPC's costs reflects a requested 8.55 percent return on its Idaho retail jurisdictional rate base (using an 11.25 percent return on common equity).

Q. DOES YOUR TESTIMONY ADDRESS EACH OF IPC'S COST STUDIES?

A. No. My testimony focuses on IPC's preferred 3CP/12CP cost-of-service study. However, most of my criticisms of IPC's 3CP/12CP cost study would also be applicable to IPC's Base Case and Modified Base Case cost studies that I described earlier.

Q. HAS THE COMMISSION EVER APPROVED IPC'S 3CP/12CP METHOD FOR ALLOCATING DEMAND-RELATED PRODUCTION COSTS?

A. No. Prior to this case, the Commission's last addressed the allocation of demand-related production costs in Case No. IPC-E-03-13, in which it approved the W12CP method—a method that the Commission had also endorsed in several preceding cases.

Q. IN ITS 3CP/12CP COST STUDY, HOW DID IPC ALLOCATE DEMAND-RELATED PRODUCTION AND PURCHASED POWER COSTS?

A. In its 3CP/12CP cost study, IPC allocated demand-related steam and hydro production plant and Account 555 purchased power costs categorized as baseload capacity on the basis of each class' unweighted 12 monthly coincident peak demands (12CP). IPC allocated demand-related CT plant and purchased power costs categorized as peaking capacity on the basis of each class' unweighted monthly coincident peak demands in the 3 summer months June-August (3CP).

Q. HOW DID IPC ALLOCATE ENERGY-RELATED COSTS?

A. In its 3CP/12CP cost study, IPC used the average of marginal-cost-weighted and unweighted summer and non-summer ratios to derive the summer and non-summer energy allocation factors (E10S and E10NS).

Q. PLEASE DESCRIBE HOW IPC CLASSIFIED PRODUCTION PLANT AND PURCHASED POWER COSTS.

A. In its 3CP/12CP cost study,[7] IPC classified steam (FERC Accounts 310-316) and hydro (FERC Accounts 330-336) production plant costs and purchased power costs (FERC Account 555) as demand- and energy-related costs. IPC set the energy-related component of these costs equal to the Idaho jurisdictional load factor (59.38 percent), with the residual—40.62 percent or (1 – load factor)—classified as demand-related costs. IPC classified 100 percent of its investment in combustion turbines (FERC Accounts 340-346) as demand related costs.

Q. DO YOU AGREE WITH IPC'S CLASSIFICATION OF PRODUCTION PLANT AND PURCHASED POWER COSTS?

A. I agree with the classification of CT costs, but disagree with IPC' classification of steam and hydro production plant costs and purchased power expenses. For example, according to the NARUC cost allocation manual and contrary to IPC's classification, all hydro plant costs and most hydro operation and maintenance expenses should be classified as demand-related costs.[8] In general, IPC's classification of steam and hydro production plant and purchased power costs rests on questionable assumptions, the validity of which is neither intuitively obvious nor empirically demonstrable. More specifically, IPC's steam and hydro classification scheme rests on the following arbitrary assumptions:

1. Higher load factor customers receive a disproportionate share of the cheaper energy benefits of baseload and intermediate capacity without paying a proportionate share of the higher capital costs of such capacity—

[7] IPC also used the same classification scheme in its Base Case and Modified Base Case cost studies.
[8] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, Washington, DC, January 1992, at 35-38. (NARUC cost manual)

particularly if demand-related capacity costs are allocated on the basis of peak demands.

2. System load factor somehow identifies the portion of generation plant costs that are supposedly energy-related costs.

Regarding the first assumption, baseload and intermediate plants are planned and designed to operate during more than peak demand periods, and higher load factor customers use energy from such plants in non-peak periods. However, whether higher load factor customers benefit disproportionately from cheaper baseload and intermediate plant energy is an empirical question that IPC has not addressed in this case. Moreover, in addressing this question, the method used to allocate energy-related costs must be considered. For example, if production plant costs are classified as energy-related costs and energy costs are allocated on the basis of average energy use, then low load factor customers will likely receive the benefits of cheaper baseload and intermediate energy without paying a fair share of the capital costs for these plants.

Regarding the second assumption, using IPC's system load factor to identify the portion of production plant costs to classify as energy-related costs is totally arbitrary. System load factor is an indicator of the relative use of supply resources (production plant) over time, and provides neither an economic nor engineering rationale for classifying production plant costs.

Q. IF THE COMMISSION REQUIRES THAT SOME PART OF STEAM AND HYDRO PLANT COSTS BE CLASSIFIED AS ENERGY COSTS, HOW SHOULD THE ENERGY-RELATED COMPONENT BE IDENTIFIED?

A. Let me reiterate—in my opinion, all production plant costs should be classified as demand-related costs. Nonetheless, if part of IPC's production plant costs is classified as energy-related costs, I recommend setting the percentage of such plant costs classified as energy-related costs equal to the ratio of IPC's ***weighted energy allocators in non-capacity deficit months***—that is, all months ***other than*** May – September and December—to the weighted 12-month allocator. This approach provides at least some intuitive linkage between the energy cost of production plant and high load factor energy use.

Q. WHAT IS THE RESULT OF USING THIS APPROACH?

A. Under this approach, 42.90 percent of IPC's steam and hydro production plant costs would be classified as energy-related costs. This percentage is derived as follows:

- In IPC's Exhibit No. 59, page 5, sum the weighted retail jurisdiction energy factors for the six non-capacity deficit months—that is, all months other than May – September and December. This value is 468,444,966.
- Divide 468,444,966 by 1,092,008,268—the sum of weighted retail jurisdiction energy use for all 12 months. The resulting value is 42.90 percent. The remaining 57.10 percent of costs should be classified as demand.

Q. DOES THIS ALTERNATIVE CLASSIFICATION SCHEME BETTER REFLECT DRIVERS UNDERLYING IPC'S NEED FOR STEAM AND HYDRO PRODUCTION PLANT?

A. Yes. As I noted earlier, steam and hydro generation plant investments are primarily undertaken to meet demand, and a classification scheme that results in allocating nearly 60 percent of these costs on the basis of energy simply makes no economic or engineering sense. This problem is particularly acute for hydro plant.

IPC has publicly stated that it often manages its hydro plant to serve peak hours—not simply to meet baseload demand.[9] This operating flexibility is not reflected in a classification scheme based on system load factor. My recommended alternative demand-energy classification scheme is reasonable because it recognizes why IPC adds capacity and how it uses that capacity. Moreover, my alternative classification yields logical results that happen to fall between the 100-percent demand classification scheme IPC uses for peaking CTs and the approximately 40 percent demand/60 percent energy scheme it uses to classify baseload steam generating costs.

Q. SHOULD YOUR ALTERNATIVE CLASSIFICATION SCHEME ALSO APPLY TO IPC'S PURCHASED POWER COSTS?

A. Yes. In this case, IPC finally recognized that its purchased power costs have a significant demand-related component. However, IPC used its system load factor method to classify Account 555 costs as demand- and energy-related costs. I disagree with this method, and recommend that my alternative method be used to classify purchased power costs. As a result, 57.10 percent of Account 555 costs should be classified as demand, and 42.90 percent should be classified as energy.

Q. DID IPC ASSIGN ANY HYDRO PLANT COSTS TO THE PEAKING CAPACITY CATEGORY?

A. No. IPC assigned all demand-related hydro plant costs to the baseload capacity category. This assignment ignores hydro's role in meeting IPC's summer peak demands and understates cost-responsibility for summer peak usage. To address this problem, I recommend assigning 50 percent of demand-related hydro costs to

---

[9] For example, *see* the direct testimony of IPC's witness Timothy Tatum in Docket No. E-07-08 at 12:24-25. In his testimony in the current case, witness Tatum inexplicably omits any reference to hydro as a peaking resource. *See* the direct testimony of witness Tatum at 24:4-7.

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).

Q. DID IPC PROPERLY SPLIT PURCHASED POWER COSTS INTO BASELOAD AND PEAKING CAPACITY CATEGORIES?

A. No. IPC assigned demand-related purchased power costs to baseload and peaking capacity categories on the basis of how it assigns production plant to these categories. This approach ignores the simple fact that nearly half of IPC's Account 555 purchases occur in the summer peak months June-August. IPC's approach assigns far too little of Account 555 costs to the peaking category. 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.

Q. WOULD YOUR RECOMMENDED CHANGES SIGNIFICANTLY AFFECT HOW IPC'S PRODUCTION AND PURCHASED POWER COSTS WERE ALLOCATED TO CUSTOMER CLASSES?

A. Yes. Exhibit No. 607 summarizes these differences. As shown in this exhibit, my recommended changes would justifiably reduce the portion of production plant and purchased power costs classified as energy and shift more costs to the peaking category.

Q. HAVE YOU PERFORMED A COST STUDY THAT INCORPORATES YOUR RECOMMENDED CHANGES?

A. Yes. I modified IPC's 3CP/12CP cost study to reflect the recommended changes shown in Exhibit No. 607. In general, results from this study indicate significantly lower cost responsibilities for Schedule 19 and special contract customers. (See Exhibit No. 608.) For example, my analysis indicates that a 15.71 percent revenue increase (about $916,000) is required to bring DOE to cost of service. In contrast, IPC's 3CP/12CP analysis (Exhibit No. 66) indicates that a 25.37 percent increase ($1.48 million) is required. This huge disparity shows why properly classifying IPC's hydro plant costs and purchased power costs is critical.

Q. WHY ARE YOU CONCERNED SINCE IPC'S PROPOSED INCREASE FOR DOE—15 PERCENT—IS ALMOST IDENTICAL TO THE INCREASE SUGGESTED BY YOUR MODIFIED 3CP/12CP ANALYSIS?

