EXHIBIT NO.	
WITNESS:	**DENNIS W. GOINS**
TYPE OF EXHIBIT	**DIRECT TESTIMONY**
ISSUES:	**COST OF SERVICE, REVENUE SPREAD**
SPONSORING PARTY:	**U.S. DEPT. OF ENERGY**
CASE NO.	**ER-2010-0355**

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2010-0355

IN THE MATTER OF THE APPLICATION OF KANSAS CITY POWER & LIGHT COMPANY FOR APPROVAL TO MAKE CERTAIN CHANGES IN ITS CHARGES FOR ELECTRIC SERVICE TO CONTINUE THE IMPLEMENTATION OF THE REGULATORY PLAN

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

November 24, 2010

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

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 economics 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. Following graduate school I worked as a staff economist at the North Carolina Utilities Commission (NCUC). During my tenure at the NCUC, I testified in numerous cases involving electric, gas, and telephone utilities on such issues as cost of service, rate design, intercorporate transactions, and load forecasting. While at the NCUC I also served as a member of the

Ratemaking Task Force in the national Electric Utility Rate Design Study sponsored by the Electric Power Research Institute (EPRI) and the National Association of Regulatory Utility Commissioners (NARUC).

Since leaving the NCUC, 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 150 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, Hawaii, Idaho, Illinois, Indiana, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, and the District of Columbia. Additional details of my educational and professional background are presented in the Appendix.

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

A. I am testifying on behalf of the U.S. Department of Energy (DOE) representing the Federal Executive Agencies (FEA), which is comprised of all federal facilities served by Kansas City Power & Light Company (KCPL). One of the largest FEA customers served by KCPL is the National Nuclear Security Administration (NNSA), which operates a site office and a large industrial facility in Kansas City. NNSA is an agency within DOE.

Q. WHAT ASSIGNMENT WERE YOU GIVEN WHEN YOU WERE RETAINED?

A. I was asked to undertake two primary tasks:

1. Review and evaluate KCPL's application for an increase in base rates, in particular the method KCPL proposes to allocate its cost of service among retail rate classes.
2. Identify any major deficiencies in KCPL's cost analyses, and suggest recommended changes.

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

A. I reviewed KCPL's filing, testimony, exhibits, and responses to requests for information. I also reviewed information (including information on prior regulatory cases) found on web sites operated by this Commission, and by KCPL and its parent company, Great Plains Energy.

CONCLUSIONS

Q. WHAT CONCLUSIONS HAVE YOU REACHED?

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

1. KCPL's Cost of Service. In this case, KCPL initially conducted a jurisdictional separation study in which it allocated and/or assigned total company test-year costs to each regulatory jurisdiction in which it operates (including the Missouri retail jurisdiction).[1] In addition, KCPL conducted a class cost-of-service study (COSS) in which it allocated its Missouri retail costs to various rate classes.[2] KCPL's cost studies are significantly deficient in at least two major areas—the allocation of demand-related (fixed) production costs, and the allocation of nonfirm off-system sales margins.[3]

2. Production Cost Allocation. In its jurisdictional separation study, KCPL allocated demand-related production costs on the basis of contributions to KCPL's system coincident peaks in the four summer months of June through September (the 4CP Method). However, in its class COSS, KCPL allocated demand-related production costs assigned to the Missouri retail jurisdiction on the basis of each class' relative use of production plant and equipment classified as base, intermediate, and peak (the BIP Method). I agree with the 4CP Method KCPL used in its jurisdictional study. However, in my opinion, the BIP Method does not result in a reasonable allocation of demand-related production costs to KCPL's retail rate classes. The BIP Method has never been approved by this Commission (to my knowledge), nor has it been widely used by regulatory commissions in other states to allocate fixed production costs. In particular, the BIP Method:

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[1] The costing approaches KCPL used in its jurisdictional separation study are described primarily in the direct testimony of KCPL witnesses John P. Weisensee and Larry W. Loos.

[2] KCPL's class COSS is described in the direct testimony of KCPL witness Paul M. Normand. The test year for both the jurisdictional and class cost studies is 2009 adjusted for known and measurable changes through December 31, 2010.

[3] Although my testimony focuses on these two problem areas, my decision not to address other allocation issues or elements in the jurisdictional and class cost studies should not be construed as my implicit endorsement of the methods and approaches KCPL took in addressing those issues.

- Is inconsistent with the 4CP Method that KCPL used to allocate fixed production costs in its jurisdictional separation study. Even though KCPL used class contributions to its 4CP demands to allocate fixed production costs to the Missouri retail jurisdiction, it then used the markedly different BIP Method to allocate jurisdictional fixed production costs to Missouri rate classes. As a result, customer loads (demand and energy) used to allocate fixed production costs to the Missouri retail jurisdiction do not match the customer loads used to allocate these jurisdictional costs among Missouri retail rate classes in KCPL's BIP cost study. More importantly, KCPL's different jurisdictional and class allocation methods reflect fundamentally different concepts about cost drivers and cost responsibility. The 4CP Method emphasizes contributions to system peak demands, while the BIP Method emphasizes relative use of production facilities.
- Classifies production plant by operating characteristics and assumed dispatch order, and then relies on an implicit, complex, and indirect linkage between plant classification and customer cost responsibility using an array of nontraditional allocation factors.
- Essentially allocates all baseload capacity costs on the basis of minimum class average demands—that is, energy use. This approach fails to recognize any meaningful capacity value of baseload plants.
- Fails to align allocated plant and fuel costs properly by base, intermediate, and peaking category. The BIP Method allocates a relatively larger share of expensive baseload plant costs to higher load factor classes compared to lower load factor classes based on the assumed trade-off of higher baseload

plant costs (relative to peaking and intermediate capacity) for lower relative fuel costs. However, KCPL allocated *average* monthly fuel costs on the basis of class energy (kWh) use. This average cost approach to fuel cost allocation ensures that even though higher load factor classes are allocated a larger share of expensive baseload plant costs, they do not get the corresponding benefit of being allocated a sufficiently larger share of lower baseload fuel costs. In other words, higher load factor classes get the higher baseload plant costs, but not the corresponding savings from lower baseload fuel costs. Similarly, under KCPL's proposed BIP Method and average fuel cost allocation, a class with predominately peak usage and lower annual load factor receives the benefit of lower fuel costs from baseload units without being allocated a corresponding share of baseload plant costs.

