BEFORE THE
STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Joint Application of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes to their Charges for Electric Service	**)))))**	**Docket No. 18-WSEE-328-RTS**

CROSS-ANSWERING TESTIMONY

OF

LARRY BLANK

ON BEHALF OF

THE UNITED STATES DEPARTMENT OF DEFENSE
AND ALL OTHER FEDERAL EXECUTIVE AGENCIES

June 22, 2018

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EXHIBIT LIST

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Larry Blank and my business address is 6061 Montgomery Road, Midlothian, TX 76065. My email address is LB@tahoeconomics.com.

Q. DID YOU ALSO PROVIDE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, my direct testimony in this docket was filed on June 11, 2018.

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

A. I am providing independent expert witness testimony on behalf of the U.S. Department of Defense and all other Federal Executive Agencies ("DoD/FEA").

II. PURPOSE OF TESTIMONY AND SUMMARY OF RECOMMENDATIONS

Q. WHAT IS THE PURPOSE OF YOUR CROSS-ANSWERING TESTIMONY?

A. I respond to recommendations for rate class revenue allocation provided by the Utilities Division of the Kansas Corporation Commission ("Staff"). Specifically, my testimony reviews the Class Cost of Service ("CCOS") study results sponsored by Staff witness Dorothy J. Myrick and the "Step 1" and "Step 2" allocation of revenue requirement recommendations provided by Staff witness Robert H. Glass.[1]

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS ON THESE ISSUES IN RESPONSE TO STAFF.

A. First, Staff's recommendations for revenue requirement allocation to the rate classes would move customers further from cost of service and result in rates that are not just

[1] Dr. Glass refers to the two phases of revenue change described by Westar witness Larry Wilkus as "Step 1" and "Step 2."

and reasonable. I provide an alternative to Staff's approach in which I use a 1.25 relative rate of return for those customers being asked to contribute more than their fair share toward cost recovery. My recommendation is to deny Staff's approach using outdated revenue ratios based on rates set in the past, and instead utilize a more objective approach that recognizes updated cost of service results produced in this record. Second, the Staff CCOS study; specifically, the allocation of production (generation) capacity costs, is inconsistent with the widely accepted use of the average and excess demand methodology, as filed by Westar. I recommend denial of Staff's recommended hybrid peak and average methodology.

III. <u>ALLOCATION OF REVENUE CHANGE BETWEEN RATE CLASSES</u>

Q. WHAT IS STAFF'S RECOMMENDATION FOR ALLOCATING THE STEP 1 CHANGE IN REVENUE?

A. As reflected in Table 2 of Dr. Glass' direct testimony (page 20), Staff would have the Commission allocate the Step 1 revenue change based on revenue ratios derived from the "Old Rates." This should be rejected because it ignores all the updated cost of service evidence provided in this case. These "Old Rates" were set based on past cost information and conditions.

Q. DID STAFF PREPARE A CCOS STUDY?

A. Yes. Ms. Myrick states that "KCC-CCOS serves as a guide for the rate design analyst to distribute the revenue *decrease* among the classes and within the classes."[2] Dr. Glass states: "The class rates of return, which are found by dividing net operating revenue

[2] Myrick Direct at p. 4, lines 12-13.

by the rate base, are the important information generated by the CCOS for class revenue allocation."[3] However, Dr. Glass does not use the CCOS whatsoever for this purpose.

Q. ARE YOU SAYING THAT STAFF DID NOT USE ITS OWN CCOS STUDY AS A GUIDE FOR DISTRIBUTING THE REVENUE DECREASE?

A. Yes. Rather than relying on the data or indices developed in the CCOS study, Dr. Glass recommends an approach that diminishes reliance on cost of service and effectively causes movement away from CCOS. As he explains:

> For step one, I allocated to each class an equal percentage of the revenue decrease based on existing revenue generated by each class. For step two, I again allocated an equal percentage increase based on class revenue generated. However, for step two, I only allocated to classes with relative rates of return less than one.[4]

Therefore, Staff emphasizes the importance of CCOS as a guide in revenue allocation, but in practice, does not rely on the results. My cross-answering testimony demonstrates the appropriate way to use the CCOS study results as a determining factor in revenue allocation.

Q. HAVE YOU DEVELOPED AN ALTERNATIVE REVENUE ALLOCATION APPROACH BASED ON CCOS IN RESPONSE TO STAFF'S APPROACH?

A. Yes. For the Step 1 reduction in rates, I develop allocation ratios based on the differences between current return dollars and target return dollars, utilizing Staff's recommended CCOS rate base allocation;[5] Staff's CCOS calculation of current rates

[3] Glass Direct at p. 21, lines 1-3.
[4] Ibid., p. 24, lines 6-9.
[5] Myrick Direct at p. 25, Table 1.

of return;[6] Staff's recommended rate of return, 7.06%;[7] and Staff's recommended reduction for Step 1, $58,279,120.[8] The development of my recommended allocation ratios and DoD/FEA's recommended rate class allocation of Staff's Step 1 reduction of $58,279,120 are found in attached Exhibit LB-CA-1. The results are summarized in the following table.

