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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 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 FILING DIRECT TESTIMONY OF DR. JAY ZARNIKAU ON RATE DESIGN ON BEHALF OF NUCOR STEEL**

Nucor Steel ("Nucor'), hereby provides notice of filing the Direct Testimony of Dr. Jay Zarnikau on Rate Design, in the above-referenced matter.

DATED this 9 day of December, 2015.

MUNGER CHADWICK, P.L.C.

Robert J. Metli
Attorneys for Nucor Corporation

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ORIGINAL and 13 copies of the foregoing hand-delivered for filing this 9th day of December, 2015 to:

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[SERVICE LIST]

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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. SUMMARY OF CONCLUSIONS

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.

[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,

[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?

[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 load during the Top 20 hours) contributed by that rate class during the previous year, the customer would be billed for one-quarter 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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"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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California PUC Rulemaking 13-09-011 to Enhance the Role of Demand Response. Compared the attributes of different types of demand response. On behalf of Pacific Gas and Electric.

Arkansas PSC Docket No. 13-126-TF: In the Matter of a Request by Arkansas Electric Cooperative Corporation to Establish a Rider for the Collection of Certain Costs Related to the Transmission of Electricity by Other and TRO-Market Administration, Monitoring, and Compliance Services Costs. Reviewed treatment of interruptible discount in rate rider. On behalf of Nucor Steel.

Arizona Corporation Commission Docket No. E-04204A-12-0504: 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 Relative Approvals. Rate Design. On behalf of Nucor Steel.

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

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.

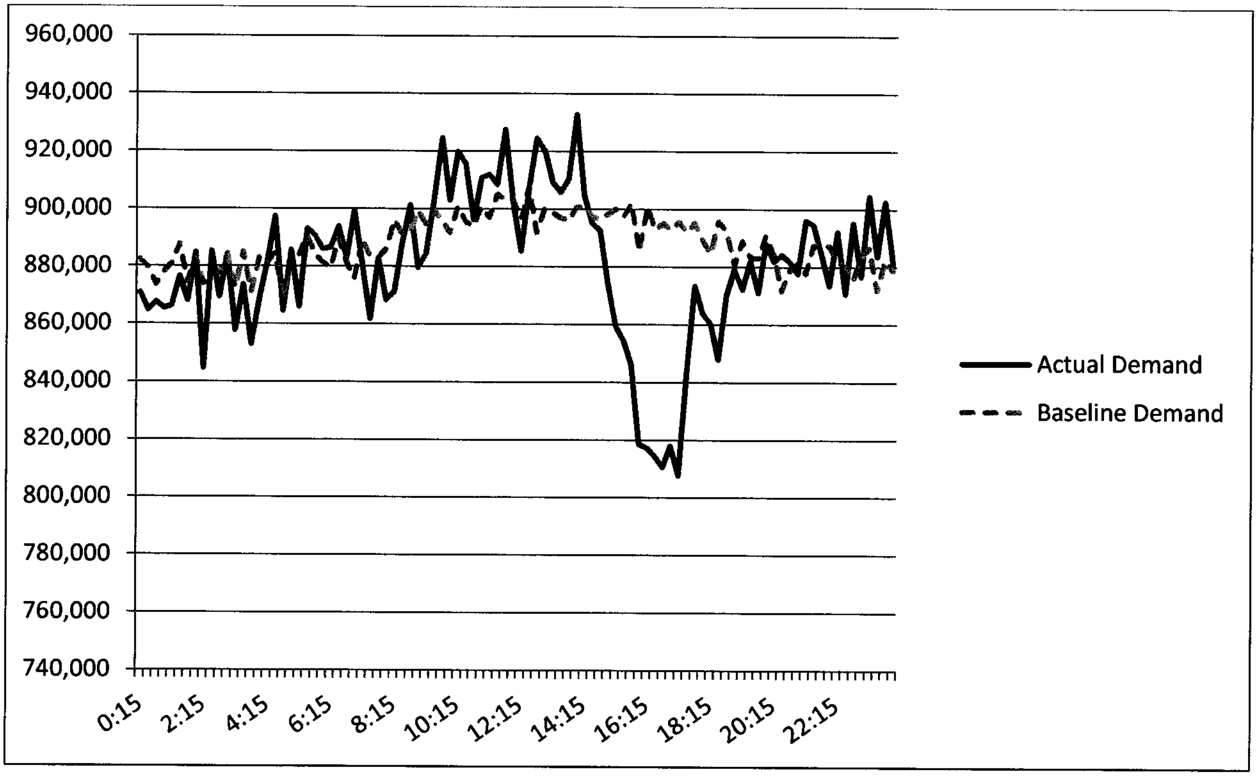

Fig. 1. Energy Consumption (in kWh) by Transmission Voltage Customers on June 16, 2008, Contrasted against Baseline Energy

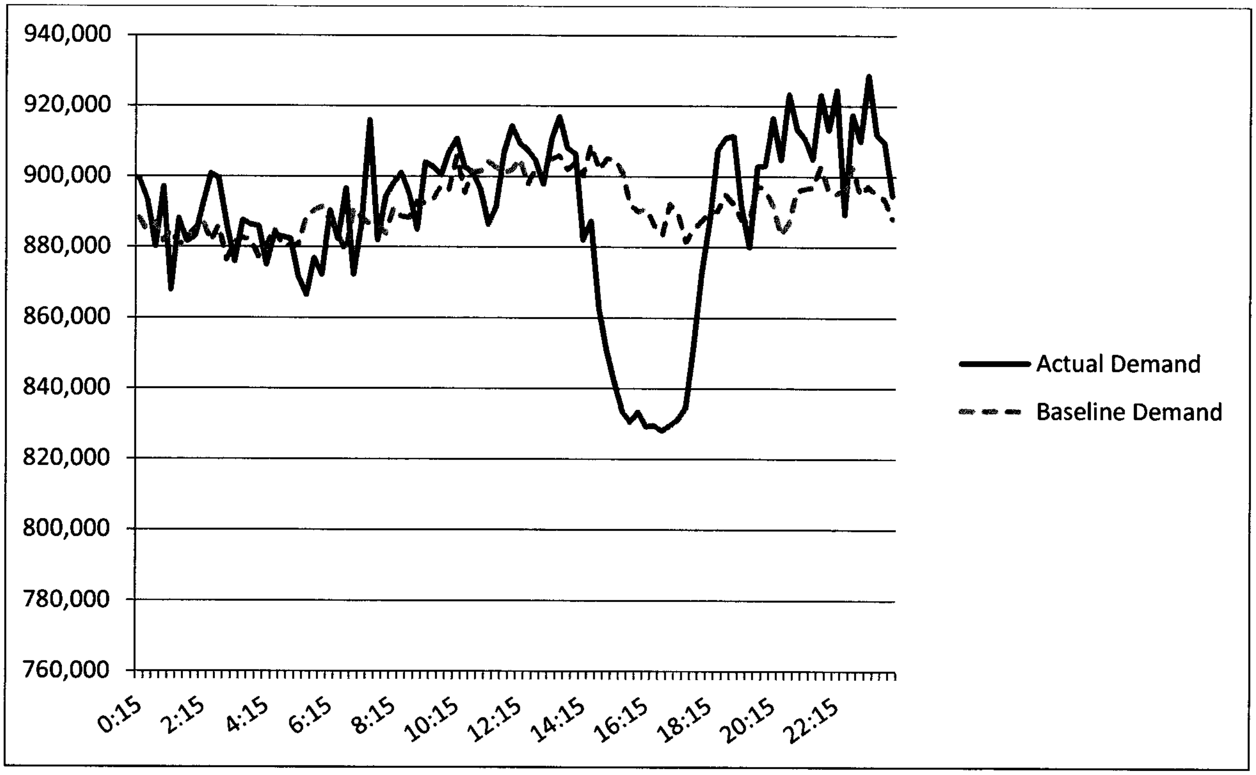

Fig. 2. Energy Consumption (in kWh) by Transmission Voltage Customers on June 26, 2011, Contrasted against Baseline Energy

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.

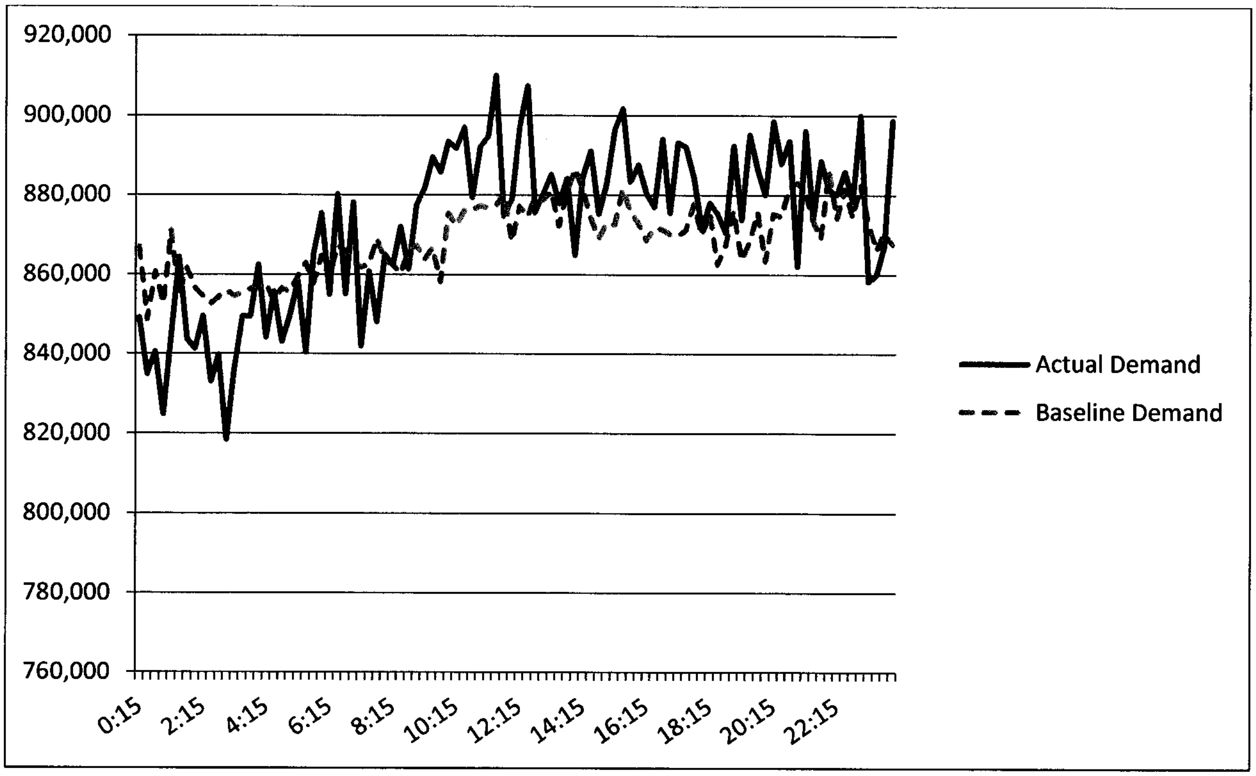

Fig. 3. Energy Consumption (in kWh) by Transmission Voltage Customers on September 2, 2008, Contrasted against Baseline Energy

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.