3. Off-System Sales Margin Allocation. In prior rate cases, the Commission approved allocating off-system sales margins on the basis of class energy use. However, in this case, KCPL allocated nonfirm off-system sales margins using a modified 12CP allocator (factor DEM1B in KCPL's BIP COSS)—the same factor KCPL used to allocate fixed production costs classified as Intermediate.[4] In my opinion, KCPL's arguments supporting the DEM1B allocation are not sufficient to justify overturning Commission precedent and allocating off-system margins using anything other than an energy allocator.[5]

4. Revenue Spread. KCPL proposed spreading its proposed $92.1 million (13.8 percent) rate increase on a uniform, across-the-board

[4] In KCPL's class cost study, Factor DEM1B is designated the 12CP Remaining allocator, and equals each class' 12CP demand (average of each class' monthly test-year coincident peak demand) less the class' Base demand (lowest average monthly test-year demand).

percentage basis to each class. This proposal is reasonable given the unreliability of results from KCPL's class COSS and the need to temper class rate increases during tough economic times. As I show later, correcting the two major allocation problems in KCPL's BIP COSS that I have highlighted results in significantly different cost responsibility assigned to each class relative to class cost responsibility identified in KCPL's cost study.

RECOMMENDATIONS

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

A. I recommend that the Commission:

1. Reject KCPL's BIP Method for allocating fixed production costs to rate classes. Instead, KCPL should be required to use the 4CP Method.
2. Reject KCPL's proposed allocation of off-system sales margins. Instead, the energy component of such margins should be allocated using loss-adjusted kWh (energy) for each class.
3. Approve an across-the-board revenue spread of any rate increase granted to KCPL. An across-the-board spread is both reasonable and fair in this case.

KCPL'S COST OF SERVICE

Q. HOW DID KCPL ALLOCATE DEMAND-RELATED PRODUCTION COSTS IN THIS CASE?

A. As I noted earlier, KCPL allocated these costs using the 4CP Method in the jurisdictional separation study, and the BIP Method in the Missouri

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[5] KCPL also used the DEM1B factor to allocate the capacity component of firm bulk sales in Account 447.

retail class COSS. The Commission approved the 4CP Method in KCPL's 2006 Missouri rate case (Case No. ER-2006-0314) for allocating jurisdictional fixed production (as well as transmission) costs, even though KCPL proposed a 12CP allocation method. The Commission in that case rendered no decision regarding the appropriate method for allocating fixed production costs in KCPL's class COSS.

Q. IS THE 4CP METHOD APPROPRIATE FOR ALLOCATING JURISDICTIONAL FIXED PRODUCTION COSTS?

A. Yes. KCPL confirms that it is predominately a summer peaking utility, with system peaks most likely in June through September.[6] As a result, the 4CP Method properly reflects the principal factor—coincident peak demands—driving KCPL's need for production capacity.

Q. SHOULD THE 4CP METHOD ALSO BE USED TO ALLOCATE FIXED PRODUCTION COSTS AMONG MISSOURI RETAIL RATE CLASSES?

A. Yes. As I will discuss in more detail, the 4CP Method is superior to KCPL's BIP Method for allocating fixed production costs in the Missouri retail class COSS. Moreover, using the 4CP Method to allocate fixed production costs in both the jurisdictional and class cost studies ensures consistency in linking customer demands that drive KCPL's need for production capacity with the cost responsibility for fixed production costs ultimately assigned to each rate class.

Q. ARE CONSISTENT ALLOCATION METHODS REQUIRED IN THE JURISDICTIONAL AND CLASS COST STUDIES?

A. No—but they are desirable. In its filing, KCPL raises the issue of cost recovery problems arising when jurisdictions use different methods to

[6] *See* Larry W. Loos direct testimony at 35:15-17.

allocate fixed production (and other) costs.[7] KCPL's principal fix for these problems is to promote consistent cost allocation methods among jurisdictions. KCPL's approach for this jurisdictional allocation issue is also relevant in determining the reasonableness of cost allocation methods used in class cost studies. In general, consistency in jurisdictional and class production cost allocation methods is desirable to ensure a direct linkage between customer demands that determine how fixed production costs are allocated to the Missouri retail jurisdiction and customer demands that are then used to allocate jurisdictional costs to Missouri rate classes. KCPL's 4CP and BIP allocation methods do not provide this consistency because they reflect fundamentally different concepts about cost drivers and cost responsibility. As I noted earlier, the 4CP Method emphasizes system coincident peak demands as the key factor driving KCPL's need for production capacity, while the BIP Method emphasizes relative use of KCPL's production facilities. As a result, these methods cannot and do not provide a direct linkage between allocated jurisdictional fixed production costs and retail class cost assignments.

Q. DO YOU SUPPORT KCPL'S BIP METHOD FOR ALLOCATING FIXED PRODUCTION COSTS IN ITS CLASS COSS?

A. No. The BIP Method is described in detail in KCPL's filing.[8] This allocation method received some national attention in the late 1970s and early 1980s following enactment of the Public Utility Regulatory Policies Act of 1978 (PURPA). However, the BIP method was subsequently overshadowed by probability of dispatch (POD) methods that facilitated the analysis of time-differentiated embedded (accounting) costs. Both the BIP and the POD allocation methods have fallen out of favor with cost analysts and regulators. In my opinion, the lack of enthusiasm for these

[7] *Ibid*. at 14:15-22.
[8] *See* Paul M. Normand direct testimony at 8-11.

cost allocation methods is due largely to their intensive data requirements and suspect data manipulations required to develop allocation factors.

Q. DOES THE BIP METHOD PROVIDE A DIRECT LINKAGE BETWEEN FIXED PRODUCTION COSTS AND OBSERVABLE FACTORS DRIVING THESE COSTS?

A. No. In general, the BIP method requires multiple mathematical manipulations of demand and energy measures necessary to develop class allocation factors for plant and equipments costs that have been assigned to Base, Intermediate, and Peaking categories. That is, BIP allocators provide no direct linkage between a utility's fixed production costs and observable measures (demand and energy) of production plant use by rate classes.

Q. ARE THERE MORE SERIOUS PROBLEMS WITH THE BIP METHOD?

A. Yes. In my opinion, the BIP Method's most serious problem is its allocation of baseload capacity costs on the basis of class energy use (minimum average demand).[9] This approach implicitly assumes that baseload plants have little or no capacity value, and are built solely to provide energy on a year-round basis. As a result, higher load factor classes are assigned a disproportionate share of these costs relative to lower load factor classes. I agree that baseload plants are planned and designed to operate during most hours of the year, and higher load factor customers use energy from such plants during many of those hours. However, this fact does not automatically lead to the conclusion that baseload capacity must be allocated on an energy basis. System peak demands drive the need for production capacity—and customer

[9] Average demand is simply total kWh used in a period divided by the number of hours in the period. KCPL uses factor DEM1A to allocate Base capacity costs in its BIP cost study.

contributions to system peaks should be the principle component of factors used to allocate fixed production costs.