	DOD/FEA Allocation of Step 1 Reduction	**Staff Allocation of Step 1 Reduction[a]**
Residential	($10,071,060)	(25,554,100)
Residential DG	(5,160)	(7,240)
Small General Service	(4,742,313)	(12,117,451)
Medium General Service	(3,454,615)	(6,847,849)
Large General Service	(23,043,710)	(11,019,522)
I&LP/LTM/ICS	(12,304,373)	(Combined w/LGS)
Public Schools & Churches	(4,307,059)	(1,641,490)
Lighting Service	(350,831)	(1,091,468)
System Totals:	**($58,279,120)**	**(58,279,120)**
[a] From Glass Direct Testimony, p. 20, Table 2, Column 2 as corrected on June 19, 2018.		

Q. ARE YOU ADOPTING STAFF'S REVENUE REQUIREMENT AND CCOS IN YOUR RECOMMENDATION?

A. No. My recommended approach can be applied to any revenue requirement reduction and CCOS study results that may be ordered by the Commission.

Q. IS YOUR ALLOCATION METHOD A PURELY COST-BASED APPROACH?

A. No, but it provides movement toward cost of service, rather than movement away from cost of service as would occur with Staff's recommendation.

[6] Ibid., p. 27, Table 2.
[7] Gatewood Direct at p. 9, lines 3-4.
[8] Glass Direct at p. 20, Table 2.

Q. HOW DID YOU LIMIT THE MOVEMENT TO A PURELY COST-BASED ALLOCATION OF THE REVENUE REDUCTION?

A. As a starting point, I use the Staff CCOS-based relative rates of return ("RORs") in Table 2 of Ms. Myrick's testimony. These provide a measure of how much a rate class is paying above or below the overall ROR at current prices and CCOS study results. A value of 1.0 indicates that the rate class is currently paying cost of service. For those rate classes with current relative RORs that exceed 1.25, I set the target return on rate base down to 1.25. For example, given Staff's recommended overall ROR of 7.06%, any class with a relative ROR of 1.25 would be set at 7.06% times 1.25, or 8.82%, times Staff's allocated rate base to that rate class. Therefore, my adjusted target return on rate base exceeds cost-based levels for those classes, but not excessively. For the remaining rate classes, I retain the current relative ROR as computed by Staff in my computation of target return. For example, I maintain the current Residential rate class relative ROR of 0.78 times 7.06%, or 5.49% times the residential allocated rate base; therefore, my adjusted target return on rate base for Residential and other rate classes remains below cost of service. I then compute the differences between the current dollar return on rate base and my adjusted target return on rate base for each rate class. These differences are the foundation for the allocation ratios applied to the Step 1 revenue reduction.

Q. DOES YOUR METHODOLOGY IN RESPONSE TO STAFF DIFFER FROM YOUR RECOMMENDATION IN YOUR DIRECT TESTIMONY?

A. Yes, it alters my direct testimony recommendation for the Step 1 revenue decrease in favor of those rate classes with current relative RORs below 1.0. In my direct testimony on page 13, I stated:

> For the September 2018 rate changes, those rate classes with current rates of return below the Company's approved rate of return should not receive a decrease, and that additional revenue should be used to further reduce the rates of those classes with the highest cost-based rates of return, most notably Lighting and LGS. For the February 2019 rate changes, no class should receive a rate increase that causes their implied cost-based rate of return to exceed 1.25 times the Company's approved, cost-based rate of return.

Q. WHAT HAS CHANGED SINCE YOU READ STAFF'S TESTIMONY?

A. Given the magnitude of the Step 1, September 2018 revenue reduction recommended by Staff, I agree that all rate classes should receive some amount of revenue reduction in Step 1. With such a large decrease, this is an opportunity to ensure movement toward cost of service, while at the same time granting a decrease to all customers. However, I disagree with Staff's approach, which is not linked to the CCOS study results at all.

Q. DOES THIS ALTER YOUR DIRECT TESTIMONY RECOMMENDATION FOR THE STEP 2, FEBRUARY 2019 INCREASE?

A. No. For the February 2019 rate changes, no class should receive a rate increase that causes their implied cost-based ROR to exceed 1.25 times the Company's approved, cost-based rate of return.