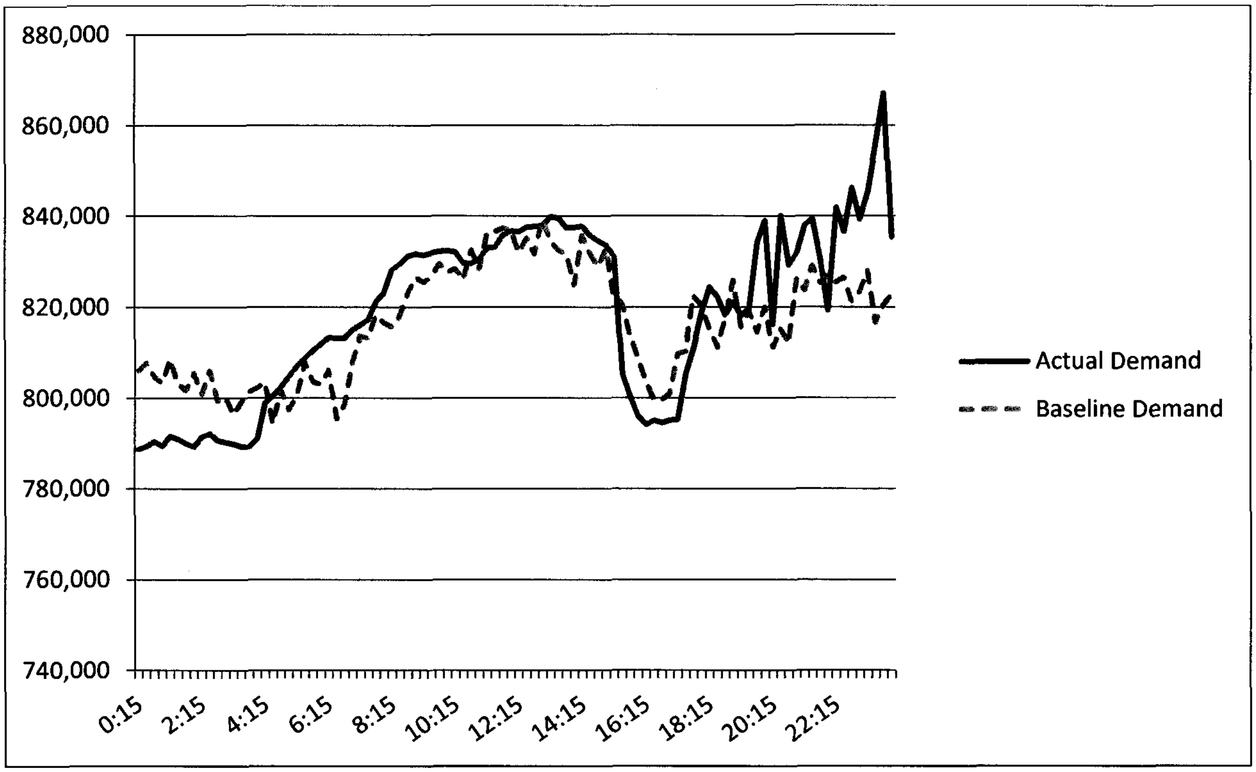

Fig. 4. Energy Consumption (in kWh) by Transmission Voltage Customers on June 21, 2010, Contrasted against Baseline Energy

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:

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www.FrontierAssoc.com | (512) 372-8778

June 23, 2014

Public Version

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.

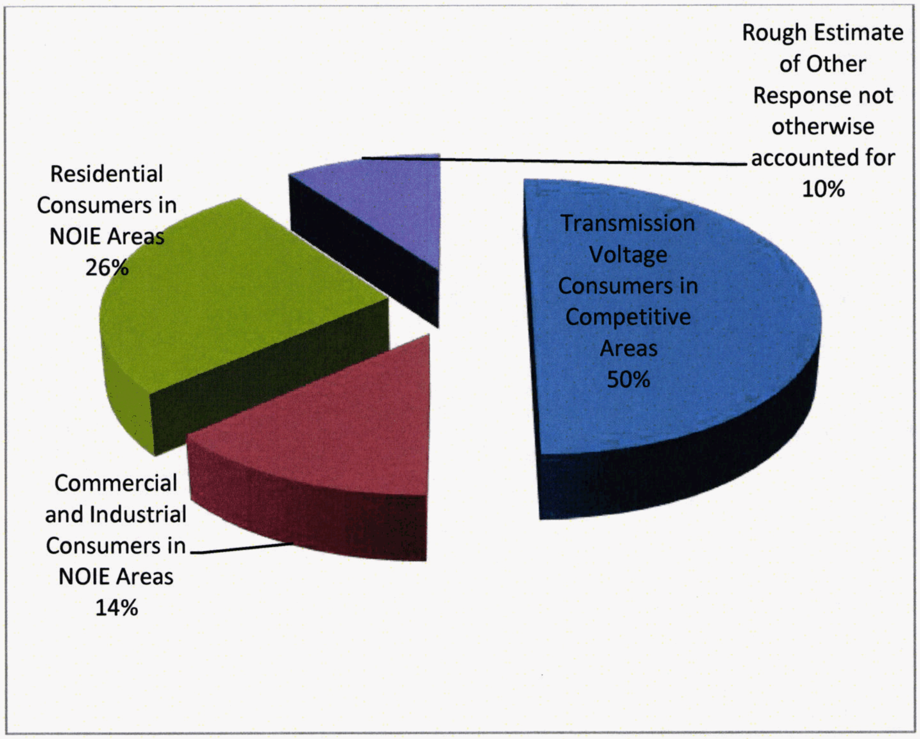

Figure ES.1: Composition of Demand Response during a 4CP by Source

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.

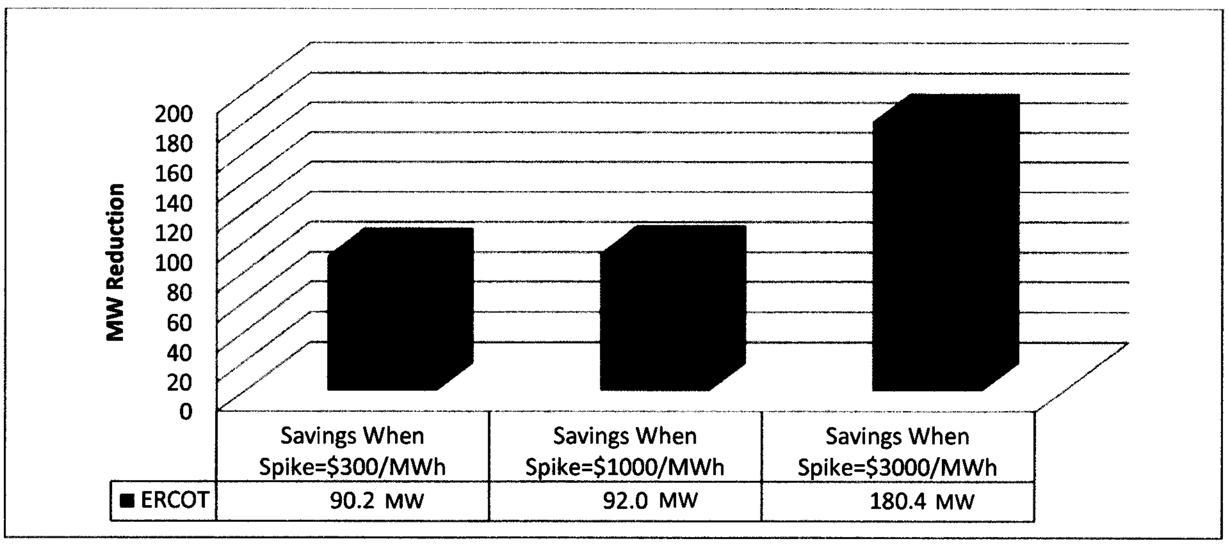

Figure ES.2: Demand Response by Consumers with IDRs Increase as the Wholesale Market Price Increases

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.

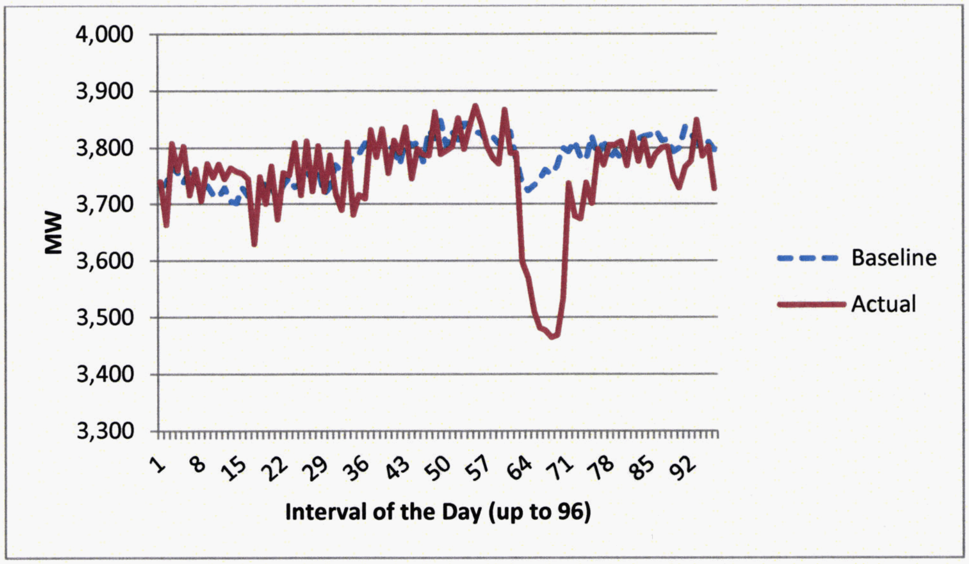

Figure 2.1: Energy Consumption (in kWh) by Transmission Voltage Customers on June 12, 2012, Contrasted against Baseline Energy

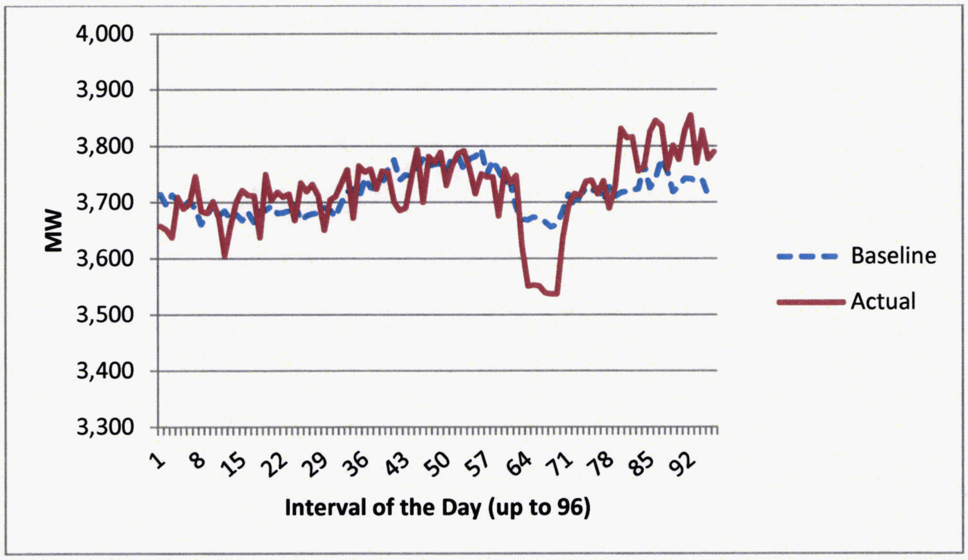

Figure 2.2: Energy Consumption (in kWh) by Transmission Voltage Customers on July 31, 2012, Contrasted against Baseline Energy

