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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

BOB STUMP – Chairman
GARY PIERCE
BRENDA BURNS
BOB BURNS
SUSAN BITTER SMITH

Arizona Corporation Commission
DOCKETED
JUL 12 2013
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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-12-0504 **NOTICE OF FILING *REDACTED* DIRECT TESTIMONY OF JAY ZARNIKAU ON BEHALF OF NUCOR CORPORATION**

Nucor Corporation, by and through undersigned counsel, files the *Redacted* Direct Testimony of Jay Zarnikau, PhD regarding rate design issues. Nucor Corporation has provided a copy of Dr. Zarnikau's unredacted Direct Testimony under seal to the five Commissioners, the Administrative Law Judge, and all parties that have executed a Confidentiality Agreement.

RESPECTFULLY SUBMITTED this 12th day of July, 2013.

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BEFORE

THE 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 FOR RELATED APPROVALS	§ § § § § § § § § § § § §	**DIRECT TESTIMONY OF DR. JAY ZARNIKAU ON BEHALF OF NUCOR STEEL**

REDACTED

DIRECT TESTIMONY OF

JAY ZARNIKAU

RATE DESIGN

July 12, 2013

Attachments

Attachment JZ-1	Background and Qualifications of Dr. Jay Zarnikau
Attachment JZ-2	UNS Electric's response to Nucor data request 3.02
Attachment JZ-3	UNS Electric's response to Nucor data request 3.03
Attachment JZ-4	UNS Electric's responses to Nucor data requests 4.07 and 4.08
Attachment JZ-5	UNS Electric's response to Nucor data request 3.01
Attachment JZ-6	UNS Electric's response to Nucor data request 3.04
Attachment JZ-7	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-8	Jay Zarnikau & Dan Thal, *The response of large industrial energy consumers to four coincident peak (4CP) transmission charges in the Texas (ERCOT) market* (2013).
Attachment JZ-9	UNS Electric's responses to Nucor data requests 2.07, 2.08, 2.09, 4.5, and 5.2
Attachment JZ-10	UNS Electric's response to Nucor data request 5.1
Attachment JZ-11	UNS Electric's response to Nucor data request 7.5
Attachment JZ-12	UNS Electric's response to Nucor data request 7.6
Attachment JZ-13	UNS Electric's response to Nucor data request 6.3
Attachment JZ-14	UNS Electric's response to Nucor data request 3.9

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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 over 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 Division of Statistics and Scientific Computation. I also teach graduate-level courses in research and quantitative methods in 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 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.

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. However, I was not cross-examined in that proceeding.

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 Steel's facility in Kingman, Arizona. I propose a number of changes which I believe would be of mutual benefit to both UNS Electric ('UNS') and Nucor Steel ('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 Steel, as well as related discovery materials.

II. SUMMARY OF CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. I conclude that:

- The current design of the winter time-of-use blocks in UNS's Large Power Service Time of Use (LPS-TOU) tariff imposes unnecessary economic costs upon Nucor. This tariff should be re-designed in a manner which would assist large industrial customers like Nucor without harming (and, perhaps, even benefitting) UNS and other customers/ratepayers served through the utility's time-of-use tariffs.

- The design of the demand charge used to recover certain capacity-related costs from industrial energy consumers is needlessly complicated and could be greatly improved. Changes could be made which would yield benefits to UNS and all of its ratepayers.

- Nucor would be willing to partially curtail purchases of electricity from UNS during on-peak periods in return for a credit or discount in the tariff's demand charge. The ability to partially curtail Nucor could have considerable value to UNS and the entire utility system.

- The proposed differences in the increases to customer charges among industrial tariffs have not been adequately justified by the utility.

- UNS has not adequately explained its proposal to recover credit costs and broker fees through its Purchased Power and Fuel Adjustment Clause (PPFAC).

Q. PLEASE PROVIDE YOUR RECOMMENDATIONS.

A. I recommend the following:

- The two existing discontiguous winter on-peak blocks (non-holiday weekdays from 6 to 10 a.m. and from 5 to 9 p.m.) in the LPS-TOU tariff should be replaced with a single six-hour on-peak block from 6 a.m. to noon.

- The demand charges in the utility's tariffs for industrial energy consumers should be based upon the customer's contribution to four coincident peaks (4 CP). This is the same basis upon which capacity-related costs are partially allocated to various customer classes.

- I recommend adding an interruptible service option onto the LPS-TOU tariff, which would allow UNS to curtail or interrupt service to subscribing industrial energy consumers in return for a bill credit or discount in the demand charge associated with that tariff. The demand charge applied to interruptible load should be one-half of the demand charge applied to firm load. Alternately, a credit could be set at a level that is one-half of the demand charge.

- The customer charges in the tariffs applicable to industrial energy consumers should be changed by the same percentage as other non-residential customer classes.
- Credit costs and broker fees should not be recovered through the PPFAC.

III. NUCOR STEEL'S OPERATION IN KINGMAN

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

A. Nucor 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. Since then, the Kingman mill has nearly doubled its staff of highly-skilled employees to 62. The return of steel production at this facility has been very important to the local and state economy.

Q. WHAT ELECTRICITY TARIFF IS NUCOR SERVED THROUGH?

A. UNS'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 the second or third highest variable input cost 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.

Of course, Nucor's operating strategy benefits not only Nucor, but also benefits UNS and all other consumers on the UNS system. Because Nucor produces steel during off-peak periods rather than on-peak periods, UNS'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 system load factor by filling in the periods of low demand, and in the process helps UNS 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 and its customers. For industrial customers like Nucor, even small percentage increases in electricity rates can translate into hundreds of thousands or millions of dollars in additional costs, impacting Nucor's ability to operate in a highly competitive international market.

IV. <u>WINTER TOU PERIODS IN THE LPS-TOU TARIFF</u>

Q. IN THE PRESENT LPS-TOU TARIFF, WHAT ARE THE WINTER ON-PEAK TOU PERIODS?

A. Unlike the summer, where there is a single 8-hour long on-peak period, there are two discontiguous on-peak blocks in the winter under the LPS-TOU tariff. The on-peak periods are non-holiday weekdays from 6 to 10 a.m. and from 5 to 9 p.m.

