RECEIVED
2007 DEC 10 AM 10: 23
IDAHO PUBLIC
UTILITIES COMMISSION

STATE OF IDAHO
BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-07-08

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

December 10, 2007

Table of Contents

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. During my tenure at the Commission, 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. 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. A listing of these regulatory, administrative, and court proceedings is presented in Appendix A.

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

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

A. I am appearing 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/INL) and Mountain

Home Air Force Base. IPC serves DOE/INL 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. Cost of Service. IPC has proposed increasing base revenues by approximately $63.95 million (10.35 percent). In developing proposed rates for its retail electric services, IPC first conducted four (4) cost-of-service studies for the test year ending December 31, 2007. 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 8.561 percent return on its retail jurisdictional rate base (using an 11.5 percent return on common equity).

In its cost studies, IPC classified steam and hydro production costs as demand- and energy-related costs. IPC set the energy-related component of these costs equal to the Idaho jurisdictional load factor (58.53 percent), with the residual (1 – load factor) classified as demand-related costs. IPC has used this classification scheme in prior rate cases. IPC classified transmission costs as demand-related costs and distribution costs as demand- or customer-related costs.

IPC classified the cost of all power purchases assigned to FERC Account 555.1 as energy-related costs. With respect to purchases from cogeneration and small power producers assigned to FERC Account 555.2, IPC classified almost 97 percent of these costs as energy-related costs. IPC's energy-based classification scheme reflects the dominance of 1-part pricing (that is, prices stated on a $/MWh basis) for Account 555 transactions in power markets—particularly Account 555.1 transactions.

IPC's four cost studies include a Base Case analysis that generally follows functionalization, classification, and allocation steps reflected in cost studies that IPC submitted in its last two rate cases. In allocating demand-related production costs to major customer classes, IPC used a weighted 12-month coincident peak (W12CP) methodology. This methodology develops class allocation factors using the simple average of seasonal allocators derived from two different costing approaches—a traditional 12CP methodology and a methodology that weights class monthly coincident peak demands by IPC's estimated generation-related marginal cost. IPC assumes that its marginal generation cost is positive (non-zero) only in the six months in which its projects capacity deficits (May through September and December). IPC's estimated marginal generation cost in all other months is zero. IPC also used a W12CP methodology to allocate demand-related transmission costs.

In its Base Case study, IPC allocated energy-related costs using E10 allocation factors reflecting monthly energy use by class weighted by IPC's estimated monthly marginal energy cost. Finally, IPC allocated distribution plant demand-related costs on the basis of coincident group peak demands, and customer-related distribution plant costs using average number of customers.

IPC's conducted a second cost-of-service study (Base Case – Non-weighted) that differs in one major respect from its Base Case study. Specifically, the second study is the Base Case without marginal cost weightings of demand-related production and transmission plant costs and energy-related production costs.

In its third and fourth cost studies, IPC allocated its steam, hydro, and combustion turbine (CT) plant costs differently. IPC first designated generation plant assigned to FERC accounts 310-316 (steam production) and 330-336 (hydro production) as Baseload/Intermediate Load capacity (hereinafter referred to as Baseload capacity). IPC then designated its CT capacity reflected in FERC accounts 340-346 as Peaking capacity. In its third cost study, IPC allocated Baseload capacity using an unweighted 12 CP allocation method, and its Peaking capacity using an unweighted 3CP method (the 3CP/12CP method). IPC's fourth cost study replicated its 3CP/12CP study with one exception. In this fourth study, IPC allocated demand-related Baseload costs on the basis of unweighted annual energy use. IPC called this study its 3CP/Average Energy cost study. In both the 3CP/12CP and 3CP/Average Energy cost studies, IPC allocated energy-related production and demand-related transmission and distribution costs the same way these costs were allocated in IPC's Base Case study.

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. 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 class cost-of-service study (COSS).
- Set a 20-percent limit on rate increases to Schedule 24 Irrigation Service and Special Contracts customers and a 15-percent limit on the Small General Service, Large Power Service, and Traffic Control Lighting classes.
- Hold revenues from the Dusk-to-Dawn Lighting class 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 20- and 15-percent caps on class increases across all other schedules.

RECOMMENDATIONS

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

A. I recommend the following:

1. 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 defects. First, the scheme arbitrarily assumes that higher load factor customers 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. Second, the classification scheme arbitrarily assumes that IPC's system load factor somehow identifies the portion of generation plant costs that are supposedly energy-related costs. Neither assumption is intuitively obvious or empirically supportable.

2. If the Commission requires IPC to classify 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 approximately 60 percent of hydro plant costs as demand and 40 percent as energy. As IPC notes, it 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. My recommended alternative 60/40 classification scheme is reasonable because it 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.

3. Reject IPC's classification of Account 555 purchased power costs. Classifying these costs on the basis of how they are priced ignores the capacity component of the underlying products, and is inconsistent with how IPC classifies production plant (built or acquired) that could substitute for off-system purchases. My review of IPC's 2006 purchased power costs indicates that nearly 68 percent of its purchases were short-term firm transactions, while nearly 19 percent were long-term purchases from a designated generating unit. By not imputing a meaningful demand-related capacity component to the cost of these transactions (that is, by classifying more than 98 percent of Account 555 expenses as energy costs), IPC ensured that a disproportionate share of Account 555 costs would be allocated to high load factor customer classes. Because purchased power cost represent a significant test-year cost (nearly $144 million), IPC's energy-only classification scheme distorts the results of its cost-of-service studies. As a step to correct this error, I recommend classifying Account 555 purchased power expense on a 50/50 basis—that is, 50 percent classified as demand-related costs and 50 percent classified as energy-related costs.

4 Approve IPC's 3CP/12CP allocation methodology, but modify the approach to reflect my recommended classification of hydro plant and

Account 555 costs. As I show later in my testimony, these changes dramatically alter the results of IPC's 3CP/12CP cost study.

5. Reject IPC's proposed revenue spread, which is based on its 3CP/12CP cost study results. As I just noted, correcting this study to reflect a balanced classification of hydro plant and Account 555 costs significantly alters the class cost responsibilities on which IPC based its proposed revenue spread. I recommend spreading IPC's revenue increase to reflect results from a 3CP/12CP cost study, modified as I have suggested. In addition, I recommend limiting the increase to any class to 2.5 times the system average increase, and not reducing rates for any class below present levels. Details of how to implement this revenue spread approach are presented later in my testimony.

COST OF SERVICE

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

A. Yes. IPC conducted four detailed cost-of-service studies using data (adjusted in many cases) for the test year ending December 31, 2007. In these cost analysis, 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 8.561 percent return on its Idaho retail jurisdictional rate base (using an 11.5 percent return on common equity).

Q. HOW DID IPC ALLOCATE ITS DEMAND-RELATED PRODUCTION COSTS?

A. In its Base Case cost study, IPC used a weighted 12-month coincident peak (W12CP) methodology to allocate demand-related production costs to major customer classes. Under this methodology, class allocation factors are set equal to the simple average of seasonal allocators derived from two different costing approaches—a traditional 12CP methodology and a methodology that weights class monthly coincident peak demands by IPC's estimated generation-related marginal capacity cost.

Q. DOES IPC WEIGHT ALL MONTHLY PEAK DEMANDS BY MARGINAL GENERATION CAPACITY COSTS?

A. No. IPC weights class monthly coincident peak demands by marginal generation costs only in the six months in which it projects capacity deficits (May through September and December). IPC's estimated marginal generation cost in all other months is zero.

Q. DID IPC USE A SIMILAR METHODOLOGY TO ALLOCATE DEMAND-RELATED TRANSMISSION COSTS?

A. Yes. IPC also used a W12CP methodology to allocate these costs in its Base Case study. However, in developing these class allocators, IPC weighted class monthly coincident peak demands by each month's estimated transmission marginal cost.

Q. IS IPC'S WEIGHTED 12CP METHODOLOGY REASONABLE?

A. Yes. Although the methodology is not widely used, it appears to be reasonable. I prefer allocation methods that are more straightforward than IPC's method. Nevertheless, the W12CP methodology has some intuitive costing logic underlying its application.

Q. HOW DID IPC ALLOCATE ITS ENERGY-RELATED COSTS?

A. In its Base Case study, IPC used allocation factors (E10 factors) based on class monthly energy use weighted by estimated monthly marginal energy cost to allocate its energy-related production costs.[1]

Q. IS THIS ALLOCATION APPROACH CONSISTENT WITH THE W12CP METHODOLOGY IPC USED TO ALLOCATE DEMAND-RELATED PRODUCTION AND TRANSMISSION COSTS?

