BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR AN ORDER OF THE COMMISSION	)	CAUSE NO. PUD 201100087
AUTHORIZING APPLICANT TO MODIFY ITS	)	
RATES, CHARGES, AND TARIFFS FOR RETAIL	)	
ELECTRIC SERVICE IN OKLAHOMA	)	

Direct Testimony

of

James B. Long

on behalf of

Oklahoma Gas and Electric Company

July 28, 2011

I. INTRODUCTION

Q. **Please state your name, business address and job responsibilities.**

A. My name is James B. Long. My business address is 2626 West Quincy Circle, Broken Arrow, Oklahoma 74012. I am President of B & B Consulting International, L.L.C. ("BBCI"). BBCI is an independent consulting firm providing pricing and costing analysis for utilities in both the regulated and competitive electric markets.

Q. **On whose behalf are you submitting this direct testimony?**

A. I am submitting this Direct Testimony on behalf of Oklahoma Gas and Electric Company ("OG&E" or the "Company").

Q. **Would you please summarize your education and professional background?**

A. I earned a BSEE from Auburn University and an MBA from Georgia State University. I have served as Chairman of the EPRI Innovative Pricing group and as Chairman of the EPRI Producing Successful Retail Products and Services group. I have been an active member of the Professional Pricing Society, the Association of Edison Illuminating Companies (AEIC) Load Research Committee, and the Edison Electric Institute's (EEI) Economic Regulation and Competition Committee. I have over 40 years experience in the electric utility business. Over thirty years of this experience has been in the pricing and costing areas, managing the activities for rate design, cost of service, and load research. The rate design activities included the design of fuel adjustment clauses, innovative pricing options as well as traditional tariffs. Since 2000, I have provided

pricing and costing consulting to North American regulated utility companies and retail companies seeking to compete in previously regulated electric markets.

My earlier experience has included managing the Rate Department at Public Service Company of Oklahoma ("PSO"), where I was responsible for directing the pricing, costing, and load research associated with regulatory activities and filings at both the state and federal level. I was also responsible for directing the pricing product development activities for Central and South West Corporation ("CSW") as it prepared to make the transition into the competitive electric market. In initiatives directly related to the transition to an open market, I have participated in the formulation and implementation of market transition plans for Texas, Oklahoma, Louisiana, and Arkansas. I have used my experience in pricing to focus on the areas of proper design of default service rates, Provider of Last Resort ("POLR") rates, and to address customer load profiling and metering issues. Other experience includes electric distribution system design and operation, industrial marketing, and rate design for Georgia Power Company. I have testified before a number of jurisdictions on costing, pricing, and policy issues.

Q. **Have you previously filed testimony before the Oklahoma Corporation Commission (the "Commission" or "OCC")?**

A. Yes. Exhibit JBL-1 is a list of my previous testimony filed before the OCC, the Federal Energy Regulatory Commission ("FERC"), and other state commissions.

Q. **What is the purpose of your testimony?**

A. The purpose of my testimony is to (i) provide an overview of how OG&E allocates transmission costs among its jurisdictions and Oklahoma retail customer classes, (ii) introduce a report produced by BCCI for OG&E that recommends changes to OG&E's transmission cost allocation methodology, and (iii) address the reasonableness of OG&E adopting a 4 Coincident Peak ("CP") customer class allocation method for transmission assets allocated to the Oklahoma retail jurisdiction. I have attached as Exhibit JBL-2, a copy of the Investigation into Retail Transmission Cost Allocation Report and Findings ("Report") recently prepared for OG&E investigating the feasibility of using a different class allocation methodology.

Q. **Did you prepare the Report?**

A. Yes. The Report is my work product and it contains a detailed explanation of the evaluation that I performed to arrive at my recommendations.

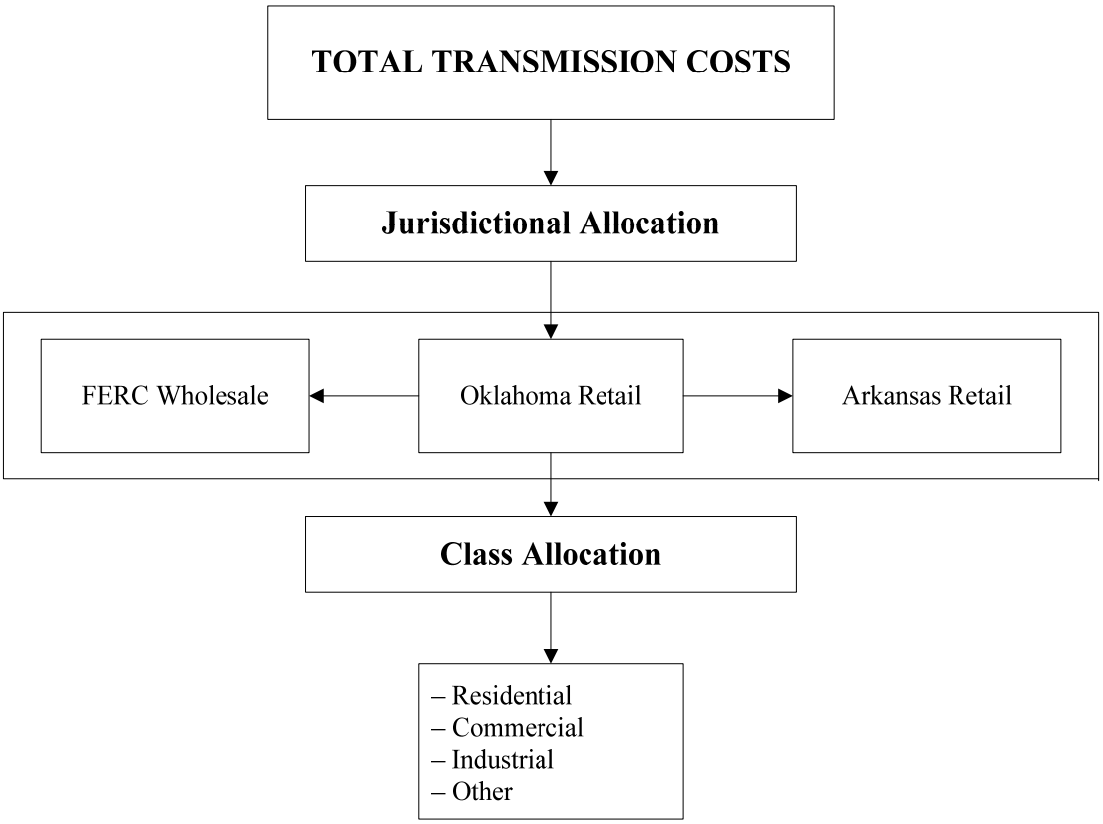
II. OVERVIEW OF TRANSMISSION ALLOCATION

Q. **Please provide an overview of how transmission costs are allocated.**

A. Transmission costs are allocated in two ways. First, such costs are allocated among OG&E's three jurisdictions: (1) FERC-regulated wholesale contracts; (2) the Arkansas retail jurisdiction; and (3) the Oklahoma retail jurisdiction. Second, once transmission costs are allocated to the various jurisdictions, those jurisdictional amounts are then allocated to the various retail customer classes in those respective jurisdictions. Therefore, the jurisdictional allocation divides the transmission costs between FERC,

Arkansas, and Oklahoma. The class allocation process then divides the jurisdictional amount between the classes. The class allocation does not change the costs to be recovered by the Oklahoma jurisdiction. My testimony addresses the jurisdictional allocation and the method to allocate to the retail customer classes served by OG&E in Oklahoma. Chart 1 is an illustration of the process.

