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Arizona Corporation Commission
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Exhibit #: AriSEIA 1; NUCOR 1-2; WRA 1-2; SWEEP 1-4; WAL-MART 1-5

Part 3 of 8

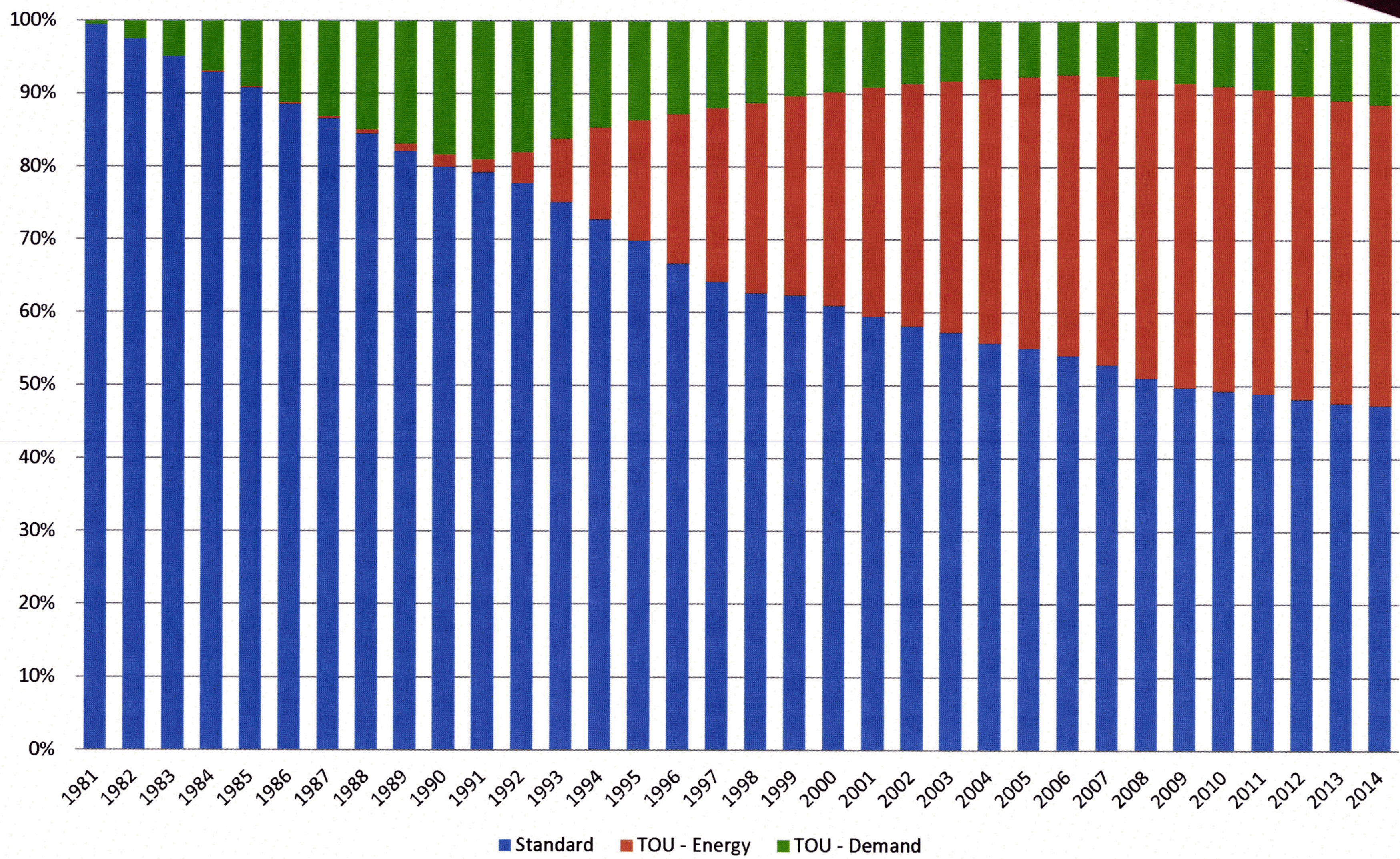
For Part 4, see Barcode 0000169259

AriSEIA-1

EXHIBIT
AriSEIA-1
admitted

APS

Historic Customer Count Percentage
Standard vs. Time of Use



BEFORE THE ARIZONA CORPORATION COMMISSION

<u>**COMMISSIONERS**</u>
SUSAN BITTER SMITH – CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

EXHIBIT
Nucor 1
admitted

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-04204A-15-0142

DIRECT TESTIMONY OF

DR. JAY ZARNIKAU ON RATE DESIGN

ON BEHALF OF NUCOR STEEL

December 9, 2015

ATTACHMENTS

Attachment JZ-1 Background and Qualifications of Dr. Jay Zarnikau.

Attachment JZ-2 Karen Abbott, *Direct Energy Business Unveils Service Alerting Customers to Likely 5CP Days in PJM Region*, ENERGY CHOICE MATTERS (June 5, 2013), http://www.energychoicematters.com/stories/20130605f.html.

Attachment JZ-3 Jay Zarnikau & Dan Thal, *The response of large industrial energy consumers to four coincident peak (4CP) transmission charges in the Texas (ERCOT) market*, 26 UTILITIES POLICY 1 (2013).

Attachment JZ-4 Frontier Associates, Report to the Staff of the Electric Reliability Council of Texas, *2013-2014 Retail Demand Response and Dynamic Pricing Project, Final Report* (June 23, 2014), http://www.ercot.com/content/services/programs/load/2013-2014_DR_and_PriceResponse_Survey_AnalysisFinalReport.pdf.

Attachment JZ-5 Raish, Carl L., *Four-CP Response in ERCOT Competitive Area 2009-2014* (March 9, 2015), www.ercot.com/content/wcm/key_documents_lists/51664/DSWG_ercot_4_cp_analysis_rev.ppt.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jay Zarnikau. My business address is 1515 Capital of Texas Hwy, South, Suite 110, Austin, Texas, 78746.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the president of Frontier Associates LLC. With a professional staff of nearly 30, my consulting firm provides assistance to energy consumers, electric and gas utilities, and government agencies on topics related to energy economics and pricing, utility cost allocation and rate design, forecasting, resource planning, energy efficiency program design and evaluation, and regulatory policy.

I am also a Visiting (adjunct) Professor at The University of Texas. I teach graduate-level courses in applied statistics in the Department of Statistics and the LBJ School of Public Affairs.

Q. PLEASE STATE BRIEFLY YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I have a Ph.D. degree in Economics from the University of Texas. I completed undergraduate studies in Business Administration and Economics at the State University of New York and McGill University in Canada.

From 1983 through 1991, I was employed by the Public Utility Commission of Texas, where I served as the Manager of Economic Analysis from 1985 through 1988; as the Assistant Director of the Electric Division from 1987 to 1988; and as the Director of

Electric Utility Regulation from 1988 to 1991. From 1991 through 1993, I held a faculty-level research position at The University of Texas College of Engineering Center for Energy Studies. I served as a vice president at Planergy, Inc. from 1992 to 1999. Since 1999, I have been president and a principal of Frontier Associates LLC. I have taught courses in applied statistics at The University of Texas since 2003.

My resume, which is attached to this direct testimony as Attachment JZ-1, describes in greater detail my educational background and work experience.

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

A. I am appearing on behalf of Nucor Steel – Kingman ("Nucor").

Q. HAVE YOU PREVIOUSLY APPEARED BEFORE THIS COMMISSION?

A. I provided pre-filed direct testimony on behalf of the applicant in Docket No. E-04100A-04-527, Application of Southwest Transmission Cooperative, Inc. for a Rate Increase. I also provided pre-filed testimony for Nucor Steel in UNS Electric's previous rate case, Docket No. E-04204A-12-0504. I was not cross-examined in those proceedings.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony reviews the rates and tariff changes proposed by UNS Electric in this proceeding, with a focus upon the proposed changes which might impact Nucor's facility in Kingman, Arizona. I propose a number of changes which I believe would be of mutual benefit to both UNS Electric and Nucor.

Q. WHAT MATERIALS DID YOU REVIEW IN ORDER TO PREPARE YOUR TESTIMONY?

A. I reviewed the sections of the rate change application that I determined to potentially have an effect on the cost of electricity incurred by Nucor, as well as related discovery materials.

II. <u>SUMMARY OF CONCLUSIONS</u>

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. I conclude that:

- The design of the demand charges paid by industrial customers of UNS Electric does not properly reflect how the customer's coincident demand (i.e., demand at the time of the utility's system peak) affects the utility's cost of acquiring and maintaining generating and transmission capacity.

- The utility has provided no support for its proposal to reduce the differential between on-peak and off-peak energy rates in the Large Power Service Time of Use (LPS-TOU) tariff. A reduction in this differential will send an inappropriate price signal.

- The proposed Interruptible Rider restricts participation to industrial energy consumers with potentially-interruptible loads which are available throughout the summer months. There is no need to limit the proposed Interruptible Rider solely to industrial energy consumers that are available to be interrupted "around the clock."

Q. PLEASE PROVIDE YOUR RECOMMENDATIONS.

A. I recommend the following:

- The demand charges in the utility's tariffs for industrial energy consumers should be set on the same basis upon which capacity-related costs are incurred by the utility.

- The utility incurs capacity-related costs to meet peak demand on the utility system. Consequently, the demand charges to industrial energy consumers should be based upon their contribution to peak demand.

- The present differential between on-peak energy charges and off-peak energy charges in the LPS-TOU tariff should be increased or maintained.

- The proposed Interruptible Rider should be redesigned so that it is available to all industrial energy consumers, regardless of when they operate.

- In the proposed Rider-13 Economic Development Rider (EDR), it should be clarified that the calculation of the customer's monthly load factor in the summer months is based upon the customer's billing demand.

III. NUCOR'S OPERATION IN KINGMAN

Q. PLEASE DESCRIBE NUCOR'S OPERATION IN KINGMAN, ARIZONA.

A. Nucor Steel is the largest steel producer in the U.S., as well as the nation's largest recycler of steel. The Nucor-Kingman facility produces coiled rebar and wire rod products. This former North Star Steel facility was acquired by Nucor in 2003. Operations at the facility were re-started by Nucor in 2009. The return of steel production at this facility has provided a boost to the local and state economy.

Q. WHAT ELECTRICITY TARIFF IS NUCOR SERVED THROUGH?

A. Most of Nucor's electricity is purchased through UNS Electric's Large Power Service Time of Use (LPS-TOU) tariff.

Q. HOW DOES THE STRUCTURE OF THE ELECTRICITY TARIFF THROUGH WHICH NUCOR IS SERVED AFFECT NUCOR STEEL'S OPERATION IN KINGMAN, ARIZONA?

A. In the steel industry, electricity is a very important input and tends to be one of the highest variable input costs in steel production. Managing energy costs is critical for Nucor and other American steel manufacturers who must compete against steel producers in Mexico, China, Turkey, and other countries that flood the U.S. market with competing products. To keep electricity costs as low as possible, Nucor schedules operations to minimize its production during on-peak periods. Wherever possible, labor and production shifts are scheduled to coincide with the off-peak periods in the LPS-TOU tariff.

Nucor's operating strategy benefits not only Nucor, but also benefits UNS Electric and all other consumers on the UNS Electric system. To the extent that Nucor is able to produce steel during off-peak periods rather than on-peak periods, UNS Electric's need for generating capacity to meet on-peak demands may be reduced, and energy generation costs may be lowered. By increasing operations during off-peak periods, Nucor also helps improve the UNS Electric system load factor by filling in the periods of low demand, and in the process helps UNS Electric make better use of its generation resources. In general, steel production facilities are very "price responsive" and can respond to economic price signals in a manner that ultimately benefits UNS Electric and its customers. For industrial customers like Nucor, even small percentage increases in electricity rates can translate into hundreds of thousands of dollars in additional costs, impacting Nucor's ability to operate in a highly competitive international market.

III. INDUSTRIAL DEMAND CHARGES SHOULD BE RE-DESIGNED

Q. WHAT COSTS DOES UNS ELECTRIC RECOVER FROM INDUSTRIAL ENERGY CONSUMERS THROUGH A DEMAND CHARGE?

A. As detailed in UNS Electric's Class Cost of Service Schedule G-7, UNS Electric seeks to recover costs associated with generation and transmission capacity from industrial energy consumers through demand charges. UNS Electric has properly classified these costs as "demand related."[1]

Q. WHAT CAUSES A UTILITY SUCH AS UNS ELECTRIC TO INCUR COSTS RELATED TO GENERATING AND TRANSMISSION CAPACITY?

A. In large part, these costs are incurred by a utility to meet the utility's peak demand. Utility system infrastructure is designed and built to meet the anticipated needs of the system during peak periods. Maximum demand on the system is forecast. Power plants are constructed and other resources (including purchased power and demand side resources) are secured in order to ensure that there is adequate generating resource capacity to meet hourly peak demand, plus some reserve margin. Similarly, the transmission system is designed and constructed to meet the needs of the system during peaks.

[1] Some costs related to distribution capacity are also demand–related and recovered through a demand charge. I shall ignore these costs in this discussion, since I am focusing on the demand charges billed to large industrial energy consumers and UNS Electric incurs little if any distribution system costs in order to serve these large consumers, who tend to be served at high voltages.

As a witness for Tucson Electric Power ("TEP"), an affiliate of UNS Electric, D. Bentley Erdwurm, described the role of system peak demand in TEP's cost allocation methodology in TEP's 2007 rate case:

> The allocator includes the peak component to *recognize that the system must have adequate capacity to satisfy demand at the time of the peak*, and that classes of customers should receive some allocation of costs reflecting contribution to this peak.[2]

In the 2012 TEP rate case, Craig Jones (a witness for UNS Electric in this proceeding) likewise testified:

> This is because the allocator includes the peak component to *recognize that the system must have adequate capacity to satisfy demand at the time of the peak*, and that classes of customers should receive some allocation of costs reflecting contribution to this peak.[3]

In the present rate case, Mr. Jones states that the utility's peak demand partly "drives" generating capacity costs. From his Direct Testimony:

> . . . class non-coincident peaks drive the allocation of part of the distribution system capacity *while it is some combination of coincident peaks and demand and energy methods for generation.*[4]

I generally agree with the above statements. Indeed, the system peak plays a primary role in determining the need for generation and transmission capacity.

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[2] Direct Testimony of D. Bentley Erdwurm on behalf of Tucson Electric Power Company at 22, lines 6-8, Docket No. E-01933A-07-0402 (July 2, 2007) (emphasis added).
[3] Direct Testimony of Craig A. Jones on behalf of Tucson Electric Power Company at 17, lines 19-22, Docket No. E-01933A-12-0291 (July 2, 2012) (emphasis added).
[4] Direct Testimony of Craig A. Jones on behalf of UNS Electric, Inc. at 18, lines 6-8, Docket No. E-04204A-15-0142 (May 5, 2015) (emphasis added). This language is repeated in Direct Testimony of Craig A. Jones on behalf of Tucson Electric Power Company at 18, lines 23-26, Docket No. E-01933A-15-0322 (Nov. 5, 2015).

The design of the demand charge should recognize that generating and transmission capacity costs are incurred to meet peak system demands. Customers should pay for these costs in proportion to their contribution to the system peak demand. As noted in the Direct Testimony of Mr. Jones:

> Just and reasonable rates must avoid undue discrimination and must reflect the principle of user pays," also known as "cost causation," or as I prefer to say, those who cause the costs should pay the costs.[5]

Customers who contribute to system peak demand cause UNS Electric to incur capacity-related costs and should be responsible for paying those costs in relation to their contribution to the system peak.

Q. DOES THE MANNER IN WHICH UNS ELECTRIC PRESENTLY COLLECTS DEMAND-RELATED COSTS REFLECT THE MANNER IN WHICH UNS ELECTRIC INCURS THESE COSTS?

A. No. The tariffs that UNS Electric applies to its largest customers apply a complicated set of alternatives that distort the connection between how and why the utility's demand costs are incurred and how the demand costs are paid by these customers. For example, under the **LPS tariff**, the monthly billing demand is the greater of the following three alternatives:

1. The greatest measured 15 minute interval demand read of the meter during all hours of the billing period;
2. The greatest demand metered in the preceding eleven (11) months; or
3. The contract capacity or 500 kW, whichever is greater.

[5] Direct Testimony of Craig A. Jones on behalf of UNS Electric, Inc. at 12, Docket No. E-04204A-15-0142 (May 5, 2015).

Under the **LPS-TOU** tariff, monthly billing demand charges are the greater of the following four alternatives:

1. The greatest measured fifteen-minute interval demand read of the meter during the on-peak hours of the billing period;

2. One-half of the greatest measured fifteen-minute interval read of the meter during the off-peak hours of the billing period;

3. The greater of (i) or (ii) above during the preceding 11 months; or

4. The contract capacity or 500 kW, whichever is greater.

For the **LGS, LGS-TOU**, and **LGS-TOU-S** tariffs, the monthly billing demand is the greater of the following three alternatives:

1. The greatest measured 15 minute interval demand read of the meter during all hours of the billing period;

2. 75% of the greatest demand used for billing purposes in the preceding 11 months; or

3. The contract capacity or 450 kW, whichever is greater.

The design of the demand charge in the MGS tariffs is similar to the design of the LGS tariffs, although a lower minimum demand is set in the third item of the list.

The design of demand charges in these UNS Electric tariffs is inconsistent with the theory that at least some of the costs are related to a customer's contribution to *coincident peak demand.*

Q. WHAT DO YOU MEAN BY COINCIDENT PEAK DEMAND?

A. As discussed in the NARUC Cost Allocation Manual cited by Mr. Jones:

> A customer or class of customers contributes to the system maximum peak to the extent that it is imposing demand at the time of – coincident with – the system peak. The customer's demand at the time of the system peak is that customer's "coincident" peak.[6]

Q. IS IT YOUR CONTENTION THAT NONE OF THE CRITERIA SET FORTH IN THESE TARIFFS IS A GOOD MEANS OF MEASURING A CUSTOMER'S CONTRIBUTION TO SYSTEM DEMAND OR RESPONSIBILITY FOR SYSTEM DEMAND-RELATED COSTS?

A. Yes.

Q. WHY WOULDN'T THE FIRST CRITERIA IN THE LPS-TOU TARIFF, "THE GREATEST MEASURED FIFTEEN-MINUTE INTERVAL DEMAND READ OF THE METER DURING THE ON-PEAK HOURS OF THE BILLING PERIOD," BE A GOOD INDICATOR OF A CUSTOMER'S CONTRIBUTION TO THE DEMAND AT THE TIME OF THE SYSTEM PEAK?

A. In the summer on-peak period of the test year, there were 3,096 on-peak hours, and an additional 3,024 winter on-peak hours for LPS-TOU customers. In many of these hours, the system demand was not very high. For example, when I compared the hourly demand figures for all peak hours to the highest system demand reading for the test year,

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[6] NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS, ELECTRIC UTILITY COST ALLOCATION MANUAL, 41 (1992).

I found that during the test year there were hours within the peak period in which the load on the UNS Electric system was less than 17% of the annual system peak.[7]

If an LPS customer's individual demand peaked in one of these hours of low system demand, it would be a poor measure of that customer's contribution to the system peak demand. That customer's highest demand certainly wouldn't create a need for additional generation or transmission capacity.

Q. WHY WOULDN'T THE SECOND CRITERIA, "ONE-HALF OF THE GREATEST MEASURED FIFTEEN-MINUTE INTERVAL READ OF THE METER DURING THE OFF-PEAK HOURS OF THE BILLING PERIOD IN THE LPS-TOU TARIFF," BE A GOOD INDICATOR OF A CUSTOMER'S CONTRIBUTION TO THE DEMAND AT THE TIME OF THE SYSTEM PEAK?

A. These time of use periods were defined so that there is extremely little probability that a system peak would be set within the off-peak period. Consequently, a customer's highest demand reading during an off-peak period has no impact on the utility's need for generation and transmission capacity.

It is also unclear why *one-half* of the off-peak period demand should be used? Why not one-quarter, two-thirds, or one-eighth? This seems arbitrary.

Q. WHY WOULDN'T THE FOURTH CRITERIA, "THE CONTRACT CAPACITY OR 500 KW, WHICHEVER IS GREATER," BE A GOOD INDICATOR OF A CUSTOMER'S CONTRIBUTION TO THE DEMAND AT THE TIME OF THE SYSTEM PEAK?

A. Apparently, there are no customers of UNS with a "contract capacity."

[7] The hourly demand information was provided as a response to Nucor's discovery request No. 1.07.

I asked UNS Electric for information pertaining to contract capacities through discovery (Nucor 4.4), and was informed that there are no customers of UNS with a "contract capacity." The utility's response to Nucor 4.4 states:

> There are no current LPS or LGS customers with special agreements that would specify a "contract capacity" demand that exceeded the minimum provided for in the tariff. All current LPS customers have a minimum billing demand of 500 kW and all current LGS customers have a minimum billing demand of 20 kW.

I see no need to include language about "contract capacity" in the LPS and LPS-TOU tariffs (or the LGS tariff, for that matter), if none of these customers have a contract capacity.

Q. YOU HAVE SHOWN THAT THE CRITERIA IN UNS ELECTRIC'S LARGE CUSTOMER TARIFFS ARE POOR INDICATORS OF A CUSTOMER'S CONTRIBUTION TO SYSTEM DEMAND AT THE TIME OF THE SYSTEM PEAK. WHAT WOULD BE A BETTER MEASURE?

A. A more accurate approach would be to simply bill a customer based on its contribution to the utility's system peak. For load forecasting and generation planning purposes, a single hour or interval representing the highest demand on the utility system in a given year is typically used to represent peak demand. Nonetheless, a one coincident peak, or 1 CP, approach is seldom used in practice for rate design or cost allocation purposes. The use of a larger number of hours is thought to provide a more "stable" basis for rate design.

When the Electric Reliability Council of Texas (or ERCOT) was restructuring its market to introduce customer choice in 1999-2001, I proposed that all industrial energy consumers exposed to retail competition compensate transmission owners for the use of the transmission network based on the consumers' contribution to ERCOT's highest system peak demand in each of the four summer months. My proposal was designed to recognize that system peak demand drives the need for investments in the transmission system; and where the metering infrastructure permits, transmission costs should be recovered from customers based on the costs they impose on the system. Further, this proposal was designed to encourage industrial energy consumers to reduce their demand on the system during hours with high system demand, to assist ERCOT in preserving reliability and to reduce the need for additional investment in generating and transmission capacity. My 4 CP pricing proposal (sponsored by Nucor Steel – Texas Division) was adopted by the Texas Commission and remains intact today.[8]

Q. IS THE PRACTICE OF BILLING INDUSTRIAL ENERGY CONSUMERS BASED UPON THEIR CONTRIBUTION TO SYSTEM 4 CP MEASUREMENTS COMMON?

A. It is becoming common. As noted above, energy consumers in the competitive areas within the ERCOT market – the electricity market which covers most of Texas – with a demand over 700 kW are charged for transmission service based on their contribution to ERCOT's summer 4 CPs during the previous year. Many utilities and competitive retail service providers in the PJM market – the electricity market which serves much of the northeast U.S. – follow a similar practice, as well. For example, Attachment JZ-2 includes a recent press release that describes how Direct Energy's demand charges for transmission cost recovery in the PJM market are based upon five coincident peaks.

Q. YOUR ERCOT AND PJM EXAMPLES FOCUS ON THE RECOVERY OF TRANSMISSION COSTS. IS THIS PRICING ALSO APPLICABLE TO THE RECOVERY OF COSTS RELATED TO GENERATION CAPACITY?

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[8] *See* Direct Testimony of Dr. Jay Zarnikau on behalf of Nucor Steel – Texas Division, Docket No. 22344 (Pub. Util. Comm'n of Tex. Oct. 16, 2000).

A. Yes. The logic behind recovering transmission costs based on 4 CP (or 5 CP) billing demands can likewise be applied to the recovery of costs related to generation capacity.

Q. WOULD THE USE OF A LARGER NUMBER OF HOURS TO DETERMINE THE DEMAND CHARGE ALSO BE REASONABLE?

A. Yes. Using a slightly larger number of hours might also have some merit, if, for some reason, a 4-CP (or 5CP) methodology is deemed inappropriate.

Several years ago, I proposed that sponsors of energy efficiency projects in Texas receive incentive payments that would be based upon the energy efficiency project's expected demand reduction during 20 peak hours. I proposed 20 hours because this is a reasonable estimate of the run-time of a combustion turbine generating unit used to meet peak demands on a utility system, and the Texas Commission bases its estimate of the generating capacity costs avoided by energy efficiency using the cost of a combustion turbine.[9] My proposal was accepted by the Texas Commission and is presently being implemented.

At the same time I proposed an approach for quantifying the capacity values of energy efficiency based upon the 20 hours of highest system load, the ERCOT staff independently developed a very similar proposal for determining the contribution of non-dispatchable generation resources towards meeting ERCOT's peak demand. Under ERCOT's "Top 20 Hours Approach," the capacity value of wind turbines, solar photovoltaics, and power transactions with other reliability councils is determined based

[9] PUB. UTIL. COMM'N OF TEX. SUBSTANTIVE RULE § 25.181(d) (2013).

on each resource's contribution toward meeting system demand during the 20 hours of highest demand in a previous year or years.

The ERCOT Staff takes a simple average of the contribution of these resources over each of the 20 hours, while my approach involves a probabilistic weighting of the 20 hours. But these approaches are conceptually similar and have the same basic objective.

These approaches using 20 peak hours are essentially a "20 CP" method, and represent an acceptable alternative to a 4-CP methodology.

Q. WOULD THERE BE BENEFITS TO UNS IF DEMAND CHARGES WERE BASED UPON ON A CUSTOMER'S CONTRIBUTION TO EITHER THE 4 CP OR THE TOP 20 HOURS?

A. Yes. This type of pricing encourages energy consumers to reduce their electricity purchases during summer peaks, which is exactly the time when a utility system would benefit the most from demand reduction. The present design of the demand charges requires a consumer to flatten its load pattern over the entire year in order to obtain significant cost savings -- it does not, however, encourage the consumer to reduce demand during those hours when demand reduction would have its greatest value to the system. The papers that I have provided as Attachments JZ-3 through JZ-5 demonstrate how industrial energy consumers in the ERCOT market have reduced system demand through their response to 4 CP price signals. In fact, 4 CP pricing is often viewed as one of the ERCOT market's most successful demand response initiatives.

Q. SHOULD THE DESIGN OF A DEMAND CHARGE BASED UPON A CUSTOMER'S 4 CP DEMAND OR CONTRIBUTION TO SYSTEM DEMAND DURING 20 PEAK HOURS BE APPLIED TO ALL CUSTOMERS WITHIN THE LPS RATE CLASS?

A. Yes. It should at a minimum apply to all customers taking service under the LPS and LPS-TOU tariffs, since UNS Electric has combined these two groups of customers for cost allocation purposes.

I would favor extending this rate design to other customer classes with adequate metering (e.g. consumers within the LGS class), as well.

Q. ARE ALL OF THE COSTS INCURRED BY UNS ELECTRIC FOR GENERATION AND TRANSMISSION CAPACITY RELATED TO MEETING THE SYSTEM PEAK DEMAND?

A. Rate analysts differ on how to answer this question. Some generation capacity costs may arguably be incurred to achieve greater diversity in fuel costs. Some transmission investments may arguably be made to accommodate economy energy transactions. Nonetheless, I view system peak demand as the greatest "driver" of generation and transmission costs, and other alleged drivers to be largely incidental to the primary motivation for adding the generation or transmission in the first place. Even if one was to allege that half of a utility's generation and transmission capacity costs were driven by factors other than the need to meet system peak demand, I would support a 4 CP or Top 20 Hours method, since it sends a better price signal which motivates customers to respond in a way that is more likely to lead to reductions in the utility's capacity requirements.

Q. WOULD RE-DESIGNED DEMAND CHARGES RESULT IN A LOSS IN REVENUES TO UNS?

A. No. It should not. I propose that my recommendation be implemented in a "revenue-neutral" manner. The demand charges should be adjusted to ensure that revenues approved by the Commission to be recovered by UNS under their proposed tariff design equal the revenues collected by UNS with my proposed demand charge design.

Q. WILL YOUR RECOMMENDATION RESULT IN ANY SHIFT IN COSTS TO CUSTOMER CLASSES WITH RELATIVELY HIGH CONTRIBUTIONS TO THE SUMMER PEAK?

A. No. My recommendation is not intended to affect cost allocation. The costs assigned to each class will not change. My recommendation only affects how costs are recovered from industrial energy consumers, and not how costs are allocated between customer classes. I suggest that after costs are allocated, that the demand charge be designed to recover demand-related costs in a manner which better reflects how system peak demand affects capacity requirements and capacity costs.

My recommendation may affect the costs incurred by individual consumers within the LPS class (and the LGS class, if it is extended to those customers). Those customers with disproportionately high usage during the 4 CPs might (appropriately) pay more. Those customers within the LPS class with relatively-low purchases of electricity during the peaks may (appropriately) pay less. But this will depend on the ability of customers to shift load into less costly periods on an annual basis.

Q. PLEASE EXPLAIN THE STEPS NECESSARY FOR UNS TO IMPLEMENT THIS RECOMMENDATION.

A. One way to implement this would be to simply calculate a customer's share of its customer class's 4 CPs or Top 20 hours in the previous year and multiply it by the generation and transmission costs allocated to the rate class. For example, if a customer in the LPS (including LPS-TOU) rate class was responsible for 25% of the 4 CP load (or

20%.

load during the Top 20 hours) contributed by that rate class during the previous year, the customer would be billed for ~~one-quarter~~ 20% of the generation and transmission costs allocated to that class. The utility would recover these costs in equal monthly payments. An example is provided in Table JZ-1 below.

TABLE JZ-1
Load During Monthly Summer Coincident Peaks of Previous Year (kW)

	Customer A	Total for Class
June	450	2500
July	500	2400
August	550	2500
September	500	2600
Average	500	2500
Customer A's Percent Contribution to 4 CPs:		20%
Costs to be recovered from Class through Demand Charge:		$2,500,000
Annual Cost to be recovered from Customer A:		$500,000
Monthly Cost to be recovered from Customer A:		$41,667

This example is very similar to the calculation provided by UNS Electric in response to Nucor 1.05. This discovery response provides the "evaluation" for the allocation of demand costs on a 4CP basis referenced on page 78, lines 21-27 of the direct testimony of Mr. Craig Jones in this proceeding. This is the study required by Settlement Agreement in the previous UNS Electric rate case, Docket No. E-04204A-12-0504.[10]

If a portion of demand-related costs will also be collected through a separate customer charge, then the amount collected through this demand charge would be adjusted

[10] *See* Opinion and Order, Decision No. 74235, Exhibit A, Proposed Settlement of Rate Application of UNS Electric, Inc., § 15.2, Docket No. E-04204A-12-0504, (Sep. 30, 2013).

accordingly. The formulas in row 56 of the spreadsheet provided by UNS Electric in response to Nucor 1.05 provide such an adjustment.[11]

Alternatively, to set the demand charge for 2016, for example, the rate class's costs to be collected through the demand charge could be divided by the class's contribution to the 4 CP or the class's contribution to the Top 20 Hours in the previous year (2015). The denominator is in kW, to obtain a per-kW demand charge. This annual per-kW cost is, in turn, divided by 12, so that the annual per-kW amount is collected over 12 months.

This second method is similar to the manner in which UNS Electric presently determines the demand charge, but the determination of billing determinants that I am recommending would be simpler – that is, it would no longer be based on the highest of four or five different measurements. An example using this approach is provided in Table JZ-2 below.

TABLE JZ-2
Load During Monthly Peak of Previous Year (kW)

	Total for Class
June	2500
July	2400
August	2500
September	2600
Average	2500
Costs to be recovered from Class through Demand Charge:	
	$2,500,000
Monthly Demand Charge per Average of Previous Year's 4 CPs:	
	$83.33
Customer A's Average Contribution to Current Year's 4 CPs (kW):	
	500

[11] In row 56, 1200*12 is subtracted from the annual costs which would be allocated to customers within the LPS rate class under a 4 CP pricing approach. Since $1,200 is the monthly customer charge applicable to LPS and LPS-TOU customers, I presume that this adjustment is intended to remove those costs recovered from a customer charge from the calculation of the demand charge.

Monthly Cost to be recovered from
Customer A:

$41,667

An adjustment may again be needed if a portion of the demand-related costs will also be collected through a separate customer charge.

The same amount will be collected from the customer under either of these two approaches. The first approach essentially allocates the demand-related costs to each customer within the class based on the customer's relative contribution to the class's contribution to the 4 CPs, while the second approach develops a per-4 CP kW charge, i.e., a per-kW charge where the kW demand is measured as the customer's demand during the 4 CP hours.

While I am assuming that a customer's contributions to the class's 4 CPs are the basis for charges in my examples, the math would be very similar if a Top 20 hours approach was adopted.

Note that I am not suggesting that the allocation of costs among rate classes be changed every year. Rather, these approaches would assure that the costs are recovered from customers within a rate class in proportion to their contribution to the system peak.

IV. DIFFERENTIAL BETWEEN ON-PEAK AND OFF-PEAK ENERGY PRICES

Q. WHAT IS THE PRESENT DIFFERENCE BETWEEN THE ON-PEAK AND OFF-PEAK ENERGY CHARGES IN THE LPS-TOU TARIFF?

A. Presently, the Power Supply Charge: Base Power price during on-peak periods in the summer is $0.12358 per kWh and the price during off-peak periods is $0.024716 per kWh. Thus, the differential in the summer is 5 to 1. During the winter, the current charges are $0.09338 during the on-peak period and $0.022105 during the off-peak period, resulting in a differential of roughly 4.25 to 1 during the winter pricing period.

Q. HAS UNS ELECTRIC PROPOSED CHANGING THE DIFFERENTIAL IN THIS PROCEEDING?

A. Yes. Under the proposal by UNS Electric, the summer Power Supply Charge: Base Power price would be $0.12251 and $0.03211 during on-peak and off-peak periods, respectively. Thus the differential would be 3.8 to 1. During the winter, the proposed charges are $0.09211 during the on-peak period and $0.03091 during the off-peak period, resulting in a differential of less than 3 to 1.

Thus, UNS Electric is proposing to greatly increase the off-peak energy charges, while the on-peak energy charges would be left at very similar levels. This has the effect of greatly reducing the difference between the on-peak and off-peak energy charges.

Q. WHY HAS UNS ELECTRIC PROPOSED TO CHANGE THE RATIO OF ON-PEAK TO OFF-PEAK PRICES?

A. When I requested an explanation from UNS Electric, I received the following response:

> NUCOR 5.8: Please explain why UNS Electric has proposed increasing the Off-Peak Power Supply Charges for LPS-TOU customers. Provide any relevant work papers used to calculate or support the new Off Peak Power Supply Charges.
>
> RESPONSE: The LPS TOU customers in the test period are currently paying well below the system average compared to all other rate classes. Even though the Company raised the off-peak price for the LPS TOU customers in this case to be closer to the system average, they continue to be charged below the system average.

Q. DOES THIS ADEQUATELY PROVIDE A JUSTIFICATION FOR INCREASING THE OFF-PEAK CHARGE?

A. No. It is not clear what "system average" means in this context. If the objective of UNS Electric is to make all customers – residential, commercial, and industrial – pay the same system average price for electricity, that strategy conflicts with sound utility ratemaking practice. Different customers impose different costs on the utility system and their prices should reflect this difference in cost.

Q. HAS UNS ELECTRIC PROPOSED SHRINKING THE ON-PEAK TO OFF-PEAK DIFFERENTIALS IN THE LGS-TOU TARIFF TO THESE SAME LEVELS?

A. No. Under the utility's proposed LGS-TOU tariff, the differences in these charges between the on-peak to off-peak periods in the summer actually *increase* from the current 2.88 to 1 to 4.22 to 1.[12] And while there would be a reduction from 4.39 to 1 to 3.7 to 1 in the winter, both of these differentials would remain higher than what the utility has proposed for the LPS-TOU tariff.

Q. ONE OF THE GOALS OF TOU PRICING IS TO SEND A PRICE SIGNAL TO CONSUMERS TO ENCOURAGE THE SHIFTING OF CONSUMPTION FROM ON-PEAK TO OFF-PEAK PERIODS. WILL THEIR SUGGESTED CHANGE CONTRIBUTE TO THAT OBJECTIVE?

A. No. The proposed changes to the LPS-TOU energy charges reduce the incentive for consumers on this tariff to shift consumption from high-cost to low-cost periods.

Q. PLEASE STATE YOUR RECOMMENDATION REGARDING THIS ISSUE?

A. I recommend that the present differentials between on-peak and off-peak Power Supply Charge: Base Power charges be increased, or at a minimum maintained in the LPS-TOU tariff.

[12] We note that in a similar fashion, the on-peak to off-peak ratio for summer energy charges for LGS-TOU-S customers would *increase* from 2.65 to 3.83 under the proposed changes.

Q. WOULD RE-SETTING THE ON-PEAK AND OFF-PEAK POWER SUPPLY CHARGE: BASE POWER TO MAINTAIN THE SAME DIFFERENTIAL BETWEEN ON-PEAK AND OFF-PEAK PERIODS RESULT IN A LOSS IN REVENUES TO UNS?

A. No. It should not. I propose that my recommendation be implemented in a "revenue-neutral" manner.

V. <u>THE INTERRUPTIBLE RIDER SHOULD BE RE-DESIGNED TO ALLOW FOR GREATER PARTICIPATION</u>

Q. PLEASE DESCRIBE THE UTILITY'S PROPOSED RIDER R-12: INTERRUPTIBLE SERVICE.

A. Under the proposed Rider R-12, industrial energy consumers would be eligible to receive a bill credit during five summer months in return for allowing UNS Electric to interrupt the supply of power to the consumer with a notice period of 10 minutes.[13] The consumer must have at least 500 kW of load available for interruption.

Q. COULD A PORTION OF THE ELECTRICAL DEMAND AT NUCOR'S KINGMAN FACILITY POTENTIALLY BE INTERRUPTED?

A. Yes. A portion of the electrical service provided by UNS to Nucor could be interrupted, under the right circumstances.

Q. WOULD NUCOR BE ABLE TO USE THE NEW INTERRUPTIBLE RIDER AS PROPOSED BY UNS?

A. Not as the rider is currently designed. The proposed rider is limited to industrial energy consumers who are able to designate loads which are *always* available for interruption

[13] A 10-minute notice requirement is stated in the Terms and Conditions, although a 30-minute notice requirement is suggested in the section Nomination of Interruptible Load By Customer.

during five summer months. That is, the load must be available "around the clock" During those months. Through Nucor 2.07 (part c), I asked:

> In the "Nomination of Interruptible Load by Customer" process, would a customer be able to nominate different amounts during different times of the day or days of the week under the Company's proposal? If the quantity varies by time of day or day of the week, how will the quantity of interruptible load available from a customer be determined for the purpose of calculating the Interruptible Credit?

And the utility responded:

> The answer to the first part of this request is no, see Terms and Conditions of Service No. 2 and 3. The Company cannot predict when these interruptions will be needed during its peak times in the summer; this is why the Company is offering a credit to any qualified participant for all summer months whether the Company interrupts service or not. Once a participant has been qualified by the Company, the Commission-approved credit for that participating season will be automatically applied to the customer's monthly bill (the credit is multiplied by the nominated interruptible load of the customer for all summer months regardless of an interruption). Should an interruption occur, the Company will validate that the customer's complied with all terms and conditions during the interruption by reviewing the customer's interval data for the customers nominated service points.

Q. CAN YOU ADDRESS THE CONCERN EXPRESSED BY UNS ELECTRIC?

A. I agree that the utility can certainly not anticipate when it might need to call for an interruption. Yet, the utility may be ignoring a valuable system demand-side resource if it only considers loads which can be interrupted at any time during the summer. That is, at the time of a system emergency or spike in wholesale prices, there may be other loads available from industrial facilities which operate based on certain production schedules that are willing and able to be interrupted. Further, the utility's proposal fails to consider the possibility that an emergency or a spike in wholesale electricity prices could occur during the non-summer months.

Q. HOW SHOULD THIS LIMITATION IN THE UTILITY'S PROPOSAL BE ADDRESSED?

A. I recommend that the utility's proposed Rider R-12 be modified in either of the following ways:

- Allow participation by industrial facilities which operate based on a production schedule (as opposed to "around the clock" operations) and adjust the bill credit accordingly; or
- Introduce a simple system whereby industrial customers would be notified by UNS Electric when a load reduction would be valuable in order to maintain reliability or for economic reasons, and allow industrial customers an opportunity to voluntarily reduce load in return for a payment or bill credit from the utility.

Q. PLEASE DISCUSS HOW THIS FIRST OPTION FOR IMPROVING RIDER R-12 WOULD WORK.

A. An industrial facility that operates largely on a predetermined fixed schedule such as Nucor could provide UNS Electric with information about the expected amounts of load available for potential interruptions during various days (e.g. days of the week and holidays) and times of the day. This should still have value to UNS Electric. Indeed, there is no guarantee that an industrial facility that operates on a schedule will have a load which could be interrupted when UNS Electric needs it. Consequently, the bill credit provided to a potentially-interruptible customer that operates on a schedule could be prorated accordingly. For example, an industrial customer with a 1 MW potentially-interruptible load during half of the summer hours could receive a bill credit that is one-half of the credit received by an industrial customer with 1 MW of load which is available for interruption around-the-clock. This might be adjusted accordingly, depending upon the value that UNS Electric assigns to resources available during various day types and hours of the day.

Certainly, UNS Electric purchases and values other resources which are not available around the clock, including solar power from the Rio Rico and La Senita facilities.[14]

Q. PLEASE EXPLAIN YOUR SECOND PROPOSED OPTION FOR ENHANCING THE UTILITY'S PROPOSED RIDER R-12.

A. A second way to address UNS Electric's concern while enabling expanded participation in Rider R-12 would be to add a "peak time rebate" option. This option would permit UNS Electric to interrupt or curtail service to LPS or LPS-TOU customers at any time, upon voluntary agreement between the utility and the customer. Under such an option UNS would notify Nucor and other industrials that it is short of resources or expects a spike in prices and offers to split the savings with the industrial customer. Participation in this option would, of course, be limited to customers who were not otherwise interruptible – i.e., taking service under the interruptible tariff or participating in the Rider R-12 program as proposed by UNS Electric. There would be no obligation placed on the customer to interrupt, but of course the customer would receive to bill credit if is declined to curtail at the utility's request or had no load that could be shed at the time of the utility's request. When the industrial customer receives a request from UNS Electric, the customer could compare the payment quoted by UNS Electric against the value of their lost production.

[14] The investments of the utility in solar facilities are discussed in the direct testimonies of Terry Nay and Carmine Tilghman in this proceeding.

This option is similar to how demand-side resources are handled in many restructured wholesale markets. It also has some similarities to the "peak building" or "peak time rebate" programs offered by some vertically-integrated utilities.

Q. UNDER THIS OPTION, HOW WOULD COMPENSATION BE DETERMINED?

A. A simple approach would be to simply split the savings evenly between the utility and the participating load. The savings would be cost avoided by the actions taken by the consumer. For example, the interruption of 1 MW of load for an hour-long period when the wholesale price was $1,000 would result in savings of $1,000. A purchase of power at $1,000 per MWh could be avoided, or 1 MWh of excess generation on the UNS Electric system could be sold, resulting in a similar economic outcome.

Q. WHAT SHOULD BE THE NOTICE PERIOD?

A. Ideally, this should be established following discussions with candidate industrial energy consumers. However, either a 10-minute or 30-minute notice period would seem reasonable.

Q. ARE THERE OTHER POTENTIAL BENEFITS ASSOCIATED WITH YOUR SECOND PROPOSED OPTION FOR ENHANCING RIDER R-12?

A. While Rider R-12 as proposed by UNS Electric would provide a system resource only during the summer months, my proposed option could be introduced year-round, whenever there was a price spike or system emergency.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE INTERRUPTIBLE RIDER PROPOSED BY UNS ELECTRIC.

A. The proposed Rider R-12 should be redesigned to allow for greater participation by industrial energy consumers with potentially-interruptible loads. Greater participation, and the availability of a demand-side resource during times other than the summer months, will provide a valuable resource to the benefit of the utility and its customers. This may be accomplished by:

- Removing restrictions that the interruptible load be available "around the clock" during summer months; or
- Introducing an option whereby a customer not already involved in an interruptible program would be offered a financial incentive (determined on a "shared savings" basis) to curtail during times when the utility anticipates high wholesale energy prices or a reliability problem.

VI. THE ECONOMIC DEVELOPMENT RIDER SHOULD BE CLARIFIED

Q. HAVE YOU REVIEWED THE UTILITY'S PROPOSED ECONOMIC DEVELOPMENT RIDER?

A. Yes, I have reviewed Rider-13.

Q. DO YOU SUPPORT RIDER-13?

A. Generally, yes. Nucor supports measures that provide economic incentives for businesses in Arizona to create jobs and opportunities for economic growth. While it is not yet clear whether this rider will apply to Nucor, I believe it recognizes the value provided by Arizona businesses that provide jobs and invest in local communities.

Q. DO YOU HAVE ANY COMMENTS REGARDING THIS RIDER?

A. Yes. I believe that the "load factor" requirement requires some clarification. The Availability section of the proposed rider reads:

> Customers with a projected peak demand of 1,000 kW or more and a load factor of 75% or higher for the highest 4 coincident-peak months in a rolling 12-month period.

I suggest that the following sentence be added following the sentence cited above:

> The monthly load factor shall be calculated based upon the customer's billing demand and monthly energy usage.

Thus, if the customer's billing demand was based upon the 4 CP pricing approach which I have recommended in this testimony, then the customer's average demand at the time of the four coincident peaks during the previous calendar year would be used in the calculation of the customer's load factor.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Attachment JZ-1

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PROFESSIONAL EXPERIENCE

2003- **Visiting Professor or Fellow. The University of Texas.**

As adjunct faculty member, teaches interdisciplinary courses in Applied Regression Analysis, Advanced Empirical Methods, Introduction to Empirical Methods, and independent study.

1999- **President, Frontier Associates, Austin, Texas**

Responsible for providing assistance in the design and implementation of energy efficiency programs, utility resource planning, electricity pricing, rate analysis/design, program evaluation, demand forecasting, and energy policy. Assist in supervision of a staff of over 30 professionals.

1992-1999 **Vice President, Planergy, Austin, Texas**

Responsible for providing assistance in the design and implementation of energy efficiency programs, and providing consulting assistance in the areas of utility resource planning, electricity pricing, program evaluation, demand forecasting, and energy policy.

1991-1993 **Manager of Energy Strategies Research Program, The University of Texas at Austin Center for Energy Studies College of Engineering, Austin, Texas**

Held faculty-level research position responsible for the oversight of research projects in the areas of utility resource planning, regulation, electricity pricing, and policy analysis, including assessments of the potential for energy efficiency savings in Texas.

Program Manager for EPRI-sponsored effort to develop a new integrated resource planning framework and model.

1983-1991 **Director of Electric Utility Regulation (from 1988 to 1991), Economist (1983 to 1988) Public Utility Commission of Texas, Austin, Texas**

Supervised a professional staff of over fifty accountants, economists, and engineers responsible for analyzing regulatory and technical issues and providing recommendations to the Commission. Prepared and defended testimony in over twenty proceedings.

1982-1983 Research Associate, Bureau of Business Research, University of Texas at Austin, Austin, Texas

Assisted in maintenance of statewide economic-demographic forecasting model, prepared projections for state legislature and state agencies, and conducted studies to determine the value of various mineral resources in Texas.

EDUCATION

Ph.D. (1990) and M.A. (1983) in Economics, University of Texas at Austin. Fields completed in Econometrics, Resource Economics, and Micro Modeling

B.S. in Business Administration and Economics, State University of New York, Oswego, New York, May 1981

McGill University, Montreal, Quebec, 1979-1980

PUBLICATIONS AND RESEARCH PAPERS

Refereed Journals:

"Ex post payoffs of a tolling agreement for natural-gas-fired generation in Texas." Forthcoming in *Journal of Energy Markets.* With C.K. Woo and Yun Liu.

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"Aggregate Consumer Response to Wholesale Prices in the Restructured Texas Electricity Market," *Energy Economics*. Vol. 30(4), pp. 1798-1808, 2008. With Ian Hallett.

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"Rewired for Competition: The Restructuring of Electricity Markets in Texas?" *Texas Business Review*, 1999.

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"Real-Time Pricing of Electricity: An Assessment," in Proceedings of the Eleventh Annual Industrial Energy Technology Conference, Houston, September 1989; with Martin Baughman.

"Wheeling Nonutility Power: The Texas Experience" *The Electricity Journal*, Vol. 2(7), pp. 32-41, 1989. With Bill Moore and Martin Baughman.

OTHER ACTIVITIES

Adjunct Lecturer and Visiting Professor, University of Texas LBJ School of Public Affairs and College of Natural Sciences Division of Statistics. Teaches courses in Applied Regression Analysis and Introduction of Quantitative Analysis. Since 2003

ERCOT Working Group on Demand Side Resources, Founder and Co-Chair (2001)

Board Member and Vice President for Publications, Association of Energy Services Professionals, 2001-2007

Retail Energy Aggregators of Texas, Director, 2001-2003

State of Texas Energy Policy Partnership, Member, 1992

National Association of Regulatory Utility Commissioners Staff Subcommittee on Wheeling and Transmission, Member, 1990

Member of American Economic Association, International Association for Energy Economics (Vice President of local chapter), and American Statistical Association.

Reviewer for International Energy Review, ACEEE Summer Study, IEEE Transactions on Power Systems, Energy Economics, Energy Policy, Energy – The International Journal, British Journal of Economics, Management and Trade, Power Engineering Society, Energy Exploration and Exploitation, Applied Energy, and The Energy Journal.

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SOAH Docket No. 473-09-5470 and PUCT Docket No. 36633: Petition of CPS Energy for Enforcement Against AT&T Texas and Time Warner Cable Regarding Poll Attachments. Analysis of statistical issues. On behalf of Time Warner Cable.

Arkansas PSC Docket No. 12-053-U: In the Matter of the Application of Arkansas Electric Cooperative Corporation for Modification of Rates and Charges. Reviewed proposed interruptible credit riders in light of new state laws pertaining to the rate regulation of electric cooperatives. On behalf of Nucor Steel.

Arizona Corporation Commission Docket No. E-04100A-04-527: Application of Southwest Transmission Cooperative, Inc. for a Rate Increase. Provided cost allocation and rate design recommendations on behalf of the applicant.

Arkansas PSC Docket No. 09-071-U: In the Matter of the Application of Arkansas Electric Cooperative Corporation for Modification of Rates and Charges. Reviewed proposed interruptible credit riders in light of new state laws pertaining to the rate regulation of electric cooperatives. On behalf of Nucor Steel.

Virginia State Corporation Commission Case No. PUE-2007-00031 and PUE-2007-000033; Public Service Commission of West Virginia Case No.07-0508-E-CN; and Pennsylvania PUC Docket No. A-110172, Application of Trans-Allegheny Interstate Line Company for A Certificate of Convenience and Necessity to Construct a Transmission Line. Examined the feasibility of using demand-side management as an alternative to the proposed line. Testimony on behalf of the applicant.

PUCT Docket No. 31540: Proceeding to Consider Protocols to Implement a Nodal Market in the Electric Reliability Council of Texas Pursuant to PUC Subst. R. 25.501. Testimony before the PUCT on behalf of Nucor Steel and Chaparral Steel on demand side issues.

Public Service Commission of South Carolina, Docket No. 2005-1-E: Progress Energy Carolinas, Inc. Annual Review of Base Rates for Fuel Costs. Reviewed the utility's fuel costs and rates on behalf of a large industrial customer of the utility.

Railroad Commission of Texas, Docket No. 9400: Application of TXU Gas Company for a Rate Increase. Provided cost allocation and rate design testimony on behalf of a group of cities. Also provided testimony in a district court to support a Writ of Mandamous.

U.S. Bankruptcy Court, Southern District, In re. Texas Commercial Energy, LLC, Case No. 03-20366-C-11. Testified in support of a claim.

PUCT Docket No. 23950: Petition of Reliant Energy to Establish Price to Beat Fuel Factor. Presented (on the utility's behalf) a forecast of the Company's future sales of electricity.

PUCT Docket No. 23220: Petition for Approval of ERCOT Protocols. On behalf of Nucor Steel. Successfully introduced four coincident peak allocation of transmission costs.

PUCT Docket No. 22537: Application of Reliant Energy HL&P to Implement Wholesale Power Service – General Land Office Rate Schedule. Testified in support of tariff approval.

PUCT Docket No. 22355: Application of Reliant Energy HL&P for Approval of Unbundled Cost of Service Rate. Examined competitive opportunities that might be available to commercial and residential customers under various parties' rate design proposals.

PUCT Docket No. 22349: Application of Texas-New Mexico Power Company for Approval of Unbundled Cost of Service Rate. Requested (on behalf of the utility) funding for energy efficiency programs and system benefit fund programs.

PUCT Docket No. 22344: Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA 39.201 and PUC Substantive Rule, 25.344. On behalf of Nucor Steel. Introduced the concept of 4CP billing for transmission service for industrial energy consumers in ERCOT.

PUCT Docket No. 21527: Application of TXU Electric Company for Financing Order to Securitize Regulatory Assets. Evaluated application on behalf of Nucor Steel.

PUCT Docket No. 17942: Application for Approval of Time-of-Use Rate Options for TU Electric Company. Analyzed utility proposal on behalf of Nucor Steel Company.

PUCT SOAH Docket No. 473-96-0333: Application of TU Electric Company for Real-Time Pricing Proposal in Compliance with the Commission's Order in Docket No. 14570. Analyzed the utility's filing on behalf of Nucor Steel Company.

PUCT Docket No. 9491: Texas-New Mexico Power Company rate case. Described applicable prudence standards and explored purchased power, cogeneration, and conservation as alternatives to the completion of the TNP One power plant project. Analyzed the utility's filing on behalf of PUCT Staff.

PUCT Docket No. 6992 Remand: Texas-New Mexico Power Company power plant certification case. Projected the costs of standby, wheeling, purchased power and cogeneration over a forty-year horizon, and explored purchased power, cogeneration, and conservation as alternatives to the completion of the TNP One power plant project. Analyzed the utility's filing on behalf of PUCT Staff.

PUCT Docket No. 9300: TU Electric rate case. Recommended changes to proposed tariffs for interruptible service and explored other rate design and system planning issues. Analyzed the utility's filing on behalf of PUCT Staff.

PUCT Docket No. 8425: Houston Lighting and Power Company rate case. Analyzed proposed tariffs for interruptible service, standby service, economic development rates and wheeling services, and recommended alternative rates and calculation methodologies. Analyzed the utility's filing on behalf of PUCT Staff.

PUCT Docket No. 8422: Rita Blanca Cooperative tariff application. Proposed some modifications to the design of a proposed economic development tariff. Analyzed the utility's filing on behalf of PUCT Staff.

PUCT Docket No. 8363: El Paso Electric Company rate case. Provided recommendations regarding future generation mix and total fuels expenses. Analyzed the utility's filing on behalf of PUCT Staff.

PUCT Docket No. 7460: El Paso Electric Company rate case. Reviewed the demand forecasts upon which the utility relied in its decision to participate in the Palo Verde nuclear project. Analyzed the utility's filing on behalf of PUCT Staff.

PUCT Docket No. 7195/6755: Gulf States Utilities Company rate case. Reviewed the demand forecasts upon which the utility relied in its decision to initiate the River Bend nuclear project. Analyzed the utility's filing on behalf of PUCT Staff.

PUCT Docket No. 6992: Texas-New Mexico Power Company power plant certification case. Projected the availability of purchased power and confirmed its viability as an alternative to the proposed TNP One power plant. Analyzed the utility's filing on behalf of PUCT Staff.

PUCT Docket No. 6184: Economic Viability for South Texas Unit 2. Analyzed the capabilities of various resource planning models to assist in selecting an appropriate means of determining the reasonableness of completing a nuclear power plant construction project. Analyzed the utility's filing on behalf of PUCT Staff.

PUCT Docket No. 8191: Cherokee County Electric Cooperative rate case. Reviewed adjustments to test-year sales for weather normalization, demand, and numbers of customers data. Analyzed the utility's filing on behalf of PUCT Staff.

PUCT Docket No. 6375: Central Power and Light Company rate case. Reviewed adjustments to test-year sales for weather normalization, demand, and numbers of customers data. Critiqued the utility's long-term load forecast. Analyzed the utility's filing on behalf of PUCT Staff.

PUCT Docket No. 6105: Central Power and Light Company Avoided Cost calculation. Recommended rejection of the utility's long-term load forecast for the purpose of calculating long-run avoided costs. Analyzed the utility's filing on behalf of PUCT Staff.

PUCT Docket No. 6064: Houston Lighting and Power Company Avoided Cost calculation. Reviewed the utility's demand projections. Analyzed the utility's filing on behalf of PUCT Staff.

PUCT Docket No. 5994: Inquiry into the rates paid by Houston Lighting and Power Company to Qualifying Facilities. Projected future demand for electricity on the utility system and the need for firm cogeneration capacity. Analyzed the utility's filing on behalf of PUCT Staff.

PUCT Docket No. 8015: Amendment to TU Electric's certificate for the Comanche Peak nuclear plant. Reviewed the utility's future demand and capacity needs. Analyzed the utility's filing on behalf of PUCT Staff.

PUCT Docket No. 6526: TU Electric Company power plant certificate case. Reviewed the utility's demand projections. Analyzed the utility's filing on behalf of PUCT Staff.

PUCT Docket No. 5568: Texas-New Mexico Power Company rate case. Reviewed adjustments to test-year sales for weather normalization, demand, and number of customers data, and miscellaneous operations and maintenance expenses. Analyzed the utility's filing on behalf of PUCT Staff.

Attachment JZ-2

Direct Energy Business Unveils Service Alerting Customers to Likely 5CP Days in PJM Region

June 5, 2013

Email This Story
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Reporting by Karen Abbott • kabbott@energychoicematters.com

Direct Energy Business is now offering an email alert service in the PJM region as part of a new pilot program for 2013.

This free service includes email notifications throughout the summer months that will alert customers if a particular day shows medium or high probability of being one of PJM's coincident peak days.

Additionally, customers will have access to additional data that provides the details behind why the probability is medium or high.

In the PJM region, data from the five coincident peak days, as selected by the Independent System Operator (ISO), determines a business' peak load contribution (PLC), also known as a capacity tag for invoicing purposes. If customers can be forewarned of when these five days might occur, they have the opportunity, if they choose, to attempt to curtail or otherwise lower their demand during on-peak hours.

Factors such as weather, offline power plants, and monitoring PJM's grid demand reports and forecasts allow Direct Energy Business to provide customers with an estimate of how likely it may be for PJM to hit a coincident peak day on a particular day in the summer.

"Last year, our portfolio strategy team provided a similar alert system to PowerPortfolio customers in PJM as part of our consultative services, which received positive feedback. This sparked the creation of the peak demand probability alert service," said Mike Senff, vice president of sales and marketing of Direct Energy Business.

Attachment JZ-3

Jay Zarnikau & Dan Thal, *The response of large industrial energy consumers to four coincident peak (4CP) transmission charges in the Texas (ERCOT) market*, 26 UTILITIES POLICY 1 (2013).

The response of large industrial energy consumers to four coincident peak (4CP) transmission charges in the Texas (ERCOT) market

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Abstract

Large industrial energy consumers served at transmission voltage in the ERCOT market reduce their consumption up to 4% during intervals in which consumers are charged for transmission services. The response normally lasts two to three hours, since consumers do not know exactly which interval will set one of the four summer coincident peaks (CPs), which are the basis for transmission charges. Thus, the design of transmission prices in ERCOT has been successful in eliciting demand response from that market's largest industrial energy consumers. However, there is no noticeable response during some CPs, reflecting the difficulties in predicting the actual timing of the peak. The response by industrials served at primary voltage to the price signals is insignificant.

Keywords: Electricity pricing; transmission charges; ERCOT

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1. Introduction

When the Electric Reliability Council of Texas (ERCOT) wholesale market was redesigned to foster competition among generators and provide a foundation for retail competition during the 1999-2001 timeframe, the Public Utility Commission of Texas (PUCT) grappled with how to charge consumers for transmission services under the new unbundled market structure. Under the resulting policy, large industrial energy consumers with interval data recorders (IDRs) are charged for transmission services based on the individual consumer's contribution to four coincident peaks (4CPs), i.e., the 15-minute intervals of highest demand on the ERCOT system in each of four summer months -- June, July, August, and September. The total level of compensation provided to transmission owners is approved by the PUCT each year. Transmission costs are then apportioned to each load, or user of the transmission system, based on its share of total demand during these 4CPs. The costs are recovered through levelized monthly charges paid the following year. Revenues from the transmission charges are collected by the retail electric provider (REP) providing electricity to the consumer at the retail level and these revenues are ultimately passed through to transmission owners.

A consumer that can reduce its demand for electricity by 1 MW during each of the four CPs can save about $25,000 in transmission charges the following year, as illustrated in Table 1 for energy consumers in the three largest transmission and distribution utility (TDU) services areas. This potential avoidance of transmission charges provides a strong incentive for industrial energy consumers with some flexibility in their operations to engage in "4CP chasing." In 2012, 14 REPs and eight municipal utilities or cooperatives, as well as a number of consulting firms, operated 4CP forecasting services to notify industrial energy consumers of opportunities to reduce their transmission costs by strategically reducing their energy purchases during the summer peaks. (Wattles and Farley, 2012)

Table 1.
Example Savings Calculations for a 1 MW Reduction in Demand during 4CP Periods

	Monthly Charge per Previous Year's 4-CP kW	Annual Savings from a 1 MW demand reduction during 4CP periods
CenterPoint Energy		
Primary Voltage (with IDR)	$2.1546	$25,855.20
Transmission Voltage	$2.1187	$25,424.40
Oncor		
Primary Voltage (with IDR)	$2.5684	$30,820.25
Transmission Voltage	$2.6368	$31,641.71
AEP-Texas Central		
Primary Voltage (with IDR)	$1.9250	$23,100.00
Transmission Voltage	$1.7180	$20,616.00

Source of rates:
http://www.puc.texas.gov/industry/electric/rates/Trans/TDGenericRateSummary.pdf
Last accessed December 15, 2012. The calculations assume the customer has a power factor of one.

Despite the significant potential savings, not all industrial energy consumers respond to transmission prices. Some industrial facilities have little flexibility in their operations. A curtailment may impose economic costs upon some consumers in excess of the value of the potential savings in transmission costs. Energy consumers with the ability to easily interrupt or curtail their purchases from the grid and commit to providing an ancillary service to the ERCOT market (i.e., commit to curtail at the request of the system operator to provide an operating reserve) cannot concurrently chase 4CPs. This could limit the response of an interruptible load that had elected to provide an ancillary service in ERCOT's day-ahead market or has an obligation with a load-serving entity through a bilateral arrangement to "be available" to provide a curtailment at ERCOT's request.

Demand response to the 4CPs may also be hampered by difficulties in predicting the CPs. Until a summer month is over, the interval with the highest level of system demand is not known. It is particularly difficult to discern whether a hot day during the first week of a month will indeed set a CP, since weather forecasts for the later days of the month will not yet be widely available, and any available forecasts so early in a month will possess considerable uncertainty. Further, a strong response to a likely CP may move the monthly peak demand to a different 15-minute interval within the same day or to another day.

When the service areas of the investor-owned TDUs were opened to retail competition in January 2002, consumers with a non-coincident peak demand or "billing demand" of over 1 MW were required to have Interval Data Recorders (IDRs) installed. The interval-level measurements obtained from IDRs facilitates the settlement of energy generation transactions and provides a measurement of each large load's contribution to the 4CPs. The IDR threshold was lowered to 700 kW in 2006. (Raish and Linsey, 2004)

Until recently, the contribution of smaller consumers (e.g., residential and commercial energy consumers) to the 4CPs was difficult to cost-effectively measure, so generic profiles were used to approximate their level of demand in given time periods. As a result, there is no direct benefit to an individual residential or small commercial consumer from reducing electricity use during a 4CP. Perhaps this situation will change, once advanced metering systems are fully deployed.

On occasion, the staff of ERCOT has provided graphs showing a significant drop in demand from large industrial energy consumers during a 4CP. In previous studies of the response of industrial energy consumers to price signals in the ERCOT market, real-time energy prices were combined with the 4CP transmission prices and consumer response to the combined prices was analyzed. It was apparent that certain customers responded to wholesale market price signals – either the 4CP charges, real-time energy prices, or both. (Zarnikau and Hallett, 2008; and Zarnikau, et. al. 2007) In this analysis, the focus is solely on the 4CP transmission charges.

In the U.S., demand response activities are increasing. (FERC, 2012) The price elasticity of demand of industrial electricity consumers has been estimated in a number of previous studies, including Caves and Christensen (1984), Boisvert et al (2007), Herriges (1993), Schwarz et al (2002), Taylor et al (2005), and Choi et al (2011). In these studies, the response to changes in wholesale generation prices or retail energy prices was the subject. The only previous analysis of customer response to CP transmission prices with which we are aware is Liu et al (undated). That study simulated the benefits to data centers of avoiding transmission charges, rather than analyzing the actual consumption behavior of industrial facilities.

This paper contributes a more-detailed analysis of consumer response to 4CP in ERCOT than has been conducted to date. In Texas, a better understanding of demand response is critically important in light of ERCOT's "energy-only" market design which relies extensively on market forces to balance supply and demand. As low natural gas prices have impaired the profitability of constructing new power plants in recent years, means of reducing peak demand and preserving system reliability through demand response have become increasingly important.

It is anticipated that this analysis will also prove instructive to those faced with the task of designing tariffs for transmission service for other markets or utility systems. An important consideration in the design of transmission prices is the impact such pricing will have on system demand. While the design of policies to foster the efficient operation of wholesale electricity markets tends to focus on electricity generation, transmission pricing can make an important contribution toward reliability and efficiency by affecting consumption behavior during peak periods, as is demonstrated in this analysis.

The following section uses a regression approach to explore the degree to which these two groups of large energy consumers respond to the transmission prices. Section III estimates the response of consumers served at transmission voltage to the 4CP-based transmission prices using an historical baseline approach. The final section summarizes our findings and offers some observations.

2. Do Large Consumers Respond to Transmission Prices?

As noted above, large consumers of electricity in ERCOT with their interval-level consumption metered with IDRs can realize significant cost savings by reducing their purchases during the 4CPs. But, to what degree do they indeed take advantage of this opportunity and respond to this price signal?

To explore this question, 15-minute interval aggregated load data for the two groups of energy consumers thought most likely to respond to 4CP events were obtained from the staff of ERCOT. These groups were 1) consumers with a non-coincident peak demand (billing demand) that exceeded 1 MW at least 10 times since January 2002 and were served at transmission voltage and 2) consumers served at primary voltage with a peak demand meeting these same criteria. The former group includes many very large refineries and chemical production facilities along the Gulf Coast. Data for the period from January 2007 through mid-2012 was used in this analysis.

Regression models were used to screen whether demand by the two groups of consumers during summer afternoons were affected by the transmission price signals. The observations used in the estimation were confined to the nine 15-minute intervals from 3:00 pm through 5:15 pm (intervals 61 through 69) during weekday summer months. In recent years, the monthly CPs during the summer have always fallen within this period.

Because the timing of the CPs cannot be perfectly predicted (and a response by consumers to an anticipated CP period could shift CP to a different interval), we are interested in detecting both 1) any reduction in demand during an actual CP and 2) changes in consumption during other intervals when a CP might have been considered probable. To determine the intervals when consumers might have thought a CP was likely, a logistic regression model was used to estimate the historical relationship between a CP and a set of explanatory variables. Variables representing the month of the year and interval within the day were included to capture seasonal and diurnal factors affecting electricity use. The variable *Interval61_62_63* represents the period from 3 p.m. to 3:45 p.m., while *Interval 64_65_66* covers the period from 3:45 p.m. to 4:30 p.m. While a CP may occur later in an afternoon than 4:30 p.m., a third variable was not included in the model, to avoid multicollinearity. Binary monthly variables were used to represent the months of June, July, and August. A September variable was not included, to avoid multicollinearity. The real-time market price of electricity was included as an explanatory variable, to recognize that the response by consumers to a high price could reduce the odds of setting a CP, *ceteris paribus*. Or, perhaps a high price would signal the possibility of a CP to a consumer monitoring market prices. The real time energy price is the market-clearing price of balancing energy during the period in which ERCOT had a zonal market structure, and the zonal average of locational marginal prices for the period since ERCOT adopted a nodal market structure. Energy prices (expressed in dollars per MWh) were obtained from ERCOT's website. Total system demand during the same interval of the previous day was included to recognize that patterns in demand across consecutive days may affect the likelihood of a CP, or the perception that one might occur. Finally, since summer peak loads are largely determined by air conditioning usage in Texas, a variable was constructed to represent the difference between the actual temperature in a central location within the ERCOT market (Austin) for a given interval and the highest temperature reading during the given month. Since interval-level temperature data were not available, it was assumed that all intervals within each hour had the same temperature. Of course, at any given time prior to the end of the month, a consumer will not have complete information about hourly temperatures for the entire month. Thus, our use of this variable implicitly assumes that a consumer has access to – and responds -- to reasonably accurate weather forecasts. As noted earlier, the uncertainty surrounding weather forecasts makes it more difficult to predict CPs that occur early in a month. A variable representing "heat storms," representing the cooling degree days over four consecutive days with declining weights assigned to previous days, was also tested. However, it yielded inferior results to a simpler measure of relative temperature and consequently was not used.