Whether higher load factor customers benefit disproportionately from cheaper baseload and intermediate plant energy is an empirical question that KCPL 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 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.

Q. IS THE RELATIVE USE OF PARTICULAR TYPES OF PRODUCTION CAPACITY A GOOD INDICATOR OF CLASS COST RESPONSIBILITY FOR THAT CAPACITY?

A. No. Yet the BIP Method rests on this assumption. Production capacity is built (or acquired) to meet system peak demands—not average demands. Once capacity is built to meet system peaks, its fixed (sunk) costs do not change because of the intensity of its use. How we allocate those costs should be linked to peak demands that the capacity was built to serve.

Q. DOES KCPL'S BIP METHOD PROPERLY ALIGN ALLOCATED BASELOAD CAPACITY AND FUEL COSTS?

A. No. Recall the BIP Method's general premise—utilities trade off higher baseload capacity costs (relative to peaking capacity costs) in exchange for fuel cost savings. The logical consequence of this trade-off is that high load factor customers that are allocated a disproportionate share of baseload capacity costs should get a disproportionate share of the fuel-cost savings from the baseload capacity. This would require matching baseload fuel costs assigned to a class with a class' relative use of baseload capacity. However, in its BIP Method, KCPL did not separately identify fuel costs by capacity type. Instead, KCPL allocated average monthly fuel costs on the basis of class energy (kWh) use—ignoring any matching of fuel costs and customer energy use by capacity type. This average cost approach to fuel cost allocation in KCPL's BIP Method ensures that higher load factor classes pay a larger share of expensive baseload plant costs without getting the full, corresponding benefit of lower baseload fuel costs.

Q. DOES THIS MISMATCH OF ALLOCATED CAPACITY AND FUEL COSTS DISTORT RESULTS IN KCPL'S CLASS COST STUDY?

A. Yes. KCPL's mismatch of BIP-allocated capacity and fuel costs also means that a low load factor class with predominately peak usage receives the benefit of lower baseload fuel costs without being allocated a corresponding share of baseload plant costs. As a result, cost of service for lower load factor classes is understated in KCPL's BIP cost study, and overstated for higher load factor classes.

Q. HOW DID KCPL ALLOCATE OFF-SYSTEM SALES MARGINS?

A. In the jurisdictional study, KCPL allocated margins "in the same manner as the fixed costs of the generating units [predominately coal-fired units] used to generate the energy sold off-system."[10] In the class cost study, KCPL allocated off-system sales margins using the same modified 12CP allocator (factor DEM1B in KCPL's BIP cost study) that it used to allocate fixed production costs classified as Intermediate.

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[10] *See* Larry W. Loos direct testimony at 53:8-9.

Q. DO YOU AGREE WITH KCPL'S PROPOSED MARGIN ALLOCATIONS?

A. No. This Commission has generally found that off-system sales margins should be allocated on the basis of energy. For example, in Case No. ER-2006-0314, the Commission rejected KCPL's proposed allocation of off-system sales and related margins (specifically, sales and margins related to the energy component of firm transactions and all nonfirm sales) using a demand-based allocation factor (unused energy). In its final order in the case, the Commission said:

> Staff recommends that the Commission continue to use the energy allocator for revenues from non-firm off-system sales of energy, including the margin component thereof. ***This is the time-tested and widely accepted method for allocating such revenues in this state*** because it is appropriate for allocating revenues and associated costs that are purely variable with the amount of energy sold.[11] (Emphasis added.)
>
> The only costs assigned to non-firm off-system sales is the fuel and purchased power costs – the variable costs – hence the appropriateness of using the energy allocator. This is consistent with the way KCPL itself allocates the costs relating to the energy portion of firm capacity contracts – using the energy allocator. The reason is simple – the energy allocator is used to allocate variable costs of fuel and purchased power costs relating to retail sales. Using the same rationale, the energy allocator is equally appropriate to use as the allocation factor for both energy of firm (as KCPL does) and non-firm off-system sales. The demand based unused energy allocator should not be

[11] Case No. ER-2006-0314, *Report and Order* (December 21, 2006) at 38.

> used to allocate off-system sales – either energy from firm capacity sales contracts or non-firm off-system sales. Because plant is not dedicated to support non-firm off-system sales, there is no associated demand charge.[12]

KCPL ignored this precedent in its jurisdictional and class cost studies. However, even KCPL is not convinced that an energy allocation approach is wrong. For example, regarding the Commission's prior decision to allocate off-system sales margins on the basis of energy, KCPL witness Loos says:

> I believe that the ***Commission decision may be reasonable*** based on my understanding of the evidence presented for the Commission's consideration. On the other hand, the collective result in Missouri and Kansas is that the allocation of off-system sales margins does not align with the responsibility for power supply fixed costs and the methods relied on represent approaches that allocate the highest margin (least net overall cost) to each jurisdiction [Missouri and Kansas].[13] (Emphasis added.)

I understand KCPL's concern about how the different allocation methods used in Kansas and Missouri can adversely affect its ability to recover costs. However, two points are important regarding witness Loos' statement:

- The Commission's prior decision to allocate off-system margins was reasonable.
- KCPL's decision to reject allocating margins on energy is premised on the assumption that its capacity-based allocation method is superior to an energy allocation approach. In my

[12] *Ibid*. at 39-40.

opinion, this assumption is ill-founded and cannot withstand scrutiny. The Commission reached a similar conclusion in Case No. ER-2006-0314.

Q. SHOULD THE COMMISSION CONTINUE REQUIRING KCPL TO ALLOCATE OFF-SYSTEM SALES MARGINS ON THE BASIS OF ENERGY?

A. Yes. The Commission got it right when it previously required an energy allocation of off-system sales margins. KCPL's arguments for a capacity-based allocation method are not sufficient to justify overturning Commission precedent and allocating off-system margins using anything other than an energy allocator.