Q. WHAT CHALLENGES DO THE CURRENT WINTER ON-PEAK PERIODS POSE FOR NUCOR?

A. At Nucor, the current designation of winter on-peak periods presents two operational challenges:

- In order to limit steel production to the off-peak periods, Nucor operates a 9-hour production shift from 9 p.m. to 6 a.m., and a 7-hour production shift from 10 a.m. to 5 p.m. Having labor shifts that differ in duration by two hours creates some logistical and operational difficulties at the steel mill.

- The need to turn off production equipment twice each weekday during six months of each year – during both of the 4-hour long on-peak electricity price periods each day in the winter period – imposes unnecessary costs on Nucor. There are significant costs involved in re-starting production equipment. These costs could be reduced if Nucor was able to suspend production operations just once per weekday, rather than twice each weekday, during the winter period.

Q. HAS UNS PROVIDED A STUDY WHICH WOULD JUSTIFY WHY IT HAS DESIGNED ITS WINTER TOU PERIODS IN THIS MANNER?

A. No. In response to Nucor 3.02 (Attachment JZ-2), UNS conceded that no study had been performed. In response to Nucor 3.03 (Attachment JZ-3) which asked how on-peak periods had been defined, UNS Respondent Brenda Pries and Witness Craig Jones stated: "While TEP and UNS Electric have some differences in how the marginal cost of fuel is incurred during the peak periods, both utilities incur the highest cost of marginal fuel mid-day through the early evening hours during the summer, and in the early morning and late afternoon during the winter."

Q. DO YOU AGREE THAT UNS INCURS ITS HIGHEST MARGINAL COST OF FUEL IN THE EARLY MORNING AND LATE AFTERNOON DURING THE WINTER?

A. Based upon the data provided by UNS in response to Nucor 4.07 and 4.08 (Attachment JZ-4), I fail to see a spike in marginal operating costs (or, the highest marginal cost of fuel) during late afternoon hours in the winter. When I graphed the data that I received from UNS, I obtained:

Clearly, there is a spike in operating costs in the early morning hours. But I fail to see a similar spike in the late afternoon hours.

Q. DOES TOTAL SYSTEM DEMAND ON THE UNS SYSTEM FOLLOW A SIMILAR PATTERN?

A. A plot of demand, based on UNS's response to Nucor 3.01 (Attachment JZ-5), shows a second spike in system demand during the late afternoon hours.

Perhaps this provided some initial rationale for establishing two on-peak periods during the winter period.

However, I fully agree with UNS that the pattern in marginal operating costs should be used to define on-peak periods, rather than load patterns. An important policy goal is to align retail prices to costs. Thus, the pattern in marginal operating costs is a more important factor than patterns in demand, particularly for a summer-peaking utility such as UNS. For a summer-peaking utility, winter demand is not a key determinant of the need for generating capacity (as reflected in the utility's choice of a 4 summer coincident peak or 4 CP allocator for generating and transmission capacity costs within their Average and Peak method). The pattern in marginal operating costs, rather than the pattern of demand, should be the basis for designing TOU periods in the non-summer months.

Q. IN LIGHT OF THE PATTERN IN MARGINAL OPERATING COSTS, HOW SHOULD THE WINTER ON-PEAK PERIOD BE DEFINED?

A. Clearly, there is a spike in marginal operating cost in the early morning hours, beginning around 6 a.m. (i.e., the hour-ending 7 a.m.) and lasting about three hours. This suggests to me that an eight hour-long on-peak period is far too long.

The marginal generating operating costs incurred by UNS to serve its customers are clearly higher after the morning spike in operating costs than before it. This suggests to me that if it was desirable to "extend" the three hour period of high marginal operating costs into a longer on-peak period, the extension should go toward the later hours of the day, i.e., the hours after the spike in marginal operating costs.

UNS presently includes 8 hours in its on-peak periods, yet the data provided by UNS supports a three or four-hour on-peak period. But, I realize that future patterns in marginal operating costs may deviate from past patterns. There is some uncertainty regarding when future periods of high operating costs might begin and end. Consequently, I would be comfortable with defining a 6-hour long on-peak period, from 6 a.m. to noon. This would seem reasonable, in light of the data provided by UNS. It is also noteworthy that Tucson Electric Power (TEP), an affiliate of UNS, agreed to a summer peak period of six hours in duration (i.e., from 2 p.m. to 8 p.m.) in Docket No. E-01933A-12-0291. (See UNS Response to Nucor 3.04, Attachment JZ-6.)

Q. WOULD A SHORTER WINTER ON-PEAK PERIOD 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 TOU charges should be adjusted to ensure that revenues collected by UNS under their proposed tariff design with an eight-hour on-peak period equal the revenues collected by UNS with my proposed six-hour on-peak period based on billing determinants approved by this Commission.

I anticipate that my recommendation will result in a slightly greater differential between on-peak and off-peak rates, and a better match between retail prices and marginal operating costs.

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 YOUR SUGGESTED CHANGE TO THE DEFINITION OF THE WINTER PEAK PERIOD CONTRIBUTE TO THAT OBJECTIVE?

A. Yes. Based on the hourly data provided to me by UNS, the utility's marginal operating cost during on-peak hours is per MWh and during off-peak hours is per MWh under the present TOU definitions. Thus, the differential between on-peak and off-peak marginal operating costs is about

Under my proposal, the utility's marginal operating cost during on-peak hours is and during off-peak hours is . That increases the differential between on-peak and off-peak marginal costs to Thus, my proposal would provide a better match between prices and costs, since the differential in retail prices within the TOU prices is quite a bit greater. Customers who cause the utility to incur increased costs during on-peak hours will be paying something closer to their fair share of these costs than under the current peak/off-peak definitions.

The differential could be increased greatly if the on-peak winter period began at 6 a.m. (i.e., the hour ending 7 a.m.) and had a duration of only 3 or 4 hours. Under a 4-hour on-peak period, the differential between on-peak marginal operating costs and off-peak costs would be . A greater differential in marginal operating costs will better support the large differential in TOU prices proposed by UNS. However, if the Commission determines that a more gradual shift is in order, I believe that an on-peak period with a duration of 6 hours might be a reasonable compromise, since it would pose a more modest change in UNS's present rate structure for TOU rates.