Estimation results are presented in Table 2. As one would expect, the greater the gap between the temperature of an interval and the highest temperature reading for the month, the lower the odds of setting a CP. An increase in energy prices and an increase in system load during the previous days tend to raise the odds of reaching a CP, holding other variables constant. The dummy variables representing the month of the year and time of day tended to not have significant impacts. The high percent concordant suggests the predictive power of the model is quite satisfactory.

Table 2

Estimation Results from Logistic Regression Model used to Determine Probability of a CP

Variable or Statistic	Odds Ratio Estimate (p-value in parentheses)
Temperature Relative to Monthly Highest Temperature	-0.741 (<.0001)
Energy Price in Real-Time Market	1.001 (.0248)
June Dummy	0.426 (.1919)
July Dummy	0.439 (.2081)
August Dummy	0.45 (.2707)
Interval61_62_63 Dummy	0.077 (.0161)
Interval64_65_66 Dummy	0.79 (.6032)
System Demand Previous on Same Interval of Previous Day	1.001 (.013)
Percent Concordant	94
Percent Discordant	5.2

From the logistic regression model, the estimated probability of a CP during every interval of the estimation period (summer weekday late afternoons from 2007 to mid-2012) was obtained. Some scaling was performed to ensure that the probability of setting a CP over all intervals in a given month was equal to one. Two new variables were created to represent intervals when the estimated probability was greater than 1.4%, yet a CP was not actually set. *NearCP Low Probability* was set to one when the probability of a CP in a given interval was between 1.4% and 6.5%, and *NearCP High Probability* was coded as one for periods with a probability of reaching summer month CP was over 6.5%. While the variable *CP* represents may represent perfect foresight of the CP interval, the *NearCP* variables might reflect imperfect foresight. The *NearCP* variables may also encompass periods that would have established a peak, had consumers not responded to transmission prices. The 1.4% cutoff point was adopted since it resulted in numbers of 15-minute intervals with a high likelihood of a CP (but no actual CP) ranging from 6 per month (1.5 hours) to 29 per month (7.25). It was thought unlikely that a consumer hoping to avoid transmission charges would respond by curtailing its energy use in a greater number of periods than this. The cut-off point distinguishing a *NearCP High Probability* from a *NearCP High Probability* was set so as to maximize the R^2 of the linear regression model used to explain variations in electricity purchases by energy consumers served at transmission voltage. Model runs using the raw probability values for hitting a CP as a variable (rather than a pair of dummy variables) provided inferior statistical results.Having now constructed variables to represent intervals when the response of a consumer chasing CP's might have been expected to respond, a set of simple linear models was used to detect whether the presence of an actual CP or a *NearCP* (either associated with a high probability or low probability of occurrence) had any detectable effect on the electricity consumption of either group of large energy consumers. The dependent variables represented the energy consumption of the two groups, expressed in kWh per 15-minute interval. The explanatory variables were the real-time energy price (dollars per MWh), the presence of a CP (coded with a 1 if the interval was a CP and 0 otherwise), the

NearCP High Probability (coded with a 1 if the interval had a high probability of setting CP and 0 otherwise), the similarly-coded *NearCP Low Probability,* and variables representing the month of the year and interval within the day to capture seasonal and diurnal factors affecting electricity use. Again, the variable *Interval61_62_63* represents the period from 3 p.m. to 3:45 p.m., while *Interval 64_65_66* covers the period from 3:45 p.m. to 4:30 p.m. The real time energy price (the same variable as was used in the logit model) was used to distinguish the response by consumers to a high market price of electricity generation from a 4CP-based transmission price. The temperature at a central location within the ERCOT market (i.e., Austin) was also used a as control variable.

Regression results are provided in Table 3. In the regression model which seeks to explain interval-level demand of energy consumers served at primary voltage, the high *p*-value on the coefficient estimated for the variable representing the CP interval suggests no significant response by primary voltage customers to CPs, after controlling for the effects of real-time market prices, temperature, and time-of-day and month-of-year effects. Similarly, the effect of a *NearCP* (either one associated with a high probability or low probability of occurrence) upon the energy purchased by consumers served at primary voltage does not significantly differ from zero.

In contrast, a CP reduces the consumption of consumers served at transmission voltage by 36,865 kWh on average and after controlling for the effects of the other variables considered. A *NearCP* reduces the energy consumption of consumers served at transmission voltage by a lesser, but still significant, amount – perhaps reflecting the success of these consumers in identifying a true CP. Indeed, the response to a *NearCP* with a high probability is much stronger than the response to a *NearCP* which is less probably. Similar results were obtained when the variable representing the 15-minute interval of the CP was replaced with a variable representing the day in which the CP occurred. It is also interesting to note that the consumers taking service at transmission voltage are quite responsive to real-time energy prices, whereas the consumers served at primary voltage do not appear to react to changes in wholesale electricity prices. While the electricity demand of consumers served at primary voltage is quite temperature-sensitive, temperature changes have no significant impact on the electricity demand of the generally-larger industrial energy consumers served at transmission voltage.

Table 3

Estimated Impacts of CP Events and Other Factors on Load (in kWh) of Customers Served at Transmission and Primary Voltages

(*p*-values are provided in parentheses.)

Variable or Statistic	Transmission Voltage Consumers (kWh/Interval)	Primary Voltage Consumers (kWh/Interval)
R^2	0.102	0.257
Intercept	825,633 (<.0001)	447,352 (<.0001)
CP Interval	-36,865 (.0003)	3,405 (.5310)
NearCP_High Probability Interval	-11,723 (.0774)	3,072 (.3863)
NearCP_Low Probability Interval	-7,918 (.0119)	401 (.7929)
Energy Price in Real-Time Market	-9.7442 (<.0001)	1.532 (.1943)
June Dummy	34,643 (<.0001)	16,639 (<.0001)
July Dummy	35,404 (<.0001)	12,569 (<.0001)
August Dummy	37,550 (<.0001)	21,899 (<.0001)
Austin Temperature (degrees F)	-15.782 (.8811)	1,131 (<.0001)
Interval61_62_63 Dummy	6,643 (.0002)	14,114 (<.0001)
Interval64_65_66 Dummy	1,301 (.4631)	7,710 (<.0001)

3. Estimating the Impacts with an Historical Baseline Approach

Graphical analysis illustrates that the response to a CP is quite pronounced on certain days. Figures 1 and 2 compare actual interval-level energy consumption by transmission voltage consumers against a baseline usage pattern. The baseline was constructed by averaging the load levels exhibited by this group of consumers over the five previous weekdays. Weekend days were not included in the baseline calculations, since no CPs were set on weekends during the timeframe studied here. Near-CP days were also excluded from the baselines, as these days tend to have CP responses, so including them would blur the picture. The historical baseline was then scaled, so that the total energy up to 15:00 (3 p.m.) for the baseline matched the total energy consumed up to 15:00 on the CP day. On the two days represented in the first two figures, the response to the anticipated CP appears obvious. While the CPs on these two days actually occurred during intervals 67 and 68 -- ending at 16:45 (4:45 p.m.) and 17:00 (5 p.m.), respectively -- the response started earlier and diminished later than the actual CP interval, since the consumers did not know which interval would set the CP. Thus the period of response is typically 2 or 3 hours.

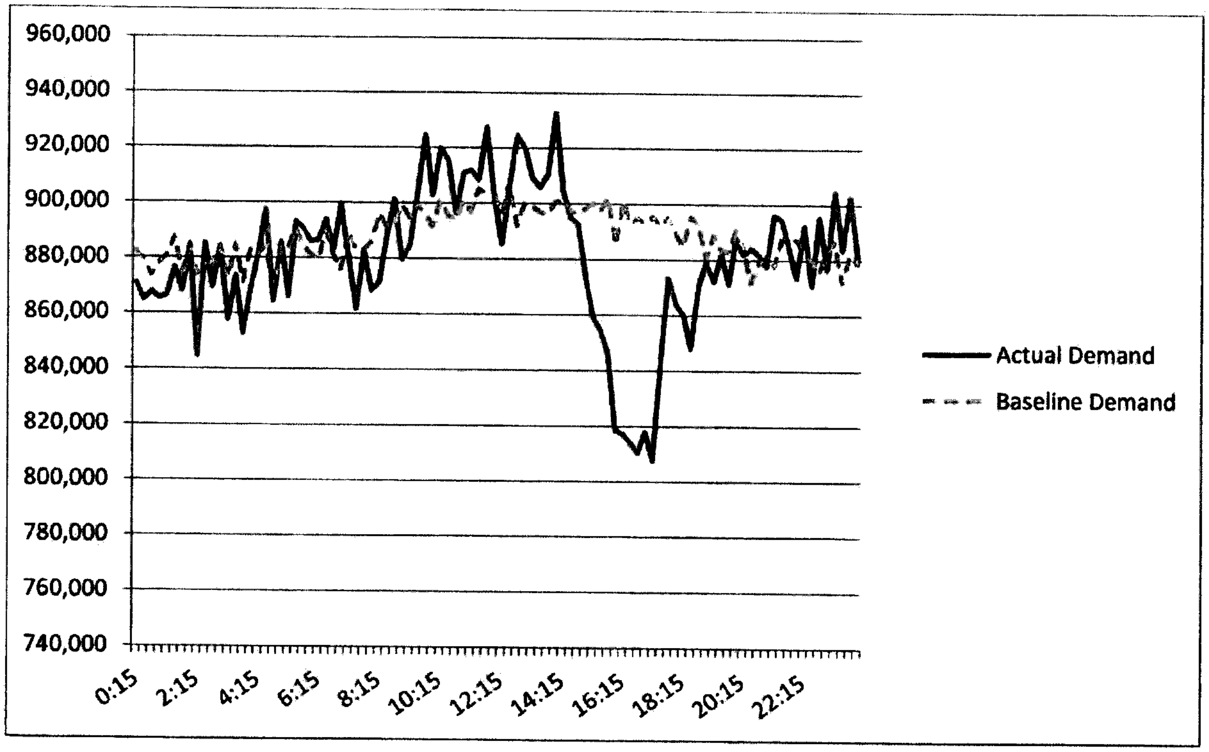

Fig. 1. Energy Consumption (in kWh) by Transmission Voltage Customers on June 16, 2008, Contrasted against Baseline Energy

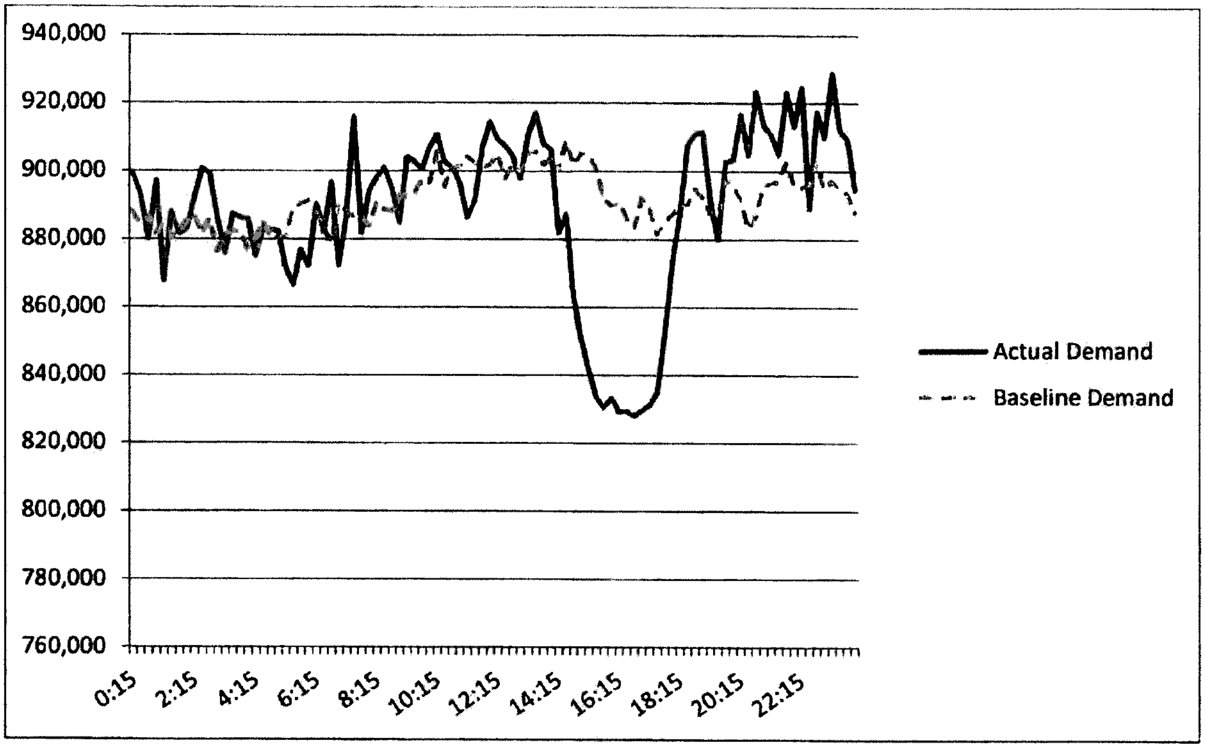

Fig. 2. Energy Consumption (in kWh) by Transmission Voltage Customers on June 26, 2011, Contrasted against Baseline Energy

On some days, it appears as though this group of consumers failed to anticipate the CP, as demonstrated in Fig. 3. The CP was reached in the interval ending 16:45 on the September 2008 CP. A lack of response was sometimes exhibited when the CP occurred early in the month, at which time weather conditions and the resulting load levels for the entire month would be difficult to anticipate.

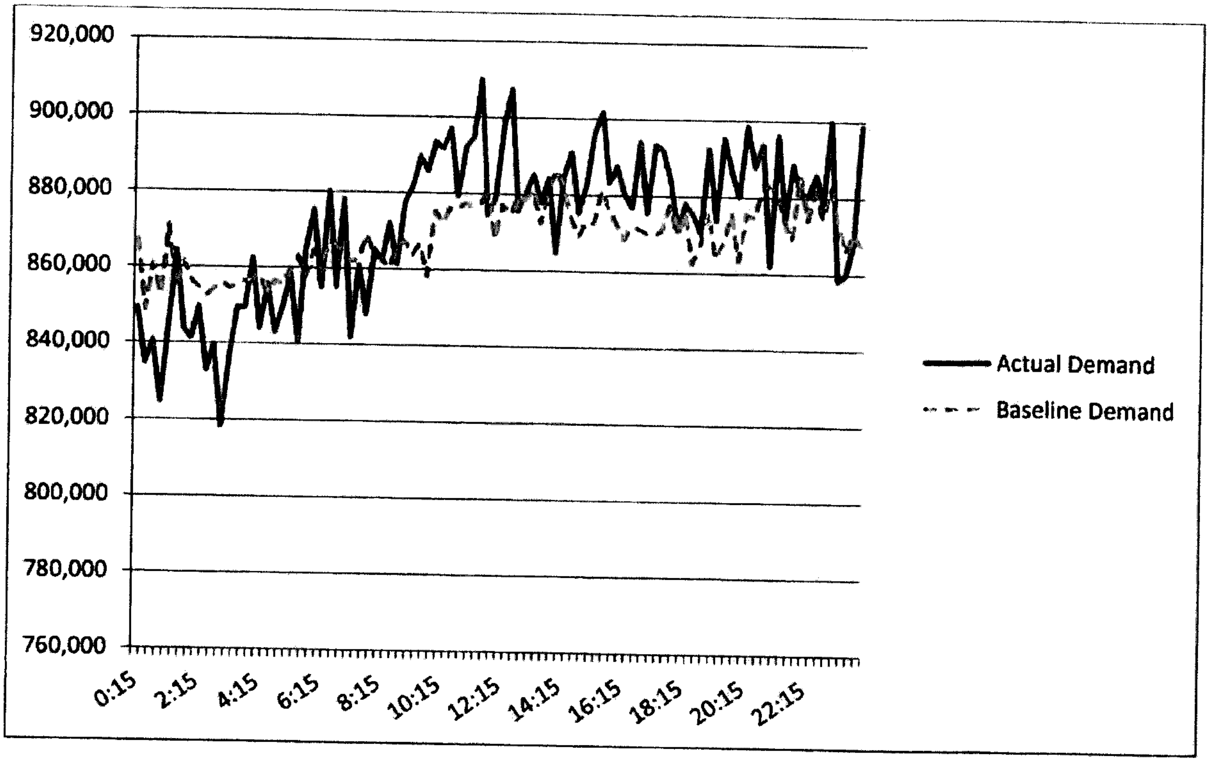

Fig. 3. Energy Consumption (in kWh) by Transmission Voltage Customers on September 2, 2008, Contrasted against Baseline Energy

Finally, there are some days when both the load for the day containing the CP interval and the baseline load show a significant drop during the late afternoon, as can be seen from Fig. 4. Presumably, this reflects a situation where consecutive days appear to be equally likely to set the CP, and consumers engage in a pattern of reducing their energy consumption during the late afternoon in each of the days.

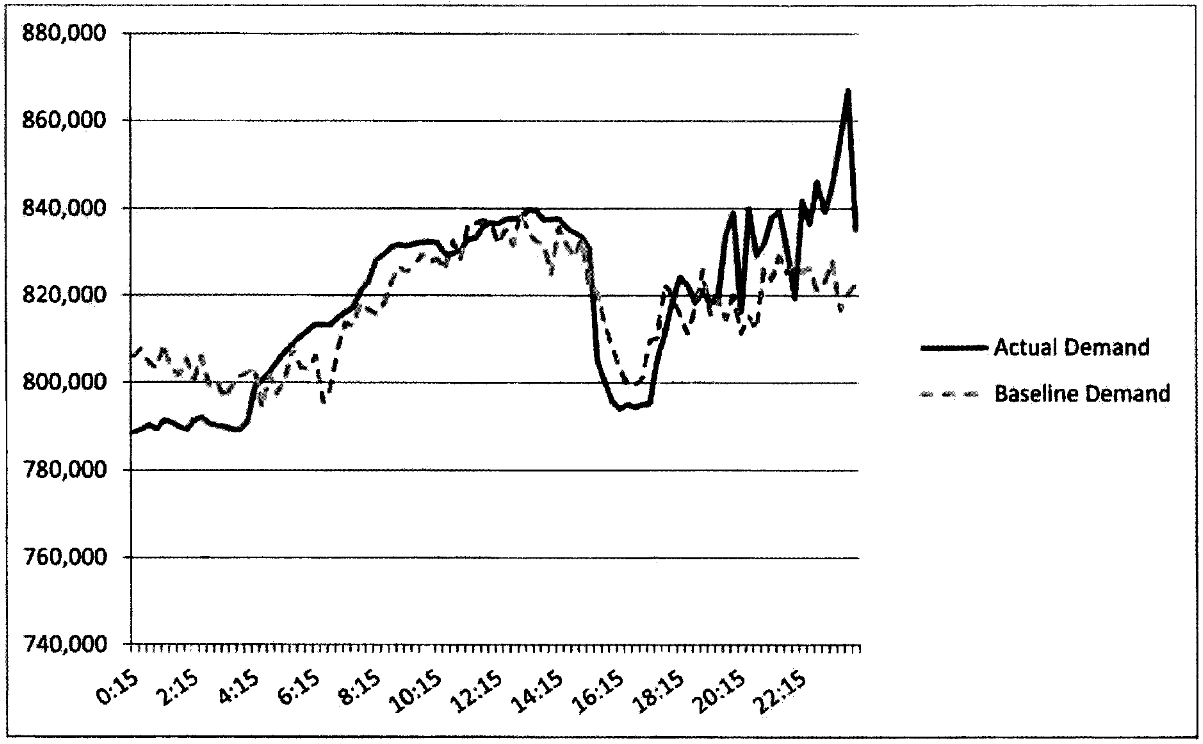

Fig. 4. Energy Consumption (in kWh) by Transmission Voltage Customers on June 21, 2010, Contrasted against Baseline Energy

The estimated demand reduction during each of the CP events from 2007 through mid-2012 is provided on Table 4. A baseline constructed from the five previous weekdays (excluding near-CP days) was again used to the estimate the load pattern which would have prevailed had a CP not been expected. If the previous month's CP was among the five previous weekdays – as was the case for the August 2008 CP, then the previous month's CP was removed from the baseline calculation and replaced with an earlier day.

Table 4.
Estimated Demand Reduction During CP Intervals

Year	Month	Day	Interval	Actual kWh	Baseline kWh	kWh Drop within Interval	Demand Reduction in MW	Percentage Drop in Load Served at Transmission Voltage
2007	6	19	16:45	921,415	909,321	-12,094	-48	-0.53%
2007	7	12	16:30	867,977	895,888	27,910	112	1.25%
2007	8	13	15:30	885,253	906,844	21,591	86	0.95%
2007	9	7	16:00	848,865	902,231	53,366	213	2.37%
2008	6	16	16:45	810,464	895,107	84,643	339	3.78%
2008	7	31	16:45	817,820	848,674	30,854	123	1.45%
2008	8	4	17:00	809,458	877,318	67,860	271	3.09%
2008	9	2	16:45	894,133	871,420	-22,713	-91	-1.04%
2009	6	25	16:15	755,751	821,269	65,518	262	3.19%
2009	7	13	17:00	782,326	816,379	34,053	136	1.67%
2009	8	5	16:00	770,848	839,342	68,493	274	3.26%
2009	9	3	16:00	808,405	846,666	38,262	153	1.81%
2010	6	21	16:45	794,491	799,680	5,189	21	0.26%
2010	7	16	16:30	813,729	871,681	57,952	232	2.66%
2010	8	23	16:00	779,120	802,858	23,738	95	1.18%
2010	9	14	16:45	785,135	850,913	65,778	263	3.09%
2011	6	15	17:00	806,468	893,428	86,959	348	3.89%
2011	7	27	16:30	824,147	902,259	78,112	312	3.46%
2011	8	3	17:00	819,712	910,745	91,033	364	4.00%
2011	9	2	16:30	796,848	863,959	67,111	268	3.11%
2012	6	26	16:30	829,475	886,217	56,743	227	2.56%
2012	7	31	17:00	723,581	776,613	53,032	212	2.73%

Response to transmission prices appear to be generally increasing over time. In recent years, consumers served at transmission voltage reduced their electricity purchases up to 4% during a summer CP, if a baseline calculation using previous days is used to quantify the impact.

The average energy reduction over all 22 CP events reported in Table 3 is 47,427 kWh. This is higher than the 36,861 kWh energy reduction implied by the coefficient estimate presented in Table 3, which controls for the effects of market prices. Relatively high prices may be expected during a summer peak and some large industrial energy consumers in the ERCOT market purchase energy with pricing based upon real-time energy prices, as confirmed by the regression results presented in Table 3. Thus some of the demand reduction estimated against an historical baseline may actually be attributable to consumer response to a high energy price. The regression approach strives to separate the influences of these two motivations for demand response, whereas the historical baseline approach does not.

4. Conclusions

Industrial energy consumers served at transmission voltage reduce their energy purchased by up to 4% in response to a CP – the basis for recovering transmission costs from consumers in the ERCOT market. Given that ERCOT's total annual system peak demand is slightly over 66,500 MW, a reduction of 364 MW (the largest demand reduction estimated during a CP using an historical baseline) impacts ERCOT's summer peak by less than six-tenths of one percent. During peak, consumers served at transmission voltage contribute about 5.4% of ERCOT's total demand.

Responsiveness to transmission prices has generally increased over time. The magnitude of the response appears to be related to the certainty or predictability of the timing of the CP.

As ERCOT strives to maintain reliability under its energy-only market structure, this approach to transmission pricing is one market feature with considerable value as a source of demand response. An expansion of direct 4CP pricing of transmission services to smaller loads (e.g., residential and commercial customers) should be considered, now that advanced meters have been widely deployed in the ERCOT power region. Technology which will facilitate the response of consumers to likely peaks should be encouraged, including better communications, control, and metering infrastructure.

The estimates presented here – ranging from negative values, suggesting an absence of any response, up to 364 MW -- are lower than the demand reduction of 500 MW that ERCOT commonly assumes as a response to both 4CP pricing and high real-time prices during the peak summer hour of the year. Yet, this analysis is confined to large industrial energy consumers that purchase power at transmission voltage. Additional demand reduction during peak periods comes from demand response programs implemented by municipal utilities or rural electric cooperatives within the ERCOT power region and programs within the competitive retail market operated by REPs involving smaller loads. Consequently, the demand reduction estimates presented here appear to be compatible with ERCOT's planning assumption.

Issues surrounding the appropriate method to use for the allocation and recovery of transmission costs frequently arise in rate cases and in market design. There are great differences in how each of the world's restructured markets have approached the problem of recovering the cost of transmission services from load-serving entities and industrial energy consumers. (PJM, 2010) If a prominent objective of rate design or market design is to encourage demand response during peak periods, ERCOT's experience demonstrates that a 4CP approach may prove valuable.

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Attachment JZ-4

Frontier Associates, Report to the Staff of the Electric Reliability Council of Texas, *2013-2014 Retail Demand Response and Dynamic Pricing Project, Final Report* (June 23, 2014), http://www.ercot.com/content/services/programs/load/2013-2014_DR_and_PriceResponse_Survey_AnalysisFinalReport.pdf.

2013-2014 Retail Demand Response and Dynamic Pricing Project

Final Report

To:

Staff of the Electric Reliability Council of Texas (ERCOT)
800 Airport Road
Taylor, Texas 76574

From:

FRONTIER ASSOCIATES

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June 23, 2014

Public Version

FRONTIER ASSOCIATES

Table of Contents

Executive Summary

This report provides estimates of the amount of demand response that is occurring outside of ERCOT's formal markets for energy and ancillary services and outside of ERCOT's Emergency Response Service (ERS) program. This analysis is based on data collected through a survey of load-serving entities (LSEs) -- including Retail Electric Providers (REPs), municipal electric systems, and rural electric cooperatives serving the ERCOT power region.

Demand Response to 4CP Events

During one of the four summer coincident peak (4CP) intervals used to recover transmission costs from consumers with interval data recorders (IDRs) and LSEs, we estimate about 500 MW of demand reduction. About half of this response is from energy consumers served at transmission voltage in areas opened to retail competition. A similar amount of demand reduction may be traced to programs operated by non-opt-in entities (NOIEs). The demand reduction achieved through the NOIE programs varies considerably during different events and we have been unable to independently verify the impacts reports by the NOIEs. So we are using a "round number" to report the impacts of the NOIE programs here.

Table ES.1: Estimated Average Demand Response During a 4CP in 2013

	Total MW
Demand Response from Energy Consumers Served at Transmission Voltage in Competitive Areas (regardless of their participation in formal programs) (1)	250
Programs Implemented by NOIEs (2)	200
Other Load Control Programs activated during a CP	Small
Real Time Pricing (RTP) and Block and Index (BI) Programs (incidental impacts during a CP)	Small
Rough Estimate of Other Response not otherwise accounted for (3)	50
TOTAL	500
Notes:	
(1) An historical baseline calculation yields an average estimate of 251 MW for the four CPs in 2013. Regression analysis suggests a reduction of 201 MW on average over the past 5 years.	
(2) Based on a review of savings estimates reported by NOIEs. We have been unsuccessful in independently confirming these estimates.	
(3) This is a conservative estimate based on judgment, to account for response by industrials with IDRs served at a voltage other than transmission and industrials within NOIE service areas.	

There is some "Other Response" that is similarly difficult to independently verify with the data available to us. Yet, we know anecdotally that it exists. This might include response by large industrial energy consumers served by NOIEs and the response of energy consumers with IDRs served at a voltage other than transmission. With only aggregate NOIE-level data or aggregate consumption for consumers served at primary voltage to us, we were unable to detect this response. Our conservative estimate of 50 MW is based on judgment.

One REP-sponsored Other Load Control program was deployed during one of the CPs in 2013, but the impact of this 15-minute deployment which overlapped part of the interval setting the CP was difficult to detect.

About three-quarters of the demand reduction during 4CPs is coming from larger commercial, industrial, and institutional consumers. The source of the other one-quarter is from the residential sector, as noted in Figure ES.1. This estimate was informed by a review of the composition of participants in the NOIE programs.

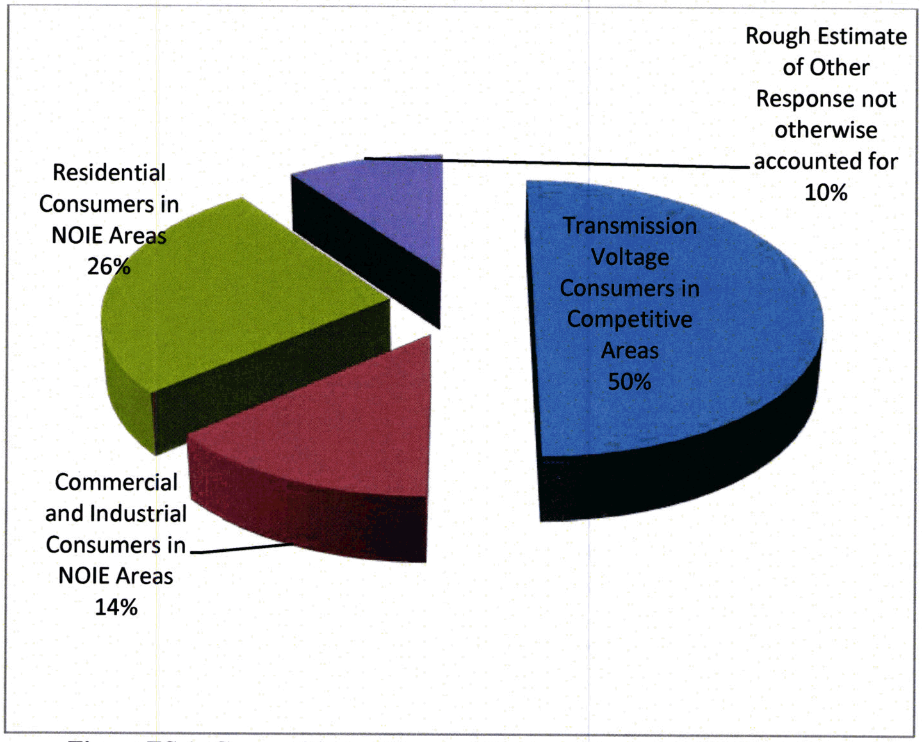


Figure ES.1: Composition of Demand Response during a 4CP by Source

We note that our estimate of about 500 MW is lower than the estimates of demand response during 4CPs that ERCOT had earlier estimated.[1] Consequently, we conducted discussions with the ERCOT staff to identify the differences, and the ERCOT staff conducted some supplemental analysis.

Demand Response to Spikes in Wholesale Prices

The demand reduction in response to price spikes in 2013 was around 432.5 MW, as shown in Table ES.2. Most of this came from larger commercial and industrial energy consumers served through real-time pricing programs and block and index programs. The load control programs of the NOIEs can have a large impact, as well.

[1] Calvin Opheim, *Load Forecasting Process Review*, presentation to the Generation Adequacy Task Force, October 7, 2013, slide 14.

Table ES.2: Estimated Demand Response During a Spike in Wholesale Energy Prices in 2013 (1)

(Load Zone Settlement Point Price above $3,000/MWh)	
	Total MW
RTP and BI Programs	
Customers with IDR Meters	180
Customers with AMS Meters	2
Rough Estimate of Other Response not otherwise accounted for (2)	50
Load Control Programs Implemented by NOIEs	200
Peak Load Rebate Programs (3)	0.5
TOTAL	432.5
Notes:	
(1) There were very few price spikes in ERCOT in 2013. Consequently, many programs were not activated and the estimates here do not reflect potential demand reduction. Methodology: Regression analysis.	
(2) This is a conservative estimate based on judgment, to account for response by industrials with IDRs served at a voltage other than transmission and industrials within NOIE service areas.	
(3) A discussion of the data and calculations used to derive our estimate of the demand reduction from Peak Load Rebate Programs has been removed from this "public" report, in order to protect confidential information from disclosure.	

We detected a strong increase in demand reduction as wholesale market prices increase, as noted in Figure ES.2.

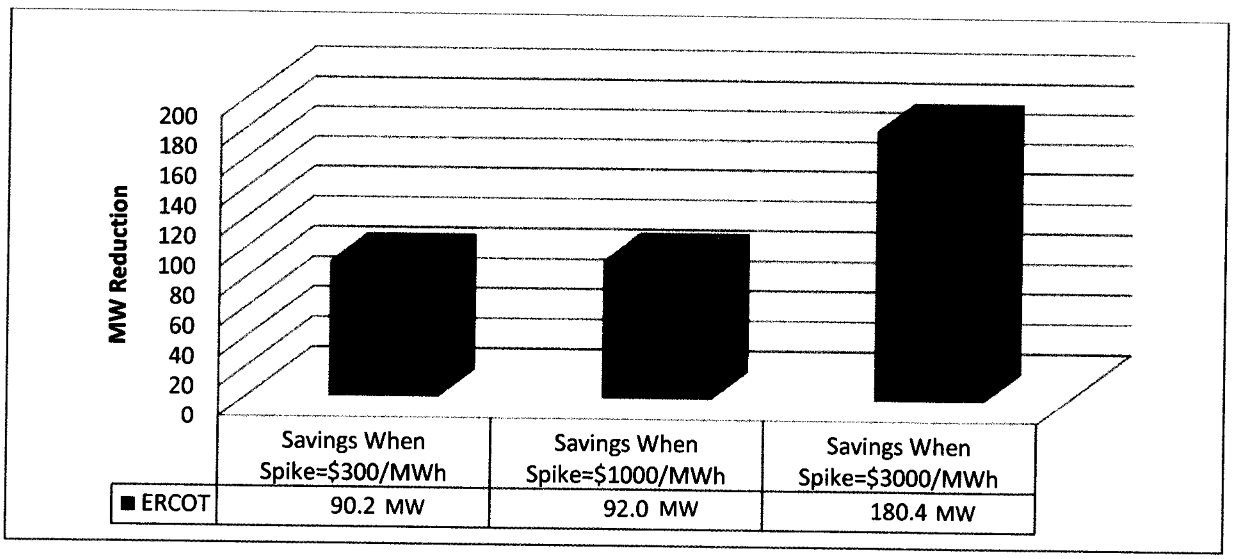


Figure ES.2: Demand Response by Consumers with IDRs Increase as the Wholesale Market Price Increases

Chapter 1: Introduction

A better understanding of demand response (DR) is important to maintaining reliability in the Electric Reliability Council of Texas (ERCOT) power market in light of ERCOT's "energy-only" market design which relies extensively on market forces to balance supply and demand. While the amount of curtailable or interruptible load participating in ERCOT's formal markets and the Emergency Response Service program is well-known to ERCOT's system operators and planners, the amount of demand response that is occurring outside of formal markets in response to a spike in wholesale prices or a program implemented by a load-serving entity (LSEs) is not well-understood. Deployments of such "out-of-market DR"[2] are generally not reported to ERCOT in advance or in real-time.

Using its authority under Public Utility Commission of Texas (PUCT) Substantive Rule §25.505(e)(5), ERCOT has periodically surveyed LSEs to determine the magnitude of out-of-market DR activities. This report summarizes the results obtained through the survey conducted by ERCOT during the summer of 2013.

The types of DR products for which data were collected include:

- Time of Use (TOU) pricing
- Critical Peak pricing/rebates
- Real-Time pricing
- Direct Load Control
- Programs designed to facilitate response to Four Coincident Peak (4CP) transmission charges

As a component of ERCOT's survey, Retail Electric Providers (REPs) serving energy consumers in the areas of ERCOT opened to retail competition were asked to provide the ESI IDs or account numbers of consumers participating in a REP-sponsored out-of-market DR program during the summer of 2013. This report provides an independent quantification of the customer-specific response to various REP-initiated deployments.

While REPs were asked to identify the consumers participating in time-of-use pricing (TOU) programs such as "Free Weekends" and "Free Nights" programs, it was decided that the analysis described in this report would focus on "event-driven" DR. Nonetheless, we have included data summarizing the popularity of TOU programs during the summer of 2013 in this report, albeit without any quantification of the change in load patterns resulting from such programs.

Information was also collected pertaining to DR programs offered by non-opt-in entities (NOIEs, which tend to be municipal utility systems and rural electric cooperative utilities which have not opted-in to retail competition). However, since the Smart Meter Texas (SMT) repository of interval-level usage information does not include data for consumers in the NOIE areas, no independent analysis was conducted to quantify the impacts from the NOIE programs.

[2] The California Public Utilities Commission and the Midcontinent Independent System Operator (MISO) have adopted the term "Load Modifying Resource Demand Response" to describe demand response programs which are not directly dispatched by an ISO.

Table 1.1 summarizes the numbers of REPs reporting programs and the number of programs provided by these REPs under various categories.

Table 1.1: Programs by REPs - Summary Table[3]

	REP1	REP2	REP5	REP6	REP7	REP8
OLC	11	4	--	--	--	--
RTP	--	--	4	--	--	--
PR	--	4	--	--	--	--
BI	--	--	1	4	--	--
4CP	--	--	--	--	4	4
OTHER	--	--	4	--	--	--

Where:

- OLC = Other Load Control
- RTP = Real-Time Pricing
- PR = Peak Rebate
- BI = Block & Index pricing
- 4CP = REP-initiated 4CP notification
- OTH = Other

The survey responses from REPs in the competitive retail market indicated the numbers of customers enrolled in various types of programs. Aggregate numbers of customers (excluding customers enrolled in multiple programs) are provided in Table 1.2, while Table 1.3 identifies the types of energy consumers participating in each category of DR program.

Table 1.2: ESI IDs Participating in Only One Program (in Areas Opened to Retail Competition)

	4CP	BI	OLC	OTH	PR	RTP	TOU	Total
ESIID Count	10	22,947	10,071	733	1,877	4,105	117,570	157,313
REP Count	3	14	2	3	2	12	4	21

[3] Tables 1.1 through 1.3 were provided by ERCOT.

Table 1.3: Participation in Categories of Programs by Type of Energy Consumer[4]

ESIIDs Participating in Only One Program

prof_type		program_type						
	total	4CP	BI	OLC	OTH	PR	RTP	TOU
BUSHILF	3,215		2,688		110		417	
BUSHIPV	1						1	
BUSIDRRQ	1,806	10	1,262		36	32	466	
BUSLOLF	1,983		1,075	1	108	17	768	14
BUSLOPV	15						2	13
BUSMEDLF	11,101		9,062	2	383	3	1,555	96
BUSMEDPV	6						1	5
BUSNODEM	8,320		7,456	2	76	5	604	177
BUSNODPV	3						1	2
BUSOGFLT	1,494		1,404				90	
NMLIGHT	1						1	
RESHIPV	148			4		2		142
RESHIWD	5			2				3
RESHIWR	58,455			4,224	9	768	50	53,404
RESLOPV	224			6		1		217
RESLOWD	1			1				
RESLOWR	70,535			5,829	11	1,049	149	63,497
total	157,313	10	22,947	10,071	733	1,877	4,105	117,570

Summary

A summary of the approach to quantifying impacts and the data sources used in the analysis of each type of demand response program is presented in Table 1.4.

The chapters that follow provide a detailed description of the analysis and findings for 4CP response and real-time pricing (combined with block and index pricing). Our analysis of the impacts from Other Load Control and Peak Rebate programs has been removed from this public version, in order to protect confidential information from disclosure.

[4] Please note "prof_type" stands for Profile Type.

Table 1.4: Summary of Programs, Data Sources, and Methods of Analysis

Program	Data Source	Method of Analysis
OLC - Other Load Control	• 15-minute interval consumption data (anonymized) from 05/01/2013 to 10/15/2013 for each ESI ID in this type of program. • Event information, as reported by two REPs operating larger programs (including start and stop times). • Start date for participation in the program, as reported by REP, for over 10,000 ESI IDs.	• Baseline analysis focused on events as reported by REPs. Impacts were calculated on a customer-specific basis, for each program. An historical baseline was constructed, same as the ERCOT ERS "Middle 8-of-10" methodology, and actual usage was compared against baseline usage to estimate demand response. (1)
4CP	• Aggregated IDR data for consumers served at transmission voltage for each regulated transmission and distribution utility (TDU) service area from 2001 to early 2014. • Evaluation was limited to use of aggregated (non-individual) data.	• A probabilistic analysis (logistic regression) was conducted to identify the days most likely to have elicited a 4CP response, based on weather, time of day, and other factors. • Baseline analysis focused on actual and potential 4CP days (summer weekday afternoons). Baselines excluded weekend days, holidays, prior CPs, and near-CPs. • Additionally, a regression model quantified the response of the aggregate usage of the transmission voltage customers in each TDU service area to 4CPs and "near 4CPs," while controlling for other factors.
RTP (Real Time Pricing) and BI (Block & Index)	• Anonymized data for 4,100 RTP customers and 23,000 BI customers (10/15/2011-10/15/2013), along with location-related information for each account. • Wholesale price data. • Start date for program, as reported by REP, for each ESI ID enrolled in this type of program. • Weather data.	• Regression baseline focused on pricing events, defined as LZ SPPs at three distinct price levels: o $300/MWh o $1,000/MWh o $3,000/MWh • Additional models were estimated looking at single price spike levels (e.g., just $3,000MWh). • An historical baseline was constructed, same as the ERCOT ERS "Middle 8-of-10" methodology, and actual usage was compared against baseline usage to estimate demand response.
PR (Peak Rebate)	• 15-minute interval consumption data (anonymized) for each ESI ID in this type of program.	• An historical baseline was constructed, same as the ERCOT ERS "Middle 8-of-10" methodology, and actual usage was compared against baseline usage to estimate demand response. (2)
TOU	*No analysis will be performed for TOU, at least for now. TOU price offerings are designed to promote a behavioral shift in customers and are not considered event-driven DR.*	
OTH	*No analysis is envisioned for OTH. ERCOT will bilaterally contact the REPs reporting "Other" products to better define the product types in future data collection exercises.*	
Notes:		
(1) A discussion of the data used to derive our estimate of the demand reduction from Other Load Control Programs has been removed from this "public" report, in order to protect confidential information from disclosure.		
(2) A discussion of the data and calculations used to derive our estimate of the demand reduction from Peak Load Rebate Programs has been removed from this "public" report, in order to protect confidential information from disclosure.		

Chapter 2: The Response of Large Industrial Energy Consumers to Four Coincident Peak (4CP) Transmission Charges

The Motivation to Avoid 4CP Intervals

In the areas of ERCOT opened to retail competition, large energy consumers with interval data recorders (IDRs) are charged for transmission services based on the individual consumer's contribution to four coincident peaks (4CPs), i.e., the 15-minute intervals of highest demand on the ERCOT system in each of four summer months -- June, July, August, and September. This chapter presents estimates of the degree to which large industrial energy consumers seek to reduce their demand, and thus their transmission costs, during periods in which 4CPs are set or there is a high likelihood that a CP will be set.

All energy consumers with a billing demand over 700 kW in a competitive area have an incentive to respond to the 4CP transmission prices. There is no apparent advantage to conducting this analysis on an individual-load basis, so aggregated or class-level data for energy consumers served at transmission voltage within each TDU service area were used. The data used were 15-minute interval aggregated load data for consumers with a non-coincident peak demand (billing demand) that exceeded 1 MW at least 10 times since January 2002 and were served at transmission voltage. Data for the summers of 2008 through 2013 were used in this analysis.

A consumer that can reduce its demand for electricity by 1 MW during each of the four CPs can save roughly $40,000 to over $55,000 in transmission charges the following year, as illustrated in Table 2.1 for energy consumers in the three largest transmission and distribution utility (TDU) services areas. This potential avoidance of transmission charges provides a strong incentive for industrial energy consumers with some flexibility in their operations to engage in "4CP chasing." These charges have been increasing in recent years and will continue to increase over the next couple years, as the costs associated with the Competitive Renewable Energy Zone (CREZ) projects are recovered.

Table 2.1: Example Savings Calculations for a 1 MW Reduction in Demand during 4CP Periods

	Monthly Charge per Previous Year's 4-CP kW	Annual Savings from a 1 MW demand reduction during 4CP periods
CenterPoint Energy (Docket Nos. 42053, 38339, and 41072; and base rates from tariff)		
Primary Voltage (with IDR; excluding Distribution Charge)	$3.4356	$41,226.97
Transmission Voltage (including Distribution Charge)	$4.0154	$48,184.27
Oncor (Docket No. 42059)		
Primary Voltage (with IDR)	$3.3259	$39,910.32
Transmission Voltage	$3.6055	$43,266.19
AEP-Texas Central (Docket No. 42054 and base rates from tariff)		
Primary Voltage (with IDR)	$4.6183	$55,420.02
Transmission Voltage	$3.7265	$44,718.00
Tariffs and TCRFs last accessed April 20, 2014. The calculations assume the customer has a power factor of one.		

The survey of LSEs conducted during the summer of 2013 identified very few customers who were involved in REP-initiated programs to provide 4CP warnings. However, many organizations other than REPs provide such services. Therefore the 2013 survey does not reflect the full numbers of industrial and institutional energy consumers involved in 4CP chasing.

Although industrial and institutional energy consumers served at primary voltage have about as much incentive to reduce their transmission costs by reducing demand during CPs as consumers served at transmission voltage, previous analysis could find no significant response among primary voltage consumers.[5] Consequently, the demand response of the smaller energy consumers served at primary voltage was not considered here.

Despite the significant potential savings, not all industrial and institutional energy consumers respond to transmission prices. For some facilities, a curtailment may impose economic costs upon some consumers in excess of the value of the potential savings in transmission costs. Energy consumers with the ability to easily interrupt or curtail their purchases from the grid and commit to providing an ancillary service to the ERCOT market (i.e., commit to curtail at the request of the system operator to provide an operating

[5] Zarnikau, Jay, Dan Thal (2013). "The response of large industrial energy consumers to four coincident peak (4CP) transmission charges in the Texas (ERCOT) market," *Utilities Policy*, Vol. 26, Sept. 2013, pp. 1-6.

reserve) cannot concurrently chase 4CPs. This could limit the response of an interruptible load that had elected to provide an ancillary service in ERCOT's day-ahead market or has an obligation with a load-serving entity through a bilateral arrangement to "be available" to provide a curtailment at ERCOT's request.

The following section identifies "near-CP" intervals and days. Near-CP days are excluded from baseline calculations and near-CP intervals are used as a variable in the regression analysis presented here. Chapter 3 provides estimates of the response of consumers served at transmission voltage to the 4CP-based transmission prices using an historical baseline approach. Chapter 2 uses a regression approach to explore the degree to which these two groups of large energy consumers respond to the transmission prices. The final section summarizes our findings and offers further observations.

Identification of Near-CP Intervals and Days

The timing of the CPs cannot be perfectly predicted. Until a summer month is over, the interval with the highest level of system demand is not known. It is particularly difficult to determine whether a hot day during the first week of a month will indeed set a CP, since weather forecasts for the later days of the month will not yet be widely available, and forecasts made early in a month will be uncertain. Further, a strong response to a likely CP may move the monthly peak demand to a different 15-minute interval within the same day or to another day.

Consequently, days when consumers are likely to have responded to a likely CP should be excluded from our calculation of savings from CP-chasing relative to an historical baseline, and in our regression analysis we are interested in detecting both 1) any reduction in demand during an actual CP and 2) during other intervals when a CP might have been considered probable. Thus, an identification of near-CPs is needed to implement both of the methods used to quantify the demand reduction during CPs.

To determine the intervals when consumers might have thought a CP was likely, a logistic regression model was used to estimate the historical relationship between a CP and a set of explanatory variables. Variables representing the month of the year and interval within the day were included to capture seasonal and diurnal factors affecting electricity use. The observations used in the estimation were confined to the nine 15-minute intervals from 3:00 pm through 5:15 pm (intervals 61 through 69) during weekday summer months in the years 2008 through 2013. In recent years, the monthly CPs during the summer have always fallen within this period. The variable *Interval61_62_63* is coded 1 for the period from 3 p.m. to 3:45 p.m. and 0 otherwise. Similarly, *Interval 64_65_66* was coded 1 for the period from 3:45 p.m. to 4:30 p.m. and 0 otherwise. Binary monthly variables were used to represent the months of June, July, and August. The real-time market price of electricity was included as an explanatory variable, to recognize that the response by consumers to a high price could change the odds of setting a CP, *ceteris paribus*. Alternatively, it might signal the possibility of a CP to a consumer monitoring market prices. The real time energy price is the market-clearing price of balancing energy during the period in which ERCOT had a zonal market structure, and the zonal average of locational marginal prices for the period since ERCOT adopted a nodal market structure. Energy prices (expressed in dollars per MWh) were obtained from ERCOT's website. Total system demand during the same interval of the previous day was included to recognize that patterns in demand across consecutive days may affect the likelihood of a CP, or the perception that one might occur. Finally, since summer peak loads are largely determined by air conditioning usage in Texas, a variable was constructed to represent the difference between the actual temperature in a central location within the ERCOT market (Austin) for a given interval and the highest temperature reading during the given month. Since interval-level temperature data were not available, it was assumed that all intervals within each hour had the same temperature.

Of course, at any given time prior to the end of the month, a consumer will not have complete information about hourly temperatures for the remainder of the month. Thus, our use of this variable implicitly assumes that a consumer has access to – and responds -- to reasonably accurate weather forecasts. As noted earlier, the uncertainty surrounding weather forecasts makes it more difficult to predict CPs that occur early in a month.

Estimation results are presented in Table 2.2. The greater the gap between the temperature of an interval and the highest temperature reading for the month, the lower the odds of setting a CP. An increase in energy prices and an increase in system load during the previous days tend to raise the odds of reaching a CP, holding other variables constant. While the dummy variable for intervals 61, 62, and 63 was significant, the dummy variables representing the month of the year and the variable representing the intervals 64, 65, and 66 did not have significant impacts. The high percent concordant suggests the predictive power of the model is satisfactory.

Table 2.2: Estimation Results from Logistic Regression Model used to Determine Probability of a CP

Variable or Statistic	Odds Ratio Estimate (p-value in parentheses)
Temperature Relative to Monthly Highest Temperature	0.490 (<.0001)
Energy Price in Real-Time Market	1.001 (.0003)
June Dummy	0.849 (.7728)
July Dummy	0.885 (.8310)
August Dummy	0.829 (.7427)
Interval61_62_63 Dummy	0.058 (.0062)
Interval64_65_66 Dummy	0.552 (.1493)
McFadden's Pseudo R^2	0.293

Scaling was performed to ensure that the probability of setting a CP over all intervals in a given month was equal to one. A new variable, *NearCP*, was created to represent intervals when the estimated probability was greater than 7%, yet a CP was not actually set. The 7% cutoff point was adopted since it resulted in roughly 50 15-minute intervals with a high likelihood of a CP (but no actual CP), as reported on Table 2.3. It was thought that it was reasonable for consumers to respond to roughly this number of possible CP events. Some of these near-CP intervals were on the same days as actual CP intervals.

Table 2.3: Identification of Near-CP Intervals

Year	Month	Day	Hour	Interval	Austin Temp. in F degrees
2007	6	19	16	68	94
2007	8	13	15	64	99
2007	8	13	17	69	98
2007	8	14	15	64	99
2007	9	27	16	67	94
2007	9	27	16	68	94
2008	8	7	16	67	100
2008	8	7	16	68	100
2008	9	2	15	64	100
2008	9	2	16	65	100
2008	9	2	16	66	100
2008	9	2	16	68	100
2009	6	25	16	67	104
2009	6	25	16	68	104
2009	6	25	17	69	104
2009	6	29	16	67	105
2009	6	29	16	68	105
2009	7	8	17	69	105
2009	9	3	16	65	99
2009	9	3	16	66	99
2009	9	3	16	67	99
2009	9	3	16	68	99
2009	9	3	17	69	98
2010	6	28	15	64	98
2010	6	28	16	67	97
2010	6	28	16	68	97
2010	8	23	16	65	104

Table 2.3: Identification of Near-CP Intervals – Continued

Year	Month	Day	Hour	Interval	Austin Temp. in F degrees
2010	9	1	15	64	98
2010	9	1	16	65	98
2010	9	1	16	66	98
2010	9	1	16	67	98
2010	9	1	16	68	98
2010	9	2	16	67	97
2010	9	2	16	68	97
2011	6	17	16	67	104
2011	6	17	16	68	104
2011	6	17	17	69	104
2011	9	12	16	67	104
2011	9	12	16	68	104
2012	6	26	15	64	106
2012	6	26	16	65	107
2012	6	26	16	67	107
2012	6	26	16	68	107
2012	9	4	16	67	103
2013	6	28	16	67	102
2013	6	28	16	68	102
2013	6	28	17	69	104
2013	7	30	17	69	102
2013	8	6	17	69	104
2013	8	8	17	69	104
2013	9	3	16	66	99
2013	9	3	16	68	99
2013	9	3	17	69	101

Estimating the Impacts with an Historical Baseline Approach

Our first attempt to quantify the impacts of the demand response associated with 4CP events involves comparing actual load to a baseline constructed using historical data. The baseline was constructed by averaging the load levels exhibited by this group of consumers during the previous "middle 8 of 10" weekdays. Thus, the same baseline approach discussed elsewhere in this report was applied here. Weekend days were not included in the baseline calculations, since no CPs were set on weekends during the timeframe studied here. Days with a near-CP interval, as identified in the previous section, were also omitted from the baseline calculation. If a CP from a previous month was within the historical period used to construct the baseline, then it was removed. Calculations were conducted separately for each

TDU service area. The historical baseline was then scaled, so that the total energy up to 15:00 (3 p.m.) for the baseline matched the total energy consumed up to 15:00 on the CP day.

Figures 2.1 to 2.8 compare the actual aggregate system-wide load of consumers served at transmission voltage to the baselines during each CP in 2012 and 2013. The response appears to be prominent and consistent. The period of response is typically 2 or 3 hours, since consumers do not know exactly which interval may set the CP.

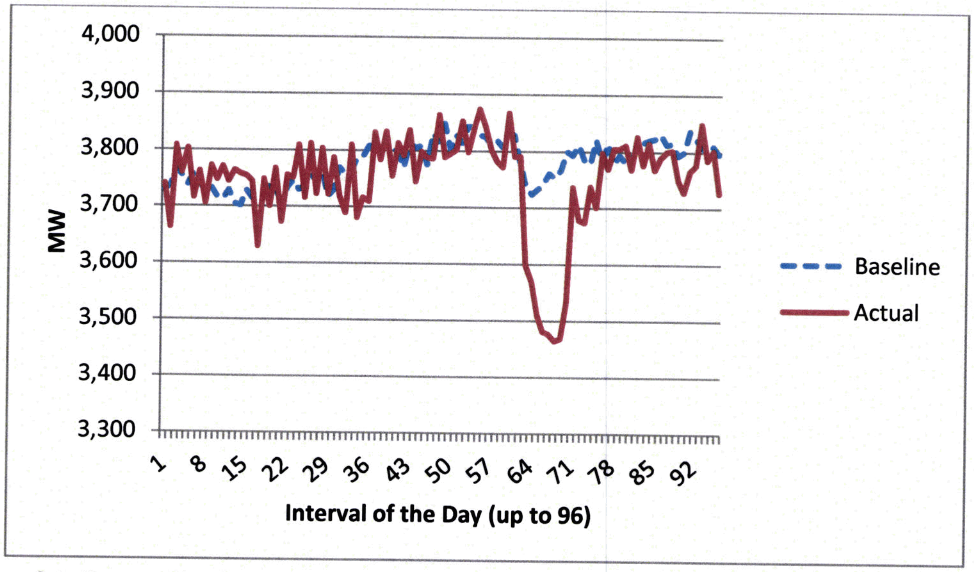


Figure 2.1: Energy Consumption (in kWh) by Transmission Voltage Customers on June 12, 2012, Contrasted against Baseline Energy

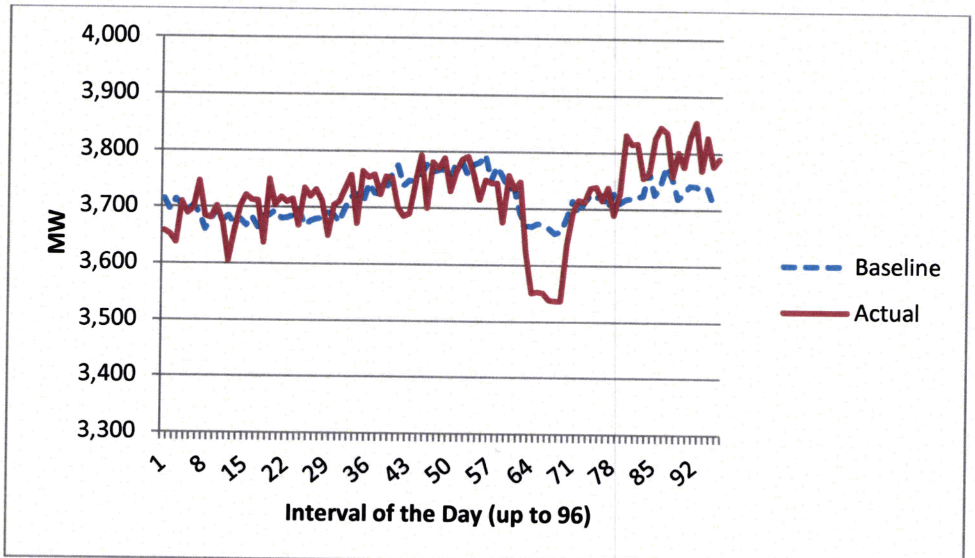


Figure 2.2: Energy Consumption (in kWh) by Transmission Voltage Customers on July 31, 2012, Contrasted against Baseline Energy

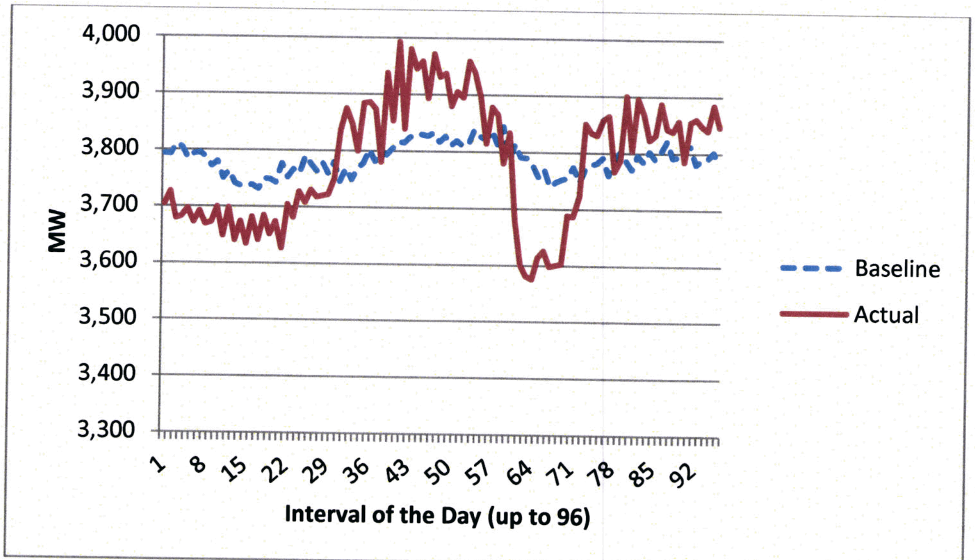


Figure 2.3: Energy Consumption (in kWh) by Transmission Voltage Customers on August 1, 2012, Contrasted against Baseline Energy

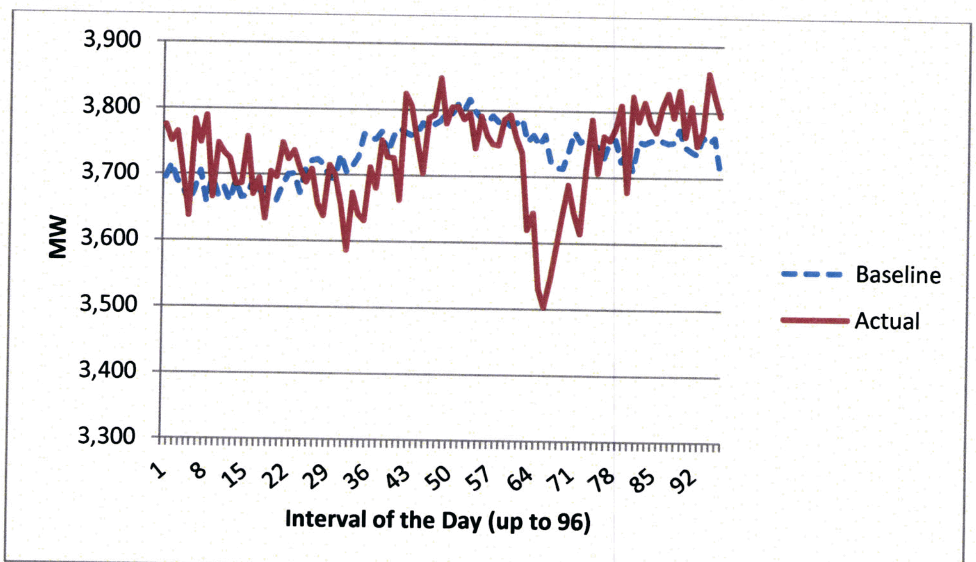


Figure 2.4: Energy Consumption (in kWh) by Transmission Voltage Customers on September 4, 2012, Contrasted against Baseline Energy

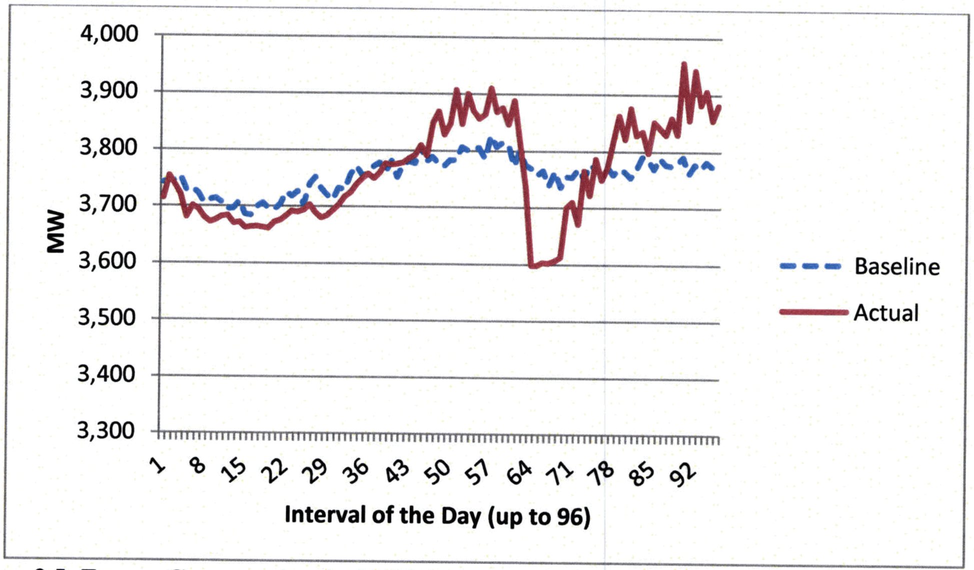


Figure 2.5: Energy Consumption (in kWh) by Transmission Voltage Customers on June 27, 2013, Contrasted against Baseline Energy

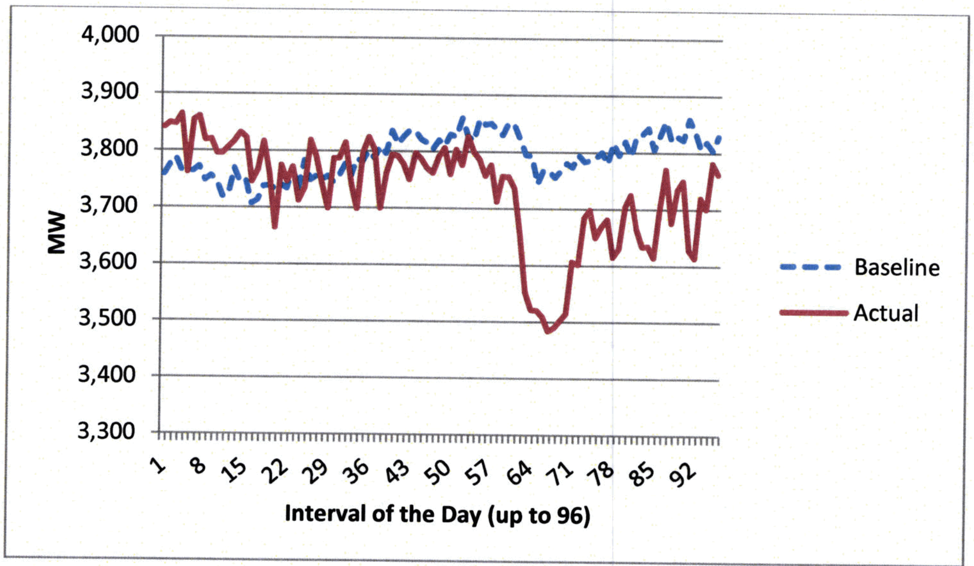


Figure 2.6: Energy Consumption (in kWh) by Transmission Voltage Customers on July 31, 2013, Contrasted against Baseline Energy

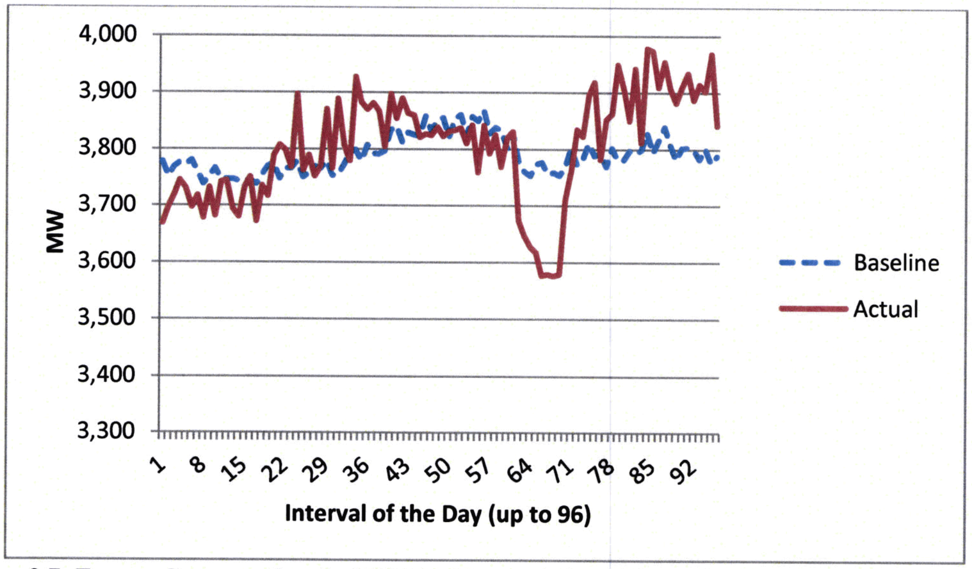


Figure 2.7: Energy Consumption (in kWh) by Transmission Voltage Customers on August 7, 2013, Contrasted against Baseline Energy

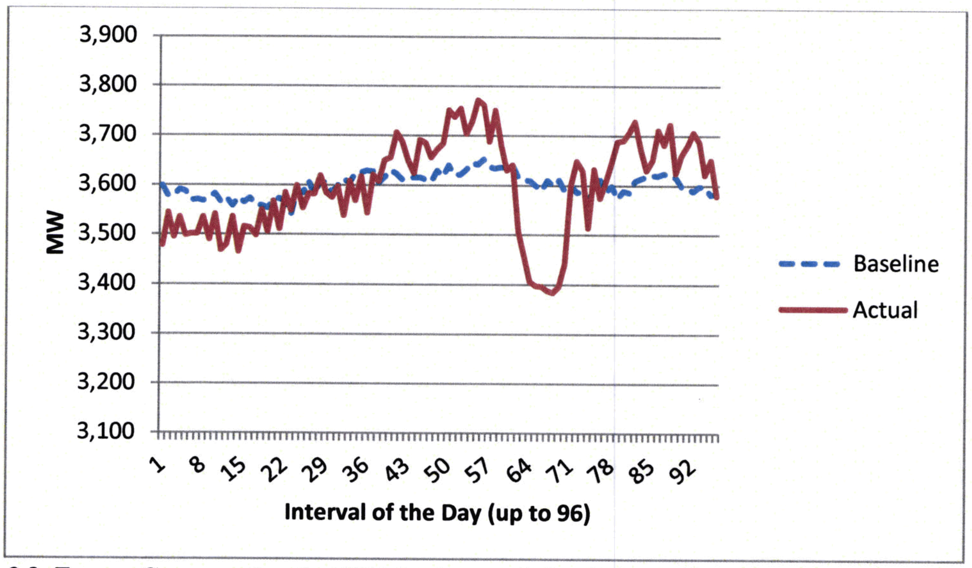


Figure 2.8: Energy Consumption (in kWh) by Transmission Voltage Customers on September 3, 2013, Contrasted against Baseline Energy

The estimated demand reduction during each of the CP events from 2007 through 2013 is provided in Table 2.4.