Chart 1



Q. **What does it mean that transmission costs are allocated under a CP methodology?**

A. The CP methodology takes into consideration the contribution of each customer class' load at the time of the OG&E monthly peak. For example, a 12-CP allocator is developed by averaging the customer class load contribution to the annual 12 monthly peaks.

III. THE REPORT

Q. **Why did OG&E request BBCI to examine the method of allocating retail transmission costs?**

A. In OG&E's last base rate case, Cause PUD 200800398, the parties in that case executed a settlement agreement that was approved by the Commission (Order No. 569281). That settlement agreement contained an agreement that OG&E would evaluate and consider the use of a 4-CP Transmission Plant class allocation methodology. BBCI was thereafter requested to perform such an evaluation by OG&E.

Q. **After the evaluation, did you make a recommendation to OG&E?**

A. Yes.

Q. **What are your recommendations?**

A. I recommended that OG&E continue using the 12-CP jurisdictional allocation procedure of transmission assets and changing the existing 12-CP class allocation of transmission assets to a 4-CP class allocation methodology because I believe that the 4-CP class allocation methodology more appropriately reflects the seasonal nature of class loads on OG&E's system. These recommendations are based on cost causation and prevailing practices.

Q. **Did OG&E agree to take your recommendations?**

A. Yes. In fact, after completing my evaluations, OG&E, in a settlement approved by the Commission in Cause PUD 201000146 (Southwest Power Pool "SPP" Cost Tracker,

Order No. 583894) agreed to use a 4-CP Transmission Plant allocation in OG&E's next general rate case. Pursuant to that settlement agreement in Cause No. PUD 201000146, OG&E has used a 4-CP Transmission Plant allocation in the preparation of the present rate case.

Q. **What factors did your Report evaluate in making its recommendation for the class transmission allocation methodology?**

A. The key factor is the seasonable nature of OG&E's system load. Other factors that I considered include allocation methodologies employed by other jurisdictions and utilities and whether OG&E's transmission planning processes for addressing reliability issues on the system reflect patterns that can be linked to a particular allocation methodology.

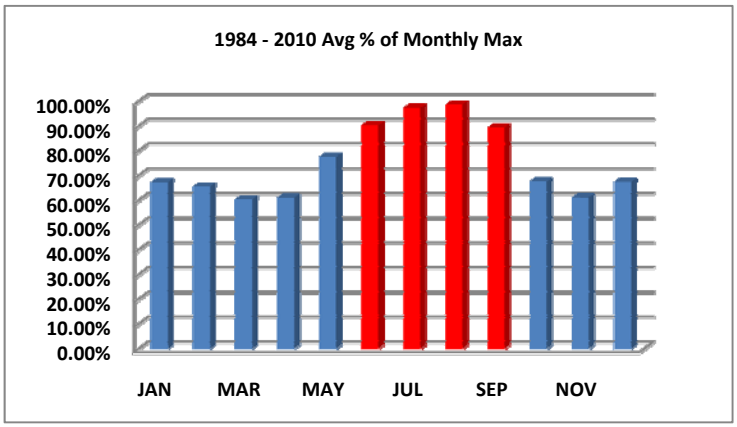
Q. **What did your review of the customer class contributions to the seasonal peak reveal?**

A. The examination of OG&E system load characteristics over the past 27 years shows that the peak loads on the OG&E system occur in the summer. Therefore, OG&E should examine the customer class contributions to the summer seasonal peak and utilize a transmission allocator that captures those customer class contributions to the summer peak season. OG&E's system has a significant seasonal difference and therefore, a demand allocation that relies on the class contribution to the seasonal peak should be considered.

Chart 2, shows that the four peak months are June – September; the other months are not likely to be classified as a peak season month in the foreseeable future. By examining

monthly peak load data for the Oklahoma jurisdiction over the time period 1984 through 2010, it is apparent that the peak season covers June through September.

Chart 2
Monthly System Peaks 1984 – 2010



OG&E's current practice of using a 12-CP class transmission allocator does not adequately capture the class contribution to the summer peak season: a 4-CP appears to be a more appropriate methodology. Since the OG&E transmission system serves two primary purposes: 1) to provide for the reliable delivery of power to the various load centers and 2) to deliver generation to customers to meet the system peak, BBCI believes that cost causation principles warrant a 4CP customer class allocator.

Finally, the report also found that utilities that used a class allocator methodology different from their jurisdictional allocator did so to reflect the seasonal nature of their system load. The adoption of an allocator that reflected the seasonal load is a normal industry practice.

Q. **Were any other factors instrumental in your recommendation for a 4CP customer class allocation methodology?**

A. No, but I did consider some other factors. I looked at both OG&E's other jurisdictions and the methods employed by other utilities and such review did not provide any clear guidance for the appropriate transmission allocation methodology.

Most utilities have traditionally used a 12-CP allocator for the jurisdictional assignment of transmission assets, while some utilities use 4CP or 5CP jurisdictional allocators.[1] With regard to customer class transmission allocators, there is no predominant method used by other utilities. As one can see from Table 2 of my Report, utilities employ a myriad of different customer class allocation methods.

I also considered whether OG&E's other jurisdictions provide any guidance as the appropriate method for allocating transmission costs among customer classes. For OG&E, there are three jurisdictions—FERC-regulated wholesale contracts, the Arkansas Public Service Commission (APSC) for Arkansas retail customers, and the OCC for Oklahoma retail customers. The FERC jurisdiction uses the 12-CP for the jurisdictional allocation of transmission plant. The APSC also requires the use of a 12-CP allocator for both jurisdictional and class allocation of transmission assets. In the past, due to these other jurisdictions' use of the 12 CP allocation method, OG&E elected to use a 12-CP jurisdictional allocator and a 12 CP customer class allocator in Oklahoma to be consistent with its other jurisdictions.

Q. **Did you consider any other factors in making your recommendations?**

A. Yes. I did consider whether OG&E's transmission planning processes for addressing reliability issues on the system reflect patterns that can be linked to a particular allocation methodology. However, based on my review, OG&E's transmission planning processes

[1] Cite to Report

identified reliability issues that were not limited to the peak season. The voltage excursions caused by unplanned forced outages can occur during low load months or periods of planned outages and maintenance of the transmission system and generation resources. These voltage excursions are not chronologically modeled and cannot be tied to the monthly peaks. These voltage excursions are caused by factors other than demand. These other factors are not customer, demand or energy related and are not measureable in a manner which can be associated with any customer class characteristics. Therefore, an allocation method based upon reliability issues cannot be easily developed; planning processes considering voltage excursions are not useful for developing transmission allocators at this time.