A. Yes. Both approaches weight selected customer usage measures (peak demands and energy consumption) by relevant marginal costs. This marginal cost weighting reflects a reasonable attempt to introduce a dynamic costing element to IPC's analysis of historical embedded costs.

Q. HOW DID IPC CLASSIFY PRODUCTION PLANT COSTS?

A. In its Base Case cost study, IPC classified steam (FERC Accounts 310-316) and hydro (FERC Accounts 330-336) production costs as demand- and energy-related costs. IPC set the energy-related component of these costs equal to the Idaho jurisdictional load factor (58.53 percent), with the residual—41.47 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 COSTS?

A. I agree with the classification of CT costs, but disagree with IPC' classification of steam and hydro production plant costs. IPC's classification of these latter 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—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

[1] IPC developed seasonal E10 factors (E10S and E10NS) to facilitate identifying seasonal cost responsibility.

(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, 38.31 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. 47, 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 443,673,889.
- Divide 443,673,889 by 1,158,007,470—the sum of weighted retail jurisdiction energy use for all 12 months. The resulting value is 38.31

percent. The remaining 61.69 percent of costs should be classified as demand.[2]

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 admits that it often manages its hydro plant to serve peak hours—not simply to meet baseload demand.[3] This operating flexibility is not reflected in a classification scheme based on system load factor. My recommended alternative 60/40 demand-energy classification scheme is reasonable because it 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.

Q. HOW DID IPC CLASSIFY ITS PURCHASED POWER COSTS?

A. IPC's separated its test-year purchased power costs into FERC Account 555.1—all transactions except those involving cogeneration and small power production (CSPP)—and FERC Account 555.2—all CSPP purchases. IPC classified about 98 percent of its total Account 555 costs as energy costs—100 percent of Account 555.1 purchases and 97 percent of Account 555.2 purchases. (See Table 1 below.)

---

[2]As I describe later in my testimony, I prepared cost studies using classification schemes for hydro plant and purchased power costs that differ from the classification schemes that IPC used in its cost studies. The 60/40 demand-energy split I used to classify hydro plant costs approximates the 61.49/38.31 demand-energy split derived in my alternative classification approach.

[3] See the direct testimony of IPC's witness Timothy Tatum at 12:24-25.

Table 1. IPC 2007 Test-Year Account 555 Expense

Accunt 555		Total	Demand	Energy
555.1	Purchased Power	$ 55,420,025	$ -	$ 55,420,025
555.2	Cogeneration & Sm Power			
	Capacity	2,673,562	2,673,562	0
	Energy	85,479,748	0	85,479,748
	Total 555/CSPP	$ 143,573,335	$ 2,673,562	$ 140,899,773
	Percent	100%	2%	98%

Source: IPC Exhibit No. 41 at 51.

Q. WHY IS IPC'S CLASSIFICATION OF THESE COSTS SO HEAVILY SKEWED TOWARD ENERGY?

A. IPC's classification scheme reflects how these transactions are priced. For example, the classification of Account 555.1 costs reflects the dominance of 1-part pricing (that is, prices stated on a $/MWh basis) for such purchases in power markets. In classifying Account 555.2 costs, IPC relied on prior Commission rulings requiring energy-only prices for more recent CSPP transactions.

Q. SHOULD THE PRICING OF PURCHASED POWER DICTATE ITS CLASSIFICATION?

A. No. Classifying these costs on the basis of how transactions are priced ignores the underlying products. I reviewed IPC's 2006 Account 555 purchased power costs as recorded in FERC Form 1. My review indicates that nearly 68 percent of IPC's purchases were short-term firm[4] transactions, while nearly 19 percent were long-term purchases from designated generating units.[5] Settlement prices for almost all of these transactions were energy-only prices—implying that the purchases had no

[4] Such purchases are classified in FERC Form 1 as SF – short-term service, including all firm services with commitments of one year or less. All nonfirm services, regardless of length, are put in a category called OS – other service.

[5] Such purchases are classified in FERC Form 1 as LU - long-term service (5 years or longer) from a designated generating unit, with availability and reliability that matches the availability and reliability of the

capacity component. Yet the underlying products either hedged IPC's short-term pricing risk or provided access to energy on a basis that matched a designated unit's availability and reliability. In both cases, IPC was buying more than nonfirm energy to reduce real-time generating costs.

IPC's classification of Account 555 costs is also inconsistent with how it classifies production plant (built or acquired) that could substitute for off-system purchases. IPC's customers should be indifferent to IPC's decision to purchase electricity instead of building or buying generating capacity. If IPC had built or bought generating capacity instead of purchasing electricity, IPC would have classified the cost of that capacity as either demand or as both demand and energy. For this reason, the cost of IPC's short-term firm and long-term unit power purchases should not be classified only as energy-related. Using an energy-only classification scheme unfairly shifts purchased power costs to high load factor customers—thereby forcing them to subsidize low load factor classes.

Q. WHAT HAPPENS IF THE CAPACITY COMPONENT OF PURCHASED POWER COSTS IS IGNORED?

A. By not imputing a meaningful demand-related capacity cost component to these transactions (for example, by classifying more than 98 percent of Account 555 costs as energy costs), IPC ensured that a disproportionate share of these costs were allocated to high load factor customer classes. Moreover, because Account 555 represents a significant test-year cost (nearly $144 million), IPC's energy-only classification scheme distorts the results of its cost-of-service studies.

---

designated unit.

Q. SHOULD THIS CLASSIFICATION ERROR BE CORRECTED?

A. Yes. As a step to correct this error, I recommend classifying Account 555 purchased power expense on a 50/50 basis—that is, 50 percent classified as demand-related costs and 50 percent classified as energy-related costs. This is a reasonable approach to address a serious cost-of-service issue—particularly with IPC's increased reliance on purchased power to serve load.

Q. DID IPC CONDUCT SEVERAL DIFFERENT COST-OF-SERVICE STUDIES?

A. Yes. As I noted earlier, IPC conducted four cost studies.[6] IPC's Base Case study is essentially the same type of cost study that IPC has submitted in recent rate cases. It includes a weighted 12CP allocation of all production plant costs and marginal-cost-weighted energy costs allocators. IPC's second cost study differs from the Base Case study in one major respect. Specifically, this second study (the Base Case – Non-weighted study) is the Base Case without marginal cost weightings of demand-related production and transmission plant costs and energy-related production costs.

The third and fourth studies reflect a significant departure from IPC's previous cost studies. In these studies, IPC first designated steam and hydro production plant as Baseload capacity. IPC then designated its CT capacity as Peaking capacity. In its third cost study, IPC allocated Baseload capacity using an unweighted 12 CP allocation method, and its Peaking capacity using an unweighted 3CP method (the 3CP/12CP method). IPC's fourth cost study replicated its 3CP/12CP study with one exception. In this fourth study, IPC allocated demand-related Baseload costs on the basis of unweighted annual energy

[6] For a succinct description of these different studies, see the direct testimony of IPC witness Timothy Tatum at 16.

use. IPC called this study its 3CP/Average Energy cost study. In both the 3CP/12CP and 3CP/Average Energy cost studies, IPC allocated energy-related production and demand-related transmission and distribution costs the same way these costs were allocated in IPC's Base Case study.

To simplify discussion of these studies and my modifications to them, I will refer to IPC's four cost studies as follows:

- Case 1 = Base Case study.
- Case 2 = Base Case – Non-weighted study.
- Case 3 = 3CP/12CP study.
- Case 4 = 3CP/Average Energy cost study.

Q. DOES IPC HAVE A PREFERRED COST-OF-SERVICE STUDY?

A. Yes. IPC's preferred cost-of-service methodology is Case 3—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.

Q. DO YOU AGREE WITH IPC REGARDING THE 3CP/12CP STUDY?

A. I agree that the 3CP/12CP methodology is reasonable, but only if modified to classify hydro plant and purchased power costs properly. As I discuss later, I used results from my Case 3 cost study that reflects the 3CP/12CP methodology with corrected cost classifications to develop my recommended revenue spread.

Q. DID YOU CONDUCT COST STUDIES THAT REFLECT YOUR RECOMMENDED CLASSIFICATION OF HYDRO PLANT AND PURCHASED POWER COSTS?

A. Yes. I conducted cost studies that replicate Cases 1-4 except that I classified hydro plant and purchased power costs to reflect my earlier testimony. Exhibit No. 607 shows how my recommended classification of production costs differs from IPC's classification for each of the four cost study cases. In general, my classification scheme results in more costs classified as demand (all cases) and more costs assigned to the Peaking category of production plant (Cases 3 and 4). Results from my cost analyses for Cases 1-4 are shown in Exhibit Nos. 608 (Case 1), 609 (Case 2), 610 (Case 3), and 611 (Case 4).