Q. WHAT IS YOUR RECOMMENDATION FOR THE COMMISSION ON ALLOCATION OF THE REVENUE DECREASE?

A. I recommend that the Commission deny Staff's proposal on the basis that it is founded on outdated revenue ratios based on past cost conditions in the last rate case, it will move rate classes away from the cost of service results in this case, and results in rates that are not just and reasonable. I ask the Commission to adopt my revenue decrease allocation methodology, which is explicitly founded on current CCOS conditions and provides gradual movement toward cost of service.

Q. DOES YOUR USE OF THE STAFF CCOS STUDY RESULTS AS A STARTING POINT IN YOUR METHODOLOGY CONVEY ACCEPTANCE OF THEIR CCOS STUDY?

No. The Staff CCOS study contains the same flaws I found in the Westar CCOS study and were enumerated in my direct testimony. Furthermore, Staff has adopted an average and peak methodology for production costs and eliminated the customer classification of distribution costs, both of which I disagree.

IV. STAFF'S CLASS COST OF SERVICE STUDY

Q. HAVE YOU REVIEWED STAFF'S TESTIMONY DESCRIBING THE METHODS EMPLOYED IN THEIR CCOS STUDY?

A. Yes, this is contained in the direct testimony of Dorothy J. Myrick.

Q. DO YOU AGREE WITH THE CHANGES MADE BY STAFF RELATIVE TO THE WESTAR CCOS STUDY?

A. No. Staff has adopted a version of the peak and average methodology for production capacity costs and eliminated the customer classification of distribution costs, both of which I disagree. Ms. Myrick describes Staff's production allocation methodology on page 10 of her direct testimony as 'hybrid peak and average'. For the purposes of this testimony, I will use the term peak and average, or "P&A." The P&A method is described in the NARUC Electric Utility Cost Allocation Manual, which I will reference more, later in this testimony. See attached Exhibit LB-CA-3.[9]

[9] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January, 1992, p. 57.

Q. WHAT ARE THE PROBLEMS INHERENT IN THE USE OF A PEAK AND AVERAGE METHODOLOGY FOR PRODUCTION COSTS?

A. The P&A methodology is flawed and does not align with common industry practice, and I recommend that the Commission embrace the methodology used by Westar—the average and excess methodology.

Q. YOU MENTIONED THAT THE P&A METHOD DOES NOT ALIGN WITH STANDARD INDUSTRY PRACTICE. WHAT EVIDENCE SUPPORTS THAT STATEMENT?

A. In a prior case in Arkansas, I commissioned a survey of 20 states west of the Mississippi River, plus the State of Mississippi, on production allocation methods performed by the Garrett Group under my direction.[10] The report on this survey is attached as Exhibit LB-CA-2, originally marked as Exhibit HHEG-LB-5 in my Arkansas testimony. Of the 21 states surveyed, only 4.5 states used some variant of a P&A methodology in the past, including Kansas. Two of these 4.5, Utah and Wyoming, do not use system load factor to determine the energy/demand split. Instead, these two states define costs as only 25% energy-related and 75% demand-related. PacifiCorp in Idaho also uses a 25/75 split for energy-related and demand-related costs, respectively. Arizona companies are divided on methodology, hence the 0.5, in that the Arizona Public Service Co. consistently uses the Average and Excess methodology, while Tucson Electric and UNS Electric use the P&A method. Due to legislation in Arkansas since the time of this survey, most electric utilities in Arkansas now file using an Average & Excess methodology because of preference stated in statute; however, the Arkansas Public Service Commission may deviate from Average & Excess for economic reasons.

[10] Nebraska has no investor-owned electric utilities, and Montana Power divested itself of all generation over ten years ago.

Of the remaining 16 states, 10.5 states use either an Average and Excess methodology or a coincident peak (hereinafter "CP") demand method, such as 12-CP (the 0.5 accounts for the APS territory in Arizona). The majority of these jurisdictions use the Average and Excess method. California, Nevada, and Oregon traditionally use a marginal cost approach. The remaining three states (North Dakota, Minnesota, and Missouri) use some form of a stratification method or a base-intermediate-peak method.

Q. DO YOU HAVE TECHNICAL CONCERNS ABOUT THE USE OF THE P&A METHOD?

A. Yes, and I am particularly troubled by the way in which Staff applies this method in which the system load factor is used to determine the "energy-related" portion of capacity-related costs. This method of determining the energy allocation portion contradicts the NARUC Cost Allocation Manual (see the footnote on p. 57 of the Manual),[11] places excessive weight on the energy allocation ratios, and effectively double-counts energy (or average demand) because the average demand level is also embedded in the CP allocation ratios. See Exhibit LB-CA-3 for page 57 of the Manual.