Table 2.4: Estimated Demand Reduction During CP Intervals

Year	Month	Day	Interval	Demand Reduction in MW
2007	6	19	16:45	-18
2007	7	12	16:30	28
2007	8	13	15:30	206
2007	9	7	16:00	263
2008	6	16	16:45	72
2008	7	31	16:45	220
2008	8	4	17:00	-116
2008	9	2	16:45	209
2009	6	25	16:15	111
2009	7	13	17:00	270
2009	8	5	16:00	167
2009	9	3	16:00	87
2010	6	21	16:45	87
2010	7	16	16:30	98
2010	8	23	16:00	294
2010	9	14	16:45	311
2011	6	15	17:00	264
2011	7	27	16:30	345
2011	8	3	17:00	230
2011	9	2	16:30	284
2012	6	26	16:30	238
2012	7	31	17:00	176
2012	8	1	17:00	178
2012	9	4	17:00	219
2013	6	27	17:00	304
2013	7	31	17:00	268
2013	8	7	16:45	268
2013	9	3	16:45	164

Response to transmission prices appear to be generally increasing over time. In recent years, consumers served at transmission voltage reduced their electricity purchases up to 4% during a summer CP, using an historical baseline calculation.

Where, within the ERCOT network, is the demand response to a 4CP event coming from? The two largest service areas account for over 80% of the demand reduction. The contributions from transmission voltage consumers in the Oncor and CenterPoint service areas were very similar. There was no noticeable demand response to 4CPs in the AEP-Texas North service area in 2013.

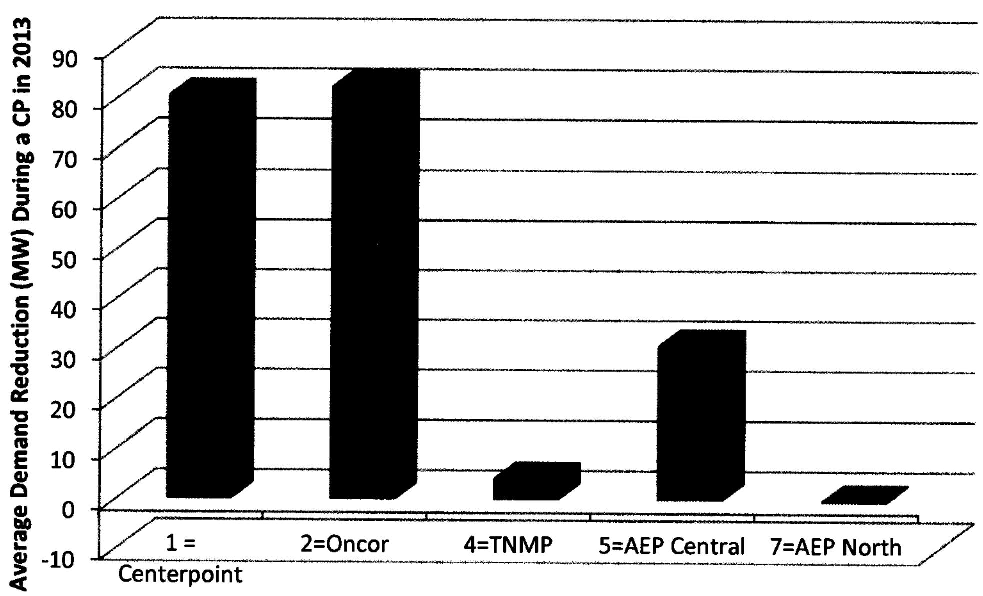


Figure 2.9: Distribution of the 4CP Response in 2013 by TDU Service Area

Regression Approach

A set of simple linear models was additionally used to detect whether the presence of an actual CP or *NearCP* had any detectable effect on the electricity consumption of energy consumers served at transmission voltage. This approach can better separate the effects of spikes in wholesale energy prices and local temperature from behavior designed to avoid the 4CPs.

Separate models were constructed for each TDU service area. The dependent variables represented the energy consumption of transmission voltage energy consumers, expressed in kWh per 15-minute interval. The explanatory variables were the real-time energy price (dollars per MWh), the presence of a CP (coded with a 1 if the interval was a CP and 0 otherwise), the *NearCP* variable discussed earlier (coded with a 1 if the interval had a high probability of setting CP and 0 otherwise), variables representing the month of the year and interval within the day to capture seasonal and diurnal factors affecting electricity use. Again, the variable *Interval61_62_63* represents the period from 3 p.m. to 3:45 p.m., while *Interval 64_65_66* covers the period from 3:45 p.m. to 4:30 p.m, five dummy variables representing year (year2008, year2009, year2011, year2012, year2013) to capture variation between years and one dummy variable "Ike" representing the widespread power outages due to hurricane Ike in 2008. The real time energy price (the same variable as was used in the logit model) was used to distinguish the response by consumers to a high market price of electricity generation from a 4CP-based transmission price. The temperature at a central location within each TDU service area was also used a as control variable. Data since the beginning of 2008 were used in the estimation, which treated the equations as a set in the estimation, applying Zellner's method for seemingly unrelated regressors (SUR).

Regression results are provided in Table 2.3. On average, over the period since 2008 and controlling for other factors, a CP reduces demand among energy consumers served at transmission voltage in the Oncor service area by 79MW (the coefficient of 19830.8 kWh/Interval * 4 Intervals/Hour /1000 to convert from kW to MW). Response in the Oncor service area to a near-CP is about 35% as great (27.6 MW = 6903*4/1000). Response to a CP in the CenterPoint area is about 52 MW. Estimation of the response by CenterPoint consumers to a near-CP yielded an implausible estimate (a positive coefficient), and the variable was consequently dropped from the model. It is also interesting to note that the consumers taking service at transmission voltage within the Oncor service area are particularly responsive to real-time energy prices.

Table 2.5: Estimated Impacts of CP Events and Other Factors on Load (in kWh) of Customers Served at Transmission and Primary Voltages by TDU Service Area

	CenterPoint Transmission Voltage Consumers (kWh/Interval)		Oncor Transmission Voltage Consumers (kWh/Interval)		TNMP Transmission Voltage Consumers (kWh/Interval)		AEP-Texas Central Transmission Voltage Consumers (kWh/Interval)		AEP-Texas North Transmission Voltage Consumers (kWh/Interval)	
Variable or Statistic	**Estimate**	**p-Value**	**Estimate**	**p-Value**	**Estimate**	**p-Value**	**Estimate**	**p-Value**	**Estimate**	**p-Value**
R^2	0.78		0.36		0.86		0.77		0.76	
Intercept	363677.3	<.0001	350369.8	<.0001	64856.54	<.0001	88657.47	<.0001	9992.432	<.0001
CP Interval	-15580.8	<.0001	-19830.8	<.0001	-1018.18	0.2368	-6706.68	<.0001	280.7897	0.0656
NearCP_High Probability Interval	NA	NA	-6903.33	0.0205	-770.56	0.1689	-25.6753	0.9723		
Energy Price in Real-Time Market in Local Zone	-2.35895	0.0001	-12.8803	<.0001	-0.088	0.6457	-0.92722	<.0001	-0.47994	<.0001
June Dummy	8043.149	<.0001	-20.5485	0.9819	-11.0228	0.9509	-609.731	0.0047	-50.9359	0.1052
July Dummy	7978.235	<.0001	468.9615	0.616	19.82816	0.9143	3502.168	<.0001	235.5142	<.0001
August Dummy	7001.718	<.0001	8596.896	<.0001	866.3201	<.0001	2591.734	<.0001	140.131	<.0001
Local Temperature (degrees F)	188.0845	<.0001	-211.927	<.0001	-63.6615	<.0001	205.8192	<.0001	41.51656	<.0001
Interval61_62_63 Dummy	2233.152	<.0001	4527.598	<.0001	407.4673	0.0056	615.9458	0.0008	-8.70573	0.7372
Interval64_65_66 Dummy	619.8589	0.2465	535.0589	0.4777	170.1504	0.2459	89.50766	0.6238	-10.0201	0.6993
year2008	28673.35	<.0001	10049.27	<.0001	-6497.35	<.0001	-9249.52	<.0001	-280.012	0.0002
year2009	10694.27	<.0001	-17219	<.0001	-8421.09	<.0001	-14360.8	<.0001	-1576.02	<.0001
year2011	6297.305	<.0001	13038.81	<.0001	8284.497	<.0001	7911.582	<.0001	-1260.18	<.0001
year2012	18258.21	<.0001	13883.01	<.0001	11891.87	<.0001	7969.366	<.0001	568.7932	<.0001
year2013	30939.03	<.0001	31638.89	<.0001	11704.42	<.0001	7134.617	<.0001	1350.582	<.0001
Ike	-183402	<.0001	NA	NA	-32601.1	<.0001	NA	NA	NA	NA

A system-wide estimation was also conducted, as presented in Table 2.6. In this estimation, the loads of transmission voltage energy consumers in all service areas were combined. Temperature data for Austin – a central location within the ERCOT market – were used to construct a weather variable. A simple average of the prices in the North and Houston zones were used to control for the effects of changes in energy prices. The coefficients were estimated using ordinary least-squares (OLS).

Table 2.6: ERCOT-Wide Estimated Impacts of CP Events and Other Factors on Load (in kWh) of Customers Served at Transmission Voltage

Variable or Statistic	Estimate	p-Value
R^2	0.75	
Intercept	992971.7	<.0001
CP Interval	-50259.8	<.0001
NearCP_High Probability Interval	-8884.02	0.0766
Energy Price, Average of North and Houston Zones	-19.3721	<.0001
June Dummy	5063.015	0.0007
July Dummy	12388.67	<.0001
August Dummy	19965.19	<.0001
Austin Temperature (degrees F)	-77.0511	0.3379
Interval61_62_63 Dummy	9056.429	<.0001
Interval64_65_66 Dummy	1770.888	0.1405
year2008	17410.7	<.0001
year2009	-40736.5	<.0001
year2011	45865.84	<.0001
year2012	61354.8	<.0001
year2013	90024.4	<.0001
Ike (for Hurricane Ike)	-257865	<.0001

These modeling results suggest that a CP has resulted in about 201 MW of demand response (four times the coefficient on the variable for CP Interval) on average over the past 5 years, after controlling for the effects of weather and energy prices. A near-CP event prompts a demand response of about 36 MW. Since the historical baseline analysis suggests that this response is increasing over time, higher values than these five-year averages should be expected in the future.

Conclusions

The historical baseline and regression methods provide very similar results. An average of the impacts for the 4CPs in 2013 estimated using an historical baseline approach as reported on Table 2.2 yields about 251 MW. Results from the regression analysis suggest that a CP has resulted in about 201 MW of demand response on average over the past 5 years. In addition to this response from large industrial and institutional energy consumers, NOIE utility systems and some REP programs may also contribute demand reduction during 4CPs.

Chapter 3: The Response of NOIEs to Four Coincident Peak (4CP) Transmission Charges

Non-Opt-In Entities (NOIEs) have an incentive to reduce their consumers' usage similarly to the incentive faced by large industrial and institutional energy consumers, as discussed in the previous chapter. NOIEs are charged for transmission services based on their contribution to ERCOT's system-wide four coincident peaks (4CPs), i.e., the 15-minute intervals of highest demand on the ERCOT system in each of four summer months -- June, July, August, and September. These already significant costs have been increasing in recent years and will continue to rise over the next couple years, as the Competitive Renewable Energy Zone (CREZ) project costs are recovered.

Unfortunately, our efforts to provide independent demand reduction estimates proved unsuccessful. Because ERCOT does not maintain NOIE customer data, only total usage data for the NOIE systems was available. We found it difficult to detect the impacts of relatively-small demand response programs using aggregate system-wide data for the NOIEs. The historical baseline approach described in the previous chapter was applied to the NOIE-system data for over 70 NOIEs. Baselines were developed for each NOIE and the NOIE-specific demand reduction during 4CPs was estimated. The results suggested no systematic pattern of 4CP response. For the sum of all NOIEs, demand was higher than the historical baseline for two of the CPs in 2013 and lower than the baseline for the other two. For most other years, there was a similar absence of any pattern. Figure 3.1 displays the demand reduction (or, lack thereof) achieved each year, calculated against the historical baseline described in the previous chapter.

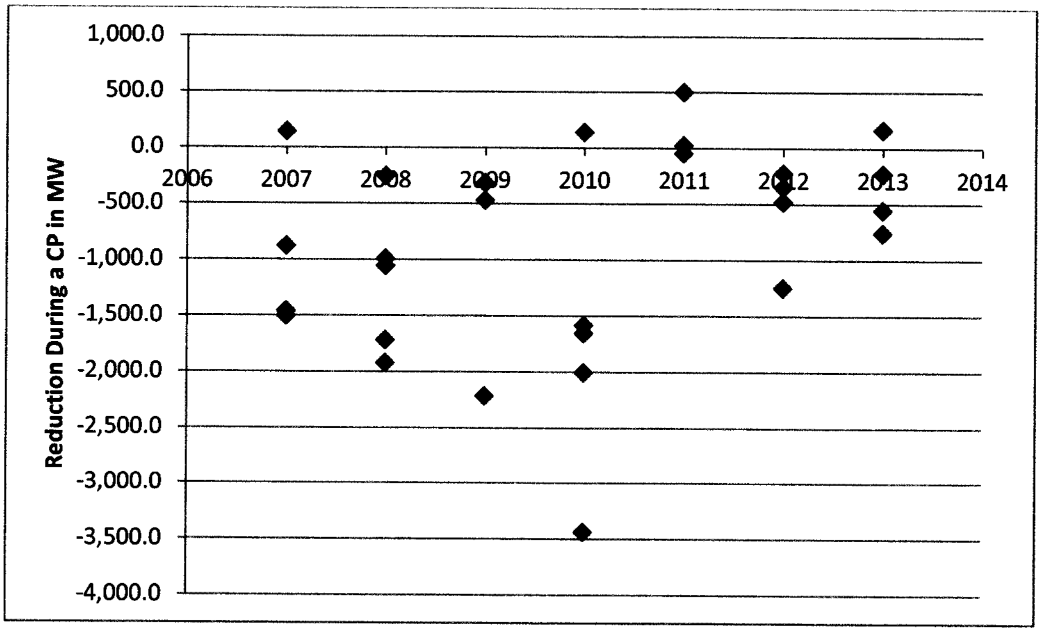


Figure 3.1: Aggregate Demand Reduction in MW of all NOIEs Relative to a 5-Day Adjusted Historical Baseline

A second attempt at an independent estimate of NOIE impacts from programs designed to reduce contributions to 4CPs focused on the two NOIEs that reported specific load control programs to ERCOT. Data for all other NOIEs were removed from the modeling. The results again were mixed, with both positive and negative estimates for peak demand reduction using both a 5-day historical baseline and a 10-baseline.

In summary, we have concluded that attempts to detect the impacts of NOIE-sponsored demand response programs using NOIE-system level data is too difficult and imprecise.

Our review of supplemental information provided by NOIEs with formal demand response programs suggests that they were very successful in predicting the timing of 4CPs in 2013 (although one of the NOIEs appears to have ended a direct load control deployment before the precise CP interval).

Chapter 4: RTP (Real Time Pricing) and BI (Block & Index)

General Description and Goal

A real-time pricing (RTP) rate provides customers with incentives to shift load from higher priced periods to lower priced periods. In the ERCOT market, wholesale electricity prices may change every 15 minutes of the day, and price spikes (extremely high price) may occur occasionally when the demand is high or generating capacity poses a constraint.

BI (Block & Index) pricing is a compromise between a fully indexed pricing and a fully fixed pricing. Under this purchasing strategy, buyers purchase part, or a "block," of their energy at a fixed price. The remainder of their energy is purchased at real-time prices (e.g., zonal averages of locational marginal prices).[6]

The goal of this analysis is to quantify any load reductions during price spikes during the period from October 2010 to October 2013. This analysis is somewhat limited, because there were rather few price spikes in ERCOT's wholesale market during this period.

Data Available

- Time Range:
  - October 15th, 2010 and October 15th, 2013. All customers who the REPs reported to have been served under a RTP or BI contract or program are included. Customers served by a NOIE under an analogous tariff or contract were not included.
- Customer demographic information:
  - To perform this analysis, the following information was obtained from ERCOT to each customer served under a RTP or BI contract or program:
    - Masked REP Code
    - Masked UIDESIID number
    - Profile Code: customer profile code
    - All of the data in a dataset of customers with Interval Data Recorders (IDRs) had a "BUSIDRRQ" code, all of the data in use have 1537 UIDESIIDs.
    - In a dataset of customers with 15-minute usage information collected with an Advanced Metering System (AMS), there were 11 profile types
    - Program start date
      This date is used to delete those who started RTP program later than the trade date. In other words, only those who have program start date earlier than trade date are used.

[6] http://energysmart.enernoc.com/bid/287786/Block-and-Index-Pricing-Model-Explained

Table 4.1: Profile Types

Profile Type	# of UIDESIIDs
BUSHILF	1944
BUSHIPV	1
BUSLOLF	1688
BUSLOPV	2
BUSMEDLF	5274
BUSMEDPV	1
BUSNODEM	2824
BUSNODPV	1
BUSOGFLT	1356
RESHIWR	48
RESLOWR	116

- Weather and Price Data:
  - In our modeling, we sought to control for the effects of temperature when estimating the response of these energy consumers to price spikes.
  - To enable us to test our modeling at a few different levels of geographic granularity, we collected weather data for four settlement zones: north region, south region, Houston region and west region.

We used Austin hourly weather data for an ERCOT-wide model run, given Austin's central location in the ERCOT power region.

- Price Data:
  - For our ERCOT-wide model run, we used the North zone's real time market 15-minute interval price (LMPz) to develop variables to represent price spikes. ERCOT north settlement zone is the largest region within the ERCOT market.

- Consumption Data:
  - 15-minute interval kWh consumption data for each customer with traditional IDR meter, one day for each row. All the customers in this dataset in use have a profile code of BUSIDRRQ.
  - 15-minute interval kWh consumption data for each customer with advanced meter, one day for each row. There are 11 profile types are in this dataset.

Methodologies

Regression method was used to estimate load reduction of RTP customers with AMS customers. Two methods were used to estimate load reduction of RTP customers with IDR meters: regression analysis and ERCOT's ERS "8-of-10" baseline methodology.

1. Regression Analysis

Regression analysis is used to detect the potential relation between load reduction and price spike. One advantage for regression analysis is that it can control the weather factor and focus solely on the load reduction caused by price spike to some extent. For both IDR and AMS dataset, we applied the following regression model equation for each profile type.

We first estimated a regression model on an ERCOT-wide basis, using:

Consumption = $\beta_0 + \beta_1$ * austincdh + β_2 * austinhdh + β_3 * mon + β_4 * tue + β_5 * wed + β_6 * thu + β_7 * fri + β_8 * sat + β_9 * northspike300 + β_{10} * northspike1000 + β_{11} * northspike3000 + β_{12}* year2011+ β_{13}* year2012+ β_{14}* year2013;

In the equation above:

- Consumption: average 15-minute kWh consumption for each profile code
- austincdh: Austin cooling degree hours. Balance point is set as 65F. austincdh = max(Austin temperature at that hour – 65,0).
- austinhdh: Austin heating degree hours. Balance point is set as 65F. austinhdh = max(65 - Austin temperature at that hour,0).
- mon-sat: A set of dummy variables to control for day-of-week factor. For example, mon = 1 if that day is Monday, otherwise mon = 0. Other variables are designed in the similar manner.
- northspike300: dummy variable indicating price spike. If price in north region > 300, then northspike300 = 1, otherwise northspike300 = 0.
- northspike1000: dummy variable indicating high price spike. If price in north region > 1000, then northspike1000 = 1, otherwise northspike1000 = 0.
- northspike3000: dummy variable indicating extreme price spike. If price in north region > 3000, then northspike3000 = 1, otherwise northspike3000 = 0.
- year2011, year2012, and year2013: dummy variables indicating year, with year 2010 as baseline year.

Due to considerable heterogeneity in this group and varying dates at which customers enrolled in these programs (more than 80% of the customers joined the RTP/BI program during the three-year period), these three dummy variables can explain a great deal of variation of average consumption change over the year.

2. ERCOT ERS "8-of10" Baseline Methodology

The coefficients of northspike, northspike1000 and northspike300 will show a rough picture of how customers reduce their energy usage gradually as prices increase.

Since there is only one profile type in the IDR dataset, the model is run only once. There are 11 profile codes in the AMS (advanced meters) dataset, the model is run 11 times for that dataset consequently.

A disadvantage of this ERCOT-wide estimation is that Austin weather data may not match the weather actually experienced by the consumer, given the state's large size and climatological diversity. And the North zone's wholesale prices may not exactly match the prices faced by RTP and BI customers in the Houston, South, and West settlement zones.

This led us to also estimate models for various settlement zones within ERCOT. OncorTNMP Region (Dallas-Fort Worth area), CenterPoint Region (Houston area), AEPCentral Region (South area) and AEPNorth (West area). We used corresponding weather data and real-time 15-minute price data, running similar models mentioned above. We use customers' zip code to match their service area.

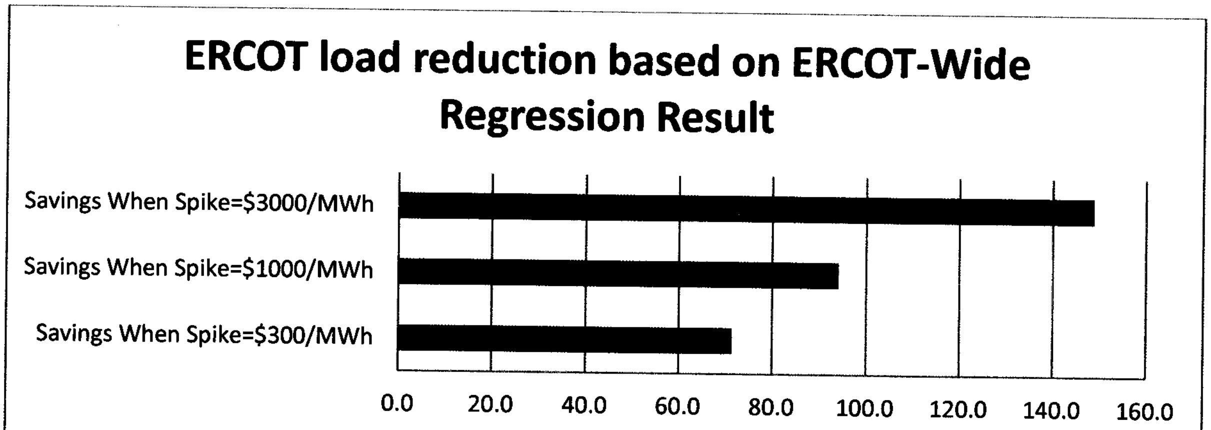
Results and Interpretation

The ERCOT-wide regression results for traditional meter is as follows:

Table 4.2: Table Results for IDR (Traditional Meter) Dataset

Parameter	Estimate	Approx P-Value
Intercept	263.6523	<.0001
cdh	2.147348	<.0001
hdh	-0.97035	<.0001
mon	16.95715	<.0001
tue	22.68545	<.0001
wed	23.4731	<.0001
thu	25.31967	<.0001
fri	24.65566	<.0001
sat	7.279482	<.0001
spike300	-11.6215	<.0001
spike1000	-3.70562	0.3119
spike3000	-8.86777	0.0934
year2011	32.67268	<.0001
year2012	47.59334	<.0001
year2013	121.9359	<.0001

As we can see from the result, the coefficients of spike300, spike1000 and spike3000 show us the 15-minute kWh usage reduction in a price spike. Based on the coefficients above, we can estimate the MW load reduction for different price spikes:



	Savings When Spike=$300/MWh	Savings When Spike=$1000/MWh	Savings When Spike=$3000/MWh
■ ERCOT	71.4 MW	94.2 MW	148.8 MW

Figure 4.1: ERCOT Load Reduction Based on ERCOT-Wide Regression Results

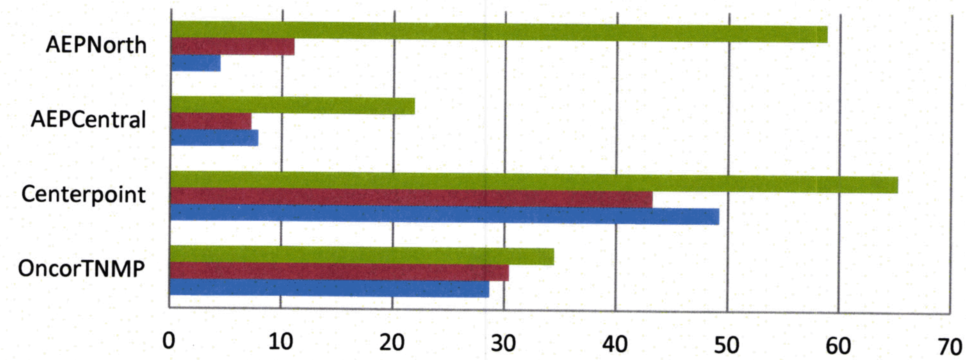
As we can see from the Figure 4.1, we can get an overall load reduction of 71.4MW if the price spike is set at $300/MWh. We can get an overall load reduction of 94.2MW if the price spike is set at $1000/MWh. We can get an overall load reduction of 148.8MW if the price spike is set at $3000/MWh.

The region-based regression results for IDR meters are presented in Table 4.3.:

Table 4.3: Region-Based Regression Results for IDR Meters

	OncorTNMP	Adjusted	CenterPoint	Adjusted	AEPCentral	Adjusted	AEPNorth	Adjusted
Parameter	**Estimate**	**P-value**	**Estimate**	**P-value**	**Estimate**	**P-value**	**Estimate**	**P-value**
R^2	0.3859		0.7061		0.6329		0.7368	
intercept	272.8794	<.0001	331.0149	<.0001	161.8939	<.0001	159.1689	<.0001
cdh	2.02035	<.0001	3.5562	<.0001	3.816527	<.0001	1.090409	<.0001
hdh	-0.11518	<.0001	-1.22374	<.0001	0.008857	0.8406	-1.10035	<.0001
mon	21.43919	<.0001	23.46694	<.0001	15.50464	<.0001	1.098698	0.0618
tue	33.41428	<.0001	26.77246	<.0001	21.44107	<.0001	0.039425	0.9467
wed	37.67381	<.0001	24.89043	<.0001	22.52676	<.0001	2.179524	0.0002
thu	41.25911	<.0001	25.56702	<.0001	20.00804	<.0001	2.370597	<.0001
fri	38.07965	<.0001	25.96479	<.0001	21.31024	<.0001	3.725477	<.0001
sat	11.65019	<.0001	6.557132	<.0001	12.14564	<.0001	0.883711	0.1335
spike300	-13.5334	<.0001	-19.8066	<.0001	-14.1144	0.0003	-4.51961	0.0161
spike1000	-0.81206	0.8698	2.401403	0.5578	1.162505	0.871	-6.74183	0.1953
spike3000	-1.90622	0.7887	-8.86314	0.1485	-26.1713	0.0181	-48.525	<.0001
year2011	-2.06366	0.0002	-26.1882	<.0001	-69.5993	<.0001	194.3828	<.0001
year2012	14.58787	<.0001	1.017165	0.0364	-64.0176	<.0001	209.8581	<.0001
year2013	46.1671	<.0001	80.18717	<.0001	119.2617	<.0001	320.6365	<.0001

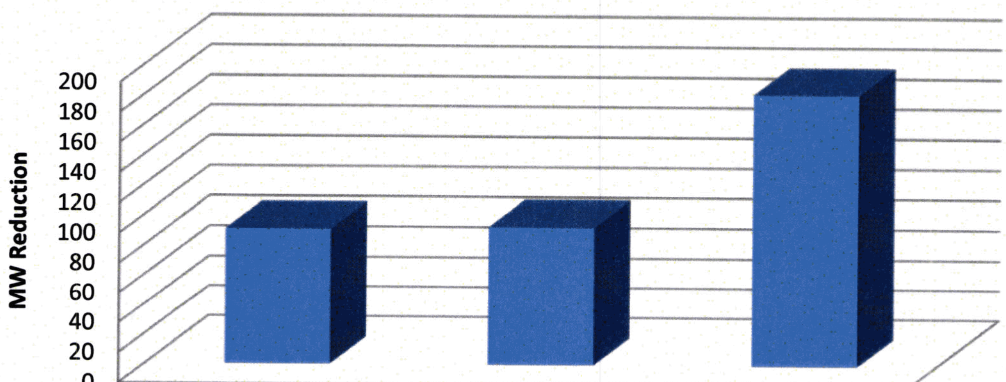
As we can see from the result, the coefficients of spike300, spike1000 and spike3000 show us the 15-minute kWh usage reduction in a price spike. Based on the coefficients in Table 4.3, we can estimate the MW load reduction for different price spikes in four areas:



	OncorTNMP	Centerpoint	AEPCentral	AEPNorth
MWSaving when spike = 3000	34.4535616	65.25055656	21.9089892	58.82985696
MWSaving when spike = 1000	30.4123752	43.2345168	7.2530612	11.08125696
MWSaving when spike = 300	28.690808	49.1995944	7.904064	4.44729624

Figure 4.2: Load Reduction (MW) By Region

The Overall load reduction calculated by summarizing four areas is graphed as shown in Figure 4.3:



	Savings When Spike=$300/MWh	Savings When Spike=$1000/MWh	Savings When Spike=$3000/MWh
ERCOT	90.2 MW	92.0 MW	180.4 MW

Figure 4.3: ERCOT Load Reduction Based on 4 Areas: Regression Results

Using this approach, we can get an overall load reduction of 90.24MW if the price spike is set at \$300/MWh. We can get an overall load reduction of 91.98MW if the price spike is set at \$1000/MWh. We can get an overall load reduction of 180.44MW if the price spike is set at \$3000/MWh.

An alternative ERCOT ERS "8-of-10" baseline methodology was also adopted.

Since this method is event-based, we set intervals with north region price higher than \$3,000/MWh as events. During Oct.15th, 2010 – Oct.15th, 2013, there were 70 events (intervals) in total. After using ERCOT's ERS "8-of-10" baseline methodology, the results are on Table 4.4 below:

Table 4.4: ERCOT ERS "8-of-10" Baseline Methodolgy Procedure and Results

Year	Month	Day	IntervalDuration	MW Savings	#Of Customers In Use
2011	3	3	76	-3.00	292
2011	6	27	63	0.86	374
2011	8	1	60	-10.29	380
2011	8	2	63-68	-0.46	380
2011	8	3	61-70	10.30	380
2011	8	4	55-65	30.20	380
2011	8	5	61-68	7.48	380
2011	8	23	64,65,67,68	-2.76	382
2011	8	24	57-67	28.72	383
2013	4	5	28	181.88	1192
2013	9	3	67	90.09	1531
Note that Feb 2nd, 2011 price spike event was deleted due to overlapping ERCOT EEA and ERS deployment.					

As we can see from the results in Table 4.4, load savings vary by a great deal, ranging from -10MW to 182MW. Thus, some of the events with high levels of estimated demand reduction as estimated with this historical baseline approach are consistent with the 148.75 MW of demand reduction estimated with a regression approach on ERCOT-wide basis. And we can also see that more than 1,200 customers joined the program gradually during the less-than-3-year period, also partly explained the variations in this part of result.

Further Analysis - Breakdown Analysis by Customer Size

Due to significant heterogeneity in customer size and variation in program joining dates (and correlation between these, as several large customers joined late in the analysis period), Frontier performed an additional analysis in which we split RTP program participants into two groups by size. A simple overall 15-minute average consumption was used as the criterion to group customers by size. Customers consuming more than 5000kWh in 15-minute intervals went into the large customers group, while the rest were placed in a "small" customer group.

Large Customers

In the RTP traditional meter (IDR) dataset group, only 31 of the 1537 customers belong to the large customer group. Among these 31 customers, 27 of them joined the respective RTP/BI rate offerings after April 2012. If price spike event threshold is set as $3,000/kWh, as we can see from Table 4.4, only 2 events occurred after April 2012. Regression is not appropriate in this case due to too few price spikes. Therefore, Frontier used the 'middle 8-of-10 days' baseline method to calculate load reduction for the large customer group for price spike events on April, 5th and September, 3rd 2013.

Calculation Procedures and Results

Using the same "8-of-10" baseline methodology applied to ERCOT's ERS program, the load reduction estimates for these two events contributed by this group are presented in Table 4.5.

Table 4.5 ERCOT ERS "8-of-10" Baseline Methodology Procedure and Results for Bigger-Size Group

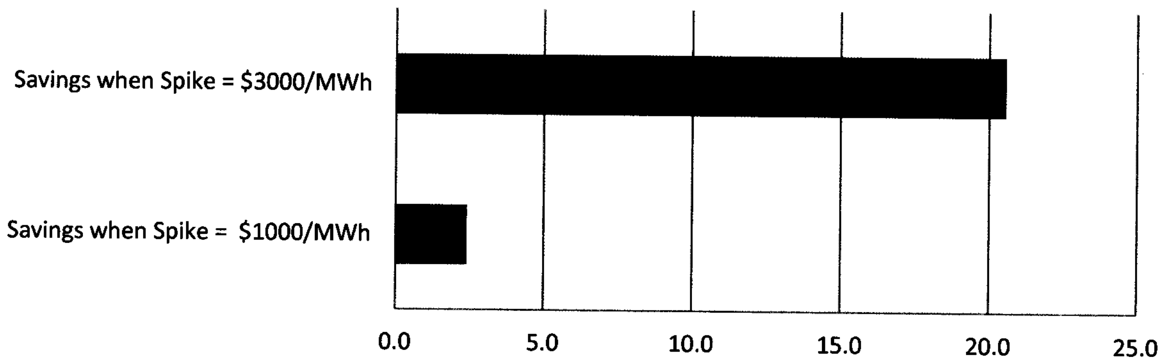
Date	Interval	MW Savings	# Of Customers In Use
4/5/2013	28	133.67	24
9/3/2013	67	87.06	31

As we can see from Table 4.5, these 31 customers alone contributed load reductions of 134 MW and 87 MW respectively during these 2 events, while the overall customers (1537 customers): these load reductions represented 74 and 97 percent, respectively, of total load shed for these 2 events (totals of 182 MW and 90 MW load reductions, as shown in Table 4.4. For these two events, the large customers contributed most of the load reduction.

Smaller Customers

Frontier applied regression analysis for the smaller customers group to estimate their load reduction. Since smaller customers tend to be less sensitive to price signals, some of them may not respond until the price is higher. Based on this assumption, we removed the spike300 variable from this analysis, leaving only the two price spikes dummy variables: spike1000 and spike3000. The regression-based load reduction estimates for the smaller- customers group by region are as follows:

Figure 4.6: Smaller-Size Customer Group Load Reduction Based on 4 Areas Regression Results



	Savings when Spike = $1000/MWh	Savings when Spike = $3000/MWh
■ ERCOT	2.4 MW	20.6 MW

As shown in Figure 4.4, although the RTP rate participants in the smaller customers group provide about 21 MW of load reduction when prices spike to $3000/MWh. Although they account for more than 95% of the customers in RTP rate programs, they only contribute between 15 and 25 percent of total load reduction (as compared to the 87 and 134 MW provided by the large customers to the two events evaluated in Table 4.5.

Results

This analysis shows that the smaller customers make small contributions, individually, to overall load reduction by RTP rate program participants during price spikes. Most of the load reduction is driven by large customers. Overall, the results of this analysis are consistent with the observations from the original analysis: it shows load shed on the order of 155 MW in the largest event (134 MW from large customers plus 21 MW from smaller customers according to the regression analysis), a result similar to the 148 MW reported in Figure 4.1. These two results are also generally consistent with the 8-of-10 baseline methodology results for overall ERCOT-wide data provided in Table 4.4. Since most of the larger customers joined the RTP/BI program during the past 2 years and only experienced 2 or less price spikes, Frontier believes it is reasonable to conclude that the findings for the most recent events are the most representative of the load reduction capacity in RTP rate programs for the future.

Results for AMS (Advanced Meter) Dataset

Unlike traditional meter users, advanced meter users consume relatively small amount of energy. Although there are some significant load reductions for most profile type groups, the overall load reduction for this dataset is trivial compared with IDR group. The preliminary results are summarized in Table 4.7.

Table 4.7: Results for AMS (Advanced Meter) Dataset

Profile Type	Spike300 Coefficient	# of Individuals	MWSavings
BUSHILF	-0.9434	1944	7.335878
BUSHIPV	-1.8511	1	0.007404
BUSLOLF	0.5505	1688	-3.71698
BUSLOPV	-0.2773	2	0.002218
BUSMEDLF	0.2811	5274	-5.93009
BUSMEDPV	-0.0415	1	0.000166
BUSNODEM	-0.061	2824	0.689056
BUSNODPV	-0.1589	1	0.000636
BUSOGFLT	-0.6726	1356	3.648182
RESHIWR	-0.341	48	0.065472
RESLOWR	0.1507	116	-0.06992
Summary	**NA**	**13255**	**2.032027**

As we can see from the table above, the overall load reduction for this group is around 2MW. The result is relatively small compared with the IDR group.

Four-CP Response in ERCOT Competitive Area 2009 - 2014

Carl L Raish

DSWG – March 9, 2015

4 CP Response Methodology

- Analysis limited to ESIIDs in competitive ERCOT areas with 'BUSIDRRQ' profile types
  - Transmission charges are based on ESIID-specific load during CP intervals
  - ESIIDs classified by connection at transmission or distribution voltage level
  - Distribution ESIIDs were classified based on weather sensitivity
- Classified days as CP Days, Near-CP Days and Non-CP Days
  - Near-CP days
    - Base-lined transmission total load for all summer weekdays using the 20 days nearest in time (before and after) excluding CP days and holidays
      - Applied Day-of-Adjustment factor to baseline
    - Days with at least 100 MW reduction for Hour-ending 5:00 PM were classified as near CP days – found 69 Near-Peak days between 2009 - 2014
  - Non-CP days were all remaining non-holiday weekdays (June 1 – Sep 30)
- Classified ESIIDs based on Weather Sensitivity and Load Factor
  - Weather sensitivity (R^2 for week-day use vs average temperature >= 0.6)
  - Load Factor based on week-day afternoon usage (1:00 PM – 6:00 PM)
  - High LF > 0.85
  - Medium LF > 0.60
  - Low LF ≤ 0.60

4 CP Response Type Classification

- **All ESIIDs subject to 4-CP charges were base-lined**
  - Non-weather sensitive: 20 Non-CP days clostest in time (before and after)
  - Weather sensitive using regression baseline
  - Day-of-adjustment factor from midnight to 3:00 PM was applied to baseline
- **Used baselines to calculate hour-ending 5:00 pm CP and Near-CP reductions (MW and percent) for three years closest to the analysis year (40 – 48 days of possible reductions)**
  - Usually used the analysis year, the year before and the year after
  - If the frequency and magnitude of MW17 reductions on CP and Near-CP days met thresholds the ESIID was classified as 4-CP responder
  - If not, just the analysis year and year after were examined
    - This was done to improve the classification of ESIIDs that started responding to 4-CP during the analysis year)
- **ESIIDs classified as responders were also examined for usage patterns indicating 'day-use' reduction for the 9:00 am – 4:00 pm time period on CP- and Near-CP days.**
- **Based on the frequency and magnitude of 'day-use' reductions ESIIDs were classified as reducing or not reducing 'day-use' on CP- and Near-CP days.**

Quantifying 4-CP and Near-CP Reductions

- ESIIDs already classified as responders were used in the calculation for a day if they reduced by more than the lesser of 10% or the ESIID's average reduction determined during the classification for the hour-ending 5:00 PM

- ESIIDs with a lower reduction or ESIIDs already classified as non-responders were not part of the reduction calculation.

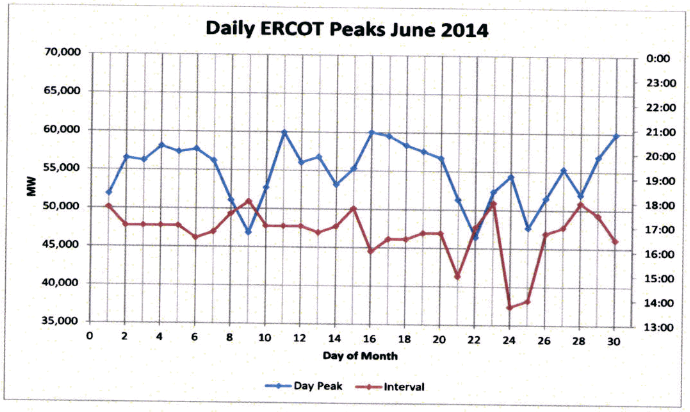
- If the ESIID was classified as a peak responder, a scalar day-of-adjustment was applied to the baseline for calculating the load reduction for the CP/Near-CP day.

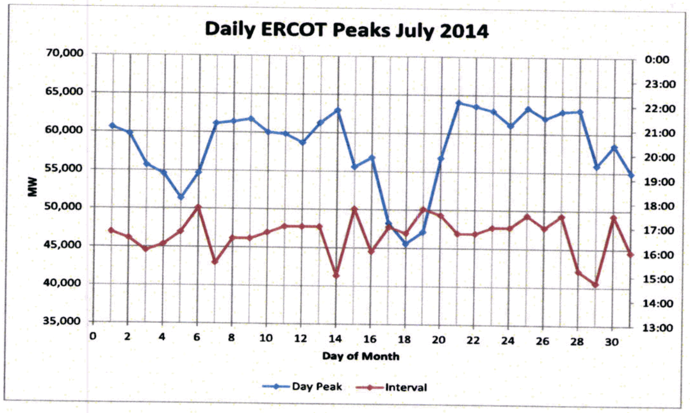
- No scalar adjustment was applied to ESIIDs previously classified as having 'day-use' response.

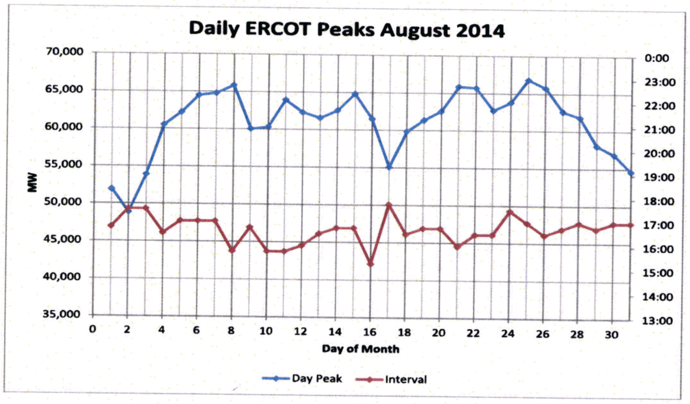
- The methodology was modified from last year to narrow in on response from responding ESIIDs and to more effectively remove the impact of non-responding ESIIDs from reduction calculations.

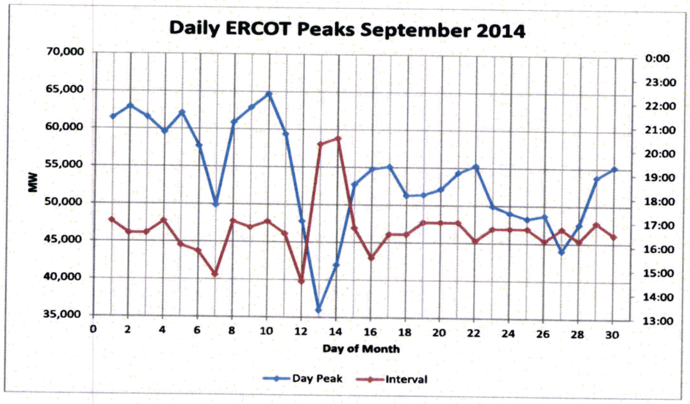
ERCOT Daily Peaks June – September 2014

Examined ERCOT Load daily peaks to determine possible Near-CP days



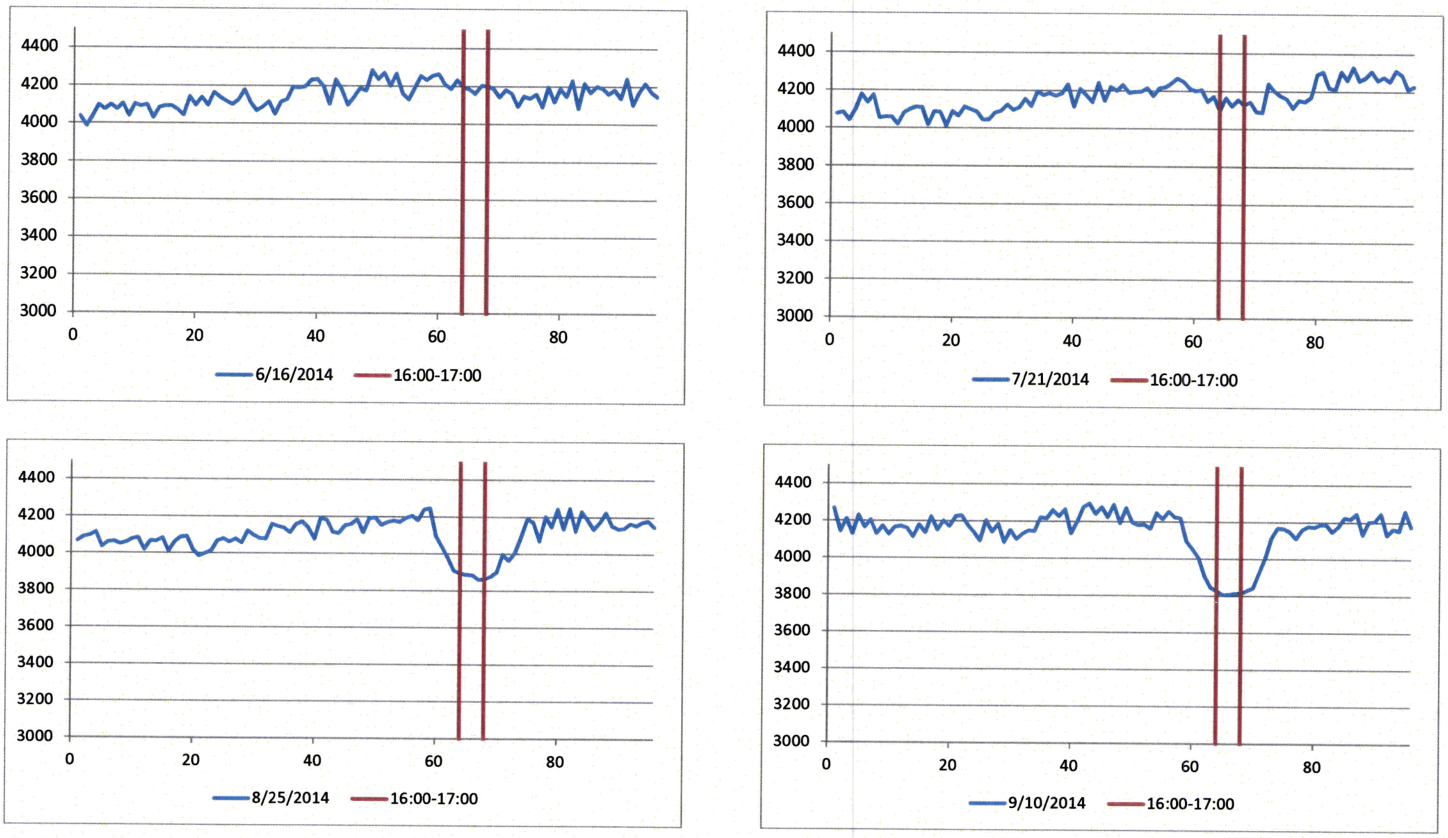




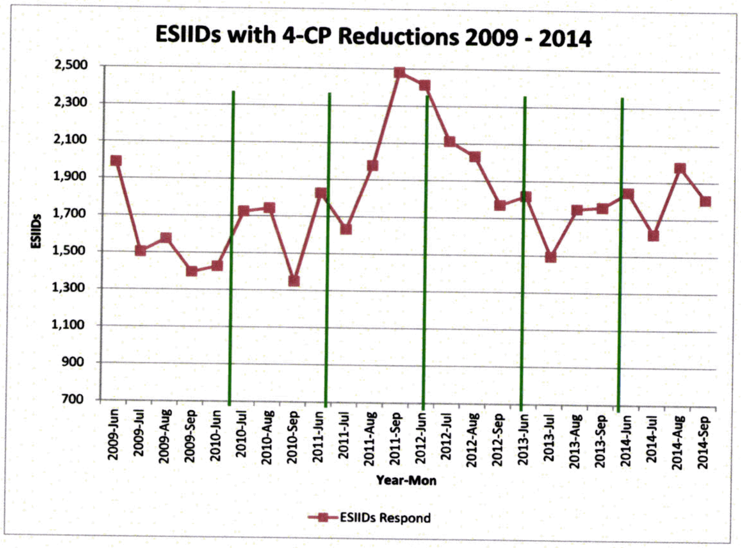


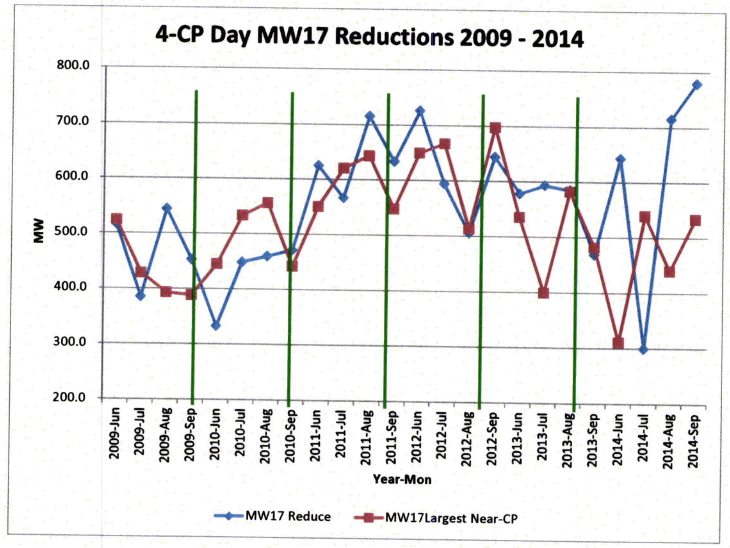
Total Load - Transmission Connected ESIIDs - 2014

Examined Transmission ESIID Load to Identify Near-CP days



Hour Ending 17:00 Response on 4 CP Days 2009 - 2014





	2009-Jun	2009-Jul	2009-Aug	2009-Sep	2010-Jun	2010-Jul	2010-Aug	2010-Sep	2011-Jun	2011-Jul	2011-Aug	2011-Sep
MW-17	516.4	385.1	544.0	452.6	332.3	448.5	459.5	471.5	624.7	566.8	715.5	633.5
Largest Near CP17	389.6	336.7	392.8	388.6	444.8	533.5	556.4	442.1	550.8	620.7	643.7	547.6
MW-CP-Int	524.3	428.1	408.1	398.5	591.1	564.5	634.2	553.3	672.5	583.4	495.3	527.6
ESIIDs	1,988	1,504	1,575	1,396	1,427	1,724	1,743	1,349	1,827	1,977	2,480	1,737

	2012-Jun	2012-Jul	2012-Aug	2012-Sep	2013-Jun	2013-Jul	2013-Aug	2013-Sep	2014-Jun	2014-Jul	2014-Aug	2014-Sep
MW-17	726.1	594.0	505.6	643.7	578.1	593.4	585.1	468.9	643.1	299.2	715.2	779.6
Largest Near CP17	649.4	667.1	513.1	697.8	535.5	399.1	582.8	482.1	311.0	540.0	439.9	534.0
MW-CP-Int	672.5	583.4	495.3	527.6	545.9	589.0	566.0	425.8	211.2	258.7	633.1	750.6
ESIIDs	2,413	2,112	2,031	1,770	1,819	1,495	1,751	1,761	1,842	1,617	1,983	1,806

4 CP 15-Minute Response 2009 - 2014

CP Date	CP Time	Reduce MW	Near-CP Date	Near-CP Time	Reduce MW	CP Date	CP Time	Reduce MW	Near-CP Date	Near-CP Time	Reduce MW
6/25/2009	16:15	558.8	6/4/2009	17:00	348.2	6/26/2012	16:30	725.2	6/11/2012	16:30	532.6
7/13/2009	17:00	394.5	6/12/2009	17:00	349.2	7/31/2012	17:00	599.6	6/25/2012	17:00	641.7
8/5/2009	16:00	486.7	6/16/2009	17:00	407.8	8/1/2012	17:00	526.7	7/20/2012	16:00	489.1
9/3/2009	16:00	401.7	6/24/2009	16:30	535.0	9/5/2012	17:00	655.6	7/30/2012	16:45	665.7
			7/8/2009	16:45	397.0				8/2/2012	16:45	518.1
			7/10/2009	16:45	402.2				9/4/2012	16:45	549.0
			7/17/2009	16:45	403.1				9/6/2012	17:00	683.6
			7/31/2009	16:00	377.7				9/7/2012	16:30	694.6
			8/4/2009	17:00	405.7				9/28/2012	14:30	171.2
			8/6/2009	17:00	333.7						
			9/2/2009	17:00	416.5						
	average	460.4	n=11	average	397.8		average	626.8	n=9	average	549.5
6/21/2010	16:45	335.6	6/18/2010	16:00	353.6	6/27/2013	17:00	585.7	6/19/2013	16:30	337.8
7/16/2010	16:30	434.2	6/22/2010	16:30	468.1	7/31/2013	17:00	600.5	6/26/2013	17:00	385.8
8/23/2010	16:00	424.9	6/23/2010	17:00	344.7	8/7/2013	16:45	601.9	6/28/2013	17:00	603.5
9/14/2010	16:45	474.3	6/23/2010	17:00	428.8	9/3/2013	16:45	471.7	7/9/2013	16:45	339.2
			7/14/2010	17:00	522.0				7/10/2013	17:00	413.5
			7/15/2010	16:45	560.9				8/1/2013	16:45	607.3
			8/3/2010	16:30	445.1				8/6/2013	16:45	515.9
			8/4/2010	16:45	508.0				9/4/2013	17:00	477.0
			8/5/2010	16:30	448.9						
			8/11/2010	15:15	126.7						
			8/20/2010	15:30	176.5						
			9/1/2010	15:30	336.7						
	average	417.3	n=12	average	393.3		average	565.0	n=8	average	460.0
6/15/2011	17:00	631.2	6/14/2011	17:00	494.0	6/30/2014	16:30	662.5	6/3/2014	17:00	316.5
7/27/2011	16:30	566.4	6/16/2011	17:00	355.1	7/21/2014	16:45	304.0	7/8/2014	16:30	436.3
8/3/2011	17:00	707.7	6/17/2011	16:45	562.9	8/25/2014	17:00	714.0	7/14/2014	15:00	249.0
9/2/2011	16:30	639.6	6/28/2011	17:00	428.1	9/10/2014	17:00	781.9	7/22/2014	16:45	476.2
			7/7/2011	16:45	461.3				7/25/2014	17:00	490.4
			7/13/2011	17:00	594.6				8/6/2014	17:00	396.5
			7/14/2011	16:45	636.2				8/8/2014	15:45	448.5
			8/1/2011	16:45	468.7				8/21/2014	16:00	318.4
			8/2/2011	16:45	640.3				8/22/2014	16:30	565.0
			8/5/2011	16:45	478.0				9/2/2014	16:30	729.8
			8/23/2011	16:45	403.7				9/9/2014	16:45	560.5
			9/1/2011	16:45	540.6						
			9/13/2011	16:30	533.3						
	average	636.2	n=13	average	507.4		average	615.6	n=11	average	416.1

4 CP 15-Minute Response 2009 - 2014

	CP	Near-CP	Total
14:30	0	1	1
14:45	0	0	0
15:00	0	1	1
15:15	0	1	1
15:30	0	2	2
15:45	0	1	1
16:00	3	4	7
16:15	1	0	1
16:30	5	11	16
16:45	5	21	26
17:00	10	22	32

4-CP Peak Shifting

Actual Peak		Peak with no 4-CP Reduction	
Date	Time	Date	Time
7/16/2010	16:30	7/15/2010	16:45
6/15/2011	17:00	6/15/2011	16:45
7/27/2011	16:30	7/27/2011	16:45
8/3/2011	17:00	8/3/2011	16:45
6/26/2012	16:30	6/26/2012	16:45

- Number of Near-CP days averaged about 10 per year
- Since 2009, no CP intervals have occurred prior to interval ending 4:00 pm
- Of the 24 CP intervals since 2009, only 5 appear to have been shifted by 4-CP response
  - 2 shifted one interval earlier
  - 2 shifted one interval later
  - 1 (7/16/2010) shifted one day earlier and one interval later

4 CP Response – ERCOT REP Survey

REPs with 4_CP in 2013 Only	2
REPs with 4_CP in both 2013 and 2014	3
REPs with 4_CP in 2014 Only	2

Total ESIIDs on 4_CP in 2014	228
ESIIDs on 4-CP in 2014 and on other 2014 program(s)	83
ESIIDs on 4-CP in 2014 and not on other 2014 program(s)	145

4-CP Reports		Other Programs Reported		Number of ESIIDs	Pct
2013	2014	2013	2014		
NO	YES/N	BI/N	BI/N	1	0.4%
NO	YES/N	BI/N	BI/N#RTP/N	6	2.5%
NO	YES/N	BI/N	NO	6	2.5%
NO	YES/N	BI/N	RTP/N	13	5.5%
NO	YES/N	PR/N	PR/N	32	13.4%
NO	YES/N	RTP/N	RTP/N	5	2.1%
NO REPT	YES/N	NO REPT	NO	139	58.4%
NO REPT	YES/N	NO REPT	PR/N	1	0.4%
NO REPT	YES/N	NO REPT	RTP/N	21	8.8%
YES/N	NO	OLC/Y	OLC/N#RTP/N	2	0.8%
YES/N	NO REPT	BI/N	NO REPT	1	0.4%
YES/N	NO REPT	NO	NO REPT	1	0.4%
YES/N	YES/N	BI/N	RTP/N	3	1.3%
YES/N	YES/N	NO	RTP/N	1	0.4%
YES/Y	NO REPT	NO	NO REPT	6	2.5%
Total				238	100.0%

Key

NO: ESIID submitted but not for this program
NO REPT: ESIID not submitted for any program
YES/N: ESIID submitted for REP 4-CP notification - no DLC
BI/N: ESIID on Block and Index - no DLC
OLC/Y: ESIID on Other Load Control - no DLC
RTP/NP: ESIID on Real Time Pricing - no DLC

#: Used to separate multiple programs

4 CP Response – ERCOT REP Survey

Response Date	Entity			ERCOT Analysis		
				Near CP Day	CP Day	CP Interval
6/3/2014				Yes		
6/4/2014						
6/5/2014						
6/6/2014						
6/11/2014						
6/16/2014		REP 2				
6/17/2014						
6/23/2014	REP 1					
6/24/2014	REP 1					
6/30/2014	REP 1	REP 2	REP 3		Yes	16:30
8/4/2014	REP 1					
8/5/2014	REP 1					
8/6/2014	REP 1			Yes		
8/7/2014	REP 1	REP 2				
8/8/2014	REP 1	REP 2		Yes		
8/15/2014	REP 1			Yes		
8/21/2014		REP 2		Yes		
8/22/2014	REP 1	REP 2		Yes		
8/25/2014	REP 1	REP 2	REP 3		Yes	17:00
8/26/2014	REP 1					

Response Date	Entity			ERCOT Analysis		
				Near CP Day	CP Day	CP Interval
7/1/2014						
7/2/2014	REP 1					
7/7/2014						
7/8/2014				Yes		
7/9/2014	REP 1					
7/10/2014	REP 1					
7/11/2014	REP 1					
7/14/2014	REP 1	REP 2		Yes		
7/21/2014		REP 2	REP 3		Yes	16:45
7/22/2014	REP 1	REP 2		Yes		
7/23/2014	REP 1	REP 2				
7/24/2014	REP 1					
7/25/2014	REP 1	REP 2		Yes		
7/28/2014	REP 1	REP 2				
9/2/2014	REP 1	REP 2		Yes		
9/3/2014	REP 1					
9/5/2014						
9/8/2014	REP 1					
9/9/2014	REP 1	REP 2		Yes		
9/10/2014	REP 1	REP 2	REP 3		Yes	17:00

- Notifications: REP 1 – 27 REP 2 – 16 REP 3 – 4
- REP 1 missed July CP, otherwise REP notifications were sent for all actual CP days

4 CP Response – ERCOT REP Survey

REP Reports		ERCOT Analysis		
4-CP 2013	4-CP 2014	Non Responders	Responders	Percent Respond
NO	YES/N	12	51	81.0
NO REPT	YES/N	43	128	74.9
YES/N	NO	1	1	50.0
YES/N	NO REPT	1	2	66.7
YES/N	YES/N	1	3	75.0
YES/Y	NO REPT	1	7	87.5
Total		59	192	76.5

- 238 ESIIDs reported by REPS as being on 4-CP notification programs in 2013 or 2014
- 182 (76%) were classified by ERCOT as 4-CP responders.