Q. DO THE RESULTS OF YOUR COST STUDIES INDICATE SIGNIFICANTLY DIFFERENT CLASS COST RESPONSIBILITIES RELATIVE TO CLASS COST ALLOCATIONS IN IPC'S COST STUDIES?

A. Yes. In general, results from my studies indicate significantly lower cost responsibilities for Large Power Service and Special Contracts customers. For example, in Case 3, my analysis indicates that a 9.71 percent revenue increase (about $523,000) is required to bring DOE/INL to cost of service. In contrast, IPC's Case 3 analysis (Exhibit No. 53) indicates that a 24.48 percent increase ($1.32 million) is required. This huge disparity shows why properly classifying IPC's hydro plant costs and purchased power costs is critical.

Q. WHICH COST STUDY DO YOU RECOMMEND USING AS THE BASIS FOR SPREADING IPC'S REVENUE INCREASE?

A. I recommend using results from my Case 3 analysis shown in Exhibit No. 610.

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 discussed in detail by IPC witness Maggie Brilz[7] and presented in Exhibit No. 58.

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

A. No. As I just noted, correcting IPC's 3CP/12CP cost study to reflect a balanced classification of hydro plant and Account 555 costs significantly alters the class cost responsibilities on which IPC based its proposed revenue spread. I recommend spreading IPC's revenue increase to reflect results from a 3CP/12CP cost study, modified as I have suggested. (See Exhibit No. 610.) In addition, I recommend limiting the increase to any class to 2.5 times the system average increase, and not reducing rates for any class below present levels.

Q. HAVE YOU DEVELOPED A REVENUE SPREAD THAT REFLECTS THESE MODIFICATIONS?

A. Yes. This alternative revenue spread is shown in Exhibit No. 612.

---

[7] *See* IPC witness Maggie Brilz, direct testimony at 3:4 – 4:22.

Q. IF THE COMMISSION ALLOWS LESS THAN IPC'S REQUESTED SALES REVENUE INCREASE, HOW SHOULD THE APPROVED INCREASE BE SPREAD?

A. If IPC's retail base revenue increase is below 10.35 percent, I recommend using the same 4-step sequential approach that I used to develop the DOE revenue spread shown in Exhibit No. 612.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

STATE OF IDAHO
BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-07-08

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

December 10, 2007

STATE OF IDAHO
BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-07-08

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 US DOE

December 10, 2007

Alternative Classification of Production Function Costs: COS Cases 1 and 2

Cost Item	Demand (%)		Energy (%)	
	IPC	DOE	IPC	DOE
Hydro Plant (330-336)[1]	41.47	60.00	58.53	40.00
Purchased Power (555.1)	0.00	50.00	100.00	50.00
CSPP (555.2)[2]	3.03	50.00	96.97	50.00
CTs/Other (340-346)	100.00	100.00	0.00	0.00
Steam Plant (310-316)[1]	41.47	41.47	58.53	58.53

[1] IPC energy classification reflects system load factor; demand classification reflects the value (1 - system load factor). Tatum direct at 19.

[2] CSPP = cogeneration and small power production. For IPC demand value, see Schwendiman workpapers at 72 and Exhibit No. 41 at 51.

Alternative Classification of Production Function Costs: COS Cases 3 and 4

Cost Item	Demand (%) Base/Intermed IPC	Demand (%) Base/Intermed DOE	Demand (%) Peaking IPC	Demand (%) Peaking DOE	Energy (%) IPC	Energy (%) DOE
Hydro Plant (330-336)[1]	41.47	24.00	0.00	36.00	58.53	40.00
Purchased Power (555.1)	0.00	25.00	0.00	25.00	100.00	50.00
CSPP (555.2)[2]	3.03	25.00	3.03	25.00	96.97	50.00
CTs/Other (340-346)	0.00	0.00	100.00	100.00	0.00	0.00
Steam Plant (310-316)[1]	41.47	41.47	0.00	0.00	58.53	58.53

[1] IPC energy classification reflects system load factor; demand classification reflects the value (1 - system load factor). Tatum direct at 19.
[2] CSPP = cogeneration and small power production. For IPC demand value, see Schwendiman workpapers at 72 and Exhibit No. 49 at 51.

STATE OF IDAHO
BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-07-08

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 US DOE

December 10, 2007

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007

*** REVENUE REQUIREMENT SUMMARY ***

Line		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)
10	TOTAL RATE BASE		1,882,670,920	829,644,593	44,078,228	42,065,172	386,797,084	890,883	209,852,377	278,045,631
12	REVENUES FROM RATES									
13	RETAIL		617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659
15	TOTAL SALES REVENUES		617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659
17	TOTAL OTHER OPERATING REVENUES		178,391,078	67,717,440	2,885,486	5,479,331	38,300,062	175,402	28,950,719	21,161,844
19	TOTAL REVENUES		796,211,346	361,805,050	18,266,814	18,252,028	164,521,272	1,106,549	94,820,193	91,912,503
21	OPERATING EXPENSES									
22	WITHOUT INC TAX		629,346,490	273,691,906	14,948,121	14,514,973	128,645,039	869,533	76,800,035	81,985,934
24	OPERATING INCOME									
25	BEFORE INCOME TAXES		166,864,856	88,113,143	3,318,694	3,737,055	35,876,233	237,016	18,020,159	9,926,569
27	TOTAL FEDERAL INCOME TAX		46,753,611	20,603,112	1,094,624	1,044,632	9,605,588	22,124	5,211,403	6,904,891
28	TOTAL STATE INCOME TAX		2,849,268	1,255,599	66,709	63,662	585,386	1,348	317,594	420,799
30	TOTAL OPERATING EXPENSES		678,949,369	295,550,618	16,109,453	15,623,268	138,836,012	893,005	82,329,032	89,311,624
32	TOTAL OPERATING INCOME		117,261,977	66,254,432	2,157,361	2,628,761	25,685,259	213,544	12,491,162	2,600,879
34	ADD: IERCO OPERATING INCOME	E10	4,969,962	1,835,515	77,059	128,840	1,143,569	2,165	766,782	616,581
35	CONSOLIDATED OPER INCOME		122,231,938	68,089,947	2,234,420	2,757,601	26,828,828	215,709	13,257,944	3,217,460
37	RATES OF RETURN		6.49	8.207	5.069	6.556	6.936	24.213	6.318	1.157
38	RATES OF RETURN - INDEX		1.000	1.264	0.781	1.010	1.068	3.729	0.973	0.178
39	AVERAGE MILLS/KWH		50.20	59.24	73.93	35.41	40.86	157.75	30.70	45.96
41	**REVENUE REQUIREMENT CALCULATION**									
42	RATE OF RETURN REQUIRED		8.561	8.561	8.561	8.561	8.561	8.561	8.561	8.561
44	REQUIRED REVENUE		681,765,526	298,908,402	17,908,559	14,157,886	136,540,967	702,185	73,599,219	104,552,915
45	REVENUE DEFICIENCY		63,945,258	4,820,792	2,527,231	1,385,189	10,319,757	(228,962)	7,729,745	33,802,256
46	PERCENT CHANGE REQUIRED		10.35%	1.64%	16.43%	10.84%	8.18%	-24.59%	11.73%	47.78%
47	RETURN AT CLAIMED ROR		161,175,457	71,025,874	3,773,537	3,601,199	33,113,698	76,268	17,965,462	23,803,486
48	EARNINGS DEFICIENCY		38,943,519	2,935,927	1,539,117	843,599	6,284,870	(139,441)	4,707,518	20,586,027
50	**REVENUE REQUIREMENT FOR RATE DESIGN**									
51	TOTAL IDAHO SALES REVENUES		617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659
53	REQUESTED CHANGE IN REVENUE (%)		10.35%	1.64%	16.43%	10.84%	8.18%	-24.59%	11.73%	47.78%
55	SALES REVENUE REQUIRED		681,765,526	298,908,402	17,908,559	14,157,886	136,540,967	702,185	73,599,219	104,552,915
56	RATE OF RETURN AT REQUIRED REVENUE		8.561	8.561	8.561	8.561	8.561	8.561	8.561	8.561
57	REQUESTED AVERAGE MILLS/KWH		55.40	60.21	86.08	39.25	44.20	118.96	34.31	67.92
59	ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		-3.25	-0.18	-1.65	-6.78	-3.26	4.28	-7.84	-6.68
60	REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		0.15	0.40	4.08	-3.48	-0.59	-21.42	-4.16	5.48