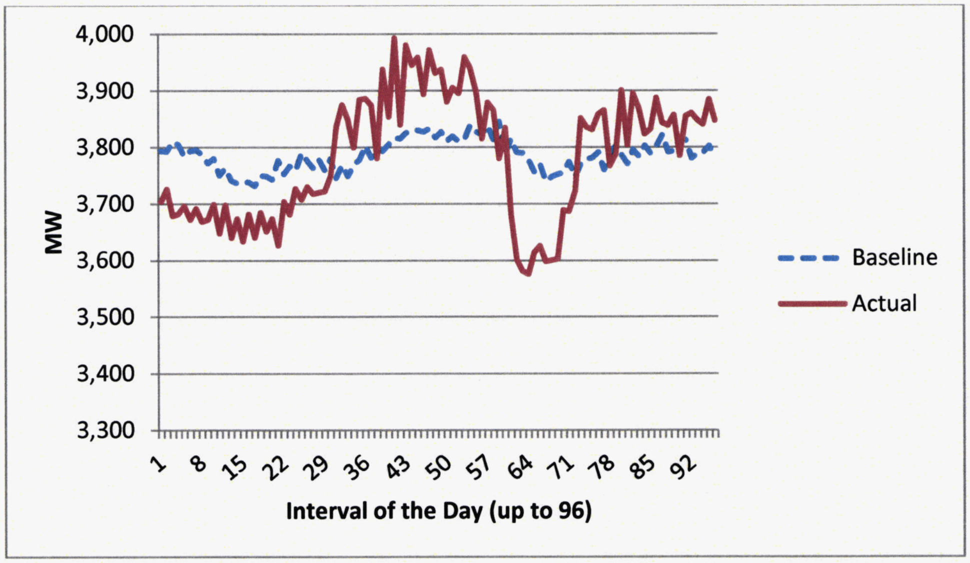

Figure 2.3: Energy Consumption (in kWh) by Transmission Voltage Customers on August 1, 2012, Contrasted against Baseline Energy

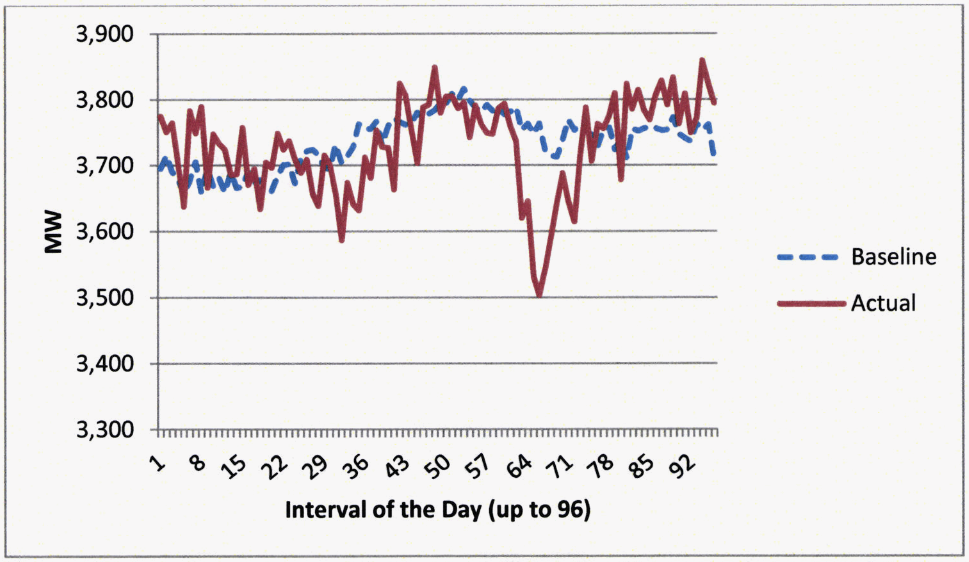

Figure 2.4: Energy Consumption (in kWh) by Transmission Voltage Customers on September 4, 2012, Contrasted against Baseline Energy

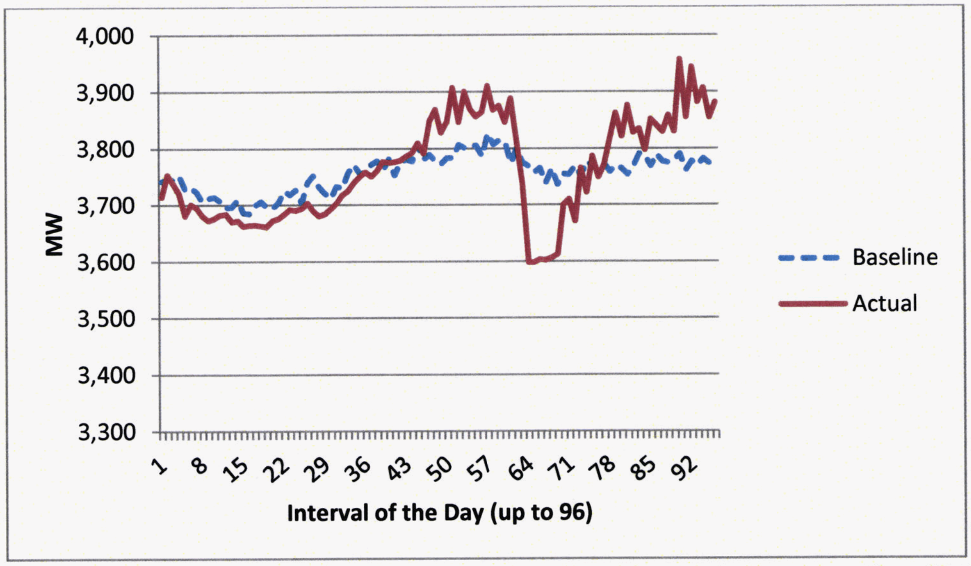

Figure 2.5: Energy Consumption (in kWh) by Transmission Voltage Customers on June 27, 2013, Contrasted against Baseline Energy

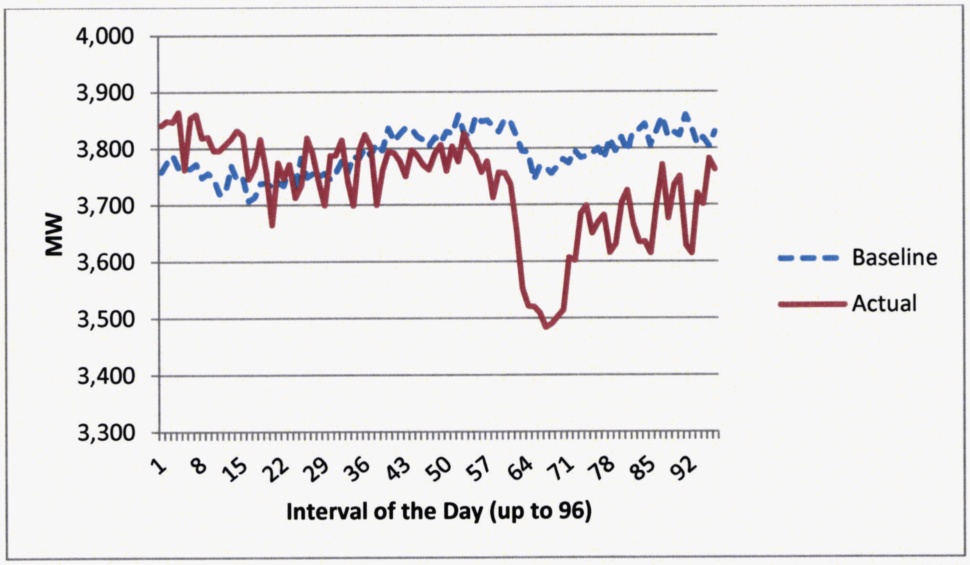

Figure 2.6: Energy Consumption (in kWh) by Transmission Voltage Customers on July 31, 2013, Contrasted against Baseline Energy

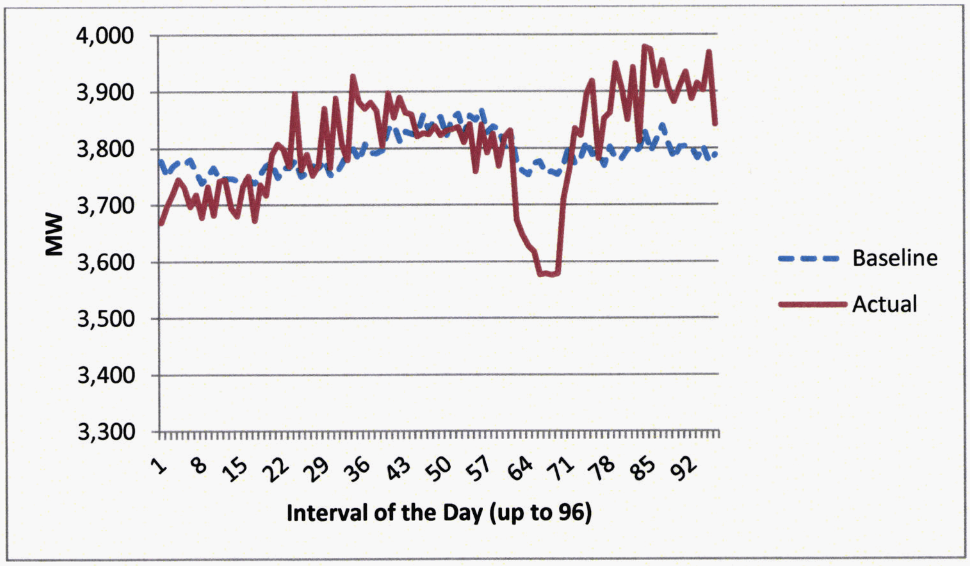

Figure 2.7: Energy Consumption (in kWh) by Transmission Voltage Customers on August 7, 2013, Contrasted against Baseline Energy

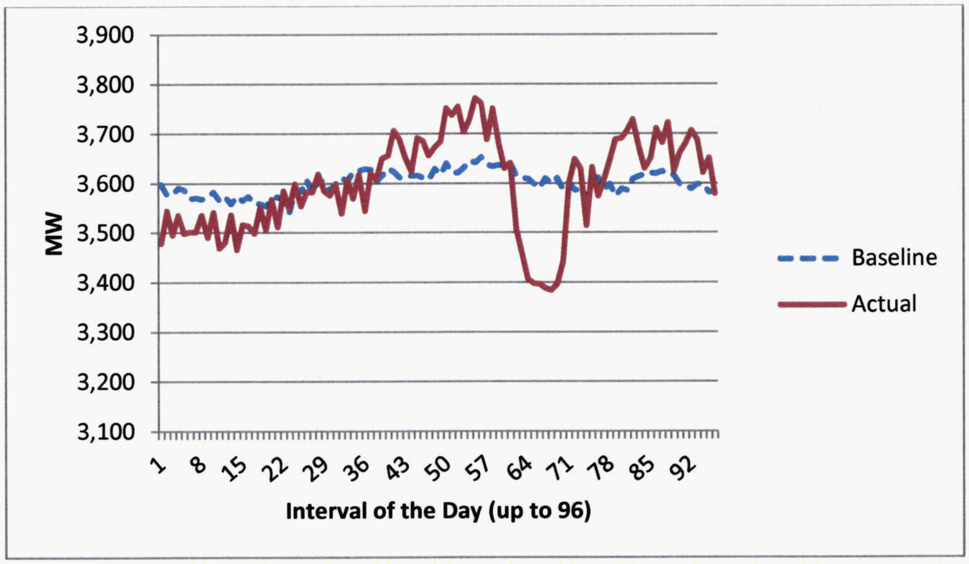

Figure 2.8: Energy Consumption (in kWh) by Transmission Voltage Customers on September 3, 2013, Contrasted against Baseline Energy

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.