Q. HOW DOES THE NARUC COST ALLOCATION MANUAL DESCRIBE THE P&A METHOD?

A. On page 57 of the NARUC Manual, one can find the allocator most similar to that used by Staff; the Manual terms this method the "peak and average demand" allocator. As the note at the bottom of this page explains, the energy-related portion of production plant is the percentage calculated as average system demand divided by the sum of system peak demand and average system demand. This would result in a much smaller

[11] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January, 1992.

portion classified as average demand or energy relative to the Staff's use of system load factor.[12] As I mentioned earlier, Utah, Wyoming, and PacifiCorp in Idaho also use an energy and peak allocator, but treat only 25% of the capacity costs as "energy-related." Therefore, not only does the P&A method double-count the average demand, but the variant used by Staff allocates a much greater portion based on the energy allocator than that suggested by the NARUC Manual and used in these other states.

Q. EXPLAIN THE SIMILARITIES BETWEEN THE P&A AND THE AVERAGE & EXCESS METHODS FOR ALLOCATING DEMAND-RELATED PRODUCTION COSTS.

A. Each method is essentially a weighted average of two different allocation methods: (1) the average demand allocation method (which looks at each rate class's average demand as a percentage of the system average demand); and (2) some other allocation method. Both the P&A method and the Average & Excess demand method are examples of "energy weighting methods" as described on page 49 of the NARUC Manual. Again, the fact that a part of each of these two allocators incorporates each class's portion of system average demand is an implicit acknowledgement that average load drives a major portion of the demand-related costs owed to base-load resources.

Q. HOW DOES THE A&P DEMAND ALLOCATION METHOD COMPARE TO THE AVERAGE & EXCESS DEMAND ALLOCATION METHOD?

A. In my opinion, the argument for using the average and excess demand allocation method is more compelling. The driving force behind the amount of base-load resources required on a system is average load (or perhaps something in between minimum and average load). The amount of non-base-load resources such as intermediate and peaker generation units (e.g., combined cycle and combustion

[12] See p. 10 of Myrick Direct.

turbines) is given by the difference between peak load and average load (i.e., excess demand).[13] Therefore, the weighted average already accounts for the average load, and excess demand (not total peak load) actually drives the need for incremental intermediate and peak-load resource capacity. Because total peak load itself has an average load component (peak demand = average demand + excess demand), using a weighted average between average demand and peak demand actually double-counts the effects of the average load on the capacity needs of the system.

In general, double-counting the role of average demand will favor relatively low load factor customer classes and penalize high load factor rate classes. One might call this ironic because the high load factor customers bring greater efficiency to the system in terms of lower overall generation costs, but they are allocated a greater portion of capacity costs without any offsetting benefits related to lower fuel costs since those costs are bundled and allocated uniformly across customer classes based on kWh usage.

Q. WHAT IS YOUR RECOMMENDATION REGARDING STAFF'S USE OF THEIR HYBRID PEAK AND AVERAGE METHOD?

A. I recommend that the Commission order the use of Westar's Average & Excess methodology instead.

Q. DOES THIS CONCLUDE YOUR CROSS-ANSWERING TESTIMONY?

A. Yes, it does at this time.

[13] This does not include regulation and contingency reserves.

AFFIDAVIT OF LARRY BLANK

VERIFICATION

STATE OF MARYLAND)
COUNTY OF HOWARD) **ss:**

Larry Blank, of lawful age, being first duly sworn, on his oath states:

1. My name is Larry Blank. I am a Principal of TAHOEconomics, LLC, having its principal place of business at 6061 Montgomery Road, Midlothian, TX 76065. I have been retained by the U.S. Department of Defense and all other Federal Executive Agencies in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my cross-answering testimony which was prepared in written form for introduction into evidence in the Kansas State Corporation Commission Docket No. 18-WSEE-328-RTS.

3. I have read the above direct testimony; I know the contents thereof, and declare that the statements made therein are true and correct to the best of my knowledge, information and belief.

Larry Blank
LARRY BLANK

SUBSCRIBED AND SWORN to before me this 20 day of June 2018.