Q. HAVE YOU IDENTIFIED HOW ADDRESSING THE TWO MAJOR PROBLEM AREAS YOU DESCRIBE AFFECT CLASS COST RESPONSIBILITY?

A. Yes. I ran KCPL's class cost-of-service model using the 4CP Method instead of KCPL's BIP Method to allocate fixed production costs. I also used an energy allocator to assign revenues and margins from off-system sales (that is, the energy component of firm transactions, plus all nonfirm to transactions) to Missouri rate classes. Summary results from my cost analysis are presented in Schedule DWG-1, and shown in Table 1 below.[14]

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[13] Larry W. Loos direct testimony at 38:17-22.

[14] Additional details of the DOE 4CP class COSS are shown in Schedule DWG-2. Results shown in Table 1 and Schedules DWG-1 and DWG-2 reflect KCPL's proposed revenue increase.

Table 1. KCPL BIP Method vs DOE 4CP Method: Sales Revenue Increases Required at Equal Rates of Return

Rate Class	KCPL BIP	DOE 4CP
Residential	15.31%	30.52%
Small Gen Serv	-13.43%	-16.08%
Med Gen Serv	9.37%	6.44%
Large Gen Serv	13.05%	3.41%
Large Pwr Serv	26.47%	13.72%
Lighting	3.04%	-37.41%
MO Retail	13.86%	13.86%

Source: Schedule DWG-1.

As shown in Table 1, correcting two major problems in KCPL's class COSS produces dramatically different results regarding revenue increases necessary to recover each rate class' cost responsibility. These dramatic differences highlight the importance of relying on widely accepted and tested costing approaches such as the allocation of fixed production costs on a 4CP basis and off-system sales margins on an energy basis.

REVENUE SPREAD

Q. HOW DID KCPL PROPOSE SPREADING ITS REQUESTED REVENUE INCREASE ACROSS RATE CLASSES?

A. KCPL proposed an across-the-board revenue spread.[15] That is, KCPL proposed that each class receive an increase equal to the system average increase.

Q. DO RESULTS FROM KCPL'S BIP CLASS COSS INDICATE THAT IT EARNS THE SAME RATE OF RETURN FROM EACH CLASS?

A. No. As shown in Table 1, results from KCPL's BIP cost study indicate that rate increases necessary for KCPL to earn its proposed system average rate of return from each rate class would be well-above average for the Large Power Service (LPS) class, well-below-average for the Small General Service (SGS) and Lighting classes, and about average for the remaining classes.

Q. WHY DID KCPL CHOOSE NOT TO BRING RATES MORE IN LINE WITH RESULTS FROM ITS BIP COSS?

A. According the KCPL,[16] moving class rates closer to cost of service as measured by results from its BIP class COSS would have required significant interclass revenue shifts, and complicated the design of its retail rates.

Q. ARE SIGNIFICANT SHIFTS IN CLASS REVENUE REQUIREMENTS ALSO INDICATED BY RESULTS FROM DOE'S 4CP CLASS COSS?

A. Yes. However, unlike KCPL's BIP cost study, the DOE 4CP cost study shows that only a system average increase is necessary for the LPS class, but a well-above average increase is necessary to move the Residential class closer to cost of service. (See Table 1.) Moreover, my cost study shows that a much smaller-than-average increase is necessary for the Large General Service Class compared to results from KCPL's BIP study. In general, results for the DOE 4CP cost study demonstrate why relying on KCPL's cost analyses to address revenue spread and rate design issues is problematic. My analysis of KCPL's costs supports rejecting KCPL's proposed BIP Method and capacity-based allocation of off-system sales and replacing them with the costing approaches I have recommended. I urge the Commission to do so in this case.

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[15] *See* the direct testimony of KCPL witness Tim M. Rush at 8:21-23.
[16] *Ibid.* at 7:15-8:3.

Q. WHY ARE YOU SUPPORTING AN ACROSS-THE-BOARD REVENUE SPREAD EVEN THOUGH YOUR COST STUDY SHOWS THAT MAJOR INTERCLASS REVENUE SHIFTS ARE NECESSARY TO MOVE CLASSES CLOSER TO COST OF SERVICE?

A. Results from the DOE 4CP cost study show that significant revenue shifts to lower load factor classes are required to move rates closer to cost of service. However, I support an across-the-board revenue spread in this case. In particular, an across-the-board spread is appropriate simply because current economic conditions do not justify a dramatic above-average increase for any class. Moreover, the Commission has not yet decided how key cost items (in particular fixed production costs) should be allocated among rate classes. The Commission's decisions on various allocation issues will have a significant impact on the types and forms of rates necessary to track costs assigned to each class. As a result, an across-the-board revenue spread is both reasonable and prudent at this time.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

AFFIDAVIT

Commonwealth of Virginia)
County of Fairfax) SS

Before me this day appeared DENNIS W. GOINS of Potomac Management Group, who stated under oath that the foregoing testimony was prepared by him or under his direct supervision and control; that he has knowledge of the matters set forth in said testimony; and that such matters are true and correct to the best of his knowledge, information, and belief.

Subscribed and sworn to me this 23th day of November 2010.

Dennis W. Goins

Notary Public

REYNA MARIBEL VANEGAS
Notary Public
Commonwealth of Virginia
320413
My Commission Expires Jan 31, 2014

My Commission Expires: ____________________

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2010-0355

IN THE MATTER OF THE APPLICATION OF KANSAS CITY POWER & LIGHT COMPANY FOR APPROVAL TO MAKE CERTAIN CHANGES IN ITS CHARGES FOR ELECTRIC SERVICE TO CONTINUE THE IMPLEMENTATION OF THE REGULATORY PLAN

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

November 24, 2010

SCHEDULE DWG-1

DOE'S 4CP CLASS COSS VS KCPL'S BIP COST STUDY

Missouri Class Cost-of-Service Study
KCPL Proposed BIP Method vs DOE Recommended 4CP Method
Revenue Requirements at Class Equalized Rates of Return