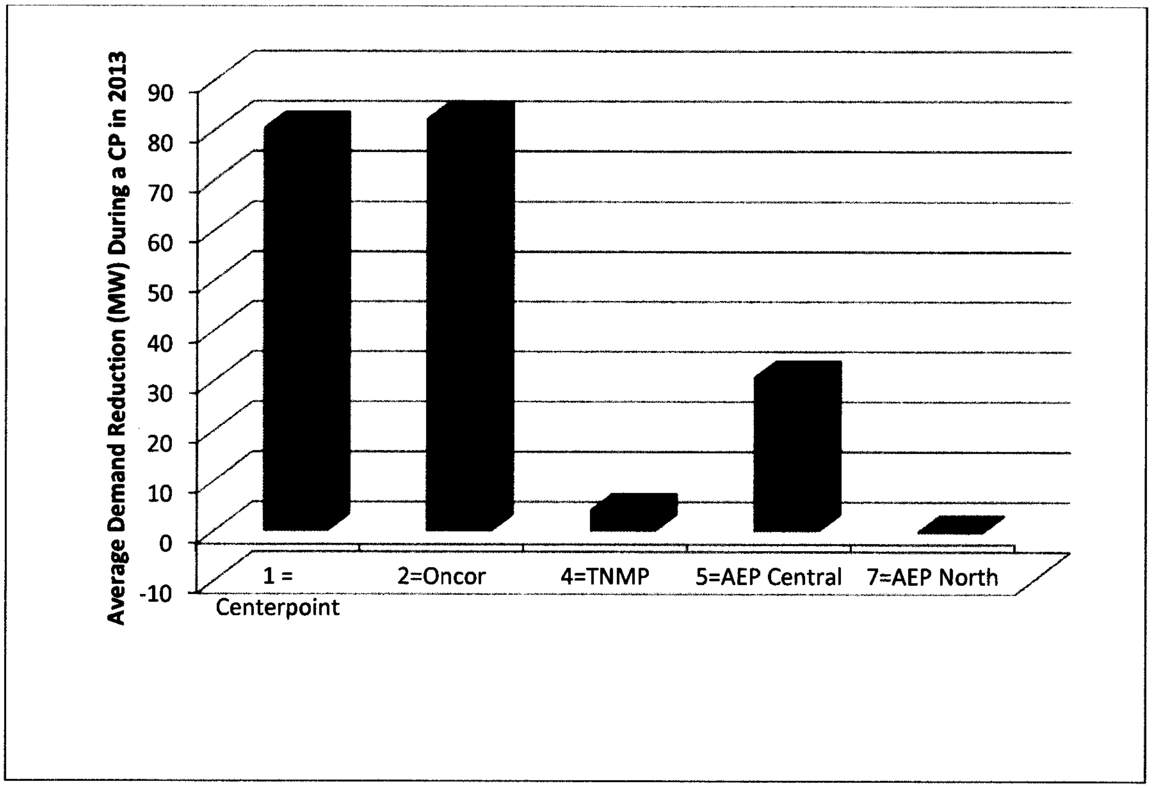

Figure 2.9: Distribution of the 4CP Response in 2013 by TDU Service Area

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.

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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.

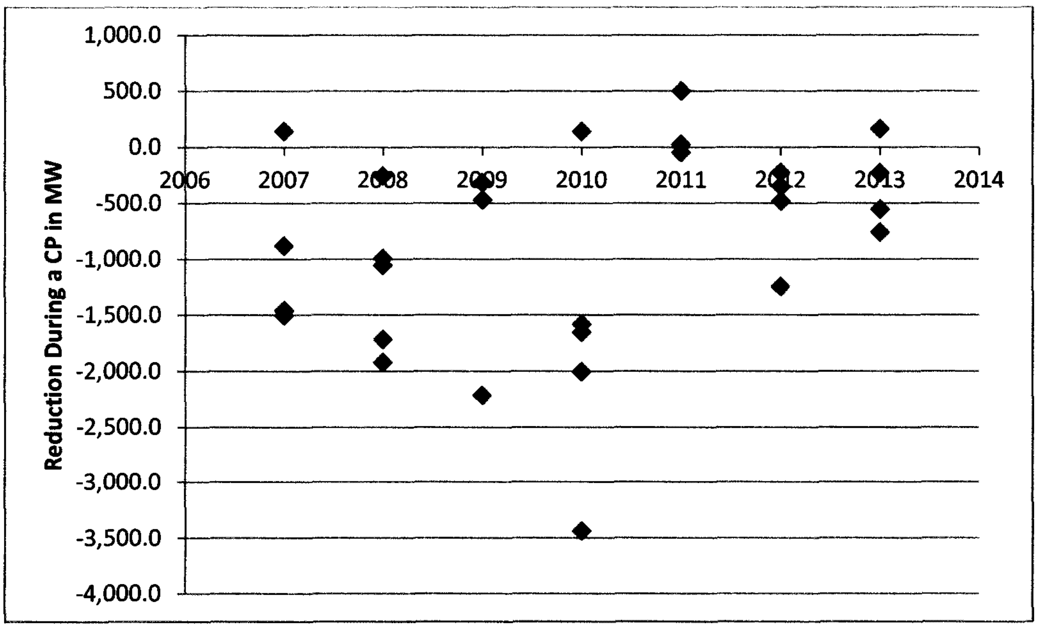


Figure 3.1: Aggregate Demand Reduction in MW of all NOIEs Relative to a 5-Day Adjusted Historical Baseline

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.

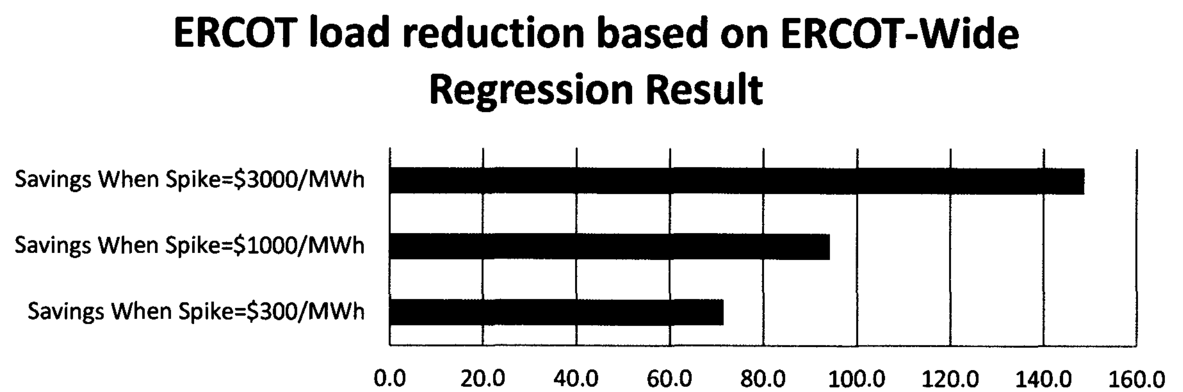
Results and Interpretation

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

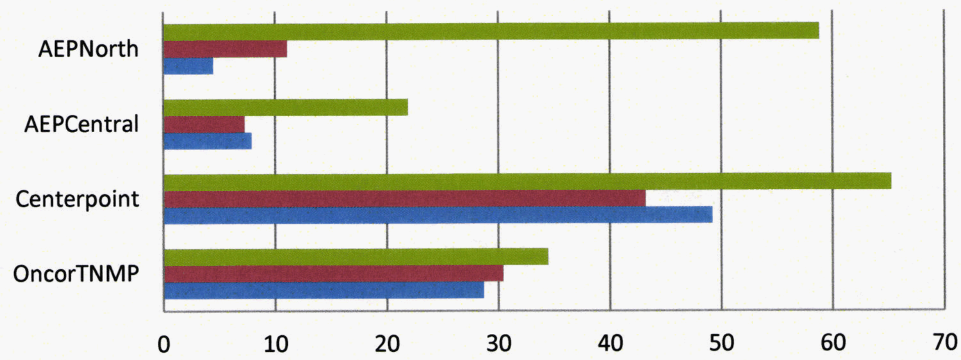
As we can see from the Figure 4.1, we can get an overall load reduction of 71.4MW if the price spike is set at $300/MWh. We can get an overall load reduction of 94.2MW if the price spike is set at $1000/MWh. We can get an overall load reduction of 148.8MW if the price spike is set at $3000/MWh.

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

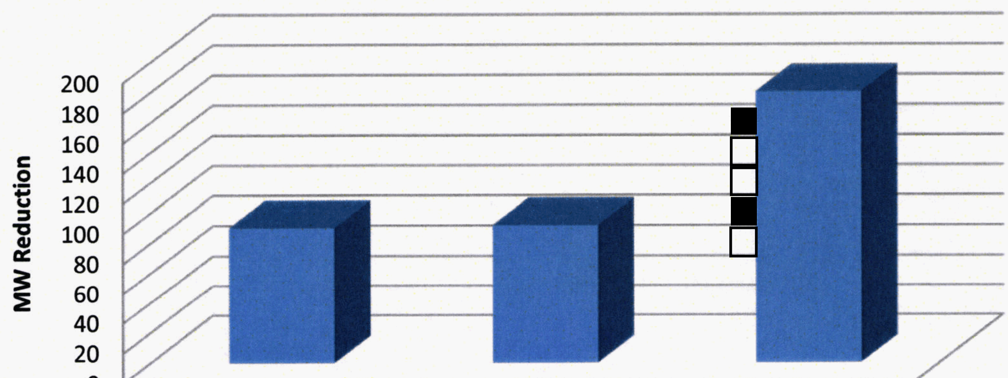
As we can see from the result, the coefficients of spike300, spike1000 and spike3000 show us the 15-minute kWh usage reduction in a price spike. Based on the coefficients in Table 4.3, we can estimate the MW load reduction for different price spikes in four areas:



	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

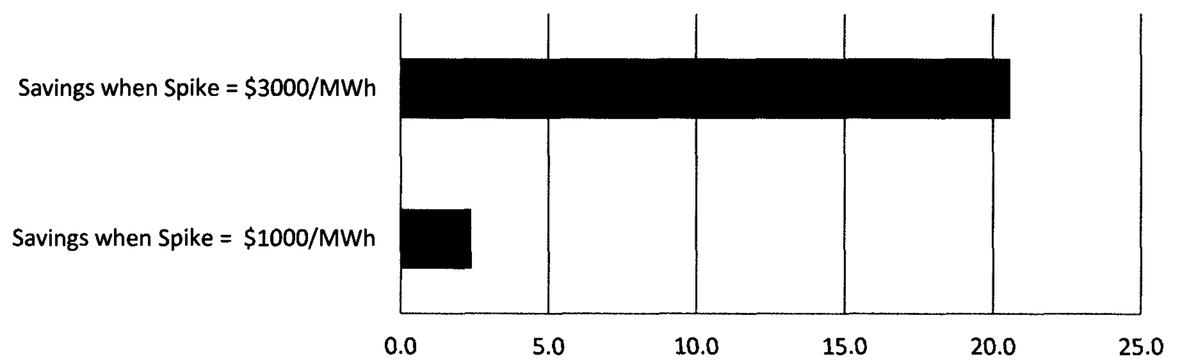
Date	Interval	MW Savings	# Of Customers In Use
4/5/2013	28	133.67	24
9/3/2013	67	87.06	31

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.