Case 1

Exhibit No. 608
Case No. IPC-E-07-08
D. Goins, DOE

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007

*** 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		1,882,670,920	2,410,248	2,830,939	561,605	15,772,212	16,372,017	53,349,930
REVENUES FROM RATES		0						
RETAIL		617,820,268	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
TOTAL SALES REVENUES		617,820,268	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
TOTAL OTHER OPERATING REVENUES		178,391,078	202,991	431,528	67,964	2,396,033	2,658,935	7,963,342
TOTAL REVENUES		796,211,346	1,083,601	2,487,674	256,507	7,780,882	7,316,816	26,601,456
OPERATING EXPENSES		0						
WITHOUT INC TAX		629,346,490	790,713	2,128,898	204,201	6,497,510	5,905,360	22,364,267
		0						
OPERATING INCOME		0						
BEFORE INCOME TAXES		166,864,856	292,888	358,776	52,306	1,283,372	1,411,456	4,237,188
TOTAL FEDERAL INCOME TAX		46,753,611	59,855	70,303	13,947	391,682	406,577	1,324,874
TOTAL STATE INCOME TAX		2,849,268	3,648	4,284	850	23,870	24,778	80,741
TOTAL OPERATING EXPENSES		678,949,369	854,216	2,203,485	218,997	6,913,062	6,336,715	23,769,882
TOTAL OPERATING INCOME		117,261,977	229,385	284,189	37,509	867,821	980,101	2,831,573
		0						
ADD: IERCO OPERATING INCOME	E10	4,969,962	5,994	7,591	2,008	73,495	65,719	244,645
CONSOLIDATED OPER INCOME		122,231,938	235,379	291,780	39,518	941,315	1,045,820	3,076,218
RATES OF RETURN		6.492	9.766	10.307	7.037	5.968	6.388	5.766
RATES OF RETURN - INDEX		1.000	1.504	1.588	1.084	0.919	0.984	0.888
AVERAGE MILLS/KWH		50.201	53.90	109.93	34.44	24.99	24.73	26.54
REVENUE REQUIREMENT CALCULATION								
RATE OF RETURN REQUIRED		8.561	8.561	8.561	8.561	8.561	8.561	8.561
REQUIRED REVENUE		681,765,526	832,930	1,974,993	202,600	6,056,335	5,242,085	21,086,450
REVENUE DEFICIENCY		63,945,258	(47,680)	(81,153)	14,057	671,486	584,204	2,448,336
PERCENT CHANGE REQUIRED		10.35	-5.41%	-3.95%	7.46%	12.47%	12.54%	13.14%
RETURN AT CLAIMED ROR		161,175,457	206,341	242,357	48,079	1,350,259	1,401,608	4,567,288
EARNINGS DEFICIENCY		38,943,519	(29,038)	(49,423)	8,561	408,944	355,788	1,491,070
REVENUE REQUIREMENT FOR RATE DESIGN								
TOTAL IDAHO SALES REVENUES		617,820,268	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
REQUESTED CHANGE IN REVENUE (%)		10.35%	-5.41%	-3.95%	7.46%	12.47%	12.54%	13.14%
SALES REVENUE REQUIRED		681,765,526	832,930	1,974,993	202,600	6,056,335	5,242,085	21,086,450
RATE OF RETURN AT REQUIRED REVENUE		8.561	8.561	8.561	8.561	8.561	8.561	8.561
REQUESTED AVERAGE MILLS/KWH		55.40	50.98	105.59	37.01	28.10	27.84	30.03
ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		(3.25)	1.10	-5.20	-5.42	-9.69	-10.25	-9.62
REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		0.15	-0.88	-8.07	-2.92	-5.43	-6.69	-5.03

Case 1

STATE OF IDAHO
BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-07-08

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 US DOE

December 10, 2007

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007

*** 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		1,882,670,920	854,443,900	43,941,029	42,533,803	389,897,207	877,734	213,809,081	242,303,759
REVENUES FROM RATES									
RETAIL		617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659
TOTAL SALES REVENUES		617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659
TOTAL OTHER OPERATING REVENUES		178,391,078	68,492,124	2,913,448	5,510,988	38,619,031	169,948	29,251,866	19,505,516
TOTAL REVENUES		796,211,346	362,579,734	18,294,776	18,283,685	164,840,241	1,101,095	95,121,340	90,256,175
OPERATING EXPENSES									
WITHOUT INC TAX		629,346,490	280,475,685	14,948,007	14,660,905	129,753,370	859,598	78,083,948	71,583,874
OPERATING INCOME									
BEFORE INCOME TAXES		166,864,856	82,104,049	3,346,769	3,622,780	35,086,871	241,497	17,037,392	18,672,300
TOTAL FEDERAL INCOME TAX		46,753,611	21,218,970	1,091,217	1,056,270	9,682,575	21,797	5,309,662	6,017,289
TOTAL STATE INCOME TAX		2,849,268	1,293,131	66,501	64,371	590,078	1,328	323,583	366,707
TOTAL OPERATING EXPENSES		678,949,369	302,987,786	16,105,725	15,781,547	140,026,022	882,724	83,717,193	77,967,870
TOTAL OPERATING INCOME		117,261,977	59,591,949	2,189,051	2,502,139	24,814,219	218,371	11,404,147	12,288,304
ADD: IERCO OPERATING INCOME	E10	4,969,962	1,852,802	78,028	129,716	1,153,031	1,988	775,314	574,031
CONSOLIDATED OPER INCOME		122,231,938	61,444,750	2,267,080	2,631,855	25,967,250	220,359	12,179,461	12,862,335
RATES OF RETURN		6.49	7.191	5.159	6.188	6.660	25.105	5.696	5.308
RATES OF RETURN - INDEX		1.000	1.108	0.795	0.953	1.026	3.867	0.877	0.818
AVERAGE MILLS/KWH		50.20	59.24	73.93	35.41	40.86	157.75	30.70	45.96
REVENUE REQUIREMENT CALCULATION									
RATE OF RETURN REQUIRED		8.561	8.561	8.561	8.561	8.561	8.561	8.561	8.561
REQUIRED REVENUE		681,765,526	313,305,893	17,835,645	14,430,237	138,391,467	692,702	75,926,288	83,691,737
REVENUE DEFICIENCY		63,945,258	19,218,283	2,454,317	1,657,540	12,170,257	(238,445)	10,056,814	12,941,078
PERCENT CHANGE REQUIRED		10.35%	6.53%	15.96%	12.98%	9.64%	-25.61%	15.27%	18.29%
RETURN AT CLAIMED ROR		161,175,457	73,148,942	3,761,791	3,641,319	33,379,100	75,143	18,304,195	20,743,625
EARNINGS DEFICIENCY		38,943,519	11,704,192	1,494,712	1,009,464	7,411,850	(145,216)	6,124,734	7,881,290
REVENUE REQUIREMENT FOR RATE DESIGN									
TOTAL IDAHO SALES REVENUES		617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659
REQUESTED CHANGE IN REVENUE (%)		10.35%	6.53%	15.96%	12.98%	9.64%	-25.61%	15.27%	18.29%
SALES REVENUE REQUIRED		681,765,526	313,305,893	17,835,645	14,430,237	138,391,467	692,702	75,926,288	83,691,737
RATE OF RETURN AT REQUIRED REVENUE		8.561	8.561	8.561	8.561	8.561	8.561	8.561	8.561
REQUESTED AVERAGE MILLS/KWH		55.40	63.11	85.73	40.00	44.80	117.35	35.39	54.37
ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		-3.25	-1.04	-1.65	-7.07	-3.54	5.52	-8.35	-2.98
REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		0.15	1.21	3.94	-3.18	-0.42	-21.65	-3.84	2.36