A. My concern is that even with the changes I have discussed, IPC's 3CP/12CP cost study still significantly overstates cost responsibility for higher load factor customers. My recommended changes mitigate—but do not fix—fundamental flaws in IPC's 3CP/12CP cost study. For example, in addition to the problems I have cited, IPC's costing approach

- Double counts average demands by combining a 3CP and 12CP allocation approach for demand-related production costs. IPC's 3CP/12CP methodology is similar to peak and average allocation methods described in the NARUC cost manual. In typical peak and average cost studies, all demand-related production costs are allocated on the basis of a single measure of peak demand (for example, a single CP or a single measure of several CPs). However, in IPC's 3CP/12CP cost study, IPC has allocated only production costs assigned to the peaking category on the basis of the 3CP demands that are driving IPC's need for capacity. The bulk of demand-related production costs are allocated across all peak and non-peak months on the basis of 12 CPs, thereby diluting the influence of the principal system peaks that drive the need for capacity. Moreover, IPC's allocation of capacity cost responsibility is further diluted by classifying almost 60 percent of its fixed production plant costs as energy. The end result of this convoluted process is an assignment of production costs that has no relationship to why and how IPC incurs costs to serve peak demands.

- Fails to reflect the concentration of purchased power costs in the summer peak months, thereby understating costs assigned to summer peak usage. As a result, costs that should be allocated to lower load factor classes with heavy summer usage are instead allocated to higher load factor classes (for example, special contract and Schedule 19 customers). Even my recommended 50/50 split of Account 555 costs into baseload and peaking capacity categories is only an indirect correction for this problem. Moreover, the impact of my proposed modification is muted because nearly 43 percent of purchased power costs are allocated on annual energy in my analysis, resulting in a likely understatement of purchased power costs that should be assigned to the summer peaking period.
- Fails to align cost responsibility with the allocation of steam and hydro production plant costs; fuel costs, and revenues from off-system sales (Account 447). I discussed this problem earlier regarding the allocation of off-system sales revenue. A similar problem exists with the allocation of fuel costs under IPC's 3CP/12CP methodology. For example, higher load factor classes are allocated a higher percentage

of fixed production costs without being allocated a similar higher percentage of the fuel-cost savings associated with these plants.

Q. HAVE YOU ANALYZED HOW THESE FLAWS AFFECT THE ALLOCATION OF COSTS?

A. Yes. I ran IPC's 3CP/12CP cost study again, but made only one change. Instead of assigning production costs to peaking and baseload categories, I simply allocated all demand-related production costs on the basis of a 3CP allocator. I used IPC's classification scheme to identify demand- and energy-related production and purchased power costs. This approach is consistent with a typical peak and average cost study.[10] The results were dramatic for selected customers compared to IPC's 3CP/12CP study. (See Exhibit No. 609.) For example, the required rate increases for DOE and Schedule 19 fell to 10.82 percent and 11.40 percent, respectively, compared to 25.37 percent and 15.87 percent in IPC's study.

Q. DID YOU PERFORM A WEIGHTED 12CP COST STUDY?

A. Yes. Since the W12CP demand-related cost allocation methodology is the last methodology formally approved by the Commission, I decided to conduct a W12CP cost analysis. In my W12CP analysis, I used marginal-cost-weighted loads to allocate demand-related production and transmission costs, and marginal-cost-weighted energy to allocate energy-related costs. I developed this factor without averaging weighted and unweighted loads and energy as IPC did in its Base Case study. I ran two versions of the W12CP model. In the first version, I used IPC's load factor method to identify demand- and energy-related fixed production costs. Results from this study indicate that rate increases for Schedule 19 and DOE should be around 11.75 percent—far below results shown in IPC's

[10] I am not recommending a peak and average allocation method. I present this peak and average analysis

3CP/12CP cost study and well below the 15 percent capped increase that IPC recommends. (See Exhibit No. 610.) Results from the second version included my recommended alternative method for identifying demand- and energy-related fixed production costs. Results from this second study indicate that rate increases for Schedule 19 and DOE should be below 8 percent—less than IPC's proposed system average increase. (See Exhibit No. 611.)

Q. IS IPC'S 3CP/12CP METHODOLOGY REASONABLE?

A. No. In my direct testimony in IPC's 2007 rate case (Case No. IPC-E-07-08), I noted that although the methodology is not widely used, it appeared to be reasonable, even though I preferred allocation methods that were more straightforward. However, in this case, after examining IPC's 3CP/12CP cost methodology and underlying costs more closely, I have concluded that IPC's 3CP/12CP COSS is seriously and probably fatally flawed. The 3CP/12CP methodology as applied by IPC simply does not track cost of service, resulting in too few costs assigned to summer peak months and too many costs assigned to higher load factor customers. As a result, its results should not be relied on to determine class revenue increases.

Q. SHOULD THE COMMISSION REQUIRE IPC TO ADDRESS PROBLEMS WITH ITS COST ANALYSES NOW INSTEAD OF WAITING FOR FUTURE CASES?

A. Yes. Stakeholders have waited more than 5 years since the Commission ordered IPC to work with stakeholders to address cost-of-service issues. The issues have not been resolved. Large customers such as DOE and Mountain Home AFB no longer have confidence that IPC's cost studies properly reflect class cost

---

only to highlight the serious problems in IPC's 3CP/12CP cost study.

responsibility. While my recommended changes mitigate some of the more obvious problems with IPC's cost analyses, they do not resolve a fundamental problem. Specifically, classes driving the need for additional capacity to meet summer peak demands are not being assigned a fair share of the costs of meeting those demands. As a result, I recommend that the Commission require IPC to retain the services of a reputable outside firm to examine, evaluate, and recommend necessary changes to its cost-of-service model. Interested stakeholders should be allowed to participate in this process, or at least be regularly briefed on IPC's progress in improving its costing analyses.

REVENUE SPREAD

Q. HOW DID IPC SPREAD ITS PROPOSED REVENUE INCREASE AMONG CUSTOMER CLASSES?

A. As I described earlier, IPC used a 4-step sequential approach to spread its proposed revenue increase among rate classes. This approach—which is linked to results from IPC's 3CP/12CP cost study—is presented in IPC Exhibit No. 70.

Q. DO YOU AGREE WITH IPC'S PROPOSED REVENUE SPREAD?

A. No. As I just noted, correcting some of the obvious flaws in IPC's never-before-approved 3CP/12CP cost study significantly alters the class cost responsibilities on which IPC based its proposed revenue spread. I do not consider results from any of IPC's cost studies reliable, and do not believe they should be used to spread any revenue increase that IPC receives in this case. As a result, an across-the-board increase for all classes would be reasonable. If the Commission wants to use results from a cost study as a starting point in spreading any revenue increase that IPC receives, then I recommend using results from my W12CP study shown in Exhibit No. 611. If the Commission rejects an across-the-board revenue spread, I recommend that any increase applied to Schedule 19 and DOE be limited to the system average increase, and under no circumstances should they be more than 1.10 times the system average increase. I base this recommendation on results from my cost analyses.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

RECEIVED
2008 OCT 27 AM 10: 24
IDAHO PUBLIC
UTILITIES COMMISSION

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

EXHIBITS TO THE
DIRECT TESTIMONY OF
DR. DENNIS W. GOINS
ON BEHALF OF THE
U.S. DEPARTMENT OF ENERGY

October 24, 2008

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

EXHIBIT NO. 607 OF
DR. DENNIS W. GOINS
ON BEHALF OF THE
U.S. DEPARTMENT OF ENERGY

October 24, 2008

Alternative Classification of Production Function Costs: 3CP/12CP

	Demand (%)				Energy (%)	
	Base/Intermediate		Peaking			
Cost Item	IPC	DOE	IPC	DOE	IPC	DOE
Hydro Plant (330-336)[1]	40.62	28.55	0.00	28.55	59.38	42.90
Purchased Power (555.1)	31.95	28.55	8.67	28.55	59.38	42.90
CSPP (555.2)	31.95	28.55	8.67	28.55	59.38	42.90
CTs/Other (340-346)	0.00	0.00	100.00	100.00	0.00	0.00
Steam Plant (310-316)[1]	40.62	57.10	0.00	0.00	59.38	42.90

[1] IPC energy classification reflects system load factor; demand classification reflects the value (1 - system load factor). Tatum direct at 29.