Number of ESIIDs with 4 CP Responses - 2014

Load Factor	High			Medium			Low			Total		
Response Type	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond
June												
Transmission	11	1	152	15	8	120	7	18	39	33	27	311
Distribution NWS	136	1	1,704	321	50	5,207	791	269	2,299	1,248	320	9,210
Distribution WS	69	5	521	91	35	1,202	6	8	62	166	48	1,785
Total	216	7	2,377	427	93	6,529	804	295	2,400	1,447	395	11,306
July												
Transmission	5	1	159	15	8	122	7	19	39	27	28	320
Distribution NWS	68	2	1,771	231	56	5,293	725	266	2,365	1,024	324	9,429
Distribution WS	40	6	549	109	39	1,180	11	9	56	160	54	1,785
Total	113	9	2,479	355	103	6,595	743	294	2,460	1,211	406	11,534
August												
Transmission	8	1	156	19	10	116	8	18	39	35	29	311
Distribution NWS	142	5	1,695	351	59	5,169	757	270	2,337	1,250	334	9,201
Distribution WS	112	6	477	160	37	1,131	11	9	56	283	52	1,664
Total	262	12	2,328	530	106	6,416	776	297	2,432	1,568	415	11,176
September												
Transmission	12	3	150	22	10	113	13	23	29	47	36	292
Distribution NWS	143	3	1,696	340	56	5,178	595	242	2,522	1,078	301	9,396
Distribution WS	113	6	476	166	36	1,126	13	10	53	292	52	1,655
Total	268	12	2,322	528	102	6,417	621	275	2,604	1,417	389	11,343

Hour-ending 17:00 Reductions on 4 CP Days - 2014

Responding Transmission Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
30-Jun-14	99.0	79.0	20.0	124.7	75.3	49.4	132.3	109.5	22.8	355.9	263.8	92.1
21-Jul-14	25.3	20.1	5.2	35.6	14.0	21.6	48.3	31.9	16.4	109.2	66.0	43.2
25-Aug-14	110.1	78.5	31.6	122.8	79.0	43.8	127.4	104.8	22.6	360.3	262.3	98.0
10-Sep-14	119.5	81.8	37.7	127.6	82.3	45.3	177.6	134.4	43.2	424.8	298.6	126.2
Near CP Day with Largest Response												
8-Aug-14	72.0	65.8	6.1	99.4	73.6	25.8	147.1	125.9	21.2	318.5	265.3	53.2

Hour-ending 17:00 MW Reductions on 4 CP Days - 2014

Responding NWS Distribution Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
30-Jun-14	51.4	50.8	0.6	102.9	84.8	18.1	108.8	63.8	45.1	263.2	199.4	63.8
21-Jul-14	9.4	8.2	1.2	62.3	46.4	16.0	99.3	54.6	44.7	171.1	109.2	62.0
25-Aug-14	78.6	76.4	2.1	106.2	85.4	20.8	134.5	82.5	52.0	319.3	244.3	75.0
10-Sep-14	73.0	71.6	1.4	121.7	90.2	31.5	121.9	72.0	49.9	316.7	233.9	82.8
Near CP Day with Largest Response												
8-Aug-14	45.0	43.8	1.1	103.1	88.1	15.0	130.4	95.5	34.9	278.4	227.4	51.0

Hour-ending 17:00 Reductions on 4 CP Days - 2014

Responding WS Distribution Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
30-Jun-14	9.0	8.6	0.4	14.0	5.4	8.6	0.9	0.1	0.8	23.9	14.0	9.9
21-Jul-14	2.8	2.2	0.5	14.7	5.7	9.0	1.4	0.6	0.9	18.8	8.5	10.4
25-Aug-14	10.7	10.0	0.8	23.1	9.9	13.1	1.9	0.5	1.4	35.6	20.4	15.2
10-Sep-14	11.7	11.0	0.7	24.5	11.2	13.3	2.0	0.5	1.4	38.2	22.8	15.4
Near CP Day with Largest Response												
8-Aug-14	8.6	7.9	0.7	17.3	4.0	13.3	1.4	0.2	1.2	27.3	12.1	15.1

Hour-ending 17:00 MW Reductions on 4 CP Days - 2014

All Responding 4-CP ESIIDS

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
30-Jun-14	159.4	138.4	21.0	241.7	165.5	76.1	242.0	173.4	68.7	643.1	477.3	165.8
21-Jul-14	37.5	30.5	7.0	112.7	66.1	46.6	149.0	87.1	62.0	299.2	183.6	115.5
25-Aug-14	199.4	164.9	34.5	252.0	174.3	77.7	263.8	187.8	76.0	715.2	526.9	188.2
10-Sep-14	204.3	164.4	39.8	273.9	183.8	90.1	301.5	207.0	94.5	779.6	555.2	224.4
Near CP Day with Largest Response												
8-Aug-14	125.5	117.6	7.9	219.8	165.7	54.1	278.8	221.6	57.2	624.2	504.9	119.3

Hour-ending 17:00 MW Reductions on 4 CP Days - 2014

Reductions by Voltage Group

	Reductions for Hour Ending 17:00											
	Transmission			Distribution Non-Weather Sensitive			Distribution Weather Sensitive			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
30-Jun-14	355.9	263.8	92.1	263.2	199.4	63.8	23.9	14.0	9.9	643.1	477.3	165.8
21-Jul-14	109.2	66.0	43.2	171.1	109.2	62.0	18.8	8.5	10.4	299.2	183.6	115.5
25-Aug-14	360.3	262.3	98.0	319.3	244.3	75.0	35.6	20.4	15.2	715.2	526.9	188.2
10-Sep-14	424.8	298.6	126.2	316.7	233.9	82.8	38.2	22.8	15.4	779.6	555.2	224.4
Near CP Day with Largest Response												
8-Aug-14	318.5	265.3	53.2	278.4	227.4	51.0	27.3	12.1	15.1	624.2	504.9	119.3

Hour-ending 17:00 MW Reductions on 4 CP Days - 2014

Reductions as a Percent of Total Voltage Group Load

CP Date	Total Reduction	Responders Total Load	Non-Responders Total Load	Total Load	Response as Percent of Total Load	Total Reduction	Responders Total Load	Non-Responders Total Load	Total Load	Response as Percent of Total Load
	High Load Factor MW					Medium Load Factor MW				
30-Jun-14	159.4	527.8	5,436.6	5,964.4	2.7%	241.7	769.8	5,967.0	6,736.9	3.6%
21-Jul-14	37.5	277.8	5,782.9	6,060.7	0.6%	112.7	563.9	6,344.9	6,908.8	1.6%
25-Aug-14	199.4	570.0	5,473.0	6,043.0	3.3%	252.0	868.2	6,115.1	6,983.3	3.6%
10-Sep-14	204.3	625.2	5,417.4	6,042.6	3.4%	273.9	874.5	6,036.3	6,910.9	4.0%
	Low Load Factor					Total				
30-Jun-14	242.0	409.1	850.9	1,260.0	19.2%	643.1	1,706.7	12,254.6	13,961.3	4.6%
21-Jul-14	149.0	325.7	987.5	1,313.2	11.3%	299.2	1,167.3	13,115.3	14,282.7	2.1%
25-Aug-14	263.8	506.6	1,095.6	1,602.2	16.5%	715.2	1,944.7	12,683.8	14,628.5	4.9%
10-Sep-14	301.5	492.4	1,115.4	1,607.8	18.8%	779.6	1,992.1	12,569.1	14,561.2	5.4%

Hour-ending 17:00 Reductions on 4 CP Days - 2014

Percentage of Load Reduction by Load Factor and Voltage Group

4 CP Days	High Load Factor		Medium Load Factor		Low Load Factor		Total Reduction
	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	
30-Jun-14	159.4	24.8%	241.7	37.6%	242.0	37.6%	643.1
21-Jul-14	37.5	12.5%	112.7	37.7%	149.0	49.8%	299.2
25-Aug-14	199.4	27.9%	252.0	35.2%	263.8	36.9%	715.2
10-Sep-14	204.3	26.2%	273.9	35.1%	301.5	38.7%	779.6

4 CP Days	Transmission		Distribution NWS		Distribution WS		Total Reduction
	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	
30-Jun-14	355.9	55.3%	263.2	40.9%	23.9	3.7%	643.1
21-Jul-14	109.2	36.5%	171.1	57.2%	18.8	6.3%	299.2
25-Aug-14	360.3	50.4%	319.3	44.6%	35.6	5.0%	715.2
10-Sep-14	424.8	54.5%	316.7	40.6%	38.2	4.9%	779.6

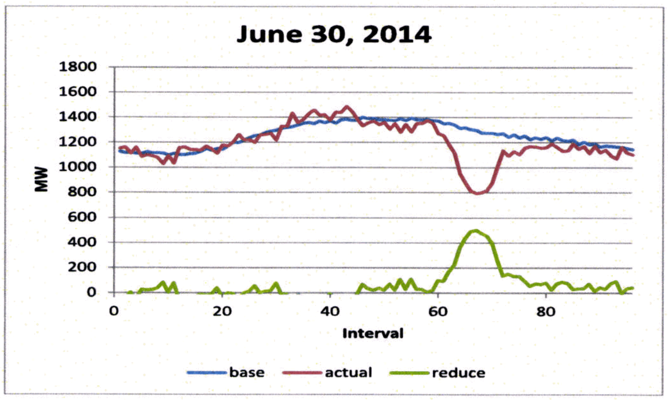
Hour-ending 17:00 Reductions on 4 CP Days - 2014

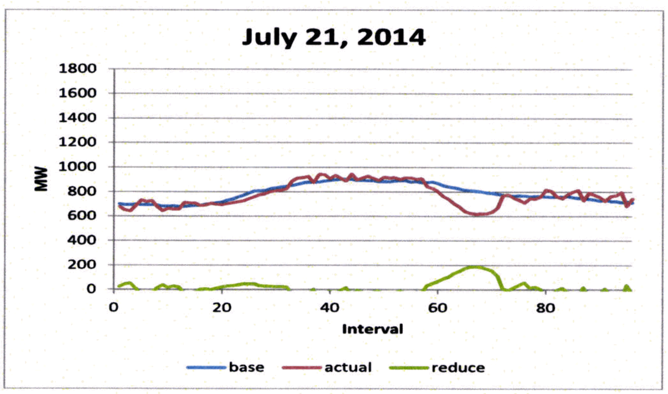
Percentage of Load Reduction based on Customer Peak

4 CP Days	< 1 MW		1 - 10 MW		10 - 30 MW		> 30 MW		Total Reduction
	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	
30-Jun-14	72.7	11.3%	202.9	31.6%	98.4	15.3%	269.0	41.8%	643.1
21-Jul-14	58.8	19.6%	134.7	45.0%	30.6	10.2%	75.1	25.1%	299.2
25-Aug-14	92.8	13.0%	212.1	29.7%	99.3	13.9%	310.9	43.5%	715.2
10-Sep-14	82.8	10.6%	234.9	30.1%	123.6	15.8%	338.4	43.4%	779.6

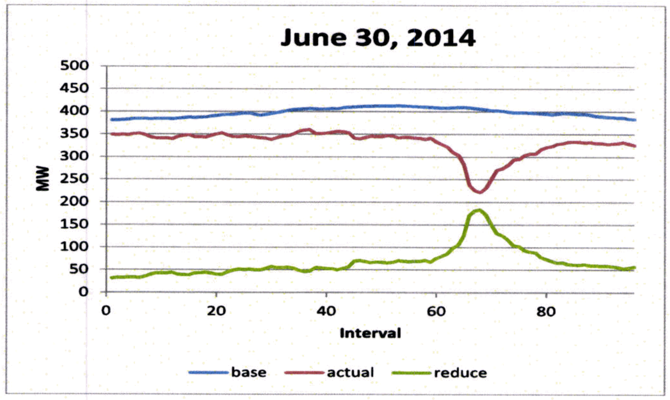
Hour-ending 17:00 Reductions on 4 CP Days - 2014

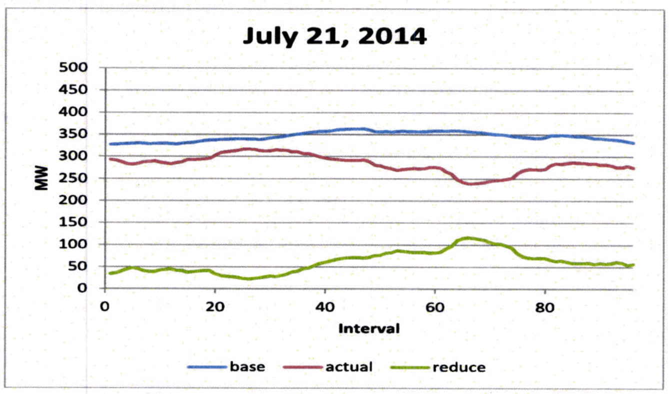
Peak Response





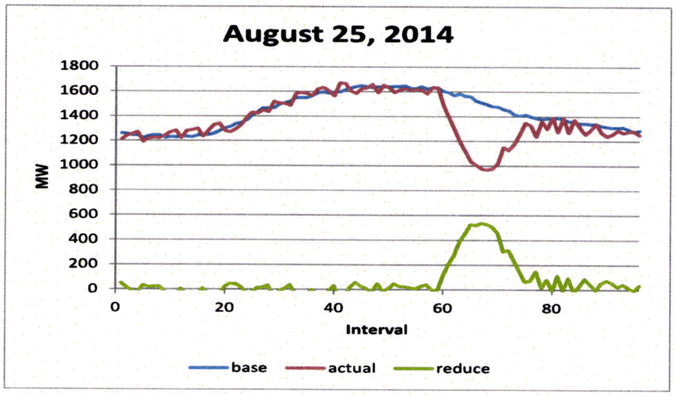
Day-use Response

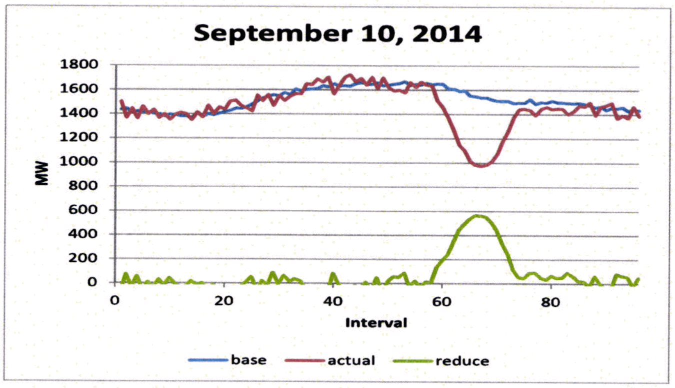




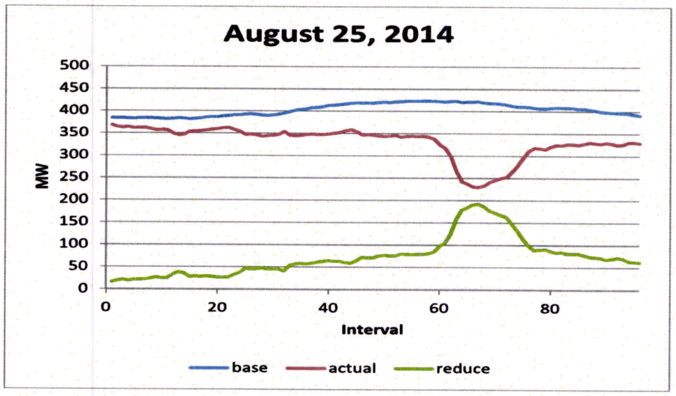
Hour-ending 17:00 Reductions on 4 CP Days - 2014

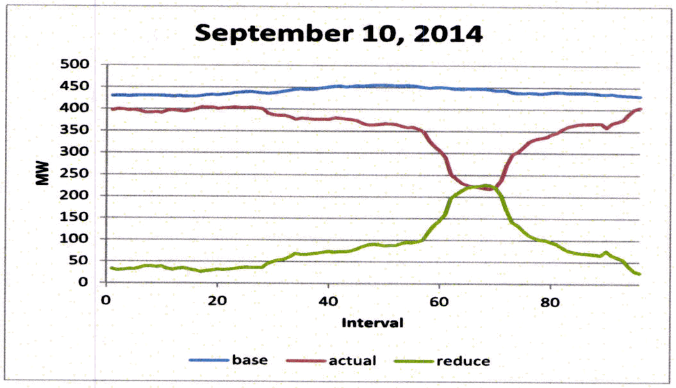
Peak Response



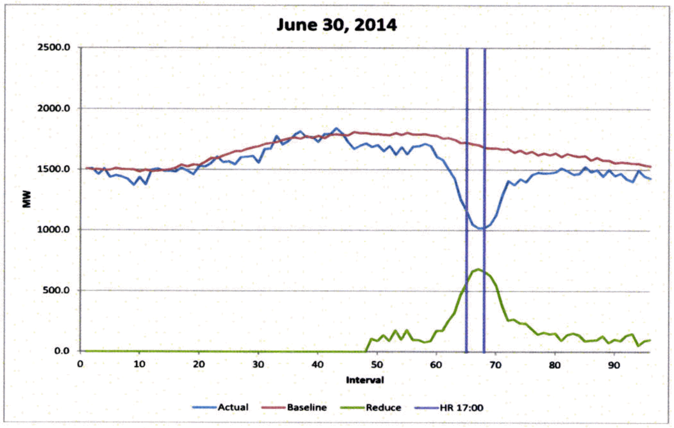


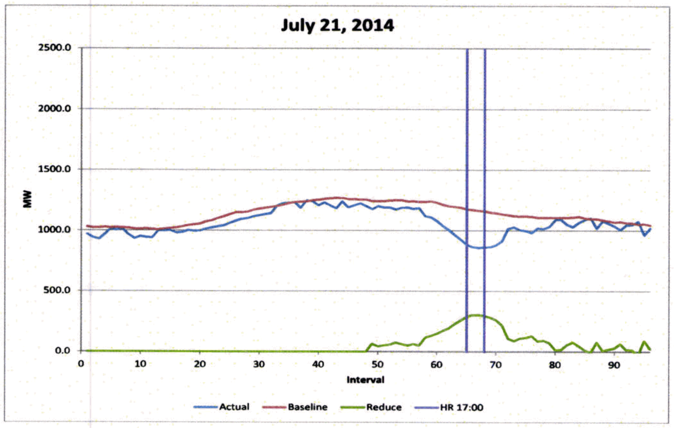
Day-use Response

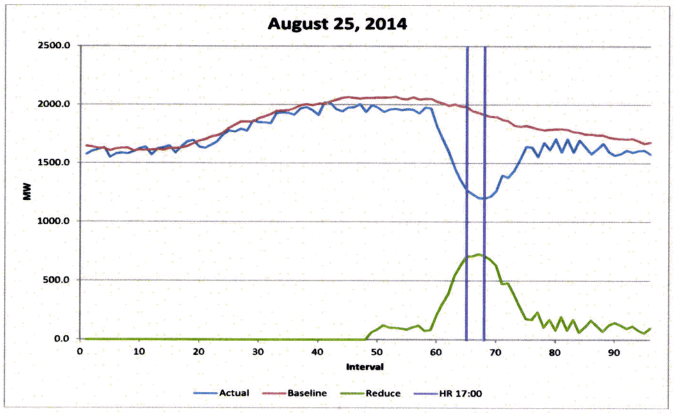


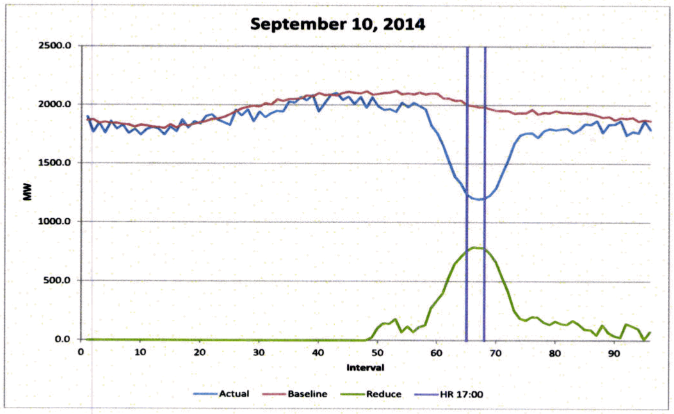


Hour-ending 17:00 Reductions on 4 CP Days - 2014









Questions?

craish@ercot.com 512/248-3876

Appendix 1 – ESIIDs Responding

Number of ESIIDs with 4 CP Responses – 2009

Load Factor	High			Medium			Low			Total		
Response Type	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond
June												
Transmission	7	2	131	15	4	112	19	17	34	41	23	277
Distribution NWS	117	3	1,717	384	41	4,598	864	196	2,009	1,365	240	8,324
Distribution WS	30	1	893	219	28	1,629	31	10	78	280	39	2,600
Total	154	6	2,741	618	73	6,339	914	223	2,121	1,686	302	11,201
July												
Transmission	4	1	135	13	9	109	13	18	39	30	28	283
Distribution NWS	62	4	1,770	243	35	4,746	684	229	2,153	989	268	8,669
Distribution WS	27	1	896	101	26	1,749	28	6	85	156	33	2,730
Total	93	6	2,801	357	70	6,604	725	253	2,277	1,175	329	11,682
August												
Transmission	9	1	130	10	5	116	13	14	43	32	20	289
Distribution NWS	101	2	1,733	261	38	4,726	689	200	2,178	1,051	240	8,637
Distribution WS	34	1	889	140	22	1,745	28	7	84	202	30	2,718
Total	144	4	2,752	411	65	6,587	730	221	2,305	1,285	290	11,644
September												
Transmission	6	1	133	9	6	116	13	11	45	28	18	294
Distribution NWS	61	1	1,771	236	54	4,733	595	215	2,257	892	270	8,761
Distribution WS	26	1	895	109	22	1,028	20	10	89	155	33	2,012
Total	93	3	2,799	354	82	5,877	628	236	2,391	1,075	321	11,067

Number of ESIIDs with 4 CP Responses – 2010

Load Factor	High			Medium			Low			Total		
Response Type	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond
June												
Transmission	6	1	147	7	4	107	7	17	50	20	22	304
Distribution NWS	54	1	2,106	196	32	4,697	710	250	2,125	960	283	8,928
Distribution WS	27	2	892	83	10	1,101	18	2	46	128	14	2,039
Total	87	4	3,145	286	46	5,905	735	269	2,221	1,108	319	11,271
July												
Transmission	3	1	150	10	6	102	15	21	39	28	28	291
Distribution NWS	96	1	2,065	347	29	4,547	821	214	2,052	1,264	244	8,664
Distribution WS	38	2	881	100	10	1,084	8	2	56	146	14	2,021
Total	137	4	3,096	457	45	5,733	844	237	2,147	1,438	286	10,976
August												
Transmission	7	3	144	12	5	101	14	22	39	33	30	284
Distribution NWS	89	1	2,072	255	39	4,630	787	237	2,071	1,131	277	8,773
Distribution WS	61	2	858	186	12	1,118	10	1	55	257	15	2,031
Total	157	6	3,074	453	56	5,849	811	260	2,165	1,421	322	11,088
September												
Transmission	7	3	143	10	9	99	10	16	50	27	28	292
Distribution NWS	93	1	2,064	253	38	4,629	580	217	2,293	926	256	8,986
Distribution WS	26	2	893	64	12	1,028	7	1	57	97	15	1,978
Total	126	6	3,100	327	59	5,756	597	234	2,400	1,050	299	11,256

Number of ESIIDs with 4 CP Responses – 2011

Load Factor	High			Medium			Low			Total		
Response Type	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond
June												
Transmission	8	4	147	16	7	113	13	16	30	37	27	290
Distribution NWS	138	1	2,151	328	50	4,707	777	196	2,000	1,243	247	8,858
Distribution WS	79	1	1,093	145	29	1,376	12	7	54	236	37	2,523
Total	225	6	3,391	489	86	6,196	802	219	2,084	1,516	311	11,671
July												
Transmission	5	1	153	9	12	115	14	16	30	28	29	298
Distribution NWS	110	3	2,177	305	46	4,734	723	203	2,049	1,138	252	8,960
Distribution WS	40	1	1,132	99	23	1,428	17	5	51	156	29	2,611
Total	155	5	3,462	413	81	6,277	754	224	2,130	1,322	310	11,869
August												
Transmission	7	1	151	18	12	106	16	18	26	41	31	283
Distribution NWS	155	4	2,131	358	66	4,662	764	212	2,001	1,277	282	8,794
Distribution WS	93	-	1,080	212	23	1,315	13	5	55	318	28	2,450
Total	255	5	3,362	588	101	6,083	793	235	2,082	1,636	341	11,527
September												
Transmission	7	2	150	13	9	114	16	16	28	36	27	292
Distribution NWS	182	3	2,104	540	47	4,496	1,038	212	1,723	1,760	262	8,323
Distribution WS	100	1	1,072	240	28	1,282	19	7	47	359	36	2,401
Total	289	6	3,326	793	84	5,892	1,073	235	1,798	2,155	325	11,016

Number of ESIIDs with 4 CP Responses – 2012

Load Factor	High			Medium			Low			Total		
Response Type	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond
June												
Transmission	13	1	147	14	17	102	17	16	25	44	34	274
Distribution NWS	106	4	1,717	322	52	5,061	778	214	2,256	1,206	270	9,034
Distribution WS	195	1	469	598	13	983	38	14	54	831	28	1,506
Total	314	6	2,333	934	82	6,146	833	244	2,335	2,081	332	10,814
July												
Transmission	11	-	149	12	14	107	11	15	32	34	29	288
Distribution NWS	99	2	1,725	316	50	5,068	784	247	2,216	1,199	299	9,009
Distribution WS	106	1	558	398	11	1,185	27	8	71	531	20	1,814
Total	216	3	2,432	726	75	6,360	822	270	2,319	1,764	348	11,111
August												
Transmission	6	-	155	10	11	112	10	12	36	26	23	303
Distribution NWS	81	1	1,745	329	40	5,065	788	223	2,236	1,198	264	9,046
Distribution WS	117	-	548	359	9	1,226	25	10	71	501	19	1,845
Total	204	1	2,448	698	60	6,403	823	245	2,343	1,725	306	11,194
September												
Transmission	10	1	150	15	13	104	8	16	34	33	30	288
Distribution NWS	94	-	1,733	302	50	5,079	684	220	2,342	1,080	270	9,154
Distribution WS	70	-	595	238	12	1,344	25	12	69	333	24	2,008
Total	174	1	2,478	555	75	6,527	717	248	2,445	1,446	324	11,450

Number of ESIIDs with 4 CP Responses – 2013

Load Factor	High			Medium			Low			Total		
Response Type	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond
June												
Transmission	11	1	152	17	11	97	11	15	37	39	27	286
Distribution NWS	133	4	1,761	317	51	5,102	876	235	2,153	1,326	290	9,016
Distribution WS	36	-	362	90	2	753	6	3	31	132	5	1,146
Total	180	5	2,275	424	64	5,952	893	253	2,221	1,497	322	10,448
July												
Transmission	7	4	153	15	7	103	14	19	30	36	30	286
Distribution NWS	86	3	1,808	254	40	5,174	736	229	2,299	1,076	272	9,281
Distribution WS	19	-	379	54	2	789	2	4	34	75	6	1,202
Total	112	7	2,340	323	49	6,066	752	252	2,363	1,187	308	10,769
August												
Transmission	9	2	152	15	8	102	11	20	32	35	30	286
Distribution NWS	165	1	1,731	377	43	5,051	760	225	2,280	1,302	269	9,062
Distribution WS	23	-	375	75	5	765	6	6	28	104	11	1,168
Total	197	3	2,258	467	56	5,918	777	251	2,340	1,441	310	10,516
September												
Transmission	7	2	154	12	15	98	8	14	39	27	31	291
Distribution NWS	98	4	1,795	236	64	5,171	714	240	2,308	1,048	308	9,274
Distribution WS	23	-	375	39	6	800	4	5	31	66	11	1,206
Total	128	6	2,324	287	85	6,069	726	259	2,378	1,141	350	10,771

Number of ESIIDs with 4 CP Responses – 2014

Load Factor	High			Medium			Low			Total		
Response Type	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond	Reduce Hour	Reduce Day	Non Respond
June												
Transmission	11	1	152	15	8	120	7	18	39	33	27	311
Distribution NWS	136	1	1,704	321	50	5,207	791	269	2,299	1,248	320	9,210
Distribution WS	69	5	521	91	35	1,202	6	8	62	166	48	1,785
Total	216	7	2,377	427	93	6,529	804	295	2,400	1,447	395	11,306
July												
Transmission	5	1	159	15	8	122	7	19	39	27	28	320
Distribution NWS	68	2	1,771	231	56	5,293	725	266	2,365	1,024	324	9,429
Distribution WS	40	6	549	109	39	1,180	11	9	56	160	54	1,785
Total	113	9	2,479	355	103	6,595	743	294	2,460	1,211	406	11,534
August												
Transmission	8	1	156	19	10	116	8	18	39	35	29	311
Distribution NWS	142	5	1,695	351	59	5,169	757	270	2,337	1,250	334	9,201
Distribution WS	112	6	477	160	37	1,131	11	9	56	283	52	1,664
Total	262	12	2,328	530	106	6,416	776	297	2,432	1,568	415	11,176
September												
Transmission	12	3	150	22	10	113	13	23	29	47	36	292
Distribution NWS	143	3	1,696	340	56	5,178	595	242	2,522	1,078	301	9,396
Distribution WS	113	6	476	166	36	1,126	13	10	53	292	52	1,655
Total	268	12	2,322	528	102	6,417	621	275	2,604	1,417	389	11,343

Appendix 2 – Transmission MW Response

Hour-ending 17:00 Reductions on 4 CP Days - 2009

Responding Transmission Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
25-Jun-09	87.0	67.8	19.2	70.6	57.8	12.8	149.9	125.1	24.8	307.5	250.7	56.8
13-Jul-09	72.3	55.7	16.6	85.4	57.7	27.7	69.1	51.4	17.6	226.7	164.7	61.9
5-Aug-09	87.0	70.4	16.6	75.1	49.8	25.3	204.2	158.3	45.9	366.3	278.5	87.8
3-Sep-09	87.5	76.2	11.4	80.7	59.0	21.8	116.0	101.6	14.4	284.3	236.7	47.6
Near CP Day with Largest Response												
24-Jun-09	84.3	64.2	20.1	80.1	56.1	24.0	159.3	128.6	30.7	323.8	249.0	74.8

Hour-ending 17:00 Reductions on 4 CP Days - 2010

Responding Transmission Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
21-Jun-10	76.2	58.0	18.2	65.9	8.7	57.2	32.2	5.4	26.8	174.3	72.1	102.2
16-Jul-10	54.0	35.9	18.1	56.3	18.6	37.7	131.5	104.1	27.4	241.7	158.6	83.1
23-Aug-10	81.9	59.9	22.0	90.7	29.2	61.5	63.4	11.7	51.7	236.0	100.8	135.2
14-Sep-10	99.1	62.9	36.2	63.8	13.3	50.5	140.1	113.1	26.9	303.0	189.3	113.6
Near CP Day with Largest Response												
20-Aug-10	127.3	118.0	9.3	110.3	60.7	49.6	38.5	6.3	32.2	276.1	185.0	91.1

Hour-ending 17:00 Reductions on 4 CP Days - 2011

Responding Transmission Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Total Peak Response	Day Response
4 CP Days												
15-Jun-11	78.9	74.8	4.0	110.5	26.1	84.4	218.1	190.7	27.4	407.4	291.6	115.8
27-Jul-11	89.1	67.4	21.7	134.0	31.4	102.6	130.4	116.1	14.4	353.6	214.9	138.7
3-Aug-11	89.2	67.5	21.7	130.1	33.0	97.1	204.2	179.9	24.2	423.5	280.5	143.0
24-Sep-11	73.5	63.8	9.6	89.5	25.5	64.0	166.0	139.8	26.2	329.0	229.2	99.8
Near CP Day with Largest Response												
2-Aug-11	81.4	81.4	0.0	140.7	38.5	102.1	175.4	162.8	12.6	397.5	282.8	114.7

Hour-ending 17:00 Reductions on 4 CP Days - 2012

Responding Transmission Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
26-Jun-12	94.3	92.5	1.8	138.8	58.2	80.6	184.3	157.3	27.0	417.4	308.0	109.4
31-Jul-12	106.5	106.5	0.0	112.7	31.4	81.3	97.1	64.8	32.2	316.3	202.8	113.5
1-Aug-12	67.3	67.3	0.0	91.1	14.5	76.7	90.5	69.8	20.7	248.9	151.6	97.3
5-Sep-12	116.1	105.3	10.8	107.5	43.9	63.6	183.4	164.0	19.4	407.0	313.2	93.8
Near CP Day with Largest Response												
7-Sep-12	107.4	104.5	2.8	102.4	44.1	58.3	170.2	152.1	18.1	379.9	300.6	79.3

Hour-ending 17:00 Reductions on 4 CP Days - 2013

Responding Transmission Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
27-Jun-13	73.1	69.6	3.5	109.6	73.2	36.4	139.8	110.0	29.8	322.5	252.8	69.7
31-Jul-13	111.5	75.6	35.9	117.9	85.0	32.9	127.7	97.8	29.8	357.0	258.4	98.6
7-Aug-13	75.4	54.2	21.2	99.7	82.9	16.7	128.4	104.8	23.6	303.5	241.9	61.6
3-Sep-13	101.1	70.3	30.8	105.5	38.7	66.8	30.8	18.7	12.1	237.5	127.7	109.7
Near CP Day with Largest Response												
1-Aug-13	77.2	56.9	20.3	90.7	61.9	28.8	150.1	123.5	26.6	318.0	242.3	75.7

Hour-ending 17:00 Reductions on 4 CP Days - 2014

Responding Transmission Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
16-Jun-14	99.0	79.0	20.0	124.7	75.3	49.4	132.3	109.5	22.8	355.9	263.8	92.1
21-Jul-14	25.3	20.1	5.2	35.6	14.0	21.6	48.3	31.9	16.4	109.2	66.0	43.2
25-Aug-14	110.1	78.5	31.6	122.8	79.0	43.8	127.4	104.8	22.6	360.3	262.3	98.0
10-Sep-14	119.5	81.8	37.7	127.6	82.3	45.3	177.6	134.4	43.2	424.8	298.6	126.2
Near CP Day with Largest Response												
8-Aug-14	72.0	65.8	6.1	99.4	73.6	25.8	147.1	125.9	21.2	318.5	265.3	53.2

Appendix 3 – Distribution NWS MW Response

Hour-ending 17:00 Reductions on 4 CP Days – 2009

Responding NWS Distribution Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
25-Jun-09	22.5	20.7	1.8	76.0	59.0	17.0	109.8	78.7	31.2	208.3	158.4	50.0
13-Jul-09	8.3	6.8	1.5	58.4	33.7	24.7	88.5	53.2	35.3	155.2	93.7	61.5
5-Aug-09	17.3	16.8	0.5	66.4	47.2	19.1	94.6	65.7	28.9	178.3	129.7	48.6
3-Sep-09	7.9	7.6	0.3	65.2	46.8	18.4	91.9	62.1	29.8	165.1	116.5	48.6
Near CP Day with Largest Response												
24-Jun-09	17.4	15.6	1.7	64.3	47.2	17.1	95.5	65.1	30.4	177.2	128.0	49.2

Hour-ending 17:00 Reductions on 4 CP Days – 2010

Responding NWS Distribution
Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
21-Jun-10	8.2	8.2	0.0	49.0	25.5	23.4	93.0	57.6	35.4	150.2	91.3	58.9
16-Jul-10	12.6	12.1	0.5	74.6	60.3	14.3	110.3	76.8	33.5	197.5	149.2	48.3
23-Aug-10	13.2	13.2	0.0	61.3	42.7	18.6	132.5	86.1	46.4	206.9	141.9	65.0
14-Sep-10	12.1	11.7	0.4	59.1	49.7	9.4	91.2	55.4	35.8	162.4	116.8	45.5
Near CP Day with Largest Response												
20-Aug-10	73.3	73.3	0.0	84.7	76.3	8.4	106.7	73.0	33.6	264.7	222.6	42.0

Hour-ending 17:00 Reductions on 4 CP Days – 2011

Responding NWS Distribution Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
15-Jun-11	27.2	24.7	2.5	73.6	49.8	23.8	96.7	63.5	33.1	197.5	138.1	59.5
27-Jul-11	24.9	24.6	0.3	64.5	45.0	19.5	110.2	76.8	33.4	199.6	146.4	53.3
3-Aug-11	23.6	23.0	0.6	99.2	66.5	32.7	141.2	108.5	32.7	264.0	198.0	66.0
24-Sep-11	19.6	17.6	2.1	96.8	79.8	17.0	160.6	127.6	33.1	277.0	224.9	52.1
Near CP Day with Largest Response												
2-Aug-11	14.3	13.9	0.4	80.9	50.9	30.0	124.6	91.7	32.9	219.8	156.6	63.2

Hour-ending 17:00 Reductions on 4 CP Days – 2012

Responding NWS Distribution Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
26-Jun-12	37.7	30.8	6.8	84.1	69.3	14.8	116.2	70.3	45.9	238.0	170.4	67.5
31-Jul-12	24.8	24.7	0.1	94.6	82.4	12.2	124.3	80.5	43.8	243.6	187.6	56.1
1-Aug-12	12.9	12.0	0.9	89.6	78.2	11.4	120.8	80.8	40.0	223.4	171.1	52.3
5-Sep-12	24.3	24.3	0.0	79.0	65.5	13.6	113.3	72.7	40.6	216.7	162.4	54.2
Near CP Day with Largest Response												
7-Sep-12	44.3	44.3	0.0	119.0	102.7	16.4	133.4	87.7	45.7	296.7	234.6	62.1

Hour-ending 17:00 Reductions on 4 CP Days - 2013

Responding NWS Distribution Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
27-Jun-13	35.4	33.1	2.3	90.2	71.9	18.3	117.3	80.4	36.9	242.9	185.4	57.5
31-Jul-13	39.0	38.4	0.6	78.7	62.9	15.8	112.4	70.3	42.1	230.1	171.6	58.5
7-Aug-13	37.9	37.7	0.1	109.0	88.8	20.1	120.2	79.1	41.1	267.0	205.6	61.4
3-Sep-13	34.9	34.3	0.6	72.2	52.8	19.3	117.0	73.2	43.8	224.0	160.3	63.7
Near CP Day with Largest Response												
1-Aug-13	33.4	33.3	0.2	99.9	84.2	15.7	117.4	73.3	44.1	250.8	190.8	60.0

Hour-ending 17:00 MW Reductions on 4 CP Days - 2014

Responding NWS Distribution Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
16-Jun-14	51.4	50.8	0.6	102.9	84.8	18.1	108.8	63.8	45.1	263.2	199.4	63.8
21-Jul-14	9.4	8.2	1.2	62.3	46.4	16.0	99.3	54.6	44.7	171.1	109.2	62.0
25-Aug-14	78.6	76.4	2.1	106.2	85.4	20.8	134.5	82.5	52.0	319.3	244.3	75.0
10-Sep-14	73.0	71.6	1.4	121.7	90.2	31.5	121.9	72.0	49.9	316.7	233.9	82.8
Near CP Day with Largest Response												
8-Aug-14	45.0	43.8	1.1	103.1	88.1	15.0	130.4	95.5	34.9	278.4	227.4	51.0

Appendix 4 – Distribution WS MW Response

Hour-ending 17:00 Reductions on 4 CP Days - 2009

Responding WS Distribution
Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
25-Jun-09	1.7	1.7	0.1	18.2	16.1	2.1	3.0	2.1	0.9	23.0	19.9	3.1
13-Jul-09	1.5	1.4	0.1	7.8	5.7	2.0	2.3	1.6	0.7	11.6	8.7	2.9
5-Aug-09	2.3	2.2	0.1	11.8	10.7	1.2	2.6	2.0	0.6	16.7	14.9	1.9
3-Sep-09	1.4	1.3	0.1	7.3	6.0	1.3	2.4	2.0	0.5	11.1	9.3	1.9
Near CP Day with Largest Response												
24-Jun-09	3.4	3.3	0.1	17.4	15.4	1.9	2.5	1.7	0.8	23.3	20.5	2.9

Hour-ending 17:00 Reductions on 4 CP Days - 2010

Responding WS Distribution Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
21-Jun-10	1.2	1.0	0.2	5.8	4.9	1.0	0.8	0.7	0.1	7.8	6.6	1.2
16-Jul-10	2.1	1.9	0.2	6.9	5.6	1.2	0.3	0.3	0.1	9.3	7.8	1.4
23-Aug-10	3.7	3.4	0.3	12.4	11.4	1.0	0.5	0.4	0.0	16.6	15.2	1.3
14-Sep-10	1.1	1.0	0.1	4.9	4.3	0.6	0.2	0.2	0.0	6.1	5.5	0.7
Near CP Day with Largest Response												
20-Aug-10	3.0	2.8	0.1	12.3	11.5	0.8	0.3	0.3	0.0	15.6	14.6	1.0

Hour-ending 17:00 Reductions on 4 CP Days - 2011

Responding WS Distribution Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
15-Jun-11	6.5	6.4	0.1	12.3	10.1	2.2	0.9	0.6	0.4	19.7	17.1	2.6
27-Jul-11	3.3	3.3	0.0	9.5	8.2	1.4	0.8	0.4	0.3	13.6	11.9	1.7
3-Aug-11	5.9	5.9	0.0	21.4	19.9	1.5	0.6	0.4	0.2	28.0	26.3	1.7
24-Sep-11	7.0	6.9	0.0	19.0	17.2	1.8	1.5	1.3	0.3	27.5	25.4	2.1
Near CP Day with Largest Response												
2-Aug-11	6.4	6.3	0.1	19.4	18.0	1.4	0.8	0.6	0.2	26.5	24.9	1.7

Hour-ending 17:00 Reductions on 4 CP Days - 2012

Responding WS Distribution Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
26-Jun-12	15.9	15.8	0.1	51.8	50.4	1.4	3.1	2.2	0.9	70.7	68.4	2.4
31-Jul-12	6.4	6.2	0.2	26.0	25.4	0.6	1.7	1.2	0.5	34.1	32.7	1.4
1-Aug-12	7.0	7.0	0.0	24.7	24.2	0.6	1.6	1.1	0.5	33.3	32.2	1.1
5-Sep-12	3.8	3.8	0.0	15.0	14.2	0.8	1.2	0.7	0.5	20.1	18.7	1.3
Near CP Day with Largest Response												
7-Sep-12	4.2	4.2	0.0	15.6	14.2	1.4	1.3	0.7	0.5	21.1	19.2	2.0

Hour-ending 17:00 Reductions on 4 CP Days - 2013

Responding WS Distribution Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
27-Jun-13	2.3	2.3	0.0	10.0	4.0	6.0	0.5	0.4	0.1	12.8	6.7	6.1
31-Jul-13	1.5	1.5	0.0	4.5	3.8	0.7	0.2	0.1	0.1	6.3	5.4	0.9
7-Aug-13	2.2	2.2	0.0	11.7	4.5	7.2	0.7	0.5	0.2	14.6	7.2	7.4
3-Sep-13	1.8	1.8	0.0	5.3	2.0	3.3	0.3	0.2	0.1	7.4	3.9	3.4
Near CP Day with Largest Response												
1-Aug-13	2.7	2.7	0.0	10.6	7.6	3.0	0.6	0.4	0.2	13.9	10.7	3.2

Hour-ending 17:00 Reductions on 4 CP Days - 2014

Responding WS Distribution Connected ESIIDs

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
16-Jun-14	9.0	8.6	0.4	14.0	5.4	8.6	0.9	0.1	0.8	23.9	14.0	9.9
21-Jul-14	2.8	2.2	0.5	14.7	5.7	9.0	1.4	0.6	0.9	18.8	8.5	10.4
25-Aug-14	10.7	10.0	0.8	23.1	9.9	13.1	1.9	0.5	1.4	35.6	20.4	15.2
10-Sep-14	11.7	11.0	0.7	24.5	11.2	13.3	2.0	0.5	1.4	38.2	22.8	15.4
Near CP Day with Largest Response												
8-Aug-14	8.6	7.9	0.7	17.3	4.0	13.3	1.4	0.2	1.2	27.3	12.1	15.1

Appendix 5 – Total MW Response

Hour-ending 17:00 Reductions on 4 CP Days - 2009

All Responding 4-CP ESIIDS

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
25-Jun-09	88.7	69.5	19.3	164.9	133.0	31.9	262.8	205.8	56.9	516.4	408.3	108.1
13-Jul-09	73.8	57.1	16.7	151.5	97.1	54.4	159.8	106.2	53.7	385.1	260.4	124.7
5-Aug-09	89.3	72.6	16.8	153.3	107.7	45.6	301.4	226.0	75.4	544.0	406.2	137.8
3-Sep-09	88.9	77.4	11.5	153.3	111.8	41.5	210.4	165.7	44.7	452.6	354.9	97.7
Near CP Day with Largest Response												
24-Jun-09	105.1	83.2	22.0	161.8	118.8	43.0	257.4	195.5	61.9	524.3	397.4	126.9

Hour-ending 17:00 Reductions on 4 CP Days - 2010

All Responding 4-CP ESIIDS

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
21-Jun-10	85.6	67.1	18.4	120.7	39.1	81.6	126.1	63.8	62.3	332.3	170.0	162.3
16-Jul-10	68.7	49.9	18.7	137.7	84.5	53.2	242.1	181.2	60.9	448.5	315.7	132.8
23-Aug-10	98.8	76.4	22.4	164.4	83.3	81.0	196.3	98.2	98.1	459.5	257.9	201.5
14-Sep-10	112.3	75.6	36.7	127.8	67.3	60.5	231.5	168.7	62.7	471.5	311.7	159.9
Near CP Day with Largest Response												
20-Aug-10	203.5	194.1	9.5	207.4	148.5	58.8	145.5	79.6	65.8	556.4	422.2	134.1

Hour-ending 17:00 Reductions on 4 CP Days - 2011

All Responding 4-CP ESIIDS

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
15-Jun-11	112.6	106.0	6.6	196.4	86.0	110.4	315.7	254.8	60.9	624.7	446.8	177.9
27-Jul-11	117.3	95.3	22.1	208.1	84.6	123.5	241.4	193.3	48.1	566.8	373.1	193.6
3-Aug-11	118.7	96.4	22.3	250.8	119.5	131.2	346.0	288.8	57.2	715.5	504.8	210.7
24-Sep-11	100.0	88.3	11.7	205.3	122.5	82.7	328.2	268.6	59.5	633.5	479.5	154.0
Near CP Day with Largest Response												
2-Aug-11	102.1	101.6	0.4	240.9	107.4	133.5	300.8	255.1	45.7	643.8	464.2	179.6

Hour-ending 17:00 Reductions on 4 CP Days - 2012

All Responding 4-CP ESIIDS

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
26-Jun-12	147.8	139.1	8.7	274.7	177.9	96.8	303.5	229.7	73.8	726.1	546.8	179.3
31-Jul-12	137.7	137.3	0.3	233.3	139.2	94.1	223.1	146.5	76.5	594.0	423.1	170.9
1-Aug-12	87.2	86.3	0.9	205.5	116.9	88.6	213.0	151.7	61.3	505.6	354.8	150.7
5-Sep-12	144.2	133.4	10.8	201.6	123.6	78.0	297.9	237.3	60.6	643.7	494.3	149.4
Near CP Day with Largest Response												
7-Sep-12	155.9	153.1	2.8	237.0	160.9	76.1	304.9	240.5	64.4	697.8	554.4	143.4

Hour-ending 17:00 Reductions on 4 CP Days - 2013

All Responding 4-CP ESIIDS

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
27-Jun-13	110.7	104.9	5.8	209.8	149.1	60.6	257.6	190.9	66.8	578.1	444.9	133.2
31-Jul-13	152.0	115.5	36.5	201.1	151.7	49.4	240.3	168.2	72.1	593.4	435.4	158.0
7-Aug-13	115.5	94.1	21.4	220.3	176.3	44.1	249.3	184.4	64.9	585.1	454.8	130.3
3-Sep-13	137.7	106.4	31.4	183.0	93.5	89.5	148.2	92.1	56.0	468.9	292.0	176.9
Near CP Day with Largest Response												
1-Aug-13	113.4	92.9	20.4	201.2	153.7	47.5	268.1	197.2	71.0	582.8	443.8	138.9

Hour-ending 17:00 MW Reductions on 4 CP Days - 2014

All Responding 4-CP ESIIDS

	Reductions for Hour Ending 17:00											
	High Load Factor			Medium Load Factor			Low Load Factor			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
16-Jun-14	159.4	138.4	21.0	241.7	165.5	76.1	242.0	173.4	68.7	643.1	477.3	165.8
21-Jul-14	37.5	30.5	7.0	112.7	66.1	46.6	149.0	87.1	62.0	299.2	183.6	115.5
25-Aug-14	199.4	164.9	34.5	252.0	174.3	77.7	263.8	187.8	76.0	715.2	526.9	188.2
10-Sep-14	204.3	164.4	39.8	273.9	183.8	90.1	301.5	207.0	94.5	779.6	555.2	224.4
Near CP Day with Largest Response												
8-Aug-14	125.5	117.6	7.9	219.8	165.7	54.1	278.8	221.6	57.2	624.2	504.9	119.3

Appendix 6 – Reductions by Voltage Level

Hour-ending 17:00 Reductions on 4 CP Days - 2009

Reductions by Voltage Group

	Reductions for Hour Ending 17:00											
	Transmission			Distribution Non-Weather Sensitive			Distribution Weather Sensitive			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
25-Jun-09	307.5	250.7	56.8	185.9	137.7	48.2	23.0	19.9	3.1	516.4	408.3	108.1
13-Jul-09	226.7	164.7	61.9	146.9	86.9	60.0	11.6	8.7	2.9	385.1	260.4	124.7
5-Aug-09	366.3	278.5	87.8	161.0	112.9	48.1	16.7	14.9	1.9	544.0	406.2	137.8
3-Sep-09	284.3	236.7	47.6	157.2	108.9	48.2	11.1	9.3	1.9	452.6	354.9	97.7
Near CP Day with Largest Response												
24-Jun-09	323.8	249.0	74.8	177.2	128.0	49.2	23.3	20.5	2.9	524.3	397.4	126.9

Hour-ending 17:00 Reductions on 4 CP Days - 2010

Reductions by Voltage Group

	Reductions for Hour Ending 17:00											
	Transmission			Distribution Non-Weather Sensitive			Distribution Weather Sensitive			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
21-Jun-10	174.3	72.1	102.2	150.2	91.3	58.9	7.8	6.6	1.2	332.3	170.0	162.3
16-Jul-10	241.7	158.6	83.1	197.5	149.2	48.3	9.3	7.8	1.4	448.5	315.7	132.8
23-Aug-10	236.0	100.8	135.2	206.9	141.9	65.0	16.6	15.2	1.3	459.5	257.9	201.5
14-Sep-10	303.0	189.3	113.6	162.4	116.8	45.5	6.1	5.5	0.7	471.5	311.7	159.9
Near CP Day with Largest Response												
20-Aug-10	276.1	185.0	91.1	264.7	222.6	42.0	15.6	14.6	1.0	556.4	422.2	134.1

Hour-ending 17:00 Reductions on 4 CP Days - 2011

Reductions by Voltage Group

	Reductions for Hour Ending 17:00											
	Transmission			Distribution Non-Weather Sensitive			Distribution Weather Sensitive			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
15-Jun-11	407.4	291.6	115.8	197.5	138.1	59.5	19.7	17.1	2.6	624.7	446.8	177.9
27-Jul-11	353.6	214.9	138.7	199.6	146.4	53.3	13.6	11.9	1.7	566.8	373.1	193.6
3-Aug-11	423.5	280.5	143.0	264.0	198.0	66.0	28.0	26.3	1.7	715.5	504.8	210.7
24-Sep-11	329.0	229.2	99.8	277.0	224.9	52.1	27.5	25.4	2.1	633.5	479.5	154.0
Near CP Day with Largest Response												
14-Jul-11	397.5	282.8	114.7	219.8	156.6	63.2	26.5	24.9	1.7	643.8	464.2	179.6

Hour-ending 17:00 Reductions on 4 CP Days - 2012

Reductions by Voltage Group

	Reductions for Hour Ending 17:00											
	Transmission			Distribution Non-Weather Sensitive			Distribution Weather Sensitive			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
26-Jun-12	417.4	308.0	109.4	238.0	170.4	67.5	70.7	68.4	2.4	726.1	546.8	179.3
31-Jul-12	316.3	202.8	113.5	243.6	187.6	56.1	34.1	32.7	1.4	594.0	423.1	170.9
1-Aug-12	248.9	151.6	97.3	223.4	171.1	52.3	33.3	32.2	1.1	505.6	354.8	150.7
5-Sep-12	407.0	313.2	93.8	216.7	162.4	54.2	20.1	18.7	1.3	643.7	494.3	149.4
Near CP Day with Largest Response												
7-Sep-12	379.9	300.6	79.3	296.7	234.6	62.1	21.1	19.2	2.0	697.8	554.4	143.4

Hour-ending 17:00 Reductions on 4 CP Days - 2013

Reductions by Voltage Group

	Reductions for Hour Ending 17:00											
	Transmission			Distribution Non-Weather Sensitive			Distribution Weather Sensitive			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
27-Jun-13	322.5	252.8	69.7	242.9	185.4	57.5	12.8	6.7	6.1	578.1	444.9	133.2
31-Jul-13	357.0	258.4	98.6	230.1	171.6	58.5	6.3	5.4	0.9	593.4	435.4	158.0
7-Aug-13	303.5	241.9	61.6	267.0	205.6	61.4	14.6	7.2	7.4	585.1	454.8	130.3
3-Sep-13	237.5	127.7	109.7	224.0	160.3	63.7	7.4	3.9	3.4	468.9	292.0	176.9
Near CP Day with Largest Response												
1-Aug-13	318.0	242.3	75.7	250.8	190.8	60.0	13.9	10.7	3.2	582.8	443.8	138.9

Hour-ending 17:00 MW Reductions on 4 CP Days - 2014

Reductions by Voltage Group

	Reductions for Hour Ending 17:00											
	Transmission			Distribution Non-Weather Sensitive			Distribution Weather Sensitive			Total		
	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response	Total Response	Peak Response	Day Response
4 CP Days												
16-Jun-14	355.9	263.8	92.1	263.2	199.4	63.8	23.9	14.0	9.9	643.1	477.3	165.8
21-Jul-14	109.2	66.0	43.2	171.1	109.2	62.0	18.8	8.5	10.4	299.2	183.6	115.5
25-Aug-14	360.3	262.3	98.0	319.3	244.3	75.0	35.6	20.4	15.2	715.2	526.9	188.2
10-Sep-14	424.8	298.6	126.2	316.7	233.9	82.8	38.2	22.8	15.4	779.6	555.2	224.4
Near CP Day with Largest Response												
8-Aug-14	318.5	265.3	53.2	278.4	227.4	51.0	27.3	12.1	15.1	624.2	504.9	119.3

Appendix 7 – Reductions as a Percent of Total Load

Hour-ending 17:00 Reductions on 4 CP Days - 2009

Reductions as a Percent of Total Voltage Group Load

	Total Reduction	Responders Total Load	Non-Responders Total Load	Total Load	Response as Percent of Total Load	Total Reduction	Responders Total Load	Non-Responders Total Load	Total Load	Response as Percent of Total Load
CP Date	High Load Factor MW					Medium Load Factor MW				
25-Jun-09	88.7	232.9	2,914.8	3,147.7	2.8%	164.9	697.1	6,217.3	6,914.4	2.4%
13-Jul-09	73.8	192.0	3,019.4	3,211.4	2.3%	151.5	486.5	6,565.6	7,052.1	2.1%
5-Aug-09	89.3	227.0	2,951.3	3,178.3	2.8%	153.3	513.2	6,506.0	7,019.1	2.2%
3-Sep-09	88.9	201.2	2,955.1	3,156.3	2.8%	153.3	449.3	6,188.6	6,637.9	2.3%
	Low Load Factor					Total				
25-Jun-09	262.8	633.6	920.6	1,554.2	16.9%	516.4	1,563.5	10,052.7	11,616.3	4.4%
13-Jul-09	159.8	342.9	1,042.0	1,384.9	11.5%	385.1	1,021.4	10,627.0	11,648.4	3.3%
5-Aug-09	301.4	583.0	997.1	1,580.2	19.1%	544.0	1,323.2	10,454.5	11,777.6	4.6%
3-Sep-09	210.4	421.9	1,204.8	1,626.7	12.9%	452.6	1,072.4	10,348.5	11,420.9	4.0%

Hour-ending 17:00 Reductions on 4 CP Days - 2009

Reductions as a Percent of Total Voltage Group Load

	Total Reduction	Responders Total Load	Non-Responders Total Load	Total Load	Response as Percent of Total Load	Total Reduction	Responders Total Load	Non-Responders Total Load	Total Load	Response as Percent of Total Load
CP Date	High Load Factor MW					Medium Load Factor MW				
21-Jun-10	85.6	214.6	5,910.9	6,125.5	1.4%	120.7	388.6	5,596.9	5,985.5	2.0%
16-Jul-10	68.7	246.2	5,887.6	6,133.8	1.1%	137.7	611.2	5,290.6	5,901.8	2.3%
23-Aug-10	98.8	347.3	5,812.0	6,159.2	1.6%	164.4	573.2	5,628.5	6,201.8	2.7%
14-Sep-10	112.3	346.1	5,606.5	5,952.6	1.9%	127.8	475.4	5,512.3	5,987.7	2.1%
	Low Load Factor					Total				
21-Jun-10	126.1	325.2	1,088.9	1,414.1	8.9%	332.3	928.4	12,596.7	13,525.0	2.5%
16-Jul-10	242.1	512.8	838.9	1,351.7	17.9%	448.5	1,370.2	12,017.1	13,387.4	3.4%
23-Aug-10	196.3	532.9	1,017.9	1,550.8	12.7%	459.5	1,453.4	12,458.4	13,911.8	3.3%
14-Sep-10	231.5	476.9	1,197.3	1,674.3	13.8%	471.5	1,298.5	12,316.1	13,614.6	3.5%

Hour-ending 17:00 Reductions on 4 CP Days - 2010

Reductions as a Percent of Total Voltage Group Load

	Total Reduction	Responders Total Load	Non-Responders Total Load	Total Load	Response as Percent of Total Load	Total Reduction	Responders Total Load	Non-Responders Total Load	Total Load	Response as Percent of Total Load
CP Date	**High Load Factor MW**					**Medium Load Factor MW**				
15-Jun-11	112.6	387.4	6,094.5	6,481.9	1.7%	196.4	636.9	5,981.2	6,618.1	3.0%
27-Jul-11	117.3	277.7	6,213.3	6,491.0	1.8%	208.1	668.8	6,099.1	6,767.9	3.1%
3-Aug-11	118.7	377.7	6,212.5	6,590.2	1.8%	250.8	906.5	5,964.2	6,870.7	3.6%
24-Sep-11	100.0	421.9	6,069.7	6,491.6	1.5%	205.3	841.9	5,545.3	6,387.2	3.2%
	Low Load Factor					**Total**				
15-Jun-11	315.7	612.3	880.5	1,492.9	21.1%	624.7	1,636.6	12,956.3	14,592.9	4.3%
27-Jul-11	241.4	464.1	965.6	1,429.8	16.9%	566.8	1,410.6	13,278.1	14,688.8	3.9%
3-Aug-11	346.0	624.7	900.9	1,525.5	22.7%	715.5	1,908.8	13,077.5	14,986.3	4.8%
24-Sep-11	328.2	733.2	790.6	1,523.9	21.5%	633.5	1,997.0	12,405.7	14,402.7	4.4%

Hour-ending 17:00 Reductions on 4 CP Days - 2011

Reductions as a Percent of Total Voltage Group Load

CP Date	Total Reduction	Responders Total Load	Non-Responders Total Load	Total Load	Response as Percent of Total Load	Total Reduction	Responders Total Load	Non-Responders Total Load	Total Load	Response as Percent of Total Load
	High Load Factor MW					Medium Load Factor MW				
26-Jun-12	147.8	590.5	5,342.1	5,932.6	2.5%	274.7	1,176.6	5,870.7	7,047.3	3.9%
31-Jul-12	137.7	427.1	5,428.9	5,856.0	2.4%	233.3	967.8	6,005.3	6,973.1	3.3%
1-Aug-12	87.2	274.8	5,623.2	5,898.0	1.5%	205.5	832.2	6,201.1	7,033.3	2.9%
5-Sep-12	144.2	431.9	5,476.5	5,908.5	2.4%	201.6	770.3	6,166.9	6,937.2	2.9%
	Low Load Factor					Total				
26-Jun-12	303.5	533.3	834.1	1,367.4	22.2%	726.1	2,300.4	12,046.9	14,347.3	5.1%
31-Jul-12	223.1	447.4	893.1	1,340.6	16.6%	594.0	1,842.3	12,327.4	14,169.7	4.2%
1-Aug-12	213.0	489.4	907.5	1,396.9	15.2%	505.6	1,596.3	12,731.8	14,328.1	3.5%
5-Sep-12	297.9	509.2	1,112.1	1,621.3	18.4%	643.7	1,711.4	12,755.6	14,467.0	4.4%

Hour-ending 17:00 Reductions on 4 CP Days - 2012

Reductions as a Percent of Total Voltage Group Load

CP Date	Total Reduction	Responders Total Load	Non-Responders Total Load	Total Load	Response as Percent of Total Load
	High Load Factor MW				
26-Jun-12	139.2	397.5	5,517.4	5,914.9	2.4%
31-Jul-12	135.4	321.6	5,523.5	5,845.1	2.3%
1-Aug-12	83.5	162.3	5,722.8	5,885.1	1.4%
4-Sep-12	130.2	328.5	5,559.7	5,888.2	2.2%
	Low Load Factor				
26-Jun-12	302.2	522.9	855.9	1,378.8	21.9%
31-Jul-12	225.8	438.2	916.5	1,354.7	16.7%
1-Aug-12	213.7	482.6	927.2	1,409.8	15.2%
4-Sep-12	211.7	425.7	1,115.5	1,541.1	13.7%

CP Date	Total Reduction	Responders Total Load	Non-Responders Total Load	Total Load	Response as Percent of Total Load
	Medium Load Factor MW				
26-Jun-12	233.7	745.4	6,257.2	7,002.6	3.3%
31-Jul-12	214.7	618.6	6,333.2	6,951.8	3.1%
1-Aug-12	180.2	493.8	6,511.3	7,005.0	2.6%
4-Sep-12	168.1	491.0	6,392.2	6,883.3	2.4%
	Total				
26-Jun-12	675.0	1,665.8	12,630.5	14,296.3	4.7%
31-Jul-12	575.9	1,378.4	12,773.2	14,151.6	4.1%
1-Aug-12	477.3	1,138.6	13,161.2	14,299.9	3.3%
4-Sep-12	510.0	1,245.3	13,067.3	14,312.6	3.6%

Hour-ending 17:00 Reductions on 4 CP Days - 2013

Reductions as a Percent of Total Voltage Group Load

	Total Reduction	Responders Total Load	Non-Responders Total Load	Total Load	Response as Percent of Total Load	Total Reduction	Responders Total Load	Non-Responders Total Load	Total Load	Response as Percent of Total Load
CP Date	High Load Factor MW					Medium Load Factor MW				
27-Jun-13	110.7	319.1	5,221.8	5,540.8	2.0%	209.8	783.8	5,624.1	6,407.9	3.3%
31-Jul-13	152.0	379.4	5,188.9	5,568.2	2.7%	201.1	648.4	5,697.4	6,345.8	3.2%
7-Aug-13	115.5	328.4	5,184.5	5,512.9	2.1%	220.3	850.6	5,612.1	6,462.7	3.4%
3-Sep-13	137.7	396.3	5,149.3	5,545.6	2.5%	183.0	627.0	5,640.9	6,268.0	2.9%
	Low Load Factor					Total				
27-Jun-13	257.6	481.7	915.7	1,397.4	18.4%	578.1	1,584.6	11,761.6	13,346.1	4.3%
31-Jul-13	240.3	491.2	883.7	1,374.9	17.5%	593.4	1,519.0	11,769.9	13,288.9	4.5%
7-Aug-13	249.3	470.8	1,004.7	1,475.5	16.9%	585.1	1,649.9	11,801.2	13,451.1	4.3%
3-Sep-13	148.2	365.8	1,138.1	1,503.9	9.9%	468.9	1,389.2	11,928.3	13,317.5	3.5%

Hour-ending 17:00 MW Reductions on 4 CP Days - 2014

Reductions as a Percent of Total Voltage Group Load

	Total Reduction	Responders Total Load	Non-Responders Total Load	Total Load	Response as Percent of Total Load	Total Reduction	Responders Total Load	Non-Responders Total Load	Total Load	Response as Percent of Total Load
CP Date	High Load Factor MW					Medium Load Factor MW				
16-Jun-14	159.4	527.8	5,436.6	5,964.4	2.7%	241.7	769.8	5,967.0	6,736.9	3.6%
21-Jul-14	37.5	277.8	5,782.9	6,060.7	0.6%	112.7	563.9	6,344.9	6,908.8	1.6%
25-Aug-14	199.4	570.0	5,473.0	6,043.0	3.3%	252.0	868.2	6,115.1	6,983.3	3.6%
10-Sep-14	204.3	625.2	5,417.4	6,042.6	3.4%	273.9	874.5	6,036.3	6,910.9	4.0%
	Low Load Factor					Total				
16-Jun-14	242.0	409.1	850.9	1,260.0	19.2%	643.1	1,706.7	12,254.6	13,961.3	4.6%
21-Jul-14	149.0	325.7	987.5	1,313.2	11.3%	299.2	1,167.3	13,115.3	14,282.7	2.1%
25-Aug-14	263.8	506.6	1,095.6	1,602.2	16.5%	715.2	1,944.7	12,683.8	14,628.5	4.9%
10-Sep-14	301.5	492.4	1,115.4	1,607.8	18.8%	779.6	1,992.1	12,569.1	14,561.2	5.4%

Appendix 8 – Percent of Load by Group

Hour-ending 17:00 Reductions on 4 CP Days - 2009

Percentage of Load Reduction by Load Factor and Voltage Group

4 CP Days	High Load Factor		Medium Load Factor		Low Load Factor		Total Reduction
	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	
25-Jun-09	88.7	17.2%	164.9	31.9%	262.8	50.9%	516.4
13-Jul-09	73.8	19.2%	151.5	39.3%	159.8	41.5%	385.1
5-Aug-09	89.3	16.4%	153.3	28.2%	301.4	55.4%	544.0
3-Sep-09	88.9	19.6%	153.3	33.9%	210.4	46.5%	452.6

4 CP Days	Transmission		Distribution NWS		Distribution WS		Total Reduction
	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	
25-Jun-09	307.5	59.6%	185.9	36.0%	23.0	4.5%	516.4
13-Jul-09	226.7	58.9%	146.9	38.1%	11.6	3.0%	385.1
5-Aug-09	366.3	67.3%	161.0	29.6%	16.7	3.1%	544.0
3-Sep-09	284.3	62.8%	157.2	34.7%	11.1	2.5%	452.6

Hour-ending 17:00 Reductions on 4 CP Days - 2010

Percentage of Load Reduction by Load Factor and Voltage Group

4 CP Days	High Load Factor		Medium Load Factor		Low Load Factor		Total Reduction
	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	
21-Jun-10	85.6	25.8%	120.7	36.3%	126.1	37.9%	332.3
16-Jul-10	68.7	15.3%	137.7	30.7%	242.1	54.0%	448.5
23-Aug-10	98.8	21.5%	164.4	35.8%	196.3	42.7%	459.5
14-Sep-10	112.3	23.8%	127.8	27.1%	231.5	49.1%	471.5

4 CP Days	Transmission		Distribution NWS		Distribution WS		Total Reduction
	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	
21-Jun-10	174.3	52.4%	150.2	45.2%	7.8	2.4%	332.3
16-Jul-10	241.7	53.9%	197.5	44.0%	9.3	2.1%	448.5
23-Aug-10	236.0	51.4%	206.9	45.0%	16.6	3.6%	459.5
14-Sep-10	303.0	64.3%	162.4	34.4%	6.1	1.3%	471.5

Hour-ending 17:00 Reductions on 4 CP Days - 2011

Percentage of Load Reduction by Load Factor and Voltage Group

4 CP Days	High Load Factor		Medium Load Factor		Low Load Factor		Total Reduction
	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	
15-Jun-11	112.6	18.0%	196.4	31.4%	315.7	50.5%	624.7
27-Jul-11	117.3	20.7%	208.1	36.7%	241.4	42.6%	566.8
3-Aug-11	118.7	16.6%	250.8	35.0%	346.0	48.4%	715.5
24-Sep-11	100.0	15.8%	205.3	32.4%	328.2	51.8%	633.5

4 CP Days	Transmission		Distribution NWS		Distribution WS		Total Reduction
	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	
15-Jun-11	407.4	65.2%	197.5	31.6%	19.7	3.2%	624.7
27-Jul-11	353.6	62.4%	199.6	35.2%	13.6	2.4%	566.8
3-Aug-11	423.5	59.2%	264.0	36.9%	28.0	3.9%	715.5
24-Sep-11	329.0	51.9%	277.0	43.7%	27.5	4.3%	633.5

Hour-ending 17:00 Reductions on 4 CP Days - 2012

Percentage of Load Reduction by Load Factor and Voltage Group

4 CP Days	High Load Factor		Medium Load Factor		Low Load Factor		Total Reduction
	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	
26-Jun-12	147.8	20.4%	274.7	37.8%	303.5	41.8%	726.1
31-Jul-12	137.7	23.2%	233.3	39.3%	223.1	37.6%	594.0
1-Aug-12	87.2	17.2%	205.5	40.6%	213.0	42.1%	505.6
5-Sep-12	144.2	22.4%	201.6	31.3%	297.9	46.3%	643.7

4 CP Days	Transmission		Distribution NWS		Distribution WS		Total Reduction
	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	
26-Jun-12	417.4	57.5%	238.0	32.8%	70.7	9.7%	726.1
31-Jul-12	316.3	53.2%	243.6	41.0%	34.1	5.7%	594.0
1-Aug-12	248.9	49.2%	223.4	44.2%	33.3	6.6%	505.6
5-Sep-12	407.0	63.2%	216.7	33.7%	20.1	3.1%	643.7

Hour-ending 17:00 Reductions on 4 CP Days - 2013

Percentage of Load Reduction by Load Factor and Voltage Group

4 CP Days	High Load Factor		Medium Load Factor		Low Load Factor		Total Reduction
	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	
27-Jun-13	110.7	19.2%	209.8	36.3%	257.6	44.6%	578.1
31-Jul-13	152.0	25.6%	201.1	33.9%	240.3	40.5%	593.4
7-Aug-13	115.5	19.7%	220.3	37.7%	249.3	42.6%	585.1
3-Sep-13	137.7	29.4%	183.0	39.0%	148.2	31.6%	468.9

4 CP Days	Transmission		Distribution NWS		Distribution WS		Total Reduction
	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	
27-Jun-13	322.5	55.8%	242.9	42.0%	12.8	2.2%	578.1
31-Jul-13	357.0	60.2%	230.1	38.8%	6.3	1.1%	593.4
7-Aug-13	303.5	51.9%	267.0	45.6%	14.6	2.5%	585.1
3-Sep-13	237.5	50.6%	224.0	47.8%	7.4	1.6%	468.9

Hour-ending 17:00 Reductions on 4 CP Days - 2014

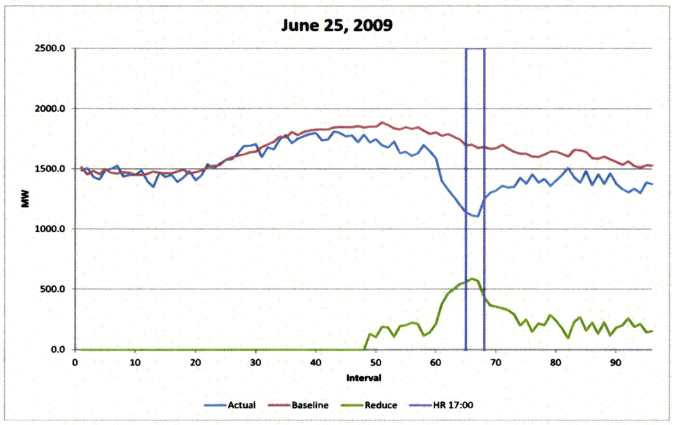
Percentage of Load Reduction by Load Factor and Voltage Group

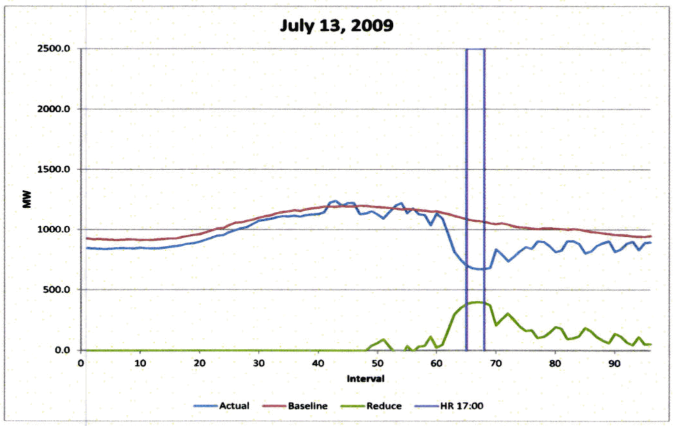
4 CP Days	High Load Factor		Medium Load Factor		Low Load Factor		Total Reduction
	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	
16-Jun-14	159.4	24.8%	241.7	37.6%	242.0	37.6%	643.1
21-Jul-14	37.5	12.5%	112.7	37.7%	149.0	49.8%	299.2
25-Aug-14	199.4	27.9%	252.0	35.2%	263.8	36.9%	715.2
10-Sep-14	204.3	26.2%	273.9	35.1%	301.5	38.7%	779.6

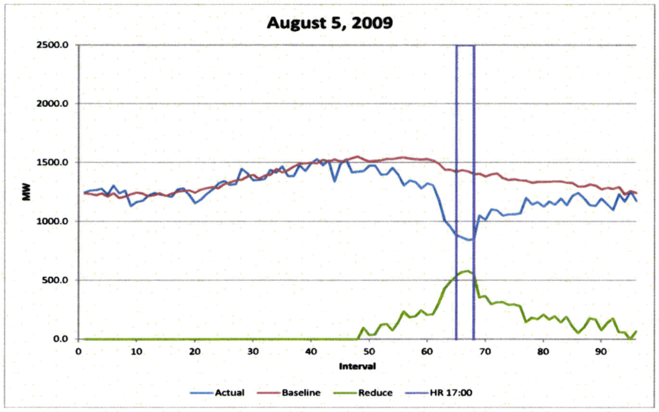
4 CP Days	Transmission		Distribution NWS		Distribution WS		Total Reduction
	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	
16-Jun-14	355.9	55.3%	263.2	40.9%	23.9	3.7%	643.1
21-Jul-14	109.2	36.5%	171.1	57.2%	18.8	6.3%	299.2
25-Aug-14	360.3	50.4%	319.3	44.6%	35.6	5.0%	715.2
10-Sep-14	424.8	54.5%	316.7	40.6%	38.2	4.9%	779.6