Case 2

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007

*** 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		1,882,670,920	2,460,429	2,929,571	561,789	17,110,237	17,003,229	54,799,152
REVENUES FROM RATES		0						
RETAIL		617,820,268	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
TOTAL SALES REVENUES		617,820,268	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
TOTAL OTHER OPERATING REVENUES		178,391,078	202,318	443,451	67,380	2,456,845	2,677,125	8,081,037
TOTAL REVENUES		796,211,346	1,082,928	2,499,597	255,923	7,841,694	7,335,006	26,719,151
OPERATING EXPENSES		0						
WITHOUT INC TAX		629,346,490	805,228	2,167,493	203,245	6,886,648	6,076,876	22,841,612
		0						
OPERATING INCOME		0						
BEFORE INCOME TAXES		166,864,856	277,700	332,104	52,677	955,046	1,258,130	3,877,539
TOTAL FEDERAL INCOME TAX		46,753,611	61,101	72,752	13,951	424,910	422,252	1,360,864
TOTAL STATE INCOME TAX		2,849,268	3,724	4,434	850	25,895	25,733	82,934
TOTAL OPERATING EXPENSES		678,949,369	870,053	2,244,679	218,047	7,337,452	6,524,862	24,285,410
TOTAL OPERATING INCOME		117,261,977	212,875	254,918	37,876	504,242	810,144	2,433,742
		0						
ADD: IERCO OPERATING INCOME	E10	4,969,962	5,964	7,952	1,988	75,046	66,100	248,001
CONSOLIDATED OPER INCOME		122,231,938	218,839	262,870	39,864	579,288	876,245	2,681,743
RATES OF RETURN		6.492	8.894	8.973	7.096	3.386	5.153	4.894
RATES OF RETURN - INDEX		1.000	1.370	1.382	1.093	0.521	0.794	0.754
AVERAGE MILLS/KWH		50.201	53.90	109.93	34.44	24.99	24.73	26.54
REVENUE REQUIREMENT CALCULATION								
RATE OF RETURN REQUIRED		8.561	8.561	8.561	8.561	8.561	8.561	8.561
REQUIRED REVENUE		681,765,526	867,143	2,036,327	202,058	6,838,872	5,609,259	21,937,898
REVENUE DEFICIENCY		63,945,258	(13,467)	(19,819)	13,515	1,454,023	951,378	3,299,784
PERCENT CHANGE REQUIRED		10.35	-1.53%	-0.96%	7.17%	27.00%	20.43%	17.70%
RETURN AT CLAIMED ROR		161,175,457	210,637	250,801	48,095	1,464,807	1,455,646	4,691,355
EARNINGS DEFICIENCY		38,943,519	(8,202)	(12,070)	8,231	885,519	579,402	2,009,613
REVENUE REQUIREMENT FOR RATE DESIGN								
TOTAL IDAHO SALES REVENUES		617,820,268	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
REQUESTED CHANGE IN REVENUE (%)		10.35%	-1.53%	-0.96%	7.17%	27.00%	20.43%	17.70%
SALES REVENUE REQUIRED		681,765,526	867,143	2,036,327	202,058	6,838,872	5,609,259	21,937,898
RATE OF RETURN AT REQUIRED REVENUE		8.561	8.561	8.561	8.561	8.561	8.561	8.561
REQUESTED AVERAGE MILLS/KWH		55.40	53.08	108.87	36.91	31.73	29.78	31.24
ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		(3.25)	0.43	-6.44	-5.25	-11.41	-10.98	-10.31
REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		0.15	-0.12	-7.11	-2.85	-2.91	-5.38	-4.28

Case 2

Exhibit No. 609
Case No. IPC-E-07-08
D. Goins, DOE

STATE OF IDAHO
BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-07-08

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 US DOE

December 10, 2007

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007

*** 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		1,882,670,920	827,119,280	44,166,830	41,710,468	385,168,971	869,400	208,089,624	285,216,127
REVENUES FROM RATES									
RETAIL		617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659
TOTAL SALES REVENUES		617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659
TOTAL OTHER OPERATING REVENUES		178,391,078	67,722,341	2,885,235	5,479,987	38,301,522	175,460	28,952,934	21,150,441
TOTAL REVENUES		796,211,346	361,809,951	18,266,563	18,252,684	164,522,732	1,106,607	94,822,408	91,901,100
OPERATING EXPENSES									
WITHOUT INC TAX		629,346,490	273,234,398	14,975,092	14,404,388	128,159,834	862,421	76,291,545	83,788,256
OPERATING INCOME									
BEFORE INCOME TAXES		166,864,856	88,575,553	3,291,471	3,848,296	36,362,898	244,186	18,530,863	8,112,844
TOTAL FEDERAL INCOME TAX		46,753,611	20,540,400	1,096,824	1,035,824	9,565,156	21,590	5,167,627	7,083,010
TOTAL STATE INCOME TAX		2,849,268	1,251,777	66,843	63,125	582,922	1,316	314,927	431,654
TOTAL OPERATING EXPENSES		678,949,369	295,026,575	16,138,759	15,503,337	138,307,911	885,327	81,774,099	91,302,920
TOTAL OPERATING INCOME		117,261,977	66,783,376	2,127,804	2,749,347	26,214,821	221,280	13,048,309	598,180
ADD: IERCO OPERATING INCOME	E10	4,969,962	1,835,515	77,059	128,840	1,143,569	2,165	766,782	616,581
CONSOLIDATED OPER INCOME		122,231,938	68,618,891	2,204,862	2,878,187	27,358,390	223,445	13,815,091	1,214,761
RATES OF RETURN		6.492	8.296	4.992	6.900	7.103	25.701	6.639	0.426
RATES OF RETURN - INDEX		1.000	1.278	0.769	1.063	1.094	3.959	1.023	0.066
AVERAGE MILLS/KWH		50.20	59.24	73.93	35.41	40.86	157.75	30.70	45.96
REVENUE REQUIREMENT CALCULATION									
RATE OF RETURN REQUIRED		8.561	8.561	8.561	8.561	8.561	8.561	8.561	8.561
REQUIRED REVENUE		681,765,526	297,684,888	17,969,547	13,910,022	135,442,560	686,463	72,436,589	108,849,596
REVENUE DEFICIENCY		63,945,258	3,597,278	2,588,219	1,137,325	9,221,350	(244,684)	6,567,115	38,098,937
PERCENT CHANGE REQUIRED		10.35%	1.22%	16.83%	8.90%	7.31%	-26.28%	9.97%	53.85%
RETURN AT CLAIMED ROR		161,175,457	70,809,682	3,781,122	3,570,833	32,974,316	74,429	17,814,553	24,417,524
EARNINGS DEFICIENCY		38,943,519	2,190,791	1,576,260	692,646	5,615,926	(149,016)	3,999,461	23,202,763
REVENUE REQUIREMENT FOR RATE DESIGN									
TOTAL IDAHO SALES REVENUES		617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659
REQUESTED CHANGE IN REVENUE (%)		10.35%	1.22%	16.83%	8.90%	7.31%	-26.28%	9.97%	53.85%
SALES REVENUE REQUIRED		681,765,526	297,684,888	17,969,547	13,910,022	135,442,560	686,463	72,436,589	108,849,596
RATE OF RETURN AT REQUIRED REVENUE		8.561	8.561	8.561	8.561	8.561	8.561	8.561	8.561
REQUESTED AVERAGE MILLS/KWH		55.40	59.97	86.37	38.56	43.84	116.30	33.76	70.71
ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		-3.25	-0.11	-1.71	-6.55	-3.14	5.27	-7.64	-7.21
REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		0.15	0.32	4.15	-3.82	-0.74	-22.87	-4.49	6.15