Q. SHOULD ALL OF UNS'S TARIFFS WITH TOU PERIODS BE RE-DEFINED IN THE MANNER IN WHICH YOU PROPOSE?

A. Yes. I believe that all of the utility's tariffs should be designed based upon the same economic principles.

Nonetheless, if the Commission determines that such a change in TOU periods would not be appropriate for all customers on TOU rates, the utility could still achieve some of the benefits of a consolidated winter peak period by creating two winter TOU options – with one based on the present definition of the winter on-peak period and one based upon my proposed definition. I suspect, however, that other customers on TOU tariffs would find my suggested changes attractive, for the same reasons as Nucor does.

V. <u>INDUSTRIAL DEMAND CHARGES SHOULD BE RE-DESIGNED</u>

Q. WHAT COSTS DOES UNS RECOVER THROUGH A DEMAND CHARGE?

A. As detailed in UNS's Schedule G-7, UNS seeks to recover costs associated with generation and transmission capacity (plant in service) through demand charges for those customers with the metering necessary to permit a demand charge to be assessed.

Q. HOW DOES UNS ALLOCATE PRODUCTION AND TRANSMISSION-RELATED COSTS TO VARIOUS CUSTOMER CLASSES?

A. As discussed in Mr. Jones' testimony, the Average and Peaks Method is used. As explained by Mr. Jones:

> The Average and Peaks 4CP factor is made up of two components: an average demand component (with a percentage weight of the system load factor) and a peak demand component (with a percentage weight of one minus the system load factor). The average demand component was calculated by dividing the number of hours in the test year into the loss-adjusted energy. The peak demand component was calculated as a combination of coincident peak demands (time of system peak) from July, August, and September 2011 and June 2012, of the test year. The system peak during a period of 12 consecutive months occurs with greatest likelihood in these four summer months.

Q. DOES THE MANNER IN WHICH UNS COLLECTS DEMAND-RELATED COSTS MIRROR THE APPROACH USED TO ALLOCATE THESE COSTS?

A. No. Under the LPS-TOU tariff, demand charges are based upon the following complicated formula:

> BILLING DEMAND
> The monthly billing demand shall be the higher of:
> i. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period;
> ii. one-half the highest measured fifteen minute integrated reading of the demand meter during the off-peak hours;
> iii. the highest demand metered during the preceding eleven (11) months; or
> iv. the contract capacity or 500 kW, whichever is higher.

The design of demand charges is inconsistent with the theory used to allocate demand-related costs.

Q. HOW SHOULD THIS INCONSISTENCY BE RESOLVED?

A. Costs which are allocated on a 4 CP basis should be collected from consumers on the same basis – based on their contribution to the system's 4 CPs, at least in situations where the metering infrastructure can accommodate this. Costs which are allocated on an energy basis should be collected from consumers on an energy basis. UNS's present design of the demand charges results in a mismatch.

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

A. It is becoming common. 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 this practice, as well. Attachment JZ-7 includes a recent press release that I came across describing how Direct Energy's charges in the PJM market are based upon five coincident peaks.

Q. WOULD THERE BE BENEFITS TO UNS FROM BASING DEMAND CHARGES BASED ON A CUSTOMER'S CONTRIBUTION TO THE 4 CP?

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 would instead encourage a consumer to flatten its load pattern. This does not encourage the consumer to reduce demand during those hours when demand reduction would have its greatest value to the system. The paper that I have provided as Attachment JZ-8 demonstrates how industrial energy consumers in the ERCOT market have reduced system demand through their response to 4 CP price signals.

This approach may also provide UNS with greater revenue stability. I doubt that the revenues collected through UNS's present demand charges will ever match the demand-related costs allocated to a rate class, since it is not clear which of the four methods for calculating the demand charge would apply to any given customer in any given month. If the costs allocated via the 4 CP component of the allocator were simply collected on the same basis as they were allocated (in more of a "pass-through" manner), the revenues would be more predictable and stable.

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 will not 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 to 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 the cost allocation principles adopted by the Commission.

My recommendation may affect the costs paid by individual consumers within the LPS class. Those customers with disproportionately high usage during the 4 CPs might pay more. Those customers within the LPS class with relatively-low purchases of electricity during the peaks may pay less.

Q. SHOULD YOUR RECOMMENDATION TO RE-DESIGN THE DEMAND CHARGE JUST BE APPLIED TO THE LPS CLASS?

A. I suggest that for now, it be applied to any customer class where the metering infrastructure can accommodate billing on the basis of a customer's contribution to the 4 CPs.

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

A. The following steps should be taken:

- Identify the customer classes with the metering infrastructure capable of recording customer demand during the 4 CP. These are the classes to which my recommendation would apply.
- Identify the demand-related costs allocated to those rate classes (from Schedule G).
- Take roughly 47% of those costs (1- system load factor). These are the costs to be collected based on the 4 CP measurements during the previous year.

- Divide the demand-related costs to be collected through 4 CP charges by the class' average demand during the test year (or previous year) 4 CPs. Such data are presented in UNS Workpaper "UNSE AvgPeak.xls."
- Divide the result by 12, to convert an annual value to a monthly demand charge, which is billed to a customer based on its contribution to the average of the 4 CPs during the previous calendar year.
- Construct an additional energy charge (or an increase to an existing energy charge) to collect the demand-related costs (the demand-related costs associated to the class multiplied by (1-system load factor)) that were allocated to the rate class based on average energy. This charge is simply the demand-related costs allocated to the class and to be recovered from the energy charge divided by the rate class's kWh consumption during the test year or the previous calendar year.

VI. AN INTERRUPTIBLE OPTION SHOULD BE ADDED TO THE LPS-TOU TARIFF

Q. COULD NUCOR'S KINGMAN FACILITY POTENTIALLY BE AN INTERRUPTIBLE CUSTOMER?

A. During on-peak summer hours, a designated portion of the electrical service provided by UNS to Nucor and potentially other large industrial customers could be interrupted. During summer off-peak hours, Nucor operates at full production and could not easily withstand an interruption in electrical service.

Q. WOULD THE ABILITY TO INTERRUPT A PORTION OF NUCOR'S AND OTHER LARGE INDUSTRIAL CUSTOMERS' LOADS DURING SUMMER ON-PEAK PERIODS PROVIDE A BENEFIT TO UNS?