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

EXHIBIT NO. 608 OF
DR. DENNIS W. GOINS
ON BEHALF OF THE
U.S. DEPARTMENT OF ENERGY

October 24, 2008

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2008

*** *REVENUE REQUIREMENT SUMMARY* ***

	SOURCES & NOTES	(A) TOTAL	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV PRIMARY (9-P)	(E) GEN SRV SECONDARY (9-S)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) IRRIGATION SECONDARY (24-S)
TOTAL RATE BASE		2,094,787,512	948,391,387	43,124,134	50,235,725	434,829,024	850,288	219,725,100	301,128,295
REVENUES FROM RATES									
RETAIL		673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574
TOTAL SALES REVENUES		673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574
TOTAL OTHER OPERATING REVENUES		136,722,443	52,513,205	2,009,232	5,067,274	29,438,669	142,222	22,112,938	15,208,617
TOTAL REVENUES		809,891,983	370,469,666	17,170,611	20,602,363	171,347,845	1,146,730	92,384,044	92,254,191
OPERATING EXPENSES									
WITHOUT INC TAX		662,531,282	291,791,371	13,983,865	16,326,160	138,864,342	792,121	77,707,026	84,258,526
OPERATING INCOME									
BEFORE INCOME TAXES		147,360,700	78,678,295	3,186,746	4,276,204	32,483,502	354,610	14,677,019	7,995,665
TOTAL FEDERAL INCOME TAX		19,062,439	8,630,304	392,427	457,142	3,956,918	7,738	1,999,485	2,740,249
TOTAL STATE INCOME TAX		(3,661,479)	(1,657,693)	(75,377)	(87,807)	(760,038)	(1,486)	(384,058)	(526,342)
TOTAL OPERATING EXPENSES		677,932,243	298,763,982	14,300,916	16,695,495	142,061,223	798,372	79,322,453	86,472,433
TOTAL OPERATING INCOME		131,959,740	71,705,684	2,869,696	3,906,869	29,286,622	348,358	13,061,591	5,781,758
ADD: IERCO OPERATING INCOME	E10	6,472,703	2,426,616	91,265	188,356	1,521,085	2,589	976,084	750,186
CONSOLIDATED OPER INCOME		138,432,443	74,132,300	2,960,961	4,095,224	30,807,708	350,947	14,037,675	6,531,944
RATES OF RETURN		6.608	7.817	6.866	8.152	7.085	41.274	6.389	2.169
RATES OF RETURN - INDEX		1.000	1.183	1.039	1.234	1.072	6.246	0.967	0.328
AVERAGE MILLS/KWH		53.72	62.77	79.55	37.86	44.47	168.62	33.09	49.66
REVENUE REQUIREMENT CALCULATION									
RATE OF RETURN REQUIRED		8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550
REQUIRED REVENUE		739,952,782	329,376,839	16,353,722	15,863,374	152,369,002	547,625	78,068,670	108,595,824
REVENUE DEFICIENCY		66,783,242	11,420,378	1,192,343	328,285	10,459,826	(456,883)	7,797,564	31,550,250
PERCENT CHANGE REQUIRED		9.92%	3.59%	7.86%	2.11%	7.37%	-45.48%	11.10%	40.95%
RETURN AT CLAIMED ROR		179,104,332	81,087,464	3,687,113	4,295,155	37,177,882	72,700	18,786,496	25,746,469
EARNINGS DEFICIENCY		40,671,889	6,955,163	726,153	199,930	6,370,174	(278,248)	4,748,821	19,214,525
REVENUE REQUIREMENT FOR RATE DESIGN									
TOTAL IDAHO SALES REVENUES		673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574
REQUESTED CHANGE IN REVENUE (%)		9.92%	3.59%	7.86%	2.11%	7.37%	-45.48%	11.10%	40.95%
SALES REVENUE REQUIRED		739,952,782	329,376,839	16,353,722	15,863,374	152,369,002	547,625	78,068,670	108,595,824
RATE OF RETURN AT REQUIRED REVENUE		8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550
REQUESTED AVERAGE MILLS/KWH		59.04	65.03	85.81	38.66	47.75	91.93	36.76	70.00
ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		-0.23	2.02	2.00	-2.31	-0.03	24.24	-4.12	-3.13
REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		2.96	3.23	4.76	-1.66	2.37	-29.49	-0.57	7.35

3CP/12CP
Modified Demand (57%)/Energy (43%) Split
Hydro and Acc. 555 -- 50% Baseload/50% Peaking

Exhibit No. 608
Case No. IPC-E-08-10
D. Goins, DOE

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2008

*** REVENUE REQUIREMENT SUMMARY ***

	SOURCES & NOTES	TOTAL	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
TOTAL RATE BASE		2,094,787,512	2,694,055	3,173,245	527,133	16,777,900	17,523,361	55,807,863
REVENUES FROM RATES		0						
RETAIL		673,169,540	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
TOTAL SALES REVENUES		673,169,540	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
TOTAL OTHER OPERATING REVENUES		136,722,443	151,038	368,614	37,950	1,759,195	2,090,904	5,822,581
TOTAL REVENUES		809,891,983	1,117,529	2,682,875	193,153	7,587,370	7,109,063	25,826,539
OPERATING EXPENSES		0						
WITHOUT INC TAX		662,531,282	838,313	1,898,033	182,169	6,682,441	6,142,169	23,064,747
		0						
OPERATING INCOME		0						
BEFORE INCOME TAXES		147,360,700	279,216	784,843	10,985	904,929	966,894	2,761,793
TOTAL FEDERAL INCOME TAX		19,062,439	24,516	28,876	4,797	152,678	159,462	507,848
TOTAL STATE INCOME TAX		(3,661,479)	(4,709)	(5,547)	(921)	(29,326)	(30,629)	(97,547)
TOTAL OPERATING EXPENSES		677,932,243	858,120	1,921,363	186,044	6,805,793	6,271,001	23,475,048
TOTAL OPERATING INCOME		131,959,740	259,409	761,513	7,109	781,577	838,062	2,351,491
		0						
ADD: IERCO OPERATING INCOME	E10	6,472,703	7,767	10,356	1,942	95,149	85,440	315,868
CONSOLIDATED OPER INCOME		138,432,443	267,177	771,869	9,051	876,726	923,501	2,667,359
RATES OF RETURN		6.608	9.917	24.324	1.717	5.225	5.270	4.780
RATES OF RETURN - INDEX		1.000	1.501	3.681	0.260	0.791	0.797	0.723
AVERAGE MILLS/KWH		53.715	57.74	104.79	36.89	27.11	26.47	28.44
REVENUE REQUIREMENT CALCULATION								
RATE OF RETURN REQUIRED		8.550	8.550	8.550	8.550	8.550	8.550	8.550
REQUIRED REVENUE		739,952,782	906,008	1,492,347	214,346	6,744,057	5,961,892	23,459,076
REVENUE DEFICIENCY		66,783,242	(60,483)	(821,914)	59,143	915,882	943,733	3,455,118
PERCENT CHANGE REQUIRED		9.92	-6.26%	-35.52%	38.11%	15.71%	18.81%	17.27%
RETURN AT CLAIMED ROR		179,104,332	230,342	271,312	45,070	1,434,510	1,498,247	4,771,572
EARNINGS DEFICIENCY		40,671,889	(36,835)	(500,557)	36,019	557,784	574,746	2,104,213
REVENUE REQUIREMENT FOR RATE DESIGN								
TOTAL IDAHO SALES REVENUES		673,169,540	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
REQUESTED CHANGE IN REVENUE (%)		9.92%	-6.26%	-35.52%	38.11%	15.71%	18.81%	17.27%
SALES REVENUE REQUIRED		739,952,782	906,008	1,492,347	214,346	6,744,057	5,961,892	23,459,076
RATE OF RETURN AT REQUIRED REVENUE		8.550	8.550	8.550	8.550	8.550	8.550	8.550
REQUESTED AVERAGE MILLS/KWH		59.04	54.13	67.58	50.95	31.37	31.45	33.35
ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		(0.23)	4.02	12.38	-5.85	-5.83	-7.15	-6.22
REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		2.96	1.78	-13.52	5.37	-0.37	-1.76	-0.03

3CP/12CP
Modified Demand (57%)/Energy (43%) Split
Hydro and Acc. 555 -- 50% Baseload/50% Peaking

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

EXHIBIT NO. 609 OF
DR. DENNIS W. GOINS
ON BEHALF OF THE
U.S. DEPARTMENT OF ENERGY

October 24, 2008

IDAHO POWER COMPANY
PEAK AND AVERAGE CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2008

****** REVENUE REQUIREMENT SUMMARY ******

	SOURCES & NOTES	(A) TOTAL	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV PRIMARY (9-P)	(E) GEN SRV SECONDARY (9-S)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) IRRIGATION SECONDARY (24-S)
TOTAL RATE BASE		2,095,374,589	930,219,959	43,085,869	49,978,569	432,971,683	837,703	219,586,056	322,219,848
REVENUES FROM RATES									
RETAIL		673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574
TOTAL SALES REVENUES		673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574
TOTAL OTHER OPERATING REVENUES		136,722,443	52,454,587	2,009,088	5,066,571	29,433,372	142,197	22,113,626	15,271,845
TOTAL REVENUES		809,891,983	370,411,048	17,170,467	20,601,660	171,342,548	1,146,705	92,384,732	92,317,419
OPERATING EXPENSES									
WITHOUT INC TAX		662,531,282	285,686,146	13,969,011	16,261,698	138,367,374	790,226	77,851,491	90,649,130
OPERATING INCOME									
BEFORE INCOME TAXES		147,360,700	84,724,902	3,201,456	4,339,962	32,975,174	356,479	14,533,241	1,668,290
TOTAL FEDERAL INCOME TAX		19,062,439	8,462,574	391,969	454,675	3,938,912	7,621	1,997,660	2,931,360
TOTAL STATE INCOME TAX		(3,661,479)	(1,625,476)	(75,289)	(87,333)	(756,579)	(1,464)	(383,707)	(563,050)
TOTAL OPERATING EXPENSES		677,932,243	292,523,243	14,285,691	16,629,039	141,549,707	796,383	79,465,444	93,017,439
TOTAL OPERATING INCOME		131,959,740	77,887,805	2,884,776	3,972,621	29,792,841	350,322	12,919,288	(700,020)
ADD: IERCO OPERATING INCOME	E10	6,472,703	2,426,616	91,265	188,356	1,521,085	2,589	976,084	750,186
CONSOLIDATED OPER INCOME		138,432,443	80,314,421	2,976,041	4,160,976	31,313,926	352,911	13,895,372	50,167
RATES OF RETURN		6.607	8.634	6.907	8.326	7.232	42.128	6.328	0.016
RATES OF RETURN - INDEX		1.000	1.307	1.046	1.260	1.095	6.377	0.958	0.002
AVERAGE MILLS/KWH		53.72	62.77	79.55	37.86	44.47	168.62	33.09	49.66
REVENUE REQUIREMENT CALCULATION									
RATE OF RETURN REQUIRED		8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550
REQUIRED REVENUE		740,035,202	316,674,692	16,323,588	15,719,307	151,277,037	542,634	78,282,812	122,199,967
REVENUE DEFICIENCY		66,865,662	(1,281,769)	1,162,209	184,218	9,367,861	(461,874)	8,011,706	45,154,393
PERCENT CHANGE REQUIRED		9.93%	-0.40%	7.67%	1.19%	6.60%	-45.98%	11.40%	58.61%
RETURN AT CLAIMED ROR		179,154,527	79,533,806	3,683,842	4,273,168	37,019,079	71,624	18,774,608	27,549,797
EARNINGS DEFICIENCY		40,722,084	(780,615)	707,801	112,191	5,705,153	(281,287)	4,879,236	27,499,630
REVENUE REQUIREMENT FOR RATE DESIGN									
TOTAL IDAHO SALES REVENUES		673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574
REQUESTED CHANGE IN REVENUE (%)		9.93%	-0.40%	7.67%	1.19%	6.60%	-45.98%	11.40%	58.61%
SALES REVENUE REQUIRED		740,035,202	316,674,692	16,323,588	15,719,307	151,277,037	542,634	78,282,812	122,199,967
RATE OF RETURN AT REQUIRED REVENUE		8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550
REQUESTED AVERAGE MILLS/KWH		59.05	62.52	85.65	38.31	47.40	91.09	36.86	78.77
ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		-0.23	2.73	2.03	-2.19	0.08	24.84	-4.19	-4.96
REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		2.96	2.60	4.73	-1.82	2.25	-30.29	-0.54	9.06