Q. **Did you examine any other customer class cost allocation methodologies other than a 4 or 12-CP?**

A. Yes, I investigated several types of cost allocation methodologies, including various Coincident Peak methods, peak and average methods, Non-Coincident Peak (NCP) methods, Average and Excess (A&E) methods, and OG&E's production allocation method. The report considered the 12 CP, 1-CP, 4-CP, and 5-CP methodologies. As explained above, the CP methodology takes into consideration the contribution of each class' load at the time of the OG&E monthly peak. The 1-CP bases the class allocation on the class contribution for the month in which OG&E's Oklahoma annual peak occurred. The 4-CP and 5-CP base the class allocation on the average class contribution for the peak hour in each of the four or five highest monthly loads.

The Non-Coincident Peak methodology is based on the maximum class demand regardless of when the OG&E system peak occurred.

The Average and Excess (A&E) methodology uses the average portion of the allocator (class annual energy sales divided by 8,760 hours) to reflect the amount of plant required to support the energy requirements of the various classes. The system excess portion, which is the difference between the system peak and the system average, is then assigned to the classes based on each class's portion of the summation of the class NCP demands less the class average demands. The other A&E approaches are variations of how the excess is determined and allocated. The 1-CP A&E methodology combines the A&E allocator with the class contribution to the system peak developing an allocator that places emphasis on the seasonal nature of OG&E's of the peak month load.

Q. **Have you compared the cost impact of the class allocation methods on the various classes of service?**

A. Yes. For each customer class allocation methodology, I compared the impact to the Residential (RS) and General Service (GS) classes with the impact to the Power and Light (PL) and Large Power and Light (LPL) classes. As one can see from Table 3 of my Report, when one moves from a 12 CP customer class allocation method to any of the other customer class allocators, there is a shift of two to five percent greater cost responsibility to the lower load factor classes (RS, GS) from the high load factor classes (PL, LPL).

Q. **Does moving from a 12-CP to a 4-CP class transmission allocator change the overall revenue requirements?**

A. No. OG&E is still using the 12-CP jurisdictional transmission allocator which allocates the revenue requirement for Oklahoma retail customers. The change I am recommending to the transmission customer class allocator establishes the amount of transmission plant assigned to each class, not the total amount for all classes.

Q. **Once selected, how is the 4-CP class allocation methodology used in the design of retail rates?**

A. OG&E witness Greg Veitch describes in detail the cost of service study and how the various allocators, including the 4-CP class allocation methodology are utilized in allocating costs among OG&E's jurisdictions and customer classes.

Q. **What is your recommendation?**

A. My recommendation is that OG&E should continue to use a 12-CP jurisdictional transmission allocator and should use a 4-CP class transmission allocator going forward.

Q. **Does this conclude your direct testimony at this time?**

A. Yes, it does.

Exhibit JBL-1

Testimony provided by James Long:

2008
New Mexico: Case No. 08-00092-UT
Topic: Establishment of Fuel Clause

2004
Texas: Docket No. 28840
Topic: Cost of Service, Rate Design, and Load Research

1999
Oklahoma: PUD 99 000392
Topic: Changes to RTP (MarketChoice^{SM}) program – rate design and policy

1996
Oklahoma: PUD 96 000049
Topic: Implement a RTP Interruptible rate program

Oklahoma: PUD 96 000214
Topic: Rate Design

1994
Oklahoma: PUD 94 000301
Topic: Implement Real Time Pricing

Before 1993:

Oklahoma: PUD 92 001342 (for PSO)
Topic: Acquisition premium for municipal system, municipal street lighting program, return of lighting programs to regulation

Oklahoma: OCC Cause No. 26669
Topic: rate design and proof of revenue statement

Oklahoma: OCC Cause No. 26959
Topic: rate design and proof of revenue statement

Oklahoma: OCC Cause No. 26965
Topic: Lifeline rate standards and design - PURPA

Oklahoma: OCC Cause No. 27068
Topic: rate design and proof of revenue statement

Oklahoma: OCC Cause No. 27510
Topic: general rules and regulatory policy

Oklahoma: OCC Cause No. 27759
Topic: general rules and regulatory policy

Oklahoma: OCC Cause No. 28076
Topic: Optional Load reduction rates - PURPA

Oklahoma: OCC Cause No. 28332
Topic: rate design and proof of revenue statement

Oklahoma: OCC Cause No. 28331
Topic: rate design and proof of revenue statement

FERC Docket No. ER82-80
Topic: rate design and proof of revenue statement

FERC Docket No. ER82-389
Topic: rate design and proof of revenue statement

Oklahoma: OCC Cause No. 27639 and PUD 734
Topic: removal of the amortization adders for PSO's retail prices

Oklahoma: PUD 153
Topic: Industrial ‘natural gas’ tolling rate – rate design and policy

Oklahoma: PUD 407
Topic: residential guaranteed price program – rate design and policy

Oklahoma: RM 12
Topic: rule making hearing - general rules and regulations - policy

Oklahoma: PUD 483
Topic: Requiring coop competitor to comply with OCC customer switching policy

Oklahoma: PUD 570
Topic: Cogen / purchased power– reasonableness of purchase price

Oklahoma: PUD 586
Topic: Cogen purchase power - Avoided Cost

Oklahoma: PUD 600
Topic: OGE Avoided Cost case – PURPA standard and avoided cost

Oklahoma: PUD 704; PUD 772; PUD 773; PUD 801; PUD 922
Topic: Rate Interpretation cases and refunds from potential overcharges – rate design and policy

Oklahoma: PUD 736
Topic: Amend municipal street lighting tariff – rate design and policy

Oklahoma: PUD 779
Topic: request for waiver of OCC rule 11d

Exhibit JBL-2

OKLAHOMA GAS & ELECTRIC COMPANY

Investigation into Retail Transmission Cost Allocation Report of Findings

Submitted by BBCI

Final Report January 13, 2011

Table of Contents

BBCI would like to express its thanks to OG&E personnel in the Costing, Transmission Planning, and Load Research groups for their very essential assistance in the conduct of BBCI's analyses.

Investigation into Retail Transmission Cost Allocation

Report of Findings

I Introduction and Executive Summary:

In October, 2009 BBCI was retained by Oklahoma Gas and Electric Company to perform an investigation of Class Retail Transmission Cost Allocation. This document is BBCI's report of findings.