A. Yes. This would provide UNS with an additional resource for meeting summer peak demand. And the cost of this resource would likely be less than the cost of acquiring a supply-side resource to meet a summer peak need.

Since UNS's system peak presumably occurs during a summer on-peak TOU period, the summer on-peak period should be the focus of such a program. Whether industrial customers are able to interrupt during off-peak or winter periods is far less important, and I do not believe that the ability to interrupt these customers only during on-peak periods would diminish the value of this resource to UNS.

Q. DOES UNS ALREADY OFFER AN INTERRUPTIBLE TARIFF FOR INDUSTRIAL ENERGY CONSUMERS?

A. Yes. But the existing tariff does not provide time-of-use pricing. If Nucor, for example, were to move onto UNS's existing interruptible tariff, UNS and Nucor would lose the benefits associated with having the steel mill schedule its operations during the off-peak TOU periods.

Q. HOW DO YOU RECOMMEND ALTERING THE LPS-TOU TARIFF?

A. The existing LPS-TOU tariff should be augmented with an "interruptible option," permitting UNS to interrupt or curtail service to LPS-TOU customers during summer on-peak periods. The ten-minute notice period in the Interruptible Power Service (IPS) tariff could be used in the LPS-TOU tariff also.

Q. HOW SHOULD INDUSTRIAL ENERGY CUSTOMERS WHO SELECT THE INTERRUPTIBLE OPTION BE COMPENSATED?

A. In return for allowing UNS to interrupt a portion of the customer's service with a ten-minute notice period and under terms and conditions similar to those in the IPS tariff (though limited to on-peak periods), UNS should either provide a bill credit or a discounted demand charge for the portion of a customer's load designated to be interruptible.

If my recommendation to re-design demand charges is accepted, a 4 CP-based demand charge for the interruptible portion of the customer's load could be discounted appropriately. A reduction in a 4 CP demand charge is an appropriate approach since a customer's contribution to the 4 CP is a good measure of the demand that may be dropped if an interruption is called, if we assume interruptions are most likely to be called during a peak and the customer is able to drop a predetermined amount of its purchases at that time.

If my recommendation to redesign demand charges is not accepted by the Commission, a payment or credit based upon the customer's contribution to 4 CPs should be used. The customer's average demand during all on-peak periods could also be used, though this would be less precise as it would seem to imply that an interruption was equally likely during any hour within the numerous on-peak hours.

Q. HOW SHOULD THE DISCOUNT TO THE DEMAND CHARGE OR CREDIT BE CALCULATED?

A. For the portion of the customer's demand which may be interrupted by the utility, I recommend that the demand charge be one-half of the demand charge which would be applied to firm, or non-interruptible, service. If compensation to the partially-interruptible customer was provided through a credit, then the credit should be calculated as the interruptible load times one-half of the demand charge as expressed in dollars per kW.

For example, if this Commission approves a demand charge for the LPS and LPS-TOU tariffs of $15/kW for customers served at >69kW, then $15/kW would be applied to the portion of the customer's demand that was firm during the average of the previous year's 4 CPs, and $7.50/kW would be applied to the interruptible portion of the customer's load during the previous year's 4 CPs. Alternatively, all of the load during the previous year's 4 CPs could be billed at the demand charge of $15/kW and a credit could be calculated as the interruptible load during the 4 CPs times $7.50/kW. For a hypothetical industrial customer with 500 kW of firm load and 500 kW of interruptible load during the 4 CPs, the demand charges would be (500kW*$15/kW + 500kW*$7.50) = $11,250 or (treating this as a credit (1MW*$15/kW – 500kW*$7.50) = $11,250. Either of these approaches would yield the same result, provided billing demand is defined in a consistent manner.

Q. WHY DO YOU BELIEVE THAT IT IS REASONABLE TO APPLY ONE-HALF OF THE "FIRM" DEMAND CHARGE TO THE INTERRUPTIBLE LOAD?

A. In this proceeding, UNS has proposed a demand charge for IPS customers of $7.37/kW. This is 51% of the demand charge that UNS has proposed for LGS and LGS-TOU customers, and 30% to 40% of the demand charge that UNS has proposed for LPS and LPS-TOU customers (with the range dependent upon the voltage at which the customer accepts service). Customers served through the LGS, LGS-TOU, LPS, and LPS-TOU tariffs could presumably agree to be interrupted and move onto the IPS tariff and see savings in their demand charges of somewhere between 49% and 70%. Based upon my experience, this level of "discount" in a demand charge for interruptible service is typical. While I believe that a discount of over 50% could be justified, setting the discount at 50% would be reasonable, if interruptible requests were confined to on-peak periods.

VII. PROPOSED INCREASES IN CUSTOMER CHARGES ARE NOT JUSTIFIED

Q. HOW DOES THE PROPOSED INCREASE IN THE CUSTOMER CHARGES FOR THE LPS AND LPS-TOU TARIFFS COMPARE WITH THE INCREASES PROPOSED BY THE UTILITY FOR ITS OTHER TARIFFS?

A. UNS proposes to increase the customer charges for the LPS and LPS TOU tariffs by 269% or 303%, depending upon the voltage at which the customer is served. This proposed increase is far greater than the increase (either in dollar or percentage terms) proposed for any other class of customers, as is evident from the following table.

UNS Proposed Increase in Customer Charges

Tariff	Current Charge	Proposed Charge	Percentage Increase

Res	$8.00	$10.50	31%
SGS	$12.50	$14.50	16%
SGS-10 TOU	$12.50	$16.50	32%
LGS	$16.00	$50.00	213%
LGS TOU	$20.00	$52.00	160%
LPS and LPS TOU <69 kV	$372.00	$1,500.00	303%
LPS and LPS TOU >69 kV	$407.00	$1,500.00	269%
IPS	$16.00	$18.00	13%

Q. HAVE YOU EXAMINED UNS'S PROPOSED INCREASE TO THE VARIOUS COMPONENTS OF THE CUSTOMER CHARGE?

A. Yes. The increases in these components are displayed in the table below.

Components of Proposed Increase in LPS Customer Charge (>69kV)

Component	Current Charge	Proposed Charge	Percentage Increase
Meter Services	$233.36	$159.46	-32%
Meter Reading	$28.22	$436.96	1448%
Billing and Collection	$145.30	$659.66	354%
Customer Delivery	$0.12	$243.92	203167%