Case 3

Exhibit No. 610
Case No. IPC-E-07-08
D. Goins, DOE
Page 1 of 2

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007

*** 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		1,882,670,920	2,439,927	2,769,392	563,477	15,516,185	16,212,126	52,827,115
REVENUES FROM RATES		0						
RETAIL		617,820,268	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
TOTAL SALES REVENUES		617,820,268	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
TOTAL OTHER OPERATING REVENUES		178,391,078	203,237	431,289	68,017	2,396,433	2,659,638	7,964,543
TOTAL REVENUES		796,211,346	1,083,847	2,487,435	256,560	7,781,282	7,317,519	26,602,657
OPERATING EXPENSES		0						
WITHOUT INC TAX		629,346,490	799,639	2,113,464	204,412	6,435,958	5,861,613	22,215,469
		0						
OPERATING INCOME		0						
BEFORE INCOME TAXES		166,864,856	284,208	373,971	52,148	1,345,324	1,455,906	4,387,188
TOTAL FEDERAL INCOME TAX		46,753,611	60,592	68,774	13,993	385,324	402,606	1,311,891
TOTAL STATE INCOME TAX		2,849,268	3,693	4,191	853	23,482	24,536	79,950
TOTAL OPERATING EXPENSES		678,949,369	863,924	2,186,429	219,258	6,844,764	6,288,755	23,607,309
TOTAL OPERATING INCOME		117,261,977	219,923	301,005	37,302	936,518	1,028,764	2,995,348
		0						
ADD: IERCO OPERATING INCOME	E10	4,969,962	5,994	7,591	2,008	73,495	65,719	244,645
CONSOLIDATED OPER INCOME		122,231,938	225,917	308,596	39,310	1,010,013	1,094,483	3,239,992
RATES OF RETURN		6.492	9.259	11.143	6.976	6.509	6.751	6.133
RATES OF RETURN - INDEX		1.000	1.426	1.716	1.075	1.003	1.040	0.945
AVERAGE MILLS/KWH		50.201	53.90	109.93	34.44	24.99	24.73	26.54
REVENUE REQUIREMENT CALCULATION								
RATE OF RETURN REQUIRED		8.561	8.561	8.561	8.561	8.561	8.561	8.561
REQUIRED REVENUE		681,765,526	852,639	1,938,730	203,205	5,907,543	5,139,704	20,744,040
REVENUE DEFICIENCY		63,945,258	(27,971)	(117,416)	14,662	522,694	481,823	2,105,926
PERCENT CHANGE REQUIRED		10.35	-3.18%	-5.71%	7.78%	9.71%	10.34%	11.30%
RETURN AT CLAIMED ROR		161,175,457	208,882	237,088	48,239	1,328,341	1,387,920	4,522,529
EARNINGS DEFICIENCY		38,943,519	(17,035)	(71,508)	8,929	318,328	293,437	1,282,537
REVENUE REQUIREMENT FOR RATE DESIGN								
TOTAL IDAHO SALES REVENUES		617,820,268	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
REQUESTED CHANGE IN REVENUE (%)		10.35%	-3.18%	-5.71%	7.78%	9.71%	10.34%	11.30%
SALES REVENUE REQUIRED		681,765,526	852,639	1,938,730	203,205	5,907,543	5,139,704	20,744,040
RATE OF RETURN AT REQUIRED REVENUE		8.561	8.561	8.561	8.561	8.561	8.561	8.561
REQUESTED AVERAGE MILLS/KWH		55.40	52.19	103.65	37.12	27.41	27.29	29.54
ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		(3.25)	0.68	-4.70	-5.45	-9.41	-10.06	-9.41
REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		0.15	-0.46	-8.94	-2.85	-6.04	-7.09	-5.42

Case 3

Exhibit No. 610
Case No. IPC-E-07-08
D. Goins, DOE
Page 2 of 2

STATE OF IDAHO
BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-07-08

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 US DOE

December 10, 2007

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007

*** 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		1,882,670,920	814,615,865	44,014,349	42,037,212	386,715,561	934,749	212,794,741	287,243,941
REVENUES FROM RATES									
RETAIL		617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659
TOTAL SALES REVENUES		617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659
TOTAL OTHER OPERATING REVENUES		178,391,078	67,705,326	2,885,507	5,479,347	38,298,627	175,421	28,949,133	21,177,568
TOTAL REVENUES		796,211,346	361,792,936	18,266,835	18,252,044	164,519,837	1,106,568	94,818,607	91,928,227
OPERATING EXPENSES									
WITHOUT INC TAX		629,346,490	268,622,674	14,918,851	14,524,904	128,730,274	886,524	78,026,968	84,535,452
OPERATING INCOME									
BEFORE INCOME TAXES		166,864,856	93,170,262	3,347,983	3,727,141	35,789,563	220,044	16,791,639	7,392,775
TOTAL FEDERAL INCOME TAX		46,753,611	20,229,894	1,093,037	1,043,938	9,603,563	23,213	5,284,472	7,133,319
TOTAL STATE INCOME TAX		2,849,268	1,232,854	66,612	63,620	585,262	1,415	322,047	434,720
TOTAL OPERATING EXPENSES		678,949,369	290,085,422	16,078,501	15,632,461	138,919,099	911,152	83,633,487	92,103,490
TOTAL OPERATING INCOME		117,261,977	71,707,513	2,188,334	2,619,583	25,600,738	195,416	11,185,119	(175,264)
ADD: IERCO OPERATING INCOME	E10	4,969,962	1,835,515	77,059	128,840	1,143,569	2,165	766,782	616,581
CONSOLIDATED OPER INCOME		122,231,938	73,543,028	2,265,392	2,748,423	26,744,307	197,581	11,951,901	441,317
RATES OF RETURN		6.492	9.028	5.147	6.538	6.916	21.137	5.617	0.154
RATES OF RETURN - INDEX		1.000	1.391	0.793	1.007	1.065	3.256	0.865	0.024
AVERAGE MILLS/KWH		50.20	59.24	73.93	35.41	40.86	157.75	30.70	45.96
REVENUE REQUIREMENT CALCULATION									
RATE OF RETURN REQUIRED		8.561	8.561	8.561	8.561	8.561	8.561	8.561	8.561
REQUIRED REVENUE		681,765,526	287,841,830	17,848,722	14,169,026	136,668,291	738,118	76,157,354	110,404,363
REVENUE DEFICIENCY		63,945,258	(6,245,780)	2,467,394	1,396,329	10,447,081	(193,029)	10,287,880	39,653,704
PERCENT CHANGE REQUIRED		10.35%	-2.12%	16.04%	10.93%	8.28%	-20.73%	15.62%	56.05%
RETURN AT CLAIMED ROR		161,175,457	69,739,264	3,768,068	3,598,806	33,106,719	80,024	18,217,358	24,590,954
EARNINGS DEFICIENCY		38,943,519	(3,803,764)	1,502,676	850,383	6,362,412	(117,557)	6,265,456	24,149,637
REVENUE REQUIREMENT FOR RATE DESIGN									
TOTAL IDAHO SALES REVENUES		617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659
REQUESTED CHANGE IN REVENUE (%)		10.35%	-2.12%	16.04%	10.93%	8.28%	-20.73%	15.62%	56.05%
SALES REVENUE REQUIRED		681,765,526	287,841,830	17,848,722	14,169,026	136,668,291	738,118	76,157,354	110,404,363
RATE OF RETURN AT REQUIRED REVENUE		8.561	8.561	8.561	8.561	8.561	8.561	8.561	8.561
REQUESTED AVERAGE MILLS/KWH		55.40	57.98	85.79	39.28	44.24	125.05	35.50	71.72
ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		-3.25	0.49	-1.58	-6.80	-3.28	2.14	-8.35	-7.43
REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		0.15	-0.28	4.02	-3.48	-0.58	-18.51	-3.51	6.37

Case 4

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007

*** 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		1,882,670,920	2,505,275	3,030,788	565,260	15,951,844	16,909,180	55,332,155
REVENUES FROM RATES		0						
RETAIL		617,820,268	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
TOTAL SALES REVENUES		617,820,268	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
TOTAL OTHER OPERATING REVENUES		178,391,078	203,207	431,196	68,015	2,395,411	2,659,034	7,963,288
TOTAL REVENUES		796,211,346	1,083,817	2,487,342	256,558	7,780,260	7,316,915	26,601,402
OPERATING EXPENSES		0						
WITHOUT INC TAX		629,346,490	823,742	2,209,876	212,446	6,596,645	6,118,713	23,139,421
		0						
OPERATING INCOME		0						
BEFORE INCOME TAXES		166,864,856	260,075	277,465	44,111	1,183,615	1,198,202	3,461,981
TOTAL FEDERAL INCOME TAX		46,753,611	62,215	75,266	14,534	396,143	419,917	1,374,100
TOTAL STATE INCOME TAX		2,849,268	3,792	4,587	886	24,142	25,591	83,741
TOTAL OPERATING EXPENSES		678,949,369	889,749	2,289,729	227,866	7,016,930	6,564,220	24,597,262
TOTAL OPERATING INCOME		117,261,977	194,068	197,613	28,691	763,331	752,694	2,004,140
		0						
ADD: IERCO OPERATING INCOME	E10	4,969,962	5,994	7,591	2,008	73,495	65,719	244,645
CONSOLIDATED OPER INCOME		122,231,938	200,062	205,203	30,700	836,825	818,414	2,248,785
RATES OF RETURN		6.492	7.986	6.771	5.245	5.246	4.840	4.064
RATES OF RETURN - INDEX		1.000	1.230	1.043	0.808	0.808	0.745	0.626
AVERAGE MILLS/KWH		50.201	53.90	109.93	34.44	24.99	24.73	26.54
REVENUE REQUIREMENT CALCULATION								
RATE OF RETURN REQUIRED		8.561	8.561	8.561	8.561	8.561	8.561	8.561
REQUIRED REVENUE		681,765,526	904,279	2,145,245	220,405	6,253,158	5,690,997	22,723,740
REVENUE DEFICIENCY		63,945,258	23,669	89,099	31,862	868,309	1,033,116	4,085,626
PERCENT CHANGE REQUIRED		10.35	2.69%	4.33%	16.90%	16.13%	22.18%	21.92%
RETURN AT CLAIMED ROR		161,175,457	214,477	259,466	50,104	1,365,637	1,447,595	4,736,986
EARNINGS DEFICIENCY		38,943,519	14,415	54,262	19,404	528,812	629,181	2,488,201
REVENUE REQUIREMENT FOR RATE DESIGN								
TOTAL IDAHO SALES REVENUES		617,820,268	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
REQUESTED CHANGE IN REVENUE (%)		10.35%	2.69%	4.33%	16.90%	16.13%	22.18%	21.92%
SALES REVENUE REQUIRED		681,765,526	904,279	2,145,245	220,405	6,253,158	5,690,997	22,723,740
RATE OF RETURN AT REQUIRED REVENUE		8.561	8.561	8.561	8.561	8.561	8.561	8.561
REQUESTED AVERAGE MILLS/KWH		55.40	55.35	114.69	40.26	29.02	30.22	32.36
ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		(3.25)	-0.36	-7.71	-6.72	-10.23	-11.27	-10.77
REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		0.15	0.58	-4.77	-1.27	-4.79	-5.16	-3.39