Deborah M Adams
Notary Public

DEBORAH M ADAMS
Notary Public
State of Maryland
Howard County

EXHIBITS FOR

CROSS ANSWERING TESTIMONY OF

LARRY BLANK

DOD/FEA Proposed Step 1 Reduction

CA Testimony L. Blank, Exhibit LB-CA-1

	Staff COSS Rate Base	Current ROR	Relative ROR	Current Return Dollars	Target Return Dollars at Staff's 7.06%	Adjusted Relative ROR	Adjusted Target Return	Difference Adjusted Target Return and Current Return	Allocation Ratios based on Difference	**DOD/FEA Allocation of Step 1 Reduction**	Staff Allocation of Step 1 Reduction (Glass Direct, Table 2, with 6-19-18 corrections)
Residential	$2,017,264,078	6.06%	0.78	$ 122,252,217	$ 142,358,326	0.78	$ 110,743,447	$ (11,508,770)	17.28%	$ (10,071,060)	$ (25,554,100)
Residential DG	$673,905	9.27%	1.19	$ 62,489	$ 47,557	1.19	$ 56,593	$ (5,896)	0.01%	$ (5,160)	$ (7,240)
Small General Service	$991,483,379	5.79%	0.74	$ 57,424,496	$ 69,968,982	0.74	$ 52,005,187	$ (5,419,309)	8.14%	$ (4,742,313)	$ (12,117,451)
Medium General Service	$615,492,400	6.78%	0.87	$ 41,751,549	$ 43,435,299	0.87	$ 37,803,764	$ (3,947,785)	5.93%	$ (3,454,615)	$ (6,847,849)
Large General Service	$1,052,812,234	11.32%	1.45	$ 119,204,550	$ 74,296,959	1.25	$ 92,871,199	$ (26,333,351)	39.54%	$ (23,043,710)	$ (11,019,522)
I&LP/LTM/ICS	$357,478,942	12.75%	1.64	$ 45,595,014	$ 25,227,289	1.25	$ 31,534,111	$ (14,060,903)	21.11%	$ (12,304,373)	(Combined w/LGS)
Public Schoools & Churches	$235,464,084	10.91%	1.40	$ 25,692,796	$ 16,616,700	1.25	$ 20,770,876	$ (4,921,920)	7.39%	$ (4,307,059)	$ (1,641,490)
Lighting Service	$72,644,025	5.84%	0.75	$ 4,244,136	$ 5,126,489	0.75	$ 3,843,221	$ (400,915)	0.60%	$ (350,831)	$ (1,091,468)
System Totals	$5,343,313,047	7.79%	1.00	$ 416,227,247	$ 377,077,602	100.0%	$ 349,628,399	$ (66,598,848)	100.00%	$ (58,279,120)	$ (58,279,120)

UAMS
UNIVERSITY OF ARKANSAS FOR MEDICAL SCIENCES

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Kristi Rhude
Secretary of the Commission
Arkansas Public Service Commission
1000 Center Street
Little Rock, AR 72201

Re: 13-028-U

Dear Secretary Rhude,

Please find attached for filing in Docket No. 13-028-U an errata page 7 and updated exhibit HHEG-LB-5 to the prefiled Direct Testimony of Larry Blank which was filed on August 2, 2013 by HHEG. This filing is to correct an error discovered on page 7 in footnote 3 in the prefiled testimony of Larry Blank and to provide an updated version of Exhibit HHEG-LB-5 Production Cost Allocation Survey 2013 results by State, to reflect the response received from the State of Washington Commission Staff.

Please let me know if you have any questions.

Sincerely,

/s/ Elizabeth Smith
Elizabeth Thomas Smith

Enclosures

Exhibit

HHEG-LB-5

Production Cost Allocation Survey 2013 by State

Updated on 8/8/2013 to Reflect Response
from Washington Commission Staff

Production Cost Allocation Survey 2013
Results By State

Updated 8/8/13
to reflect State of Washington Commission Staff

Alaska: (Regulatory Commission, Tyler Clark, Finance Manager, 907-276-6222) Alaska has not responded at this time. Alaska Administrative Code requires both the average and excess and peak responsibility (CP) be filed by the electric utility:

> §3 AAC 48.540(e) – Cost-of-Service Methods states that in a cost-of-service study required by this section, demand capacity costs will be considered as follows:
> (1) Each electric utility that sells 100,000,000 kilowatt-hours or more annually shall provide cost-of-service analyses that show the impact of (A) allocating demand-related generation and transmission costs to rate classes on the basis of both the peak responsibility method and the average and excess method; and (B) allocating demand-related distribution costs on the basis of the non-coincident peak method.

Arizona: (Corporation Commission, Barbara Keene, Public Utilities Analyst Manager, 602-542-0853) Arizona does not require the use of a particular allocation method by statute or rule. In practice, Arizona utilities use two methods; Arizona Public Service Company (APS) uses the Average and Excess method while UNS Electric Inc. (UNS) and Tucson Electric Power (TEP) use an Average and Peak method with 4-CP based on the 4 summer peaks of June through September. The results of these studies are not stringently followed. The cost of service studies are used as a tool. For example, settlements can result in a generally even, "across the board" percentage increase in rates. The cost of service studies can be used as a starting point for these settlements. In addition, the Commission considers gradualism and other factors in addition to the results of the cost of service studies when setting rates. This issue is no longer very contentious, but current practice resulted from earlier litigated cases which were highly contested by advocates for the residential and industrial classes who argued for 100% energy and 100% demand methods respectively. The current treatments are demonstrated in APS rate cases E-01345A-11-0224 and E-01345A-08-0172 and in the immediate UNS Electric Inc. rate case, Docket No. E-04204A-12-0504.