Introduction and Background

The manner in which Transmission Plant is allocated to classes in the Arkansas jurisdiction is established by prior Arkansas orders and is not likely to be considered for a change in future filings. The Arkansas Commission currently requires transmission plant to be allocated utilizing a 12 CP allocator for both jurisdictional and class allocation. In Oklahoma, OG&E has also utilized a 12 CP allocator for transmission plant for both jurisdictional and class allocation in its recent filings including Cause Number PUD 398. The final order in PUD 398 adopted the Joint Stipulation and Settlement agreement that the parties reached. As part of the settlement, OG&E and other parties agreed with OIEC suggestion that OG&E evaluate and consider the use of a 4 CP allocator for class allocation of transmission plant. Specifically, in the Findings of Fact and Conclusions of Law section 4.P. "in OG&E's next rate case the parties shall evaluate and consider the use of a 4-CP allocation methodology for the Company's transmission plant." OG&E's FERC Jurisdictional Open Access Transmission Tariff, which is linked to the Southwest Power Pool tariff referred to as the "SPP OATT" utilizes the 12 CP methodology, a FERC recognized methodology for allocation of transmission related costs. OG&E's approach to jurisdictional allocation of plant utilizing a 12 CP allocator is the approach that most other utilities use to insure that there is no revenue loss as a consequence of the FERC preference of utilizing a 12 CP allocation methodology for allocation of transmission costs.

The Changing Character of Transmission Costs

SPP regional planning and the SPP OATT have impacted the way in which OG&E plans and charges for use of its transmission system. SPP plans for the region wide transmission system and new investments and base system upgrade responsibilities are assigned to the various transmission owners. The method in which costs are assigned and revenue recovered is based in part on the Transmission owners' SPP OATT.

Significant levels of new transmission investment are required to interconnect with the emerging wind generating sites in OG&E's service territory. OG&E's transmission system is in a growth period and sizeable investments will be required for upgrades to the base transmission system.

OIEC has raised the issue of class allocation of transmission plant responsibility. This group of customers has reviewed the ways other utilities have assigned transmission costs to the class level. They have provided information on a few select utilities that use a peak season allocation methodology. BBCI has reviewed the information they provided as a part of its investigation.

II Discussion of areas examined:

a) OG&E Transmission Planning Processes.

A meeting with Transmission Planning personnel was held to discuss the OG&E planning criteria for transmission. The principal planning focus is on system reliability which considers thermal overloads, voltage regulation, and meeting system load. Reliability issues are identified by modeling loading conditions in six specified seasons. OG&E's six seasons for modeling system reliability are the seasons as defined by SPP. Two of the seasons are Summer Peak and Summer Shoulder periods for the months of June through September. Fall season is composed of the months of October through November. Winter season is composed of the months of December through March. Spring season is composed of the months of April and May. April is used to evaluate impacts at minimum loads. For the planning period of 2010-2019, reliability issues were found in all seasons. Since the modeling is not done chronologically, it is not possible to determine if the reliability issues occur during the monthly system peaks although some of the load conditions modeled included the anticipated peak loads for the season being examined. BBCI's discussions in this regard resulted in the following principal points of understanding:

- Reliability is assessed by identifying instances where voltage excursions were outside of the National Electric Reliability Council (NERC) reliability standards under various assumed loading conditions.
- Voltage excursions are not predominantly associated with the summer season.

b) Examination of OG&E system load characteristics.

Monthly system loads for a 27 year period from 1984 to present were examined to determine whether the system load exhibited any seasonal peaking characteristics. The data examined is contained in Table 1. By defining the peak period as months within 85% of the annual system peak, initial examination of the data shows OG&E's system

has a significant summer season peak. The three months of June, July, and August are in the peak season definition for all 27 years. The month of May appears in the peak season only 5 times in the 27 years, while the month of September appears 20 times in the 27 years. This initial examination indicates OG&E's system has a summer peak season comprised of the four months June through September.

Table 1 Monthly System Peaks 1984 - 2010

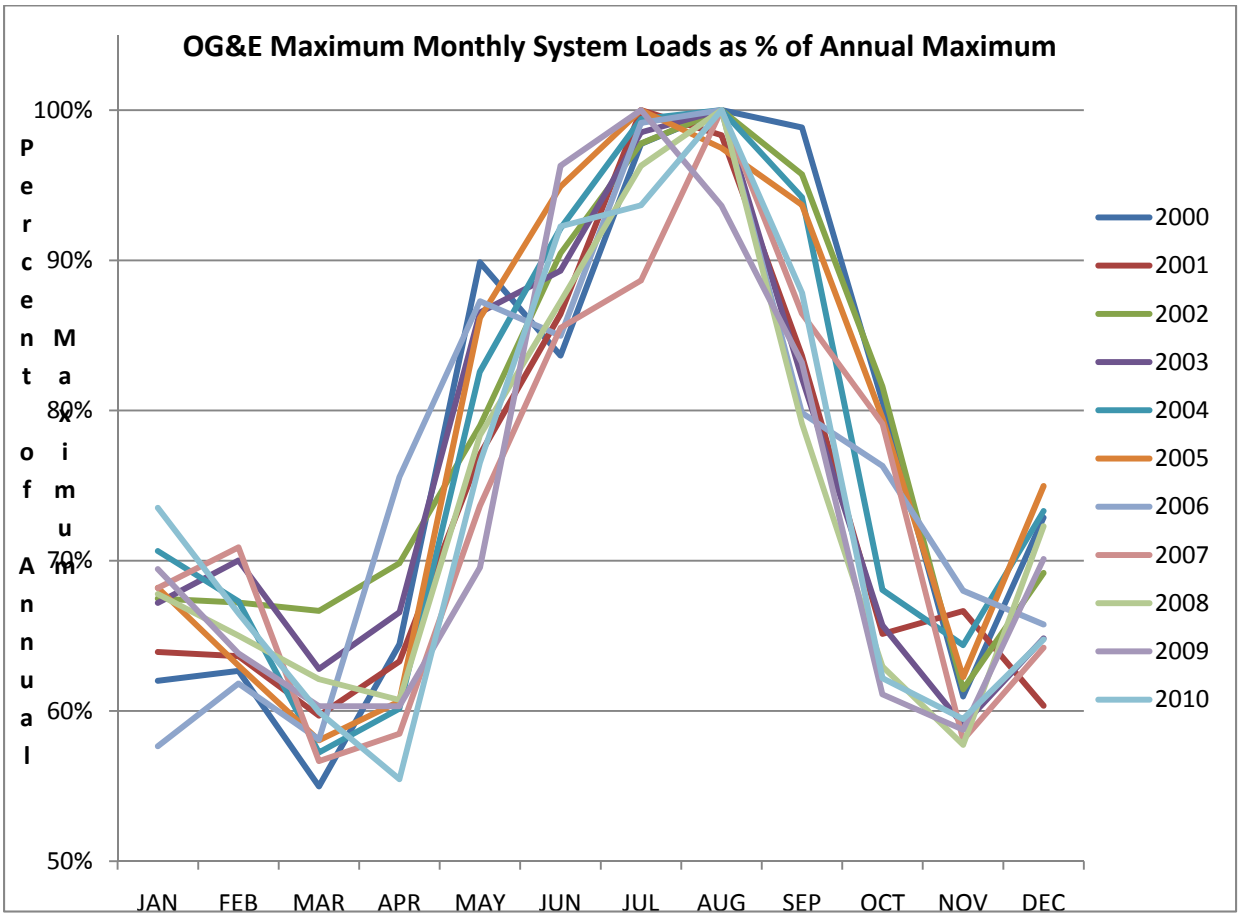
Year/Month	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
JAN	3380	3590	3150	2990	3210	2920	2870	3270	3260	3250	3430	3368	3737
FEB	2960	3399	3150	2880	3280	3490	2970	2950	2850	3440	3620	3294	3670
MAR	2820	2670	2630	2820	2850	3030	2840	2760	2810	2990	3170	3380	3540
APR	2650	2690	2890	3010	2570	3350	2770	2690	2800	2880	3210	2843	3123
MAY	3230	3950	3060	3760	3440	3800	3590	4040	3440	3180	4170	3592	4450
JUN	4260	4000	4170	4290	4410	4030	4630	4350	4360	4410	5060	4392	5010
JUL	4450	4550	4870	4400	4440	4350	4610	4660	4450	5000	4760	5133	5145
AUG	4890	4540	4470	4570	4690	4560	4810	4680	4550	5010	4842	5095	4994
SEP	4420	4670	3770	3730	3980	4350	4660	4240	4290	4280	4276	4922	4560
OCT	2770	2680	2820	2490	2900	3020	3150	3270	3110	3300	3846	3497	3298
NOV	2810	2910	3070	2820	2770	2890	2730	3140	2980	3050	2950	3133	3241
DEC	2980	3290	2930	3000	2980	3670	3480	3050	3100	3110	3155	3348	3693