Exhibit No. 609
Case No. IPC-E-08-10
D. Goins, DOE

IDAHO POWER COMPANY
PEAK AND AVERAGE CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2008

*** REVENUE REQUIREMENT SUMMARY ***

	SOURCES & NOTES	TOTAL	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
TOTAL RATE BASE		2,095,374,589	2,710,832	3,151,797	509,658	16,287,656	17,537,804	56,277,155
REVENUES FROM RATES		0						
RETAIL		673,169,540	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
TOTAL SALES REVENUES		673,169,540	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
TOTAL OTHER OPERATING REVENUES		136,722,443	151,105	368,604	37,898	1,757,837	2,091,122	5,824,591
TOTAL REVENUES		809,891,983	1,117,596	2,682,865	193,101	7,586,012	7,109,281	25,828,549
OPERATING EXPENSES		0						
WITHOUT INC TAX		662,531,282	846,006	1,900,040	176,901	6,552,875	6,175,057	23,305,328
		0						
OPERATING INCOME		0						
BEFORE INCOME TAXES		147,360,700	271,590	782,825	16,200	1,033,136	934,224	2,523,222
TOTAL FEDERAL INCOME TAX		19,062,439	24,661	28,673	4,637	148,175	159,548	511,975
TOTAL STATE INCOME TAX		(3,661,479)	(4,737)	(5,507)	(891)	(28,461)	(30,646)	(98,339)
TOTAL OPERATING EXPENSES		677,932,243	865,930	1,923,206	180,647	6,672,589	6,303,960	23,718,964
TOTAL OPERATING INCOME		131,959,740	251,666	759,659	12,454	913,422	805,321	2,109,586
		0						
ADD: IERCO OPERATING INCOME	E10	6,472,703	7,767	10,356	1,942	95,149	85,440	315,868
CONSOLIDATED OPER INCOME		138,432,443	259,433	770,015	14,396	1,008,571	890,761	2,425,454
RATES OF RETURN		6.607	9.570	24.431	2.825	6.192	5.079	4.310
RATES OF RETURN - INDEX		1.000	1.449	3.698	0.428	0.937	0.769	0.652
AVERAGE MILLS/KWH		53.715	57.74	104.79	36.89	27.11	26.47	28.44
REVENUE REQUIREMENT CALCULATION								
RATE OF RETURN REQUIRED		8.550	8.550	8.550	8.550	8.550	8.550	8.550
REQUIRED REVENUE		740,035,202	921,078	1,492,380	203,117	6,458,742	6,017,680	23,922,169
REVENUE DEFICIENCY		66,865,662	(45,413)	(821,881)	47,914	630,567	999,521	3,918,211
PERCENT CHANGE REQUIRED		9.93	-4.70%	-35.51%	30.87%	10.82%	19.92%	19.59%
RETURN AT CLAIMED ROR		179,154,527	231,776	269,479	43,576	1,392,595	1,499,482	4,811,697
EARNINGS DEFICIENCY		40,722,084	(27,657)	(500,537)	29,180	384,023	608,721	2,386,243
REVENUE REQUIREMENT FOR RATE DESIGN								
TOTAL IDAHO SALES REVENUES		673,169,540	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
REQUESTED CHANGE IN REVENUE (%)		9.93%	-4.70%	-35.51%	30.87%	10.82%	19.92%	19.59%
SALES REVENUE REQUIRED		740,035,202	921,078	1,492,380	203,117	6,458,742	6,017,680	23,922,169
RATE OF RETURN AT REQUIRED REVENUE		8.550	8.550	8.550	8.550	8.550	8.550	8.550
REQUESTED AVERAGE MILLS/KWH		59.05	55.03	67.58	48.28	30.04	31.74	34.01
ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		(0.23)	3.71	12.41	-4.99	-5.18	-7.33	-6.60
REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		2.96	2.03	-13.67	4.41	-1.31	-1.63	0.36

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

EXHIBIT NO. 610 OF
DR. DENNIS W. GOINS
ON BEHALF OF THE
U.S. DEPARTMENT OF ENERGY

October 24, 2008

IDAHO POWER COMPANY
W12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2008

*** REVENUE REQUIREMENT SUMMARY ***

	SOURCES & NOTES	(A) TOTAL	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV PRIMARY (9-P)	(E) GEN SRV SECONDARY (9-S)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) IRRIGATION SECONDARY (24-S)
TOTAL RATE BASE		2,093,398,859	928,705,976	42,817,215	49,910,032	433,323,055	896,748	219,291,358	322,243,143
REVENUES FROM RATES									
RETAIL		673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574
TOTAL SALES REVENUES		673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574
TOTAL OTHER OPERATING REVENUES		136,722,443	52,294,815	2,000,552	5,046,481	29,309,869	145,737	21,971,146	15,816,534
TOTAL REVENUES		809,891,983	370,251,276	17,161,931	20,581,570	171,219,045	1,150,245	92,242,252	92,862,108
OPERATING EXPENSES									
WITHOUT INC TAX		662,531,282	286,691,955	13,904,286	16,280,923	138,747,457	813,227	77,914,090	89,152,163
OPERATING INCOME									
BEFORE INCOME TAXES		147,360,700	83,559,320	3,257,645	4,300,648	32,471,588	337,017	14,328,162	3,709,945
TOTAL FEDERAL INCOME TAX		19,062,439	8,456,774	389,893	454,480	3,945,829	8,166	1,996,862	2,934,338
TOTAL STATE INCOME TAX		(3,661,479)	(1,624,362)	(74,890)	(87,296)	(757,908)	(1,568)	(383,554)	(563,622)
TOTAL OPERATING EXPENSES		677,932,243	293,524,367	14,219,289	16,648,107	141,935,378	819,825	79,527,398	91,522,878
TOTAL OPERATING INCOME		131,959,740	76,726,908	2,942,642	3,933,464	29,283,667	330,420	12,714,854	1,339,229
ADD: IERCO OPERATING INCOME	E10	6,472,703	2,430,902	90,962	187,671	1,516,745	2,798	970,337	759,954
CONSOLIDATED OPER INCOME		138,432,443	79,157,810	3,033,604	4,121,135	30,800,412	333,218	13,685,191	2,099,183
RATES OF RETURN		6.613	8.523	7.085	8.257	7.108	37.159	6.241	0.651
RATES OF RETURN - INDEX		1.000	1.289	1.071	1.249	1.075	5.619	0.944	0.099
AVERAGE MILLS/KWH		53.72	62.77	79.55	37.86	44.47	168.62	33.09	49.66
REVENUE REQUIREMENT CALCULATION									
RATE OF RETURN REQUIRED		8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550
REQUIRED REVENUE		739,757,827	318,361,298	16,191,353	15,775,104	152,169,557	583,259	78,586,555	118,838,753
REVENUE DEFICIENCY		66,588,287	404,837	1,029,974	240,015	10,260,381	(421,249)	8,315,449	41,793,179
PERCENT CHANGE REQUIRED		9.89%	0.13%	6.79%	1.54%	7.23%	-41.94%	11.83%	54.24%
RETURN AT CLAIMED ROR		178,985,602	79,404,361	3,660,872	4,267,308	37,049,121	76,672	18,749,411	27,551,789
EARNINGS DEFICIENCY		40,553,159	246,551	627,268	146,173	6,248,710	(256,546)	5,064,220	25,452,606
REVENUE REQUIREMENT FOR RATE DESIGN									
TOTAL IDAHO SALES REVENUES		673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574
REQUESTED CHANGE IN REVENUE (%)		9.89%	0.13%	6.79%	1.54%	7.23%	-41.94%	11.83%	54.24%
SALES REVENUE REQUIRED		739,757,827	318,361,298	16,191,353	15,775,104	152,169,557	583,259	78,586,555	118,838,753
RATE OF RETURN AT REQUIRED REVENUE		8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550
REQUESTED AVERAGE MILLS/KWH		59.03	62.85	84.96	38.45	47.68	97.91	37.01	76.60
ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		-0.23	2.63	2.20	-2.23	-0.01	20.59	-4.22	-4.49
REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		2.95	2.67	4.61	-1.75	2.36	-26.38	-0.43	8.48