Q. HAS UNS EXPLAINED WHY THE CUSTOMER CHARGES TO THE LPS AND LPS TOU CUSTOMERS SHOULD BE INCREASED AT SUCH A HIGH RATE?

A. No. Through discovery responses (e.g., UNS's response to Nucor 2.07, 2.08, 2.09, 4.5, and 5.2, all presented as Attachment JZ-9) UNS has explained differences in the proposed customer charges among rate classes. However, I have not seen an explanation of why these charges should increase at such dramatically different rates. UNS's explanation appears to be, in essence, an unquestioning reliance on the results of the cost of service model. For example, the utility's response to Nucor 2.08 reads: "The cost is developed based on the data in the test year and the class cost of service study." As the utility's response to Nucor 2.07 notes, the small (only 20) number of customers in the LPS class results in a very few number of customers paying significantly higher costs which get allocated to the LPS class under UNS's cost allocation method.

Q. DO YOU AGREE WITH UNS'S ASSERTION THAT IF THESE ARE THE CUSTOMER CHARGES THAT CAME OUT OF ITS COST ALLOCATION MODEL, THEN THESE ARE REASONABLE AND MUST BE ADOPTED BY THE COMMISSION?

A. Not necessarily. I would advise against blindly adopting charges that come out of a cost allocation model. Setting aside the question of whether the utility has adopted appropriate allocation factors to allocate customer-related costs to various rate classes, I recommend that when considering the reasonableness of charges this Commission also consider the following:

- Were the costs incurred by the utility for customer-related activities appropriately booked to the correct FERC accounts?
- Are various customer classes paying similar charges for similar services?
- Are charges being changed in accordance with the "gradualism" principles that this Commission has historically endorsed?

Q. HAVE YOU SOUGHT TO EXAMINE THE COSTS INCURRED BY UNS AS JUSTIFICATION FOR ITS PROPOSED CUSTOMER CHARGE TO THE LPS CLASS?

A. Yes. The request and the utility's response are provided below (Attachment JZ-10).

NUCOR 5.1
Please provide all invoices, purchasing records, contracts, time sheets, other documentation of costs, spreadsheets, and work papers necessary to replicate the utility's calculation of its proposed customer charges for non-residential customer classes.
RESPONSE:
The above requested documents could not be used to replicate the utility's calculation of its proposed customer charges for non-residential customer classes because the utility did not calculate customer specific charges using these specific items. Standard rate making procedures generally support a calculation based on allocations of booked expense accounts based on the results of a Cost of Service Study which uses various methods to allocate costs to each class. These methods include weighting of various cost components based on the classes' utilization of facilities and personnel, general allocators and where appropriate, customer specific data.

The primary work paper to determine the proposed customer charges is Schedule G-6-1 in the class cost of service study. This schedule shows the cost of service on a per unit basis for all charges (demand, energy and customer charges). The rate of return in Schedule G-6-1 in the cost of service is based on class rate of returns based on test year adjusted rate base divided by the test year adjusted operating revenue by class excluding Other Operating Revenue. See response to STF 2.43 for file STF 2.43 G-6-1.xls which provides unit cost based on the Company's requested overall rate of return.

It would seem difficult for the Commission to confirm the reasonableness of the utility's proposed customer charges if the utility cannot provide evidence showing the test-year customer-related costs that it incurred which were subsequently input to its cost of service model and allocated to the LPS class.

Q. HOW DO THE VARIOUS COMPONENTS OF THE PROPOSED CUSTOMER CHARGE IN THE LPS TARIFF COMPARE TO THE PROPOSED CHARGES IN OTHER TARIFFS OF UNS WHERE SIMILAR SERVICES ARE PROVIDED?

A. Through discovery, I asked UNS to explain why the proposed monthly customer charges to LPS customers are so different from the proposed charges to IPS customers. IPS customers could be of similar size to LPS customers, so I thought that the charges to IPS customers might provide a viable comparison. UNS explained that different meters are installed on LPS versus IPS customers, which might explain some differences in the Meter Services and Meter Reading charges between these two customer classes. However, I do not understand why the costs incurred by UNS for Billing and Collection would be any different between these two classes. According to UNS's response to Nucor 5.3, "the bills sent to IPS and LPS do not differ in format, nor do IPS or LPS customers pay their bills differently." Thus it is not clear to me why LPS customers would pay $659.66 per month for Billing and Collection services, while IPS customers would pay only $8.48 per month. Further, it is not clear to me why LPS customers should pay $243.92 per month for customer delivery services and IPS customers should pay $3.16 when "[t]he Company is not aware of any specific services that would differ substantially between the two types of customers" according to UNS response to Nucor 7.5 (Attachment JZ-11). Finally, according to the Company's response to Nucor 7.6 (Attachment JZ-12), similar customer delivery services are provided to LPS and LGS customers, yet LPS customers would pay 33 times more under the utility's proposal.

Q. WHAT IS THE PRINCIPLE OF GRADUALISM?

A. It is a ratemaking principle which suggests that rates should be moved in a gradual manner toward unity rate of return. Charges should not be changed abruptly and large changes in rates should be avoided.

Q. ARE THE PROPOSED INCREASES OF 269% AND 303% IN THE CUSTOMER CHARGES OF LPS CUSTOMERS A VIOLATION OF THE PRINCIPLE OF GRADUALISM?

A. Yes.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE CUSTOMER CHARGES PROPOSED BY UNS?

A. In the revenue requirements (the "non-rate design") phase of this proceeding, the utility's reasonable and necessary cost of service or revenue requirement for customer-related costs will be determined. My recommendation would not impact UNS's ability to collect a reasonable amount for large customers' customer-related costs, nor would it impact the residential customers. Rather, I recommend that all non-residential customer classes be changed proportionally and in a revenue-neutral manner. That is, each non-residential customer should receive the same percentage increase in its customer charge.

Certainly, UNS should have a reasonable opportunity to recover all of its customer-related costs. But UNS has not justified its proposal to roughly triple the customer charges for LPS customers, while exposing some other customer classes to trivial increases.

VIII. PROPOSED REDESIGN OF PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE (PPFAC)

Q. DO YOU HAVE ANY CONCERNS ABOUT THE PROPOSAL BY UNS TO RE-DESIGN ITS PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE?