Year/Month	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
JAN	3864	3485	4122	3568	3700	3844	4030	4114	4191	3732	4309	4387	4457	4872
FEB	3299	3325	3285	3606	3684	3829	4199	3919	3873	4002	4480	4208	4097	4407
MAR	3194	3491	3202	3164	3455	3797	3766	3333	3567	3761	3581	4020	3871	3971
APR	3012	2958	3411	3708	3664	3978	3992	3503	3727	4892	3696	3931	3871	3675
MAY	3572	4630	3783	5171	4460	4499	5189	4809	5294	5649	4654	5070	4463	5070
JUN	4756	5316	4671	4814	5003	5153	5356	5365	5832	5500	5403	5647	6180	6113
JUL	5287	5528	5451	5625	5788	5569	5908	5788	6145	6418	5602	6232	6418	6206
AUG	5093	5529	5748	5754	5691	5696	5997	5823	5990	6473	6319	6472	6009	6626
SEP	5111	5481	5084	5687	4841	5452	4926	5485	5757	5168	5462	5121	5338	5821
OCT	4270	3515	3743	4637	3770	4647	3940	3963	4885	4940	4999	4075	3922	4120
NOV	3256	3106	3211	3508	3858	3500	3542	3749	3826	4402	3670	3738	3771	3940
DEC	3488	3898	3532	4193	3493	3941	3888	4269	4607	4257	4058	4679	4533	4291

Note: The annual peaks are highlighted in yellow and months with load equal to at least 85% of the annual peak are highlighted in green.

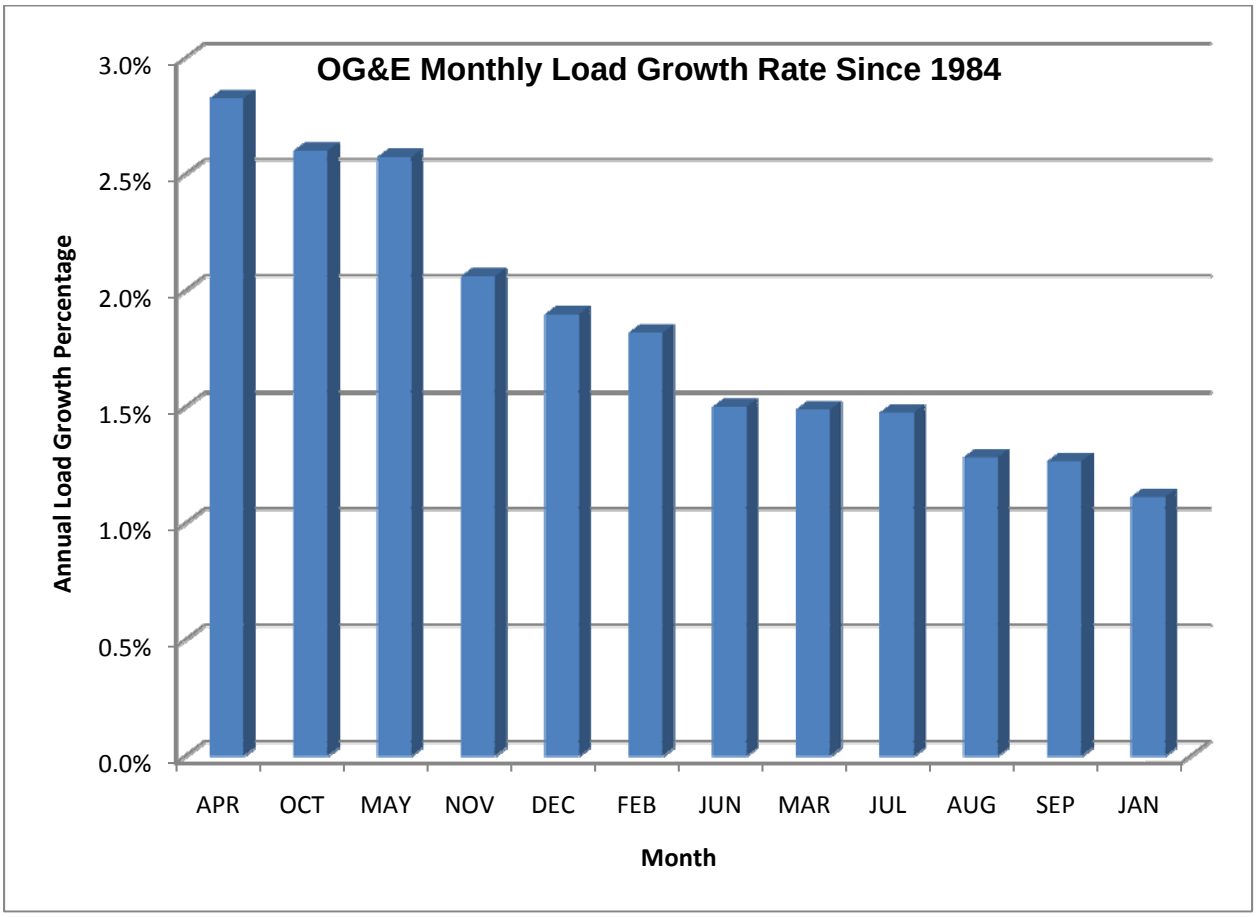
By examining the last eleven years of the data, this peak season is clearly seen when the monthly loads are plotted as a percent of annual peak as shown below in Figure 1.