Case 4

Exhibit No. 611
Case No. IPC-E-07-08
D. Goins, DOE
Page 2 of 2

STATE OF IDAHO
BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-07-08

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

December 10, 2007

Idaho Power Company
Before the Idaho Public Utilities Commission
Revenue Allocation Summary
12 Months Ending December 31, 2007
Proformed Normalized Sales and Revenue

	Tariff Description	Rate	2007 Average Number of Customers	2007 Sales Normalized (kWh)	Proformed Normalized Revenue	Average Mills per kWh
	Uniform Tariff Schedules					
1	Residential Service	1	386,277	4,964,097,044	$ 294,087,612	59.24
2	Small General Service	7	31,133	208,043,392	15,381,328	73.93
3	Large General Service	9	24,919	3,450,030,959	138,993,911	40.29
4	Dusk/Dawn Lighting	15	-	5,902,712	931,147	157.75
5	Large Power Service	19	116	2,145,340,040	65,869,473	30.70
6	Irrigation Service	24	15,375	1,539,304,092	70,750,659	45.96
7	Unmetered Service	40	1,701	16,337,412	880,614	53.90
8	Municipal Street Lighting	41	137	18,704,636	2,056,145	109.93
9	Traffic Control Lighting	42	131	5,474,735	188,539	34.44
10	Total Idaho Rates		459,789	12,353,235,022	$ 589,139,428	47.69
	Special Contracts					
11	Micron	26	1	702,140,245	$ 18,638,115	26.54
12	J R Simplot	29	1	188,325,624	4,657,881	24.73
13	DOE/INL	30	1	215,500,001	5,384,848	24.99
14	Total Specials		3	1,105,965,870	$ 28,680,844	25.93
15	Total Idaho Retail Sales		459,792	13,459,200,892	$ 617,820,272	45.90

Idaho Power Company
Before the Idaho Public Utilities Commission
Revenue Allocation Summary
12 Months Ending December 31, 2007
DOE Case 3 Cost-of-Service Results

	Tariff Description	Rate	COS Percent Change	COS Revenue Change	Revenue Allocation at COS	Average Mills per kWh
	Uniform Tariff Schedules					
1	Residential Service	1	1.22%	$ 3,597,278	$ 297,684,890	59.97
2	Small General Service	7	16.83%	2,588,219	$ 17,969,547	86.37
3	Large General Service	9	7.45%	10,358,675	$ 149,352,586	43.29
4	Dusk/Dawn Lighting	15	-26.28%	(244,684)	$ 686,463	116.30
5	Large Power Service	19	10.11%	6,657,115	$ 72,526,588	33.81
6	Irrigation Service	24	53.85%	38,098,937	$ 108,849,596	70.71
7	Unmetered Service	40	-3.18%	(27,971)	$ 852,643	52.19
8	Municipal Street Lighting	41	-5.71%	(117,416)	$ 1,938,729	103.65
9	Traffic Control Lighting	42	7.78%	14,662	$ 203,201	37.12
10	Total Idaho Rates		10.34%	$ 60,924,815	650,064,243	52.62
	Special Contracts					
11	Micron	26	11.30%	$ 2,105,926	$ 20,744,041	29.54
12	J R Simplot	29	10.34%	481,823	$ 5,139,704	27.29
13	DOE/INL	30	9.71%	522,694	$ 5,907,542	27.41
14	Total Specials		10.85%	$ 3,110,443	31,791,287	28.75
15	Total Idaho Retail Sales		10.36%	$ 64,035,258	$ 681,855,530	50.66

Idaho Power Company
Before the Idaho Public Utilities Commission
Revenue Allocation Summary
12 Months Ending December 31, 2007
First Pass Revenue Allocation

	Tariff Description	Rate	First Pass Percent Change	First Pass Revenue Change	First Pass Revenue Allocation
	Uniform Tariff Schedules				
1	Residential Service	1	1.22%	$ 3,597,278	$ 297,684,890
2	Small General Service	7	16.83%	2,588,219	17,969,547
3	Large General Service	9	7.45%	10,358,675	149,352,586
4	Dusk/Dawn Lighting	15	0.00%	-	931,147
5	Large Power Service	19	10.11%	6,657,115	72,526,588
6	Irrigation Service	24	25.91%	18,332,745	89,083,404
7	Unmetered Service	40	0.00%	-	880,614
8	Municipal Street Lighting	41	0.00%	-	2,056,145
9	Traffic Control Lighting	42	7.78%	14,662	203,201
10	Total Idaho Rates		6.59%	$ 41,548,694	$ 630,688,122
	Special Contracts				
11	Micron	26	11.30%	$ 2,105,926	$ 20,744,041
12	J R Simplot	29	10.34%	481,823	5,139,704
13	DOE/INL	30	9.71%	522,694	5,907,542
14	Total Specials		9.78%	3,110,443	$ 31,791,287
15	Total Idaho Retail Sales		6.74%	$ 44,659,137	$ 662,479,409
16	Revenue Requirement Shortfall				$ 19,376,121

Idaho Power Company
Before the Idaho Public Utilities Commission
Revenue Allocation Summary
12 Months Ending December 31, 2007
Final Revenue Allocation

	Tariff Description	Rate	Final Percent Change	Final Revenue Change	Final Revenue Allocation	Average Mills per kWh	Cost of Service Index
	Uniform Tariff Schedules						
1	Residential Service	1	4.75%	$ 13,982,052	$ 308,069,664	62.06	103%
2	Small General Service	7	16.83%	2,588,219	$ 17,969,547	86.37	100%
3	Large General Service	9	11.20%	15,568,858	$ 154,562,769	44.80	103%
4	Dusk/Dawn Lighting	15	3.49%	32,483	$ 963,630	163.25	-
5	Large Power Service	19	13.95%	9,187,214	$ 75,056,687	34.99	103%
6	Irrigation Service	24	25.91%	18,332,745	$ 89,083,404	57.87	82%
7	Unmetered Service	40	3.49%	30,720	$ 911,334	55.78	107%
8	Municipal Street Lighting	41	3.49%	71,729	$ 2,127,874	113.76	110%
9	Traffic Control Lighting	42	11.54%	21,751	$ 210,290	38.41	103%
10	Total Idaho Rates		10.15%	$ 59,815,772	$ 648,955,200	52.53	
	Special Contracts						
11	Micron	26	15.18%	$ 2,829,584	$ 21,467,699	30.57	103%
12	J R Simplot	29	14.19%	661,122	$ 5,319,003	28.24	103%
13	DOE/INL	30	13.53%	728,779	$ 6,113,627	28.37	103%
14	Total Specials		14.71%	$ 4,219,486	$ 32,900,330	29.75	
15	Total Idaho Retail Sales		10.36%	$ 64,035,258	$ 681,855,530	50.66	

APPENDIX A

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 General Accounting Office, the First Judicial District Court of Montana, the Circuit Court of Kanawha County, West Virginia, and regulatory commissions 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. 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. 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.
2. 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.
3. 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.
4. 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.
5. 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.
6. 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.
7. 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.
8. 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.
9. 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.
10. 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.