	Description	Missouri Retail	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Total Lighting
1	Current Revenue[1]							
2	Operating Revenue							
3	Retail Sales Revenue	668,323,387	247,439,033	46,531,284	89,839,660	154,950,292	121,279,587	8,283,530
4	Other Operating Revenue	69,914,288	30,741,491	3,073,106	7,987,721	15,323,297	12,702,614	86,059
5	Total Operating Revenue	738,237,675	278,180,524	49,604,390	97,827,381	170,273,589	133,982,201	8,369,589
6	KCPL BIP Cost Study[2]							
7	Operating Revenue							
8	Retail Sales Revenue	760,949,897	285,316,746	40,283,397	98,260,530	175,173,184	153,380,782	8,535,258
9	Other Operating Revenue	69,914,288	30,741,491	3,073,106	7,987,721	15,323,297	12,702,614	86,059
10	Total Operating Revenue	830,864,185	316,058,237	43,356,503	106,248,251	190,496,481	166,083,396	8,621,317
11	Change in Sales Revenue	92,626,510	37,877,713	(6,247,887)	8,420,870	20,222,892	32,101,195	251,728
12	Percent Change							
13	Sales Revenue	13.86%	15.31%	-13.43%	9.37%	13.05%	26.47%	3.04%
14	Total Revenue	12.55%	13.62%	-12.60%	8.61%	11.88%	23.96%	3.01%
15	DOE 4CP Cost Study[3]							
16	Operating Revenue							
17	Retail Sales Revenue	760,949,897	322,949,682	39,046,861	95,626,451	160,228,152	137,914,126	5,184,625
18	Other Operating Revenue	69,914,288	22,956,335	3,388,855	8,877,456	17,704,274	16,370,066	617,301
19	Total Operating Revenue	830,864,185	345,906,017	42,435,716	104,503,907	177,932,426	154,284,192	5,801,926
20	Change in Sales Revenue	92,626,510	75,510,649	(7,484,423)	5,786,791	5,277,860	16,634,539	(3,098,905)
21	Percent Change							
22	Sales Revenue	13.86%	30.52%	-16.08%	6.44%	3.41%	13.72%	-37.41%
23	Total Revenue	12.55%	27.14%	-15.09%	5.92%	3.10%	12.42%	-37.03%

(1) Current revenue from KCPL's class cost-of-service study, Schedule PNM-2, Schedule 1, page 1, rows 40, 50, and 60. See Schedule DWG-2, p. 1.

(2) Revenue at equalized rates of return using KCPL's proposed class cost-of-service study, ignoring KCPL's proposed across-the-board revenue spread, as shown in Schedule PNM-2, Schedule 1, page 29, rows 1020, 1030, and 1040. See Schedule DWG-2, p. 3.

(3) DOE 4CP Study (1) replaces BIP allocators with 4 CP allocators, and (2) allocates off-system sales margins using an energy allocator. See Schedule DWG-3, p. 3.

SCHEDULE DWG-2

DETAILS FROM DOE'S 4CP CLASS COSS

KANSAS CITY POWER & LIGHT COMPANY
MISSOURI CUSTOMERS
CLASS COST OF SERVICE - DOE 4CP Method
DEC2009 TEST YEAR INCL KNOWN & MEAS TO 12/31/2010

LINE NO.	DESCRIPTION	ALLOCATION BASIS	MISSOURI RETAIL COL. 601	RESIDENTIAL COL. 602	SMALL GEN. SERVICE COL. 603	MEDIUM GEN. SERVICE COL. 604	LARGE GEN. SERVICE COL. 605	LARGE PWR SERVICE COL. 606	TOTAL LIGHTING
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(h)
0010	**SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE**								
0020									
0030	OPERATING REVENUE								
0040	RETAIL SALES REVENUE		668,323,387	247,439,033	46,531,284	89,839,660	154,950,292	121,279,587	8,283,530
0050	OTHER OPERATING REVENUE	TSFR	69,914,288	22,956,335	3,388,855	8,877,456	17,704,274	16,370,066	617,301
0060	TOTAL OPERATING REVENUE		738,237,675	270,395,368	49,920,139	98,717,116	172,654,566	137,649,654	8,900,831
0070									
0080	OPERATING EXPENSES								
0090	FUEL	TSFR	167,502,786	50,556,184	8,111,308	21,339,136	43,951,544	41,876,028	1,668,585
0100	PURCHASED POWER	TSFR	17,930,093	5,610,776	860,240	2,268,559	4,666,459	4,358,952	165,106
0110	OTHER OPERATION & MAINTENANCE EXPENSES	TSFR	247,431,627	109,805,296	13,755,128	29,966,629	49,098,828	42,338,771	2,466,976
0120	DEPRECIATION EXPENSES (AFTER CLEARINGS)	TSFR	92,323,818	41,369,380	4,630,111	11,942,016	18,626,752	15,237,132	518,427
0130	AMORTIZATION EXPENSES	TSFR	10,089,113	5,498,850	624,137	959,252	1,594,481	1,379,026	33,367
0140	INTEREST ON CUSTOMER DEPOSITS	CUST21	227,566	9,561	173,419	36,224	7,194	676	491
0150	TAXES OTHER THAN INCOME TAXES	TSFR	43,366,539	19,039,585	2,216,064	5,486,392	8,943,914	7,431,384	249,201
0160	FEDERAL AND STATE INCOME TAXES	TSFR	23,596,471	(1,281,703)	5,724,257	5,503,273	9,494,618	2,799,051	1,356,975
0170	TOTAL ELECTRIC OPERATING EXPENSES		602,468,012	230,607,928	36,094,665	77,501,482	136,383,792	115,421,018	6,459,128
0180									
0190	NET ELECTRIC OPERATING INCOME		135,769,663	39,787,440	13,825,474	21,215,634	36,270,774	22,228,636	2,441,704
0200									
0210	RATE BASE								
0220	TOTAL ELECTRIC PLANT	TSFR	4,016,606,546	1,792,958,102	204,178,747	511,972,138	819,523,672	667,896,352	20,077,536
0230	LESS: ACCUM. PROV. FOR DEPREC	TSFR	1,517,382,643	677,746,197	78,282,310	189,903,927	308,313,281	251,136,741	12,000,188
0240	NET PLANT		2,499,223,903	1,115,211,905	125,896,437	322,068,211	511,210,391	416,759,611	8,077,347
0250	PLUS:								
0260	WORKING CAPITAL	TSFR	88,558,503	29,507,678	4,136,340	11,123,403	22,097,160	20,958,098	735,824
0270	PRIOR NET PREPAID PENSION ASSET	SALWAGES	0	0	0	0	0	0	0
0280	PENSION REGULATORY ASSET	SALWAGES	8,257,718	3,335,049	460,343	1,007,407	1,765,031	1,584,192	105,695
0290	REG ASSET - DSM PROGRAMS	DEM1B	29,779,838	12,513,820	1,321,429	3,690,772	6,510,328	5,743,255	235
0300	REG ASSET - ERPP PROGRAMS	TOTPLANT	289,914	129,414	14,737	36,954	59,152	48,208	1,449
0310	REG ASSET - IATAN 1 & COMMMON PLANT	DEM1A	13,290,035	5,584,621	589,722	1,647,104	2,905,405	2,563,079	105
0320	LESS:								
0330	ACCUM. DEFERRED TAXES	TSFR	330,262,211	148,852,517	16,425,461	42,420,007	67,117,897	54,163,064	1,283,265
0340	DEFERRED GAIN ON SO2 EMISSION CR.	ENERGY1	49,523,837	14,957,813	2,399,326	6,302,921	13,036,321	12,331,994	495,462
0350	DEFERRED GAIN ON SO2 ALLOWANCE	ENERGY1	(963,168)	(290,908)	(46,663)	(122,583)	(253,538)	(239,840)	(9,636)
0360	CUST. ADVANCES FOR CONSTRUCTION	DISTPLANT	184,485	95,859	12,381	26,207	30,042	16,735	3,262
0370	CUSTOMER DEPOSITS	CUST21	5,354,483	224,965	4,080,455	852,323	169,276	15,900	11,563
0380	REGULATORY PLAN ADDITIONAL AMORT	CLAIMEDREV	132,221,058	56,115,059	6,784,701	16,615,852	27,840,908	23,963,669	900,870
0390	TOTAL RATE BASE		2,122,817,005	946,327,181	102,763,348	273,479,124	436,606,560	357,404,921	6,235,870
0400									
0410	RATE OF RETURN		6.396%	4.204%	13.454%	7.758%	8.307%	6.219%	39.156%
0420	RELATIVE RATE OF RETURN		1.00	0.66	2.10	1.21	1.30	0.97	6.12