Figure 1 Monthly Maximum Loads 2000 - 2010



The growth in monthly peaks over the 27 year period shows that the summer months have the lowest growth rates while the shoulder months have the highest growth rates. For example April, which has the highest growth rate, has grown from 54% in 1984 to a maximum of 76% of the annual peak in 2006. A graphic representation of the monthly growth trends is shown as Figure 2. The growth trends in Figure 2 were developed by computing a compound growth percentage from 1984 through the highest monthly load experienced since then. Most of the maximum monthly loads used for this purpose occurred in the last five years.

Figure 2 Monthly Load Growth Rates



c) Practices of other utilities.

For jurisdictional allocation of transmission plant, most utilities conform to the FERC approach and use a 12 CP allocator. Predominately the reason is to prevent the loss of revenue caused by switching allocation methodology for filings in different jurisdictions. Other methods utilized for jurisdictional allocation are varied. For example, a 4 CP method is used by PSO. The Missouri PSC advocates 4 CP to reduce Missouri's responsibility. PJM uses the highest five hourly summer loads for determining transmission obligation, and ERCOT uses a 4 CP method for the same purpose. These methods serve to determine cost responsibility for jurisdictional purposes, classes, and individual customers.

To perform class allocation for transmission plant, a variety of approaches are utilized or proposed. For example, Progress Energy in Florida considered the transmission function to be capacity related and proposed production allocators weighted 75% demand (12 CP) and 25% Average Demand or energy related. The minimum filing requirement in Florida requires a study filed using a capacity allocator based on 12/13 – 12 CP and 1/13 Average Demand. Progress Energy advocates that a higher apportionment be based on energy. A witness for Progress Energy stated:

> "Generation investment strategies are different today than that reflected in the Company's generation fleet nearly thirty years ago. The emphasis years ago was to build conventional power plants that met accepted reliability criteria. Today, due to the relatively greater cost of fuel and stricter emissions requirements, the emphasis is on providing clean and efficient generation as well as satisfying reliability criteria. In recent years, PEF has applied state-of-the-art technologies in the construction of more efficient generation including the Hines Energy Complex, the repowering of Bartow power plant, and updates to the Crystal River nuclear unit. Its future plans to install new, advanced nuclear generation in Florida will provide a clean, low-cost and less volatile fuel source. All of these investment strategies have a higher up-front capital cost. However, the benefits to the customers are primarily related to the costs for fuel which is apportioned on an energy basis. There should be no question that a significant portion of the Company's production capacity costs being incurred should be apportioned in the same manner as the customer realizes the benefits, i.e. on an energy basis."

PacifiCorp in Utah proposed an approach including a 75 / 25 weighting of 12 CP and energy. However, they advocate a load weighted 12 CP component in order to reflect an increasing seasonality in their load patterns. Georgia Power advocates an allocation methodology comprised of 20% 12 CP combined with 80% 4 CP, based on a rationale incorporating the relationship between temperature and ampacity. SPS

advocates the use of a class allocator based on 3 CP and A&E and PSO advocates 4 CP and A&E. The allocation procedures of the utilities researched are shown in Table 2.

Table 2 Allocation Procedures Summary

Party	Method Advocated	Context	Location
Missouri PSC Staff (KCPL Case)	4 CP	Jurisdictional Separations	Missouri
Industrial Intervenors (KCPL Case)	3 NCP-A&E	Jurisdictional Separations	Missouri
Wisconsin Public Service Company	12 CP	Jurisdictional Separations	FERC
Progress Energy	12 CP	Jurisdictional Separations	Florida
Kansas City Power and Light	12 CP	Jurisdictional Separations	Missouri
Southwestern Public Service Company	12 CP	Jurisdictional Separations	Texas
PJM Power Pool	5 highest summer period load hours	Load Share for individual customers	PA, NJ, MD
ERCOT	4 CP	Load Share for individual customers	Texas
Southwestern Public Service Company	3 CP-A&E	Retail Class Cost of Service	Texas
Industrial Intervenors (WPSC Case)	4 CP	Retail Class Cost of Service	Wisconsin
Georgia Power	20% 12 CP and 80% 4 CP	Retail Class Cost of Service	Georgia
Idaho Power	12 CP using weighted marginal transmission costs	Retail Class Cost of Service	Idaho
Progress Energy	50% 12 CP and 50% Energy	Retail Class Cost of Service	Florida
Pacificorp	75% Load Weighted 12 CP, 25% Energy	Retail Class Cost of Service	Utah
Wisconsin Public Service Company	12 CP	Retail Class Cost of Service	Wisconsin
Public Service Company of Oklahoma	4 CP	Retail Class Cost of Service	Oklahoma

- Most utilities use a jurisdictional allocation based on 12 CP.
- Utilities are trending to use a class allocation methodology that is either a multiple number of months CP to reflect the seasonal nature of their native load or some methodology reflecting energy and demand such as Average Demand and multiple CP.

d) Comparison of different allocators.

Several class allocators were developed and are contained in Table 3.

Table 3 Class Allocation Values

Customer Class	12 CP	5 CP	4 CP	1 CP	NCP	A&E	A&E Mod*	4 CP A&E	4 CP + Avg	1 CP A&E (AED)**
Total Residential	43.54%	46.32%	46.53%	48.20%	46.46%	45.60%	45.89%	44.78%	45.31%	46.82%
Total GS	9.50%	9.93%	10.19%	10.29%	11.81%	11.40%	11.48%	11.00%	9.81%	10.03%
Total PL	28.55%	27.65%	27.51%	26.50%	25.78%	26.11%	26.22%	26.42%	27.75%	27.74%
Total LPL	17.23%	15.20%	14.87%	14.13%	14.03%	14.98%	15.00%	15.89%	16.10%	14.15%
Total Muni Pumping	0.44%	0.39%	0.37%	0.36%	0.47%	0.48%	0.48%	0.49%	0.40%	0.36%
Muni Lighting SL5	0.08%	0.00%	0.00%	0.00%	0.32%	0.31%	0.13%	0.30%	0.03%	0.13%
Sec Lighting SL5	0.16%	0.00%	0.00%	0.00%	0.60%	0.59%	0.25%	0.58%	0.06%	0.25%
OSU	0.50%	0.51%	0.53%	0.53%	0.53%	0.53%	0.54%	0.54%	0.53%	0.51%
Ok Retail	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

* Average and Excess with no excess demand assigned to outdoor lighting classes
** 1CP A&E (AED) Production Allocator for Oklahoma in PUD 398

The load data utilized to develop the allocators in Table 3 are based on the weather normalized data from OG&E's PUD 398 filing. These class allocators demonstrate a shift in responsibility caused by changing from a 12 CP allocation to a multiple monthly CP or A&E or a 4 CP + Average (energy) or using the OG&E production allocation methodology (1 CP A&E). Focusing on the impact on the Residential and GS classes contrasted with the PL and LPL classes, there is a shift of 2% to 5% of greater costs responsibility to the lower load factor classes from the high load factor classes. The 1 CP methodology would provide the greatest shift in responsibility followed by the NCP methodology. The 4 CP plus Average demand methodology allocates more on energy and thus provides slightly less benefit to the high load factor classes. The 1 CP has the weakness of being volatile or less stable from one filing to the next filing as factors such as weather, regional economics, and customer changes in operation cause noticeable shifts in contribution to the system peak. The OG&E major rate classes shifting of cost allocation responsibility under the various allocators are shown in Figures 3 through Figure 6.