A. Yes. While I take no position on the utility's proposal to remove fuel and purchased power costs from base rates and recover them exclusively through the PPFAC, I am concerned about their proposal to expand the types of costs that are collected through the PPFAC to include credit costs and broker fees.

Q. WHY IS THIS A CONCERN?

A. My chief concern is that UNS has not sufficiently explained this change and its impacts. In Nucor 6.3 (Attachment JZ-13), we asked whether "the proposed modifications to the PPFAC calculations will have a material impact on customer bills" and were told the impacts would be "minimal."

I asked questions through Nucor's 3rd discovery request which were designed to explore whether the utility was proposing to move costs between the PPFAC and base rates, but the Company's proposal to expand the types of costs that are collected through the PPFAC to include credit costs and broker fees was not identified as a change. For example, UNS response to Nucor 3.09 (Attachment JZ-14) reads: "Without waiver of objection, as the Company understands the question, since the Company's proposal includes the recovery of all fuel in the PPFAC (Rider-1), none of the other energy charges would have been changed since they can only be changed in a rate case." Yet, this does not seem accurate. If the "Company's proposal" was in effect during a previous year, then base rates would have been lower and the PPFAC would have been higher, *ceteris paribus*, because credit costs and broker fees would have been collected through the PPFAC rather than through base rates under the Company's proposal (unless the expenses proposed to be shifted were negligible).

I was unaware that the utility had proposed moving these costs into the PPFAC until I saw the issue referenced in testimony from the ACC Staff and RUCO.

Absent a good explanation for this change from UNS and better information about the impact of this change on Nucor, I cannot support the Utility's proposal to move credit costs and broker fees into the PPFAC.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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

Jay Zarnikau, PhD
President, Frontier Associates LLC
1515 S. Capital of Texas Hwy., Suite 110
Austin, TX 78746
Phone: (512) 372-8778

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:

"The Impact of Wind Generation on Wholesale Electricity Prices in the Hydro-Rich Pacific Northwest." IEEE Transactions on Power Systems. With C.K. Woo, Ira Horowitz, Jonathan Kadish, and Jianhui Wang. In Press.

"The response of large industrial energy consumers to four coincident peak (4CP) transmission charges in the Texas (ERCOT) market." Utilities Policy. 2013. With Dan Thal.

"Transparency of Retail Energy Pricing: Evidence from the U.S. Natural Gas Industry." Managerial and Decision Economics. 2013. With C.K. Woo, Ira Horowitz, and Alice Shiu.

"The Many Factors that Affect the Success of Regulatory Mechanisms Designed to Foster Energy Efficiency," Energy Efficiency. Vol. 5, No. 3, 2012, pp. 393-410.

"Blowing in the Wind: Vanishing Payoffs of a Tolling Agreement for Natural Gas-Fired Generation of Electricity in Texas," The Energy Journal, 2012, Vol. 33(1), with C.K. Woo, Ira Horowitz, Brian Horii, and Ren Orans.

"Wind Generation and Zonal-Market Price Divergence: Evidence from Texas," Energy Policy, Vol. 39(7), 2011, pp. 3928-3938. With C.K. Woo, J. Moore, and I. Horowitz.

"Successful Renewable Energy Development in a Competitive Electricity Market: A Texas Case Study," Energy Policy, Vol. 39(7), 2011, pp. 3906-3913.

"System Energy Assessment (SEA), Defining a Standard Measure of EROI for Energy Businesses as Whole Systems." Sustainability. Vol. 3(10), 2011, pp. 1908-1943. With Phil Henshaw and Carey King.

"Exact Welfare Effect for Double-Log Demand with Partial Adjustment", Empirical Economics, Springer, Vol. 42(1), 2010, pp. 171-180. With C.K. Woo and Eli Kollman.

"Demand Participation in the Restructured Electric Reliability Council of Texas Market," Energy -- the International Journal. 2009.

"Did the Expiration of Retail Price Caps Affected Competitive Electricity Prices in Texas?," Energy Policy, Vol. 37(5), pp. 1713-1717, 2009; with Linhong Kang.

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

"Industrial Energy Consumer Response to Wholesale Prices in the Restructured Texas Electricity Market," with Greg Landreth, Ian Hallett, and Subal Kumbhakar. Energy -- the International Journal. 2007.

"Trends in Prices to Commercial Energy Consumers in the Competitive Texas Electricity Market," Energy Policy. Vol. 35(8), 2007, pp. 4332-4339. With Marilyn Fox and Paul Smolen.

"Testing Functional Forms in Energy Modeling: An Application of the Bayesian Approach," Energy Economics, Vol. 54(2), 2007, pp. 158-166. With Ni Xiao and Paul Damien.

"Has Electric Utility Restructuring Led to Lower Electricity Prices for Residential Consumers in Texas?" Energy Policy, Vol. 34(15), pp. 2191-2200. With Doug Whitworth.

"A Review of Efforts to Restructure Texas' Electricity Market," Energy Policy, Vol. 33(1), 2005, pp. 15-25.

"Consumer Demand for 'Green Power' and Energy Efficiency," Energy Policy, Vol. 31(15), 2003, pp. 1661-1672.

"Functional Forms in Energy Demand Modeling," Energy Economics, Vol. 25(6), pp. 603-613, 2003.

"Defining Total Use in Econometric Studies, Does the Aggregation Approach Matter?," Energy Economics, Vol. 21(5), 1999, pp. 485-492.

"Will Tomorrow's Energy Efficiency Indices Prove Useful in Economic Studies?," The Energy Journal, Vol. 20(3), 1999.

"A Re-examination of the Causal Relationship between Energy Consumption and GDP," Journal of Energy and Development, 1996.

"The Evolution of the Cogeneration Market in Texas," Energy Policy, Vol. 24(1), 1996, pp. 67-79.

"Can Different Energy Resources be Added or Compared?," Energy - The International Journal, 1995, Vol. 21, No. 6; with Philip Schmidt and Sid Guermouche.

"Spot Market Pricing of Water Resources and Efficient Means of Rationing Water During Scarcity." Resource and Energy Economics. Vol. 16(3), 1994, pp. 189-210.