KANSAS CITY POWER & LIGHT COMPANY
MISSOURI CUSTOMERS
CLASS COST OF SERVICE - DOE 4CP Method
DEC2009 TEST YEAR INCL KNOWN & MEAS TO 12/31/2010

LINE NO.	DESCRIPTION	ALLOCATION BASIS	MISSOURI RETAIL COL. 601	RESIDENTIAL COL. 602	SMALL GEN. SERVICE COL. 603	MEDIUM GEN. SERVICE COL. 604	LARGE GEN. SERVICE COL. 605	LARGE PWR SERVICE COL. 606	TOTAL LIGHTING
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(h)
0510	**SCHEDULE 1 - SUMMARY AT EQUALIZED CLAIMED RATE OF RETURN**								
0520	RATE BASE								
0530	TOTAL ELECTRIC PLANT	TSFR	4,016,606,546	1,792,958,102	204,178,747	511,972,138	819,523,672	667,896,352	20,077,536
0540	LESS: ACCUM. PROV. FOR DEPREC	TSFR	1,517,382,643	677,746,197	78,282,310	189,903,927	308,313,281	251,136,741	12,000,188
0550	NET PLANT		2,499,223,903	1,115,211,905	125,896,437	322,068,211	511,210,391	416,759,611	8,077,347
0560	ADD: WORKING CAPITAL	TSFR	88,558,503	29,507,678	4,136,340	11,123,403	22,097,160	20,958,098	735,824
0570	PROFORMA CWC	TSFR	0	0	0	0	0	0	0
0580	PRIOR NET PREPAID PENSION ASSET	TSFR	0	0	0	0	0	0	0
0590	PENSION REGULATORY ASSET	TSFR	8,257,718	3,335,049	460,343	1,007,407	1,765,031	1,584,192	105,695
0600	REG ASSET - DSM PROGRAMS	TSFR	29,779,838	12,513,820	1,321,429	3,690,772	6,510,328	5,743,255	235
0610	REG ASSET - ERPP PROGRAMS	TSFR	289,914	129,414	14,737	36,954	59,152	48,208	1,449
0620	REG ASSET - IATAN 1 & COMMMON PLANT	TSFR	13,290,035	5,584,621	589,722	1,647,104	2,905,405	2,563,079	105
0630	LESS:								
0640	ACCUM. DEFERRED TAXES	TSFR	330,262,211	148,852,517	16,425,461	42,420,007	67,117,897	54,163,064	1,283,265
0650	DEFERRED GAIN ON EMISSION CR.	TSFR	49,523,837	14,957,813	2,399,326	6,302,921	13,036,321	12,331,994	495,462
0660	DEFERRED GAIN ON SO2 ALLOWANCE	TSFR	(963,168)	(290,908)	(46,663)	(122,583)	(253,538)	(239,840)	(9,636)
0670	CUST. ADVANCES FOR CONSTRUCTION	TSFR	184,485	95,859	12,381	26,207	30,042	16,735	3,262
0680	CUSTOMER DEPOSITS	TSFR	5,354,483	224,965	4,080,455	852,323	169,276	15,900	11,563
0690	REGULATORY PLAN ADDITIONAL AMORT	TSFR	132,221,058	56,115,059	6,784,701	16,615,852	27,840,908	23,963,669	900,870
0700	TOTAL RATE BASE		2,122,817,005	946,327,181	102,763,348	273,479,124	436,606,560	357,404,921	6,235,870
0710	OPERATING INCOME @ 9.04% ROR		191,902,657	85,547,977	9,289,807	24,722,513	39,469,233	32,309,405	563,723
0720									
0730	OPERATING EXPENSES								
0740	FUEL	TSFR	167,502,786	50,556,184	8,111,308	21,339,136	43,951,544	41,876,028	1,668,585
0750	PURCHASED POWER	TSFR	17,930,093	5,610,776	860,240	2,268,559	4,666,459	4,358,952	165,106
0760	OTHER OPERATION & MAINTENANCE EXPENSES	TSFR	247,431,627	109,805,296	13,755,128	29,966,629	49,098,828	42,338,771	2,466,976
0770	PLUS: CHANGE IN BAD DEBT		541,132	441,140	(43,725)	33,807	30,834	97,180	(18,104)
0780	DEPRECIATION EXPENSES	TSFR	92,323,818	41,369,380	4,630,111	11,942,016	18,626,752	15,237,132	518,427
0790	AMORTIZATION EXPENSES	TSFR	10,089,113	5,498,850	624,137	959,252	1,594,481	1,379,026	33,367
0800	INTEREST ON CUSTOMER DEPOSITS	TSFR	227,566	9,561	173,419	36,224	7,194	676	491
0810	TAXES OTHER THAN INCOME TAXES	TSFR	43,366,539	19,039,585	2,216,064	5,486,392	8,943,914	7,431,384	249,201
0820	PLUS: CHANGE IN TAXES OTHER THAN INCOME TAXES		602,072	490,819	(48,649)	37,614	34,306	108,124	(20,143)
0830	FEDERAL AND STATE INCOME TAXES	TSFR	23,596,471	(1,281,703)	5,724,257	5,503,273	9,494,618	2,799,051	1,356,975
0840	PLUS: CHANGE IN FEDERAL AND STATE INCOME TAXES		35,350,311	28,818,153	(2,856,382)	2,208,491	2,014,261	6,348,464	(1,182,677)
0850	TOTAL ELECTRIC OPERATING EXPENSES		638,961,528	260,358,040	33,145,910	79,781,394	138,463,192	121,974,787	5,238,203
0860									
0870	COST OF SERVICE		830,864,185	345,906,017	42,435,717	104,503,907	177,932,426	154,284,192	5,801,926
0880	LESS: PRESENT OTHER REVENUE		69,914,288	22,956,335	3,388,855	8,877,456	17,704,274	16,370,066	617,301
0890	SALES REVENUE		760,949,897	322,949,682	39,046,861	95,626,451	160,228,152	137,914,126	5,184,625
0900									
0910	TOTAL REVENUE ADJUSTMENT		92,626,510	75,510,649	(7,484,422)	5,786,791	5,277,860	16,634,538	(3,098,905)
0920	PERCENT CHANGE		12.55%	27.93%	-14.99%	5.86%	3.06%	12.08%	-34.82%