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.

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.

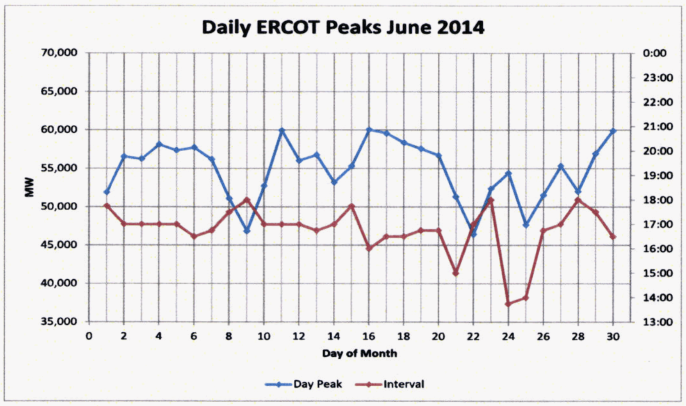
- If the ESIID was classified as a peak responder, a scalar day-of-adjustment was applied to the baseline for calculating the load reduction for the CP/Near-CP day.

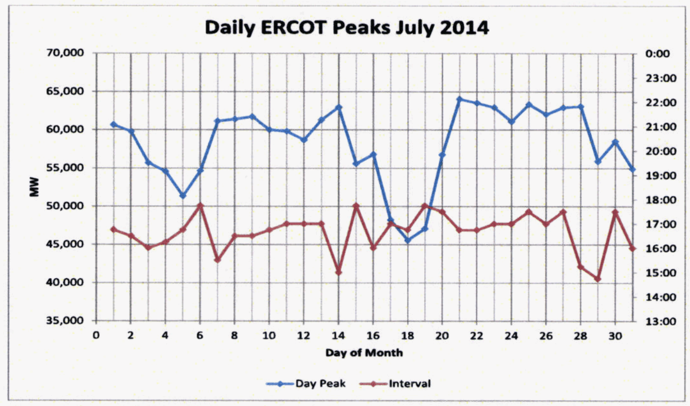
- No scalar adjustment was applied to ESIIDs previously classified as having 'day-use' response.

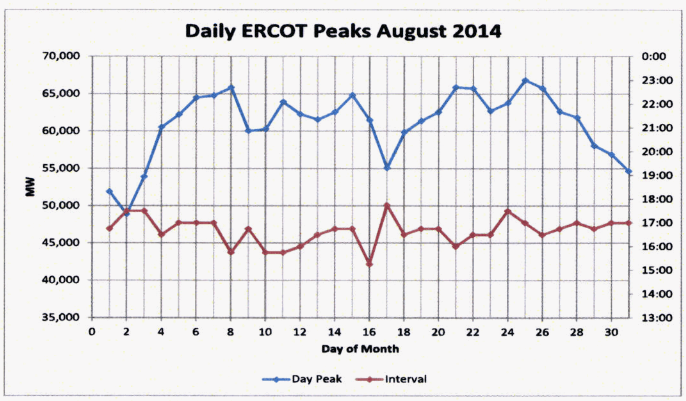
- The methodology was modified from last year to narrow in on response from responding ESIIDs and to more effectively remove the impact of non-responding ESIIDs from reduction calculations.

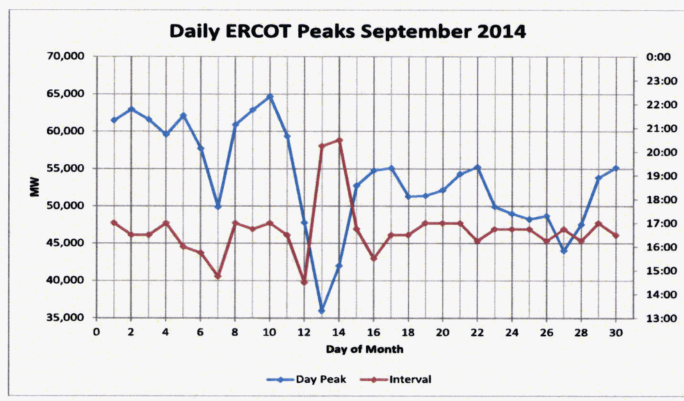
ERCOT Daily Peaks June – September 2014

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



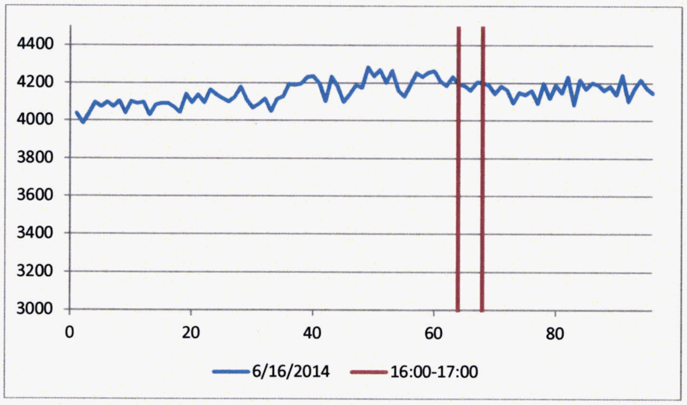


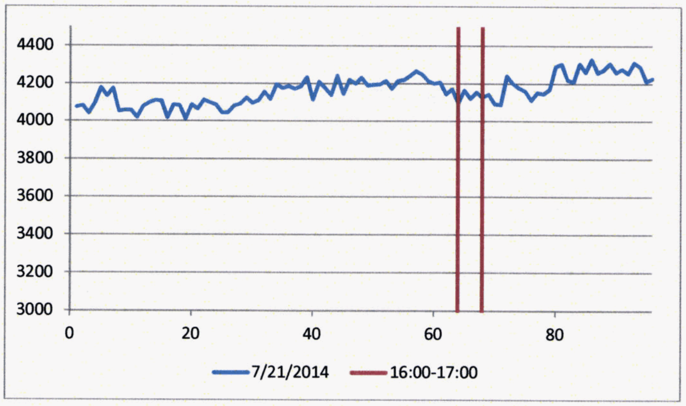


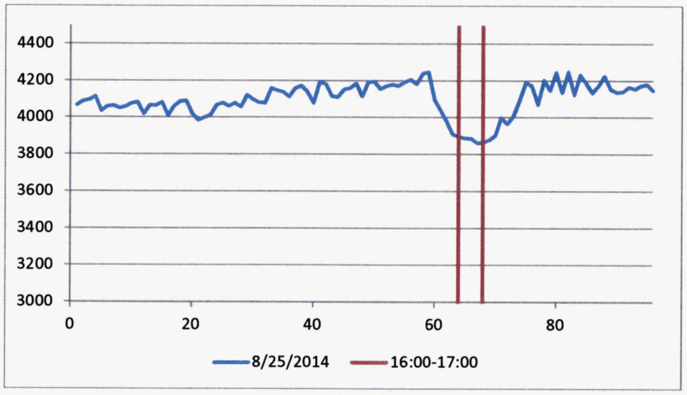


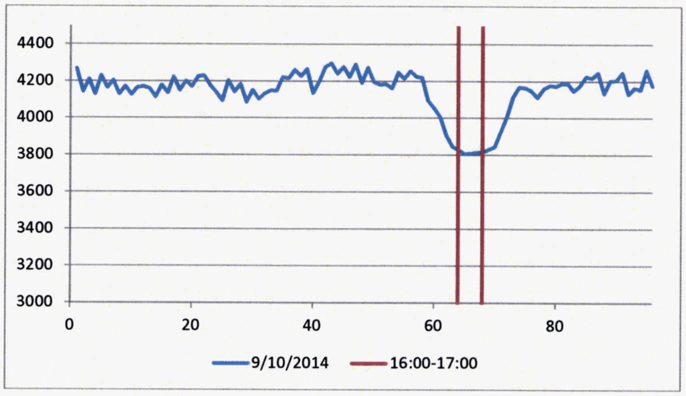
Total Load - Transmission Connected ESIIDs - 2014

Examined Transmission ESIID Load to Identify Near-CP days

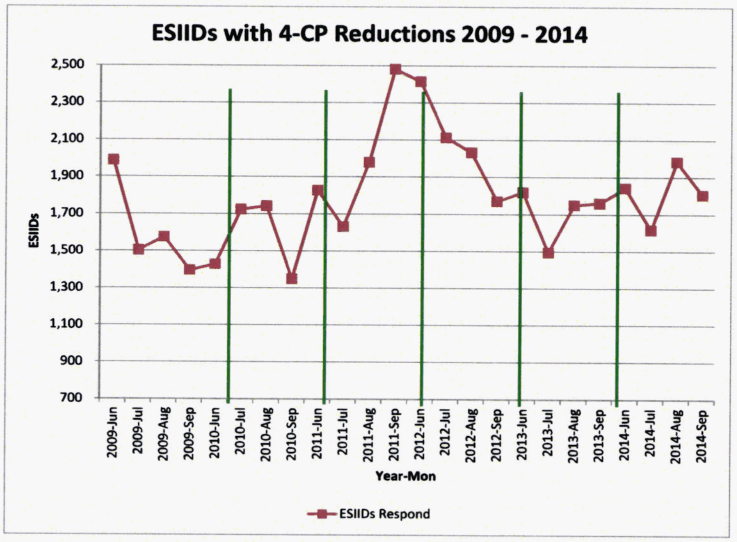


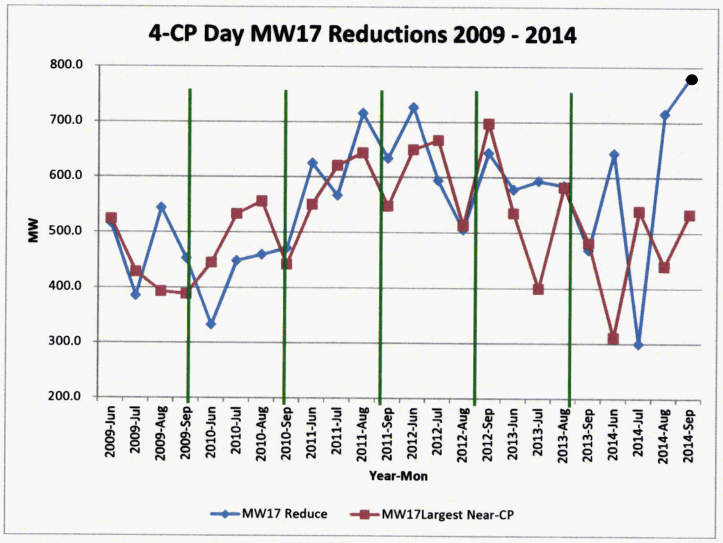






Hour Ending 17:00 Response on 4 CP Days 2009 - 2014





	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

	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				
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