"Advanced Pricing in Electrical Systems," IEEE Trans. on Power Systems, 1995; with Martin Baughman and Shams Siddiqi.

"Integrating Transmission into IRP," IEEE Trans. on Power Systems, 1998; with Martin Baughman and Shams Siddiqi.

"Customer Responsiveness to Real-Time Pricing of Electricity," The Energy Journal, December 1990, Vol. 11, No. 4.

"Spot Market Pricing of Electricity," Forum for Applied Research and Public Policy, Winter 1990, Vol. 5, No. 4; with Martin Baughman and George Mentrup.

Under Review:

"Did the introduction of a nodal market structure impact wholesale electricity prices in the Texas (ERCOT) market?" With C.K. Woo and Ross Baldick.

Non-Refereed Journals and Widely-Accessible Proceedings:

"Texas Electricity Market: Best Gets Better," forthcoming in Evolution of Global Electricity Markets, ed. Fereidoon Sioshansi, Elsevier. With Parviz Adib and Ross Baldick.

"Getting to Zero: Green Building and Net Zero Energy Homes," in Smart Living in the Coming Age of Scarcity, edited by F. P. Sioshansi, Elsevier, 2010. With Meredith Gray.

"Defining a Standard Measure for Whole System EROI, Combining Economic Top-Down and LCA Bottom-Up Accounting," Proceedings of Energy Sustainability 2010, American

Society of Mechanical Engineers, May 2010, Phoenix. With Carey King and Phil Henshaw.

"Will Electricity Market Reform Likely Reduce Retail Rates?," The Electricity Journal, Vol. 22(2), 2009, pp. 40-45. With C.K. Woo.

Barriers and Policy Solutions to Energy Efficiency as a Carbon Emissions Reduction Strategy," in Electricity Generation in a Carbon-Constrained World, edited by F. P. Sioshansi, Elsevier, 2009. With Bill Prindle and Erica Allis.

"Integrating Demand Response into Restructured Wholesale Markets," in Competitive Electricity Markets: Design, Implementation, and Performance, edited by F. P. Sioshansi, Elsevier, 2008.

"The Quest for Competitive Electricity Markets," LBJ Journal of Public Affairs, 2008.

"Texas: The Most Robust Restructured Electricity Market in North America," in Electricity Market Reform: An International Perspective, Ed. F. P. Sioshansi and Wolfgang Pfaffenberger, Elsevier, 2007.

"Changing Installation Practices of A/C Installers – Three Years of Results, " ACEEE Summer Study on Energy Efficiency in Building, 2006. With Mike Stockard and Phil Audet.

"Using Demand Response Programs to Provide Operating Reserves in Wholesale Power Markets: A Case Study of the ERCOT Market," US Energy Association's Dialogue, 2006.

"Energy Efficient Windows in the Southern Residential Windows Market," ACEEE Summer Study Proceedings, with Alison Tribble, Kate Offringa, Bill Prindle, Dariush Arasteh, Arlene Stewart, and Ken Nittler. 2002.

"Agriculture: An Often-Overlooked Opportunity for Energy Conservation," Strategic Planning for Energy and the Environment, with Alex Lee, 1997.

"Energy Efficiency Opportunities in the Industrial Sector," Energy Engineering, Vol. 93, No. 3, 1996; with Alex Lee.

"Taking Advantage of Real-Time Pricing Programs to Reduce Energy Costs in Manufacturing," ACEEE Summer Study on Energy Efficiency in Industry Proceedings, August 1997.

"Opportunities for Energy Efficiency in the Texas Industrial Sector," ACEEE Summer Study on Energy Efficiency in Industry Proceedings, August 1995; contributor.

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

"Has Texas Become a Net Importer of Energy Resources?" Texas Business Review, 1997.

"Plugging into the Texas Electricity Market: Avoiding the Mistakes of California?" Texas Business Review, 2001.

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

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

Board of Editors, ISRN Economics journal

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

TESTIMONY

PUCT Docket No. 36633: Petition of CPS Energy for Enforcement Against AT&T and Time Warner Cable regarding Pole Attachments. Rebuttal testimony before the Public Utility Commission of Texas (PUCT) on behalf of AT&T and Time Warner Cable regarding statistical sampling of electric poles.

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.

Public Utility Commission of Texas (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. 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. 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 it 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, 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, 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, demand, and number of customers data, and miscellaneous operations and maintenance expenses. Analyzed the utility's filing on behalf of PUCT Staff.

UNS ELECTRIC INC.'S RESPONSE TO NUCOR'S THIRD SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
April 10, 2013

NUCOR 3.02

Please provide copies of all studies or analyses used to set or define the on-peak and off-peak time-of-use periods proposed by UNS in this proceeding for retail tariffs containing time-of-use (TOU) pricing.

RESPONSE:

UNS Electric did not conduct any specific time-of-use studies. However, the Company did utilize a consultant's research conducted for TEP's most recent rate case as a general guide to create consistency between TEP and UNS Electric and their tariffs. Please see NUCOR 3.02 TEP 2012 RC DesLauriers Direct Testimony Pgs 24-28.pdf, Bates Nos. UNSE\011953-011958, for the relevant pages from consultant, Mr. David DesLauriers' direct testimony for TEP's most recent rate case. Additionally, as discussed by Mr. Craig A. Jones in his direct testimony, page 37, Section 3, removing the shoulder peak period for the TOU rates is more consistent with the way the Company incurs cost and would be easier for the customer to understand.

RESPONDENT:

Pricing (Brenda Pries) and Craig A. Jones

WITNESS:

Craig A. Jones

UNS ELECTRIC INC.'S RESPONSE TO NUCOR'S THIRD SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
April 10, 2013

NUCOR 3.03

Please identify and describe all other TOU periods considered by UNS or Tucson Electric Power in the course of designing the proposed TOU periods.

RESPONSE:

Please see UNS Electric's response to NUCOR 3.02. While TEP and UNS Electric have some differences in how the marginal cost of fuel is incurred during the peak periods, both utilities incur the highest cost of marginal fuel mid-day through the early evening hours during the summer, and in the early morning and late afternoon during the winter. The 12:00 p.m. to 8:00 p.m. time period was determined to be representative of a reasonable time period reflective of the highest cost of marginal fuel during the summer months and was therefore proposed in this case.