11. 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.
12. 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.
13. 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.
14. 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.
15. 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.
16. Alabama Power Company, before the Alabama Public Service Commission, Docket No. 18148 (2005), on behalf of SMI Steel-Alabama, re energy cost recovery.
17. 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.
18. 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.
19. 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.
20. 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.
21. 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.
22. 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.
23. 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.

24. 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.

25. 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.

26. 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.

27. 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.

28. 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.

29. 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.

30. 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.

31. 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.

32. 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.

33. 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.

34. 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.

35. 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.

36. 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.

37. 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.

38. 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.

39. 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.

40. 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.

41. 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.

42. 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.

43. 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.

44. 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.

45. 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.

46. 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.

47. 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.

48. 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.

49. 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.

50. 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.

51. 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.

52. 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.

53. 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.

54. 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.

55. 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.

56. 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.

57. 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.

58. 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.

59. 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.

60. 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.

61. 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.

62. 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.

63. 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. 94-342-4 (1995), Initial Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.

64. 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. 94-342-4 (1995), Reply Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.

65. 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. 94-342-4 (1995), Final Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.

66. 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.

67. 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.

68. 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.

69. 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.

70. 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.

71. 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.

72. 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.

73. 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.

74. 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.

75. 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.

76. 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.

77. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 92-209-E (1992), on behalf of Nucor Steel-Darlington.

78. 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.

79. Georgia Power Company, before the Georgia Public Service Commission, Docket Nos. 4091-U and 4146-U (1992), on behalf of Amicalola Electric Membership Corporation.

80. PacifiCorp, Inc., before the Federal Energy Regulatory Commission, Docket No. EC88-2-007 (1992), on behalf of Nucor Steel-Utah.

81. South Carolina Pipeline Corporation, before the South Carolina Public Service Commission, Docket No. 90-452-G (1991), on behalf of Nucor Steel-Darlington.

82. 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.

83. 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.

84. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E002/GR-91-001 (1991), on behalf of North Star Steel-Minnesota.

85. 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.

86. 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.

87. 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.

88. 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.

89. 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.

90. 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.

91. 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.

92. 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.

93. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E002/GR-89-865 (1989), on behalf of North Star Steel-Minnesota.

94. 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.

95. 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.

96. 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

97. 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.

98. 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.

99. 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.

100. 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.

101. 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.

102. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 88-11-E (1988), on behalf of Nucor Steel-Darlington.
103. 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.
104. Ohio Edison Company, before the Ohio Public Utilities Commission, Case No. 87-689-EL-AIR (1987), on behalf of North Star Steel-Ohio.
105. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 87-7-E (1987), on behalf of Nucor Steel-Darlington.
106. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase I (1987), on behalf of the Strategic Petroleum Reserve.
107. Gulf States Utilities Company, before the Public Utility Commission of Texas, Docket No. 7195 (1987), on behalf of the Strategic Petroleum Reserve.
108. Gulf States Utilities Company, before the Federal Energy Regulatory Commission, Docket No. ER86-558-006 (1987), on behalf of Sam Rayburn G&T Cooperative.
109. Utah Power & Light Company, before the Utah Public Service Commission, Case No. 85-035-06 (1986), on behalf of the U.S. Air Force.
110. Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 6765 (1986), on behalf of the Strategic Petroleum Reserve.
111. Central Maine Power Company, before the Maine Public Utilities Commission, Docket No. 85-212 (1986), on behalf of the U.S. Air Force.
112. Gulf States Utilities Company, before the Public Utility Commission of Texas, Docket Nos. 6477 and 6525 (1985), on behalf of North Star Steel-Texas.
113. Ohio Edison Company, before the Ohio Public Utilities Commission, Docket No. 84-1359-EL-AIR (1985), on behalf of North Star Steel-Ohio.
114. Utah Power & Light Company, before the Utah Public Service Commission, Case No. 84-035-01 (1985), on behalf of the U.S. Air Force.
115. Central Vermont Public Service Corporation, before the Vermont Public Service Board, Docket No. 4782 (1984), on behalf of Central Vermont Public Service Corporation.
116. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-15641 (1983), on behalf of the Strategic Petroleum Reserve.
117. Southwestern Power Administration, before the Federal Energy Regulatory Commission, Rate Order SWPA-9 (1982), on behalf of the Department of Defense.
118. 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.
119. Central Maine Power Company, before the Maine Public Utilities Commission, Docket No. 80-66 (1981), on behalf of the Commission Staff.

120. Bangor Hydro-Electric Company, before the Maine Public Utilities Commission, Docket No. 80-108 (1981), on behalf of the Commission Staff.
121. Oklahoma Gas & Electric, before the Oklahoma Corporation Commission, Docket No. 27275 (1981), on behalf of the Commission Staff.
122. Green Mountain Power, before the Vermont Public Service Board, Docket No. 4418 (1980), on behalf of the PSB Staff.
123. Williams Pipe Line, before the Federal Energy Regulatory Commission, Docket No. OR79-1 (1979), on behalf of Mapco, Inc.
124. Boston Edison Company, before the Massachusetts Department of Public Utilities, Docket No. 19494 (1978), on behalf of Boston Edison Company.
125. Duke Power Company, before the North Carolina Utilities Commission, Docket No. E-7, Sub 173, on behalf of the Commission Staff.
126. Duke Power Company, before the North Carolina Utilities Commission, Docket No. E-100, Sub 32, on behalf of the Commission Staff.
127. Virginia Electric & Power Company, before the North Carolina Utilities Commission, Docket No. E-22, Sub 203, on behalf of the Commission Staff.
128. Virginia Electric & Power Company, before the North Carolina Utilities Commission, Docket No. E-22, Sub 170, on behalf of the Commission Staff.
129. Southern Bell Telephone Company, before the North Carolina Utilities Commission, Docket No. P-5, Sub 48, on behalf of the Commission Staff.
130. Western Carolina Telephone Company, before the North Carolina Utilities Commission, Docket No. P-58, Sub 93, on behalf of the Commission Staff.
131. Natural Gas Ratemaking, before the North Carolina Utilities Commission, Docket No. G-100, Sub 29, on behalf of the Commission Staff.
132. General Telephone Company of the Southeast, before the North Carolina Utilities Commission, Docket No. P-19, Sub 163, on behalf of the Commission Staff.
133. Carolina Power and Light Company, before the North Carolina Utilities Commission, Docket No. E-2, Sub 264, on behalf of the Commission Staff.
134. Carolina Power and Light Company, before the North Carolina Utilities Commission, Docket No. E-2, Sub 297, on behalf of the Commission Staff.
135. 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.
136. Investigation of Intrastate Long Distance Rates, before the North Carolina Utilities Commission, Docket No. P-100, Sub 45, on behalf of the Commission Staff.

CERTIFICATE OF SERVICE - CASE NO. IPC-E-07-8

I hereby certify that I have this 10th day of December, 2007, served or caused to be served a true and correct copy of the attached DIRECT TESTIMONY OF DENNIS W. GOINS ON BEHALF OF THE UNITED STATES DEPARTMENT OF ENERGY upon each of the parties listed below, by placing the same in the U.S. Mail, postage prepaid.

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

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

Weldon Stutzman
Donovan Walker
Deputy Attorney Generals
Idaho Public Service Commission
472 W. Washington (83702)
PO Box 83720
Boise, ID 83720-0074

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

Dr. Don Reading
Ben Johnson Associates
6070 Hill Road
Boise, ID 83703

Eric L. Olsen
Racine, Olson, Nye, Budge &
Bailey, Chartered
P.O. Box 1390;
201 E. Center
Pocatello, ID 83204-1391

Anthony Yankel
29814 Lake Road
Bay Village, OH 44140

Michael Kurtz, Esq.
Kurt J. Boehm, Esq.
Boehm, Kurtz & Lowry
36 E. Seventh Street, Suite 1510
Cincinnati, OH 45202

Conley E. Ward
Michael c. Creamer
Givens Pursley LLP
601 W. Bannock Street
PO Box 2720
Bois, ID 83701-2720

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

Lot H. Cooke
Acting Assistant General Counsel
United States Department of Energy
1000 Independence Ave., SW
Washington, DC 20585

Dale Swan
Exeter Associates
5565 Sterritt Place, Suite 310
Columbia, MD 21044

Arthur Perry Bruder
Attorney-Advisor
Office of the General Counsel
United States Department of Energy
Washington, DC