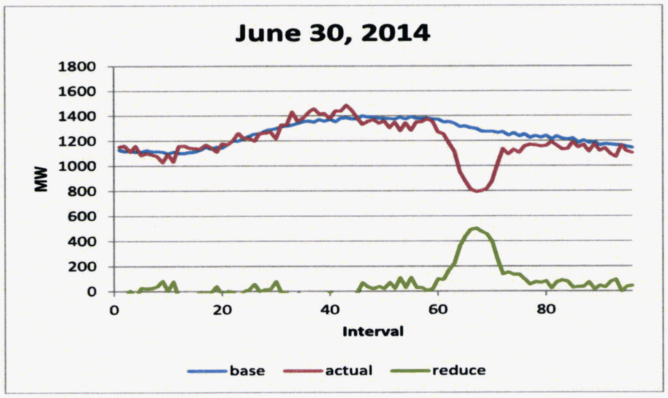
Percentage of Load Reduction based on Customer Peak

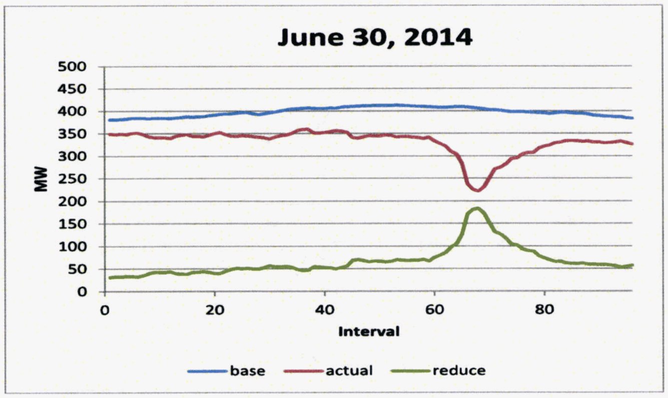
4 CP Days	< 1 MW		1 - 10 MW		10 - 30 MW		> 30 MW		Total Reduction
	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	
30-Jun-14	72.7	11.3%	202.9	31.6%	98.4	15.3%	269.0	41.8%	643.1
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

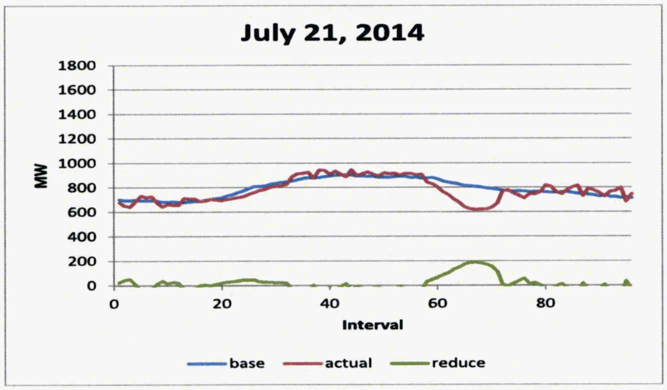
Hour-ending 17:00 Reductions on 4 CP Days - 2014

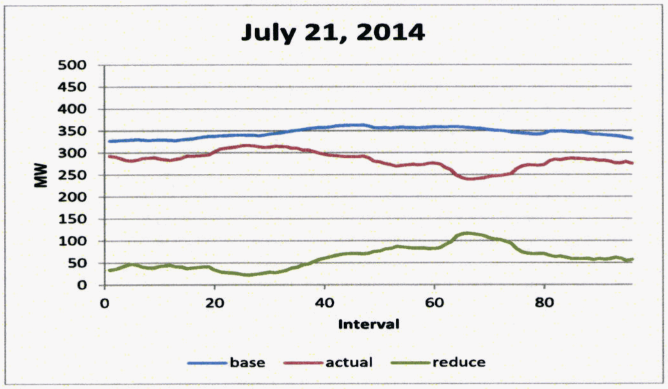
Peak Response

Day-use Response



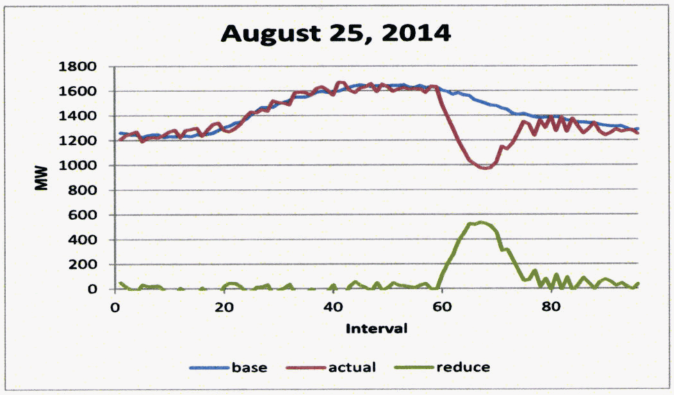


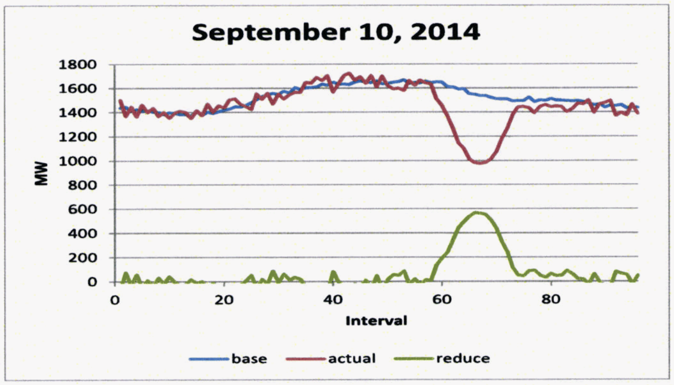




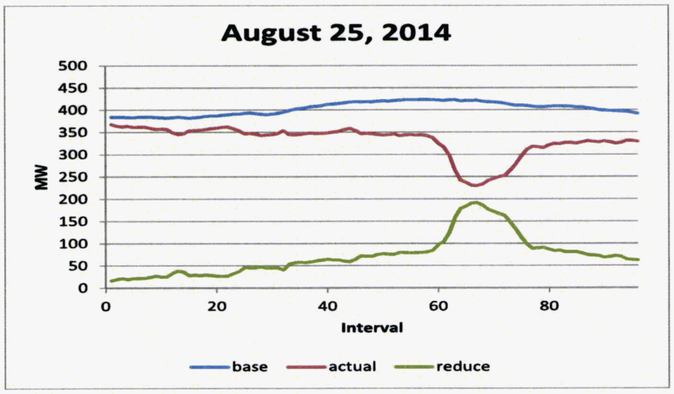
Hour-ending 17:00 Reductions on 4 CP Days - 2014

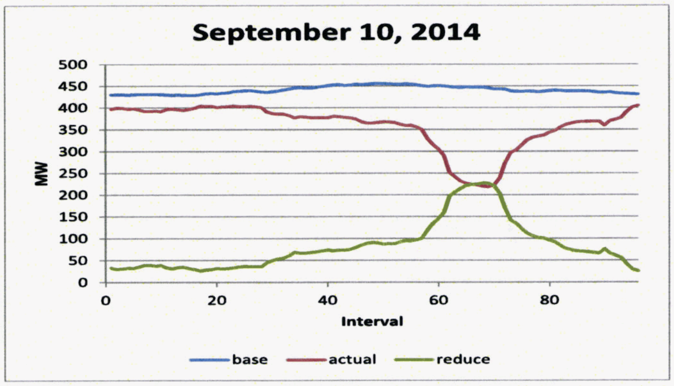
Peak Response



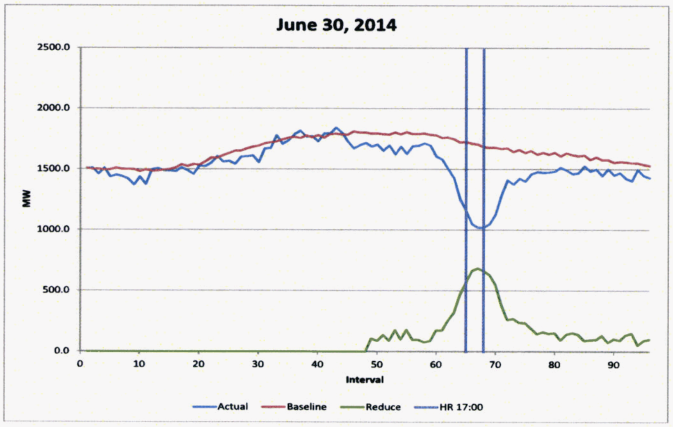


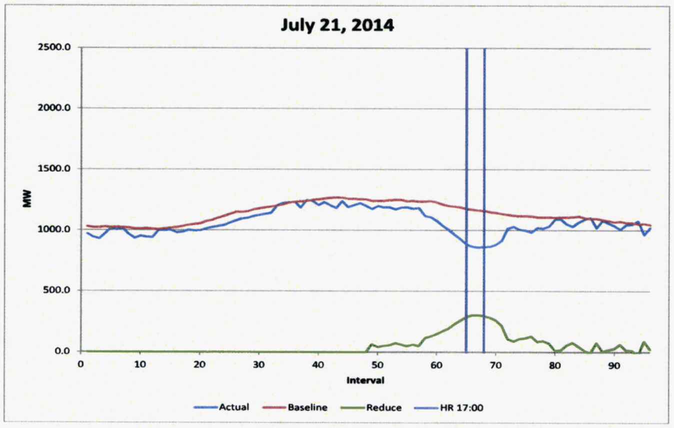
Day-use Response

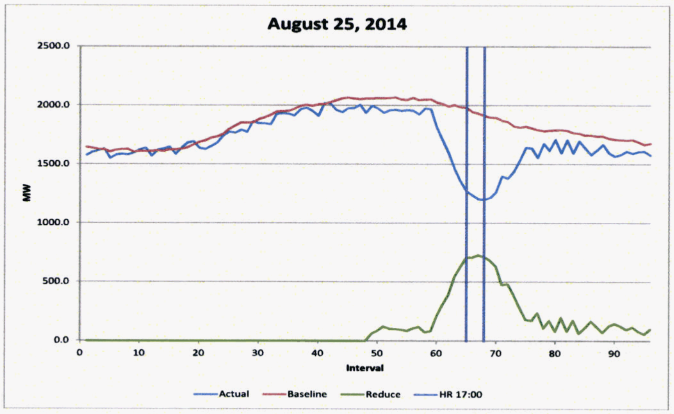


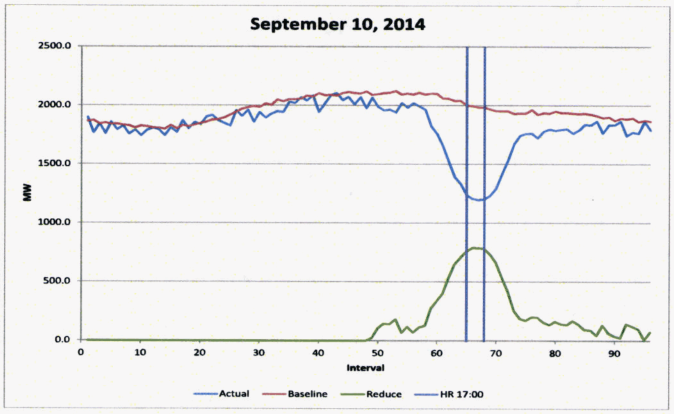


Hour-ending 17:00 Reductions on 4 CP Days - 2014









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	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