W12CP Study
Demand/Energy Split
Demand = 40.62%
Energy = 59.38%

IDAHO POWER COMPANY
W12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2008

*** *REVENUE REQUIREMENT SUMMARY* ***

	SOURCES & NOTES	TOTAL	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
TOTAL RATE BASE		2,093,398,859	2,716,870	3,150,706	511,360	16,145,709	17,534,908	56,151,779
REVENUES FROM RATES		0						
RETAIL		673,169,540	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
TOTAL SALES REVENUES		673,169,540	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
TOTAL OTHER OPERATING REVENUES		136,722,443	152,717	366,065	38,341	1,728,816	2,079,134	5,772,236
TOTAL REVENUES		809,891,983	1,119,208	2,680,326	193,544	7,556,991	7,097,293	25,776,194
OPERATING EXPENSES		0						
WITHOUT INC TAX		662,531,282	850,688	1,915,659	177,976	6,566,117	6,208,603	23,308,138
		0						
OPERATING INCOME		0						
BEFORE INCOME TAXES		147,360,700	268,520	764,667	15,569	990,874	888,690	2,468,055
TOTAL FEDERAL INCOME TAX		19,062,439	24,740	28,690	4,656	147,022	159,672	511,317
TOTAL STATE INCOME TAX		(3,661,479)	(4,752)	(5,511)	(894)	(28,240)	(30,670)	(98,213)
TOTAL OPERATING EXPENSES		677,932,243	870,676	1,938,839	181,738	6,684,900	6,337,606	23,721,242
TOTAL OPERATING INCOME		131,959,740	248,532	741,488	11,807	872,092	759,687	2,054,951
		0						
ADD: IERCO OPERATING INCOME	E10	6,472,703	7,866	10,384	1,969	94,299	85,158	313,658
CONSOLIDATED OPER INCOME		138,432,443	256,398	751,872	13,775	966,391	844,845	2,368,609
RATES OF RETURN		6.613	9.437	23.864	2.694	5.985	4.818	4.218
RATES OF RETURN - INDEX		1.000	1.427	3.609	0.407	0.905	0.729	0.638
AVERAGE MILLS/KWH		53.715	57.74	104.79	36.89	27.11	26.47	28.44
REVENUE REQUIREMENT CALCULATION								
RATE OF RETURN REQUIRED		8.550	8.550	8.550	8.550	8.550	8.550	8.550
REQUIRED REVENUE		739,757,827	926,910	1,522,018	204,374	6,508,074	6,092,666	23,997,906
REVENUE DEFICIENCY		66,588,287	(39,581)	(792,243)	49,171	679,899	1,074,507	3,993,948
PERCENT CHANGE REQUIRED		9.89	-4.10%	-34.23%	31.68%	11.67%	21.41%	19.97%
RETURN AT CLAIMED ROR		178,985,602	232,292	269,385	43,721	1,380,458	1,499,235	4,800,977
EARNINGS DEFICIENCY		40,553,159	(24,105)	(482,487)	29,946	414,067	654,389	2,432,368
REVENUE REQUIREMENT FOR RATE DESIGN								
TOTAL IDAHO SALES REVENUES		673,169,540	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
REQUESTED CHANGE IN REVENUE (%)		9.89%	-4.10%	-34.23%	31.68%	11.67%	21.41%	19.97%
SALES REVENUE REQUIRED		739,757,827	926,910	1,522,018	204,374	6,508,074	6,092,666	23,997,906
RATE OF RETURN AT REQUIRED REVENUE		8.550	8.550	8.550	8.550	8.550	8.550	8.550
REQUESTED AVERAGE MILLS/KWH		59.03	55.37	68.92	48.58	30.27	32.14	34.12
ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		(0.23)	3.53	11.92	-5.19	-5.31	-7.52	-6.62
REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		2.95	2.07	-13.23	4.43	-1.10	-1.40	0.49

W12CP Study
Demand/Energy Split
Demand = 40.62%
Energy = 59.38%

Exhibit No. 610
Case No.IPC-E-08-10
D. Goins, DOE

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

EXHIBIT NO. 611 OF
DR. DENNIS W. GOINS
ON BEHALF OF THE
U.S. DEPARTMENT OF ENERGY

October 24, 2008

IDAHO POWER COMPANY
W12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2008

REVENUE REQUIREMENT SUMMARY (in italics)

	SOURCES & NOTES	(A) TOTAL	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV PRIMARY (9-P)	(E) GEN SRV SECONDARY (9-S)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) IRRIGATION SECONDARY (24-S)
TOTAL RATE BASE		2,093,398,859	930,167,943	42,777,310	49,492,584	430,958,070	859,199	215,662,733	330,185,897
REVENUES FROM RATES									
RETAIL		673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574
TOTAL SALES REVENUES		673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574
TOTAL OTHER OPERATING REVENUES		136,722,443	52,299,946	2,000,412	5,045,016	29,301,569	145,605	21,958,410	15,844,410
TOTAL REVENUES		809,891,983	370,256,407	17,161,791	20,580,105	171,210,745	1,150,113	92,229,516	92,889,984
OPERATING EXPENSES									
WITHOUT INC TAX		662,531,282	287,266,982	13,888,591	16,116,730	137,817,252	798,458	76,486,864	92,276,238
OPERATING INCOME									
BEFORE INCOME TAXES		147,360,700	82,989,424	3,273,200	4,463,375	33,393,493	351,655	15,742,652	613,746
TOTAL FEDERAL INCOME TAX		19,062,439	8,470,087	389,529	450,678	3,924,294	7,824	1,963,820	3,006,665
TOTAL STATE INCOME TAX		(3,661,479)	(1,626,919)	(74,820)	(86,565)	(753,771)	(1,503)	(377,207)	(577,515)
TOTAL OPERATING EXPENSES		677,932,243	294,110,150	14,203,300	16,480,843	140,987,774	804,779	78,073,477	94,705,388
TOTAL OPERATING INCOME		131,959,740	76,146,257	2,958,491	4,099,262	30,222,971	345,334	14,156,039	(1,815,404)
ADD: IERCO OPERATING INCOME	E10	6,472,703	2,430,902	90,962	187,671	1,516,745	2,798	970,337	759,954
CONSOLIDATED OPER INCOME		138,432,443	78,577,158	3,049,453	4,286,934	31,739,715	348,132	15,126,377	(1,055,450)
RATES OF RETURN		6.613	8.448	7.129	8.662	7.365	40.518	7.014	-0.320
RATES OF RETURN - INDEX		1.000	1.277	1.078	1.310	1.114	6.127	1.061	-0.048
AVERAGE MILLS/KWH		53.72	62.77	79.55	37.86	44.47	168.62	33.09	49.66
REVENUE REQUIREMENT CALCULATION									
RATE OF RETURN REQUIRED		8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550
REQUIRED REVENUE		739,757,827	319,519,975	16,159,727	15,444,257	150,295,198	553,499	75,710,702	125,133,752
REVENUE DEFICIENCY		66,588,287	1,563,514	998,348	(90,832)	8,386,022	(451,009)	5,439,596	48,088,178
PERCENT CHANGE REQUIRED		9.89%	0.49%	6.58%	-0.58%	5.91%	-44.90%	7.74%	62.42%
RETURN AT CLAIMED ROR		178,985,602	79,529,359	3,657,460	4,231,616	36,846,915	73,461	18,439,164	28,230,894
EARNINGS DEFICIENCY		40,553,159	952,201	608,007	(55,318)	5,107,199	(274,670)	3,312,787	29,286,344
REVENUE REQUIREMENT FOR RATE DESIGN									
TOTAL IDAHO SALES REVENUES		673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574
REQUESTED CHANGE IN REVENUE (%)		9.89%	0.49%	6.58%	-0.58%	5.91%	-44.90%	7.74%	62.42%
SALES REVENUE REQUIRED		739,757,827	319,519,975	16,159,727	15,444,257	150,295,198	553,499	75,710,702	125,133,752
RATE OF RETURN AT REQUIRED REVENUE		8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550
REQUESTED AVERAGE MILLS/KWH		59.03	63.08	84.79	37.64	47.10	92.91	35.65	80.66
ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		-0.23	2.56	2.24	-1.91	0.21	23.25	-3.62	-5.35
REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		2.95	2.73	4.57	-2.09	2.16	-29.25	-1.10	9.22