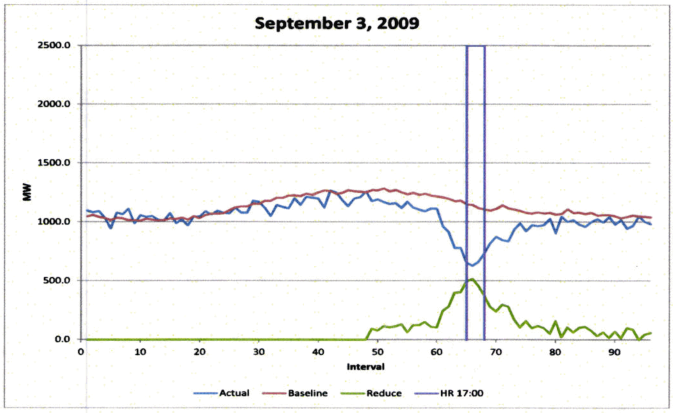
Appendix 9 – CP Day Graphs

Hour-ending 17:00 Reductions on 4 CP Days - 2009

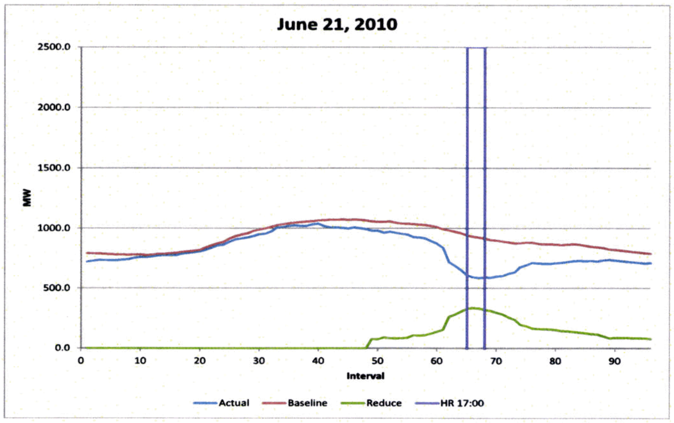


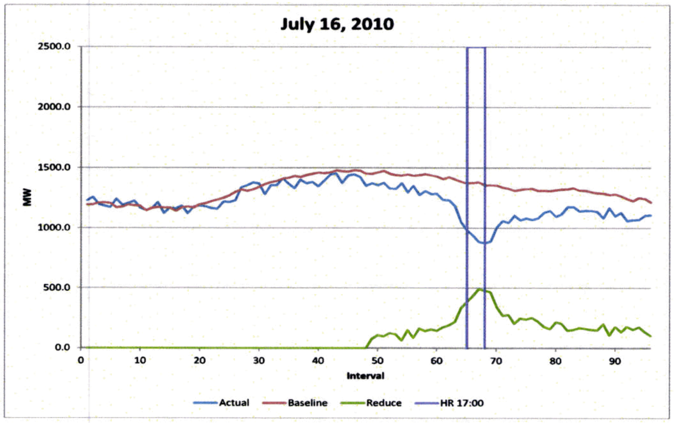


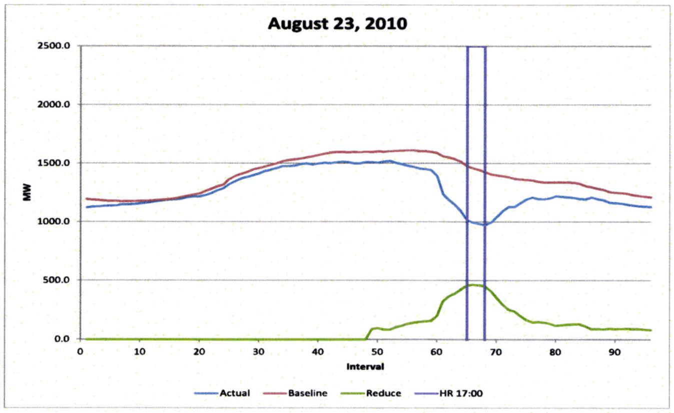


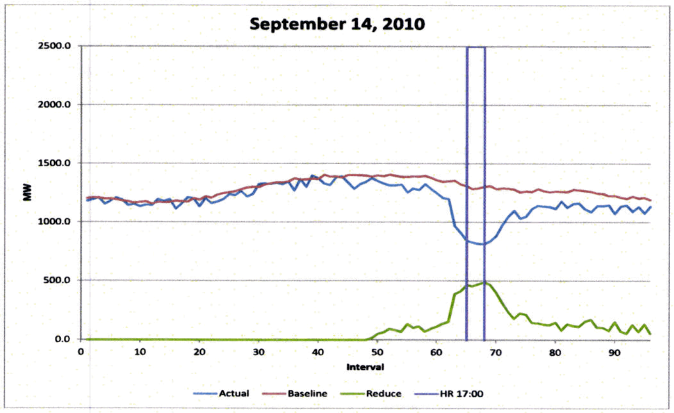


Hour-ending 17:00 Reductions on 4 CP Days - 2010

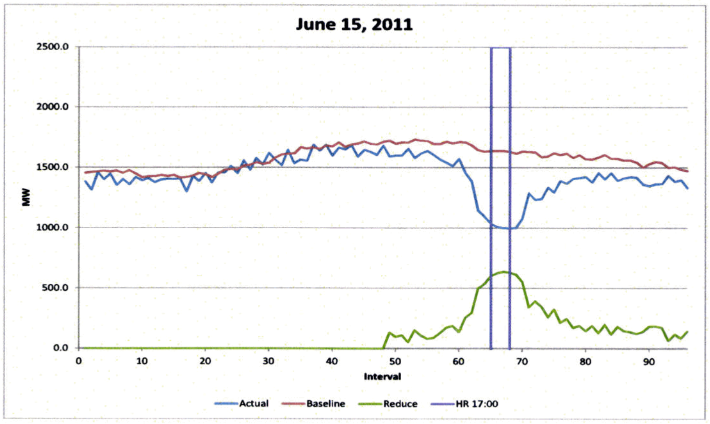


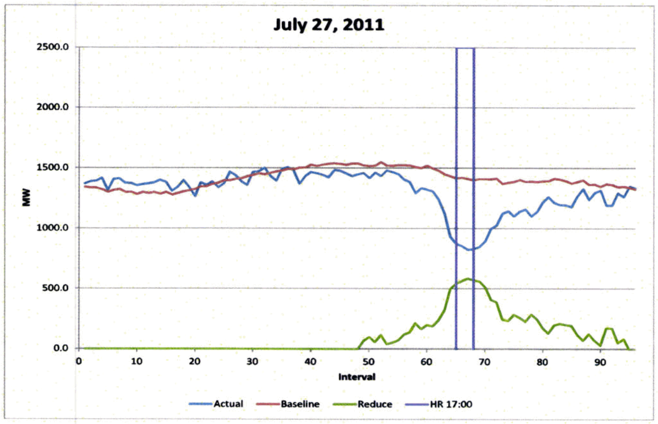


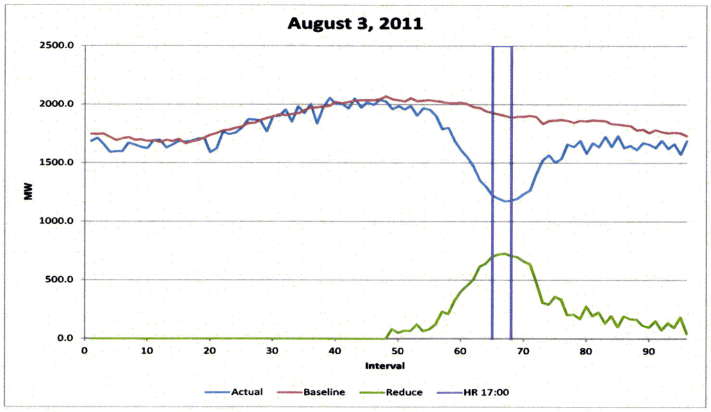


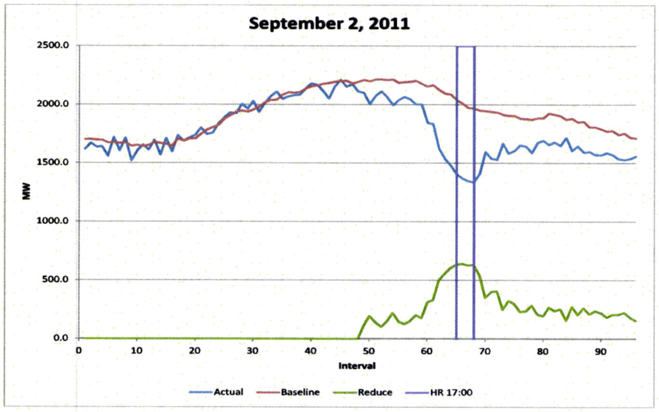


Hour-ending 17:00 Reductions on 4 CP Days - 2011

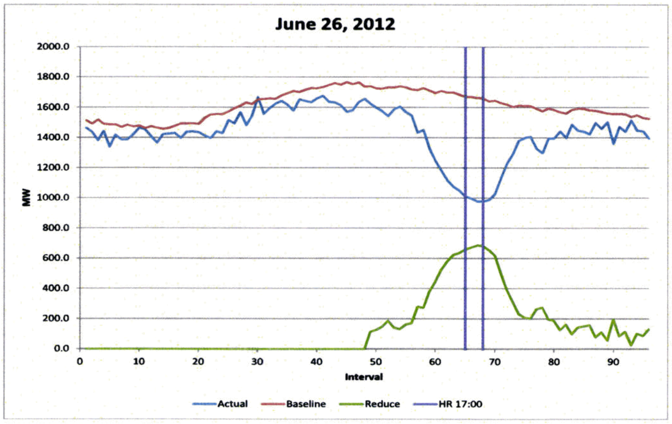


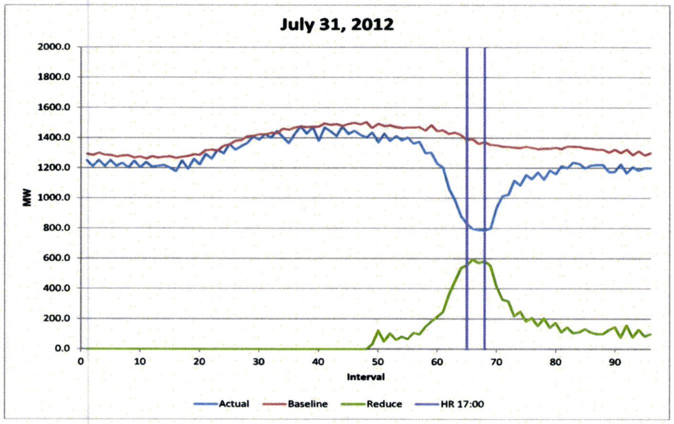


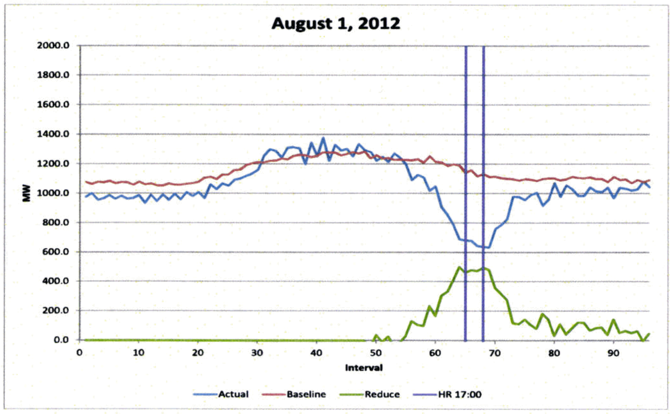


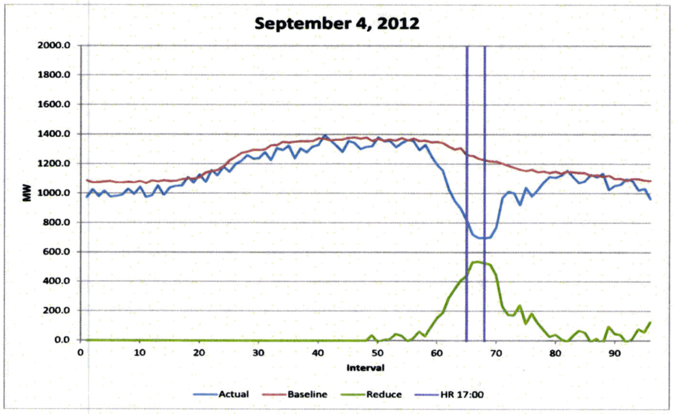


Hour-ending 17:00 Reductions on 4 CP Days - 2012









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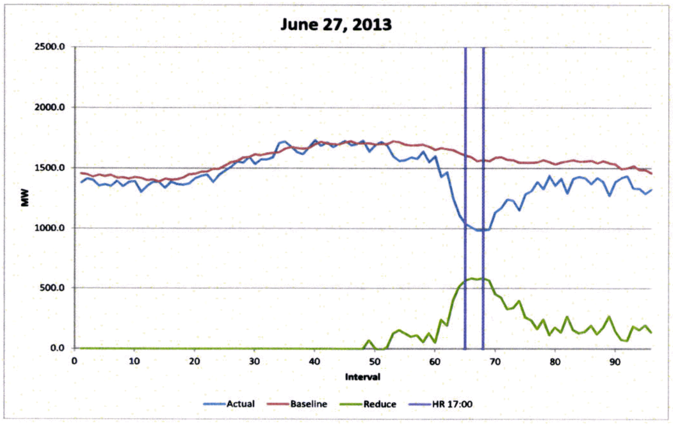

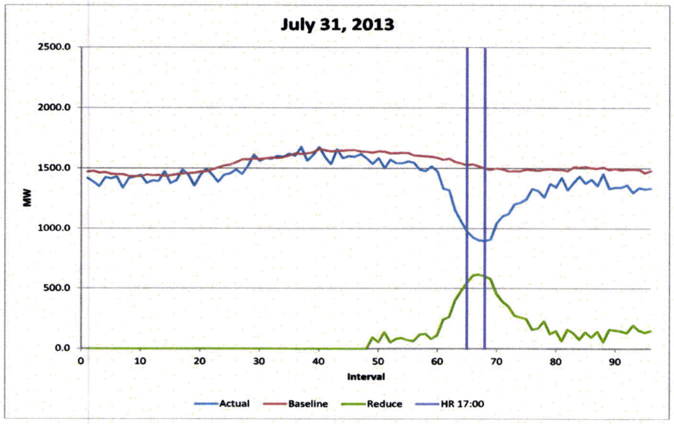

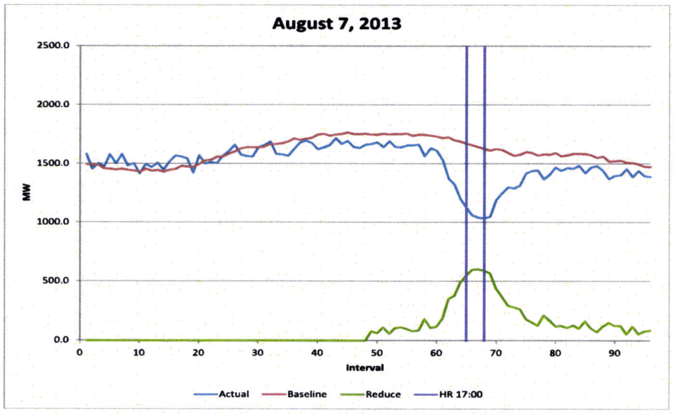

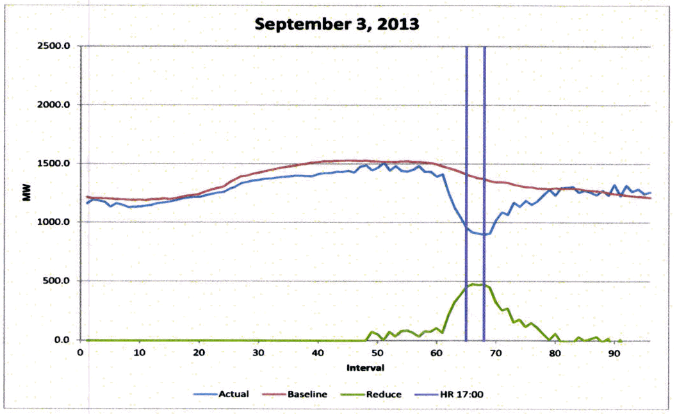

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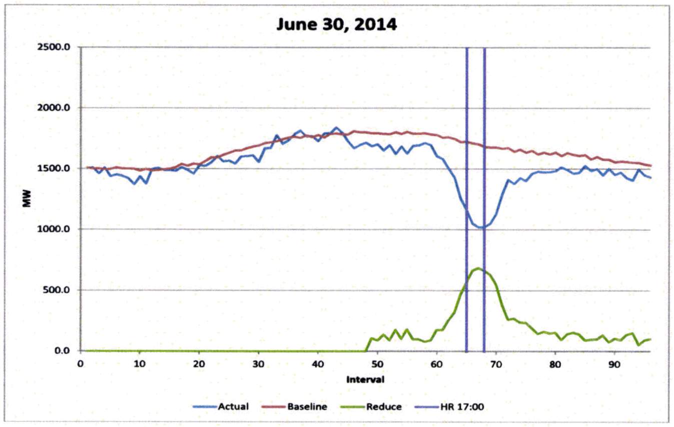
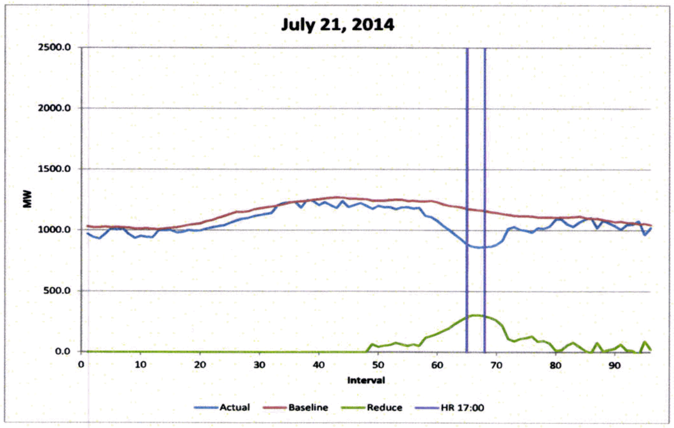
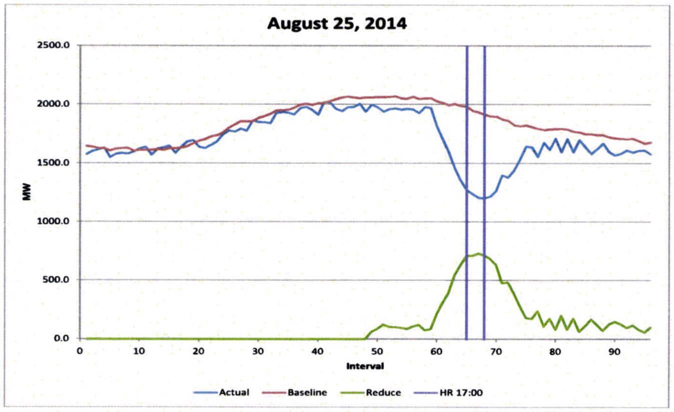
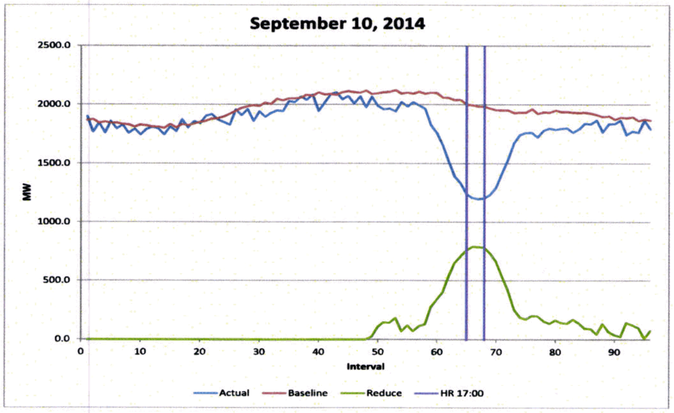








BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
SUSAN BITTER SMITH – CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

EXHIBIT
Nucor 2
admitted

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS

DOCKET NO. E-04204A-15-0142

SURREBUTTAL TESTIMONY OF

DR. JAY ZARNIKAU ON RATE DESIGN

ON BEHALF OF NUCOR STEEL

FEBRUARY 22, 2016

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jay Zarnikau. My business address is 1515 Capital of Texas Hwy, South, Suite 110, Austin, Texas, 78746.

Q. Are you the same witness who previously filed direct testimony in this proceeding on behalf of Nucor Steel-Kingman?

A. Yes, I am.

Q. Please state the purpose of your surrebuttal testimony.

A. This testimony responds to the rebuttal testimony of Mr. Craig Jones, appearing on behalf of UNS Electric, and the direct testimony of Mr. Howard Solganick, appearing on behalf of the Staff of the Arizona Corporation Commission ("Staff").

II. RESPONSE TO THE REBUTTAL TESTIMONY OF MR. CRAIG JONES

Q. Please summarize your concerns regarding the rebuttal testimony provided by Mr. Craig Jones on behalf of UNS Electric.

A. While it appears as though we are now in agreement that the "differential" in the time-of-use energy charges between on and off-peak periods should remain the same as agreed to in the previous rate case, I continue to have the following concerns:

- We continue to disagree over the design of the demand charge applicable to industrial energy consumers.
- We continue to disagree over the value and benefits to UNS Electric of interrupting large industrial energy consumers during off-peak periods.
- Mr. Jones has failed to clarify the proposed minimum load factor requirement in the proposed Economic Development Rate (EDR).

Q. On page 32 of his rebuttal testimony, Mr. Jones states:

> "Demand rates should be a combination of costs being recovered based on the system's non-coincident peak and its coincident peak depending on the cost. Further review of how these costs should be recovered may justify more costs being allocated to the off-peak period instead of less as NUCOR proposes, especially for the largest TOU rate class. Since the current differential was agreed to in the last rate case, the Company believes its current design is appropriate and is willing to leave the differential as it is in current rates for purposes of this rate case."

Do you agree with this statement?

A. No. This statement appears to confuse two separate and unrelated issues raised in my direct testimony. One issue is the design of the demand charge applicable to LPS (and LPS-TOU) customers. The second issue is the difference between the energy charges applicable to on and off-peak periods under the LPS-TOU tariff.

Indeed, the "differential" that was agreed to among the parties in the previous rate case involved the time-of-use energy charge, and had nothing to do with the demand charge. I am unaware of any "differential" in the demand charge applicable to LPS and/or LPS-TOU customers. Specifically, the issue in the previous rate case involving a "differential" pertained to how high the level of the on-peak energy charge should be set relative to the level of the off-peak energy charge.

Q. How do you interpret Mr. Jones's statement that "Demand rates should be a combination of costs being recovered based on the system's non-coincident peak and its coincident peak. . . ."

A. Mr. Jones's response seems to advocate two demand charges – one to recover costs which are incurred to meet the (coincident) system peak and another to meet the (non-coincident) peak associated with the customer's demand. I am not necessarily opposed to this proposal. However, this is not consistent with the tariff proposed by UNS Electric. UNS Electric has proposed a single demand charge, based solely on the customer's non-coincident peak. Nucor would be willing to consider the application of two demand charges – one based on the coincident peak and one based on the class non-coincident peak – as UNS has now suggested. However, UNS Electric has provided no calculations to support this new proposal.

To me, the question before the Commission is clear. Absent a more straightforward proposal to establish *both* coincident and non-coincident demand charges, the question is: Should the demand charge be based upon a customer's contribution to system peak, or should it be based on the customer's highest demand? I recommend that it be based on the customer's demand at the time of the utility's system peak, and have advocated that a four coincident peak (4CP) or a Top 20 hours metric be used to approximate a customer's contribution to the UNS Electric system peak.

Q. How is this approach different from what UNS Electric has proposed?

A. The tariff proposed by UNS Electric uses the customer's highest demand during the peak period or half of the customer's demand during an off-peak period (whichever is greater), along with some other complications (a ratchet and the possibility of using a "contract capacity" value or a simple 500 kW minimum value). If UNS Electric stands by its testimony that *system demand* largely drives the need for generating capacity, then the demand charge should be based upon the customer's contribution to the system peak. As stated once again by Mr. Jones on p. 35 of his Rebuttal testimony:

> "As NUCOR's witness states and as Company rebuttal witness Mr. Overcast states, the generation and transmission costs should be based on the capacity needs the customer contributes to the system peak."

I agree with this statement by Mr. Jones and this is precisely what I have proposed. In contrast, Mr. Jones has proposed that the demand charge be based upon the customer's highest demand during the on-peak period or one-half of the customer's highest demand during the off-peak period, or a "contract capacity" value, or a simple 500 kW minimum value. These values do not measure the customer's contribution to the system peak demand, as I have demonstrated in my direct testimony.

Q. How does the NARUC Electric Utility Cost Allocation Manual cited by Mr. Jones define coincident peak demand?

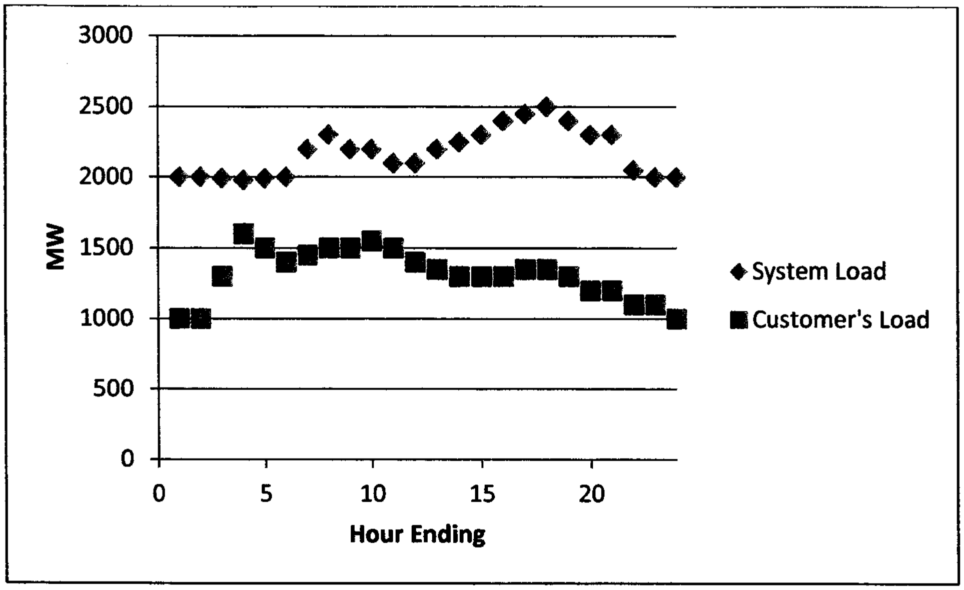
A. P. 41 of the manual states: "The customer's demand at the time of the system peak is that customer's "coincident" peak."

Q. Please explain why the customer's highest demand during the on-peak period or one-half of the customer's highest demand during the off-peak period fails to measure coincident peak – the customer's contribution to the utility's system peak.

A. Consider a very simple example. To keep this simple, let's pretend that a year had only one day (rather than 365 or 366). Alternatively, we could assume that a customer reached its noncoincident peak and the utility serving the customer reached its system peak on the same day, so that the other days of the year could be safely ignored.

I have plotted the demand for a hypothetical utility and the hypothetical (very large) customer over a 24 hour period on the graph below. In this example, the utility reaches its system peak of 2,500 MW at the hour ending 18:00 (6 p.m.). The customer's contribution to that peak – i.e., the customer's coincident peak – is 1,350 MW. The customer's noncoincident peak is 2,300 MW in this example. But, because the customer's noncoincident peak occurs during the hour ending 8 a.m., it is a very poor measure of how the customer affects the utility's need for generation and transmission capacity. The utility invests in generation and transmission capacity to meet the system's demand for the peak or hour with the maximum demand value, which ends at 6 p.m. – not a morning hour when the system load is relatively low.[1]

[1] Distribution facilities may need to be designed and acquired to meet the customer's maximum (noncoincident) demand – but not generation and transmission capacity.



Moreover, the customer's highest demand during the off-peak period (which is the hour ending 8 a.m.), clearly does not drive the utility's need to obtain capacity. To take this measurement, and divide it by half to assign a demand charge to the customer (as UNS Electric does currently and proposes to do going forward) is completely arbitrary. For this reason, I suggest that demand charges (at least for the LPS and LPS-TOU customers) be based upon the customer's coincident peak.

My recommended approach is consistent with the numerous statements pertaining to cost causation made by the utility in this, and previous, rate proceedings. I would further note that my concerns about the calculation of demand charges are similar to those raised in the direct testimony of Mr. Kent Simer on behalf of the Fresh Produce Association of the Americas.

Q. Did the Company explain why it initially proposed to reduce the differential between on-peak and off-peak energy prices in the LPS-TOU tariff?

A. No. On p. 32 of his rebuttal testimony, Mr. Jones states:

> "The Company does not currently incur a substantial difference in the marginal cost of energy purchased on peak, versus off-peak. Therefore, the Company believes its proposed differential between on- and off-peak fuel prices is appropriate. In fact, the actual difference in marginal costs associated with the on- and off-peak period may justify a smaller differential. But for purposes of this case, the Company is willing to leave the differential as proposed in the Company's direct rate case."

My testimony in the last rate case demonstrated that the differential in marginal energy cost is "significant," at least in my opinion. If, as Mr. Jones suggests, there is no significant differential in costs, then why is the Company proposing to increase the on-peak/off-peak differential for the LGS-TOU tariff? And why would they introduce a new TOU rate for schools in this proceeding? Further, even if there were no significant differences between marginal energy costs between on- and off-peak periods, TOU rates serve several other purposes as well. For example, the costs associated with transmission and generating capacity may be reduced if consumers are encouraged to shift consumption to off-peak periods.

Nonetheless, while I am concerned about some of Mr. Jones's reasoning, it now appears we are in agreement that the differential between on-peak and off-peak energy charges in the LPS-TOU tariff should not be reduced, if I am correctly interpreting page 32 of his Rebuttal testimony. Indeed, the differential between on- and off-peak energy charges should remain the same as it is in the current LPS-TOU tariff.

Q. Do you agree with Mr. Jones' explanation of the new Interruptible Rider?

A. No. While I understand the reasons why the Company feels compelled to create the new Interruptible Rider, the new rider is too narrowly designed.

I agree with the following statements on pages 32-33 of Mr. Jones's Rebuttal testimony:

> "The interruptible rate has not provided benefit to the system or other rate payers in the last few years and the capacity needs of the Company do not justify offering any discount for the interruptible service currently being provided. The Company has proposed a new Interruptible Rider and proposed to freeze the current IPS rate. Staff has agreed to this proposal."

However, I disagree with the following statement on page 33:

> "Without a need to interrupt during the peak load timeframe, the Company does not see any value in creating a special deal that allows for a discount if the customer can interrupt during the off-peak period."

To be clear, in my previous testimony, I was not proposing any "special deals." Rather, the Interruptible Rider does not appear to recognize that there is value in having loads that may be interrupted during off-peak periods, and therefore the Rider should be opened to off-peak loads.

Many of the most severe reliability problems that electricity grids have faced in recent years have started in, or extended into, off-peak periods. The Northeast blackout of 2003 started on a Thursday afternoon and lasted two days – thus encompassing periods which would be considered "off-peak" under the tariffs of UNS Electric. Many of the reliability problems faced by the Electric Reliability Council of Texas (ERCOT) have occurred during periods of relatively low demand, when generating units failed or generation from wind farms fell below projections.

Having a properly designed interruptible tariff can reduce costs for all ratepayers. My recommendation is simply to make the tariff useful during all periods, not just the on-peak period, in order to plan for a wider variety of contingencies. It is not reasonable for the utility to assume that it will never experience a need for a resource during off-peak periods in order to maintain system reliability.

Q. Did the Company's Rebuttal clarify the applicability of the Economic Development Rate (EDR)?

A. No. On p. 33 of his rebuttal testimony, Mr. Jones states:

> "NUCOR wants the load factor associated with the EDR to be calculated based on the customer's billing demand and monthly usage. The Company's proposal simply states the customer must have a load factor of greater than 75% to qualify. The Company proposed this provision to encourage only the customers with the highest load factor to participate. Changing the parameters in the tariff may result in less efficient use of the system and may result in capacity issues. Therefore the Company does not believe that any changes to the proposed tariff are necessary or appropriate."

Contrary to Mr. Jones's assertion, I am not opposed to limiting the EDR to customers with high load factors. However, the calculation of "minimum load factor" in the EDR tariff is not clear. In order for an EDR tariff to be valuable, the terms must be absolutely clear to current and potential customers. I suggest that the requirements be clarified to reduce any future confusion.

The load factor of a customer over some period of time may be calculated in the following manner:

Load Factor = (Customer's Energy Consumption (kWh)/ Hours in the Period) / Customer's Peak Demand (kW)

In the EDR tariff proposed by the utility, it is not clear which measure of the Customer's Peak Demand should be used in the formula. For an LPS or LPS-TOU customer, for example, the options for measuring demand might include the customer's highest demand during a peak period, the customer's highest demand during an off-peak period, the customer's contribution to the monthly or annual system peak, the contract capacity value mentioned in part 4 of the Billing Demand section of the tariff, or the 500 MW minimum demand also mentioned in part 4 of the Billing Demand section of the tariff.

It is also unclear how the requirement that load factors be calculated for "the highest 4 coincident-peak months in a rolling 12-month period" would be implemented. Does this suggest that the average of the load factors for four summer months would need to exceed 75%? Or would the customer's load factor in each of four months need to exceed 75%? Which months are "coincident-peak months"? How will this calculation "roll"? Would a calculation made in the middle of 2017 include values from the later summer months of 2016?

To determine whether expansion of an existing facility might qualify for the proposed EDR tariff, would both the existing load and the load of the proposed expansion be considered in the calculation of the load factor? Or would this calculation merely consider the proposed expansion?

It seems appropriate that the value for "Customer's Peak Demand" used in the load factor calculation should be the same demand value which is used as the basis for the demand charge. I presume that this is the measurement that UNS Electric intends to use in this calculation. This is a value that appears on the customer's bill, and thus is transparent and known to both the utility and the customer.

When an existing facility is expanded, I presume that this load factor calculation would need to include both existing load and the load associated with the proposed expansion. Unless the new operations associated with the expansion were separately metered, it would be difficult to calculate the load factor associated with the expansion alone.

I recommend that, at a minimum, the utility provide a further explanation or sample calculations for "the highest 4 coincident-peak months in a rolling 12-month period" feature of the formula within the tariff.

In summary, I am not challenging the utility's proposal to limit Rider EDR to customer with high load factors. I am merely recommending that the load factor calculation be described better to reduce any later confusion. The present wording is extremely unclear.

Q. Do you agree with Mr. Jones' characterization of Nucor and other Intervenors in the rate case as expressing "special interests?"

A. No. On page 34 of his rebuttal testimony, Mr. Jones states:

> "As that evidence is considered, some thought must be given to the specific parties who express a special interest. This includes the low income customers,

solar providers, specific customers such as NUCOR, WalMart, the Fresh Produce customers, and other groups like SWEEP and WRA. All of these groups want the general rate design and cost recovery allocation to benefit their individual interests."

Nucor's interest in this general rate case, as it was in the previous rate case, is in the establishment of just and reasonable rates for UNS Electric customers. The Company's own Cost of Service Study indicates that Nucor and other large customers are currently subsidizing other rate classes. And I have demonstrated through testimony that the Company's policies and pricing do not reflect the cost allocation principles outlined by Company witnesses.

As I explained in my previous testimony, electricity is one of the highest variable input costs in steel production. Nucor has operated a rolling mill in Kingman since 2008, and has sought to reduce costs wherever possible to maintain profitability. However, Nucor is not a monopoly, and the price of steel is not set by a Commission. Rather, steel prices are the product of a highly competitive global commodities market, where steel producers in Mexico, China, Turkey, and other countries put near-constant price pressure on American steel mills like Nucor.

Nucor's rolling mill is an essential component in Kingman's economy – an economy that was hit particularly hard by the bankruptcy of the Mineral Park Mine and the loss of hundreds of jobs a few years ago. As UNS Electric acknowledges on page 3 of its Application, an 8% drop in retail sales is due, in large part, to the loss of Mineral Park, UNS Electric's previously largest customer. The loss of large industrial loads affects not only the cities close to industrial customers, but ultimately all UNS Electric customers. It is therefore critical that the rate design applied to large industrial customers – and all customers, for that matter – reflect sound ratemaking principles. Each of Nucor's recommendations above would provide a more accurate and more consistent rate design for industrial customers.

Q. On page 35 of his rebuttal testimony, Mr. Jones states:

> "NUCOR is the only customer in the TOU class and is currently the Company's largest consumer. Therefore the Company is of the opinion that its allocation of demand related costs is reasonable and any change to how it is recovered would not change the total cost allocated to that class, only how that TOU customer would pay the same total amount. Therefore no change in how demand charges are recovered is warranted."

Is Nucor indeed challenging the class cost allocation proposed by UNS Electric?

A. No. Nucor has not taken issue with allocation of demand-related costs to various customer classes proposed by UNS.

It is my understanding that the LPS rate class includes LPS-TOU customers, and that there would be four LPS customers (including Nucor) if the utility's proposal to move a number of customers presently within the LPS class to the LGS rate class is adopted. My recommendation does not impact the total costs to be collected from the LPS customer class. However, it may impact the revenues collected from each of the four customers within that class. That is, revenues would be collected from the LPS class (including LPS-TOU customers) in a more equitable manner, consistent with the cost causation theories endorsed by the utility.

While we have not objected to the allocation of demand-related cost to various customer classes proposed by UNS Electric, we have objected to the utility's proposed design of the demand charge. We strongly believe that it is inconsistent with the theories of "cost causation" advanced by UNS. My direct testimony is designed to resolve these inconsistencies.

III. RESPONSE TO THE DIRECT TESTIMONY OF STAFF WITNESS MR. HOWARD SOLGANICK

Q. Please state your primary concern regarding the direct testimony of Mr. Solganick.

A. The analysis provided by the utility in this proceeding concludes that the LPS rate class (including LPS-TOU customers) should be assigned no rate increase in this proceeding. Nonetheless, Mr. Solganick recommends that all customer classes should receive a rate increase. His testimony on page 22, line 23-24 states:

> "There should be a lower bound of 50 percent for any class' increase compared to the overall increase."

Apparently, he would like to see all classes "share the pain" of the rate increase, irrespective of whether that class is already subsidizing other rate classes. Yet, imposing a rate increase on the LPS class would contradict his first proposed "principle."

Q. What is this principle?

A. The first principle identified by Mr. Solganick for the purpose of allocating revenue requirements among rate classes is:

"The individual rate classes should be gradually moved toward an UROR of 1.000 over one or more rate cases depending on the frequency of rate cases and the distance of the class' UROR from 1.000."

Q. What is the UROR?

A. Mr. Solganick defines the UROR or Unitized Rate of Return as the class return divided by the Company return. Thus, a value above 1 would suggest that the rate of return from a class is greater than the Company's anticipated overall rate of return.

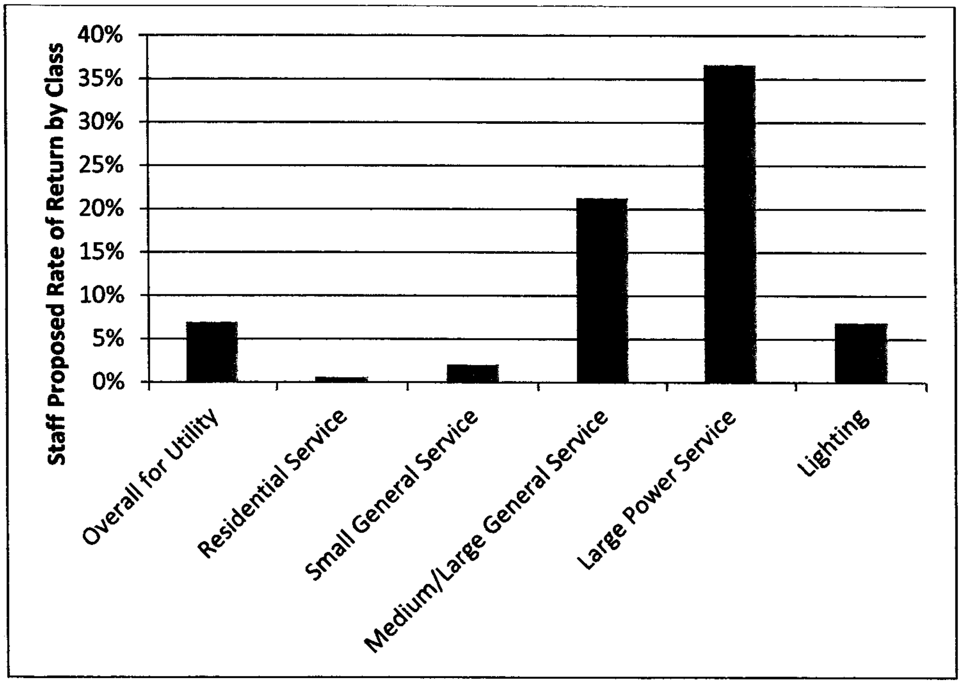
Q. Why would Mr. Solganick's recommendation to impose a rate increase on the LPS class violate his first principle?

A. Mr. Solganick's recommendation would move LPS rates *in the wrong direction*. The utility's analysis suggests that this class deserves a decrease in rates, not a rate increase. For example, Mr. Jones' Direct testimony (p. 25, line 15) suggests that UNS Electric is presently earning a return of 27.95% from this class at present rates using an Average & Excess cost allocation. Thus, LPS rates should be reduced if the goal is to gradually move each class to a UROR of 1.000 as recommended by Mr. Solganick.

The calculations within the boxed area of Mr. Solganick's Exhibit HS-4 suggest that his recommendation would raise the UROR for the LPS class to a whopping 5.29! That is, the utility would earn a 36.62% Rate of Return on Rate Base from LPS customers, which is 5.29 times the utility's overall rate of return.[2] The figure below

[2] Technically, the UROR for the LPS class would indeed decline under Mr. Solganick's recommendation, from a UROR of 12 (=27.95/2.31) to 5.29 (=36.62/6.92). However, this is not a reasonable comparison because the utility's present return at present rates is low because UNS Electric's actual rate of return is low. The percentage

graphically compares Mr. Solganick's recommended class rates of returns, based on the boxed area within his Exhibit HS-4. The bars in this graph indicate the rate of return which would be received by the utility from each class, under Mr. Solganick's recommendations. The rate of return received by the utility from the LPS class would be over 64 times higher than the rate of return from serving the Residential Service class.[3] The rate of return for serving LPS customers would be nearly 18 times higher than the return earned from serving Small General Service customers.[4]



Q. How do you recommend that this inequity be resolved?

A. Although the original proposal by UNS Electric for a small decrease in LPS rates would result in a continuation of a situation whereby LPS customers were subsidizing customer

rate of return earned by the utility from serving the LPS class would increase considerably under Mr. Solganick's recommendation.

[3] That is, the utility would receive a rate of return of 36.62% from LPS customers, as opposed to a 0.57% rate of return from Residential Service customers.

[4] That is, the utility would receive a rate of return of 36.62% from LPS customers, as opposed to a 2.07% rate of return from Small General Service customers.

in other classes, Nucor can agree to it, provided there is a commitment to reducing such subsidies in subsequent rate cases.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

SUSAN BITTER SMITH, CHAIRMAN

BOB STUMP

BOB BURNS

DOUG LITTLE

TOM FORESE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	)	Docket No. E-04204A-15-0142

EXHIBIT

WRA-1

admitted

TESTIMONY OF

KENNETH L. WILSON ON BEHALF OF

WESTERN RESOURCE ADVOCATES

December 9, 2015

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Q. Please state your name and business address.

A. My name is Kenneth L. Wilson. My business address is 2260 Baseline Road, Suite 200, Boulder, Colorado 80302.

Q. By whom are you employed and in what position?

A. I am an Engineering Fellow with Western Resource Advocates ("WRA"). WRA is a nonprofit conservation organization working to protect and restore the natural environment of the Interior American West. WRA's Clean Energy Program works to develop and implement policies to reduce the environmental impacts of the electric power industry in the Interior West by promoting the expanded use of renewable energy, energy efficiency, and other clean energy resources in an economically sound manner.

Q. Please give a brief description of your professional experience and education.

A. I am an electrical engineer with over 40 years of experience. I worked at Bell Labs as a systems engineer for 18 years and have been a consulting engineer with my own consulting firm for the past 15 years, and most recently an employee of Western Resource Advocates. For the past seven years I have worked on a number of distribution grid related projects, looking at grid efficiency, Demand Side Management ("DSM"), and renewable energy integration. I have Master's and Bachelor's degrees in Electrical Engineering from the University of Illinois and Oklahoma State University, respectively. My qualifications are included as Attachment KLW-1 to this testimony.

I. Summary

Q. Please summarize your testimony.

A. UNS Electric, Inc. (UNSE) is proposing dramatic changes in the way rates are calculated for residential customers who install Distributed Solar Generation (DSG). Currently, customers who install DSG have all of the energy generated by their system "netted" against their energy consumption. Aside from this net metering, these customers are in the same rate class and are under the same rate structure as other residential customers. UNSE is proposing in this rate case to change the rate structure for customers who install new DSG systems in two ways. First, all energy that is produced by the DSG system and exported to other UNSE customers will be credited at a lower rate. Secondly, UNSE is proposing to assess large demand charges for peak hourly energy use each month.

In the testimony below, I first address the issue of creating a special rate class for residential customers with DSG. Secondly, I address concerns I have with assessing demand charges on residential customers. Third, I propose a minimum bill as an alternative for demand charges. Fourth, I discuss the advantages of Time of Use (TOU) rates. Fifth, I discuss the problems with doubling the monthly service charge. Sixth, I discuss battery storage as a new technology that will need to be considered in rate cases.

Q. Please summarize your recommendations.

A. I recommend that the Commission not create a separate rate structure for customers with DSG systems. The issues associated with whether those customers are providing adequate contributions to fixed costs are no different from the contributions associated with vacant and seasonal properties and other customers with low energy use. In the alternative, I recommend allowing UNSE to assess a minimum bill to recover a portion of fixed costs from all residential customers and to continue recovering most fixed costs with charges for energy. I also recommend moving all residential customers to TOU rates, and I recommend against a high monthly basic service charge. Finally, if the Commission decides a demand charge is appropriate, it should be modest and should only be assessed for a customer's peak hourly demand during a defined system peak load time of day, each month.

II. Separate Rate Structures for DSG Customers

Q. Should DSG customers be treated as a separate rate class?

A. No. I do not believe it is necessary or desirable to create a separate rate class for customers who self-generate electricity. Much of the energy they generate is used on-site, lowering their load in a manner similar to customers utilizing energy efficiency measures. The method of appropriately assessing the utility's fixed costs to DSG customer and non-DSG customers can be identical. When the issue of exported energy is removed from the discussion, DSG customers look like other customers with relatively low energy use.

Q. In what way is energy generated by DSG similar to energy efficiency measures?

A. Much of the energy generated by DSG is used on-site to power part of the customer's use of air-conditioning systems, refrigerators, etc. To the UNSE system, this has the appearance of a load reduction similar in nature to putting in a more efficient air-conditioning system, a more efficient refrigerator, etc.

Q. Do we need a separate rate structure for customers who implement energy efficiency measures?

A. No. To the best of my knowledge, no state has proposed creating a separate rate class for customers who implement energy efficiency measures.

Q. Is a separate rate class needed to assess a fair share of the utility's fixed costs for distribution, transmission and generation to DSG customers?

A. No. I discuss the pros and cons of alternative rate structures below, such as demand charges, minimum bill, and TOU rates that can be used equitably for all customers, including DSG and non-DSG customers. Both sets of residential customers would have the same issues with these rate structures and there is no need to treat them in separate classes.

Q. Do your comments on these rate structure issues apply to all customers or just DSG customers?

A. My comments on demand charges, minimum bill, time of use rates and monthly customer charges apply to all customers and not just DSG customers. I will be discussing pros and cons for various rate structure elements that apply generally to all residential customers.

III. Demand Charges

Q. What are your concerns regarding UNSE's proposal to assess demand charges on residential customers who have DSG?

A. One concern is that residential customers will not understand demand charges and will not have the information necessary to change behavior in a manner that will control the level of demand charge they are assessed. I believe it will increase bills for low income customers and customers with electric heating. I am also concerned that a demand charge for residential customers will act like very high fixed charge and will surprise many customers with much more erratic, unpredictable, and unmanageable bills.

Q. What is the basis for your concern that residential customers will not understand demand charges?

A. There is a big difference between understanding how much electricity you use each month and how fast you use electricity in an hour. I look at my electricity bill each month to see how many kilowatt hours (kWh) I have used and compare it to previous months and the previous year. As an electrical engineer I understand philosophically that I have peak use hours during the month, but I generally have little control over how high that peak is. This was especially true when my two teenage daughters were living at home with my wife and me. I didn't know, and they didn't know, when various appliances get turned on and how that interacts with air conditioning, washing machines, dishwashers, refrigerators and other appliances that may be operating. To effectively manage their demand charge, customers would need to monitor individual appliances that they turn on at the same time during every hour of the day and know when large, automatic appliances (like air conditioners) are already running.

Q. Will this lack of understanding about the rate of electric use result in surprises when the electricity bill arrives each month?

A. I believe it will. I think customers could easily see demand charges vary by a factor of 2 or even 3 from one month to the next. It all depends on the simultaneous use of appliances, some automatic and some controlled by the customer, being very different from one month to the next. If your family happens on one day to all arrive home at the same time and start using various appliances, it can be very different from the average use during that month and other months. The demand charge that would be assessed is seemingly random from the point of view of the customer.

Q. Do the hourly peak demands by various residential customers occur during the same hour during the month?

A. No, the peak demand by any random group of residential customers would rarely be during the same hour in a month. The peak load hour during a month for my house is unlikely to be the peak load time for my neighbor's house. While there is some correlation with respect to average peak hours, the actual peak hours are unlikely to be at the same time of day on the same day of the month. What this means is that if you take the hourly peak kW in a month for each residential customer and add them all up, the total will be far more than the actual peak load presented by residential customers to the UNSE system. This is also true at the feeder and substation level. As a result, UNSE's demand charge proposal presents a very real risk of overcharging residential customers for demand in excess of the costs the utility incurs to satisfy that demand.

Q. Does the demand assessment for a month have the potential to penalize a customer with respect to the coincident peak load of other residential customers and with peak load on the UNSE system?

A. Yes. The demand charge that UNSE is proposing does not take into account whether the customer's peak demand coincides with peak load on the UNSE system. A particular customer's peak load could occur in the morning, when system load is average, during evening when peak load is high, or during the night time when peak load is low. It may also not correspond to the peak load times of their neighbors on the same feeder.

Q. Does the demand charge that would be assessed on a residential customer correspond to the peak load on the substation and feeder that serves that customer?

A. No, not necessarily. A particular customer's peak demand during a month may be far removed from the time of peak demand on the feeder or substation serving that customer. One of the main components of fixed costs that UNSE wants to recover is the cost of the distribution grid, which include costs such as the service transformer, actual poles and wires of the feeder, and all of the components of the substation. To more accurately assess demand charges in line with established principles of rate design, UNSE should have a portion of the demand charge that is based on the time of day and day of the week when the customer's substation experiences peak load and the customer's feeder experiences peak load. This would match the customer's peak load with the peak loading on the feeder and substation serving them. While a demand rate structure with this level of detail would be more accurate in assessing costs, it would still be unpredictable for the customer.

Q. Is it possible for UNSE to assess a portion of demand charges based on the customer's substation and feeder?

A. Yes. UNSE should have hourly load data for all feeders and substations. The times during the day when feeder and substation loads are at peak could be used, along with the information on the customer's peak hours of use, to correctly assess and bill for a portion of the customer's peak demand based on the customer's peak substation and feeder load. The portion of the customer's demand based on these distribution grid peaks could be prorated with the customer's peak load during system peak load.

Q. How would demand charges impact customers with all electric heating?

A. Customers with all electric heating have some unique problems with demand charges. Electric heating loads peak in the winter, when systems loads are not at peak. Peak heating load hours for a customer can occur during the night time, when temperatures are low, and the system load is low. Assessing high demand charges for night time peaks during winter months unduly penalizes customers with electric heat and does not accurately represent the utility's costs for capacity at the system or distribution grid level.

Q. Will demand charges increase bills for low income customers?

A. It is likely. Essentially, demand charges act like increased fixed monthly charges. Even customers with small homes and relatively low energy use still have air conditioners, refrigerators, washing machines, televisions and other household appliances. Many times they also have the least efficient appliances, causing higher loads than other customers. I would expect demand charges to unduly penalize low income customers.

Q. Do demand charges disincentivize energy efficiency?

A. Yes, they can cause energy efficiency to be disincentivized. For example, a family could have several zones of central air conditioning with setback thermostats to let the house warm up a bit when the family is gone. When the setback thermostats trigger the air conditioners to turn on when the family is to return, all the zones could be full on for more than an hour. This can cause a spike in demand. A home with several window air conditioners can have the same problem, when they are all turned on at once. In addition, the fixed charge nature of demand charges will reduce the financial incentive to save energy because a reduction in volumetric consumption will have a smaller impact on their overall bill. When more of the bill is in a fixed monthly customer charge and a demand charge, as UNSE is proposing, less of their monthly bill will be due to actual energy use. In other words, because demand charges essentially function as higher fixed charges for residential customers, the energy or volumetric price must be correspondingly reduced. Reducing the volumetric rate has been shown to increase residential energy consumption.

Q. Do demand charges help collect a fair share of revenue from vacant and seasonal homes?

A. No. The demand charge for a vacant home will be minimal, as will a home that is vacant for months at a time. UNSE has stated in testimony that vacant homes and seasonally occupied homes are not paying their fair share for connection to the system. They are making a fair observation, but their solution of demand charges does not address the issue. As I will address in the next section, a minimum bill can more effectively address this issue.

Q. How would demand charges impact electric vehicles?

A. Demand charges are bad for electric vehicles charging. This is especially true for Level II chargers that charge the vehicles quickly. Charging an electric vehicle puts a substantial load that lasts for several hours. Even if the vehicle is only charged at night, it could represent a customer's peak load for the month. If the customer needs to charge their electric vehicle during the day, when an air-conditioner is running, their demand would be very high, incurring a large spike in their utility bill under the UNSE rate structure for DSG customers. It is far better to use TOU pricing as I will explain below.

Q. If the Commission decides demand charges are appropriate for DSG customers, how should the demand charges be structured?

A. While I do not recommend using a rate structure with demand charges for residential customers, if the Commission determines that demand charges are appropriate, I have the following recommendations. UNSE has proposed a demand rate that uses an hourly average for an individual customer's peak demand. Using an hourly average is better than using a shorter time period. I would recommend against using a shorter period. The UNSE demand charge could be improved by using only those customer peak demand hours that occur within system peak load hours. This would reduce problems of setting demand charges during night time hours when system load is low. For example, if a customer hit a peak demand during one night time hour of 10 kW due to winter heating load, but their maximum load for the month during a system peak load hour was 5 kW, the demand charge for the month should be 5 kW and not 10 kW.

The Commission should also consider requiring that a portion of the demand charge be calculated during the peak load hour for the customer's feeder and substation.

Finally, if demand charges are used, they should be set at a rate much lower than those proposed by UNSE. Most of UNSE's fixed costs should be recovered from the customer's volumetric energy use. Using a much lower demand charge than proposed by UNSE would reduce, but not eliminate, the problems with demand charges that are described above.

IV. Minimum Bill – A Better Alternative

Q. What is a minimum bill and how does it differ from fixed customer costs and demand charges?

A. Charging customers a minimum bill each month is an alternative way to recover a portion of fixed costs that would otherwise not be recovered from very low use customers. A minimum bill is a fixed charge each month that includes a charge for a minimum amount of energy as well as the traditional fixed customer charge. For example, if the fixed customer charge is $10 per month and retail energy charges are $0.10 per kWh, a minimum bill of $30 per month would include 200 kWh of electricity. This guarantees that a portion of the utility's fixed costs are covered by all customers.

Q. Should the minimum bill cover all fixed costs?

A. No. Covering all of the fixed costs of the utility with a minimum bill would make the minimum bill too high. Most of the utility's fixed costs should continue to be collected with energy charges. The minimum bill just assures that all customers pay a share of the fixed charges, whether or not they actually use the electricity that is included in the minimum bill. One benchmark for setting a minimum bill is to look at how much electricity low use, low income users typically use. Monthly bills for low income, low use customers should not go up.

Q. Is this a better solution for low income customers?

A. Yes. Compared to a demand charge, a minimum bill provides far more financial predictability. The amount of the minimum bill should be set with low income customers in mind, such that very few of them would see an increase in their overall monthly bill.

Q. Does a minimum bill help with the problem of vacant and seasonally occupied properties not paying their fair share of fixed costs?

A. Yes, a minimum bill can be used with all residential customers and would certainly be assessed on vacant and seasonally occupied properties, whether or not the properties use the full kWh included in the minimum bill.

Q. Does a minimum bill help allocate costs to DSG customers?

A. Yes. For DSG systems that are producing a large percentage of the customer's yearly energy use, the minimum bill would still assess them a charge that would cover some portion of fixed costs.

Q. Is a minimum bill easier for customers to understand?

A. Yes, a minimum bill is a quantity that is easy to know and easy to understand, unlike demand charges. There would be no surprises with a minimum bill. This is very different from demand charges, which can be quite variable from month to month, making it difficult for customers to budget and, potentially, to pay.

V. Time of Use Rates

Q. Should UNSE transition to Time of Use rates for all customers?

A. Yes. Many of the issues that UNSE is raising about the need to match cost recovery to cost causation can be handled by using TOU rates for all residential customers. The costs of generation vary by time of day and day of week, and so does the need for capacity on the UNSE grid. Setting prices based on when the energy is used by the customer can better capture the cost to provide that energy and the capacity on the grid to deliver that energy to the customer.

Q. Is this true for all residential customers, or just customers with DSG?

A. In the long run, it will be better for all residential customers to be on TOU rates. TOU rates better reflect the actual cost of service.

Q. Why?

A. The cost of generation is low at night and high during the late afternoon and early evening hours, with generation costs somewhere in between during the morning and into the early afternoon. Having three different rates for the three periods of the day can reflect the relative cost of service delivery during different times of the day.

Q. What about rates during the weekend?

A. Weekend energy use is generally not as high as energy use on the weekday. A special weekend rate could be developed, or you could simply use one of the weekday rates.

Q. Does the cost to deliver energy over the grid change with time of day and day of week?

A. Yes. The energy grid, at both the transmission and distribution level, must have the capacity to deliver power during peak load conditions. Customers who use the system more during those peak periods should pay more. TOU rates do just that.

Q. How will TOU rates impact low income customers?

A. I would not expect TOU rates to impact low income customers adversely. If low income users use less air conditioning, TOU rates could actually lower their monthly bill during summer months.

Q. Will TOU rates be understandable by residential customers?

A. Yes, they should be. It would be easy for customers to understand that electricity is expensive from late afternoon into the early evening and cheaper at night.

Q. Do TOU rates give customers an opportunity to save money on their utility bill?

A. Yes. Customers can choose to use less energy during peak hours and more energy during low load hours.

Q. How do TOU rates impact customers with DSG?

A. It depends on the time periods that are used and the generation patterns of DSG in the UNSE service territory. Generally, DSG produces maximum output when the sun is high in the sky, around the noon hour. In the summer, on a cloudless day, DSG will have good production into midafternoon when demand is fairly high. DSG starts falling off in late afternoon and early evening, when demand is usually the highest. If TOU rates follow system demand, and the DSG customer's use patterns are consistent with that pattern, then the energy from the DSG system that is used on-site will be more valuable than it would be in a rate structure that has no TOU.

Q. Do TOU rates encourage adoption of energy efficiency measures?

A. Yes. As mentioned above, TOU rates will encourage customers to move some of their energy consumption to hours of the day when energy is cheaper, saving them money. TOU rates will stimulate Demand Response applications such as air conditioning systems that make ice at night and use it for cooling during the heat of the day, when energy prices are high.

Q. How will TOU rates impact electric vehicle charging?

A. TOU rates are ideal for incentivizing efficient electric vehicle charging. The EV charges can be set to charge at night, when energy prices are low. EV owners who charge during peak load hours will pay a higher price, as they should.

VI. Basic Service Charge

Q. UNSE is proposing to raise the basic service charge for residential customers from $10 per month to $20 per month. Do you think this is appropriate?

A. No. The basic service charge should remain at the $10 level. Doubling the basic service charge, or raising it significantly, is not necessary and does not incentivize economically efficient customer behavior.

Q. Why is raising the basic service charge unnecessary?

A. UNSE can continue to collect adequate revenues from charges for energy use, as it has done successfully in the past. If UNSE is concerned about inadequate funding of fixed costs from vacant properties, seasonally occupied properties and customers with DSG, they can adapt a minimum bill rate element as described above.

Q. Why is a minimum bill preferable to increasing the basic service charge?

A. A minimum bill includes some amount of energy that is essentially "prepaid." For example, a minimum bill of $35 could include 250 kWh of electricity. The basic service charge does not include a minimum level of electricity. For low income users this can make a difference. For vacant and seasonally occupied properties and for DSG customers, the minimum bill accomplishes the same goal as a higher basic service charge.

Q. Does a high basic service charge discourage energy efficiency?

A. Yes. High basic service charges discourage energy efficiency by reducing the amount of the customer's bill associated with volumetric energy consumption. When the customer reduces their use, it has less impact on their bill. The overall impact is to increase customer bills and disincentivize energy efficiency.

Q. What cost elements are generally considered appropriate to collect in the basic service charge?

A. The basic service charge should only include costs that are directly associated with the customer, such as billing, collections, and the service drop.

VII. Battery Storage

Q. Should the Commission begin consideration of customer sited battery storage in rate designs?

A. Yes. In the next few years we will see behind the meter, customer owned battery storage that is integrated with DSG. There may also be applications for such storage that is not associated with DSG.

Q. Is battery storage good for the grid and the UNSE system?

A. Yes. Battery storage can be used to reduce peak loads and to shift energy from morning hours when energy is less valuable to evening hours when it is more valuable. Both of these applications help the UNSE system. Generation costs for UNSE are much higher during peak load times. Battery storage, when it is used to shift energy to peak load times, helps to reduce the need for more expensive generation. It also can help relieve congestion on the distribution grid.

Q. Can battery storage be used to reduce a customer's peak demand and thereby reduce demand charges?

A. One application for battery storage is certainly to reduce peak customer load and thereby reduce demand charges. This is being done today by commercial customers in California and Pennsylvania, where demand charges are high. However, the economics of using battery storage to reduce residential demand charges are not as favorable.

Q. If the Commission implements the demand charges UNSE is proposing for DSG customers, can the customers use battery storage to reduce the demand charges?

A. They can, but with the current price of battery systems, it is unlikely to be cost effective. Very few customers today would be able to afford a battery system that would significantly reduce the demand charges that UNSE is proposing.

Q. Can customers use battery storage to help lower their bills if TOU rates are implemented?

A. Yes. Battery storage can be used to store energy that would have been exported from the customer's DSG system to the UNSE grid and then use that energy in the evening when the sun is down to power the customer's energy needs. This helps the customer by using more of the energy generated by the customer's DSG system on-site instead of exporting the energy to the UNSE system. And it also leads to a more efficient overall system.

Q. Is it better for the UNSE system for battery storage to be used in reducing the customer's demand charges or during a time when UNSE needs additional energy to meet total customer demand?

A. This is an interesting question that gets back to my earlier discussion about the fact that a customer's peak demand may not be coincident with the UNSE system's peak load. It would be better for the UNSE system for battery storage to discharge into the grid during system peak demand conditions, rather than trying to reduce the customer's individual peak demand that is not coincident with system peak demand. If demand charges are imposed on residential customers, operating the battery to help the customer reduce their bill may not be in the best interest of the UNSE system.

Q. How could this conflict be solved?

A. It would be better if behind the meter customer owned battery storage systems were controlled by the utility than by the customer. The utility knows when the energy is needed and can operate the battery most efficiently. However, if the battery is operated in this manner, the customer should get any demand charges waived or dramatically reduced.

Q. What are you recommending the Commission do in this rate case with respect to battery storage?

A. I am bringing this issue to the Commission's attention as I see it becoming a significant issue in the not too distant future. I don't think that changes need to be made immediately in rate structures to accommodate battery storage. However, the

Commission should be thinking about this issue for the future, when consideration should be given to battery storage in utility rates.

Q. Does this conclude your testimony?

A. Yes.

KENNETH WILSON
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WORK EXPERIENCE

Western Resource Advocates Boulder, Colorado
Engineering Fellow (2013 – present)
Mr. Wilson has worked as a consultant, and most recently on staff for Western Resource Advocates (WRA). As WRA's Engineering Fellow, Mr. Wilson has provided testimony, filed comments and presentations in Colorado, Nevada, Arizona and Utah on distribution grid improvements and issues surrounding distributed solar generation.

TransGrid Consulting Boulder, Colorado
Energy Consultant (2007-2012)
Mr. Wilson has worked as a consultant in smart grid systems engineering, project management and business development for companies and NGOs working on grid efficiency, renewable energy, and renewable integration. In 2009 Mr. Wilson was the Project Manager for a $200 million smart grid grant proposal to DOE that included CSU, CU, NREL, Sandia Labs, Lincoln Labs, Spirae and other participants. Mr. Wilson was a consultant with Power Tagging, Inc. during 2010 – 2012, working on applications for a new smart grid communication technology. He has also done engineering consulting for renewable energy projects, including solar gardens, and electric vehicle companies.

Boulder Telecommunications Consultants Boulder, Colorado
Expert Witness and Engineering Consultant (1998-2007)
Expert witness in telecommunications including testimony and case preparation at state and federal level with major telecommunications firms (AT&T, MCI, Level 3, and major CLECs). This work also included contract development and negotiations support.

AT&T Denver, Colorado
Technical Negotiations Director (1995-1998)
Technical leader of negotiations and witnessing team responsible for all aspects of AT&T's contracts in 14 states with US WEST. AT&T's lead expert in Section 271 cases in 14 states. Led technical planning for local infrastructure and Operations Support Systems "OSS" interfaces.

AT&T Bell Labs Bedminister, New Jersey
Director – Local Infrastructure Planning (1994-1995)
Local infrastructure development and business analysis – Technical lead for team evaluating local infrastructure alternatives and OSS. Helped develop AT&T's proposals to the FCC for unbundling the telecommunications network.

AT&T Bell Labs Holmdel, New Jersey
Director Network Deployment and Asset Management (1992-1994)
Key team leader on AT&T project to optimize network infrastructure by changing engineering rules and OSS processes. The project saved AT&T over $2B in avoided investments and expenses.

AT&T Bell Labs Holmdel, New Jersey

Member of Technical Staff Supervisor (1988-1992)
Led team responsible for network design and performance of the AT&T long distance network for business customers. Network performance planning for new business customer features. Competitive testing and analysis of multiple vendor networks.

AT&T Bell Labs Holmdel, New Jersey
Member of Technical Staff and MTS Supervisor (1984-1987)
Member of the Cellular Telephone Development group. Led team responsible for systems requirements and systems testing of the first cellular telephones. Made test calls to the first cell site in the US.

AT&T Bell Labs Holmdel, New Jersey
Member of Technical Staff (1980-1984)
Systems engineer in the team responsible for 4ESS switch feature and architecture planning.

Small Business Startups (1977–1980) Red Bank, New Jersey
Software, hardware and manufacturing engineering in two small companies.

EDUCATION

ABD for PhD (1976): University of Illinois, Champaign, Illinois
All but dissertation for PhD in Electrical Engineering

M.S. (1974): University of Illinois, Champaign, Illinois
Master of Science in Electrical Engineering

B.S. (1972): Oklahoma State University, Stillwater, Oklahoma
Bachelor of Science in Electrical Engineering

M.A. (2014): University of Colorado, Boulder, Colorado
Master of Arts in Biology with a specialization in Microbiology

ELECTED AND APPOINTED POSITIONS

Mr. Wilson was elected to Boulder City Council in a special election in June 2007 and reelected in November 2007 and November 2011, retiring from Council when his term expired in November 2013. While in this position he had the opportunity of evaluating Xcel Energy's Smart Grid City and was involved in Boulder's attempt to form a municipal utility. Mr. Wilson was appointed to Boulder's Water Resources Advisory Board by Boulder City Council in 2002 and served until March 2007.

RECENT FILINGS ON BEHALF OF WESTERN RESOURCE ADVOCATES

Arizona

Docket RE-00000A-07-0609 – Proposed Rulemaking Regarding Interconnection of Distributed Generation Facilities. Comments of Western Resource Advocates, 7/24/15.

Docket E-00000V-13-0070 – In the Matter of Resource Planning and Procurement in 2013 and 2014. Comments of Western Resource Advocates, 7/1/15.

Docket E-01933A-15-0100 – In the Matter of Tucson Electric Power Company for (1) Approval of a Net Metering Tariff and (2) Partial Waiver of the Net Metering Rules. Motion to Intervene of Western Resource Advocates, 4/29/15.

Docket E-04204A-15-0142 – Application of UNSE Electric for the Establishment of Just and Reasonable Rates and Charges… Motion to Intervene of Western Resource Advocates, 6/12/15.

Docket E-00000J-14-0023 – In the Matter of the Commission's Investigation of Value and Cost of Distributed Generation. Petition for Leave to Intervene of Western Resource Advocates, 11/19/15.

Docket E-00000J-13-0375 – Innovations and Technological Developments. PowerPoint presentation to Commissioners during workshop, 5/28/14.

Colorado

Proceeding 14M-0234E – In the Matter of Commission Consideration of Retail Renewable Distributed Generation and Net Metering. Comments of Western Resource Advocates on Distribution System Design and Ancillary Benefits for April 23, 2015 Net Metering Panel. Also PowerPoint presentation to Commissioners.

Proceeding 14A-1057EG – In The Matter of the Application of Public Service Company of Colorado for Approval of Its Electric and Natural Gas Demand Side Management (DSM) Plan for Calendar Years 2015 and 2016 and to Change Its Electric and Gas DSM Cost Adjustment Rates Effective January 1, 2015. Answer Testimony on behalf of Western Resource Advocates, 2/13/15.

Proceeding No. 13A-0686EG – In the Matter of the Application of Public Service Company of Colorado for Approval of a Number of Strategic Issues Relating to Its Demand Side Management Plan. Testimony on behalf of Western Resource Advocates: Answer 10/16/13, Cross-Answer 12/20/13, Surrebuttal 1/21/14.

Nevada

Docket 12-10013 – Investigation Regarding Voltage and Volt-Ampere Reactive (VAR) Control and Optimization. Comments of Western Resource Advocates, 2/20/14.

Docket 14-02004 – Application of NV Energy for Approval of Annual Plans for the Solar Energy Systems Incentive Program, the Wind Energy Systems Demonstration Program, and the Waterpower Energy Systems Demonstration Program for Program Period 2014-2015. Direct Testimony on behalf of Nevadans for Clean Affordable Reliable Energy (NCARE), 4/25/14.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

DOUG LITTLE, INTERIM CHAIRMAN

BOB STUMP

BOB BURNS

TOM FORESE

ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	)	Docket No. E-04204A-15-0142

EXHIBIT

WRA-2

admitted

SURREBUTTAL TESTIMONY OF

KENNETH L. WILSON

ON BEHALF OF

WESTERN RESOURCE ADVOCATES

February 19, 2016

Q. Please state your name and business address.

A. My name is Kenneth L. Wilson. My business address is 2260 Baseline Road, Suite 200, Boulder, Colorado 80302.

Q. Did you submit Direct Testimony on behalf of Western Resource Advocates?

A. Yes.

Q. Have you reviewed the Direct Testimony filed by the Utilities Division ("Staff") of the Arizona Corporation Commission and Rebuttal Testimony filed by UNS Electric ("Company") in this docket.

A. Yes.

Q. What subject matter do you cover in your Surrebuttal Testimony?

A. I address the opinions of Staff and the Company regarding the advisability of switching residential customers from a 2-part rate design to a 3-part rate design that includes demand charges.

I. RESPONSE TO STAFF

Q. In his testimony Mr. Broderick proposes to shift from a 2-part rate structure to a 3-part rate structure. Do you agree with his opinion in this shift?