KANSAS CITY POWER & LIGHT COMPANY
MISSOURI CUSTOMERS
CLASS COST OF SERVICE - DOE 4CP Method
DEC2009 TEST YEAR INCL KNOWN & MEAS TO 12/31/2010

LINE NO.	DESCRIPTION	ALLOCATION BASIS	MISSOURI RETAIL COL. 601	RESIDENTIAL COL. 602	SMALL GEN. SERVICE COL. 603	MEDIUM GEN. SERVICE COL. 604	LARGE GEN. SERVICE COL. 605	LARGE PWR SERVICE COL. 606	TOTAL LIGHTING
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(h)
1010	**SCHEDULE 1 - SUMMARY AT PROPOSED RATES**								
1020	PROPOSED SALES REVENUE		760,949,897	322,949,682	39,046,861	95,626,451	160,228,152	137,914,126	5,184,625
1030	PLUS: OTHER REVENUE		69,914,288	22,956,335	3,388,855	8,877,456	17,704,274	16,370,066	617,301
1040	TOTAL OPERATING REVENUE		830,864,185	345,906,017	42,435,717	104,503,907	177,932,426	154,284,192	5,801,926
1050									
1060	OPERATING EXPENSES								
1070	FUEL	TSFR	167,502,786	50,556,184	8,111,308	21,339,136	43,951,544	41,876,028	1,668,585
1080	PURCHASED POWER	TSFR	17,930,093	5,610,776	860,240	2,268,559	4,666,459	4,358,952	165,106
1090	OTHER OPERATION & MAINTENANCE EXPENSES	TSFR	247,431,627	109,805,296	13,755,128	29,966,629	49,098,828	42,338,771	2,466,976
1100	PLUS: CHANGE IN BAD DEBT		541,132	441,140	(43,725)	33,807	30,834	97,180	(18,104)
1110	DEPRECIATION EXPENSES	TSFR	92,323,818	41,369,380	4,630,111	11,942,016	18,626,752	15,237,132	518,427
1120	AMORTIZATION EXPENSES	TSFR	10,089,113	5,498,850	624,137	959,252	1,594,481	1,379,026	33,367
1130	INTEREST ON CUSTOMER DEPOSITS	TSFR	227,566	9,561	173,419	36,224	7,194	676	491
1140	TAXES OTHER THAN INCOME TAXES	TSFR	43,366,539	19,039,585	2,216,064	5,486,392	8,943,914	7,431,384	249,201
1150	PLUS: CHANGE IN TAXES OTHER THAN INCOME TAXES		602,072	490,819	(48,649)	37,614	34,306	108,124	(20,143)
1160	FEDERAL AND STATE INCOME TAXES	TSFR	23,596,471	(1,281,703)	5,724,257	5,503,273	9,494,618	2,799,051	1,356,975
1170	PLUS: CHANGE IN FEDERAL AND STATE INCOME TAXES		35,350,311	28,818,153	(2,856,382)	2,208,491	2,014,261	6,348,464	(1,182,677)
1180	TOTAL ELECTRIC OPERATING EXPENSES		638,961,528	260,358,040	33,145,910	79,781,394	138,463,192	121,974,787	5,238,203
1190									
1200	RATE BASE								
1210	TOTAL ELECTRIC PLANT	TSFR	4,016,606,546	1,792,958,102	204,178,747	511,972,138	819,523,672	667,896,352	20,077,536
1220	LESS: ACCUM. PROV. FOR DEPREC	TSFR	1,517,382,643	677,746,197	78,282,310	189,903,927	308,313,281	251,136,741	12,000,188
1230	NET PLANT		2,499,223,903	1,115,211,905	125,896,437	322,068,211	511,210,391	416,759,611	8,077,347
1240	ADD: WORKING CAPITAL	TSFR	88,558,503	29,507,678	4,136,340	11,123,403	22,097,160	20,958,098	735,824
1250	PRIOR NET PREPAID PENSION ASSET	TSFR	0	0	0	0	0	0	0
1260	PENSION REGULATORY ASSET	TSFR	8,257,718	3,335,049	460,343	1,007,407	1,765,031	1,584,192	105,695
1270	REG ASSET - DSM PROGRAMS	TSFR	29,779,838	12,513,820	1,321,429	3,690,772	6,510,328	5,743,255	235
1280	REG ASSET - HOMELAND SECURITY	TSFR	289,914	129,414	14,737	36,954	59,152	48,208	1,449
1290	REG ASSET - REGULATORY EXPENSE	TSFR	13,290,035	5,584,621	589,722	1,647,104	2,905,405	2,563,079	105
1300	LESS:								
1310	ACCUM. DEFERRED TAXES	TSFR	330,262,211	148,852,517	16,425,461	42,420,007	67,117,897	54,163,064	1,283,265
1320	DEFERRED GAIN ON EMISSION CR.	TSFR	49,523,837	14,957,813	2,399,326	6,302,921	13,036,321	12,331,994	495,462
1330	DEFERRED GAIN ON EMISSION CR.	TSFR	(963,168)	(290,908)	(46,663)	(122,583)	(253,538)	(239,840)	(9,636)
1340	CUST. ADVANCES FOR CONSTRUCTION	TSFR	184,485	95,859	12,381	26,207	30,042	16,735	3,262
1350	CUSTOMER DEPOSITS	TSFR	5,354,483	224,965	4,080,455	852,323	169,276	15,900	11,563
1360	CUSTOMER DEPOSITS	TSFR	132,221,058	56,115,059	6,784,701	16,615,852	27,840,908	23,963,669	900,870
1370	TOTAL RATE BASE		2,122,817,005	946,327,181	102,763,348	273,479,124	436,606,560	357,404,921	6,235,870
1380									
1390	OPERATING INCOME		191,902,657	85,547,977	9,289,807	24,722,513	39,469,233	32,309,405	563,723
1400									
1410	RATE OF RETURN		9.040%	9.040%	9.040%	9.040%	9.040%	9.040%	9.040%
1420	RELATIVE RATE OF RETURN		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000