W12CP Study
Demand/Energy Split
Demand = 57.10%
Energy = 42.90%

Exhibit No. 611
Case No. IPC-E-08-10
D. Goins, DOE
Page 1 of 2

IDAHO POWER COMPANY
W12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2008

*** REVENUE REQUIREMENT SUMMARY ***

Line		SOURCES & NOTES	TOTAL	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
10	TOTAL RATE BASE		2,093,398,859	2,669,954	2,992,020	499,587	15,572,950	17,020,028	54,540,583
12	REVENUES FROM RATES		0						
13	RETAIL		673,169,540	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
15	TOTAL SALES REVENUES		673,169,540	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
17	TOTAL OTHER OPERATING REVENUES		136,722,443	152,552	365,509	38,300	1,726,806	2,077,327	5,766,581
19	TOTAL REVENUES		809,891,983	1,119,043	2,679,770	193,503	7,554,981	7,095,486	25,770,539
21	OPERATING EXPENSES		0						
22	WITHOUT INC TAX		662,531,282	832,235	1,853,244	173,346	6,340,837	6,006,088	22,674,416
23			0						
24	OPERATING INCOME		0						
25	BEFORE INCOME TAXES		147,360,700	286,808	826,525	20,158	1,214,144	1,089,397	3,096,123
27	TOTAL FEDERAL INCOME TAX		19,062,439	24,313	27,245	4,549	141,807	154,984	496,645
28	TOTAL STATE INCOME TAX		(3,861,479)	(4,670)	(5,233)	(874)	(27,238)	(29,769)	(95,395)
30	TOTAL OPERATING EXPENSES		677,932,243	851,877	1,875,256	177,021	6,455,406	6,131,303	23,075,667
32	TOTAL OPERATING INCOME		131,959,740	267,166	804,513	16,482	1,099,575	964,183	2,694,872
33			0						
34	ADD: IERCO OPERATING INCOME	E10	6,472,703	7,866	10,384	1,969	94,299	85,158	313,658
35	CONSOLIDATED OPER INCOME		138,432,443	275,031	814,897	18,451	1,193,874	1,049,341	3,008,530
37	RATES OF RETURN		6.613	10.301	27.236	3.693	7.666	6.165	5.516
38	RATES OF RETURN - INDEX		1.000	1.558	4.119	0.559	1.159	0.932	0.834
39	AVERAGE MILLS/KWH		53.715	57.74	104.79	36.89	27.11	26.47	28.44
41	***REVENUE REQUIREMENT CALCULATION***								
42	RATE OF RETURN REQUIRED		8.550	8.550	8.550	8.550	8.550	8.550	8.550
44	REQUIRED REVENUE		739,757,827	889,727	1,396,252	195,044	6,054,136	5,684,600	22,720,958
45	REVENUE DEFICIENCY		66,588,287	(76,764)	(918,009)	39,841	225,961	666,441	2,717,000
46	PERCENT CHANGE REQUIRED		9.89	-7.94%	-39.67%	25.67%	3.88%	13.28%	13.58%
47	RETURN AT CLAIMED ROR		178,985,602	228,281	255,818	42,715	1,331,487	1,455,212	4,663,220
48	EARNINGS DEFICIENCY		40,553,159	(46,750)	(559,080)	24,264	137,613	405,871	1,654,690
50	***REVENUE REQUIREMENT FOR RATE DESIGN***								
51	TOTAL IDAHO SALES REVENUES		673,169,540	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
53	REQUESTED CHANGE IN REVENUE (%)		9.89%	-7.94%	-39.67%	25.67%	3.88%	13.28%	13.58%
55	SALES REVENUE REQUIRED		739,757,827	889,727	1,396,252	195,044	6,054,136	5,684,600	22,720,958
56	RATE OF RETURN AT REQUIRED REVENUE		8.550	8.550	8.550	8.550	8.550	8.550	8.550
57	REQUESTED AVERAGE MILLS/KWH		59.03	53.15	63.22	46.36	28.16	29.99	32.30
59	ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		(0.23)	4.29	14.67	-4.37	-4.03	-6.54	-5.63
60	REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		2.95	1.42	-16.01	3.61	-2.58	-2.62	-0.65

W12CP Study
Demand/Energy Split
Demand = 57.10%
Energy = 42.90%

APPENDIX

QUALIFICATIONS OF

DENNIS W. GOINS

DENNIS W. GOINS

PRESENT POSITION

Economic Consultant, Potomac Management Group, Alexandria, Virginia.

AREAS OF QUALIFICATION

- Competitive Market Analysis
- Costing and Pricing Energy-Related Goods and Services
- Utility Planning and Operations
- Litigation Analysis, Strategy Development, Expert Testimony

PREVIOUS POSITIONS

- Vice President, Hagler, Bailly & Company, Washington, DC.
- Principal, Resource Consulting Group, Inc., Cambridge, Massachusetts.
- Senior Associate, Resource Planning Associates, Inc., Cambridge, Massachusetts.
- Economist, North Carolina Utilities Commission, Raleigh, North Carolina.

EDUCATION

College	Major	Degree
Wake Forest University	Economics	BA
North Carolina State University	Economics	ME
North Carolina State University	Economics	PhD

RELEVANT EXPERIENCE

Dr. Goins specializes in pricing, planning, and market structure issues affecting firms that buy and sell products in electricity and natural gas markets. He has extensive experience in evaluating competitive market conditions, analyzing power and fuel requirements, prices, market operations, and transactions, developing product pricing strategies, setting rates for energy-related products and services, and negotiating power supply and natural gas contracts for private and public entities. He has participated in more than 100 cases as an expert on competitive market issues, utility restructuring, power market planning and operations, utility mergers, rate design, cost of service, and management prudence before the Federal Energy Regulatory Commission, the First Judicial District Court of Montana, the Circuit Court of Kanawha County, West Virginia, the General Accounting Office (now the Government Accountability Office), and regulatory commissions in Alabama, Arizona, Arkansas, Colorado, Florida, Georgia, Indiana, Idaho, Illinois, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, and the District of Columbia. He has also prepared an expert report on behalf of the United States regarding pricing and contract issues in a case before the United States Court of Federal Claims.

PARTICIPATION IN REGULATORY, ADMINISTRATIVE, AND COURT PROCEEDINGS

1. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2008-302-E (2008), on behalf of CMC Steel-SC, re fuel and purchased power cost recovery.
2. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2008-196-E (2008), on behalf of CMC Steel-SC, re base load review order for a nuclear facility.
3. Alabama Power Company, before the Alabama Public Service Commission, Docket No. 18148 (2008), on behalf of CMC Steel Alabama, Nucor Steel Birmingham, and Nucor Steel Tuscaloosa, re energy cost recovery.
4. Idaho Power Company, before the Idaho Public Utilities Commission, Case No. IPC-E-08-10 (2008), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re cost-of-service and rate design issues.
5. Ohio Edison *et al.*, before the Public Utilities Commission of Ohio, Case No. 08-935-EL-SSO (2008), on behalf of Nucor Steel Marion, Inc., re energy security plan proposal.
6. Ohio Edison *et al.*, before the Public Utilities Commission of Ohio, Case No. 08-936-EL-SSO (2008), on behalf of Nucor Steel Marion, Inc., re market rate offer proposal.
7. Entergy Texas, Inc., before the Public Utilities Commission of Texas, PUC Docket No. 35269 (2008), on behalf of Texas Cities, re jurisdictional allocation of system agreement payments.
8. Duke Energy Indiana, Inc., before the Indiana Utility Regulatory Commission, Cause No. 43374 (2008), on behalf of Nucor Steel and Steel Dynamics, Inc., re alternative regulatory plan.

9. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 34800 (2008), on behalf of Texas Cities, re affiliate transactions.
10. Commonwealth Edison Company, before the Illinois Commerce Commission, Docket No. 07-0566 (2008), on behalf of Nucor Steel Kankakee, Inc., re cost-of-service and rate design issues.
11. Ohio Edison *et al.*, before the Public Utilities Commission of Ohio, Case No. 07-0551-EL-AIR *et al.* (2008), on behalf of Nucor Steel Marion, Inc., re cost-of-service and rate design issues.
12. Appalachian Power Company dba American Electric Power, before the Public Service Commission of West Virginia, Case No. 06-0033-E-CN (2007), on behalf of Steel of West Virginia, Inc., re power plant cost recovery mechanism.
13. Oncor Electric Delivery Company and Texas Energy Future Holdings Limited Partnership, before the Public Utilities Commission of Texas, PUC Docket No. 34077 (2007), on behalf of Nucor Steel - Texas, re acquisition of TXU Corp. by Texas Energy Future Holdings Limited Partnership.
14. Arkansas Oklahoma Gas Company, before the Arkansas Public Service Commission, Docket No. 07-026-U (2007), on behalf of West Central Arkansas Gas Consumers, re gas cost-of-service and rate design issues.
15. Idaho Power Company, before the Idaho Public Utilities Commission, Case No. IPC-E-07-08 (2007), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re cost-of-service and rate design issues.
16. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1056 (2007), on behalf of the General Services Administration, re demand-side management and advanced metering programs.
17. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2007-229-E (2007), on behalf of CMC Steel-SC, re cost-of-service and rate design issues.
18. Potomac Electric Power Company, before the Maryland Public Service Commission, Case No. 9092 (2007), on behalf of the General Services Administration, re retail cost allocation and standby rate design issues for distributed generation resources.
19. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1053 (2007), on behalf of the General Services Administration, re retail cost allocation and standby rate design issues for distributed generation resources.

20. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 32907 (2006), on behalf of Texas Cities, re hurricane cost recovery.
21. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 32710/ SOAH Docket No. 473-06-2307 (2006), on behalf of Texas Cities, re reconciliation of fuel and purchased power costs.
22. Florida Power & Light Company, before the Florida Public Service Commission, Docket No. 060001-EI (2006), on behalf of the U.S. Air Force (Federal Executive Agencies), re fuel and purchased power cost recovery.
23. Arizona Public Service Company, before the Arizona Corporation Commission, Docket No. E-01345A-05-0816 (2006), on behalf of the U.S. Air Force (Federal Executive Agencies), re retail cost allocation and rate design issues.
24. PacifiCorp (dba Rocky Mountain Power), before the Utah Public Service Commission, Docket No. 06-035-21 (2006), on behalf of the U.S. Air Force (Federal Executive Agencies), re rate design issues.
25. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2006-2-E (2006), on behalf of CMC Steel-SC, re fuel and purchased power cost recovery.
26. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 31544/ SOAH Docket No. 473-06-0092 (2006), on behalf of Texas Cities, re transition to competition rider.
27. Idaho Power Company, before the Idaho Public Utilities Commission, Case No. IPC-E-05-28 (2006), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re cost-of-service and rate design issues.
28. Alabama Power Company, before the Alabama Public Service Commission, Docket No. 18148 (2005), on behalf of SMI Steel-Alabama, re energy cost recovery.
29. Florida Power & Light Company, before the Florida Public Service Commission, Docket No. 050001-EI (2005), on behalf of the U.S. Air Force (Federal Executive Agencies), re fuel and capacity cost recovery.
30. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 31315/ SOAH Docket No. 473-05-8446 (2005), on behalf of Texas Cities, re incremental purchased capacity cost rider.
31. Florida Power & Light Company, before the Florida Public Service Commission, Docket No. 050045-EI (2005), on behalf of the U.S. Air Force (Federal Executive Agencies), re cost-of-service and interruptible rate issues.

32. Arkansas Electric Cooperative Corporation, before the Arkansas Public Service Commission, Docket No. 05-042-U (2005), on behalf of Nucor Steel and Nucor-Yamato Steel, re power plant purchase.