A. No. Moving to a 3-part rate structure with demand charges for residential and small commercial customers is a radical change in rate design that is unnecessary. Transitioning to a 2-part Time of Use ("TOU") rate structure with a minimum bill is a more reasonable approach that avoids many customer issues inherent with demand charges. I addressed many of the issues with demand charges in my direct testimony and will not repeat them here.

Q. Have any other state commissions adopted a 3-part rate structure with demand charges for all residential and small commercial customers?

A. Not to the best of my knowledge.

Q. Mr. Broderick is concerned the Company does not recover a fair share of fixed costs from all customers, and proposes demand charges as a solution. Do you agree with his opinion?

A. I agree that each customer should pay their fair share of fixed costs. However, as I stated in my Direct Testimony, I believe that TOU rates with a modest minimum bill are a better mechanism to accomplish this goal. TOU rates more accurately assess both fixed and variable costs to the customers who are using energy during peak load hours. The minimum bill also helps assess fair costs to vacant and seasonal properties, which a demand rate does not.

Q. Mr. Broderick suggests that demand charges "... will better assist customers to avoid utility costs, and it will encourage adoption of additional technologies." Do you agree with this statement?

A. No. While many energy efficiency technologies have been designed to allow residential and small commercial customers to reduce their energy use, there are few if any technologies that are available to economically reduce demand charges. Battery storage solutions are being marketed in some states to reduce demand charges for larger commercial customers, but these solutions are expensive and not designed for smaller energy users. Someday, battery storage systems may be an economic means to reduce demand charges for smaller energy users, but it seems unfair to implement demand charges before such technology is widely available.

Q. Mr. Solganick presents an analogy for demand charges in the rental car energy: when a customer rents a larger sized car for a higher price, this represents a demand charge. Do you agree with his analogy?

A. No, in fact I completely disagree. Rental car companies, like other competitive businesses, cover their fixed costs with volumetric pricing. Renting a larger car for a higher price is not a demand charge, it is simply renting a higher value service. The analogy with the electric industry would be paying for a higher grade of reliability, for example. Rental car companies cover their fixed costs by renting cars one day at a time, or one week at a time. If each member of your family rents a separate car, you are not charged a "demand charge" because you are renting more cars. Virtually all competitive businesses recover fixed costs by volumetric pricing.

Q. What are additional examples of competitive businesses covering all their fixed costs with volumetric prices?

A. The airline industry has huge fixed costs in airplanes and other infrastructure. They recover those costs one seat at a time. The hotel industry recovers fixed costs one room at a time. Oil companies recover the huge fixed costs of refineries and fueling stations one gallon at a time. Grocery stores recover fixed costs one apple at a time. None of these industries use demand charges. If a non-monopoly business began assessing demand charges, customers would undoubtedly shift to a competitive replacement that does not assess demand charges.

II. Response TO THE COMPANY

Q. Mr. Overcast states in his Rebuttal Testimony that WRA's support for a low customer charge is not a good method of assessing costs to the cost causer. Do you agree with his assessment?

A. Not in general. A single distribution feeder is shared by many hundreds or thousands of residential customers. The only element of the distribution grid that is shared by small numbers of customers is the service transformer. While one could make an argument that the cost of the service transformer could be assessed more granularly, the larger costs embedded in the feeders and substation are used by all and should be shared by all in volumetric charges, as has been done for many years in many states.

Q. Mr. Dukes in his Rebuttal Testimony presents a chart on page 22. What does that chart indicate about the impact of demand charges on customer bills for customers with low monthly energy use?

A. Mr. Dukes uses the chart to discuss impacts of various rate structure changes on DG. I find his calculations of the impacts on customers without DG interesting with respect to the impacts of a 3-part rate structure on customers who use lower amounts of energy each month relative to those who use more energy each month. Looking at the second column of numbers (Proposed 3-part Rate: No DG) we can see that the monthly bill of customers who use 500 kWh per month increases by $3.51, while customers who use 1,500 kWh per month see a bill decrease of $18.81. The crossover point seems to be about 900 kWh per month, at which level customers see a $0.06 bill decrease per month. The table suggests that all customers with less than 900 kWh per month of use will see bill increases with a 3-part rate structure and customers with usage of greater than 900 kWh will see bill decreases.

Increasing bills for customers who use less energy, who are often lower income customers, is poor policy. It fails to send accurate price signals to customers about the overall cost of using energy and disincentivizes energy efficiency and energy conservation.

Q. Does this conclude your testimony?

A. Yes.

ORIGINAL

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Attorneys for Southwest Energy Efficiency Project

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AZ CORP COMMISSION
DOCKET CONTROL

BEFORE THE ARIZONA CORPORATION COMMISSION

SUSAN BITTER SMITH, Chairman
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

EXHIBIT
SWEEP-1
admitted

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	Docket No. E-04204A-15-0142 **NOTICE OF ERRATA**

Arizona Corporation Commission
DOCKETED
NOV 0 9 2015
DOCKETED BY

Southwest Energy Efficiency Project ("SWEEP"), through its undersigned counsel, hereby provides notice that it has this day filed corrected direct testimony for Jeff Schlegel reflecting the following changes:

Page 5, DELETE the following text on lines 28-30:

The 2014 authorized budget was $4.79 million, and the current total two-year budget for 2015-2016 is about $6.4 million, or about $3.2 million annually on average.

INSERT:

The 2014 authorized program budget was $4.79 million, and the current authorized program budget for 2015 and 2016 is $6.42 million each year.

Page 7, line 30, after 37,500, INSERT:

To 40,000 MWh

Page 7, DELETE the following text on lines 37-42:

SWEEP estimates that the total energy efficiency budget for 2016 should be about $4.2 million – higher than the $3.2 million approved by the Commission in Decision No. 75297 for 2015, but lower than the $4.79 million Commission-authorized budget for 2014. SWEEP also estimates that the annual energy efficiency budget for 2017 and each year for the balance of the decade should be about $5.0-5.5 million,

INSERT:

SWEEP estimates that the total energy efficiency program budget for 2016 should be about $4.85 million – which is less than the $6.42 million approved by the Commission in Decision No. 75297 for 2015 and 2016 each year, and only slightly higher than the $4.79 million Commission-authorized budget for 2014 (note that these numbers for authorized and estimated program budgets do not include other costs such as the performance incentive and evaluation). SWEEP also estimates that the annual energy efficiency program budget for 2017 and each year for the balance of the decade should be about $5.0-5.5 million,

A full copy of the corrected testimony is attached to this Notice.

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DATED this 9th day of November, 2015.

ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST

By______________________________
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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

SUSAN BITTER SMITH, CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A RESONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	Docket No. E-04204A-15-0142

Direct Testimony of

Jeff Schlegel

Southwest Energy Efficiency Project (SWEEP)

November 6, 2015
(Corrected November 9, 2015)

Direct Testimony of Jeff Schlegel, SWEEP
Docket No. E-04204A-15-0142

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Introduction

Q. Please state your name and business address.

A. My name is Jeff Schlegel. My business address is 1167 W. Samalayuca Drive, Tucson, Arizona 85704-3224.

Q. For whom are you testifying?

A. I am testifying on behalf of the Southwest Energy Efficiency Project (SWEEP).

Q. Please describe the Southwest Energy Efficiency Project (SWEEP).

A. SWEEP is a public interest organization dedicated to advancing energy efficiency as a means of promoting customer benefits, economic prosperity, and environmental protection in the six states of Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming. SWEEP works on state legislation; analysis of energy efficiency opportunities and potential; expansion of state and utility energy efficiency programs as well as the design of these programs; building energy codes and appliance standards; and voluntary partnerships with the private sector to advance energy efficiency. SWEEP collaborates with utilities, state agencies, environmental groups, universities, and energy specialists in the region. SWEEP is funded by foundations and the U.S. Department of Energy. I am the Arizona Representative for SWEEP.

Q. What are your professional qualifications?

A. I am an independent consultant specializing in policy analysis, evaluation and research, planning, and program design for energy efficiency programs and clean energy resources. I consult for public groups and government agencies, and I have been working in the field for over 30 years. I have testified before the Arizona Corporation Commission in many proceedings. In addition to my responsibilities with SWEEP in Arizona, I am working or have worked extensively in many states that have effective energy efficiency programs, including California, Connecticut, Massachusetts, Michigan, New Jersey, Vermont, and Wisconsin.

Q. What is the purpose of your testimony?

A. In my testimony, I will summarize the public interest in increasing electric energy efficiency; discuss the status of UNS Electric's energy-saving offerings for its customers; recommend an increase in energy efficiency program funding and offerings to benefit UNS Electric's customers; and propose that energy efficiency, as a core energy resource meeting the real energy needs of customers at lowest cost, should be funded through a stable cost recovery mechanism, with cost recovery in base rates.

The Public Interest in Increasing Electric Energy Efficiency

Q. What is the public interest in increasing electric energy efficiency?

A. Electric energy efficiency is in the public interest. Increasing energy efficiency will provide significant and cost-effective benefits for all UNS Electric customers, the electric system, the economy, and the environment. Electric energy efficiency is a reliable energy resource that is less expensive than other available energy resources. Consequently, increasing energy efficiency will save consumers and businesses money through lower electric bills and the deferral of unnecessary, more expensive resources, resulting in lower total costs for customers.

Increasing energy efficiency also reduces load growth; diversifies energy resources; enhances the reliability of the electricity grid; reduces the amount of water used for power generation; reduces air pollution; creates jobs that cannot be outsourced; and improves the economy. In addition, meeting a portion of load growth through increased energy efficiency can help to relieve system constraints in load pockets. By reducing electricity demand, energy efficiency mitigates electricity and fuel price increases and reduces customer vulnerability and exposure to price volatility. Energy efficiency does not rely on any fuel and is not subject to shortages of supply, increased prices, or price volatility of energy fuels.

Q. What are the estimated costs for energy efficiency savings?

A. Energy efficiency is a reliable energy resource that costs significantly less than other resources for meeting the energy needs of customers in UNS Electric's service territory. For example, in 2014, the cost of energy efficiency programs per lifetime kWh saved was $0.011.[1] Notably, in its 2014 Integrated Resource Plan, UNS Electric identifies energy efficiency as the "lowest cost resource."[2] In comparison, the levelized cost of new generation for other energy resources is substantially more: natural gas combined cycle generation costs between $0.088-$0.119/kWh; coal generation costs between $0.125-$0.261/kWh; and nuclear generation costs $0.154/kWh.[3]

Q. Why should energy efficiency be considered in the context of the UNS Electric rate case proceeding?

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[1] UNS Electric, January-December 2014 Demand Side Management Report, February 27, 2015, http://images.edocket.azcc.gov/docketpdf/0000160426.pdf. Costs include the cost of rebates and incentives; training and technical assistance; consumer education; program implementation; program marketing; measurement, evaluation, and research; and program development, analysis, and reporting costs. Demand response programs were excluded from this calculation.

[2] UNS Electric, 2014 Integrated Resource Plan, April 1, 2014, http://images.edocket.azcc.gov/docketpdf/0000152211.pdf. Note that UNS Electric in its 2014 Integrated Resource Plan used a much higher levelized cost of energy efficiency of $60/MWh ($0.060/kWh), which is much higher than the current costs of energy efficiency programs.

[3] Ibid.

A. The Commission, in approving any order that changes or increases rates for customers, should ensure that the least cost resource – energy efficiency – is fully pursued. Consequently, in its order on the UNS Electric rate case, the Commission should ensure that UNS Electric is on a path to meet the energy savings levels set forth in the Electric Energy Efficiency Standard and Rule ("EEES") beginning in 2016; ensure that there is adequate funding to achieve the EEES energy savings levels and attain the associated customer and public benefits; and treat energy efficiency as the core energy resource that it is by providing a stable, long-term cost recovery mechanism and adequate funding in base rates.

The Status of UNS Electric's Energy Efficiency Programs for Customers

Q. What energy efficiency programs and measures does UNS Electric offer to its customers?

A. UNS Electric offers a suite of programs for both residential and commercial customers, including homeowners, renters, limited income customers, small businesses, schools, and large commercial and industrial customers. Some of these programs have been recognized as best practice programs. For example UNS Electric's Efficient Home program was recognized as "exemplary" in a recent national review of utility energy efficiency programs conducted by the American Council for an Energy Efficient Economy (ACEEE).[4]

Q. At what levels has UNS Electric invested in energy efficiency in the past?

A. From 2011-2014 UNS Electric invested about $13.7 million in energy efficiency, with the average annual expenditure being about $3.85 million over the 2012-2014 period (after the 2011 ramp up year).[5] The 2014 authorized program budget was $4.79 million, and the current authorized program budget for 2015 and 2016 is $6.42 million each year.[6]

Q. What have UNS Electric's energy efficiency programs accomplished?

A. UNS Electric's cost-effective programs have delivered significant economic, energy, and environmental benefits for customers. For example, from 2011-2014, UNS Electric reports that its energy efficiency portfolio delivered net benefits exceeding $40 million dollars and lifetime savings exceeding 988,320 MWh.[7]

[4] American Council for an Energy Efficient Economy, ACEEE's Third National Review of Exemplary Energy Efficiency Programs, June 20, 2013, http://aceee.org/sites/default/files/publications/researchreports/u132.pdf
[5] See UNS Electric Annual Demand Side Management Reports for 2011-2014.
[6] See Arizona Corporation Commission Decision No. 75297, page 24.
[7] See UNS Electric Annual Demand Side Management Reports for 2011-2014.

Q. Have there been recent enhancements to or expansions of UNS Electric's energy efficiency programs?

A. Yes. Commission Decision No. 75297, dated October 27, 2015, approved several program enhancements including new lighting and appliance measures for residential customers through the Efficient Products program; new opportunities for renters to save on cooling costs through the Multi-family program; and new opportunities for commercial and school customers to save on cooling and lighting costs through the Commercial and Industrial Facilities and Schools programs. In the Decision, the Commission also enhanced program flexibility to allow UNS Electric to offer cost-effective emerging technologies through multiple programs. It also created a pathway for UNS Electric to restart a Home Energy Reports program. A similar program offered by Arizona Public Service Company (APS) enrolled about 27% of APS' residential customers in 2015[8] and delivered about 17% of all residential energy savings in 2014.[9]

SWEEP appreciates the Commission's actions in approving these additional measures and providing the enhanced program flexibility for UNS Electric.

Increasing Energy Efficiency to Reduce Utility Bills for UNS Electric Customers

Q. What should the Commission do to increase opportunities for UNS Electric customers to reduce their energy bills through energy efficiency – which will also help customers mitigate the effects of any rate increase?

A. In its order in the UNS Electric rate case, the Commission should ensure that UNS Electric is on a path to meet the energy savings levels set forth in the Electric Energy Efficiency Standard and Rule ("EEES") by 2016; ensure that there is adequate funding to achieve the EEES energy savings levels and attain the associated public benefits, including through some additional program offerings; and treat energy efficiency as the core energy resource that it is by expensing the energy efficiency program funding in base rates.

Because of SWEEP's proposal to recover costs in base rates, we need to estimate, in the rate case proceeding, the amount of funding that would be necessary to support the energy efficiency programs, though the specific details of the programs and budgets would be addressed in the Implementation Plan process.

Q. What energy savings levels should UNS Electric meet, by when?

[8] Arizona Public Service Company, January-June 2015 Demand Side Management Report, September 1, 2015, http://images.edocket.azcc.gov/docketpdf/0000166015.pdf
[9] Arizona Public Service Company, January-December 2014 Demand Side Management Report, February 27, 2015, http://images.edocket.azcc.gov/docketpdf/0000160423.pdf

A. The Commission, in approving any order that increases rates for UNS Electric customers, should ensure that the least cost resource – energy efficiency – is fully pursued, consistent with the Commission-adopted EEES, which established cumulative annual energy savings requirements to make certain that energy efficiency and all of its associated public interest benefits would be realized. While UNS Electric is not currently meeting the EEES savings levels in terms of cumulative annual savings, due to a variety of reasons, SWEEP recommends that UNS Electric increase annual energy savings slightly in 2016 and 2017 in order to meet the cumulative annual energy savings levels in the EEES beginning in 2016, and then stay on track to achieve the savings levels throughout the remaining years of the EEES.

The cumulative annual energy savings requirements set forth in the EEES are as follows (expressed below as cumulative annual energy savings as a percent of retail energy sales in the prior calendar year):

- 2015: 9.50% cumulative annual energy savings
- 2016: 12.00% cumulative annual energy savings
- 2017: 14.50% cumulative annual energy savings
- 2018: 17.00% cumulative annual energy savings
- 2019: 19.50% cumulative annual energy savings
- 2020: 22.00% cumulative annual energy savings

Staff has estimated that UNS Electric may reach a cumulative annual savings percentage of 9% in 2015 compared to the EEES level of 9.50%, and Staff has recognized that UNS Electric may have a better opportunity to meet the 12.0% standard in 2016 with the implementation of new measures.[10] SWEEP recommends that UNS Electric increase its annual energy savings in order to meet or exceed the savings levels set forth in the EEES beginning in 2016. SWEEP estimates that annual energy savings in 2016 and 2017 would need to be about 37,500 to 40,000 MWh each year, or slightly higher than the 35,004 MWh UNS Electric and its customers achieved in 2014.[11]

Q. What should the UNS Electric energy efficiency budget be in order to fund and fully support the achievement of the higher energy savings in 2016, 2017, and the remainder of the decade?

A. SWEEP estimates that the total energy efficiency program budget for 2016 should be about $4.85 million – which is less than the $6.42 million approved by the Commission in Decision No. 75297 for 2015 and 2016 each year, and only slightly higher than the $4.79 million Commission-authorized budget for 2014 (note that these numbers for authorized and estimated program budgets do not include other costs such as the performance incentive and evaluation). SWEEP also estimates that the annual energy efficiency program budget for 2017 and each year for the balance of the decade should be about $5.0-5.5 million, reflecting an

[10] See Arizona Corporation Commission Decision No. 75297, page 26.
[11] UNS Electric Annual Demand Side Management Report for 2014.

assumption that the cost per kWh saved in future years will probably be somewhat higher than the $0.011 cost per lifetime kWh saved during 2014.

Q. What new or additional energy efficiency programs or measures should UNS Electric implement?

A. Significant energy saving opportunities for UNS Electric customers exist and remain untapped. For example, UNS Electric should implement a Home Energy Reports program, a Small Business Energy Reports program, and a Conservation Voltage Reduction program. The Home Energy Reports programs will provide additional opportunities to inform customers about other ways to save energy, and will generate additional leads for other program services in addition to saving energy through changes in customer actions and behavior. UNS Electric should also explore ways to integrate energy efficiency and demand response offerings (often called "integrated demand response") and provide new energy efficiency measures such as smart thermostats. Additional efforts at targeted outreach and tailored assistance should be offered to the main types of business customers in the service territory through the Commercial and Industrial (C&I) programs.

These and perhaps other additional energy efficiency programs and measures, and the specific details, should be considered, analyzed, and approved during the Implementation Plan process before the Commission. UNS Electric is scheduled to submit its next Implementation Plan during 2016, and the specific details regarding programs and measures for 2017 and beyond can and should be addressed in the Implementation Plan proceeding. The total level of energy efficiency program funding, which SWEEP proposes be recovered in base rates, should be determined in the rate case. In the interim, prior to the 2017 Implementation Plan proceeding, the additional funding for 2016 recommended by SWEEP above, if approved in the rate case, should be used to increase the number of customers served by the current Commission-approved programs and measures, and could be used to help support the ramp up of a Home Energy Reports program (if there is adequate progress in the field and demonstrated cost-effectiveness in early 2016), as well as support the implementation of emerging technologies.

The Costs of Energy Efficiency Programs Should be Recovered in Base Rates

Q. How can adequate funding to achieve higher energy savings for UNS Electric customers be ensured? What cost recovery approach should be used?

A. UNS Electric has positioned energy efficiency as an important, core resource to meet energy needs and load over the next decade. For example in 2024, energy efficiency will comprise more than 14% of UNS Electric's energy resource portfolio, up from 5.4% in 2014.[12] As a result, energy efficiency is one of UNS Electric's fastest growing energy resources for meeting customers' energy needs and UNSE-projected load growth over the next few years.

As a core resource meeting the real energy needs of customers at lowest cost, energy efficiency should be adequately funded through a stable, fully imbedded funding and cost recovery mechanism. In order to provide adequate and appropriate treatment for this core, fundamental energy and capacity resource, a total of $5 million of energy efficiency program funding should be expensed in base rates. As a core resource, it is appropriate for energy efficiency cost recovery to be in base rates rather than in a separate adjustor mechanism. Recovery of energy efficiency program costs in base rates will help ensure that the numerous public interest benefits of this core resource will be fully realized.

The demand side management (DSM) adjustor mechanism should still remain intact, but it should be used as an adjustor to recover or refund any energy efficiency funding amounts above or below the $5 million in base rates, needed to implement energy efficiency programs to meet the energy savings levels established by the EEES. In this way, the DSM adjustor mechanism would serve as a flexible means of accounting and adjusting for the market realities of actual energy efficiency spending not necessarily being exactly what was projected in the Implementation Plan budgets. The planned level of funding for energy efficiency programs would be recovered in base rates.

Note that SWEEP plans to expand on this recommendation to recover energy efficiency program costs in base rates in my direct testimony in the rate design phase of this proceeding. At this point SWEEP is notifying UNS Electric, the Commission, Staff, and the parties of this proposal from SWEEP, since the energy efficiency funding would affect the revenue requirement and the base rates, with additional details to be provided during the rate design phase.

Q. Has the Commission allowed energy efficiency program funding to be expensed in base rates previously?

A. Yes. In Commission Decision No. 67744, approving the settlement agreement to increase Arizona Public Service Company (APS) rates in 2005, an annual $10 million allowance for DSM costs was approved for inclusion within base rates. In 2006, the year directly following that decision, the Company spent $10.6 million on energy efficiency programs. Thus the $10 million of funding in base rates equated to more than 90% of energy efficiency program expenditures in that year.

[12] UNS Electric, 2014 Integrated Resource Plan, April 1, 2014, http://images.edocket.azcc.gov/docketpdf/0000152211.pdf.

Conclusion

Q. Does this conclude your testimony?

A. Yes. Thank you for the opportunity to provide my testimony on behalf of SWEEP.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

SUSAN BITTER SMITH, CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A RESONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	Docket No. E-04204A-15-0142

EXHIBIT
SWEEP-2
admitted

Rate Design Direct Testimony of

Jeff Schlegel

Southwest Energy Efficiency Project (SWEEP)

December 9, 2015

Rate Design Direct Testimony of Jeff Schlegel, SWEEP
Docket No. E-04204A-15-0142

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Introduction

Q. Please state your name and business address.

A. My name is Jeff Schlegel. My business address is 1167 W. Samalayuca Drive, Tucson, Arizona 85704-3224.

Q. For whom are you testifying?

A. I am testifying on behalf of the Southwest Energy Efficiency Project (SWEEP).

Q. Have you filed direct testimony in this docket previously?

A. Yes. I filed direct testimony on behalf of SWEEP on November 6, 2015, and errata on November 9, 2015.

Q. What is the purpose of your rate design direct testimony?

A. In my rate design testimony, I will address:

1. Why UNS Electric's proposal to increase the Basic Service Charge is not in the interest of customers and should be rejected.

2. Why UNS Electric's proposal to eliminate the third residential usage tier is not in the interest of customers and should be rejected.

3. Why UNS Electric should expand its Demand Side Management (DSM) offerings to help customers alleviate the impact of optional demand charges.

4. SWEEP's recommendations for the proposed Economic Development Rider.

5. SWEEP's recommendations on the Lost Fixed Cost Revenue Recovery (LFCR) Mechanism and why full revenue per customer decoupling is a superior option for addressing the broader set of issues that UNS Electric has raised in its rate case application.

6. Why energy efficiency as a core, fundamental resource meeting the real energy needs of customers at lowest cost should be afforded stability by expensing program funding in base rates. And

7. How UNS Electric customers can be provided with more useful information about utility costs and resources.

UNS Electric's Proposal to Increase the Basic Service Charge is Not in the Interest of Customers and Should be Rejected

Q. Please describe the UNS Electric, Inc., ("UNS Electric" or "Company") proposal to increase the customer basic service charge.

A. To recover a large portion of its proposed rate increase, UNS Electric proposes to increase mandatory fixed charges for several customer classes. Table 1 details the Company-proposed increases to the residential customer fixed charges.

Table 1. UNS Electric Proposed Increases to Customer Fixed Charges[1]

Customer Class	Current Customer Fixed Charge ($/month)	Proposed Customer Fixed Charge ($/month)	Proposed Increase (%)
Residential Service (RES-01)	$10.00	$20.00	100%
Residential Time of Use (RES-01 TOU)	$11.50	$20.00	74%
Residential Time of Use Super Peak (RES-01 TOU SP)	$11.50	$20.00	74%
Residential CARES (CARES-F)	$4.90	$9.00	84%

Q. Please describe the changes UNS Electric proposed for residential customers.

A. The Company proposes to increase the monthly fixed charge from $10.00 to $20.00 for Residential Service customers. This represents a 100% increase in the monthly fixed charge. The Company also proposes to increase the monthly fixed charge for Residential Time of Use and Residential Time of Use Super Peak customers by 74% — from $11.50 to $20.00. Finally, the Company proposes to increase the monthly fixed charge for Residential CARES customers by 84% — from $4.90 to $9.00.

Q. Does SWEEP support these proposed increases?

A. No, SWEEP does not. These increases are very significant, and SWEEP opposes them because the Company's proposal:

1. Would significantly reduce the amount of control residential customers have over their bills.

[1] These numbers were calculated using data provided by the Company in Revised Schedule H-3.

2. Includes costs that are not appropriate for inclusion in a customer fixed charge.

3. Would disproportionately impact low-use customers, many of whom are low-income customers.

4. Would mute the price signal to customers to conserve energy and become more energy efficient. And,

5. Would make UNS Electric's fixed customer charge one of the highest in the western United States.

Q. Please explain how the Company's proposal would reduce the amount of control residential customers have over their bills.

A. Customers have no ability to decrease mandatory fixed charges on their energy bills. However, they can control and mitigate costs recovered volumetrically by reducing their energy use. For this reason, a 100% increase in the fixed customer charge has a very significant impact on the portion of the bill that residential customers can control.

For example, consider an average residential customer using ~826 kWh per month.[2] Under the current rate structure for RES-01, this customer would pay $10.00 in customer fixed charges per month. Fixed charges would constitute 12% of the monthly bill; and volumetric charges would comprise 88%. Under the new proposed rate structure, this customer would pay $20 in fixed charges per month. Fixed charges would constitute 21% of the bill, while volumetric charges would comprise 79%.

By increasing the portion of the bill recovered by fixed charges while reducing the portion of the bill recovered volumetrically, the Company's proposal would significantly reduce the portion of the bill over which residential customers have control. Specifically, the residential customer under the proposed rate design would be able to control and mitigate 88% of the bill, but under the new rate design only 79% of the bill could be controlled by a customer.

See Table 2 for my calculations for a typical residential customer (RES-01).

[2] The average monthly usage amount was calculated from Schedule E-7 using the Company reported "Average Annual kWh Use" for the residential sector for the Test Year Ending on December 31, 2014.

Table 2: Impact of Customer Fixed Charges on Average Residential Customer Using 826 kWh (Rate RES-01) Under the Current and Proposed Rates[3]

Bill Component	Current Rate	Proposed Rate	Bill for Average Residential Customer Using 826 kWh/month Under Current Rate	Bill for Average Residential Customer Using 826 kWh/month Under Proposed Rate
Basic Service Charge	$10.00	$20.00	$10.00	$20.00
Energy Charge 1st 400kWh	$0.019300	$0.030810	$7.72	$12.32
Energy Charge 401-1,000kWhs	$0.034350	$0.050810	$14.62	$21.63
Energy Charge, all additional kWhs	$0.038499	$0.050810	$ -	$ -
Base Power Supply Charge, all kWhs	$0.064510	$0.049260	$53.27	$40.68
PPFAC	$(0.002139)	$ -	$(1.77)	$ -
Total Fixed Charges			**$10.00**	**$20.00**
Total Volumetric Charges			**$73.85**	**$74.63**
TOTAL Bill			**$83.85**	**$94.63**
Fixed Charge as % Total Bill			**12%**	**21%**

Q. Please explain your second objection.

A. UNS Electric's proposal represents a significant departure from previous rate cases regarding the methodology for allocating distribution system costs. Historically, the Company acknowledges that the customer fixed charge has been limited to metering, meter reading, service (service drop) to the specific customer, and customer service and billing – consistent with the Basis Customer Method (discussed below).[4] However in this proposal, UNS Electric has reclassified several distribution-related costs as "customer" costs. Indeed, a comparison between the Company's class of service allocation factors between this rate case and its last one, reveal that the Company has newly allocated several distribution-related cost categories to the

[3] These numbers were calculated using data provided by the Company in Revised Schedule H-3.
[4] See Direct Testimony of Craig A. Jones, Page 37, Lines 5-6

"customer" category when it has not done so in the past (e.g. zero dollars were allocated to the customer category in the past).[5]

Q. In SWEEP's view is the Company's reclassification and addition of other costs to the basis customer charge appropriate?

Q. No. The definition and composition of a customer fixed charge should be consistent with the definition contained in Bonbright's *Principals of Utility Rates*. Bonbright defines basic customer costs as those operating and capital costs found to vary with the number of customers regardless, or almost regardless, of power consumption.[6] These costs include only those related to metering, accounting, billing, and other direct customer service costs.

Consistent with Bonbright's *Principals of Utility Rates,* the Basic Customer Method should be used to determine the customer fixed charge. This method includes only the costs for direct basic customer service – e.g., the costs to hook up and maintain a customer's account. The basic customer costs should include the costs for the meter and service drop, meter reading, and billing. The customer fixed charge should not include grid-related costs of transmission and distribution plant, which are driven largely by the amount of customer usage and demand.

Q. UNS Electric argues conceptually that the customer fixed charge should be designed to recover the average unavoidable fixed costs that utilities incur each month.[7] What is your view of this argument?

A. UNS Electric's argument is erroneous and should be rejected. It is not required nor always appropriate for fixed costs to be recovered through fixed charges. Just because a cost is "fixed" does not make it a basic customer cost that should be included in a customer fixed charge. There is a big leap between "fixed costs" and "recovery of fixed costs through fixed charges," and there are many examples in the commercial world of fixed costs not being recovered through fixed charges. Oil refineries, hotels, and supermarkets all have significant fixed costs, but they recover these in volumetric prices by selling gasoline, hotel rooms, and groceries. Some may argue that fixed costs of a utility distribution system or larger utility system should be recovered in a fixed customer charge. This is not the intent of a basic customer charge. The intent of a basic customer charge is to recover direct customer costs that vary based on the number of customers, not the fixed or sunk costs of the utility system.

Q. Please explain your third objection.

A. UNS Electric's proposal will disproportionately affect low-use customers, many of whom are low-income customers.[8] Indeed, low-use customers will see a greater

[5] See Schedule G-7 from the Company's current and last general rate case.
[6] See Bonbright, James C. 1961. *Principals of Public Utility Rates*, page 347.
[7] See Direct Testimony of Dallas J. Dukes, Page 17, Lines 17-20

proportional increase in bills than high-use customers under increased fixed charges. For example, a customer using 500kWh per month will experience a 19% increase in the total bill under the proposed residential rates. A different customer using 1,500kWh will experience a 7% increase. This difference highlights the inequities inherent in increasing customer fixed charges.

Q. Please explain your fourth objection.

A. Increasing the basic service charge mutes the price signal to customers by reducing the amount of utility bill cost savings that customers experience when they conserve energy or become more energy efficient. As such, a higher basic service charge reduces the customer incentive to engage in energy efficiency opportunities because customers can affect only a smaller portion of their total utility bills. As a result, increasing the fixed charge portion of the customer's bill limits options for investment in energy efficiency for a customer.

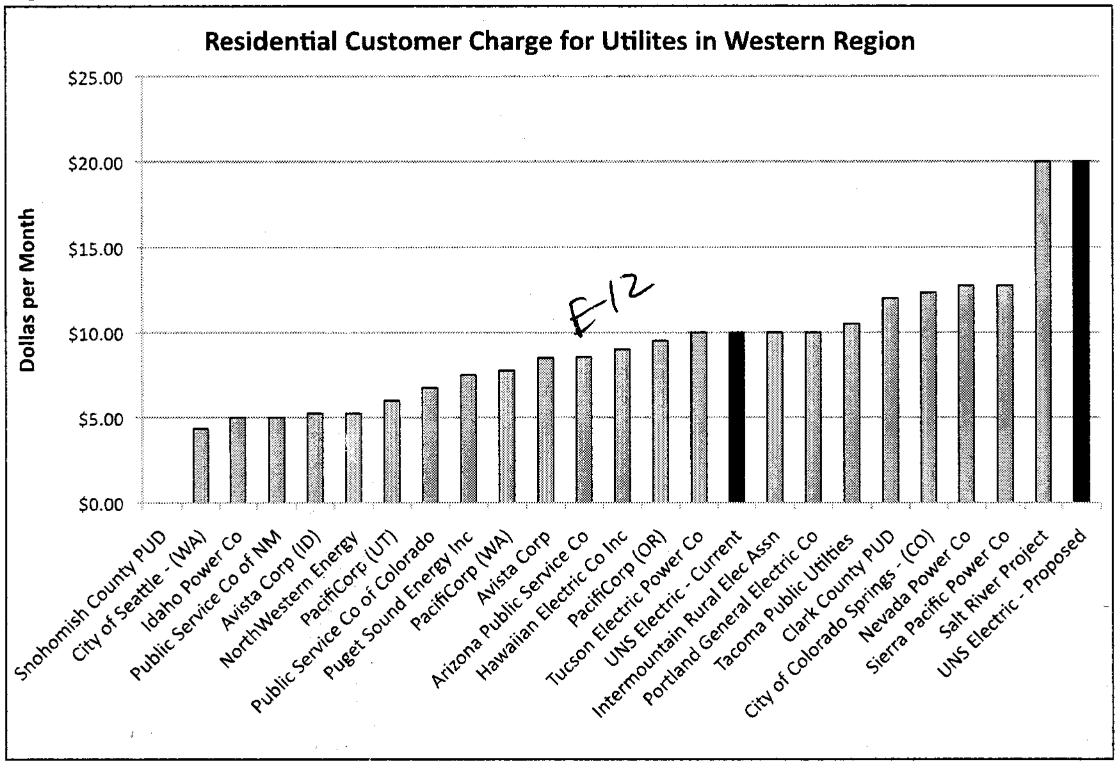
Commission policy should encourage and incent (through price signals and other means) customers to control their utility bills, and should provide opportunities and encouragement to reduce customer utility bills when lower cost options are available.

Q. Please explain your fifth objection.

A. Compared with several other utilities in the western region, UNS Electric has an above-average customer fixed charge. Increasing the residential fixed charge to $20 per month will make UNS Electric's fixed charge one of the highest in the region. See Figure 1.

[8] Average household electricity usage data by income level from the 2009 U.S. EIA Residential Energy Consumption Survey reveals that households with incomes below 150% of the federal poverty level use less electricity than households above the level. In 2009, Arizona low-income households used 25.1% less electricity than non-low-income households.

Figure 1: Residential Customer Charge for Utilities in the Western Region[9]



Q. Given these objections, what does SWEEP recommend? Zero Intercept

A. Based on my review of the Company's testimony and exhibits, it appears that the customer fixed charge for residential customers (RES-01), based on the inclusion of only those direct basic customer costs allowable under the Basic Customer Method, should be about $9.00. UNS Electric should either reduce the customer fixed charge or continue with the current $10.00 monthly customer charge for these customers.

More specifically, I recommend that UNS Electric should calculate and submit in this proceeding a schedule of proposed customer fixed charges for all sectors and rate classes that are derived using the Basic Customer Method with costs limited solely to direct basic customer costs.

UNS Electric's Proposal to Eliminate the Third Residential Usage Tier is Not in the Interest of Customers and Should be Rejected

Q. Please describe UNS Electric's proposal.

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[9] Customer charge and minimum bill are from utility specific residential single-phase customer active tariff as of October 3, 2015.

A. UNS Electric proposes to remove the third and highest volumetric usage tier from the standard residential rate (RES-01).[10] The Company would eliminate the 1,000+ volumetric usage tier and offer two usage tiers only — one for usage between 0-400kWh, and one for usage above 400kWh.

Q. Does SWEEP support this proposal?

A. No. SWEEP does not support this proposal. SWEEP believes it is appropriate to offer inclining block rates. Inclining block rates provide an important signal to customers to encourage energy conservation and the efficient use of energy, and discourage wasteful energy use.

Q. What does SWEEP recommend?

A. SWEEP recommends that the Commission reject UNS Electric's proposal. SWEEP supports the continuation of the three tiers.

UNS Electric Should Expand Demand Side Management Offerings to Help Customers Alleviate the Impact of Optional Demand Charges

Q. Is UNS Electric proposing to implement demand charges for residential customers?

A. Yes. UNS Electric is proposing to implement *optional* residential tariffs that include demand charges for residential customers who are not net metering customers. The proposed three-part rates would also include fixed customer charges and energy charges. Similar *optional* small business tariffs have also been proposed for small business for customers who are not taking service under the Net Metering Rider. UNS Electric is proposing mandatory demand charges for residential and small business net metering customers.[11]

Q. How should UNS Electric help customers – even those who opt-in – to manage and alleviate the impact of demand charges?

A. As part of any rate case proceeding, SWEEP believes it is essential to provide customers with more tools to manage and alleviate increasing energy costs caused by the rate increase itself and by any new pricing mechanisms that have been introduced. In this particular instance, SWEEP recommends that UNS Electric expand its Demand Side Management offerings to help customers alleviate the impact of optional demand charges.

Q. What are some new and expanded offerings that UNS Electric should offer?

10 See Direct Testimony of Dallas J. Dukes, Page 4, Lines 6-8.
11 See Direct Testimony of Dallas J. Dukes, Page 27, Lines 19-22.

A. UNS Electric's existing energy efficiency programs offer a great platform that should be leveraged to help customers alleviate the impact of demand charges. For example, UNS Electric's energy efficiency pool pump rebates could be leveraged to deliver a pool pump demand response program. UNS Electric should also look to programs implemented by other utilities in the southwest. For example, NV Energy's integrated energy efficiency and demand response smart thermostat program has delivered air conditioning savings of 11% while also delivering significant demand response capacity.[12] Home energy report programs have also successfully delivered demand savings.[13]

Q. What does SWEEP recommend?

A. SWEEP recommends that UNS Electric develop a DSM customer-peak-demand-reduction proposal as part of this rate case and be required to implement new DSM offerings prior to the implementation of new demand charges so that customers have a suite of tools available to them to manage demand charges.

UNS Electric Should Demonstrate that the Economic Development Rider Will be Net Beneficial; and Participants Should be Required to Deploy Demand Side Management

Q. Please describe the Economic Development Rider proposed by UNS Electric.

A. UNS Electric is proposing an Economic Development Rider to "put the UNS Electric service territory in a better competitive position to attract and expand business load."[14] The Economic Development Rider would provide a bill discount to qualifying additional load from new or expanding business over a 5-year period. The discount would begin at 20% and decline over time for qualifying "Economic Development" projects; and would begin at 30% and decline over time for qualifying "Economic Redevelopment" projects.[15]

Q. Does SWEEP have concerns about the Economic Development Rider?

A. Yes. It is unclear if the proposed Economic Development Rider will be net beneficial for all customers. For example if the Economic Development Rider drives new load during the system peak, it could add significant costs to the utility system.

Q. What does SWEEP recommend?

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12 See presentations in Arizona Corporation Commission Docket No. E-00000J-13-0375, "In the matter of the Commission's Inquiry into Potential Impacts to the Current Utility Model Resulting from Innovation and Technological Developments in Generation and Delivery of Energy," http://edocket.azcc.gov/Docket/DocketDetailSearch?docketId=18185, http://images.edocket.azcc.gov/docketpdf/0000153633.pdf

13 Ibid.

14 See Direct Testimony of Dallas J. Dukes, Page 31, Lines 18-19.

15 See Direct Testimony of Dallas J. Dukes, Pages 30-32.

A. SWEEP recommends that the Company be responsible for demonstrating that the Economic Development Rider would deliver more benefits than costs to the system. This demonstration should include the impacts of lost revenue from the proposed discount. In addition, any new or existing participating customer should be required to deploy Demand Side Management (DSM) to reduce system impacts and costs, and to help the customer lower their costs further through cost-effective DSM measures.

UNS Electric's Proposed Changes to its Lost Fixed Cost Revenue Recovery Mechanism

Q. Has UNS Electric proposed changes to its Lost Fixed Cost Revenue Recovery (LFCR) Mechanism?

A. Yes. UNS Electric has proposed several changes to the LFCR mechanism. These changes include allowing the recovery of lost fixed costs attributable to generation in the LFCR[16] and increasing the year-over-year cap from 1% to 2%.[17]

Q. What does SWEEP think of these proposed changes?

A. SWEEP supports the current LFCR mechanism and the costs included in that mechanism. Specifically, SWEEP does not support the addition of generated-related costs in the LFCR nor an increase in the year-over-year cap. UNS Electric has other opportunities to manage the amount and cost of generation resources, including through planning, market and procurement mechanisms. In addition, as I discuss further below, SWEEP believes that decoupling is a better and more effective mechanism than the LFCR to address the broader set of issues that UNS Electric has described in its rate case application, including the recovery of authorized costs and the under-recovery of fixed costs.

Decoupling to Reduce the Financial Disincentive to Electric Utility Support of Energy Efficiency

Q. Does UNS Electric experience a financial disincentive to its support of energy efficiency when its customers respond and become more energy efficient?

A. Yes. Traditional utility regulation links the utility's financial health to volumetric sales of electricity, resulting in a utility financial disincentive to support energy efficiency and other demand-side resources that reduce sales. Energy savings by UNS Electric customers (which are beneficial for customers, the economy, the utility system, and the environment) result in lower revenues for the Company and the under-recovery of Commission-authorized utility fixed costs. In general, this

[16] See Direct Testimony of Craig A. Jones, Page 76, Line 19
[17] See Direct Testimony of Craig A. Jones, Page 76, Line 24

financial disincentive can reduce utility support and enthusiasm for cost-effective resources such as energy efficiency programs that minimize the long-term costs of providing service. It could also impede potentially crucial utility support for building energy codes and other policies that reduce utility bills for customers and serve societal interests.

Q. Should a decoupling mechanism for UNS Electric be implemented to reduce the financial disincentive and encourage UNS Electric to support additional increases in energy efficiency through programs and other initiatives such as support of building energy codes?

A. Yes. The financial interest of UNS Electric should be better aligned with the interests of its customers by reducing financial disincentives to utility support of energy efficiency, thereby resulting in more energy savings and larger reductions in customer energy bills.

SWEEP supports decoupling mechanisms to address issues related to energy efficiency, e.g., when such mechanisms would be effective in substantially increasing customer energy efficiency and reducing the financial disincentive to electric utility support of increased energy efficiency.

SWEEP is not in favor of decoupling solely or primarily as a mechanism for the utility to recover its fixed costs. Therefore, in SWEEP's view the implementation of decoupling is premised on substantial increases in customer energy efficiency, for which the decoupling mechanism would reduce the financial disincentive to the utility of such increased energy efficiency. Because the Electric Energy Efficiency Resource Standard (EERS) will deliver substantial energy efficiency savings for UNS Electric customers, decoupling in this situation is justified.

Q. Does full decoupling completely and effectively reduce Company disincentives for the support of activities that eliminate energy waste, including activities not directly linked to the Company's energy efficiency programs?

A. Yes. Full decoupling completely and effectively reduces Company disincentives for the support of activities that eliminate energy waste. As such, full decoupling is important not only for full utility support of energy efficiency programs but also for activities that reduce sales but are not or may not be directly linked to the Company's portfolio of energy efficiency programs. This could include utility support for building energy codes; appliance standards; energy education and marketing; state and local government energy conservation efforts; and federal energy policies.

Q. Why is full revenue decoupling a policy option worthy of Commission consideration?

A. As I testified above, the financial interest of UNS Electric should be better aligned with the interests of its customers by reducing financial disincentives to utility support of energy efficiency, thereby resulting in more energy savings, total lower costs for customers, and larger customer energy bill reductions. Full revenue decoupling completely and effectively reduces utility company disincentives for the support of activities that eliminate energy waste. As such, full revenue decoupling is important not only for full, enthusiastic utility support of energy efficiency programs but also for activities that reduce sales but are not or may not be directly linked to the Company's portfolio of energy efficiency programs.

Q. Why is full revenue decoupling a superior option for the treatment of utility financial disincentives to energy efficiency than the Company's Lost Fixed Cost Revenue Recovery (LFCR) mechanism?

A. The Company's LFCR mechanism inadequately reduces utility disincentives to energy efficiency, and therefore results in fewer opportunities for customers to reduce their energy bills. Consequently, it discourages Company support of building energy codes, appliance efficiency standards, and state initiatives and legislation. The LFCR mechanism also represents an automatic rate increase. In contrast, because full revenue decoupling allows for rate adjustments in both a positive and negative direction, decoupling could result in either a credit or a charge on the customer bill.

LFCR does nothing to reduce UNS Electric's financial incentive to encourage customers to use more electricity – and the more customers waste energy, the more UNS Electric revenues and earnings increase. Also, under the LFCR, as the Arizona economy recovers and electric demand increases, UNS Electric revenues and earnings could also increase. Specifically, UNS Electric could retain all revenues higher than the authorized revenue levels, which would result in higher earnings. UNS Electric would also retain all revenues higher than the authorized revenue levels from increased electrification and electric vehicles. In contrast, full decoupling would provide a credit to customers for any revenues higher than authorized revenues (determined as authorized revenue per customer multiplied by the number of customers).

Q. What action does SWEEP recommend?

A. SWEEP recommends that UNS Electric develop and file a proposal for full revenue per customer decoupling in this rate case, which the parties and Commission should consider in this proceeding.

<u>Ensuring Adequate Funding and Stability for Energy Efficiency by Expensing Energy Efficiency Program Funding in Base Rates</u>

Q. Why should energy efficiency be adequately funded in base rates at stable levels?

A. As I testified in my direct testimony, energy efficiency is a core resource meeting the real energy needs of customers at lowest cost. In order to provide adequate and appropriate treatment for this core, fundamental energy and capacity resource, SWEEP recommends that a total of $5 million of energy efficiency program funding be expensed in base rates. As a core resource, it is appropriate for energy efficiency cost recovery to be in base rates rather than in a separate adjustor mechanism. Recovery of energy efficiency program costs in base rates will help ensure that the numerous public interest benefits of this core resource will be fully realized.

Q. Should the Demand Side Management (DSM) adjustor still remain intact?

A. Yes. As I explained in my direct testimony, the adjustor mechanism should remain intact and be used as an adjustor to recover or refund any energy efficiency funding amount above or below the $5 million in base rates. In this way, the DSM adjustor would serve as a flexible means of accounting and adjusting for the market realities of actual energy efficiency spending.

Providing Customers with Useful Information about Utility Costs and Resources

Q. Does SWEEP support providing customers with useful information about utility costs and resources on the customer bill?

A. Yes. Customers should be provided with useful information on utility costs and resources so that customers can fully understand how their money is being allocated and spent, and on which resources and costs. The customer bill itself should be simplified so that information is readily accessible and easy to understand for customers. There are two objectives here: providing a simple bill to customers, and providing useful and transparent information to customers.

Q. How can these two objectives be achieved without burdening or confusing customers?

A. These two crucial objectives – transparency and simplicity – could be achieved without burdening customers by:

1. Simplifying the regular bill by presenting fewer cost categories and treating all energy resources equally in terms of disclosure (for example, not including the Demand Side Management adjustor as a line item on the bill, which would be consistent with the treatment of other energy resources, whose costs are not expressly identified by the current bill format).

AND

2. Providing supplemental information on utility costs and energy resources to customers at all times via the web and quarterly or annually via a bill insert, email, and/or other communication – and not on the customer bill itself. This information could include a simple graphic that illustrates how each rate dollar is spent. If such a graphic were included, however, the costs associated with each and every energy resource would also need to be clearly delineated. In addition, all regular bills sent to customers would direct customers to the location on the

web where utility and energy resource costs, as well as the energy resource mix, would reside, with a phone number customers could call for specific details.

Conclusion

Q. Does this conclude your rate design testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

DOUG LITTLE, CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A RESONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	Docket No. E-04204A-15-0142

EXHIBIT
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SWEEP-3
admitted

Surrebuttal Testimony of

Jeff Schlegel

Southwest Energy Efficiency Project (SWEEP)

February 23, 2016

Surrebuttal Testimony of Jeff Schlegel, SWEEP
Docket No. E-04204A-15-0142

Table of Contents

Introduction

Q. Please state your name and business address.

A. My name is Jeff Schlegel. My business address is 1167 W. Samalayuca Drive, Tucson, Arizona 85704-3224.

Q. For whom are you testifying?

A. I am testifying on behalf of the Southwest Energy Efficiency Project (SWEEP).

Q. Have you filed direct testimony in this docket previously?

A. Yes. I filed direct testimony on behalf of SWEEP on November 6, 2015; direct testimony errata on November 9, 2015; and rate design testimony on December 9, 2015.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond to several recommendations and points made by other parties in this case, as well as changes to the UniSource Electric ("UNSE" or "Company") proposal for residential rate design. Specifically, I will address the following:

- The general concept of mandatory residential demand charges, which UNSE proposed in its rebuttal testimony.

- The UNSE proposal to institute a mandatory three-part rate for all residential customers.

- Comments made by several parties, specifically UNSE witnesses Overcast and Jones, regarding the SWEEP recommendation not to increase the customer fixed charge.

- Comments made by UNSE witness Smith in regards to the SWEEP proposal to move collection of some energy efficiency related costs to base rates.

- The need for UNSE to expand demand side management offerings that will help customers manage their energy usage and demand before any changes to rate design, including demand charges, are implemented.

- The need for the Commission's cost effectiveness test for energy efficiency to accurately account for the capacity and other benefits that energy efficiency delivers so that customers are not being denied opportunities to save on their utility bills.

Q: Do you offer specific recommendations to the Commission in your surrebuttal testimony?

A: Yes. I offer the following recommendations to the Commission in this case.

1. The Commission should reject proposals to force all residential customers to mandatory demand charges.[1] Residential customers should have options and choice when it comes to their electric bills. Forcing all residential customers to mandatory demand charges limits customers' options regarding how to control their bills. Customers should have options and should be able to choose a rate design that best fits their needs. The effects and implications of moving full classes of residential customers to a mandatory demand charge rate structure are not known. There is also no evidence in the record to indicate the ability of limited income customers to respond to residential demand charges. Finally, residential mandatory demand charges will disproportionately shift costs to lower usage customers, who are likely also lower income customers.

2. The Commission should deny the UNSE proposal specifically to force all residential customers to mandatory demand charges. The UNSE proposal is not fully developed in terms of which costs will be included in a residential demand charge. Currently significant differences exist between the Commission Staff and UNSE on which costs should be included. The Company does not have complete data available to fully understand and analyze this rate proposal, especially in terms of cost, revenue neutrality, and price responsiveness.

3. If, despite SWEEP's opposition, the Commission chooses to approve a mandatory three-part rate for residential customers, the demand charge should be based on the coincident peak demand and only include incremental peak related costs. The Commission should also be very careful in considering what costs will be included in the demand charge due to the likely precedential nature of this case. What costs the Commission allows UNSE to include in demand charges will likely have implications for rate design moving forward in the State of Arizona.

4. The Commission should deny the UNSE proposal to increase the customer fixed charge (the basic service charge) in this case. The Company's proposal is not cost justified by any standard. Arbitrarily increasing fixed customer charges for residential customers will reduce customer control over electricity bills and reduce the customer incentive to pursue energy efficiency to reduce their utility bills. This mandatory fixed charge is antithetical to the state policy goal of

[1] While SWEEP focuses its concerns about mandatory demand charges on the appropriateness and effectiveness of such mandatory charges for residential customers, many of the same concerns apply for small business customers.

increasing cost-effective energy efficiency in order to reduce total customer costs.

5. The Commission should order UNSE to provide customers with more tools to manage and alleviate increasing energy bills caused by the rate increase itself and by new pricing mechanisms. These tools give customers more choice. The tools should be offered and widely available to customers before any new rates and new pricing mechanisms are implemented.

6. The Commission should order the Company to consider greater use of time varying rates for residential customers as an alternative to a mandatory demand change. This structure would allow UNSE to promote state policy goals of increasing energy efficiency, and send customers appropriate price signals related to cost of service and opportunities to reduce their utility bills.

7. The Commission should direct UNSE to recover energy efficiency costs in base rates.

Mandatory Residential Demand Charges

Q. Is SWEEP supportive of residential demand charges?

A. No, not as proposed in this proceeding. SWEEP has several concerns related to the design and implementation of residential demand charges. A poorly designed residential demand charge may not be cost based and does not provide adequate price signals to customers.

Q. Do you believe residential demand charges convey the proper price signals to customers?

A. No. As noted in an article cited in Dr. Faruqui's testimony, demand charges do not convey the correct marginal price signals to customers.[2] This rate approach is also not cost based because the only distribution system component sized to individual customer demands is the final line transformer.[3] Distribution circuits are sized to the group demand, and generation and transmission are developed based on system peak demands and system load shapes. Including in demand charges significant costs that are not sized to individual customer demands will likely overcharge some customers while under charging others.

[2] Stokke, A. V., G. Doorman, and T. Ericson. 2009. *An Analysis of a Demand Charge Electricity Grid Tariff in the Residential Sector.* Discussion Papers No. 574 January 2009, Statistics Norway, Research Department.

[3] Lazar, J. and W. Gonzalez. 2015. *Smart Rate Design for a Smart Future.* Regulatory Assistance Project.

Q. What other concerns does SWEEP have regarding mandatory residential demand charges?

A. SWEEP is concerned with the ability of customers to respond to residential demand charges, especially mandatory demand charges. It is more complex for a customer to understand how to reduce demand to control their bill. Most utilities have excluded small commercial customers (under 20 kW demand) from three-part rates for this reason.

There are a number of factors customers will need to understand and consider while making changes to reduce demand. For example, customers will need to understand the demand draw of each appliance and device in their home; the actions of individual household members over the course of a day; how these events interrelate at any given time; and how demand could be reduced. It is also unclear which customers will have the ability to respond at all, especially if a demand charge is based on non-coincident peak. For most customers, it would be burdensome to respond to all hours in a month. One single short-duration event could cause a large spike in a customer's bill. For example, an apartment resident with an electric water heater, hair dryer, coffee maker, and range operating simultaneously might experience a 15-minute demand of 10 kW, even though their contribution to the system diversified peak demand is less than 1 kW.

UNSE has no experience communicating this type of rate design to residential customers. The Company has no demonstrated record communicating this type of rate design to customers so they can fully understand how it works and how they may respond.

Finally, there is no evidence in the record to indicate whether or not customers will be price responsive to the new rate structure. If in fact customers are not able to respond, the proposed mandatory demand charges will be nothing more than an unavoidable cost for customers. In this situation, the demand charge presents the same problems as a high fixed charge which I discuss further below and which Staff witness Broderick opposes.

Q. Is SWEEP concerned about any specific customer class's ability to respond to demand charges?

A. Yes. SWEEP is especially concerned with the ability of limited or low income customers to respond to this type of rate design. Residential demand charges are essentially a high fixed charge for those customers who are unable to respond. Given that high fixed charges disproportionally harm low income and low usage customers, these customers will be further harmed by a mandatory residential demand charge.

Q. What percentage of UNSE's service territory is considered low or limited income?

A. It is difficult to determine exactly how many residential customers could be described as limited or low income customers. According to discovery responses to Staff, UNSE has not conducted such a study to determine income distribution versus consumption levels. The Company did provide the following information, presented in Figure 1. As the figure shows, the majority of customers, 73.4%, fall below the category described as "midscale" in regards to income level. However, given that the table lacked detailed descriptions for income level labels, it is unclear what is meant by each level. The only take away one could make from this table is that the majority of UNSE's customers fall below the average or "midscale" income level.

STF 2.085

Rate Design: Please provide any studies, investigations, analyses or reviews performed by or for the Company that considered, evaluated or reviewed the income distribution versus consumption by rate schedule.

RESPONSE:

No specific study or evaluation was made that responds to this question. However, UNS Electric did create a table with historical data in it utilizing November 2013 through October 2014 to evaluate the percentage of customers falling within some very general income levels.

UNSE

Income Level (High to Low)	Percentage of Customers	Percentage of kWh (2013)	Cumulative Percentage of Customers	Cumulative Percentage of kWh (2013)
Wealthy	0.4%	0.7%	0.4%	0.7%
Upscale	3.5%	4.9%	3.9%	5.6%
Upper Mid	15.2%	19.2%	19.1%	24.8%
Midscale	1.4%	1.7%	20.5%	26.6%
Lower Mid	37.0%	38.7%	57.5%	65.3%
Downscale	41.9%	34.3%	99.5%	99.6%
Low Income	0.5%	0.4%	100.0%	100.0%
Grand Total	100.0%	100.0%		

Figure 1. Source: STF 2.085

Q. Please respond to statements presented by Company witness Overcast in rebuttal testimony related to the evidence of customer response to mandatory demand charges.

A. In rebuttal, Mr. Overcast cites the implementation of mandatory demand charges for a small rural electric cooperative in Kansas, the Butler REC (total of 7,500 customers, 6,500 residential) as evidence that residential customers can respond to mandatory demand charges.

Q. Do you agree with Mr. Overcast's assertion that the evidence presented in HEO-5 is conclusive evidence that residential customers can respond to mandatory demand charges?

A. No, not at all. This study does not provide any conclusive evidence on the ability of customers to respond to mandatory demand charges. Although the Managers report in HEO-5 did indicate Butler REC members were receiving a refund for reduced operation costs, there is no conclusive information in this document to support Mr. Overcast's assertion about customers' ability to respond. There is also nothing in this exhibit that demonstrates savings have resulted from the mandatory demand charges, only speculation. It is also worth noting if the intent of demand charges is to reduce peak demand, the use of a time varying rates is an efficient and effective way to meet this goal.

Q. Is the mandatory demand charge described by Mr. Overcast comparable to the rate structure proposed by UNSE in rebuttal testimony?

A. No, it is not. While the final details of the proposed UNSE rate structure seem unclear at this point, the approach to billing demand in this example (billing actual demand in July and August and billing the highest of the actual monthly demand or minimum demand for September to June) is quite different than the UNSE proposal.

Q. Arizona Public Service Company (APS) witness Dr. Faruqui also testified in support of a three-part rate structure and cited several studies to demonstrate the ability of customers to respond to this type of rate. Do you agree with Dr. Faruqui's testimony on this issue?

A. No.

Q. Can you please discuss the studies presented by Dr. Faruqui in his direct testimony?

A. Dr. Faruqui presented four studies in his testimony that specifically address customer price responsiveness to demand charges. The first three studies did not include any information on the customer sample demographics and income levels. The fourth study presented a population profile for the customers in the study. The average home value for the group on demand charges was 51% higher than the total system customer average. The group on demand charges was also far more likely to own central air conditioning, a second freezer or refrigerator, and a dishwasher; in Arizona, this group would also be more likely to own a swimming pool. All of these items could be considered luxury items. While the population profile didn't include average household income for the total system, the increased presence of luxury items and a 51% higher value average home indicate the income level of these customers greatly surpasses that of the average customer.

Q. Did Dr. Faruqui present evidence regarding how low or limited income customers respond to residential demand charges?

A. As it relates to low or limited income customers, Dr. Faruqui did not present adequate evidence to demonstrate how low or limited income customers will respond to mandatory demand charges. It is unknown how low or limited income customers in

UNSE's service territory may respond to demand charges. The price responsiveness of limited income customers is especially critical in this case because the majority of UNSE's customers fall below the average or "midscale" income level.

Q. Why does income level matter in a discussion of residential demand charges?

A. There are several reasons why income level matters. The ability of customers to respond to changes in rates is dependent on a number of different factors, including socioeconomic factors such as income level. All of the evidence presented in this case regarding customers' ability to respond appears to be based on higher than average income customers. A swimming pool pump can be curtailed for a few hours without adversely affecting the customer's lifestyle; a refrigerator cannot – the frozen food melts. For a limited income customer who may not be able to respond, the demand charge simply becomes an unavoidable fixed charge. And the majority of the residential customers in the UNSE service territory have income levels below the average or midscale level.

Q. Are there studies available that have attempted to provide insight into how low or limited income customers will respond to demand charges?

A. No, not to my knowledge. Dr. Faruqui cites four studies (based on three different pricing experiments). None of these studies provide any insight into the low income customer response. The studies are also based on volunteers with higher than average usage. Two of these experiments are quite old and the third is from Norway (which has a climate that is not comparable to Arizona). The other 18 utilities that have instituted demand charges for residential customers are voluntary charges. As Mr. Ryan Hledik (a colleague of Dr. Faruqui's at the Brattle Group) noted in a recent presentation, new research is necessary to better understand how customers will respond.[4]

His firm, Brattle Group, has estimated that TOU rates will produce about a 10% reduction in coincident peak demand, that Critical Peak Pricing rates will produce about a 30% reduction in coincident peak demand, and that demand charges will produce only a 1.7% reduction in coincident peak demand. This tells us that time-varying rates, not demand charges, are the right strategy.[5]

Q. Dr. Faruqui cites 18 utilities in the United States that currently have residential demand charges. Do any of these cases offer evidence to support price responsiveness to demand charges for limited income customers?

[4] Hledik, R. The Top Ten Questions about Residential Demand Charges. Presentation at the EUCI Residential Demand Charges Symposium, May 2015.
http://www.brattle.com/system/publications/pdfs/000/005/171/original/The_Top_10_Questions_about_Demand_Charges.pdf?1431628604

[5] Ibid.

A. No, not that I'm aware of. According to the recent presentation by Ryan Hledick of the Brattle Group enrollment has been quite low and the typical enrollee uses at least two times more energy than an average customer.[6] The majority of customers enrolling in residential demand charges have been high users who likely have above average incomes and the ability to respond to the changes in rate structure. If the Commission approves mandatory residential demand charges, the UNSE residential customer class will become a testing ground for how different residential customers respond to mandatory demand charges as no evidence currently exists to understand how moderate and low income customers will respond.

Q. Do any of the 18 utilities impose mandatory demand charges on all residential consumers?

A. No. Each has the demand charge rate as an optional rate. In the case of APS, which has a relatively large number of residential customers with demand charges, APS has targeted this rate to high-use customers who are likely to have curtailable loads like central air conditioning and swimming pools. These customers also benefit from the fact that the inclining block rate, which would otherwise be adverse to large-use customers, does not apply to the demand charge tariff.

The Company's Proposal for Mandatory Demand Charges Should be Rejected

Q. Please describe the Company's proposal for residential rate design, specifically three-part rates, in this case.

A. Initially, the Company proposed mandatory three-part rates (including demand charges) for all residential and small commercial new distributed generation customers and optional three-part rates for all other residential and small commercial customers. In rebuttal, the Company changed its position, instead requesting mandatory three-part rates for all residential and small commercial customers. The Company's proposal is based on a recommendation made by Staff in direct testimony, but does include several changes from Staff's proposal. These changes include: using a minimum 15% load factor for calculating a demand charge, and to recover generation costs through the demand charge, instead of distribution costs. However, the Company has not filed a revised tariff for the proposed rates and it is unclear exactly how UNSE intends to bill customers.

Q. Please discuss the differences between the UNSE rebuttal position and Staff's recommendations regarding the implementation of three-part rates.

A. The UNSE and Staff proposals for three-part rates are significantly different. The most significant of these differences is which costs are to be included in the demand charge. The Company initially requested the demand charge to be billed on a non-

[6] Ibid.

coincident peak basis and only include the distribution related costs. However, in rebuttal the Company agreed to bill the demand charge based on a coincident peak basis (without defining the peak period), but stated the only costs recovered in this charge would be generation unit costs (and only 50% of these costs). The Company also clearly stated an intention to move all distribution, generation, and transmission unit costs into a demand charge.

Q. Does the Company acknowledge the problem of insufficient data available in this rate case to properly design revenue neutral rates for residential customers?

A. Yes. In rebuttal testimony, the Company outlined a general idea of what guidelines the Commission should consider in a transition period. Essentially, the Company proposed leaving the docket open to make corrections to specific rates (up or down) and billing determinants as the Company continues to collect actual data following the installation of the remaining demand meters.[7] UNSE also understands its rate design is not fully developed and intends to "collect and analyze billing data to determine if any rate design changes are necessary prior to billing customers under these three-part rates."[8]

Q. Is SWEEP supportive of this approach?

A. Definitely not. The Commission should not approve a radically different rate design on partial information. There is no other investor owned utility of its size with a mandatory three-part rate design. This approach also provides uncertainty to customers as rates could likely change several times in a short time period, especially considering UNSE is approaching the three-part rate as a temporary step to moving the majority of costs into the customer charge and demand charges. Such large changes in rate design are unwise. Rate changes should be gradual. This is one of Bonbright's fundamental principles of rate design. Moving from a two-part rate to a transition two-part rate with fewer tiers, to a three-part rate with a $5 demand charge, to a three-part rate with what might be a significantly higher demand charge in the near future conflicts with this principle.

Q. What is SWEEP's recommendation for the Commission in this case?

A. SWEEP recommends the Commission reject the UNSE rebuttal request to implement a mandatory three-part rate for the residential customer class. However, SWEEP does not oppose the Company offering a voluntary three-part rate. The voluntary three-part rate will allow the Company to become familiar with how to communicate with customers regarding this rate design. The Company will also be able to better understand the customer willingness or interest in this rate structure.

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[7] *See* Jones rebuttal at 7, lines 20-24.
[8] *See* Dukes rebuttal at 13, lines 2-5.

The Commission Should Reject the UNSE Proposal to Increase the Residential Customer Fixed Charge

Q. Please describe the Company's proposed shift for residential customer charges in this case.

A. Initially, the Company proposed increasing the residential customer charge from $10 to $20 per month. Then, in rebuttal the Company suggested it would reduce this proposal to $15 per month if the Commission were to approve a mandatory three-part rate structure advocated by Staff and supported by APS with modifications from UNSE. These modifications were discussed in earlier sections of this testimony.

Q. What method did the company rely on to determine the initially-proposed $20 per month customer charge for residential customers?

A. It appears the Company did not rely on any specific method, but instead argues it should be able to collect all "fixed" costs in the customer charge. In testimony, the Company presented a customer charge of $14.73 based on the minimum system method for allocating distribution system costs.[9] The Company's proposal of $20 is not based on any established method accepted by this Commission or any other. Instead of relying on decades of established ratemaking precedent, methods, and principles, the UNSE proposed customer charge in this case appears to be movement towards straight fixed variable rate design in which all "fixed" costs are collected in a fixed charge. The proposal is also a departure from the method used in the last rate case in which the Company relied on the basic customer method to determine the customer charge.

Q. In your opinion, which costs should be included in a residential customer charge?

A. As I noted in my direct testimony in this case, the costs collected in the customer charge should be based on the Bonbright definition of customer costs, which is the "operating and capital costs found to vary with the number of customers, regardless, or almost regardless, of power consumption."[10] This approach is more commonly known as the basic customer method and usually only includes only the costs associated with customer service, meters, and service line drops. This approach also appears to be the method the Company relied on in both the 2009 and 2012 rate cases to allocate costs between customer and demand for the distribution system.

Q. Have other parties testified on the originally-proposed $20 customer charge?

A. Yes, several other parties have testified on this issue. Staff agrees the customer charge should be "narrowly focused on the cost of a meter, the costs of customer service, and

[9] *See* UNSE Response to STF 2.057, Schedule G-6-1, line 23.
[10] *See* Bonbright, James C. 1961. Principles of Public Utility Rates. p. 347.

billing, and the cost of a service line."[11] Staff also states addressing the under recovery of utility fixed costs in a customer charge is not appropriate for several reasons, including such an approach would "eliminate nearly all customer ability to control or reduce electric bills… and would be a major step backwards."[12] I agree with this logic; however, it is inconsistent with Staff accepting the UNSE proposal to include minimum system costs and supporting a $15 a month customer charge.

APS witness Faruqui also opined on the customer charge. As part of his proposal for three-part rates, Dr. Faruqi states the monthly service charge "should be designed to recover fixed costs such as metering, billing, and customer care."[13] Dr. Faruqui goes on to say that sometimes this charge also covers the cost of the line drop and associated transformer.

Q. Did APS witness Faruqui explicitly comment on the methodology used by UNSE to propose a $20 customer charge?

A. No. However, the costs described by Dr. Faruqui in his explanation clearly do not include costs associated with minimum system or other system fixed costs. Dr. Faruqui argues these costs should be collected in a demand or capacity charge.

Q. Please respond to the rebuttal testimony of Company witness Jones regarding your direct testimony on the issue of customer charges.

A. Company witness Jones responded to an exhibit in my direct testimony showing UNSE would have one of the highest customer charges in the region if the Commission were to approve a $20 per month charge. He points to three cooperative utilities in Arizona with an equally high customer charge. I would note that all three of these companies are cooperatives and all three are significantly smaller service companies with much more rural service territories than UNSE. Furthermore, two of the three companies have fewer than 2,500 customers in total. A sparsely populated rural system should not be compared with a system centered on Kingman and Lake Havasu City.