California: (CPUC, Christopher Danforth, Supervisor DRA – Rate Design, 415-703-1481) In California, electricity generation production costs are allocated to customer classes using marginal cost principles. The energy costs have been allocated using marginal costs that either come from production cost simulation models or market indexes. The generation capacity costs generally are based on a combustion turbine proxy plant. Those costs are often adjusted to reflect the resource balance year, when new capacity would be required, and the costs savings from the new combustion turbine displacing older and less efficient plants. These costs are allocated to time periods using loss-of-load probabilities. Once marginal costs are calculated, they are scaled up or down to reconcile them against the authorized revenue requirement.

Colorado: (PUC, Karl Kunzie, Financial Analyst: Economics Section, 303-894-2882) There is no required method in Colorado; the utility may propose any method it choose. However, the Commission's well established practice is to follow its previous orders. In a recent example, Public Service Company of Colorado (an Xcel Energy company) used a 4-CP Average and Excess method to allocate production costs (see Docket: 09AL-299E, Order: C10-0286).

Hawaii: (PUC, Richard VanDrunen, Engineer, 808-586-2043) Hawaii uses various allocation methods and considers the issue on a case by case basis. However, Hawaii's large utility, Hawaiian Electric Company HECO, has used an Average-Excess Demand Method (AED Method) since 2007 (Docket No. 2006-0386). Cases here tend to result in settlements that divide the dollar amount of any rate increase according to the current percentages paid by the classes. However, in the same 2006 case, the Commission accepted a modification to the classification of non-fuel production O&M expenses from 100% demand-related to partly energy-related. The resulting classification is 60.3% demand and 39.7% energy for these expenses.

Idaho: (PUC, Terri Carlock, Utility Division Deputy Administrator, Accounting Section Supervisor, 208-334-0356) Idaho does not have one standard allocation requirement and evaluates the issue case by case. Methods for each of its three major utilities have been set by multiple orders and settlements. PacifiCorp's allocator uses 75% capacity and 25% energy (see PAC-E-10-09). Idaho Power's longstanding use of a Weighted 12CP allocation method based on load factors produces an energy component between 55% and 60%. Avista uses a Peak Credit method to the classes which considers combined cycle turbine production as demand and all above that as energy. This method results in an energy component of about 70%, and is demonstrated in their most recent 2012 rate case: AVU-E-12-08. Avista may propose changing the allocation method in their next rate case in 2015.

Iowa: (Iowa Utilities Board, Barb Oswalt, Senior Utility Analyst, 515-725-7342) The administrative rules related to electric cost of service and rate design are set out in 199 IAC 20.10. Although, the rules do not prescribe a specific allocation method, the Board has determined that the average and excess (A&E) method complies with the rule. Iowa has two investor-owned rate-regulated electric utilities—Interstate Power and Light Company (Interstate) and MidAmerican Energy Company (MidAmerican). In Interstate's most recent rate proceeding (RPU-2010-0001), the Board approved IPL's proposal to continue its use of the A&E methodology for allocating generation costs. IPL noted that it has used the A&E method since 1984. MidAmerican has had a voluntary electric rate revenue freeze in effect since 1997. On May 17, 2013, MidAmerican filed a rate increase request in Docket No. RPU-2012-0004 which includes four separate cost-of-service alternatives. Per the Direct Testimony of Charles B. Rea, the four alternatives allocate generation costs as follows: 1) two of the alternatives use the Hourly Costing Model, 2) one alternative uses A&E with wholesale margins allocated on excess demand, and 3) one alternative uses A&E with wholesale margins allocated on average demand. MidAmerican supports use of the Hourly Costing Model. This docket is pending.

Kansas: (Corporation Commission, Utilities Division, Bob Glass PhD, Chief of Economic Policy (785-271-3356) Kansas uses several allocators including a Peak and Average hybrid as well as 4-CP and 12-CP methods. Kansas production includes coal and nuclear and its consumers include those with significant use that is non-congruent with major demand peaks (e.g. summer irrigation). To fairly share the production cost burden among the classes the commission there uses the various allocators to add an energy component to the allocations. This treatment is not proscribed by statute or rule but is reflected in commission orders and settlements such as the recent Kansas City Power and Light rate case docket 12-KCPE-764-RTS. An open Generic Docket is being developed that will address this issue and others.