Figure 3 Residential Allocation Responsibility

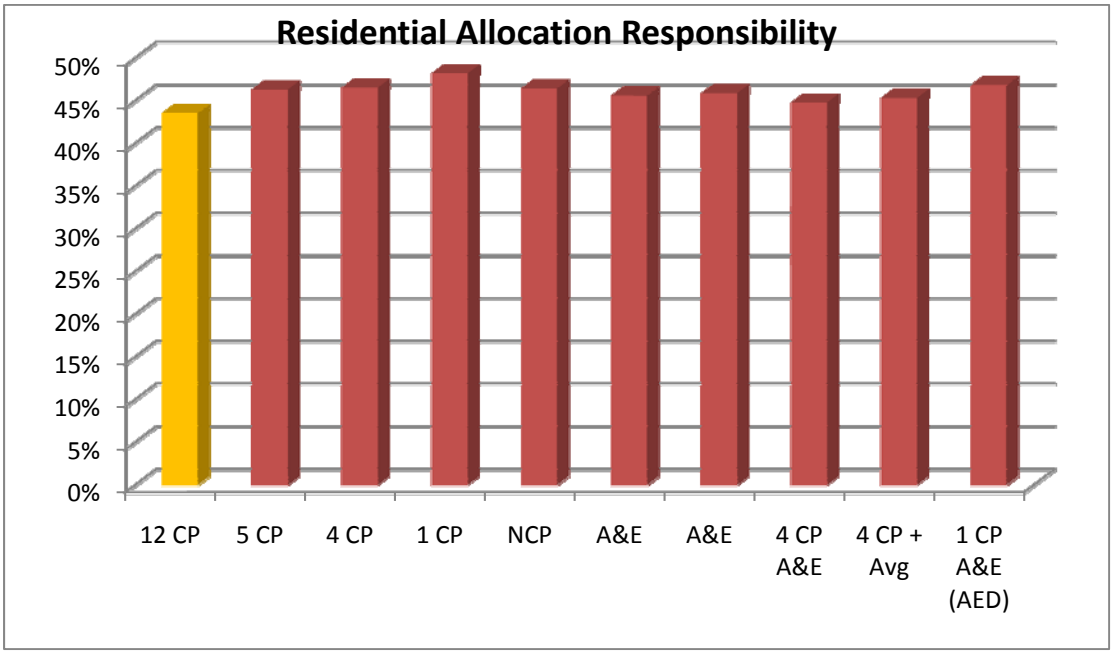


Figure 4 General Service Allocation Responsibility

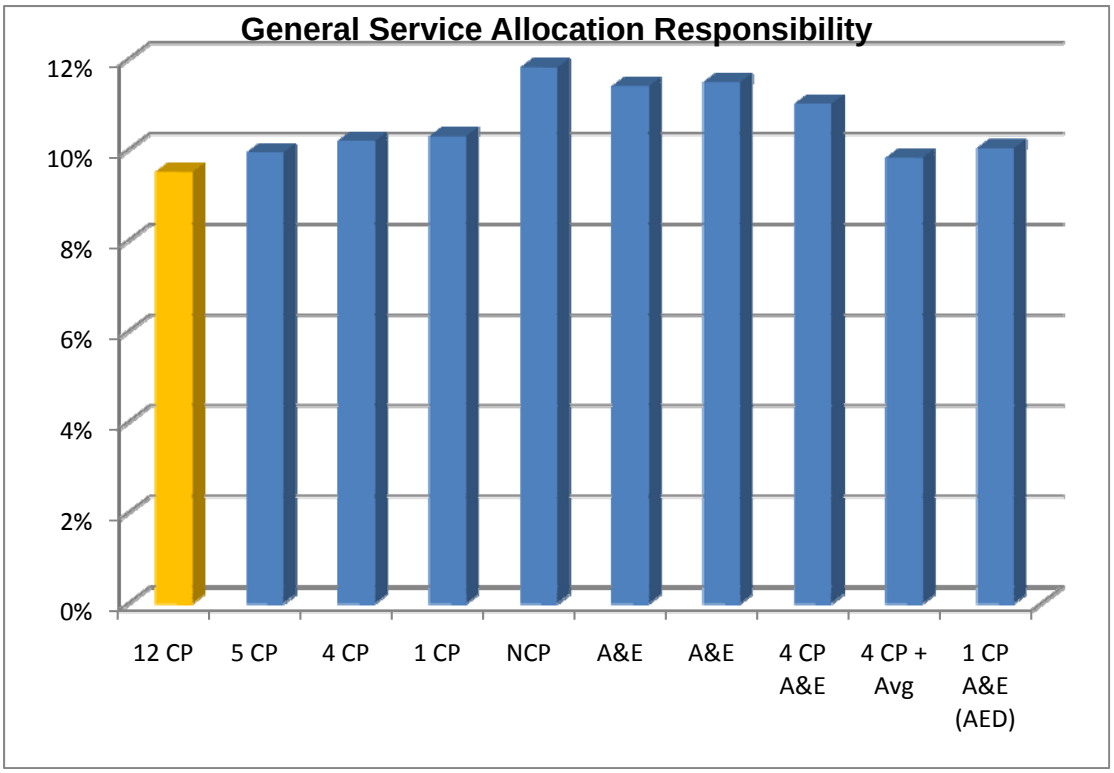


Figure 5 Power & Light Allocation Responsibility

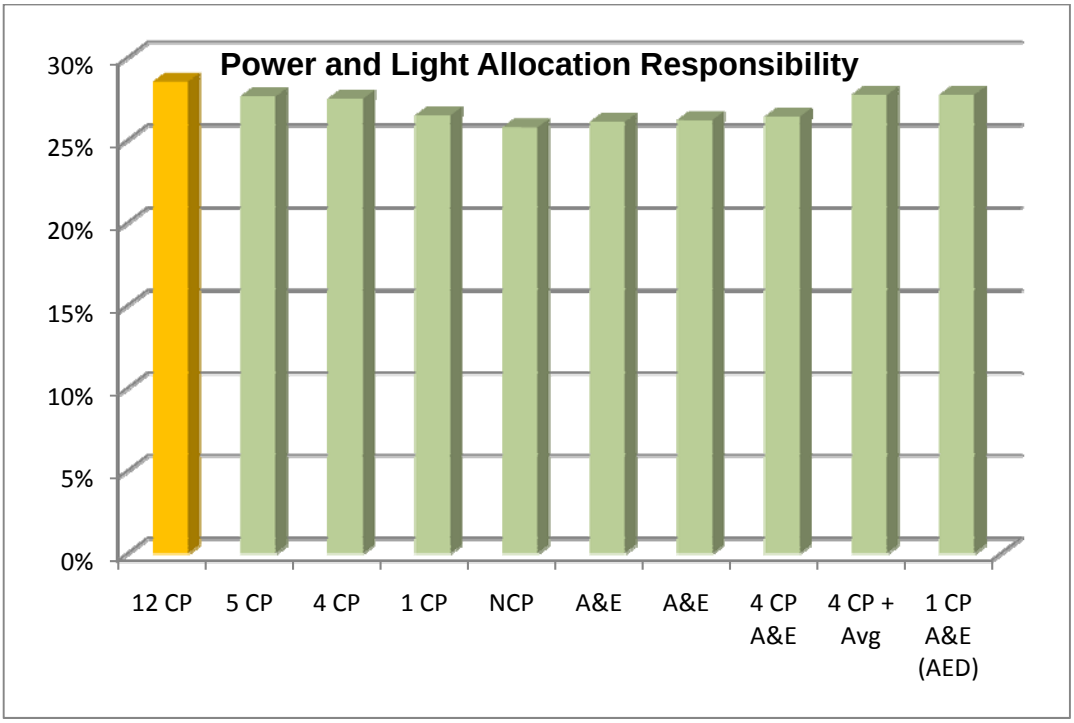
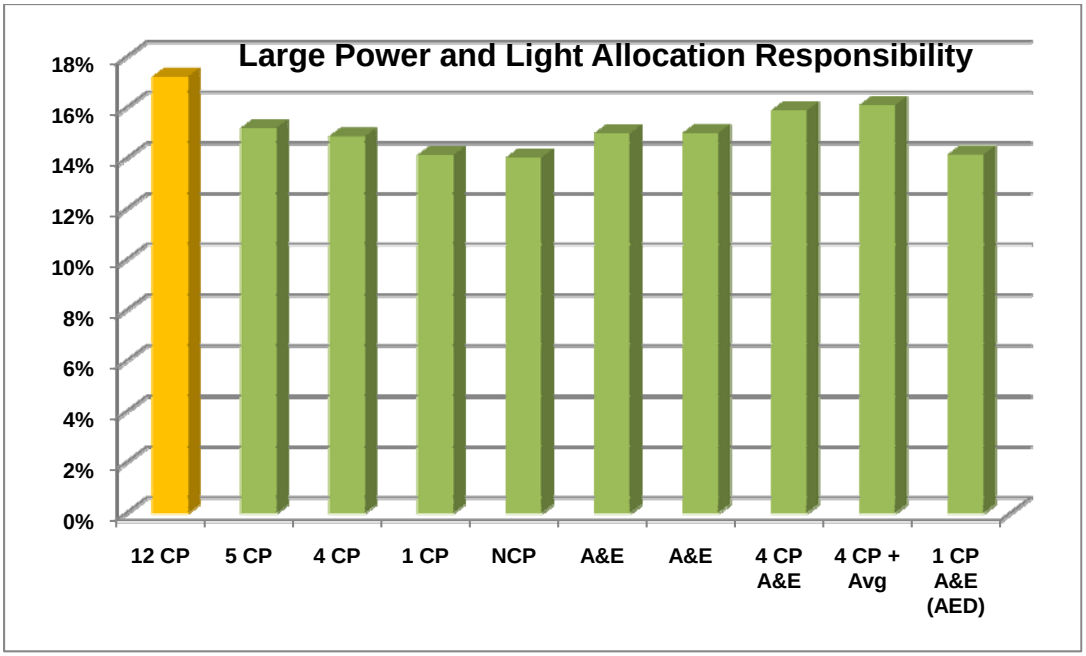


Figure 6 Large Power & Light Allocation Responsibility



III Summary of Findings:

BBCI's review of OG&E's planning process revealed the following:

- BBCI has determined that OG&E's loads are still highly seasonal in nature even though the off-peak months have shown significant growth.
- BBCI determined that reliability is assessed by identifying instances where voltage excursions outside permissible limits are expected under various assumed loading conditions.
- BBCI determined that voltage excursions are not predominantly associated with the summer season.
- BBCI determined that the excursions were not chronologically modeled and could not be related to the monthly peaks.

The planning process shows that there are factors other than demand that impact the investments made to the transmission system. These other factors are not customer, demand or energy related and are not measureable in a manner which can be associated with any measurable customer class characteristic for the development of a transmission system allocator. New transmission plant investments are made to improve system reliability and can impact voltage excursions in several months. The modeled excursions are mainly helpful to determine where upgrades to the system are required. BBCI believes that investment in transmission facilities is also a function of maximum load requirements and that transmission loads continue to be the most relevant measurable basis for allocation.

Utilities must determine how to allocate transmission plant both on a jurisdictional and class basis. When making the jurisdictional determination, utilities generally consider the requirements of the ISO in which it is a member and FERC's preference. OG&E is a member of the Southwest Power Pool which uses the 12 CP allocation methodology and FERC requires the use of the 12 CP methodology. BBCI's review of the practices of