I don't believe this to be a valid comparison. I would also further point out that in a survey of residential rates for 160 utilities in the United States, only 8 companies have a higher customer charge than the Company's proposed $20. This is 5% of the total number of companies. Of this 5%, five of the eight companies are cooperatives. Finally, the 160 companies surveyed represent nearly 80% of the residential customers in the United States. The median customer charge in this review is $9.50, lower than the UNSE current $10 customer charge and far below the revised proposed $15 charge and UNSE's originally-proposed $20.

[11] *See* Broderick direct at 9, lines 8-9.
[12] *See* Broderick direct at
[13] *See* Faruqui direct at 11, lines 7-9.

Q. In your opinion, why are most customer charges nationally lower than the current UNSE $10 charge and significantly lower than the revised (rebuttal or Staff) proposed $15 or the originally proposed $20?

A. There are several explanations, most of which have been discussed in previous testimony in this case. High customer charges reduce customer control over utility bills, reduce customer incentive to conserve electricity and engage in UNSE's energy efficiency programs, and disproportionally impact low usage customers (many of which also happen to be low income customers). Finally, based on rate design principles, increased customer charges (especially those which attempt to include demand related system fixed costs) are simply not cost justified.

Q. Please summarize Company witness Overcast's response to the SWEEP recommendation to use the basic customer method to determine the customer charge.

A. Mr. Overcast claims "the basic customer method is not a method for calculating the customer component of costs because it fails to reflect any costs more than the meter, service, and direct customer accounting costs."[14] He further goes on to state that the method is a results driven methodology to lower costs for smaller customers. Mr. Overcast asserts several FERC accounts (364-368) should be allocated to both customer and demand. Finally, he states his opinion that the basic customer method should never be considered a viable alternative for calculating a customer charge because it does not include fixed costs of the distribution system.

Q. Do you agree with Mr. Overcast's opinion?

A. No, I do not. Mr. Overcast fails to recognize customer costs, by definition, do not include fixed costs of the distribution system. This principle is clearly articulated in Bonbright's *Principles of Public Utility Rates* and in Bonbright's own definition and explanation of customer costs (and his rejection of allocating minimum system costs to the customer). What Mr. Overcast is describing is similar to the minimum system method, which does not provide cost justification for the Company's $20 proposal nor the $15 revised proposal.

Q. Mr. Overcast relies on the NARUC Cost Allocation Manual to justify the use of the minimum system method to determine the customer charge. Do the majority of states rely on this method?

A. No, most states do not use the minimum system method. As a published report prepared for NARUC stated "the most common method used is the basic customer method which classifies all wires, transformers, and poles and demand related, and meters, meter reading and billing as customer related. This approach is used by more

[14] *See* Overcast rebuttal at 37-38, lines 20-22, 1-4.

than 30 states."[15] Therefore, the use of the basic customer method is supported by Dr. Bonbright, most state commissions, and is a generally accepted rate design principle.

Q. Does Mr. Overcast provide any cost based evidence to justify the Company's proposal for a $20 basic customer charge?

A. No, he does not. Mr. Overcast spends significant time arguing why the basic customer method should not be considered as a method for determining a customer charge. He relies on portions of the NARUC Cost Allocation Manual to assert the customer allocated costs of FERC accounts 364-368 should be included in a customer charge. What Mr. Overcast fails to address is the minimum system method does not justify the Company's proposal of $20 per month. By my estimation, the minimum system method doesn't even justify Staff's proposed $15 per month.

Q. Have you calculated a proposed residential customer charge for this case?

A. Yes. Using the basic customer method, I have calculated a customer charge of $4.32 per month. This charge is far below the Company proposal of $20 and is less than half of the current customer charge of $10. For this analysis, I included the A&G and O&M accounts associated with customer costs specifically associated with meters, billings, and customer service. I also calculated a return on rate base for the deprecation plant accounts associated with meters and services. I used the Company's proposed capital structure to determine the return on rate base. This calculation is attached as Exhibit SWEEP Surrebuttal-1.

Q. Does Mr. Overcast's recommended method for allocating distribution system costs comport with the Company's allocation of these costs in prior rate cases?

A. No, not at all. The Company's allocation of costs in previous rate cases seems to indicate a reliance on the basic customer method. A review of the three last UNSE rate cases, 2006, 2009, and 2012, demonstrate a shift in how the Company is allocating distribution system costs, with each year indicating that the Company included greater levels of cost in the customer category. Table 1 shows the Company proposed allocations for each rate case. As the table shows, the Company is allocating a greater share of costs to the customer category in each case. For example, in 2012, the Company allocated 6% of total distribution plant to customer. In the current 2015 case, this increased to 45%. The company did not begin to allocate costs associated with Accounts 364-368 until this current case.

[15] Weston, F. 2000. *Charging for Distribution Utility Services: Issues in Rate Design*. Regulatory Assistance Project.

Table 1. Distribution system related cost allocations in various UNSE rate cases.

	2006		2009	
	Demand	Customer	Demand	Customer
Distribution Plant	$ 157,617,750	$ 56,761,626	$ 379,273,529	$ 26,901,461
O&M Expense – Dist.	$ 3,956,148	$ 1,295,747	$ 4,740,215	$ 1,372,041
A&G Expense	$ 5,452,921	$ 2,268,948	$ 5,441,846	$ 1,786,950
	2012		**2015**	
	Demand	Customer	Demand	Customer
Distribution Plant	$ 305,250,491	$ 20,089,083	$ 191,641,961	$ 159,238,288
O&M Expense – Dist.	$ 4,542,572	$ 977,523	$ 3,230,233	$ 2,267,078
A&G Expense	$ 4,683,375	$ 3,795,376	$ 5,133,344	$ 2,816,002

Q. Are there other reasons to reject the Company's proposed increase customer charge?

A. Yes, other than the fact the proposal is not cost justified, there are several policy reasons to reject the Company's proposal, which I described in my direct rate design testimony. An unjustified increase in this charge will harm low income and other low use customers, discourage conservation, and is antithetical to statewide policies directing utilities to implement energy efficiency programs. Increasing customer charges will also reduce the level of control a customer has over their bill. While SWEEP is fully supportive of utilities recovering the authorized costs of service, increasing the customer charge (especially when not based on any established or appropriate method) to recover fixed costs that are not customer related is an ill-suited approach to this issue.

<u>Time Varying Rates are a Better Solution than Mandatory Demand Charges for Residential Customers</u>

Q. Do you have an alternate proposal for the Commission to consider addressing the Company's concerns?

A. Yes. I would recommend that the Commission direct UNSE to make greater use of time varying rate structures for residential customers. Time varying rate structures include both time of use pricing and critical peak pricing.

Q. Can you give an example of a rate design that you believe is cost-based?

A. I have not calculated such a rate to reflect the revenue requirement for UNSE. However, the illustrative rate design published in Smart Rates for a Smart Future provides an illustrative example of this type of rate design, meaning a rate design that is cost based.[16]

Illustrative Residential Rate Design

Rate Element	Based On the Cost Of	Illustrative Rate
Customer Charge	Service Drop, Billing, and Collection Only	$4.00/month
Transformer Charge	Final Line Transformer	$1/kVA/month
Off-Peak Energy	Baseload Resources + Transmission and Distribution	$.07/kWh
Mid-Peak Energy	Baseload + Intermediate Resources + T&D	$.09/kWh
On-Peak Energy	Baseload, Intermediate, and Peaking Resources + T&D	$.14/kWh
Critical Peak Energy (or PTR)	Demand Response Resources	$.74/kWh

This rate design would recover customer-related costs in a customer charge (resulting in a lower customer fixed charge), customer-specific capacity costs (the transformer) in a customer-specific demand charge, and all other costs in a time-varying energy rate. This would provide a stronger incentive for peak load reduction, and would avoid punishing low-use and low-income consumers.

SWEEP does not consider the illustrative example above to be a simple rate design or one that is appropriate for all residential customers. Again, customers should have options. Therefore, SWEEP suggests such a rate design could be explored as a voluntary or opt-in rate design.

Q. Please discuss the alternate proposal of implementing time varying rates for residential customers instead of a three-part rate structure including a demand charge.

A. Properly designed time varying rate structures offer many advantages to the three-part rate structure as proposed by UNSE in this proceeding. Instead of collecting costs only at the highest demand peak, time varying rates collect costs throughout the day. This better captures the fact that the costs of serving electricity to customers varies throughout the day. This approach not only collects costs from those imposing costs on the system, but it provides customers stronger price signals regarding the true system costs at any given time.

Q. SWEEP recommended that the Commission consider full revenue decoupling in direct testimony. Could you please elaborate on this recommendation?

A. In testimony and rebuttal, the Company expressed concerns regarding the ability to collect authorized revenues. SWEEP supports the ability of a utility to collect Commission-authorized revenues to provide service.

[16] Lazar, J. and W. Gonzalez. 2015. *Smart Rate Design for a Smart Future.* Regulatory Assistance Project.

Implementation of time-varying rates (or, for that matter, demand charges of any magnitude) may result in over-collection or under-collection of allowed costs as customers respond to the new rate design. Revenue decoupling would help ensure that the company recovers the authorized amount of revenue, independent of usage levels or characteristics – not less and not more.

In direct testimony, SWEEP recommended the Commission consider full revenue decoupling as a policy option to remove the Company disincentive to promote greater levels of energy efficiency. While SWEEP does not support the use of full revenue decoupling solely as a mechanism to ensure utility recovery of fixed costs, we believe full revenue decoupling can better align the interests of the utility and its customers.

The Commission Should Require UNSE to Move Collection of Energy Efficiency Funding and Related Costs to Base Rates

Q. Why should energy efficiency funding be recovered in base rates?

A. As I testified earlier, UNS Electric has positioned energy efficiency as an important, core resource to meet energy needs and load over the next decade. For example in 2024, energy efficiency will comprise more than 14% of UNS Electric's energy resource portfolio, up from 5.4% in 2014.[17] As a result, energy efficiency is one of UNS Electric's fastest growing energy resources for meeting customers' energy needs and UNSE-projected load growth over the next few years. As a core resource meeting the real energy needs of customers at lowest cost, energy efficiency should be adequately funded through a stable, fully imbedded funding and cost recovery mechanism. As a core resource, it is appropriate for energy efficiency cost recovery to be in base rates rather than in a separate adjustor mechanism. Recovery of energy efficiency program costs in base rates will help ensure that the numerous public interest benefits of this core resource will be fully realized.

Q. Do you agree with UNSE witness Smith that recovery of energy efficiency program costs in base rates will decrease customer transparency?

A. Absolutely not. As I testified before all energy resources should be treated equally in terms of disclosure and transparency. Recovering energy efficiency program costs through base rates would be consistent with the treatment of other energy resources, whose costs are not expressly identified in the current bill format.

[17] UNS Electric, 2014 Integrated Resource Plan, April 1, 2014, http://images.edocket.azcc.gov/docketpdf/0000152211.pdf.

The Company Needs to Offer New and Expanded Programs and Tools to Help Customers Alleviate Higher Utility Bills Before New Rates or Pricing Mechanisms are Implemented

Q. Why should UNSE expand customer offerings and tools in this proceeding?

A. As I described in my rate design testimony, as part of any rate case proceeding, SWEEP believes it is essential to provide customers with more tools to manage and alleviate increasing energy bills caused by the rate increase itself and by new pricing mechanisms. These tools give customers more choice; and need to be offered and widely available to customers before any new rates and new pricing mechanisms are implemented.

Q. Are these tools available in the UNSE service territory now?

A. While UNSE has some programs and tools; SWEEP believes that UNSE could and should be doing a lot more to help its customers manage their utility bills, energy use, and demand.

Q. What are some new and expanded offerings that UNS Electric should offer?

A. As I testified before, UNS Electric's existing energy efficiency programs offer a great platform that should be leveraged to integrate demand response and to help customers alleviate the impact of the rate increase and new pricing mechanisms. For example, UNS Electric's energy efficiency pool pump program should be leveraged to deliver a pool pump demand response program. UNS Electric should also look to programs implemented by other utilities in the southwest. For example, NV Energy's integrated energy efficiency and demand response smart thermostat program has delivered air conditioning savings of 11% while also delivering significant demand response capacity benefits.[18] UNSE does not have a comparable offering.

Q. What does SWEEP recommend?

A. Regardless of the outcome of this proceeding, SWEEP recommends that UNS Electric develop a DSM customer-peak-demand-reduction proposal as part of this rate case and be required to implement new DSM offerings prior to the implementation of the rate increase and any new pricing mechanisms so that customers have a suite of tools available to them to manage their bills.

[18] See presentations in Arizona Corporation Commission Docket No. E-00000J-13-0375, "In the matter of the Commission's Inquiry into Potential Impacts to the Current Utility Model Resulting from Innovation and Technological Developments in Generation and Delivery of Energy," http://edocket.azcc.gov/Docket/DocketDetailSearch?docketId=18185, http://images.edocket.azcc.gov/docketpdf/0000153633.pdf

The Commission's Cost Effectiveness Test for Energy Efficiency Should Reflect the Capacity and Other Benefits that Energy Efficiency Delivers in Order to Ensure that Customers are Not Being Denied Cost-Effective Opportunities to Save Money, Energy, and Demand on their Utility Bills

Q. Does the Commission require energy efficiency investments to be "cost effective"?

A. Yes. Only those energy efficiency opportunities found to be cost effective by Commission Staff are recommended for Commission approval.

Q. How does the Commission evaluate energy efficiency cost effectiveness?

A. The Arizona Commission uses an economic test called the "Societal Cost Test." The Commission has used this test since its 1991 Resource Planning decision. The Commission's Electric Energy Efficiency Rule also requires it. SWEEP strongly supports the use of the Societal Cost Test to evaluate energy efficiency opportunities; and the use of this economic test is standard practice nationally.[19]

Q. What does it mean for an energy efficiency opportunity to be "cost effective"?

A. When an energy efficiency program is "cost effective" its monetary benefits (such as the energy costs it avoids) exceed its costs (such as the costs to market and administer the program). By definition an energy efficiency program that is cost effective is a better economic investment for customers than the next best energy resource, which is typically a natural gas investment.

Q. Does SWEEP have concerns about the way that the Societal Cost Test is implemented in Arizona?

A. Yes. While SWEEP strongly supports the use of the Societal Cost Test to evaluate energy efficiency opportunities, we have concerns about the way the test is applied in Arizona. For many reasons, the application of the test in Arizona does not follow standard practice and does not meet the definition of the Societal Cost Test. For example, the application of the test in Arizona undervalues the role that energy efficiency plays in reducing capacity, among other issues.

Q. How does it undervalue the capacity benefits of energy efficiency?

A. There are many reasons why it does. First the carrying costs of capacity are excluded in the analysis. Excluding carrying costs artificially reduces the overall cost of capacity resources that energy efficiency avoids. By excluding carrying costs in the analysis, the analysis presumes that utilities purchase all of their supply side resources with cash. Needless to say, this is not common practice and does not reflect reality. Only by including the carrying costs in the analysis will the methodology accurately

[19] See March 18, 2014, Workshop on Energy Efficiency and Integrated Resource Planning

portray the full cost of generation capacity that energy efficiency avoids. In addition, the test does not employ a societal discount rate, which the Societal Cost Test requires by definition. Because a societal discount rate is not employed the capacity benefits of energy efficiency are more heavily are discounted than they should be.

Q. What does this mean for Arizona ratepayers?

A. It means that Arizona ratepayers are being denied cost effective energy efficiency opportunities that would reduce total energy costs for all customers and that would help them to manage their utility bills, energy use, and demand. As a result, Arizona ratepayers are paying higher utility bills than they should be paying. For example, SWEEP has observed that Arizonans are being denied certain air conditioning measures that are cost effective in other southwest states and even in the Northeast. This result is surprising because these other states have significantly less need to reduce cooling loads compared with Arizona.

Q. Do other stakeholders in Arizona share SWEEP's concerns?

A. Yes. In 2010 APS, UNSE, and various Demand Side Management (DSM) Collaborative Group stakeholders, including SWEEP and Western Resource Advocates (WRA) met and worked together to develop recommendations to standardize the implementation of the Societal Cost Test in Arizona based on standard national practice. These recommendations were filed with the Commission in a memorandum submitted by UNSE to the Commission in late 2010.

Q. Why are these recommendations relevant to this proceeding?

A. As I testified earlier, it is important and appropriate to ensure that customers have maximum access to energy efficiency opportunities so that they can manage higher utility bills caused by the rate increase itself and by new pricing mechanisms. It will also help to mitigate future rate increases.

That Arizona ratepayers are being denied cost effective energy efficiency opportunities that would help them to manage demand is of particular concern and relevance to this proceeding. If the issue of demand management is of such high importance that mandatory residential demand charges are being contemplated then the Commission should ensure that it is doing all that it can to support the deployment of offerings that help customers to reduce demand. It should also ensure that it is not actually contributing to the problem itself by limiting cost effective opportunities that would help customers to manage demand.

Q. What does SWEEP recommend?

A. As part of this proceeding, SWEEP recommends that the Commission adopt the recommendations put forth by SWEEP, UNSE, APS, and other stakeholders in the 2010 memorandum. Adoption of these recommendations will ensure that Arizonans are not being denied opportunities to reduce utility bills and that Arizonans have greater access to cost-effective tools to manage energy use and demand.

Conclusion

Q. Does this conclude your testimony?

A. Yes.

Exhibit SWEEP Surrebuttal – 1

UNS Customer Charge Quantification

Components of Customer Cost		**$/month**
Return	$ 751,087	$ 0.758
Depreciation	$ 183,209	$ 0.185
O&M	$ 144,107	$ 0.145
Meter Reading	$ 601,239	$ 0.607
Billing	$ 2,599,100	$ 2.622
	$ 4,278,742	$ 4.316

Electric Customer-Related Costs for PPL			Exhibit
Expenses	Account	Amount	Part 2
Meters	597	$ 362	
	586	$ 125,478	
	Depreciation	$ 38,338	
Services	587	$ 13,272	
	Depreciation	$ 138,521	
Meter Reading	902	$ 580,400	
Billing	903	$ 2,509,015	
Subtotal Expenses		$ 3,405,386	
Net to Gross on Expenses		96.5%	
Total Expenses		$ 3,527,655	
Rate Base			
Meters			
Plant In Service		$ 1,267,806	
Less Accumulated Depreciation		$ (315,573)	
Net Plant		$ 952,233	
Depreciation Expense		$ 38,338	
Services			
Plant In Service		$ 12,449,691	
Less Accumulated Depreciation		$ (7,310,404)	
Net Plant		$ 5,139,287	
Depreciation Expense		$ 138,521	
Meters		$ 952,233	
Services		$ 5,139,287	
Total Rate Base		$ 6,091,520	
Grossed Up Return	12.33%	$ 751,087	
Total Customer-Related Revenue Requirement		**$ 4,278,742**	
Annual Residential Bills		**991,284**	
$/Month		**$ 4.32**	

UNSE Bill Impacts Based on UNSE Rejoinder Testimony, CAJ-RJ-2 Schedule H-4

SWEEP Exhibit

Summary Below from UNSE Rejoinder, CAJ-RJ-2, Schedule H-4 (p. 1-3)

		Residential Service Transition vs. Current Rate			
Size	kWh	Current	Transition	Difference	% Change
Xsmall	111	$ 19.19	$ 24.46	$ 5.27	27.4%
Small	330	$ 37.33	$ 43.11	$ 5.78	15.5%
Medium	664	$ 68.96	$ 74.21	$ 5.25	7.6%
Large	1,144	$ 116.53	$ 122.49	$ 5.96	5.1%
Xlarge	2,162	$ 220.37	$ 237.72	$ 17.35	7.9%
Mean	830	$ 85.16	$ 89.96	$ 4.80	5.6%
Sum	983	$ 100.20	$ 104.60	$ 4.40	4.4%
Win	669	$ 69.48	$ 74.72	$ 5.24	7.5%
Annual		$ 1,018.12	$ 1,075.95	$ 57.83	5.68%

Winter (November thru April)

		Residential Service Demand vs. Transition Rate			
Size	kWh	Transition	Demand	Difference	% Change
Xsmall	100	$ 23.52	$ 24.58	$ 1.06	4.5%
Small	294	$ 40.05	$ 41.94	$ 1.89	4.7%
Medium	560	$ 64.31	$ 64.97	$ 0.66	1.0%
Large	914	$ 98.00	$ 95.11	$ (2.89)	-2.9%
Xlarge	1,653	$ 180.10	$ 156.89	$ (23.21)	-12.9%
AnnAvg	830	$ 89.96	$ 87.89	$ (2.07)	-2.3%
WinAvg	669	$ 74.72	$ 74.39	$ (0.33)	-0.4%

Summer (May thru October)

		Residential Service Demand vs. Transition Rate			
Size	kWh	Transition	Demand	Difference	% Change
Xsmall	117	$ 24.97	$ 26.95	$ 1.98	7.9%
Small	386	$ 47.88	$ 52.66	$ 4.78	10.0%
Medium	813	$ 88.39	$ 92.24	$ 3.85	4.4%
Large	1,395	$ 150.90	$ 145.26	$ (5.64)	-3.7%
Xlarge	2,471	$ 272.70	$ 241.56	$ (31.14)	-11.4%
AnnAvg	830	$ 89.96	$ 93.77	$ 3.81	4.2%
SumAvg	983	$ 104.60	$ 107.84	$ 3.24	3.1%

SWEEP Calculations Below Based on CAJ-RJ-2, Schedule H-4

Residential Service Transition (2-Part) Rate vs. Current Rate

kWh	Current Annual Bill	Average Bill Per Month	Transition Annual Bill	Average Bill Per Month	Annual Difference	Monthly Difference	% Change from Current
111	$ 230.34	$ 19.19	$ 293.52	$ 24.46	$ 63.18	$ 5.27	27.4%
330	$ 448.00	$ 37.33	$ 517.32	$ 43.11	$ 69.32	$ 5.78	15.5%
664	$ 827.49	$ 68.96	$ 890.52	$ 74.21	$ 63.03	$ 5.25	7.6%
1,144	$ 1,398.32	$ 116.53	$ 1,469.88	$ 122.49	$ 71.56	$ 5.96	5.1%
2,162	$ 2,644.45	$ 220.37	$ 2,852.64	$ 237.72	$ 208.19	$ 17.35	7.9%
830	$ 1,021.92	$ 85.16	$ 1,079.52	$ 89.96	$ 57.60	$ 4.80	5.6%
983							4.4%
669							7.5%
826	$ 1,018.12	$ 84.84	$ 1,075.95	$ 89.66	$ 57.83	$ 4.82	5.68%

Residential Service Demand 3-Part Rate (Annual) vs. Transition (2-Part) Rate

kWh*	Transition Annual Bill	Average Bill Per Month	Res Demand Annual Bill	Average Bill Per Month	Annual Difference	Monthly Difference	% Change from Current
109	$ 290.94	$ 24.25	$ 309.18	$ 25.77	$ 18.24	$ 1.52	6.3%
340	$ 527.58	$ 43.97	$ 567.60	$ 47.30	$ 40.02	$ 3.33	7.6%
687	$ 916.20	$ 76.35	$ 943.26	$ 78.61	$ 27.06	$ 2.26	3.0%
1,155	$ 1,493.40	$ 124.45	$ 1,442.22	$ 120.19	$ (51.18)	$ (4.27)	-3.4%
2,062	$ 2,716.80	$ 226.40	$ 2,390.70	$ 199.23	$ (326.10)	$ (27.18)	-12.0%
830	$ 1,079.52	$ 89.96	$ 1,089.96	$ 90.83	$ 10.44	$ 0.87	1.0%
826	$ 1,075.95	$ 89.66	$ 1,093.38	$ 91.12	$ 17.43	$ 1.45	1.62%

Residential Service Demand 3-Part Rate (Annual) vs. Current Rate

kWh*	Current Annual Bill*	Average Bill Per Month	Res Demand Annual Bill	Average Bill Per Month	Annual Difference	Monthly Difference	% Change from Current
109	$ 230.34	$ 19.19	$ 309.18	$ 25.77	$ 78.84	$ 6.57	**34.2%**
340	$ 448.00	$ 37.33	$ 567.60	$ 47.30	$ 119.60	$ 9.97	**26.7%**
687	$ 827.49	$ 68.96	$ 943.26	$ 78.61	$ 115.77	$ 9.65	**14.0%**
1,155	$ 1,398.32	$ 116.53	$ 1,442.22	$ 120.19	$ 43.90	$ 3.66	**3.1%**
2,062	$ 2,644.45	$ 220.37	$ 2,390.70	$ 199.23	$ (253.75)	$ (21.15)	**-9.6%**
830	$ 1,021.92	$ 85.16	$ 1,089.96	$ 90.83	$ 68.04	$ 5.67	**6.7%**
826	***$ 1,018.12***	***$ 84.84***	***$ 1,093.38***	***$ 91.12***	***$ 75.26***	***$ 6.27***	***7.39%***

Residential Demand Annual as Winter and Summer Average (six months of each)

* Slightly different usage levels for each group compared to the first table, based on the UNSE exhibits

tabbies® EXHIBIT
SWEEP-4
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

SUSAN BITTER SMITH, CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
DOUG LITTLE

EXHIBIT
UNS-Mart-1
admitted

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS	DOCKET NO. E-04204A-15-0142

TESTIMONY AND EXHIBITS OF

STEVE W. CHRISS

ON BEHALF OF

WAL-MART STORES, INC.

NOVEMBER 6, 2015

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Exhibits

Introduction

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Steve W. Chriss. My business address is 2001 SE 10th St., Bentonville, AR 72716-0550. I am employed by Wal-Mart Stores, Inc. as Senior Manager, Energy Regulatory Analysis.

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

A. I am testifying on behalf of Wal-Mart Stores, Inc. ("Walmart").

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. In 2001, I completed a Master of Science in Agricultural Economics at Louisiana State University. From 2001 to 2003, I was an Analyst and later a Senior Analyst at the Houston office of Econ One Research, Inc., a Los Angeles-based consulting firm. My duties included research and analysis on domestic and international energy and regulatory issues. From 2003 to 2007, I was an Economist and later a Senior Utility Analyst at the Public Utility Commission of Oregon in Salem, Oregon. My duties included appearing as a witness for PUC Staff in electric, natural gas, and telecommunications dockets. I joined the energy department at Walmart in July 2007 as Manager, State Rate Proceedings, and was promoted to my current position in June 2011. My Witness Qualifications Statement is included herein as Exhibit SWC-1.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE ARIZONA CORPORATION COMMISSION ("THE COMMISSION")?

A. Yes. I submitted testimony in Docket No. E-01345A-11-0224.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE OTHER STATE REGULATORY COMMISSIONS?

A. Yes. I have submitted testimony in over 135 proceedings before 36 other utility regulatory commissions and before the Missouri House Committee on Utilities, the Missouri Senate Veterans' Affairs, Emerging Issues, Pensions, and Urban Affairs Committee, and the Kansas House Standing Committee on Utilities and Telecommunications. My testimony has addressed topics including, but not limited to, cost of service and rate design, revenue requirement, ratemaking policy, qualifying facility rates, telecommunications deregulation, resource certification, energy efficiency/demand side management, fuel cost adjustment mechanisms, decoupling, and the collection of cash earnings on construction work in progress.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I am sponsoring the exhibits listed in the Table of Contents.

Q. PLEASE BRIEFLY DESCRIBE WALMART'S OPERATIONS IN ARIZONA.

A. Walmart operates 124 retail units and employs 34,798 associates in Arizona. In fiscal year ending 2015, Walmart purchased $772.4 million worth of goods and services from Arizona-based suppliers, supporting 19,248 supplier jobs.[1]

[1] http://corporate.walmart.com/our-story/locations/united-states#/united-states/arizona

Q. PLEASE BRIEFLY DESCRIBE WALMART'S OPERATIONS WITHIN THE COMPANY'S SERVICE TERRITORY.

A. Walmart has three stores that take electric service from UNS Electric, Inc. ("UNSE" or "the Company") primarily on the Large Power Service schedule ("LPS").

Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address aspects of UNSE's rate case filing and to provide recommendations to assist the Commission in its thorough and careful consideration of the impact on customers of the Company's proposed rate increase. Walmart will also file testimony in the cost of service and rate design portion of this docket.

Summary of Recommendations

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. My recommendations to the Commission are as follows:

1) The Commission should thoroughly and carefully consider the impact on customers in examining the requested revenue requirement and ROE, in addition to all other facets of this case, to ensure that any increase in the Company's rates is only the minimum amount necessary to provide adequate and reliable service, while also providing an opportunity to earn a reasonable return.

2) The Commission should closely examine the Company's proposed revenue requirement increase and the associated proposed increase in return on equity, especially when viewed in light of (a) the customer impact of the resulting revenue requirement increases and (b) recent rate case returns on equity ("ROE") approved by commissions nationwide. In addition, unless the Commission determines that UNSE has sufficiently and substantially demonstrated a significant change in the economic environment faced by the Company since the Commission's Decision No. 74235 in Docket No. E-04204A-12-0504, the Commission should approve an ROE no higher than the currently allowed ROE of 9.5 percent.

The fact that an issue is not addressed herein or in related filings should not be construed as an endorsement of any filed position.

UNSE'S Proposed Revenue Requirement Increase

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S PROPOSED ELECTRIC REVENUE REQUIREMENT INCREASE?

A. My understanding is that the Company proposes a $22.6 million increase to non-fuel revenues, based on a test year ending December 31, 2014. The Company proposes fuel and deferred accounting offsets to the increase which would decrease UNSE's overall revenues by approximately $5.8 million in the first year. The Company proposes that in year two their overall revenues reflect an increase of $3.5 million. *See* Direct Testimony of Dallas J. Dukes, page 5, line 23, to page 6, line 7 and Schedule A-1.

Q. ARE THE PROPOSED FUEL-RELATED OFFSETS RELEVANT TO THE COMMISSION'S CONSIDERATION OF THE MERITS OF UNSE'S PROPOSED BASE RATE INCREASE?

A. No. While it is undisputed that reductions from the fuel-related offsets benefit customers, those offsets are not relevant to the Commission's consideration of the merits of UNSE's proposed base rate increase. What is at issue in this docket is a proposed *permanent* base rate increase that will be in place regardless of the level of the Company's fuel cost and should be considered by the Commission on its own merits and not in conjunction with unrelated contemporaneous changes in other components of UNSE's retail rates.

Q. SHOULD THE COMMISSION GENERALLY CONSIDER THE IMPACT OF THE PROPOSED RATE INCREASE ON CUSTOMERS IN SETTING THE REVENUE REQUIREMENT CHANGES AND ROE FOR THE COMPANY?

A. Yes. Electricity represents a significant portion of a retailer's operating costs. When electric rates increase, that increase in cost to retailers puts pressure on consumer prices and on the other expenses required by a business to operate. The Commission should thoroughly and carefully consider the impact on customers in examining the requested revenue requirement and ROE, in addition to all other facets of this case, to ensure that any increase in the Company's rates is only the minimum amount necessary to provide adequate and reliable service, while also providing an opportunity to earn a reasonable return.

Return on Equity

Q. WHAT IS THE COMPANY'S PROPOSED ROE IN THIS DOCKET?

A. The Company is proposing an ROE of 10.35 percent based on a range of 10 percent to 10.6 percent. *See* Direct Testimony of Ann E. Bulkley, page 3, line 20 to line 23. This results in a proposed overall weighted average cost of capital of 7.67 percent. *See* Direct Testimony of Ketton C. Grant , page 8, line 11.

Q. ARE YOU CONCERNED THAT THE PROPOSED ROE IS EXCESSIVE?

A. Yes. I am concerned that the Company's proposed ROE is excessive, especially when viewed in light of (a) the customer impact of the resulting revenue requirement increases as I discuss above and (b) recent rate case ROEs approved by commissions nationwide.

Customer Impact

Q. IS THE COMPANY'S PROPOSED ROE HIGHER THAN THE IMPLICIT ROE APPROVED IN DOCKET NO. E-04204A-12-0504?

A. Yes. The proposed ROE of 10.35 percent represents an increase of 85 basis points from the ROE of 9.5 approved by the Commission in the Company's last general rate case. *See* Decision No. 74235, ¶31. As such, the Company's ROE proposal has a significant impact to customers.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF THE PROPOSED 85 BASIS POINT INCREASE IN ROE?

A. The revenue requirement impact of ROE alone on the Company's proposed rate increase is approximately $2.6 million. The requested increase related to ROE constitutes about 11.3 percent of the Company's base revenue increase request. *See* Schedule SWC-2.

Q. HAVE ANY OTHER STATES RECOGNIZED THE IMPORTANCE OF CONSIDERING RATEPAYER IMPACTS IN THE ROE DETERMINATION PROCESS?

A. Yes. While I am not an attorney, it is my understanding that the North Carolina Supreme Court determined that impacts on ratepayers from any proposed utility rate increase should be carefully considered in an ROE analysis for that utility. Specifically, the Court stated:

> "Given the legislature's goal of balancing customer and investor interests, the customer-focused purpose of Chapter 62, and this Court's recognition that the Commission must consider all evidence presented by interested parties, which necessarily includes customers, it is apparent that customer interests cannot be measured only indirectly or treated as mere afterthoughts and that Chapter 62's ROE provisions cannot be read in isolation as only protecting public utilities and their shareholders. Instead, it is clear that the Commission must take customer interests into account when making an ROE determination. Therefore, we hold that in retail electric service rate cases the Commission must make findings of fact regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility." *See State Ex Rel. Utils. Comm'n v. Cooper,*366 N.C. 484, 739 S.E.2d 541, 547 (2013) (emphasis in original).

This language is instructive for the Commission's consideration of the increase in ROE being requested by the Company in this case.

National Utility Industry ROE Trends

Q. IS THE COMPANY'S PROPOSED ROE HIGHER THAN THE AVERAGES OF THOSE APPROVED BY OTHER UTILITY REGULATORY COMMISSIONS?

A. Yes. The proposed ROE is higher than the average ROE approved by other utility regulatory commissions in 2012, 2013, 2014, and so far in 2015.

Q. WHAT IS YOUR UNDERSTANDING OF THE ROES APPROVED FOR ELECTRIC UTILITIES BY COMMISSIONS NATIONWIDE DURING THIS TIME PERIOD?

A. According to data from SNL Financial, a financial news and reporting company, the average of the 135 reported electric utility rate case ROEs authorized by state regulatory commissions to investor-owned electric utilities in 2012, 2013, 2014, and so far in 2015, is 9.85 percent. The range of reported authorized ROEs for the period is 8.72 percent to 10.95 percent, and the median authorized ROE is 9.80 percent. *See* Exhibit SWC-3.

Q. SEVERAL OF THE REPORTED AUTHORIZED ROES ARE FOR DISTRIBUTION-ONLY UTILITIES OR FOR ONLY A UTILITY'S DISTRIBUTION SERVICE RATES. WHAT IS THE AVERAGE AUTHORIZED ROE IN THE REPORTED GROUP FOR PARTIALLY OR FULLY VERTICALLY INTEGRATED UTILITIES LIKE THE COMPANY?

A. In the group reported by SNL Financial, the average authorized ROE for vertically integrated utilities from 2012 to present is 9.98 percent. *Id.* However, there is a declining trend for vertically integrated utilities from 2012 to present.

Q. PLEASE EXPLAIN.

A. The average authorized ROE for vertically integrated utilities in 2012 was 10.1 percent, in 2013 it was 9.97 percent, in 2014 it was 9.92 percent, and so far in 2015 it is 9.65 percent. It should be noted that so far in 2015, five vertically integrated utilities have been authorized ROEs of 9.53 or less. As such, the Company's proposed 10.35 percent ROE in this case is a move counter to broader electric industry trends.

Conclusion

Q. GENERALLY, WHAT IS YOUR RECOMMENDATION TO THE COMMISSION ON THE COMPANY'S PROPOSED INCREASE IN ROE?

A. The Commission should closely examine the Company's proposed revenue requirement increase and the associated proposed increase in return on equity, especially when viewed in light of (a) the customer impact of the resulting revenue requirement increases as I discuss above, and (b) recent rate case ROEs approved by commissions nationwide. In addition, unless the Commission determines that UNSE has sufficiently and substantially demonstrated a significant change in the economic environment faced by the Company since the Commission's Decision No. 74235 in Docket No. E-04204A-12-0504, the Commission should approve an ROE no higher than the currently allowed ROE of 9.5 percent.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Steve W. Chriss

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EXPERIENCE
July 2007 – Present
Wal-Mart Stores, Inc., Bentonville, AR
Senior Manager, Energy Regulatory Analysis (June 2011 – Present)
Manager, State Rate Proceedings (July 2007 – June 2011)

June 2003 – July 2007
Public Utility Commission of Oregon, Salem, OR
Senior Utility Analyst (February 2006 – July 2007)
Economist (June 2003 – February 2006)

January 2003 - May 2003
North Harris College, Houston, TX
Adjunct Instructor, Microeconomics

June 2001 - March 2003
Econ One Research, Inc., Houston, TX
Senior Analyst (October 2002 – March 2003)
Analyst (June 2001 – October 2002)

EDUCATION

2001	**Louisiana State University**	M.S., Agricultural Economics
1997-1998	**University of Florida**	Graduate Coursework, Agricultural Education and Communication
1997	**Texas A&M University**	B.S., Agricultural Development B.S., Horticulture

TESTIMONY BEFORE REGULATORY COMMISSIONS
2015
Rhode Island Docket No. 4568: In Re: National Grid's Rate Design Plan.

Oklahoma Cause No. PUD 201500208: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and the Electric Service Rules, Regulations and Conditions of Service for Electric Service in the State of Oklahoma.

Wisconsin Docket No. 4220-UR-121: Application of Northern States Power Company, A Wisconsin Corporation, for Authority to Adjust Electric and Natural Gas Rates.

Arkansas Docket No. 15-015-U: In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.

New York Case No. 15-E-0283: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of New York State Electric & Gas Corporation for Electric Service.

New York Case No. 15-G-0284: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of New York State Electric & Gas Corporation for Gas Service.

New York Case No. 15-E-0285: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Rochester Gas & Electric Corporation for Electric Service.

New York Case No. 15-G-0286: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Rochester Gas & Electric Corporation for Gas Service.

Ohio Case No. 14-1693-EL-RDR: In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter Into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider.

Wisconsin Docket No. 6690-UR-124: Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates.

Arkansas Docket No. 15-034-U: In the Matter of an Interim Rate Schedule of Oklahoma Gas and Electric Company Imposing a Surcharge to Recover All Investments and Expenses Incurred Through Compliance with Legislative or Administrative Rules, Regulations, or Requirements Relating to the Public Health, Safety or the Environment Under the Federal Clean Air Act for Certain of its Existing Generation Facilities.

Kansas Docket No. 15-WSEE-115-RTS: In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in their Charges for Electric Service.

Michigan Case No. U-17767: In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority.

Texas Docket No. 43695: Application of Southwestern Public Service Company for Authority to Change Rates.

Kansas Docket No. 15-KCPE-116-RTS: In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.

Michigan Case No. U-17735: In the Matter of the Application of the Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Relief.

Kentucky Public Service Commission Case No. 2014-00396: Application of Kentucky Power Company for a General Adjustment of its Rates for Electric Service; (2) an Order Approving its 2014 Environmental Compliance Plan; (3) an Order Approving its Tariffs and Riders; and (4) an Order Granting All Other Required Approvals and Relief.

Kentucky Public Service Commission Case No. 2014-00371: In the Matter of the Application of Kentucky Utilities Company for an Adjustment of its Electric Rates.

Kentucky Public Service Commission Case No. 2014-00372: In the Matter of the Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates.

2014
Ohio Public Utilities Commission Case No. 14-1297-EL-SSO: In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan.

West Virginia Case No. 14-1152-E-42T: Appalachian Power Company and Wheeling Power Company, Both d/b/a American Electric Power, Joint Application for Rate Increases and Changes in Tariff Provisions.

Oklahoma Corporation Commission Cause No. PUD 201400229: In the Matter of the Application of Oklahoma Gas and Electric Company for Commission Authorization of a Plan to Comply with the Federal Clean Air Act and Cost Recovery; and for Approval of the Mustang Modernization Plan.

Missouri Public Service Commission Case No. ER-2014-0258: In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase its Revenues for Electric Service.

Pennsylvania Public Utility Commission Docket No. R-2014-2428742: Pennsylvania Public Utility Commission v. West Penn Power Company.

Pennsylvania Public Utility Commission Docket No. R-2014-2428743: Pennsylvania Public Utility Commission v. Pennsylvania Electric Company.

Pennsylvania Public Utility Commission Docket No. R-2014-2428744: Pennsylvania Public Utility Commission v. Pennsylvania Power Company.

Pennsylvania Public Utility Commission Docket No. R-2014-2428745: Pennsylvania Public Utility Commission v. Metropolitan Edison Company.

Washington Utilities and Transportation Commission Docket No. UE-141368: In the Matter of the Petition of Puget Sound Energy to Update Methodologies Used to Allocate Electric Cost of Service and For Electric Rate Design Purposes.

Washington Utilities and Transportation Commission Docket No. UE-140762: 2014 Pacific Power & Light Company General Rate Case.

West Virginia Public Service Commission Case No. 14-0702-E-42T: Monongahela Power Company and the Potomac Edison Company Rule 42T Tariff Filing to Increase Rates and Charges.

Ohio Public Utilities Commission Case No. 14-841-EL-SSO: In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of Case No. 14-841-EL-SSO an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service.

Colorado Public Utilities Commission Docket No. 14AL-0660E: Re: In the Matter of the Advice Letter No. 1672-Electric Filed by Public Service Company of Colorado to Revise its Colorado PUC No. 7-Electric Tariff to Implement a General Rate Schedule Adjustment and Other Rate Changes Effective July 18, 2014.

Maryland Case No. 9355: In the Matter of the Application of Baltimore Gas and Electric Company for Authority to Increase Existing Rates and Charges for Electric and Gas Service.

Mississippi Public Service Commission Docket No. 2014-UN-132: In Re: Notice of Intent of Entergy Mississippi, Inc. to Modernize Rates to Support Economic Development, Power Procurement, and Continued Investment.

Nevada Public Utilities Commission Docket No. 14-05004: Application of Nevada Power Company d/b/a NV Energy for Authority to Increase its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and for Relief Properly Related Thereto.

Utah Public Service Commission Docket No. 14-035-T02: In the Matter of Rocky Mountain Power's Proposed Electric Service Schedule No. 32, Service From Renewable Energy Facilities.

Florida Public Service Commission Docket No. 140002-EG: In Re: Energy Conservation Cost Recovery Clause.

Wisconsin Docket No. 6690-UR-123: Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates.

Connecticut Docket No. 14-05-06: Application of the Connecticut Light and Power Company to Amend its Rate Schedules.

Virginia Corporation Commission Case No. PUE-2014-00026: Application of Appalachian Power Company for a 2014 Biennial Review for the Provision of Generation, Distribution and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Virginia Corporation Commission Case No. PUE-2014-00033: Application of Virginia Electric and Power Company to Revise its Fuel Factor Pursuant to Va. Code § 56-249.6.

Arizona Corporation Commission Docket No. E-01345A-11-0224 (Four Corners Phase): In the Matter of Arizona Public Service Company for a Hearing to Determine the Fair Value of Utility Property of the Company for Ratemaking Purposes, to Fix and Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return.

Minnesota Public Utilities Commission Docket No. E-002/GR-13-868: In the Matter of the Application of Northern States Power Company, for Authority to Increase Rates for Electric Service in Minnesota.

Utah Public Service Commission Docket No. 13-035-184: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Missouri Public Service Commission Case No. EC-2014-0224: In the Matter of Noranda Aluminum, Inc.'s Request for Revisions to Union Electric Company d/b/a Ameren Missouri's Large Transmission Service Tariff to Decrease its Rate for Electric Service.

Oklahoma Corporation Commission Cause No. PUD 201300217: Application of Public Service Company of Oklahoma to be in Compliance with Order No. 591185 Issued in Cause No. PUD 201100106 Which Requires a Base Rate Case to be Filed by PSO and the Resulting Adjustment in its Rates and Charges and Terms and Conditions of Service for Electric Service in the State of Oklahoma.

Public Utilities Commission of Ohio Case No. 13-2386-EL-SSO: In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan.

2013

Oklahoma Corporation Commission Cause No. PUD 201300201: Application of Public Service Company of Oklahoma for Commission Authorization of a Standby and Supplemental Service Rate Schedule.

Georgia Public Service Commission Docket No. 36989: Georgia Power's 2013 Rate Case.

Florida Public Service Commission Docket No. 130140-EI: Petition for Rate Increase by Gulf Power Company.

Public Utility Commission of Oregon Docket No. UE 267: In the Matter of PACIFICORP, dba PACIFIC POWER, Transition Adjustment, Five-Year Cost of Service Opt-Out.

Illinois Commerce Commission Docket No. 13-0387: Commonwealth Edison Company Tariff Filing to Present the Illinois Commerce Commission with an Opportunity to Consider Revenue Neutral Tariff Changes Related to Rate Design Authorized by Subsection 16-108.5 of the Public Utilities Act.

Iowa Utilities Board Docket No. RPU-2013-0004: In Re: MidAmerican Energy Company.

South Dakota Public Utilities Commission Docket No. EL12-061: In the Matter of the Application of Black Hills Power, Inc. for Authority to Increase its Electric Rates. (filed with confidential stipulation)

Kansas Corporation Commission Docket No. 13-WSEE-629-RTS: In the Matter of the Applications of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Service.

Public Utility Commission of Oregon Docket No. UE 263: In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision.

Arkansas Public Service Commission Docket No. 13-028-U: In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.

Virginia State Corporation Commission Docket No. PUE-2013-00020: Application of Virginia Electric and Power Company for a 2013 Biennial Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Florida Public Service Commission Docket No. 130040-EI: Petition for Rate Increase by Tampa Electric Company.

South Carolina Public Service Commission Docket No. 2013-59-E: Application of Duke Energy Carolinas, LLC, for Authority to Adjust and Increase Its Electric Rates and Charges.

Public Utility Commission of Oregon Docket No. UE 262: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision.

New Jersey Board of Public Utilities Docket No. ER12111052: In the Matter of the Verified Petition of Jersey Central Power & Light Company For Review and Approval of Increases in and Other Adjustments to Its Rates and Charges For Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith; and for Approval of an Accelerated Reliability Enhancement Program ("2012 Base Rate Filing")

North Carolina Utilities Commission Docket No. E-7, Sub 1026: In the Matter of the Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Public Utility Commission of Oregon Docket No. UE 264: PACIFICORP, dba PACIFIC POWER, 2014 Transition Adjustment Mechanism.

Public Utilities Commission of California Docket No. 12-12-002: Application of Pacific Gas and Electric Company for 2013 Rate Design Window Proceeding.

Public Utilities Commission of Ohio Docket Nos. 12-426-EL-SSO, 12-427-EL-ATA, 12-428-EL-AAM, 12-429-EL-WVR, and 12-672-EL-RDR: In the Matter of the Application of the Dayton Power and Light Company Approval of its Market Offer.

Minnesota Public Utilities Commission Docket No. E-002/GR-12-961: In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota.

North Carolina Utilities Commission Docket E-2, Sub 1023: In the Matter of Application of Progress Energy Carolinas, Inc. For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

2012
Public Utility Commission of Texas Docket No. 40443: Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs.

South Carolina Public Service Commission Docket No. 2012-218-E: Application of South Carolina Electric & Gas Company for Increases and Adjustments in Electric Rate Schedules and Tariffs and Request for Mid-Period Reduction in Base Rates for Fuel.

Kansas Corporation Commission Docket No. 12-KCPE-764-RTS: In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.

Kansas Corporation Commission Docket No. 12-GIMX-337-GIV: In the Matter of a General Investigation of Energy-Efficiency Policies for Utility Sponsored Energy Efficiency Programs.

Florida Public Service Commission Docket No. 120015-EI: In Re: Petition for Rate Increase by Florida Power & Light Company.

California Public Utilities Commission Docket No. A.11-10-002: Application of San Diego Gas & Electric Company (U 902 E) for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design.

Utah Public Service Commission Docket No. 11-035-200: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Virginia State Corporation Commission Case No. PUE-2012-00051: Application of Appalachian Power Company to Revise its Fuel Factor Pursuant to § 56-249.6 of the Code of Virginia.

Public Utilities Commission of Ohio Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, and 11-350-EL-AAM: In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form on an Electric Security Plan and In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.

New Jersey Board of Public Utilities Docket No. ER11080469: In the Matter of the Petition of Atlantic City Electric for Approval of Amendments to Its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1 and For Other Appropriate Relief.

Public Utility Commission of Texas Docket No. 39896: Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs.

Missouri Public Service Commission Case No. EO-2012-0009:In the Matter of KCP&L Greater Missouri Operations Notice of Intent to File an Application for Authority to Establish a Demand-Side Programs Investment Mechanism.

Colorado Public Utilities Commission Docket No. 11AL-947E: In the Matter of Advice Letter No. 1597-Electric Filed by Public Service Company of Colorado to Revise its Colorado PUC No. 7-Electric Tariff to Implement a General Rate Schedule Adjustment and Other Changes Effective December 23, 2011.

Illinois Commerce Commission Docket No. 11-0721: Commonwealth Edison Company Tariffs and Charges Submitted Pursuant to Section 16-108.5 of the Public Utilities Act.

Public Utility Commission of Texas Docket No. 38951: Application of Entergy Texas, Inc. for Approval of Competitive Generation Service tariff (Issues Severed from Docket No. 37744).

California Public Utilities Commission Docket No. A.11-06-007: Southern California Edison's General Rate Case, Phase 2.

2011

Arizona Corporation Commission Docket No. E-01345A-11-0224: In the Matter of Arizona Public Service Company for a Hearing to Determine the Fair Value of Utility Property of the Company for Ratemaking Purposes, to Fix and Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return.

Oklahoma Corporation Commission Cause No. PUD 201100087: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

South Carolina Public Service Commission Docket No. 2011-271-E: Application of Duke Energy Carolinas, LLC for Authority to Adjust and Increase its Electric Rates and Charges.

Pennsylvania Public Utility Commission Docket No. P-2011-2256365: Petition of PPL Electric Utilities Corporation for Approval to Implement Reconciliation Rider for Default Supply Service.

North Carolina Utilities Commission Docket No. E-7, Sub 989: In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Florida Public Service Commission Docket No. 110138: In Re: Petition for Increase in Rates by Gulf Power Company.

Public Utilities Commission of Nevada Docket No. 11-06006: In the Matter of the Application of Nevada Power Company, filed pursuant to NRS 704.110(3) for authority to increase its annual revenue requirement for general rates charged to all classes of customers to recover the costs of constructing the Harry Allen Combined Cycle plant and other generating, transmission, and distribution plant additions, to reflect changes in the cost of capital, depreciation rates and cost of service, and for relief properly related thereto.

North Carolina Utilities Commission Docket Nos. E-2, Sub 998 and E-7, Sub 986: In the Matter of the Application of Duke Energy Corporation and Progress Energy, Inc., to Engage in a Business Combination Transaction and to Address Regulatory Conditions and Codes of Conduct.

Public Utilities Commission of Ohio Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, and 11-350-EL-AAM: In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form on an Electric Security Plan and In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.

Virginia State Corporation Commission Case No. PUE-2011-00037: In the Matter of Appalachian Power Company for a 2011 Biennial Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Illinois Commerce Commission Docket No. 11-0279 and 11-0282 (cons.): Ameren Illinois Company Proposed General Increase in Electric Delivery Service and Ameren Illinois Company Proposed General Increase in Gas Delivery Service.

Virginia State Corporation Commission Case No. PUE-2011-00045: Application of Virginia Electric and Power Company to Revise its Fuel Factor Pursuant to § 56-249.6 of the Code of Virginia.

Utah Public Service Commission Docket No. 10-035-124: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Maryland Public Utilities Commission Case No. 9249: In the Matter of the Application of Delmarva Power & Light for an Increase in its Retail Rates for the Distribution of Electric Energy.

Minnesota Public Utilities Commission Docket No. E002/GR-10-971: In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota.

Michigan Public Service Commission Case No. U-16472: In the Matter of the Detroit Edison Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority.

2010
Public Utilities Commission of Ohio Docket No. 10-2586-EL-SSO: In the Matter of the Application of Duke Energy Ohio for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service.

Colorado Public Utilities Commission Docket No. 10A-554EG: In the Matter of the Application of Public Service Company of Colorado for Approval of a Number of Strategic Issues Relating to its DSM Plan, Including Long-Term Electric Energy Savings Goals, and Incentives.

Public Service Commission of West Virginia Case No. 10-0699-E-42T: Appalachian Power Company and Wheeling Power Company Rule 42T Application to Increase Electric Rates.

Oklahoma Corporation Commission Cause No. PUD 201000050: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and Terms and Conditions of Service for Electric Service in the State of Oklahoma.

Georgia Public Service Commission Docket No. 31958-U: In Re: Georgia Power Company's 2010 Rate Case.

Washington Utilities and Transportation Commission Docket No. UE-100749: 2010 Pacific Power & Light Company General Rate Case.

Colorado Public Utilities Commission Docket No. 10M-254E: In the Matter of Commission Consideration of Black Hills Energy's Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act."

Colorado Public Utilities Commission Docket No. 10M-245E: In the Matter of Commission Consideration of Public Service Company of Colorado Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act."

Public Service Commission of Utah Docket No. 09-035-15 *Phase II*: In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism.

Public Utility Commission of Oregon Docket No. UE 217: In the Matter of PACIFICORP, dba PACIFIC POWER Request for a General Rate Revision.

Mississippi Public Service Commission Docket No. 2010-AD-57: In Re: Proposal of the Mississippi Public Service Commission to Possibly Amend Certain Rules of Practice and Procedure.

Indiana Utility Regulatory Commission Cause No. 43374: Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to Ind. Code § 8-1-2.5-1, *ET SEQ.*, for the Offering of Energy Efficiency Conservation, Demand Response, and Demand-Side Management Programs and Associated Rate Treatment Including Incentives Pursuant to a Revised Standard Contract Rider No. 66 in Accordance with Ind. Code §§ 8-1-2.5-1 *ET SEQ.* and 8-1-2-42 (a); Authority to Defer Program Costs Associated with its Energy Efficiency Portfolio of Programs; Authority to Implement New and Enhanced Energy Efficiency Programs, Including the Powershare® Program in its Energy Efficiency Portfolio of Programs; and Approval of a Modification of the Fuel Adjustment Clause Earnings and Expense Tests.

Public Utility Commission of Texas Docket No. 37744: Application of Entergy Texas, Inc. for Authority to Change Rates and to Reconcile Fuel Costs.

South Carolina Public Service Commission Docket No. 2009-489-E: Application of South Carolina Electric & Gas Company for Adjustments and Increases in Electric Rate Schedules and Tariffs.

Kentucky Public Service Commission Case No. 2009-00459: In the Matter of General Adjustments in Electric Rates of Kentucky Power Company.

Virginia State Corporation Commission Case No. PUE-2009-00125: For acquisition of natural gas facilities Pursuant to § 56-265.4:5 B of the Virginia Code.

Arkansas Public Service Commission Docket No. 10-010-U: In the Matter of a Notice of Inquiry Into Energy Efficiency.

Connecticut Department of Public Utility Control Docket No. 09-12-05: Application of the Connecticut Light and Power Company to Amend its Rate Schedules.

Arkansas Public Service Commission Docket No. 09-084-U: In the Matter of the Application of Entergy Arkansas, Inc. For Approval of Changes in Rates for Retail Electric Service.

Missouri Public Service Commission Docket No. ER-2010-0036: In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.

Public Service Commission of Delaware Docket No. 09-414: In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Charges.

2009

Virginia State Corporation Commission Case No. PUE-2009-00030: In the Matter of Appalachian Power Company for a Statutory Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Public Service Commission of Utah Docket No. 09-035-15 *Phase I*: In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism.

Public Service Commission of Utah Docket No. 09-035-23: In the Matter of the Application of Rocky Mountain Power for Authority To Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations.

Colorado Public Utilities Commission Docket No. 09AL-299E: Re: The Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No. 1535 – Electric.

Arkansas Public Service Commission Docket No. 09-008-U: In the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs.

Oklahoma Corporation Commission Docket No. PUD 200800398: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

Public Utilities Commission of Nevada Docket No. 08-12002: In the Matter of the Application by Nevada Power Company d/b/a NV Energy, filed pursuant to NRS §704.110(3) and NRS §704.110(4) for authority to increase its annual revenue requirement for general rates charged to all classes of customers, begin to recover the costs of acquiring the Bighorn Power Plant, constructing the Clark Peakers, Environmental Retrofits and other generating, transmission and distribution plant additions, to reflect changes in cost of service and for relief properly related thereto.

New Mexico Public Regulation Commission Case No. 08-00024-UT: In the Matter of a Rulemaking to Revise NMPRC Rule 17.7.2 NMAC to Implement the Efficient Use of Energy Act.

Indiana Utility Regulatory Commission Cause No. 43580: Investigation by the Indiana Utility Regulatory Commission, of Smart Grid Investments and Smart Grid Information Issues Contained in 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. § 2621(d)), as Amended by the Energy Independence and Security Act of 2007.

Louisiana Public Service Commission Docket No. U-30192 *Phase II (February 2009)*: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

South Carolina Public Service Commission Docket No. 2008-251-E: In the Matter of Progress Energy Carolinas, Inc.'s Application For the Establishment of Procedures to Encourage Investment in Energy Efficient Technologies; Energy Conservation Programs; And Incentives and Cost Recovery for Such Programs.

2008
Colorado Public Utilities Commission Docket No. 08A-366EG: In the Matter of the Application of Public Service Company of Colorado for approval of its electric and natural gas demand-side management (DSM) plan for calendar years 2009 and 2010 and to change its electric and gas DSM cost adjustment rates effective January 1, 2009, and for related waivers and authorizations.

Public Service Commission of Utah Docket No. 07-035-93: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge.

Indiana Utility Regulatory Commission Cause No. 43374: Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission Approve an Alternative Regulatory Plan for the Offering of Energy Efficiency, Conservation, Demand Response, and Demand-Side Management.

Public Utilities Commission of Nevada Docket No. 07-12001: In the Matter of the Application of Sierra Pacific Power Company for authority to increase its general rates charged to all classes of electric customers to reflect an increase in annual revenue requirement and for relief properly related thereto.

Louisiana Public Service Commission Docket No. U-30192 *Phase II*: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

Colorado Public Utilities Commission Docket No. 07A-420E: In the Matter of the Application of Public Service Company of Colorado For Authority to Implement and Enhanced Demand Side Management Cost Adjustment Mechanism to Include Current Cost Recovery and Incentives.

2007
Louisiana Public Service Commission Docket No. U-30192: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

Public Utility Commission of Oregon Docket No. UG 173: In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Staff Request to Open an Investigation into the Earnings of Cascade Natural Gas.

2006
Public Utility Commission of Oregon Docket No. UE 180/UE 181/UE 184: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision.

Public Utility Commission of Oregon Docket No. UE 179: In the Matter of PACIFICORP, dba PACIFIC POWER AND LIGHT COMPANY Request for a general rate increase in the company's Oregon annual revenues.

Public Utility Commission of Oregon Docket No. UM 1129 *Phase II*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

2005
Public Utility Commission of Oregon Docket No. UM 1129 *Phase I Compliance*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

Public Utility Commission of Oregon Docket No. UX 29: In the Matter of QWEST CORPORATION Petition to Exempt from Regulation Qwest's Switched Business Services.

2004
Public Utility Commission of Oregon Docket No. UM 1129 *Phase I*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

TESTIMONY BEFORE LEGISLATIVE BODIES
2014
Regarding Kansas House Bill 2460: Testimony Before the Kansas House Standing Committee on Utilities and Telecommunications, February 12, 2014.

2012
Regarding Missouri House Bill 1488: Testimony Before the Missouri House Committee on Utilities, February 7, 2012.

2011
Regarding Missouri Senate Bills 50, 321, 359, and 406: Testimony Before the Missouri Senate Veterans' Affairs, Emerging Issues, Pensions, and Urban Affairs Committee, March 9, 2011.

AFFIDAVITS
2015
Supreme Court of Illinois, Docket No. 118129, Commonwealth Edison Company et al., respondents, v. Illinois Commerce Commission et al. (Illinois Competitive Energy Association et al., petitioners). Leave to appeal, Appellate Court, First District.

2011
Colorado Public Utilities Commission Docket No. 11M-951E: In the Matter of the Petition of Public Service Company of Colorado Pursuant to C.R.S. § 40-6-111(1)(d) for Interim Rate Relief Effective on or before January 21, 2012.

ENERGY INDUSTRY PUBLICATIONS AND PRESENTATIONS
Panelist, The Governor's Utah Energy Development Summit 2015, May 21, 2015.

Mock Trial Expert Witness, The Energy Bar Association State Commission Practice and Regulation Committee and Young Lawyers Committee and Environment, Energy and Natural Resources Section of the D.C. Bar, Mastering Your First (or Next) State Public Utility Commission Hearing, February 13, 2014.

Panelist, Customer Panel, Virginia State Bar 29th National Regulatory Conference, Williamsburg, Virginia, May 19, 2011.

Chriss, S. (2006). "Regulatory Incentives and Natural Gas Purchasing – Lessons from the Oregon Natural Gas Procurement Study." Presented at the 19th Annual Western Conference, Center for Research in Regulated Industries Advanced Workshop in Regulation and Competition, Monterey, California, June 29, 2006.

Chriss, S. (2005). "Public Utility Commission of Oregon Natural Gas Procurement Study." Public Utility Commission of Oregon, Salem, OR. Report published in June, 2005. Presented to the Public Utility Commission of Oregon at a special public meeting on August 1, 2005.

Chriss, S. and M. Radler (2003). "Report from Houston: Conference on Energy Deregulation and Restructuring." USAEE Dialogue, Vol. 11, No. 1, March, 2003.

Chriss, S., M. Dwyer, and B. Pulliam (2002). "Impacts of Lifting the Ban on ANS Exports on West Coast Crude Oil Prices: A Reconsideration of the Evidence." Presented at the 22nd USAEE/IAEE North American Conference, Vancouver, BC, Canada, October 6-8, 2002.

Contributed to chapter on power marketing: "Power System Operations and Electricity Markets," Fred I. Denny and David E. Dismukes, authors. Published by CRC Press, June 2002.

Contributed to "Moving to the Front Lines: The Economic Impact of the Independent Power Plant Development in Louisiana," David E. Dismukes, author. Published by the Louisiana State University Center for Energy Studies, October 2001.

Dismukes, D.E., D.V. Mesyanzhinov, E.A. Downer, S. Chriss, and J.M. Burke (2001). "Alaska Natural Gas In-State Demand Study." Anchorage: Alaska Department of Natural Resources.