Louisiana: (PSC, Brian McManus, Economist, Division of Economics and Rates Analysis, 225-342-2720) Louisiana has not responded at this time. In a data response in the immediate Entergy Arkansas rate case: Docket No. 13-028-U, the company states that Louisiana PSC has adopted the 12-CP Production Demand Allocation Factor.

Minnesota: (PUC, Clark Kaml, Rate Analyst, 651-201-2246) Minnesota has not responded at this time. In its last rate case (Docket No. PUC E-002/GR-12-961) Excel Energy in Minnesota (Northern States Power Company) used a "stratification" method to divide Fixed Production Plant into capacity and energy components. The capacity component is allocated "based on customer demand at peak times."

Missouri: (PSC, Robert Schallenberg, Director, Audits, Accounting and Financial Analysis Department, 573-751-7162) MPSC does not endorse any particular allocation method. Cases in Missouri usually settle and settlement methodologies do not have any precedential value.

A recent Missouri PSC Staff report on their cost model related to Ameren Missouri Co. indicates that they used a Base-Intermediate-Peak ("BIP") methodology with the base component allocated by energy, the intermediate capacity allocated with 12-NCP, and the peaking capacity allocated with 3-NCP.

Montana: (PSC, Will Rosquist, Chief Rate Design and Economics Bureau, 406-444-6359) The Montana PSC does not require use of a specific allocation method. Allocation methods are addressed on a case by case basis. Often, cost allocation issues settle without reference to a particular allocation method.

Nebraska: (Public Service Commission, Laura Demman, Director and Legal Council, Natural Gas Department, NPSC, 402-471-3101) Nebraska has no investor-owned electric utilities; all electric demand is supplied by consumer-owned power districts, cooperatives, and municipalities.

Nevada: Generation production costs are allocated to customer classes using marginal cost principles. The generation capacity costs generally are based on a combustion turbine proxy plant. These costs are allocated to time periods using loss-of-load probabilities. Once marginal costs are calculated, they are scaled up or down to reconcile them against the authorized revenue requirement.

New Mexico: (Public Regulation Commission, Charles Gunter, Accounting Bureau Chief, Economist, 505-827-6977) New Mexico has no specific requirement for determining the allocation of production costs, and various methods have evolved and been proposed and accepted. The NMPRC regulates three investor owned electric utilities: Southwestern Public Service Company (SPS), Public Service Company of New Mexico (PNM) and El Paso Electric Company (EPE). SPS, in a pending rate case and in three rate cases filed since 2006, used the 12 CP method for allocating production costs between the New Mexico, Texas and FERC jurisdictions, and the 4 CP method (which includes the 4 peak summer months of June – September) for allocating demand costs among customer classes (see 10-00395-UT). Public Service Company of New Mexico (PNM) in past rate cases has used the 4 CP method, the 12 CP method, and a winter and summer peak method for allocating production demand costs. El Paso Electric Company (EPE) in its most recent rate case filed in 2009 used the 4 CP Average and Excess method, and discussed how that method was more representative of its system costs at that time than the 12 CP method it had used in previous cases.

North Dakota: (PSC, Mike Diller, Director of Accounting, 701-328-4079) The allocation method used in North Dakota varies from company to company. The various methods the companies use are well established and rarely challenged. In general, NDPSC staff does not focus on rate design and class allocations nor does it regularly file testimony on these issues in rate cases. Most cases end in settlement and the class cost of service studies are consulted to arrive at an allocation of any rate increase that slightly weights (increases) the percentage assigned to the residential class in order to gradually bring them to parity with the other classes. Prior to allocation, production costs are "stratified" into capacity and energy components. The cost of a gas turbine peaking plant is used as the lowest cost to meet peak demand. The percentage of the costs to build the state's other 5 types of generation that exceed the price of a peaking plant are considered "energy-related." These percentages are applied to the revenue requirement components of each generation type. The resulting "capacity-related" costs are allocated to the classes with a 4-CP, 12-CP or other method. In the case of Northern States Power these costs are allocated using a seasonal Average and Excess method. This treatment is described in the recent docket, PU-12-813 (see NSP Volume 1, Notice of Petition, Michael Peppin).

Oklahoma: OG&E uses a single coincident peak average and excess method (1-CP AED). They first calculate average demand by taking the total kWh sales divided by the number of hours in a year 8760 . The peak demand is the highest demand expected (OG&E uses a weather normalized peak not the actual peak). The peak demand minus the average demand is the excess portion. PSO uses a 4-CP method. They use the recorded or actual demand of the months of June, July, August and September to allocate production plant.