33. Arkansas Electric Cooperative Corporation, before the Arkansas Public Service Commission, Docket No. 04-141-U (2005), on behalf of Nucor Steel and Nucor-Yamato Steel, re cost-of-service and rate design issues.

34. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 412 (2005), on behalf of Nucor Steel-Hertford, re cost-of-service and interruptible rate issues.

35. Public Service Company of Colorado, before the Colorado Public Utilities Commission, Docket No. 04S-164E (2004), on behalf of the U.S. Air Force (Federal Executive Agencies), re cost-of-service and interruptible rate issues.

36. CenterPoint Energy Houston Electric, LLC, *et al.*, before the Public Utility Commission of Texas, PUC Docket No. 29526 (2004), on behalf of the Coalition of Commercial Ratepayers, re stranded cost true-up balances.

37. PacifiCorp, before the Utah Public Service Commission, Docket No. 04-035-11 (2004), on behalf of the U.S. Air Force (United States Executive Agencies), re time-of-day rate design issues.

38. Arizona Public Service Company, before the Arizona Corporation Commission, Docket No. E-01345A-03-0347 (2004), on behalf of the U.S. Air Force (Federal Executive Agencies), re retail cost allocation and rate design issues.

39. Idaho Power Company, before the Idaho Public Utilities Commission, Case No. IPC-E-03-13 (2004), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re retail cost allocation and rate design issues.

40. PacifiCorp, before the Utah Public Service Commission, Docket No. 03-2035-02 (2004), on behalf of the U.S. Air Force (United States Executive Agencies), re retail cost allocation and rate design issues.

41. Dominion Virginia Power, before the Virginia State Corporation Commission, Case No. PUE-2000-00285 (2003), on behalf of Chaparral (Virginia) Inc., re recovery of fuel costs.

42. Jersey Central Power & Light Company, before the New Jersey Board of Public Utilities, BPU Docket No. ER02080506, OAL Docket No. PUC-7894-02 (2002-2003), on behalf of New Jersey Commercial Users, re retail cost allocation and rate design issues.

43. Public Service Electric and Gas Company, before the New Jersey Board of Public Utilities, BPU Docket No. ER02050303, OAL Docket No. PUC-5744-02 (2002-2003), on behalf of New Jersey Commercial Users, re retail cost allocation and rate design issues.

44. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2002-223-E (2002), on behalf of SMI Steel-SC, re retail cost allocation and rate design issues.

45. Montana Power Company, before the First Judicial District Court of Montana, *Great Falls Tribune et al. v. the Montana Public Service Commission*, Cause No. CDV2001-208 (2002), on behalf of a media consortium (*Great Falls Tribune*, *Billings Gazette*, *Montana Standard*, *Helena Independent Record*, *Missoulian*, Big Sky Publishing, Inc. dba *Bozeman Daily Chronicle*, the Montana Newspaper Association, *Miles City Star*, *Livingston Enterprise*, Yellowstone Public Radio, the Associated Press, Inc., and the Montana Broadcasters Association), re public disclosure of allegedly proprietary contract information.

46. Louisville Gas & Electric *et al.*, before the Kentucky Public Service Commission, Administrative Case No. 387 (2001), on behalf of Gallatin Steel Company, re adequacy of generation and transmission capacity in Kentucky.

47. PacifiCorp, before the Utah Public Service Commission, Docket No. 01-035-01 (2001), on behalf of Nucor Steel, re retail cost allocation and rate design issues.

48. TXU Electric Company, before the Public Utilities Commission of Texas, PUC Docket No. 23640/ SOAH Docket No. 473-01-1922 (2001), on behalf of Nucor Steel, re fuel cost recovery.

49. FPL Group *et al.*, before the Federal Energy Regulatory Commission, Docket No. EC01-33-000 (2001), on behalf of Arkansas Electric Cooperative Corporation, Inc., re merger-related market power issues.

50. Entergy Mississippi, Inc., *et al.*, before the Mississippi Public Service Commission, Docket No. 2000-UA-925 (2001), on behalf of Birmingham Steel-Mississippi, re appropriate regulatory conditions for merger approval.

51. TXU Electric Company, before the Public Utilities Commission of Texas, PUC Docket No. 22350/ SOAH Docket No. 473-00-1015 (2000), on behalf of Nucor Steel, re unbundled cost of service and rates.

52. PacifiCorp, before the Utah Public Service Commission, Docket No. 99-035-10 (2000), on behalf of Nucor Steel, re using system benefit charges to fund demand-side resource investments.

53. Entergy Arkansas, Inc. *et al.*, before the Arkansas Public Service Commission, Docket No. 00-190-U (2000), on behalf of Nucor-Yamato Steel and Nucor Steel-Arkansas, re the development of competitive electric power markets in Arkansas.

54. Entergy Arkansas, Inc. *et al.*, before the Arkansas Public Service Commission, Docket No. 00-048-R (2000), on behalf of Nucor-Yamato Steel and Nucor Steel-Arkansas, re generic filing requirements and guidelines for market power analyses.

55. ScottishPower and PacifiCorp, before the Utah Public Service Commission, Docket No. 98-2035-04 (1999), on behalf of Nucor Steel, re merger conditions to protect the public interest.

56. Dominion Resources, Inc. and Consolidated Natural Gas Company, before the Virginia State Corporation Commission, Case No. PUA990020 (1999), on behalf of the City of Richmond, re market power and merger conditions to protect the public interest.

57. Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 18465 (1998) on behalf of the Texas Commercial Customers, re excess earnings and stranded-cost recovery and mitigation.

58. PJM Interconnection, LLC, before the Federal Energy Regulatory Commission, Docket No. ER98-1384 (1998) on behalf of Wellsboro Electric Company, re pricing low-voltage distribution services.

59. DQE, Inc. and Allegheny Power System, Inc., before the Federal Energy Regulatory Commission, Docket Nos. ER97-4050-000, ER97-4051-000, and EC97-46-000 (1997) on behalf of the Borough of Chambersburg, re market power in relevant markets.

60. GPU Energy, before the New Jersey Board of Public Utilities, Docket No. EO97070458 (1997) on behalf of the New Jersey Commercial Users Group, re unbundled retail rates.

61. GPU Energy, before the New Jersey Board of Public Utilities, Docket No. EO97070459 (1997) on behalf of the New Jersey Commercial Users Group, re stranded costs.

62. Public Service Electric and Gas Company, before the New Jersey Board of Public Utilities, Docket No. EO97070461 (1997) on behalf of the New Jersey Commercial Users Group, re unbundled retail rates.

63. Public Service Electric and Gas Company, before the New Jersey Board of Public Utilities, Docket No. EO97070462 (1997) on behalf of the New Jersey Commercial Users Group, re stranded costs.

64. DQE, Inc. and Allegheny Power System, Inc., before the Federal Energy Regulatory Commission, Docket Nos. ER97-4050-000, ER97-4051-000, and EC97-46-000 (1997) on behalf of the Borough of Chambersburg, Allegheny Electric Cooperative, Inc., and Selected Municipalities, re market power in relevant markets.
65. CSW Power Marketing, Inc., before the Federal Energy Regulatory Commission, Docket No.ER97-1238-000 (1997) on behalf of the Transmission Dependent Utility Systems, re market power in relevant markets.
66. Central Hudson Gas & Electric Corporation *et al.*, before the New York Public Service Commission, Case Nos. 96-E-0891, 96-E-0897, 96-E-0898, 96-E-0900, 96-E-0909 (1997), on behalf of the Retail Council of New York, re stranded-cost recovery.
67. Central Hudson Gas & Electric Corporation, supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0909 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.
68. Consolidated Edison Company of New York, Inc., supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0897 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.
69. New York State Electric & Gas Corporation, supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0891 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.
70. Rochester Gas and Electric Corporation, supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0898 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.
71. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 15015 (1996), on behalf of Nucor Steel-Texas, re real-time electricity pricing.
72. Central Power and Light Company, before the Public Utility Commission of Texas, Docket No. 14965 (1996), on behalf of the Texas Retailers Association, re cost of service and rate design.
73. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 95-1076-E (1996), on behalf of Nucor Steel-Darlington, re integrated resource planning.
74. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 13575 (1995), on behalf of Nucor Steel-Texas, re integrated resource planning, DSM options, and real-time pricing.

75. Arkansas Power & Light Company, *et al.*, Notice of Inquiry to Consider Section 111 of the Energy Policy Act of 1992, before the Arkansas Public Service Commission, Docket No. 94-342-U (1995), Initial Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.

76. Arkansas Power & Light Company, *et al.*, Notice of Inquiry to Consider Section 111 of the Energy Policy Act of 1992, before the Arkansas Public Service Commission, Docket No. 94-342-U (1995), Reply Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.

77. Arkansas Power & Light Company, *et al.*, Notice of Inquiry to Consider Section 111 of the Energy Policy Act of 1992, before the Arkansas Public Service Commission, Docket No. 94-342-U (1995), Final Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.

78. South Carolina Pipeline Corporation, before the South Carolina Public Service Commission, Docket No. 94-202-G (1995), on behalf of Nucor Steel, re integrated resource planning and rate caps.

79. Gulf States Utilities Company, before the United States Court of Federal Claims, *Gulf States Utilities Company v. the United States*, Docket No. 91-1118C (1994, 1995), on behalf of the United States, re electricity rate and contract dispute litigation.

80. American Electric Power Corporation, before the Federal Energy Regulatory Commission, Docket No. ER93-540-000 (1994), on behalf of DC Tie, Inc., re costing and pricing electricity transmission services.

81. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 13100 (1994), on behalf of Nucor Steel-Texas, re real-time electricity pricing.

82. Carolina Power & Light Company, *et al.*, Proposed Regulation Governing the Recovery of Fuel Costs by Electric Utilities, before the South Carolina Public Service Commission, Docket No. 93-238-E (1994), on behalf of Nucor Steel-Darlington, re fuel-cost recovery.