Calculation of Revenue Requirement Impact of UNSE's Proposed Increase in ROE

(1)		UNS Requested Rate of Return		7.67%	
		1) Calculate Rate of Return at ROE = 9.5%			
		Capital Component	**% of Total**	**Cost**	**Weighted Cost**
(2)		Debt	47.17%	4.66%	2.20%
(3)		Common Equity	52.83%	9.50%	5.02%
(4)		Total	100.00%		7.22%
		2) Revenue Requirement Impact			
(5)		Fair Value Rate Base ($000)	$355,720		
(6)	= (4)	Rate of Return (ROE = 9.5%)	7.22%		
(7)		Fair Value Adjustment	-1.45%		
(8)		Required Rate of Return	5.77%		
(9)	(5) x (8)	Adjusted Operating Income (ROE = 9.5%)	$20,514		
(10)		UNSE Proposed Operating Income	$22,108		
(11)	(10) - (9)	Difference in Operating Income	$1,594		
(12)		Conversion Factor	1.6084		
(13)	(11) x (12)	Difference in Revenue Requirement	$2,563		
(14)		Requested Revenue Requirement Increase ($000)	$22,621		
(15)	(13) / (14)	Increase Request from ROE Increase	11.3%		

Sources:
Schedule A-1
Schedule D-1, page 1

Reported Authorized Returns on Equity, Electric Utility Rate Cases Completed, 2012 to Present

State	Utility	Docket	Decision Date	Vertically Integrated (V)/Distribution (D)	Return on Equity (%)
South Carolina	Duke Energy Carolinas LLC	2011-271-E	1/25/2012	V	10.50%
North Carolina	Duke Energy Carolinas LLC	E-7, Sub 989	1/27/2012	V	10.50%
Michigan	Indiana Michigan Power Co.	U-16801	2/15/2012	V	10.20%
Oregon	Idaho Power Co.	UE-233	2/23/2012	V	9.90%
Florida	Gulf Power Co.	110138-EI	2/27/2012	V	10.25%
North Dakota	Northern States Power Co.	PU-10-657	2/29/2012	V	10.40%
Minnesota	Northern States Power Co.	E-002/GR-10-971	3/29/2012	V	10.37%
Hawaii	Hawaii Electric Light Co	2009-0164	4/4/2012	V	10.00%
Colorado	Public Service Co. of CO	11AL-947E	4/26/2012	V	10.00%
Hawaii	Maui Electric Company Ltd	2009-0163	5/2/2012	V	10.00%
Washington	Puget Sound Energy Inc.	UE-111048	5/7/2012	V	9.80%
Arizona	Arizona Public Service Co.	E-01345A-11-0224	5/15/2012	V	10.00%
Illinois	Commonwealth Edison Co.	11-0721	5/29/2012	D	10.05%
Michigan	Consumers Energy Co.	U-16794	6/7/2012	V	10.30%
New York	Orange & Rockland Utlts Inc.	11-E-0408	6/14/2012	D	9.40%
Wisconsin	Wisconsin Power and Light Co	6680-UR-118	6/15/2012	V	10.40%
Wyoming	Cheyenne Light Fuel Power Co.	20003-114-ER-11	6/18/2012	V	9.60%
South Dakota	Northern States Power Co.	EL11-019	6/19/2012	V	9.25%
Michigan	Wisconsin Electric Power Co.	U-16830	6/26/2012	V	10.10%
Hawaii	Hawaiian Electric Co.	2010-0080	6/29/2012	V	10.00%
Oklahoma	Oklahoma Gas and Electric Co.	PUD201100087	7/9/2012	V	10.20%
Wyoming	PacifiCorp	20000-405-ER-11	7/16/2012	V	9.80%
Maryland	Potomac Electric Power Co.	9286	7/20/2012	D	9.31%
Maryland	Delmarva Power & Light Co.	9285	7/20/2012	D	9.81%
Texas	Entergy Texas Inc.	39896	9/13/2012	V	9.80%
Illinois	Ameren Illinois	12-0001	9/19/2012	D	10.05%
Utah	PacifiCorp	11-035-200	9/19/2012	V	9.80%
District of Columbia	Potomac Electric Power Co.	1087	9/26/2012	D	9.50%
New Jersey	Atlantic City Electric Co.	ER-11080469	10/23/2012	D	9.75%
Wisconsin	Wisconsin Public Service Corp.	6690-UR-121	10/24/2012	V	10.30%
Wisconsin	Madison Gas and Electric Co.	3270-UR-118	11/9/2012	V	10.30%
Wisconsin	Wisconsin Electric Power Co.	05-UR-106	11/28/2012	V	10.40%
California	Liberty Utilities LLC	12-02-014	11/29/2012	V	9.88%
Delaware	Delmarva Power & Light Co.	11-528	11/29/2012	D	9.75%
Illinois	Ameren Illinois	12-0293	12/5/2012	D	9.71%
Pennsylvania	PPL Electric Utilities Corp.	R-2012-2290597	12/5/2012	D	10.40%
Missouri	Union Electric Co.	ER-2012-0166	12/12/2012	V	9.80%
Florida	Florida Power & Light Co.	120015-EI	12/13/2012	V	10.50%
Kansas	Kansas City Power & Light	12-KCPE-764-RTS	12/13/2012	V	9.50%
Wisconsin	Northern States Power Co.	4220-UR-118	12/14/2012	V	10.40%
Illinois	Commonwealth Edison Co.	12-0321	12/19/2012	D	9.71%
South Carolina	South Carolina Electric & Gas	2012-218-E	12/19/2012	V	10.25%
California	San Diego Gas & Electric Co.	12-04-016	12/20/2012	V	10.30%
California	Pacific Gas and Electric Co.	12-04-018	12/20/2012	V	10.40%
California	Southern California Edison Co.	12-04-015	12/20/2012	V	10.45%
Kentucky	Kentucky Utilities Co.	2012-00221	12/20/2012	V	10.25%
Kentucky	Louisville Gas & Electric Co.	2012-00222	12/20/2012	V	10.25%
Oregon	PacifiCorp	UE-246	12/20/2012	V	9.80%
Rhode Island	Narragansett Electric Co.	4323	12/20/2012	D	9.50%
North Carolina	Virginia Electric & Power Co.	E-22, Sub 479	12/21/2012	V	10.20%

Reported Authorized Returns on Equity, Electric Utility Rate Cases Completed, 2012 to Present

State	Utility	Docket	Decision Date	Vertically Integrated (V)/Distribution (D)	Return on Equity (%)
Washington	Avista Corp.	UE-120436	12/26/2012	V	9.80%
Missouri	Kansas City Power & Light	ER-2012-0174	1/9/2013	V	9.70%
Missouri	KCP&L Greater Missouri Op Co	ER-2012-0175	1/9/2013	V	9.70%
Indiana	Indiana Michigan Power Co.	44075	2/13/2013	V	10.20%
Maryland	Baltimore Gas and Electric Co.	9299	2/22/2013	D	9.75%
Louisiana	Southwestern Electric Power Co	U-32220	2/27/2013	V	10.00%
New York	Niagara Mohawk Power Corp.	12-E-0201	3/14/2013	D	9.30%
Idaho	Avista Corp.	AVU-E-12-08	3/27/2013	V	9.80%
Ohio	Duke Energy Ohio Inc.	12-1682-EL-AIR	5/1/2013	D	9.84%
Michigan	Consumers Energy Co.	U-17087	5/15/2013	V	10.30%
North Carolina	Duke Energy Progress Inc.	E-2, Sub 1023	5/30/2013	V	10.20%
Hawaii	Maui Electric Company Ltd	2011-0092	5/31/2013	V	9.00%
Arizona	Tucson Electric Power Co.	E-01933A-12-0291	6/11/2013	V	10.00%
New Jersey	Atlantic City Electric Co.	ER-12121071	6/21/2013	D	9.75%
Washington	Puget Sound Energy Inc.	UE-130137	6/25/2013	V	9.80%
Maryland	Potomac Electric Power Co.	9311	7/12/2013	D	9.36%
Minnesota	Northern States Power Co.	E-002/GR-12-961	8/8/2013	V	9.83%
Connecticut	United Illuminating Co.	13-01-19	8/14/2013	D	9.15%
Florida	Tampa Electric Co.	130040-EI	9/11/2013	V	10.25%
South Carolina	Duke Energy Carolinas LLC	2013-59-E	9/11/2013	V	10.20%
North Carolina	Duke Energy Carolinas LLC	E-7, Sub 1026	9/24/2013	V	10.20%
Texas	Southwestern Electric Power Co	40443	10/3/2013	V	9.65%
Wisconsin	Wisconsin Public Service Corp.	6690-UR-122	11/6/2013	V	10.20%
Kansas	Westar Energy Inc.	13-WSEE-629-RTS	11/21/2013	V	10.00%
Virginia	Virginia Electric & Power Co.	PUE-2013-00020	11/26/2013	V	10.00%
Florida	Gulf Power Co.	130140-EI	12/3/2013	V	10.25%
Washington	PacifiCorp	UE-130043	12/4/2013	V	9.50%
Wisconsin	Northern States Power Co.	4220-UR-119	12/5/2013	V	10.20%
Illinois	Ameren Illinois	13-0301	12/9/2013	D	8.72%
Oregon	Portland General Electric Co.	UE-262	12/9/2013	V	9.75%
Maryland	Baltimore Gas and Electric Co.	9326	12/13/2013	D	9.75%
Louisiana	Entergy Gulf States LA LLC	U-32707	12/16/2013	V	9.95%
Louisiana	Entergy Louisiana LLC	U-32708	12/16/2013	V	9.95%
Nevada	Sierra Pacific Power Co.	13-06002	12/16/2013	V	10.12%
Arizona	UNS Electric Inc.	E-04204A-12-0504	12/17/2013	V	9.50%
Georgia	Georgia Power Co.	36989	12/17/2013	V	10.95%
Illinois	Commonwealth Edison Co.	13-0318	12/18/2013	D	8.72%
Oregon	PacifiCorp	UE-263	12/18/2013	V	9.80%
Michigan	Upper Peninsula Power Co.	U-17274	12/19/2013	V	10.15%
New York	Consolidated Edison Co. of NY	13-E-0030	2/20/2014	D	9.20%
North Dakota	Northern States Power Co.	PU-12-813	2/26/2014	V	9.75%
New Hampshire	Liberty Utilities Granite St	DE-13-063	3/17/2014	D	9.55%
District of Columbia	Potomac Electric Power Co.	1103-2013-E	3/26/2014	D	9.40%
New Mexico	Southwestern Public Service Co	12-00350-UT	3/26/2014	V	9.96%
Delaware	Delmarva Power & Light Co.	13-115	4/2/2014	D	9.70%
Texas	Entergy Texas Inc.	41791	5/16/2014	V	9.80%
Massachusetts	Fitchburg Gas & Electric Light	13-90	5/30/2014	D	9.70%
Wisconsin	Wisconsin Power and Light Co	6680-UR-119	6/6/2014	V	10.40%
Maine	Emera Maine	2013-00443	6/30/2014	D	9.55%
Maryland	Potomac Electric Power Co.	9336	7/2/2014	D	9.62%

Reported Authorized Returns on Equity, Electric Utility Rate Cases Completed, 2012 to Present

State	Utility	Docket	Decision Date	Vertically Integrated (V)/Distribution (D)	Return on Equity (%)
Louisiana	Entergy Louisiana LLC (New Orleans)	UD-13-01	7/10/2014	V	9.95%
New Jersey	Rockland Electric Company	ER-13111135	7/23/2014	D	9.75%
Maine	Central Maine Power Co.	2013-00168	7/29/2014	D	9.45%
Wyoming	Cheyenne Light Fuel Power Co.	20003-132-ER-13	7/31/2014	V	9.90%
Arkansas	Entergy Arkansas Inc.	13-028-U [1]	8/15/2014	V	9.50%
New Jersey	Atlantic City Electric Co.	ER-14030245	8/20/2014	D	9.75%
Vermont	Green Mountain Power Corp	8190, 8191	8/25/2014	V	9.60%
Utah	PacifiCorp	13-035-184	8/29/2014	V	9.80%
Florida	Florida Public Utilities Co.	140025-EI	9/15/2014	V	10.25%
Nevada	Nevada Power Co.	14-05004	10/9/2014	V	9.80%
Illinois	MidAmerican Energy Co.	14-0066	11/6/2014	V	9.56%
Wisconsin	Wisconsin Public Service Corp.	6690-UR-123	11/6/2014	V	10.20%
Wisconsin	Wisconsin Electric Power Co.	05-UR-107	11/14/2014	V	10.20%
Virginia	Appalachian Power Co.	PUE-2014-00026	11/26/2014	V	9.70%
Wisconsin	Madison Gas and Electric Co.	3270-UR-120	11/26/2014	V	10.20%
Oregon	Portland General Electric Co.	UE-283	12/4/2014	V	9.68%
Illinois	Commonwealth Edison Co.	14-0312	12/10/2014	D	9.25%
Illinois	Ameren Illinois	14-0317	12/10/2014	D	9.25%
Mississippi	Entergy Mississippi Inc.	2014-UN-0132	12/11/2014	V	10.07%
Wisconsin	Northern States Power Co.	4220-UR-120	12/12/2014	V	10.20%
Connecticut	Connecticut Light & Power Co.	14-05-06	12/17/2014	D	9.17%
Colorado	Black Hills Colorado Electric	14AL-0393E	12/18/2014	V	9.83%
Wyoming	PacifiCorp	20000-446-ER-14	1/23/2015	V	9.50%
Colorado	Public Service Co. of CO	14AL-0660E	2/24/2015	V	9.83%
New Jersey	Jersey Central Power & Light Co.	ER-12111052	3/18/2015	D	9.75%
Washington	PacifiCorp	UE-140762	3/25/2015	V	9.50%
Minnesota	Northern States Power Co.	E-002/GR-13-868	3/26/2015	V	9.72%
Michigan	Wisconsin Public Service Corp.	U-17669	4/23/2015	V	10.20%
Missouri	Union Electric Co.	ER-2014-0258	4/29/2015	V	9.53%
West Virginia	Appalachian Power Co.	14-1152-E-42-T	5/26/2015	V	9.75%
New York	Central Hudson Gas & Electric	14-E-0318	6/17/2015	D	9.00%
New York	Consolidated Edison Co. of NY	15-E-0050	6/17/2015	D	9.00%
Missouri	Kansas City Power & Light	ER-2014-0370	9/2/2015	V	9.50%
Kansas	Kansas City Power & Light	15-KCPE-116-RTS	9/10/2015	V	9.30%
New York	Orange & Rockland Utlts Inc.	14-E-0493	10/15/2015	D	9.00%

[1] The Arkansas Public Service Commission originally approved a 9.3% ROE, but increased it to 9.5% on rehearing. See Order No. 35, Arkansas Docket 13-028-U.

Entire Period		
# of Decisions	**135**	
Average (All Utilities)		**9.85%**
Average (Distribution Only)		**9.51%**
Average (Vertically Integrated Only)		**9.98%**
Median		**9.80%**
Minimum		**8.72%**
Maximum		**10.95%**

Reported Authorized Returns on Equity, Electric Utility Rate Cases Completed, 2012 to Present

State	Utility	Docket	Decision Date	Vertically Integrated (V)/Distribution (D)	Return on Equity (%)
2012					
# of Decisions			51		
Average (All Utilities)					10.02%
Average (Distribution Only)					9.75%
Average (Distribution Only, exc. IL FRP)					9.75%
Average (Vertically Integrated Only)					10.10%
2013					
# of Decisions			38		
Average (All Utilities)					9.83%
Average (Distribution Only)					9.37%
Average (Distribution Only, exc. IL FRP)					9.56%
Average (Vertically Integrated Only)					9.97%
2014					
# of Decisions			33		
Average (All Utilities)					9.75%
Average (Distribution Only)					9.49%
Average (Distribution Only, exc. IL FRP)					9.53%
Average (Vertically Integrated Only)					9.92%
2015					
# of Decisions			13		
Average (All Utilities)					9.51%
Average (Distribution Only)					9.19%
Average (Vertically Integrated Only)					9.65%

Source: SNL Financial LC, October 22, 2015

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>

SUSAN BITTER SMITH, CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
DOUG LITTLE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS	DOCKET NO. E-04204A-15-0142

EXHIBIT
tabbies
Wal-Mart-2
admitted

TESTIMONY AND EXHIBITS OF

CHRIS HENDRIX

ON BEHALF OF

WAL-MART STORES, INC.

DECEMBER 9, 2015

Contents

Exhibits

Introduction

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Chris Hendrix. My business address is 2001 SE 10th St., Bentonville, AR 72716-0550. I am employed by Wal-Mart Stores, Inc. as Director of Markets and Compliance.

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

A. I am testifying on behalf of Wal-Mart Stores, Inc. ("Walmart").

Q. PLEASE DESCRIBE YOUR POSITION WITH WAL-MART?

A. In my role as Director of Markets & Compliance, I am responsible for directing and implementing regulatory and legislative policies for Walmart's retail and wholesale business interests related to electricity and natural gas in the competitive markets of the United States and the United Kingdom. In addition, I am accountable for all regulatory, legislative and market developments that effect the operation of Walmart's self-supply retail electricity provider; Texas Retail Energy, LLC in Connecticut, Illinois, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, and Texas, and Power4All, Ltd. in the United Kingdom.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. I earned a Bachelors of Business Administration with a concentration in Accounting from the University of Houston in 1991 and a Masters of Business Administration with a concentration in Finance and International Business from the University of Houston in 1994. I have more than 25 years of experience in all facets of the energy industry with the last 15 years specifically related to the competitive electric and natural gas markets. From 1990 to 1997, I was an Accountant, then an Accounting Analyst and later a Senior Rate Analyst with Tenneco Energy in Houston, Texas. My initial duties included various accounting functions for their regulated pipeline, Tennessee Gas Pipeline, and in my later position, the preparation of cost allocation and rate design studies. From 1997 to 2001, I was a Senior Specialist and later a Manager at Enron Energy Services in Houston, Texas. My duties included participating in gas and electric deregulation proceedings, performing cost of service analysis, and analyzing regulatory rules and utility tariffs. From 2002 to 2003, I was a Manager at TXU Energy in Dallas, Texas, where I supervised a pricing team for energy transactions. In 2003, I joined the Energy Department of Wal-Mart Stores Inc., as a General Manager and was promoted to my current position in 2009. My Witness Qualification Statement is found on Exhibit CWH-1.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE ARIZONA CORPORATION COMMISSION ("THE COMMISSION")?

A. Yes. I submitted testimony in Docket No. E-01345A-11-0224.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE OTHER STATE REGULTORY COMMISSIONS?

A. Yes. I have submitted testimony in one proceeding before the Oklahoma Corporation Commission. My testimony addressed the topic of natural gas competition. In addition, I have been a contributor to numerous coalition groups and industry organizations in preparing and submitting testimony regarding natural gas and electricity competition and market rules.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I am sponsoring the exhibits listed in the Table of Contents.

Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address Experimental Rider 14, Alternative Generation Service ("AGS") proposed by UNS Electric, Inc. ("UNSE" or "the Company").

Summary of Recommendations

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION.

A. My recommendation to the Commission is to approve AGS with the following modifications:

1) The Commission should reject the management fee as proposed by the Company and require the Company to file a cost-justified management fee proposal.

2) The Commission should reduce the minimum participation size to 1,000 KW and specify that a customer can aggregate utility accounts within its corporate family to meet the participation limit.

3) The Commission should allow all rate classes to participate based on Recommendation 2 above.

4) The Commission should raise the cap to 150 MW of peak load based on the amount of wholesale market purchases currently undertaken by the Company.

5) The Commission should not make an AGS customer responsible for any of the Company's generation related charges or any "lost revenues" since the AGS program is simply replacing wholesale market purchases that the Company would have to make.

The fact that an issue is not addressed herein or in related filings should not be construed as an endorsement of any filed position.

Experimental Rider 14, Alternative Generation Service

Q. PLEASE BRIEFLY DESCRIBE WALMART'S OPERATIONS WITHIN THE COMPANY'S SERVICE TERRITORY.

A. Walmart has three stores that take electric service from UNSE that are currently on the Large Power Service schedule ("LPS"). However, the Company proposes to move these stores to the Large General Service ("LGS") schedule as part of this docket.

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S AGS PROPOSAL?

A. My understanding is that the Company is proposing AGS as a buy-through tariff per the settlement agreement in the acquisition of the Company by Fortis, which settlement agreement was approved by the Commission in Decision No. 74689

(August 12, 2014). However, the Company is not supportive and states that they are opposed to the implementation of the AGS tariff.[1]

As proposed, AGS would be made available for a maximum of 10 MW of peak load for no more than four years from the effective date of the new rates in this docket. Only LPS ratepayers with peak demands of 2,500 KW or more would be allowed to participate.

Participating ratepayers would select their preferred generation service provider to sell power to the Company on the ratepayer's behalf. The Company would then take title to the power and provide it to the ratepayer. The ratepayer would be responsible for all charges and adjustments in the retail rate schedule, except for the Power Supply Charges and the Purchased Power and Fuel Adjustment Charge ("PPFAC"). The Company would still supply transmission, delivery and revenue cycle services under the provisions of the retail rate schedule.[2]

Q. DOES THE COMPANY PROPOSE A MANAGEMENT FEE FOR THE AGS TARIFF?

A. Yes. In Mr. Jones' Direct Testimony on Page 57, Line 9 states that the amount shall be \$0.0060 per kWh, however the AGS Tariff Original Sheet No. 714-2 states that the rate is \$0.0040 per kWh. This difference is not explained in Mr. Jones' Direct Testimony.

[1] See Direct Testimony of Craig A. Jones Page 56, Lines 8 to 14.
[2] See Direct Testimony of Craig A. Jones Page 57, Lines 3 to 12.

Q. IS THE MANAGEMENT FEE THAT THE COMPANY IS PROPOSING FOR THE AGS TARIFF COST BASED AND JUSTIFIED?

A. No. The Company just states the amount of the management fee but does not provide any documentation for the amount. The Company should be allowed to recover the actual just and reasonable costs of providing the AGS services but those costs should be provided for review by the Commission and parties. As such, the Commission should reject the management fee as proposed by the Company and require the Company to file a cost-justified management fee proposal.

Q. IS THE MINIMUM PARTICPATION SIZE (TO ONLY INCLUDE CUSTOMERS WITH PEAK DEMANDS GREATER THAN 2,500 KW) APPROPRIATELY SET?

A. No. The more appropriate minimum participation size would be 1,000 KW. This minimum size would ensure that the participant is sufficiently large enough to be a sophisticated user of electricity and not need any consumer protection requirements.

Q. SHOULD CUSTOMERS BE ALLOWED TO AGGREGATE SITES TO MEET THE PEAK DEMAND THRESHOLD?

A. Yes. A customer should be allowed to aggregate utility accounts within its corporate family to meet the peak demand threshold. This will allow participating customers to leverage economies of scale to reduce their generation supply costs.

Q. SHOULD AGS BE AVAILABLE TO ADDITIONAL RATE CLASES?

A. Yes. As proposed the AGS program would only be available to 4 customers that are proposed to be served on either LPS or LPS-TOU.[3] Based on my recommendation to lower the peak demand threshold and allowing a customer to aggregate utility accounts, all commercial and industrial rate classes should be allowed to participate. This would allow a significant number of customers the opportunity to participate in AGS, which, in my experience, would attract more Generation Service Providers and result in lower costs to participate.

Q. SHOULD THE CAP OF 10 MW OF PEAK LOAD BE EXPANDED?

A. Yes. The cap should be raised to 150 MW of peak load. The 10 MW limit is completely arbitrary and not supported by the Company. The proposed cap, along with the limited number of proposed customers, would severely restrict the amount of Generation Service Providers that would be interested in participating in the AGS program.

Q. HOW DID YOU ARRIVE AT THE 150 MW OF PEAK LOAD CAP?

A. As noted in the Direct Testimony of Michael E. Sheehan, after the Gila River Acquisition, the Company will still be purchasing 175 MW of Market Based Resources.[4] I based the 150 MW cap as a portion of this 175 MW that the Company is already purchasing from the wholesale power market while still allowing the company to purchase an estimated 25 MW from the market. This would significantly reduce the Company's reliance on the wholesale market and transfer the market risk

[3] See Exhibit CAJ-2 Lines 13-14 of the Direct Testimony of Craig A. Jones.
[4] See Direct Testimony of Michael E. Sheehan Section V, Pages 12 – 13.

to customers who are willingly participating in the AGS program. This will shelter UNSE's other ratepayers from market risk and volatility related to the Company's wholesale purchases.

Q. HAS STAFF NOTED THAT THE COMPANY RELIES ON THE SHORT-TERM WHOLESALE MARKET MORE THAN OTHER ARIZONA UTILITIES?

A. Yes. Staff has previously noted that the Company's reliance on the short-term wholesale markets is still higher than other Arizona utilities:

> "The acquisition of Gila River will reduce UNS Electric's reliance on the short term market from approximately 67 percent of its capacity needs to approximately 38 percent. While a significant reduction, UNS Electric's reliance on short term market purchases is still substantially higher than other utilities in Arizona and higher than suggested in the 2012 IRP Staff report."[5]

Q. SHOULD AGS CUSTOMERS BE RESPONISBLE FOR ANY OF THE COMPANY'S GENERATION RELATED CHARGES IN THE BASE RETAIL RATES?

A. No. Since the AGS Program would be replacing the Company's wholesale market purchases, there should be no charges to the participating AGS customers for the Company's generation related costs. In addition, the Company will be able to plan that the AGS Program will be a slice of its total resource mix on an ongoing basis.

Q. SHOULD THE AGS CUSTOMERS BE RESPONISBLE FOR ANY OF THE COMPANY'S CLAIMED LOST REVENUES OR EARNINGS?

A. No. Since the AGS Program would be replacing the Company's wholesale market purchases, there would be no lost revenues or earnings related to AGS.

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[5] Staff Report, Attachment A, (Engineering Analysis) at 10 (UNS Electric Inc. Financing Application (Docket No. E-04204A-13-0447)).

Q. SHOULD THE AGS PROGRAM BE LIMITED TO FOUR YEARS?

A. No. There should be no limit to the length of the program.

Q. DOES THE TERM AFFECT THE ABILITY OF CUSTOMERS TO CONTRACT FOR LARGE SCALE RENEWABLES?

A. Yes. Limiting the program to four years eliminates the ability of customers to purchase long-term contracts especially for off-site renewable contracts like solar and wind, due to the length of contract term needed by renewable developers to build new projects. Many customers would like to purchase more renewables than the Company's forecasted 5% Utility Scale Renewables[6] of its total resource mix. Eliminating the proposed program term will enable Customers to purchase large scale off-site renewables if they desire and it fits their business needs. The purchase of any additional renewable amount would be at the AGS Customer's own choosing and cost and would not harm any other UNSE customers.

Q. DOES THE EXISTENCE OF AGS HARM OTHER NON-AGS CUSTOMERS?

A. No. Contrary to the Company's contention that the existence of AGS allows certain customers to "cherry pick" available capacity resulting from current economic conditions and will ultimately result in costs being passed on to the non-AGS customers,[7] the existence of AGS does not harm any non-AGS customer. The AGS Program is replacing the Company's own wholesale market purchases with those of the customers participating in AGS, thus shifting the risk of the Company's wholesale

[6] See Chart 3 on Page 13 of the Direct Testimony of Michael E. Sheehan.
[7] See Direct Testimony of Craig A. Jones Page 56, Lines 10 to 12.

market purchases from the Company's ratepayers (the non-AGS Customers) to the AGS customers.

Conclusion

Q. GENERALLY, WHAT IS YOUR RECOMMENDATION TO THE COMMISSION ON THE COMPANY'S PROPOSED ALTERNATIVE GENERATION SERVICE?

A. The Commission should approve the Alternative Generation Service Program with my proposed changes outlined above which would enable a customer, if they were willing to participate to choose a wholesale generation product from an alternative service provider that suits their business needs.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Chris W. Hendrix

Director of Markets & Compliance
Wal-Mart Stores, Inc.
Business Address: 2001 SE 10th Street, Bentonville, AR, 72716-5530
Business Phone: (479) 204-0845
Email: chris.hendrix@wal-mart.com

EXPERIENCE

2003 – Present
Wal-Mart Stores, Inc., Bentonville, AR
Director of Markets & Compliance (2009 – Present)
General Manager (2003 – 2009)

2002 –2003
TXU Energy, Dallas, TX
Manager – Retail Pricing (2002 –2003)

1997 - 2001
Enron Energy Services, Houston, TX
Manager – Target Markets (2002 –2003)
Manager – Product Development/Structuring (1999 – 2001)
Senior Specialist (1997 – 1999)

1990 - 1997
Tenneco Energy, Houston, TX
Senior Rate Analyst (1994 – 1997)
Accounting Analyst (1992 – 1994)
Accountant (1991 – 1992)

EDUCATION

1994	**University of Houston**	M.B.A, Finance & International Business
1991	**University of Houston**	B.B.A, Accounting (Magna Cum Laude)

INDUSTRY ORGANIZATIONS

Arizona Independent Scheduling Administrator Association (AzISA)
Board Member (2014 – present)

Arizonans for Electric Choice & Competition (AECC)
Chairman (2013 – present)

COMPETE Coalition
Board Member (2008 – 2013)

Electric Reliability Council of Texas (ERCOT)
Technical Advisory Committee - TAC (2004 – 2006)

National Energy Marketers Association
Chairman (2015 – present)
Executive Committee and Policy Chair (2006 – present)

NEPOOL (ISO New England)
Participants Committee (2011 – present)
Markets Committee (2011 – present)
Consumer Liaison Group (2011 – present)

PJM Interconnection
Market Reliability Committee (2011 – present)
Members Committee (2011 – present)

TESTIMONY

1998

Oklahoma Corporation Commission Cause No. PUD 980000177: Joint Application of Oklahoma Natural Gas Company, A Division of Oneok, Inc., Oneok Gas Transportation, a Division of Oneok, Inc., and Kansas Gas Service Company, a Division of Oneok, Inc., for Approval of Their Unbundling Plan for Natural Gas Services Upstream of the Citygates or Aggregation Points.

2012

Arizona Docket No. E-01345A-11-0224: In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, and to Approve Rate Schedules Designed to Develop Such Return.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

DOUG LITTLE, CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS	DOCKET NO. E-04204A-15-0142

EXHIBIT
Wal-Mart-3
Admit Hey

SURREBUTTAL TESTIMONY OF

CHRIS HENDRIX

ON BEHALF OF

WAL-MART STORES, INC.

February 19, 2016

Contents

Introduction

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Chris Hendrix. My business address is 2001 SE 10th St., Bentonville, AR 72716-0550. I am employed by Wal-Mart Stores, Inc. as Director of Markets and Compliance.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

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

A. My Surrebuttal Testimony is filed on behalf of Wal-Mart Stores, Inc. ("Walmart").

Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to the Rebuttal Testimony of Craig A. Jones in regards to Experimental Rider 14, Alternative Generation Service ("AGS") proposed by UNS Electric, Inc. ("UNSE" or "the Company").

Summary of Recommendations

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION.

A. My recommendation to the Commission is to reject the Company's responses in the Rebuttal Testimony of Craig A. Jones and approve AGS with the following modifications that were detailed in my Direct Testimony:

1) The Commission should reject the management fee as proposed by the Company and require the Company to file a cost-justified management fee proposal.

2) The Commission should reduce the minimum participation size to 1,000 KW and specify that a Customer can aggregate utility accounts within its corporate family to meet the participation limit.

3) The Commission should allow all rate classes to participate based on Recommendation 2 above.

4) The Commission should raise the cap to 150 MW of peak load based on the amount of wholesale market purchases currently undertaken by the Company.

5) The Commission should not make an AGS Customer responsible for any of the Company's generation related charges or any "lost revenues" since the AGS program is simply replacing wholesale market purchases that the Company would in the absence of AGS have to make.

The fact that an issue is not addressed herein or in related filings should not be construed as an endorsement of any filed position.

Response to Rebuttal Testimony of Craig A. Jones

Q. DO YOU AGREE WITH THE COMPANY'S RESPONSES IN THE REBUTTAL TESTIMONY OF MR. JONES?

A. No. I will address the Company's responses individually.

Q. IS THE MANAGEMENT FEE THAT THE COMPANY IS PROPOSING FOR THE AGS TARIFF COST BASED AND JUSTIFIED?

A. No. The Company states "Since the level of participation and therefore the level of personnel necessary to monitor the program, nor the equipment or software needs are known at this time, the initial charge should be large enough to capture any and all possible costs".[1] Walmart agrees that the Company should be allowed to recover the actual just and reasonable costs of providing the AGS services but those costs should be provided for review by the Commission and parties. As such, the Commission should reject the management fee as proposed by the Company and require the Company to file a cost-justified management fee proposal.

Q. DID THE COMPANY RESPOND SUFFICIENTLY TO YOUR INITITAL PROPOSAL TO ALLOW AGS BE AVAILABLE TO ADDITIONAL RATE CLASSES?

A. No. The Company relies numerous times upon the assertion that the Fortis Acquisition Settlement agreement specified that a program like that proposed in Rider 14 be available to customers in the Large Power Service ("LPS") rate class.[2] The Company fails to mention in this portion of its Rebuttal Testimony that, as part of this

[1] See Rebuttal Testimony of Craig A. Jones, Page 52 Lines 5-8.
[2] Ibid, Page 52 Lines 19-21.

proceeding, they are proposing to change the definition of LPS; moving ten (10) customers, including Walmart, from LPS to Large General Service ("LGS") and leaving four (4) customers in the LPS class. Walmart has three (3) stores, the entirety of our portfolio in the UNS service territory, that are currently on LPS that will be switched to the LGS schedule as part of this proceeding which would make them ineligible for AGS if the Company's proposal is approved. The operational characteristics of these Walmart locations have not changed, only the definition by the Company of a LPS customer after the Fortis Acquisition Settlement was agreed upon. Given these circumstances, at the very least, AGS should be available to all LPS and LGS customers.

Q. DID THE COMPANY UNDERSTAND YOUR RATIONALE REGARDING RAISING THE CAP TO 150 MW AND SUPPLANTING THE COMPANY'S MARKET POWER PURCHASES?

A. No. The Company does not seem to understand that my increased cap proposal is to supplant the market power purchases in the future. Since the Company is buying power on the open market, the AGS Program with my increased cap of 150 MW is replacing the Company's own wholesale market purchases with those of the Customers participating in AGS.

Q. WOULD REPLACING THE COMPANY'S MARKET POWER PURCHASES WITH PURCHASES MADE BY AGS CUSTOMERS INCREASE THE COST OR HARM OTHER NON-AGS CUSTOMERS?

A. No. The AGS Program is replacing the Company's own wholesale market purchases with those of the Customers participating in AGS, thus shifting all of the risk of the

Company's wholesale market purchases from the the non-AGS Customers to the AGS Customers.

Q. COULD YOU CLARIFY YOUR PROPOSAL IN DIRECT TESTIMONY THAT THE AGS PROGRAM SHOULD NOT BE LIMITED TO FOUR YEARS?

A. Yes. To be clear, the proposal in my Direct Testimony is that the AGS program term should not be tagged with an "Experimental" or "Pilot" program determination. The Company relies upon the argument that a buy-through program needs to be tested and evaluated and that the Fortis Acquisition Settlement specified that the program be a pilot.[3] There is ample evidence in Arizona from the APS AG-1 program and in various other jurisdictions around the country (including Central Hudson in New York which is also owned by Fortis) and the world (including the provinces of Alberta and Ontario in Canada where Fortis operates Distribution Utilities) that electric competition is an effective way for a customer to manage their electricity needs to better suit their business needs. Furthermore, limiting the program to a set term of four years precludes a Customer from the ability to purchase long-term contracts especially for off-site renewable contracts like solar and wind, due to the length of contract term needed by renewable developers to build new projects. These purchases of an additional renewable amount than the Company would otherwise provide ratepayers would be at the AGS customer's own choosing and cost and would not harm any other UNSE customers. This would have the added benefit of

[3] See Rebuttal Testimony of Craig A. Jones, Page 54 Lines 12-15.

increasing the renewable fuel mix for all of Arizona with no risk to any other non-AGS ratepayers.

Conclusion

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

SUSAN BITTER SMITH, CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
DOUG LITTLE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS	DOCKET NO. E-04204A-15-0142

EXHIBIT
tabbies
Wal-Mart-4
Admitted

TESTIMONY AND EXHIBITS OF

GREGORY W. TILLMAN

ON BEHALF OF

WAL-MART STORES, INC.

DECEMBER 9, 2015

Contents

Exhibits

Introduction

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Gregory W. Tillman. My business address is 2001 SE 10th St., Bentonville, AR 72716-0550. I am employed by Wal-Mart Stores, Inc. as Senior Manager, Energy Regulatory Analysis.

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

A. I am testifying on behalf of Wal-Mart Stores, Inc. ("Walmart").

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. I earned a Bachelor of Science in Electrical Engineering from the University of Tulsa in 1987. I have more than 23 years of experience in the regulated and deregulated energy industry including roles in regulatory, pricing, billing, and metering information. After serving on active duty as a Signal Officer in the United States Army, I joined Public Service Company of Oklahoma ("PSO") where I was employed in various positions in the Information Services, Business Planning, Rates and Regulatory, and Ventures departments from 1990 through 1997. Within the Rates and Regulatory department I served as the Supervisor of Power Billing and Data Collection. In this position I managed the billing for large industrial and commercial customers and led the implementation of the company's real-time pricing program. I also managed the implementation of real-time pricing for three other utilities within the Central and South West Corporation – Southwestern Electric Power Company ("SWEPCO"), Central Power and Light ("CPL") and West Texas Utilities ("WTU"). Following my employment at PSO, I joined the Retail department of the Williams Energy Company as the manager of systems for the retail gas and electric data and billing systems in 1997. During this time I also managed the customer billing function at Thermogas and billing and accounting systems support functions at Williams Communications. In 2000, I joined Automated Energy where I served as the Vice President of Energy Solutions for two years. Following several assignments as a consultant and project manager in various industries, I joined OG&E in 2008 as a senior pricing analyst, was promoted to Manager of Pricing in January 2010, and became the Product Development Pricing Leader in 2013. While at OG&E, I was instrumental in developing and managing OG&E's pricing strategy and products including – the design and implementation of the OG&E's SmartHours™ rate. I have been in my current position as Senior Manager, Energy Regulatory Analysis at Walmart since November 2015. My Witness Qualification Statement is found in Exhibit GWT-1.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE ARIZONA CORPORATION COMMISSION ("THE COMMISSION")?

A. No.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE OTHER STATE REGULTORY COMMISSIONS?

A. Yes. I have submitted testimony in proceedings before the Oklahoma Corporation Commission and Arkansas Public Service Commission. My testimony addressed the topics of rate design, revenue allocation, pricing, customer impacts, tariffs and terms and conditions of service.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I am sponsoring the exhibits listed in the Table of Contents.

Q. PLEASE BRIEFLY DESCRIBE WALMART'S OPERATIONS WITHIN THE COMPANY'S SERVICE TERRITORY.

A. Walmart has three stores that take electric service from UNS Electric, Inc. ("UNSE" or "the Company") on the Large Power Service schedule ("LPS"). UNSE proposed rate class modifications will place these stores on the Large General Service ("LGS") rate schedule.

Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address the rate design proposed by UNSE. Specifically, I respond to the rate design proposals that affect the proposed LGS rate class which are supported within the testimonies of Dallas J. Dukes and Craig A. Jones.

Summary of Recommendations

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. My recommendations to the Commission are as follows:

1) The Commission should approve UNSE proposed Cost of Service Model.

2) The Commission should order UNSE to further mitigate the disparity in the Medium and Large General Service rate class' Relative Rate of Return in all future proceedings until all classes are brought to their cost of service.

3) The Commission should order that any reduction in the revenue requirement created by its approval of an ROE lower than that requested by the Company be used primarily to move the Medium/Large General Service class closer to its cost of service.

4) The Commission should approve the Economic Development Rider ("EDR") subject to the development of guidelines for the recovery and allocation of the costs and/or any revenue deficiencies associated with the EDR.

The fact that an issue is not addressed herein or in related filings should not be construed as an endorsement of any filed position.

General Rate Design

Q. WHAT IS WALMARTS POSITION ON SETTING RATES BASED ON THE COST OF SERVICE?

A. Walmart advocates that rates be set by regulatory agencies based on the utility's cost of service. A regulatory policy that supports the fair-cost-apportionment objective ensures that rates reflect cost causation, send proper price signals and minimize price distortions. In addition to the fairness objective, Walmart supports rate structures that encourage the efficient use of electricity in a manner that seeks to minimize the long-term costs of electric service.

Q. WHAT ARE THE COMPANY'S GOALS FOR ITS PROPOSED RATE DESIGN?

A. According to the testimony of Mr. Dukes, UNSE is seeking to establish rates which generally follow the principles set forth in Dr. James C. Bonbright's "Principles of

Public Utility Rates" to drive a reasonable rate design.[1] Mr. Jones elaborates on the goal by explaining the "Company's goal is to create fair and equitable rates for all customer classes under sound Cost-of-Service and Rate Design principles."[2]

Cost of Service Study

Q. WHAT IS THE PURPOSE OF A COST OF SERVICE STUDY?

A. The cost of service study is foundational in establishing distribution of the utility's authorized revenue requirement amongst the various customer or rate classes. This is accomplished by identifying, classifying and allocating total costs to each of the rate classes in a manner that is consistent with how costs are incurred by each rate class.

Q. DO YOU HAVE ANY CONCERNS WITH THE COST OF SERVICE MODEL PRESENTED BY THE COMPANY?

A. No. However, to the extent that alternative cost of service models or modifications to the Company's model are proposed by other parties, Walmart reserves the right to address any such changes in rebuttal testimony.

Revenue Allocation

Q. HAS THE COMPANY PROPOSED A CLASS REVENUE ALLOCATION?

A. Yes. UNSE's proposed rates establish the revenue allocation to each of the classes defined within the Company's cost of service study.

[1] Direct Testimony of Dallas J. Dukes, page 8, line 10 to page 9, line 27.
[2] Direct Testimony of Craig A. Jones, page 8, lines 20-21.

Q. WHAT METRIC DO YOU USE TO DETERMINE IF RATES ACCURATELY REFLECT THE UNDERLYING COST CAUSATION?

A. I employ the relative rate of return ("RROR"), which is a measure of the relationship of the rate of return for an individual rate class to the total system rate of return. A RROR greater than 100 percent means that the rate class is paying rates in excess of the costs incurred to serve that class, and a RROR less than 100 percent means that the rate class is paying rates less than the costs incurred to serve that class. As such, when rates are set such that each class does not have a RROR equal to 100 percent there are inter-class subsidies, as those rate classes with a RROR greater than 100 percent shoulder some of the revenue responsibility burden for the classes with a RROR less than 100 percent.

Q. WHAT ARE THE PROPOSED RATES OF RETURN FOR THE TOTAL COMPANY AND INDIVIDUAL RATE CLASSES?

A. The Company proposed a total return 7.93 per cent.[1] The individual rate classes current and proposed returns and the calculated RROR of each class are shown in Table 1.

Table 1. Company Total and Class Rates of Return on Rate Base

	Total	Residential	Small General Service	Medium/Large General Service	Large Power Service	Lighting
Current Return	2.31%	-3.88%	-1.02%	16.02%	27.95%	3.94%
Proposed Return	7.93%	6.00%	6.40%	12.96%	9.06%	9.06%
Proposed Relative Rate of Return	100.00%	75.66%	80.71%	163.43%	114.25%	114.25%

[1] Schedule G-2, sheet 1 of 1, line 37.

Q. HAS THE COMPANY'S PROPOSED REVENUE ALLOCATION MOVED THE CLASSES CLOSER TO THEIR RESPECTIVE COST OF SERVICE?

A. Yes. All classes have been moved closer to their respective costs of service at the proposed revenue levels. However, as can be seen in Table 1, the Medium/Large General Service class' proposed RROR is 163% of the system average.

Q. DO YOU AGREE WITH THE PROPOSED REVENUE ALLOCATION?

A. No. The proposed return on the Medium/Large General Service class is excessive when compared to other classes. While I do not agree with the proposed rate of return to the LGS class, I am cognizant of the dilemma in which the Company finds itself for this particular case—balancing the proposed increase to the other classes with the goal of bringing each class to its cost of service. This balancing act imposes limitations on the rate at which individual classes can be moved to their equitable proportion of the costs.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE REVENUE ALLOCATION AS PROPOSED?

A. At the Company's proposed revenue requirement, I am not opposed to the revenue allocation proposed by the Company. In order to ensure future mitigation of the disproportionate share of revenue in the Medium/Large General Service Class. I recommend that the Company be ordered to further mitigate the disparity in the Medium and Large General Service rate class' Relative Rate of Return in all future proceedings until all classes are brought in line with their cost of service.

Q. HAS WALMART TESTIFIED TO THE OVERALL RATE OF RETURN BEING PROPOSED BY THE COMPANY?

A. Yes. Steve W. Chriss has testified to the ROE proposed by the Company as being excessive when assessed against the recent trends of commission ordered returns on equity in other cases. Within his testimony, Mr. Chriss proposed that the Commission order an ROE limited to the most recently approved ROE for UNSE, or 9.5 percent.

Q. IF THE COMMISSION ORDERS AN ROE LOWER THAN THAT PROPOSED BY THE COMPANY, HOW SHOULD THE REVENUE ALLOCATION TO EACH CLASS BE MODIFIED?

A. I recommend that any resulting reduction in revenue requirement created by a Commission approved ROE lower than that requested by the Company be primarily used to move the Medium/Large General Service class closer to its cost of service—the stated objective of the Company.

Rate Structure

Q. DOES WALMART HAVE ANY ISSUES WITH THE PROPOSED RATE STRUCTURE FOR THE LGS CLASS?

A. No. However, to the extent that alternative rate structures or modifications to the rate structures are proposed by other parties, Walmart reserves the right to address any such changes in rebuttal testimony.

Economic Development Rider

Q. HAS THE COMPANY PROPOSED AN ECONOMIC DEVELOPMENT RIDER ("EDR")?

A. Yes. UNSE has proposed the implementation of a discount based economic development program that reduces the electric billing for existing or new customers that add or expand load within the Company's service territory.

Q. DOES WALMART SUPPORT THE INTRODUCTION OF THE EDR?

A. Walmart is receptive to the approval of the EDR and agrees with the underlying drivers and need for the program.

Q. DO YOU HAVE ANY CONCERNS WITH THE APPROVAL OF THIS RIDER AS PRESENTED BY THE COMPANY?

A. Yes. The Company has not provided information on the disposition of the costs or the future treatment of any revenue deficiencies created by the use of the rider.

Q. WHAT ARE YOUR RECOMMENDATIONS FOR CHANGES TO THE ECONOMIC DEVELOPMENT RIDER IN ORDER TO BE SUPPORTIVE OF ITS APPROVAL?

A. Prior to approval, the Company should be required to provide a cost recovery plan that provides guidelines for the recovery and fair allocation of the costs and/or any revenue deficiencies associated with the EDR.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes

Gregory W. Tillman

Senior Manager, Energy Regulatory Analysis
Wal-Mart Stores, Inc.
Business Address: 2001 SE 10th Street, Bentonville, AR, 72716-0550
Business Phone: (479) 204-7993

EXPERIENCE

November 2015 – Present
Wal-Mart Stores, Inc., Bentonville, AR
Senior Manager, Energy Regulatory Analysis

November 2008 – November 2015
Oklahoma Gas & Electric, Oklahoma City, OK
Product Development Pricing Leader
Manager, Pricing
Senior Pricing Analyst

May 2006 – November 2008
LSG Solutions, Oklahoma City, OK
Project Manager, International Registration Plan/Interstate Fuel Tax Agreement Systems Development

August 2002 – May 2006
OnPeak Utility Solutions, Oklahoma City, OK
Owner/Consultant

May 2000 – August 2002
Automated Energy, Inc., Oklahoma City, OK
Vice President, Utility Solutions

November 1997 – May 2000
Williams Energy, Tulsa, OK
Sr. Manager Accounting Services
Process Manager, Customer Billing and Accounting
Retail Systems Manager, Billing and Electricity

May 1990 – November 1997
Public Service Company of Oklahoma, Tulsa, OK
Manager, Software Development and Support
Supervisor, Data Translation and Power Billing
Administrator, Disaster Recovery and Research and Development
Programmer/Analyst

June 1987 – May 1990
United States Army, Signal Command, Ft. Monmouth, NJ
Project Officer, Joint Tactical Information Distribution System

EDUCATION

1991-1994	**The University of Tulsa**	Graduate Coursework, M.B.A.
1987	**The University of Tulsa**	B.S., Electrical Engineering

TESTIMONY BEFORE REGULATORY COMMISSIONS

2012

Arkansas Public Service Commission Docket No. 12-067U: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order Approving a Temporary Surcharge to Recover the Costs of a Renewable Wind Generation Facility.

2011

Oklahoma Corporation Commission Cause No. PUD 201100087: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

2010

Arkansas Public Service Commission Docket No. 10-067U: In the Matter of the Application of Oklahoma Gas and Electric Company for Approval of a General Change in Rates and Tariffs

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

DOUG LITTLE, CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS	DOCKET NO. E-04204A-15-0142

EXHIBIT
tabbies
Wal-Mart-5
admitted

SURREBUTTAL TESTIMONY OF

GREGORY W. TILLMAN

ON BEHALF OF

WAL-MART STORES, INC.

FEBRUARY 19, 2015

Contents

Exhibits

Exhibit GWT-S-1 – Schedule G-2 Proposed Rates

Exhibit GWT-S-2 – Calculation of Subsidies for the UNSE Direct and Rebuttal Cases

Introduction

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Gregory W. Tillman. My business address is 2001 SE 10th St., Bentonville, AR 72716-0550. I am employed by Wal-Mart Stores, Inc. as Senior Manager, Energy Regulatory Analysis.

Q. DID YOU FILE DIRECT RESPONSIVE TESTIMONY IN THIS CASE?

A. Yes.

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

A. I am testifying on behalf of Wal-Mart Stores, Inc. ("Walmart").

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I am sponsoring the exhibits listed in the Table of Contents.

Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address the modifications to rate design proposed by UNSE. Specifically, I respond to the changes in the rate design proposals that affect the proposed LGS rate class and are supported within the rebuttal testimonies of Dallas J. Dukes and Craig A. Jones.

Summary of Recommendations

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION FROM YOUR DIRECT TESTIMONY.

A. My recommendations to the Commission from my Direct Testimony are as follows:

1) The Commission should approve UNSE's proposed Cost of Service Model.

2) The Commission should order UNSE to further mitigate the disparity in the Medium and Large General Service rate class' Relative Rate of Return in all future proceedings until all classes are brought to their cost of service.

3) The Commission should order that any reduction in the revenue requirement created by its approval of an ROE lower than that requested by the Company be used primarily to move the Medium/Large General Service class closer to its cost of service.

4) The Commission should approve the Economic Development Rider ("EDR") subject to the development of guidelines for the recovery and allocation of the costs and/or any revenue deficiencies associated with the EDR.

Q. DO YOU HAVE ANY UPDATES TO YOUR RECOMMENDATIONS??

A. Yes. I am updating my recommendations to the Commission as follows:

5) The Commission should order UNSE to allocate the revenue requirement reductions resulting from a lower ROE as described in this testimony, which will reduce overall subsidy levels and bring all classes closer to their underlying cost of service.

6) The Commission should approve the Economic Development Rider ("EDR") as proposed by the Company in its direct and rebuttal testimonies.

The fact that an issue is not addressed herein or in related filings should not be construed as an endorsement of any filed position.

General Rate Design

Q. DID THE COMPANY STIPULATE TO A REDUCED RETURN ON EQUITY IN ITS REBUTTAL TESTIMONY?

A. Yes, UNSE has stipulated to an ROE of 9.5%.

Q. DID THE REDUCTION IN ROE RESULT IN A REDUCTION TO THE COMPANY'S MARGIN REVENUE AS PROPOSED IN ITS DIRECT CASE?

A. Yes, the margin revenue was reduced from the direct case amount of $92,205,352 to $88,041,483, a reduction of $4,163,869.[1]

Q. **DO YOU HAVE ANY CONCERNS WITH THE REVISED COST OF SERVICE MODEL PRESENTED BY THE COMPANY IN ITS REBUTTAL TESTIMONY?**

A. No. However, to the extent that alternative cost of service models or modifications to the Company's model are proposed by other parties, Walmart reserves the right to address any such proposals.

Revenue Allocation

Q. HAS THE COMPANY PROPOSED A CHANGE TO ITS CLASS REVENUE ALLOCATION TO INCLUDE THE REDUCED MARGIN REVENUE?

A. Yes. The change made to the revenue allocations in the Company's rebuttal case incorporates the reduced margin revenue. I am concerned that the changes also serve

[1] Schedule G-2 Proposed Rates, Line 40, for the respective cases. See Exhibit GWT-S-1

to move all classes, except the lighting class, away from their respective cost of service, relative to UNSE's proposed revenue allocation in its direct case.

Q. HAS THE COMPANY'S REBUTTAL CASE INCLUDED A REDUCTION IN THE PROPOSED SUBSIDY RELATIVE TO THE SUBSIDY IN ITS DIRECT CASE?

A. No. The proposed subsidy level has increased significantly. Specifically, the Company proposes a subsidy of $6,580,312 in its rebuttal case, nearly $3 million higher than the $3,635,421 proposed in its direct case.[1]

Q. IN YOUR DIRECT TESTIMONY, YOU PROVIDED A COMPARISON OF THE RELATIVE RATES OF RETURN ("RROR") FOR THE RATE CLASSES.[2] DID UNSE MAKE IMPROVEMENTS IN THE RROR OF THE MAJOR RATE CLASSES?

A. No. The Company's application of the reduction in revenue requirement caused each of the major rate classes to be moved further from their respective cost of service when compared to the proposed allocation in the direct case. This can be seen in Table 1.

[1] Schedule G-2 Proposed Rates for the respective cases, the total subsidy is the sum of the difference between the class revenue requirement at full cost of service and the class proposed rate revenue for all subsidized classes. See Exhibit GWT-S-2.

[2] Direct Testimony of Gregory W. Tillman, page 6, lines 12-16.

Table 1: Change in Proposed Margin Revenue and RROR

	Total	Residential	Small General Service	Medium/Large General Service	Large Power Service	Lighting
Current Rate Margin Revenue	$ 69,654,260	$ 33,425,187	$ 6,136,594	$ 26,394,695	$ 3,191,840	$ 505,944
Current Rate of Return	2.47%	-3.77%	-0.87%	16.27%	28.64%	4.13%
Company's Direct Case						
Proposed Margin Revenue	$ 92,205,352	$ 53,981,835	$ 8,800,930	$ 26,421,040	$ 2,420,010	$ 581,536
Rate of Return	7.93%	6.00%	6.40%	12.96%	9.06%	9.06%
RROR		76%	81%	163%	114%	114%
Company's Rebuttal Case						
Proposed Margin Revenue	$ 88,041,483	$ 49,353,476	$ 7,953,132	$ 27,631,370	$ 2,521,969	$ 581,536
Rate of Return	9.85%	6.45%	6.34%	18.59%	17.18%	10.41%
RROR		65%	64%	189%	174%	106%

Q. DO YOU AGREE WITH THE COMPANY'S CHANGES IN THE PROPOSED REVENUE ALLOCATION?

A. No. If, as stated by the Company, the goal is to reduce inter-class subsidies, the allocation of the reductions in non-fuel revenues proposed in the Company's rebuttal case does not serve to improve the Company's rate design.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE APPLICATION OF THE REDUCTION IN NON-FUEL REVENUE?

A. In an effort to reduce the inter-class subsidies and move all classes closer to their cost of service, the Commission should order a distribution of the reduced margin revenue resulting from the decreased ROE in a manner that both limits rate increases to customers and further reduces inter-class subsidies. Beginning with the revenue allocation proposed in the Company's direct case, I recommend allocating 25% of the reduction, or $1.04 million, to the classes bearing the subsidy – namely, the Medium/Large General Service class ("M/LGS") and the Large Power Service class ("LPS"). The decrease to the subsidizing classes should be proportioned on the total revenue found in the Company's originally filed rate design from its direct case. The remaining 75% of the reduction, or $3.1 million should be allocated to the classes to which the Company proposed a rate increase in its direct case. The application of this portion of the reduction should be proportionate to the level of increase proposed by the Company within its direct case.

Q. UNDER YOUR PROPOSED GUIDELINES, HOW WOULD THE RESULTING CHANGES AFFECT EACH CLASS' PROPOSED REVENUE?

A. Table 2 provides the calculation of the resulting margin revenues for each class based on my recommendation.

Table 2: Walmart Proposed Distribution of Margin Reduction

Description	Total Jurisdiction	Residential	Small General Service	Medium/Large General Service	Large Power Service	Lighting
Margin Revenue - Direct Case	$ 92,205,352	$ 53,981,835	$ 8,800,930	$ 26,421,040	$ 2,420,010	$ 581,536
Total Revenue - Direct Case	$ 169,727,738	$ 94,209,675	$ 14,569,488	$ 53,726,298	$ 6,603,676	$ 618,601
Proportion of Subsidization				89.05%	10.95%	
Margin Increase - Direct Case	$ 22,551,092	$ 20,556,648	$ 2,664,336	$ 26,345	$ (771,829)	$ 75,592
Proportion of Increase		88.14%	11.42%	0.11%		0.32%
Margin Reduction - Rebuttal	$ (4,163,869)	$ (4,628,359)	$ (847,799)	$ 1,210,330	$ 101,958	$ -
25% of Margin Reduction	$ (1,040,967)					
Allocation to Subsidizing Classes				$ (927,024)	$ (113,944)	
75% of Margin Reduction	$ (3,122,902)					
Allocation to Classes Increased		$ (2,752,502)	$ (356,750)	$ (3,528)	$ -	$ (10,122)
Total Change in Margins	$ (4,163,869)	$ (2,752,502)	$ (356,750)	$ (930,551)	$ (113,944)	$ (10,122)
Proposed Margins	$ 88,041,483	$ 51,229,333	$ 8,444,180	$ 25,490,489	$ 2,306,067	$ 571,414

Q. DOES THE RESULTING REVENUE ALLOCATION RESULT IN A REDUCTION OF THE OVERALL SUBSIDY LEVEL AND MOVEMENT TOWARD THE INDIVIDUAL CLASSES' RESPECTIVE COSTS OF SERVICE?

A. Yes. The subsidy level resulting from the recommended approach is reduced from the Company's proposed $6.5 million to $3.2 million. Under the proposal for allocation of these reductions, every class is moved closer to its own cost of service. The resulting RRORs are shown in Table 3.

Table 3: Walmart Proposed Margin, Rates of Return and RROR

	Total	Residential	Small General	Medium/Large	Large Power	Lighting
Walmart Recommendation						
Proposed Margin Revenue	$ 88,041,483	$ 52,146,834	$ 8,563,097	$ 24,579,343	$ 2,177,421	$ 574,788
Rate of Return	9.85%	8.14%	8.58%	14.26%	11.08%	9.94%
RROR		83%	87%	145%	113%	101%

Q. **IN ADDITION TO MORE CLOSELY ALIGNING WITH THE STATED GOALS, ARE THERE OTHER IMPERATIVES TO MOVING TOWARD RATES THAT REFLECT OF THE UNDERLYING COSTS?**

A. Yes. Simply stated, removal of inter-class subsidies is essential in establishing sound rate design on several fronts. Some of the more pressing issues in utility rate design are being skewed by the existence of intra-class subsidies.

- Subsidies tend to perpetuate themselves by encouraging the inefficient use of system resources. Arguably, the most effective way to ensure efficient operations and proper allocation of system resources is to present proper price signals to consumers. If a particular group of customers is subsidized, then the price signal to that group of customers is artificially low. Pursuant to the theory of own-price elasticity as it applies to electric service (which simply means that consumption of a product increases as its price decreases, and consumption decreases as its price increases), the artificially low price will create an undesirable increase in consumption relative to consumption at the price that accurately reflects the underlying costs. This increased demand will likely result in increased allocation of costs to the subsidized class perpetuating the need for subsidies to the class.
- Subsidies support inequalities in the evaluation and selection of alternative supply options and energy efficiency efforts. If subsidies exist within the rate design, then the underlying economics of alternative supply options or energy efficiency

actions is distorted and customers are likely to accept or reject potential projects based on a value that is not reflective of the true avoided costs. Customers may choose to implement technologies that ultimately provide less benefit than expected or, alternatively, reject projects that, in the long run, would be economically beneficial to themselves, other utility customers, and society.

Economic Development Rider

Q. DOES WALMART AGREE WITH THE APPROVAL OF THE ECONOMIC DEVELOPMENT RIDER AS PRESENTED IN THE COMPANY'S REBUTTAL TESTIMONY?

A. Yes. The Company has clarified its intent and method to make the adjustments necessary to prevent transfer of any revenue deficiencies to other customers.[1] The Commission should approve the Economic Development Rider.

Customer Special Interests

Q. HAS UNSE MADE STATEMENTS WITHIN ITS REBUTTAL TESTIMONY REGARDING WALMART, OTHER CUSTOMERS, AND CUSTOMER INTEREST GROUPS PARTICIPATION IN THIS RATE PROCEEDING?

A. Yes. In the testimony of Mr. Jones, he discourages situations where "*customers seek special treatment to make their rates lower at the expense of other customers.*"[2]

[1] Rebuttal Testimony of Dallas J Dukes, pages 24-28.
[2] Rebuttal testimony of Craig A. Jones, page 33, line 26 – page 34, line 2.

Further, Mr. Jones implies that Walmart and other interveners seek a decision of the Commission to create "winners" at the expense of "losers"[1].

Q. DOES MR. JONES' STATEMENTS ACCURATELY REPRESENT THE INTENT OF WALMART AS A PARTICIPANT IN THIS, OR ANY OTHER, RATE PROCEEDING?

A. Absolutely not. Walmart's motivation as a participant in rate proceedings is to ensure that its interests are heard by the Commission. To characterize Walmart's intent as anything other than exercising its rights and fulfilling its responsibilities as an intervener in a manner that seeks to establish rates based on the cost-causation principles of sound rate-making, is misleading. Walmart seeks "fair treatment" for all customers and desires that Commissions establish rates that require all customers to be responsible for their own costs. My Direct Testimony states Walmart's goal for rate-making in all such proceedings: *"Walmart advocates that rates be set by regulatory agencies based on the utility's cost of service. A regulatory policy that supports the fair-cost-apportionment objective ensures that rates reflect cost causation, send proper price signals and minimize price distortions. In addition to the fairness objective, Walmart supports rate structures that encourage the efficient use of electricity in a manner that seeks to minimize the long-term costs of electric service."*[2]

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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[1] Ibid, page 34, lines 15-18
[2] Direct testimony of Gregory W. Tillman, page 4, lines 14-19

Schedule G-2 Proposed Rates

Original - Direct Case

LINE NO.	DESCRIPTION	TOTAL (A)	RESIDENTIAL SERVICE (B)	SMALL GENERAL SERVICE (C)	MEDIUM/ LARGE GENERAL SERVICE (E)	LARGE POWER SERVICE (G)	LIGHTING (H)
1	**DEVELOPMENT OF RATE BASE**						
2	Electric Plant in Service	$569,545,363	$355,060,733	$54,862,175	$146,410,407	$7,997,295	$5,214,752
3	Depreciation & Amort. Reserve	260,863,085	166,228,675	22,396,618	66,848,412	1,868,317	3,521,063
4	**Net Plant in Service**	$308,682,277	$188,832,058	$32,465,557	$79,561,995	$6,128,978	$1,693,689
5	**ADDITIONS & DEDUCTIONS**						
6	Cash Working Capital	($5,198,426)	($3,240,755)	($500,745)	($1,336,336)	($72,994)	($47,597)
7	Fuel Inventory	276,430	167,165	23,780	73,336	11,700	450
8	Materials & Supplies	11,353,152	7,077,677	1,093,607	2,918,503	159,416	103,949
9	Prepayments	743,554	463,540	71,624	191,142	10,441	6,808
10	Customer Advances for Construction	(3,833,219)	(2,446,421)	(378,008)	(1,008,789)	0	0
11	Customer Deposits	(4,427,886)	(2,188,260)	(1,933,430)	(306,196)	0	0
12	Deferred Credits - Asset Retirement	(421,645)	(262,858)	(40,615)	(108,390)	(5,921)	(3,861)
13	Plant Held for Future Use	0	0	0	0	0	0
14	Regulatory Assets	0	0	0	0	0	0
15	Accum Deferred Income Taxes	(35,161,108)	(21,919,815)	(3,386,938)	(9,038,704)	(493,716)	(321,935)
16	**Total Additions & Deductions**	($36,669,148)	($22,349,727)	($5,050,726)	($8,615,436)	($391,075)	($262,185)
17	**TOTAL RATE BASE**	$272,013,129	$166,482,331	$27,414,831	$70,946,559	$5,737,904	$1,431,504
18	**CLAIMED RATE OF RETURN**	7.67%	7.67%	7.67%	7.67%	7.67%	7.67%
19	**RETURN ON RATE BASE**	$20,852,600	$12,762,580	$2,101,628	$5,438,782	$439,869	$109,739
20	**PROPOSED SALES REVENUE**	$169,727,738	94,209,675	14,569,488	53,726,298	6,603,676	618,601
21	**OTHER OPERATING REVENUES**						
22	Miscellaneous Service Revenue	$1,386,204	$1,100,159	$172,379	$113,665	$0	$0
23	Other Revenue	442,874	212,523	39,018	167,822	20,294	3,217
24	**TOTAL OTHER OPERATING REVENUE**	$1,829,078	$1,312,682	$211,397	$281,487	$20,294	$3,217
25	**TOTAL OPERATING REVENUE**	$171,556,815	$95,522,357	$14,780,884	$54,007,786	$6,623,970	$621,818
26	**OPERATING EXPENSES**						
27	Operation & Maintenance	$120,384,494	$67,436,416	$10,160,314	$37,045,863	$5,428,011	$313,890
28	Depreciation & Amortization	13,059,523	8,029,429	1,297,813	3,377,283	254,484	100,515
29	Interest on Customer Deposits	7,440	3,677	3,249	514	0	0
30	Taxes Other Than Income	6,149,421	3,843,749	597,937	1,576,340	71,007	60,388
31	Tax Expense	8,556,716	4,910,251	755,179	2,529,831	330,282	31,172
32	**TOTAL OPERATING EXPENSES**	$148,157,593	$84,223,522	$12,814,492	$44,529,831	$6,083,785	$505,964
33							
34	**OPERATING INCOME**	$23,399,222	$11,298,835	$1,966,393	$9,477,955	$540,186	$115,854
35	**RATE OF RETURN ON RATE BASE**	8.60%	6.79%	7.17%	13.36%	9.41%	8.09%
36	**RETURN AT PROPOSED RATES**	**$21,570,144**	**$9,986,153**	**$1,754,996**	**$9,196,467**	**$519,892**	**$112,637**
37	**RETURN ON RATE BASE**	**7.93%**	**6.00%**	**6.40%**	**12.96%**	**9.06%**	**7.87%**
38	**INPUTS**						
39	TEST YEAR ADJUSTED SALES (kWh)	1,600,809,167	823,953,185	118,683,796	562,579,661	92,765,274	2,827,250
40	TEST YEAR PROPOSED MARGIN REVENUES	$92,205,352	53,981,835	8,800,930	26,421,040	2,420,010	581,536
41	TEST YEAR PROPOSED FUEL REVENUES	$77,522,386	40,227,839	5,768,557	27,305,258	4,183,666	37,065
42	TEST YEAR ADJUSTED CUSTOMERS	95,144	82,607	8,758	1,387	4	2,388

Schedule G-2 Proposed Rates

Revised - Rebuttal Case

LINE NO.	DESCRIPTION	TOTAL	RESIDENTIAL SERVICE	SMALL GENERAL SERVICE	MEDIUM/ LARGE GENERAL SERVICE	LARGE POWER SERVICE	LIGHTING
		(A)	(B)	(C)	(E)	(G)	(H)
1	**DEVELOPMENT OF RATE BASE**						
2	Electric Plant in Service	$567,545,363	$353,854,482	$54,691,888	$145,878,406	$7,907,798	$5,212,788
3	Depreciation & Amort. Reserve	260,863,085	166,230,083	22,397,394	66,847,792	1,866,186	3,521,630
4	**Net Plant in Service**	$306,682,277	$187,624,399	$32,294,494	$79,030,614	$6,041,612	$1,691,158
5	**ADDITIONS & DEDUCTIONS**						
6	Cash Working Capital	($5,010,668)	($3,124,063)	($482,856)	($1,287,912)	($69,815)	($46,022)
7	Fuel Inventory	276,430	167,165	23,780	73,336	11,700	450
8	Materials & Supplies	11,353,152	7,078,489	1,094,054	2,918,145	158,187	104,276
9	Prepayments	726,837	453,170	70,042	186,822	10,127	6,676
10	Customer Advances for Construction	(3,833,219)	(2,446,503)	(378,132)	(1,008,584)	0	0
11	Customer Deposits	(4,427,886)	(2,188,260)	(1,933,430)	(306,196)	0	0
12	Deferred Credits - Asset Retirement	(421,645)	(262,888)	(40,632)	(108,377)	(5,875)	(3,873)
13	Plant Held for Future Use	0	0	0	0	0	0
14	Regulatory Assets	0	0	0	0	0	0
15	Accum Deferred Income Taxes	(35,161,108)	(21,922,328)	(3,388,324)	(9,037,597)	(489,911)	(322,948)
16	**Total Additions & Deductions**	($36,498,108)	($22,245,218)	($5,035,498)	($8,570,364)	($385,587)	($261,440)
17	**TOTAL RATE BASE**	$270,184,170	$165,379,181	$27,258,996	$70,460,250	$5,656,025	$1,429,718
18	**CLAIMED RATE OF RETURN**	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%
19	**RETURN ON RATE BASE**	$19,501,053	$11,936,555	$1,967,470	$5,085,602	$408,234	$103,193
20	**PROPOSED SALES REVENUE**	$173,345,402	94,097,555	14,277,738	57,570,682	6,776,797	622,630
21	**OTHER OPERATING REVENUES**						
22	Miscellaneous Service Revenue	$1,386,204	$1,100,159	$172,379	$113,665	$0	$0
23	Other Revenue	442,874	212,523	39,018	167,822	20,294	3,217
24	**TOTAL OTHER OPERATING REVENUE**	$1,829,078	$1,312,682	$211,397	$281,487	$20,294	$3,217
25	**TOTAL OPERATING REVENUE**	$175,174,479	$95,410,237	$14,489,134	$57,852,169	$6,797,092	$625,847
26	**OPERATING EXPENSES**						
27	Operation & Maintenance	$127,527,717	$71,562,036	$10,650,914	$39,521,517	$5,480,388	$312,862
28	Depreciation & Amortization	13,059,523	8,029,665	1,297,943	3,377,179	254,128	100,609
29	Interest on Customer Deposits	7,440	3,677	3,249	514	0	0
30	Taxes Other Than Income	6,140,682	3,838,350	597,122	1,574,072	70,810	60,327
31	Tax Expense	0	0	0	0	0	0
32	**TOTAL OPERATING EXPENSES**	$146,735,363	$83,433,728	$12,549,228	$44,473,282	$5,805,326	$473,799
33							
34	**OPERATING INCOME**	$28,439,117	$11,976,509	$1,939,907	$13,378,887	$991,766	$152,048
35	**RATE OF RETURN ON RATE BASE**	10.53%	7.24%	7.12%	18.99%	17.53%	10.63%
36	**RETURN AT PROPOSED RATES**	**$26,610,039**	**$10,663,827**	**$1,728,510**	**$13,097,400**	**$971,472**	**$148,831**
37	**RETURN ON RATE BASE**	**9.85%**	**6.45%**	**6.34%**	**18.59%**	**17.18%**	**10.41%**
38	**INPUTS**						
39	TEST YEAR ADJUSTED SALES (kWh)	1,600,809,167	823,953,185	118,683,796	562,579,661	92,765,274	2,827,250
40	TEST YEAR PROPOSED MARGIN REVENUES	$88,041,483	49,353,476	7,953,132	27,631,370	2,521,969	581,536
41	TEST YEAR PROPOSED FUEL REVENUES	$85,303,919	44,744,078	6,324,606	29,939,311	4,254,829	41,094
42	TEST YEAR ADJUSTED CUSTOMERS	95,144	82,607	8,758	1,387	4	2,388

Calculation of Subsidies for the UNSE Direct and Rebuttal Cases

Calculation of Total and Class Subsidy (Direct Case)

LINE NO.	DESCRIPTION	TOTAL	RESIDENTIAL SERVICE	SMALL GENERAL SERVICE	MEDIUM/ LARGE GENERAL SERVICE	LARGE POWER SERVICE	LIGHTING
		(A)	(B)	(C)	(E)	(G)	(H)
17	**TOTAL RATE BASE**	$272,013,129	$166,482,331	$27,414,831	$70,946,559	$5,737,904	$1,431,504
35	**RATE OF RETURN ON RATE BASE**	8.60%	6.79%	7.17%	13.36%	9.41%	8.09%
36	**RETURN AT PROPOSED RATES**	**$21,570,144**	**$9,986,153**	**$1,754,996**	**$9,196,467**	**$519,892**	**$112,637**
37	**RETURN ON RATE BASE**	**7.93%**	**6.00%**	**6.40%**	**12.96%**	**9.06%**	**7.87%**
38	**INPUTS**						
40	TEST YEAR PROPOSED MARGIN REVENUES	$92,205,352	$53,981,835	$8,800,930	$26,421,040	$2,420,010	$581,536
41	TEST YEAR PROPOSED FUEL REVENUES	$77,522,386	$40,227,839	$5,768,557	$27,305,258	$4,183,666	$37,065
43	Return on Rate Base at Full COS (L37)	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%
44	Return at Full COS (L43 * L17)	$21,570,144	$13,201,745	$2,173,946	$5,625,933	$455,005	$113,516
45	Revenue at Full COS (L54-L36+L40+L41)	$169,727,738	$97,425,267	$14,988,438	$50,155,763	$6,538,790	$619,480
46	Proposed Revenue (L40+L41)	$169,727,738	$94,209,675	$14,569,488	$53,726,298	$6,603,676	$618,601
47	**Class Subsidy/(Subsidization) (L45-L46)**		**$3,215,592**	**$418,950**	**($3,570,535)**	**($64,886)**	**$879**
48	**Total Subsidy (L47:RS + L47:SGS + L47:L)**	**$3,635,421**					

Calculation of Total and Class Subsidy (Rebuttal Case)

LINE NO.	DESCRIPTION	TOTAL	RESIDENTIAL SERVICE	SMALL GENERAL SERVICE	MEDIUM/ LARGE GENERAL SERVICE	LARGE POWER SERVICE	LIGHTING
		(A)	(B)	(C)	(E)	(G)	(H)
17	**TOTAL RATE BASE**	$270,184,170	$165,379,181	$27,258,996	$70,460,250	$5,656,025	$1,429,718
35	**RATE OF RETURN ON RATE BASE**	10.53%	7.24%	7.12%	18.99%	17.53%	10.63%
36	**RETURN AT PROPOSED RATES**	**$26,610,039**	**$10,663,827**	**$1,728,510**	**$13,097,400**	**$971,472**	**$148,831**
37	**RETURN ON RATE BASE**	**9.85%**	**6.45%**	**6.34%**	**18.59%**	**17.18%**	**10.41%**
38	**INPUTS**						
40	TEST YEAR PROPOSED MARGIN REVENUES	$88,041,483	$49,353,476	$7,953,132	$27,631,370	$2,521,969	$581,536
41	TEST YEAR PROPOSED FUEL REVENUES	$85,303,919	$44,744,078	$6,324,606	$29,939,311	$4,254,829	$41,094
43	Return on Rate Base at Full COS (L37)	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%
44	Return at Full COS (L43 * L17)	$26,610,039	$16,287,951	$2,684,698	$6,939,526	$557,054	$140,811
45	Revenue at Full COS (L54-L36+L40+L41)	$173,345,402	$99,721,679	$15,233,926	$51,412,808	$6,362,379	$614,610
46	Proposed Revenue (L40+L41)	$173,345,402	$94,097,555	$14,277,738	$57,570,682	$6,776,797	$622,630
47	**Class Subsidy/(Subsidization) (L45-L46)**		**$5,624,124**	**$956,188**	**($6,157,874)**	**($414,418)**	**($8,020)**
48	**Total Subsidy (L47:RS + L47:SGS)**	**$6,580,312**					