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				
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

	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				
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

	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				
26-Jun-12	139.2	397.5	5,517.4	5,914.9	2.4%	233.7	745.4	6,257.2	7,002.6	3.3%
31-Jul-12	135.4	321.6	5,523.5	5,845.1	2.3%	214.7	618.6	6,333.2	6,951.8	3.1%
1-Aug-12	83.5	162.3	5,722.8	5,885.1	1.4%	180.2	493.8	6,511.3	7,005.0	2.6%
4-Sep-12	130.2	328.5	5,559.7	5,888.2	2.2%	168.1	491.0	6,392.2	6,883.3	2.4%
	Low Load Factor					Total				
26-Jun-12	302.2	522.9	855.9	1,378.8	21.9%	675.0	1,665.8	12,630.5	14,296.3	4.7%
31-Jul-12	225.8	438.2	916.5	1,354.7	16.7%	575.9	1,378.4	12,773.2	14,151.6	4.1%
1-Aug-12	213.7	482.6	927.2	1,409.8	15.2%	477.3	1,138.6	13,161.2	14,299.9	3.3%
4-Sep-12	211.7	425.7	1,115.5	1,541.1	13.7%	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

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				
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

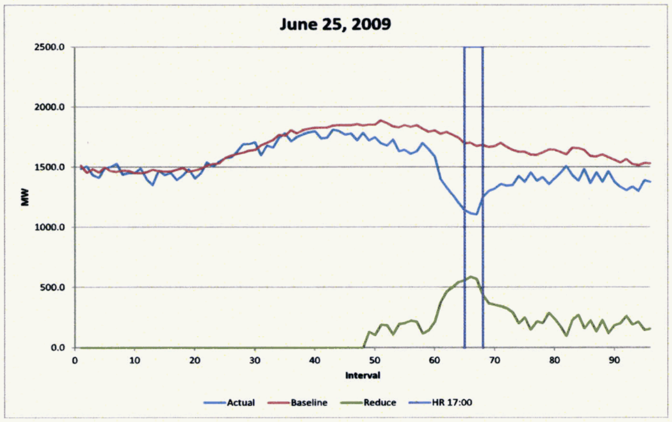
Percentage of Load Reduction by Load Factor and Voltage Group

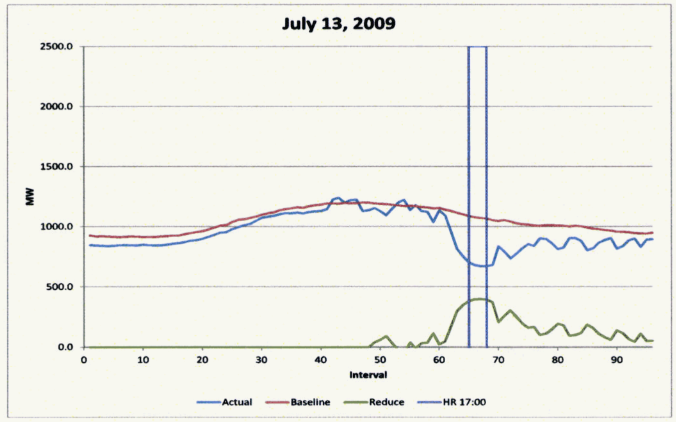
4 CP Days	High Load Factor		Medium Load Factor		Low Load Factor		Total Reduction
	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	
16-Jun-14	159.4	24.8%	241.7	37.6%	242.0	37.6%	643.1
21-Jul-14	37.5	12.5%	112.7	37.7%	149.0	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

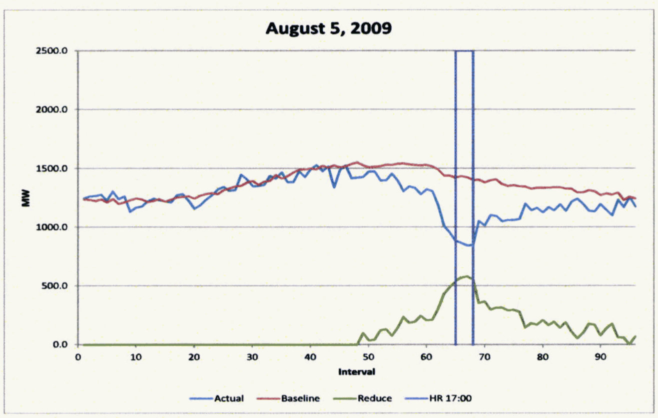
4 CP Days	Transmission		Distribution NWS		Distribution WS		Total Reduction
	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	Total Reduction	Percent of Total Reduction	
16-Jun-14	355.9	55.3%	263.2	40.9%	23.9	3.7%	643.1
21-Jul-14	109.2	36.5%	171.1	57.2%	18.8	6.3%	299.2
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