83. Southern Natural Gas Company, before the Federal Energy Regulatory Commission, Docket No. RP93-15-000 (1993-1995), on behalf of Nucor Steel-Darlington, re costing and pricing natural gas transportation services.

84. West Penn Power Company, *et al.*, v. State Tax Department of West Virginia, *et al.*, Civil Action No. 89-C-3056 (1993), before the Circuit Court of Kanawha County, West Virginia, on behalf of the West Virginia Department of Tax and Revenue, re electricity generation tax.

85. Carolina Power & Light Company, *et al.*, Proceeding Regarding Consideration of Certain Standards Pertaining to Wholesale Power Purchases Pursuant to Section 712 of the 1992 Energy Policy Act, before the South Carolina Public Service Commission, Docket No. 92-231-E (1993), on behalf of Nucor Steel-Darlington, re Section 712 regulations.
86. Mountain Fuel Supply Company, before the Public Service Commission of Utah, Docket No. 93-057-01 (1993), on behalf of Nucor Steel-Utah, re costing and pricing retail natural gas firm, interruptible, and transportation services.
87. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 11735 (1993), on behalf of the Texas Retailers Association, re retail cost-of-service and rate design.
88. Virginia Electric and Power Company, before the Virginia State Corporation Commission, Case No. PUE920041 (1993), on behalf of Philip Morris USA, re cost of service and retail rate design.
89. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 92-209-E (1992), on behalf of Nucor Steel-Darlington.
90. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Rate Design (1992), on behalf of the Department of Energy, Strategic Petroleum Reserve.
91. Georgia Power Company, before the Georgia Public Service Commission, Docket Nos. 4091-U and 4146-U (1992), on behalf of Amicalola Electric Membership Corporation.
92. PacifiCorp, Inc., before the Federal Energy Regulatory Commission, Docket No. EC88-2-007 (1992), on behalf of Nucor Steel-Utah.
93. South Carolina Pipeline Corporation, before the South Carolina Public Service Commission, Docket No. 90-452-G (1991), on behalf of Nucor Steel-Darlington.
94. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 91-4-E, 1991 Fall Hearing, on behalf of Nucor Steel-Darlington.
95. Sonat, Inc., and North Carolina Natural Gas Corporation, before the North Carolina Utilities Commission, Docket No. G-21, Sub 291 (1991), on behalf of Nucor Corporation, Inc.
96. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E002/GR-91-001 (1991), on behalf of North Star Steel-Minnesota.

97. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase IV-Rate Design (1991), on behalf of the Department of Energy, Strategic Petroleum Reserve.
98. Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 9850 (1990), on behalf of the Department of Energy, Strategic Petroleum Reserve.
99. General Services Administration, before the United States General Accounting Office, Contract Award Protest (1990), Solicitation No. GS-00P-AC87-91, Contract No. GS-00D-89-B5D-0032, on behalf of Satilla Rural Electric Membership Corporation, re cost of service and rate design.
100. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 90-4-E (1990 Fall Hearing), on behalf of Nucor Steel-Darlington, re fuel-cost recovery.
101. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase III-Rate Design (1990), on behalf of the Department of Energy, Strategic Petroleum Reserve, re cost of service and rate design.
102. Atlanta Gas Light Company, before the Georgia Public Service Commission, Docket No. 3923-U (1990), on behalf of Herbert G. Burris and Oglethorpe Power Corporation, re anticompetitive pricing schemes.
103. Ohio Edison Company, before the Ohio Public Utilities Commission, Case No. 89-1001-EL-AIR (1990), on behalf of North Star Steel-Ohio, re cost of service and rate design.
104. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase III-Cost of Service/Revenue Spread (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.
105. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E002/GR-89-865 (1989), on behalf of North Star Steel-Minnesota.
106. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase III-Rate Design (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.
107. Utah Power & Light Company, before the Utah Public Service Commission, Case No. 89-039-10 (1989), on behalf of Nucor Steel-Utah and Vulcraft, a division of Nucor Steel.

108. Soyland Power Cooperative, Inc. v. Central Illinois Public Service Company, Docket No. EL89-30-000 (1989), before the Federal Energy Regulatory Commission, on behalf of Soyland Power Cooperative, Inc., re wholesale contract pricing provisions

109. Gulf States Utilities Company, before the Public Utility Commission of Texas, Docket No. 8702 (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.

110. Houston Lighting and Power Company, before the Public Utility Commission of Texas, Docket No. 8425 (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.

111. Northern Illinois Gas Company, before the Illinois Commerce Commission, Docket No. 88-0277 (1989), on behalf of the Coalition for Fair and Equitable Transportation, re retail gas transportation rates.

112. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 79-7-E, 1988 Fall Hearing, on behalf of Nucor Steel-Darlington, re fuel-cost recovery.

113. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 869 (1988), on behalf of Peoples Drug Stores, Inc., re cost of service and rate design.

114. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 88-11-E (1988), on behalf of Nucor Steel-Darlington.

115. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E-002/GR-87-670 (1988), on behalf of the Metalcasters of Minnesota.

116. Ohio Edison Company, before the Ohio Public Utilities Commission, Case No. 87-689-EL-AIR (1987), on behalf of North Star Steel-Ohio.

117. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 87-7-E (1987), on behalf of Nucor Steel-Darlington.

118. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase I (1987), on behalf of the Strategic Petroleum Reserve.

119. Gulf States Utilities Company, before the Public Utility Commission of Texas, Docket No. 7195 (1987), on behalf of the Strategic Petroleum Reserve.

120. Gulf States Utilities Company, before the Federal Energy Regulatory Commission, Docket No. ER86-558-006 (1987), on behalf of Sam Rayburn G&T Cooperative.

121. Utah Power & Light Company, before the Utah Public Service Commission, Case No. 85-035-06 (1986), on behalf of the U.S. Air Force.

122. Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 6765 (1986), on behalf of the Strategic Petroleum Reserve.

123. Central Maine Power Company, before the Maine Public Utilities Commission, Docket No. 85-212 (1986), on behalf of the U.S. Air Force.

124. Gulf States Utilities Company, before the Public Utility Commission of Texas, Docket Nos. 6477 and 6525 (1985), on behalf of North Star Steel-Texas.

125. Ohio Edison Company, before the Ohio Public Utilities Commission, Docket No. 84-1359-EL-AIR (1985), on behalf of North Star Steel-Ohio.

126. Utah Power & Light Company, before the Utah Public Service Commission, Case No. 84-035-01 (1985), on behalf of the U.S. Air Force.

127. Central Vermont Public Service Corporation, before the Vermont Public Service Board, Docket No. 4782 (1984), on behalf of Central Vermont Public Service Corporation.

128. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-15641 (1983), on behalf of the Strategic Petroleum Reserve.

129. Southwestern Power Administration, before the Federal Energy Regulatory Commission, Rate Order SWPA-9 (1982), on behalf of the Department of Defense.

130. Public Service Company of Oklahoma, before the Federal Energy Regulatory Commission, Docket Nos. ER82-80-000 and ER82-389-000 (1982), on behalf of the Department of Defense.

131. Central Maine Power Company, before the Maine Public Utilities Commission, Docket No. 80-66 (1981), on behalf of the Commission Staff.

132. Bangor Hydro-Electric Company, before the Maine Public Utilities Commission, Docket No. 80-108 (1981), on behalf of the Commission Staff.

133. Oklahoma Gas & Electric, before the Oklahoma Corporation Commission, Docket No. 27275 (1981), on behalf of the Commission Staff.

134. Green Mountain Power, before the Vermont Public Service Board, Docket No. 4418 (1980), on behalf of the PSB Staff.

135. Williams Pipe Line, before the Federal Energy Regulatory Commission, Docket No. OR79-1 (1979), on behalf of Mapco, Inc.

136. Boston Edison Company, before the Massachusetts Department of Public Utilities, Docket No. 19494 (1978), on behalf of Boston Edison Company.

137. Duke Power Company, before the North Carolina Utilities Commission, Docket No. E-7, Sub 173, on behalf of the Commission Staff.

138. Duke Power Company, before the North Carolina Utilities Commission, Docket No. E-100, Sub 32, on behalf of the Commission Staff.

139. Virginia Electric & Power Company, before the North Carolina Utilities Commission, Docket No. E-22, Sub 203, on behalf of the Commission Staff.

140. Virginia Electric & Power Company, before the North Carolina Utilities Commission, Docket No. E-22, Sub 170, on behalf of the Commission Staff.

141. Southern Bell Telephone Company, before the North Carolina Utilities Commission, Docket No. P-5, Sub 48, on behalf of the Commission Staff.

142. Western Carolina Telephone Company, before the North Carolina Utilities Commission, Docket No. P-58, Sub 93, on behalf of the Commission Staff.

143. Natural Gas Ratemaking, before the North Carolina Utilities Commission, Docket No. G-100, Sub 29, on behalf of the Commission Staff.

144. General Telephone Company of the Southeast, before the North Carolina Utilities Commission, Docket No. P-19, Sub 163, on behalf of the Commission Staff.

145. Carolina Power and Light Company, before the North Carolina Utilities Commission, Docket No. E-2, Sub 264, on behalf of the Commission Staff.

146. Carolina Power and Light Company, before the North Carolina Utilities Commission, Docket No. E-2, Sub 297, on behalf of the Commission Staff.

147. Duke Power Company, *et al.*, Investigation of Peak-Load Pricing, before the North Carolina Utilities Commission, Docket No. E-100, Sub 21, on behalf of the Commission Staff.

148. Investigation of Intrastate Long Distance Rates, before the North Carolina Utilities Commission, Docket No. P-100, Sub 45, on behalf of the Commission Staff.