other utilities revealed that most utilities use a 12 CP jurisdictional allocation methodology.

It is not uncommon, however, to change to a different class allocation methodology. In the 1960's through 1980's some utilities consider the transmission system as a means to make it possible to interconnect generation resources to serve the load centers and thus the transmission system was allocated to class in the same manner as production plant. If Table 1, OG&E's monthly peaks for the period 1984 through 2010, is examined, it can be determined that the load characteristics of OG&E's system reflect a strong summer season peak period comprised of the four summer months June through September. The shoulder and winter months show somewhat larger growth rates, but there is still a very large difference in shoulder or winter monthly peaks compared to the summer season peak loads.

Since OG&E's system has a large seasonal difference, a demand allocation that relies on the class contribution to the seasonal peak is a factor to be considered. The current OG&E 12 CP methodology for allocating transmission plant to classes does not rely exclusively on the various class contributions to the summer peak season. Table 3 Class Allocation Values shows the selection of any other allocation methodology will make a 2% to 5% impact on class responsibility. In fact, it shows that OG&E's production allocator has essentially the same impact as selecting the 4 CP allocation method. The reasonableness of changing the class allocation methodology from 12 CP is supported by the system load characteristics and approaches used by certain other utilities that rely on the 4 CP allocation methodology for allocating transmission plant to classes. BBCI's investigation has been based on cost causation and prevailing practices. Based on this analysis, BBCI recommends changing the existing 12 CP class allocation of transmission assets to a 4 CP allocation procedure that reflect the seasonal nature of class loads on the OG&E system or adopting a method that follows the production allocation procedure. BBCI recommends OG&E continue with 12 CP jurisdictional allocation of transmission assets.