APPENDIX

QUALIFICATIONS OF

DENNIS W. GOINS

DENNIS W. GOINS

PRESENT POSITION

Economic Consultant, Potomac Management Group, Alexandria, Virginia.

AREAS OF QUALIFICATION

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

PREVIOUS POSITIONS

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

EDUCATION

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

RELEVANT EXPERIENCE

Dr. Goins specializes in pricing, planning, and market structure issues affecting firms that buy and sell products in electricity and natural gas markets. He has extensive experience in evaluating competitive market conditions, analyzing power and fuel requirements, prices, market operations, and transactions, developing product pricing strategies, setting rates for energy-related products and services, and negotiating power supply and natural gas contracts for private and public entities. He has participated in more than 100 cases as an expert on competitive market issues, utility restructuring, power market planning and operations, utility mergers, rate design, cost of service, and management prudence before the Federal Energy Regulatory Commission, the 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. Kansas City Power & Light Company, before the Missouri Public Service Commission, Case No. ER-2010-0355 (2010), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re cost-of-service and rate design issues.
2. Appalachian Power Company and Wheeling Power Company, dba American Electric Power, before the Public Service Commission of West Virginia, Case No. 10-0699-E-42T (2010), on behalf of Steel of West Virginia, Inc., re cost-of-service and rate design issues.
3. Entergy Arkansas, Inc., before the Arkansas Public Service Commission, Docket No. 10-010-U (2010), on behalf of Arkansas Electric Energy Consumers, Inc., re industrial opt out of utility-sponsored energy efficiency programs.
4. Indiana Michigan Power Company, before the Indiana Utility Regulatory Commission, Cause No. 38702 – FAC 62-S1 (2010), on behalf of Steel Dynamics, Inc., re fuel and purchased power cost recovery.
5. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 459 (2010), on behalf of Nucor Steel-Hertford, re cost of service and retail rate design.
6. Entergy Texas, Inc., before the Public Utilities Commission of Texas, PUC Docket No. 37744 (2010), on behalf of Texas Cities, re cost of service and retail rate design.
7. Kentucky Utilities, Inc., before the Kentucky Public Service Commission, Case No. 2009-00548 (2010), on behalf of the Kentucky Industrial Utility Customers, re interruptible rates.
8. Louisville Gas and Electric Company, Inc., before the Kentucky Public Service Commission, Case No. 2009-00549 (2010), on behalf of the Kentucky Industrial Utility Customers, re interruptible rates.

9. Ohio Edison *et al*., before the Public Utilities Commission of Ohio, Case No. 09-1948-EL-POR *et al*., (2010), on behalf of Nucor Steel Marion, Inc., re energy efficiency and peak demand reduction portfolios.
10. Kauai Island Utility Cooperative, before the Hawaii Public Utilities Commission, Docket No. 2009-0050 (2010), on behalf of Kauai Marriott Resort & Beach Club, re retail cost allocation and rate design issues.
11. Entergy Arkansas, Inc., before the Arkansas Public Service Commission, Docket No. 09-024-U (2009), on behalf of Arkansas Electric Energy Consumers, Inc., re power plant environmental retrofit.
12. Appalachian Power Company, before the Virginia State Corporation Commission, Case No. PUE-2009-00030 (2009), on behalf of Steel Dynamics, Inc., re retail cost allocation and rate design issues.
13. Ohio Edison *et al*., before the Public Utilities Commission of Ohio, Case No. 09-906-EL-SSO (2009), on behalf of Nucor Steel Marion, Inc., re market rate offer.
14. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 456 (2009), on behalf of Nucor Steel-Hertford, re fuel cost adjustment.
15. Appalachian Power Company, before the Virginia State Corporation Commission, Case No. PUE-2009-00068 (2009), on behalf of Steel Dynamics, Inc., re demand response programs.
16. Indiana Michigan Power Company, before the Indiana Utility Regulatory Commission, Cause No. 43750 (2009), on behalf of Steel Dynamics, Inc., re wind power purchased power agreement.
17. Entergy Arkansas, Inc., before the Arkansas Public Service Commission, Docket No. 07-085-TF (2009), on behalf of Arkansas Electric Energy Consumers, Inc., re energy efficiency cost recovery.
18. CenterPoint Energy Arkansas Gas, before the Arkansas Public Service Commission, Docket No. 07-081-TF (2009), on behalf of Arkansas Gas Consumers, Inc., re energy efficiency cost recovery.
19. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2009-261-E (2009), on behalf of CMC Steel-SC, re DSM cost recovery surcharge.
20. Duke Energy Indiana, Inc., before the Indiana Utility Regulatory Commission, Cause No. 38707 FAC81 (2009), on behalf of Steel Dynamics, Inc., re fuel and purchased power cost recovery.

21. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1076 (2009), on behalf of the General Services Administration, re retail cost allocation and standby rate design issues for distributed generation resources.
22. Appalachian Power Company, before the Virginia State Corporation Commission, Case No. PUE-2009-00039 (2009), on behalf of Steel Dynamics, Inc., re environmental and reliability cost recovery.
23. Indiana Michigan Power Company, before the Indiana Utility Regulatory Commission, Cause No. 38702 – FAC 63 (2009), on behalf of Steel Dynamics, Inc., re fuel and purchased power cost recovery.
24. Appalachian Power Company, before the Virginia State Corporation Commission, Case No. PUE-2009-302-00038 (2009), on behalf of Steel Dynamics, Inc., re fuel and purchased power cost recovery.
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