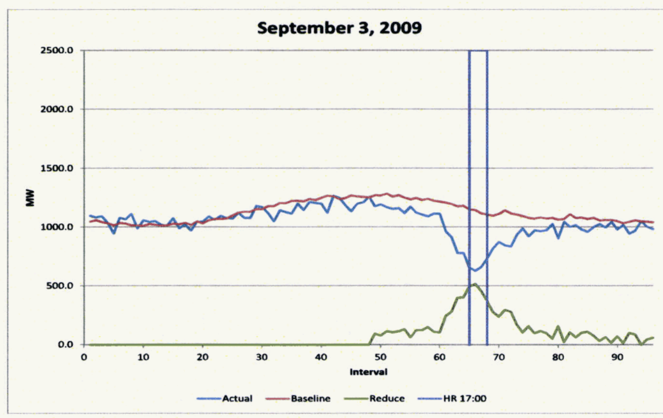
Appendix 9 – CP Day Graphs

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

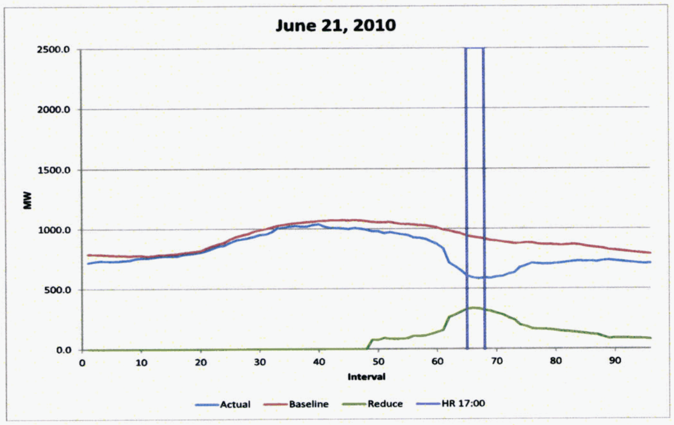


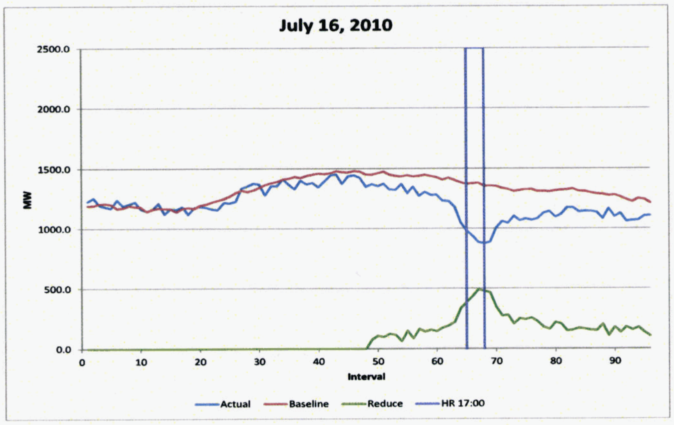


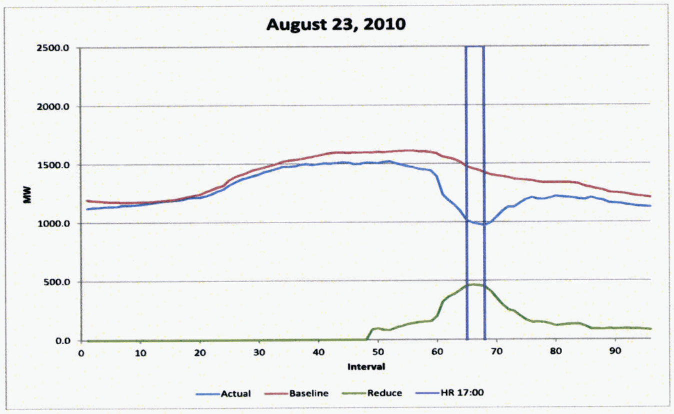


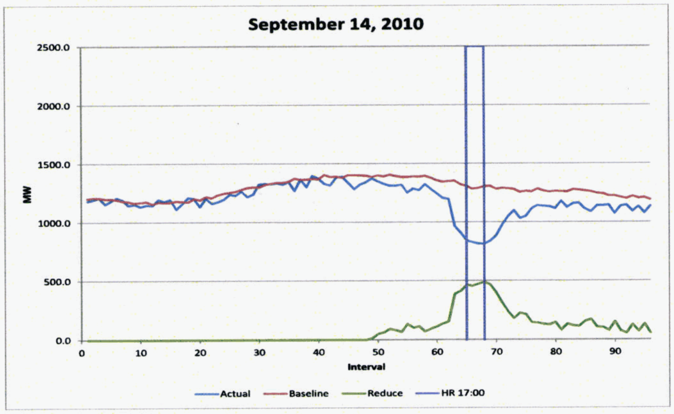


Hour-ending 17:00 Reductions on 4 CP Days - 2010

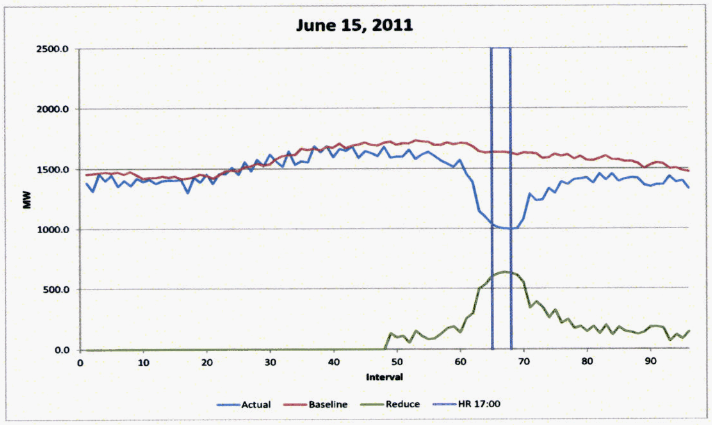


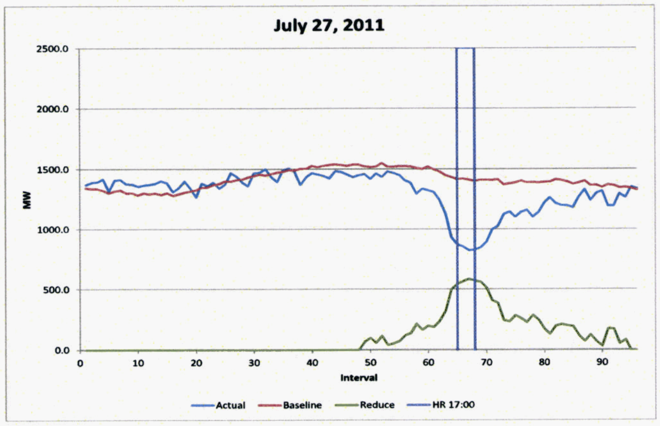


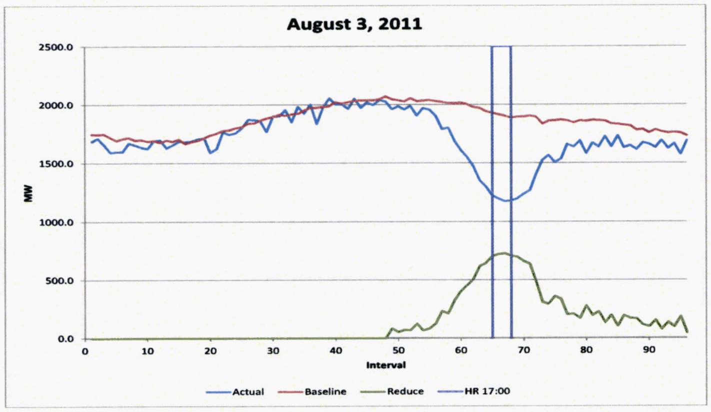


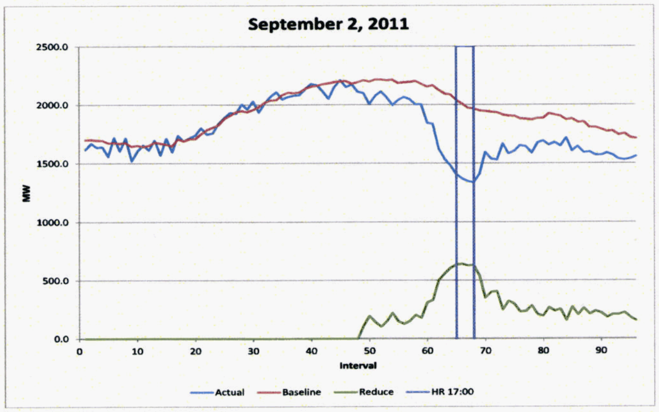


Hour-ending 17:00 Reductions on 4 CP Days - 2011

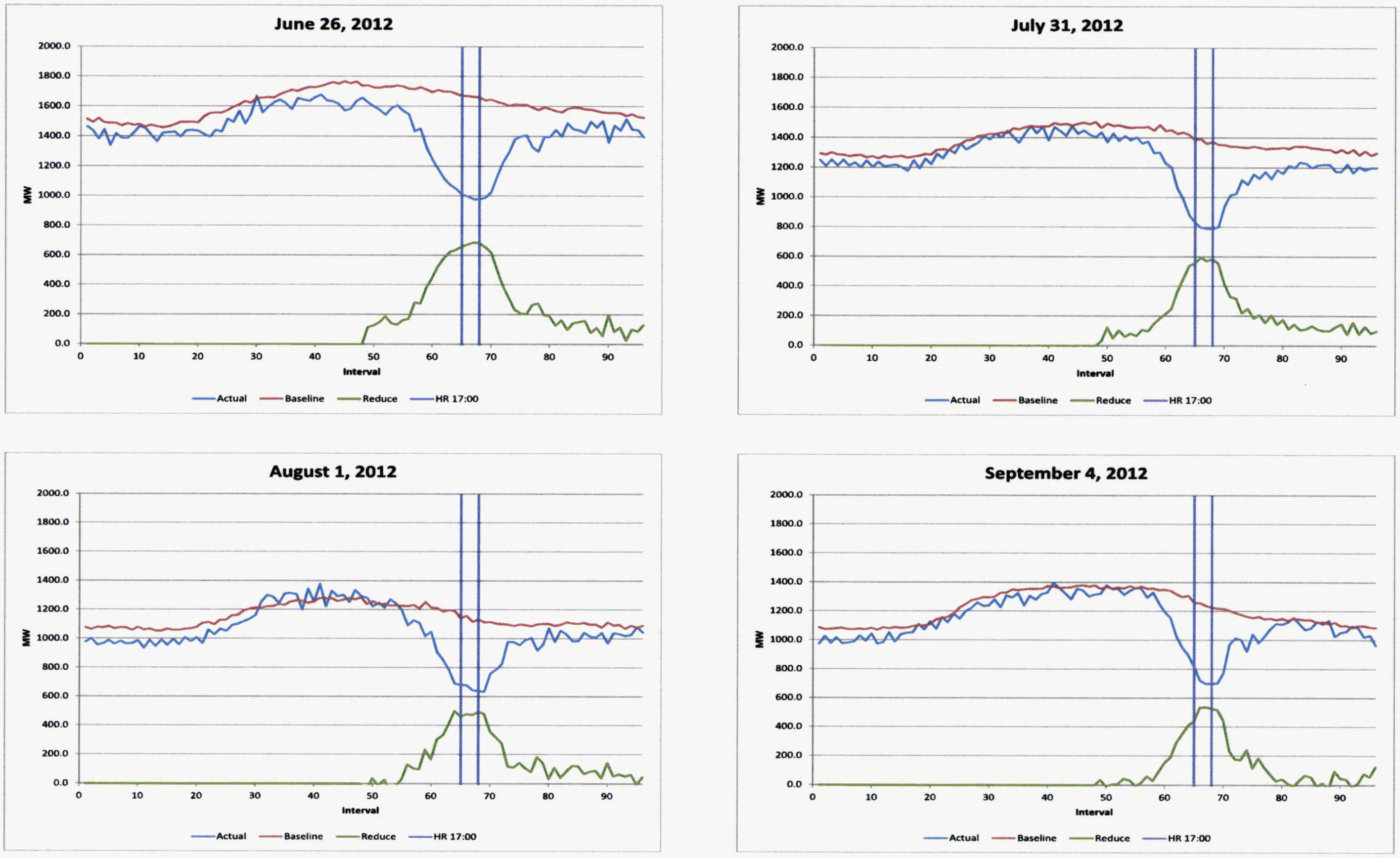




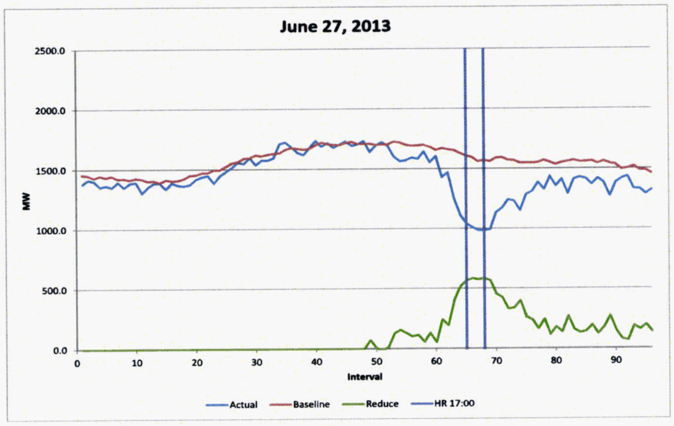


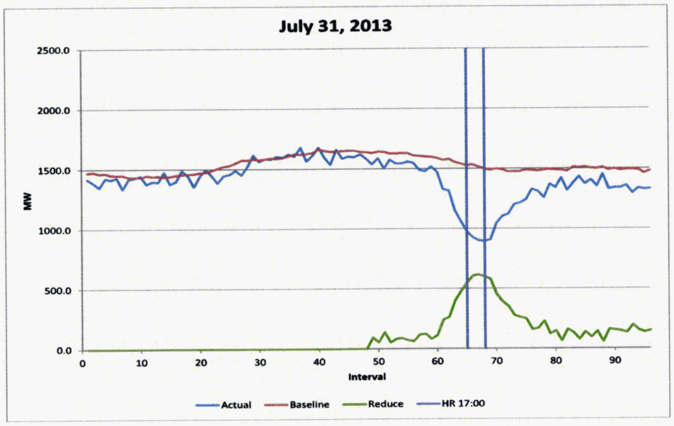


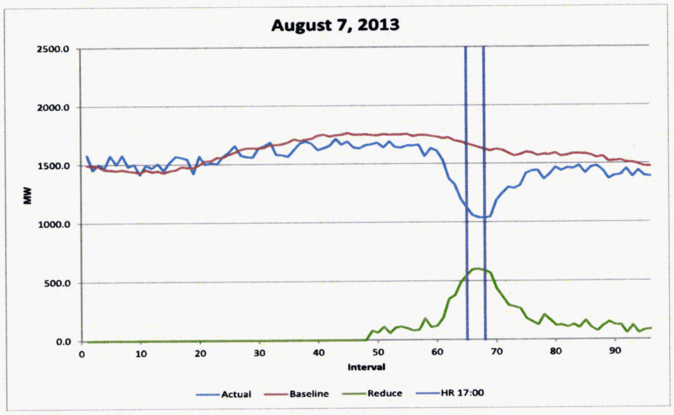
Hour-ending 17:00 Reductions on 4 CP Days - 2012

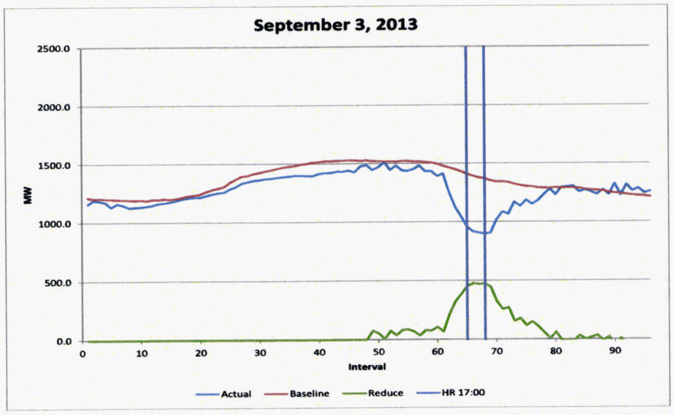


Hour-ending 17:00 Reductions on 4 CP Days - 2013









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