Oregon: (PUC, George Compton, 503-378-6123) Oregon has two major electric utilities and the allocation method is similar for both. Utilities are required by statute to start with marginal costs when allocating production costs. For Portland General Electric (PGE) marginal costs for demand are considered to be the capital cost of a simple cycle combined turbine peaking plant with a 13% reserve. This capital cost is then allocated to the classes by a 4CP (2 winter and 2 summer peaks) allocator. An energy component is calculated based on 8760 (hr/yr) marginal costs at the hub with some wind cost factored in. The shared sum of these demand and energy components is then used to allocate the imbedded cost of production to the classes. PacifiCorp has asked recently to incorporate a 12CP method as opposed to the 4CP method favored by staff. The issue was not clarified in the settlement. In that case an increase to the residential class was smaller than that to the commercial and industrial classes, but similar to the proportions indicated in the cost of service studies of the company and staff.

South Dakota: (PUC, Brittany Mehlhaff, Utility Analyst, 605-773-8372) Allocation method is not established by statute or rule and can vary by utility and case. Both Ottertail and Xcel have had settlements recently using the 12CP Method for both jurisdictional and class allocation of production cost. In the current Black Hills case, the company has asked to use a 12CP jurisdictional allocator and an Average and Excess method for the class allocations. Northern States, MidAmerican, Northwestern and other South Dakota utilities do not have recently litigated cases.

Texas: (PUC, William Abbott, Director Tariff and Rate Analysis, 512-936-7453) The Texas PUC does not require an allocation method by statute or rule. However, by general precedent the Average and Excess with 4-CP Demand Method is the norm for vertically integrated utilities in Texas. This treatment is demonstrated in the most recent Entergy Texas rate case: Docket No. 39896 in the Order on Rehearing.

Utah: (PSC, Jamie Dalton, Technical Consultant, 801-530-6707) Utah classifies fixed generation costs as 75% related to demand and 25% related to energy and then allocates to the classes using a 12-CP method. This treatment is consistent with prior decisions and supported by analysis which was accepted by the commission in the past. The order in the Rocky Mountain Power rate case docket 09-035-23 filed February 18th, 2010 discusses and accepts this treatment.

Washington: (Utilities and Transportation Commission, Roland Martin, Accounting Advisor, 360-664-1304): Generation and transmission related costs are allocated based on the relative customer class energy and capacity needs. The energy and capacity/demand factors are weighted (e.g. 75/25) based on peak credit methodology. The energy portion is based on each class annual energy as a percentage of total and the demand portion is based on each class contribution to the total peaks (e.g. 12 CP, 200 CP or other system peak measurements). The Commission regulates three electric utilities: Avista, Pacific Power and Light Company (PacifiCorp) and Puget Sound

Energy. The peak credit method is used with varying demand/energy weightings. PacifiCorp uses the same 75% demand and 25% energy weighting it uses elsewhere but is proposing to modify the allocation factor in the pending case UE-130043.

Wyoming: (PSC, Marci Norby, Senior Rate Analyst, 307-777-5720) Class allocation of production costs use a 12-CP method and are based on 75% Demand and 25% Energy. This is a well established practice based on Commission orders and approval.

4. Judgmental Energy Weightings

Some regulatory commissions, recognizing that energy loads are an important determinant of production plant costs, require the incorporation of judgmentally-established energy weighting into cost studies. One example is the "peak and average demand" allocator derived by adding together each class's contribution to the system peak demand (or to a specified group of system peak demands; e.g., the 12 monthly CPs) and its average demand. The allocator is effectively the average of the two numbers: class CP (however measured) and class average demand. Two variants of this allocation method are shown in Tables 4-14 and 4-15.

TABLE 4-14

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 1 CP AND AVERAGE DEMAND METHOD

Rate Class	Demand Allocation Factor - 1 CP MW (Percent)	Demand-Related Production Plant Revenue Requirement	Avg. Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	34.84	233,869,251	30.96	120,512,062	354,381,313
LSMP	37.25	250,020,306	33.87	131,822,415	381,842,722
LP	24.63	165,313,703	31.21	121,450,476	286,764,179
AG&P	3.29	22,078,048	3.22	12,545,108	34,623,156
SL	0.00	0	0.74	2,864,631	2,864,631
TOTAL	100.00	671,281,308	100.00	389,194,692	$1,060,476,000

Notes: The portion of the production plant classified as demand-related is calculated by dividing the annual system peak demand by the sum of (a) the annual system peak demand, Table 4-3, column 2, plus (b) the average system demand for the test year, Table 4-10A, column 3. Thus, the percentage classified as demand-related is equal to 13591/(13591+7880), or 63.30 percent. The percentage classified as energy-related is calculated similarly by dividing the average demand by the sum of the system peak demand and the average system demand. For the example, this percentage is 36.70 percent.

Some columns may not add to indicated totals due to rounding.