RESPONDENT:

Pricing (Brenda Pries) and Craig A. Jones

WITNESS:

Craig A. Jones

NUCOR 4.7

Refer to UNSE's response to Nucor 2.13. Please provide hourly estimates of the short-run marginal cost for the UNSE system for each hour of the past 5 years.

RESPONSE:

Please see UNS Electric's response to Nucor 4.8.

RESPONDENT:

Michael Bowling

WITNESS:

Michael DeConcini

UNS ELECTRIC INC.'S RESPONSE TO NUCOR'S FOURTH SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
April 18, 2013

NUCOR 4.8

Refer to UNSE's response to Nucor 2.13. Please indicate the cost on a $/MWh basis of the highest-cost resource (regardless of whether it is purchased power or generation from Black Mountain Generating Station or Valencia Generating Station) on the UNSE system for each hour of the past 5 years.

RESPONSE:

UNS Electric is in the process of gathering this information consistent with discussions between UNS Electric and Nucor held on April 16, 2013 and UNS Electric will provide it as soon as possible.

RESPONDENT:

Michael Bowling

WITNESS:

Michael DeConcini

**UNS ELECTRIC INC.'S RESPONSE TO NUCOR'S THIRD SET OF DATA REQUESTS
REGARDING THE 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
April 10, 2013**

NUCOR 3.01

Please provide hourly load data for UNS's total system for the years 2010, 2011, and 2012.

RESPONSE:

THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

Please see Nucor 3.01-Confidential.xls for the hourly load data for the years 2010, 2011, and 2012. The Excel file is not identified by Bates numbers.

RESPONDENT:

Victor Aguirre

WITNESS:

Michael DeConcini

UNS ELECTRIC INC.'S RESPONSE TO NUCOR'S THIRD SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
April 10, 2013

NUCOR 3.04

Please explain why the summer on-peak time-of-use period of noon to 8 p.m. on non-holiday weekdays proposed by UNS in this proceeding differs from the summer on-peak period that Tucson Electric Power recently agreed to in Docket No. E-01933A-12-0291 (i.e., 2 p.m. to 8 p.m.).

RESPONSE:

In the above referenced docket, TEP originally applied for a 12-hour on-peak TOU period, but agreed to the shortened duration (2 p.m. to 8 p.m.) in the final Settlement Agreement in Docket No. E-01933A-12-0291. The consultant research conducted in connection with the TEP application, which UNS Electric relied upon in this application, concluded that a twelve hour summer on-peak period was appropriate. However, given the specific circumstances of this application, UNS Electric has only proposed an eight hour on-peak period, which the Company sees as reasonable and appropriate.

RESPONDENT:

Pricing (Brenda Pries) and Craig A. Jones

WITNESS:

Craig A. Jones

Attachment JZ-7

http://www.energychoicematters.com/stories/20130605f.html

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

June 5, 2013

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-8

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

Published in *Utilities Policy*. 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

	Odds Ratio Estimate (p-value in parentheses)
Variable or Statistic	
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.)

	Transmission Voltage Consumers (kWh/Interval)	Primary Voltage Consumers (kWh/Interval)
Variable or Statistic		
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.

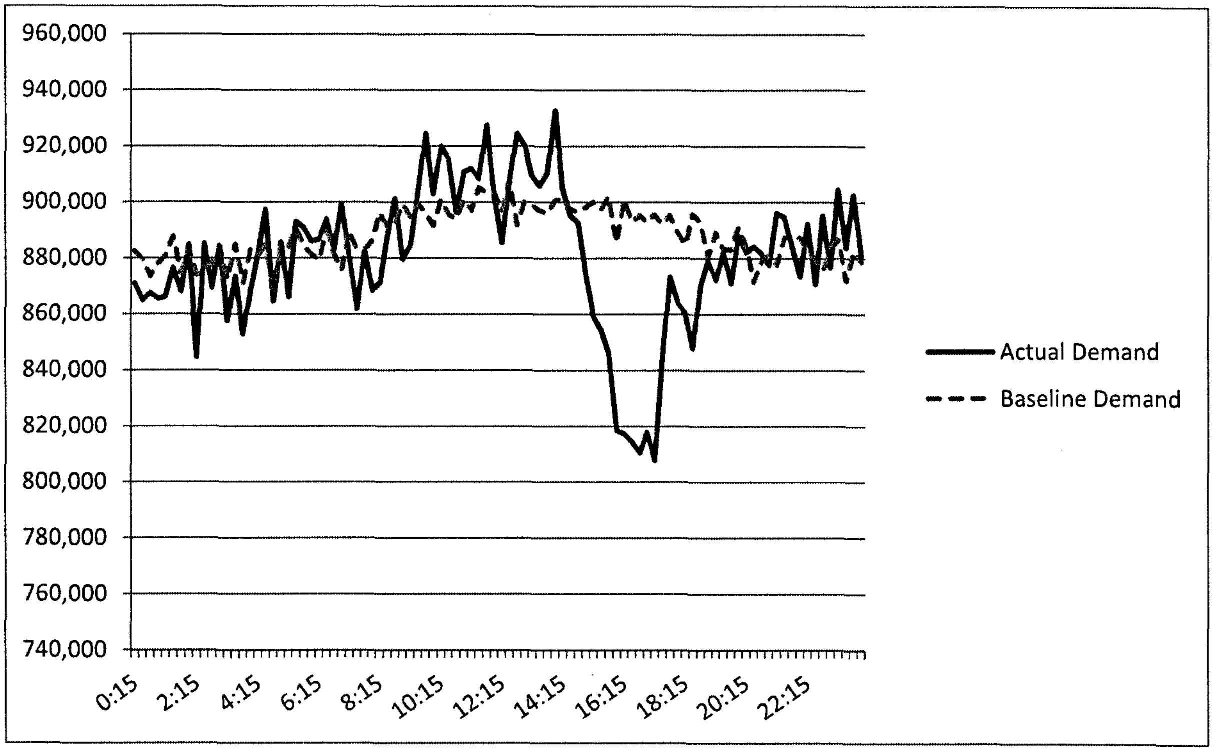

Fig. 1. Energy Consumption (in kWh) by Transmission Voltage Customers on June 16, 2008, Contrasted against Baseline Energy

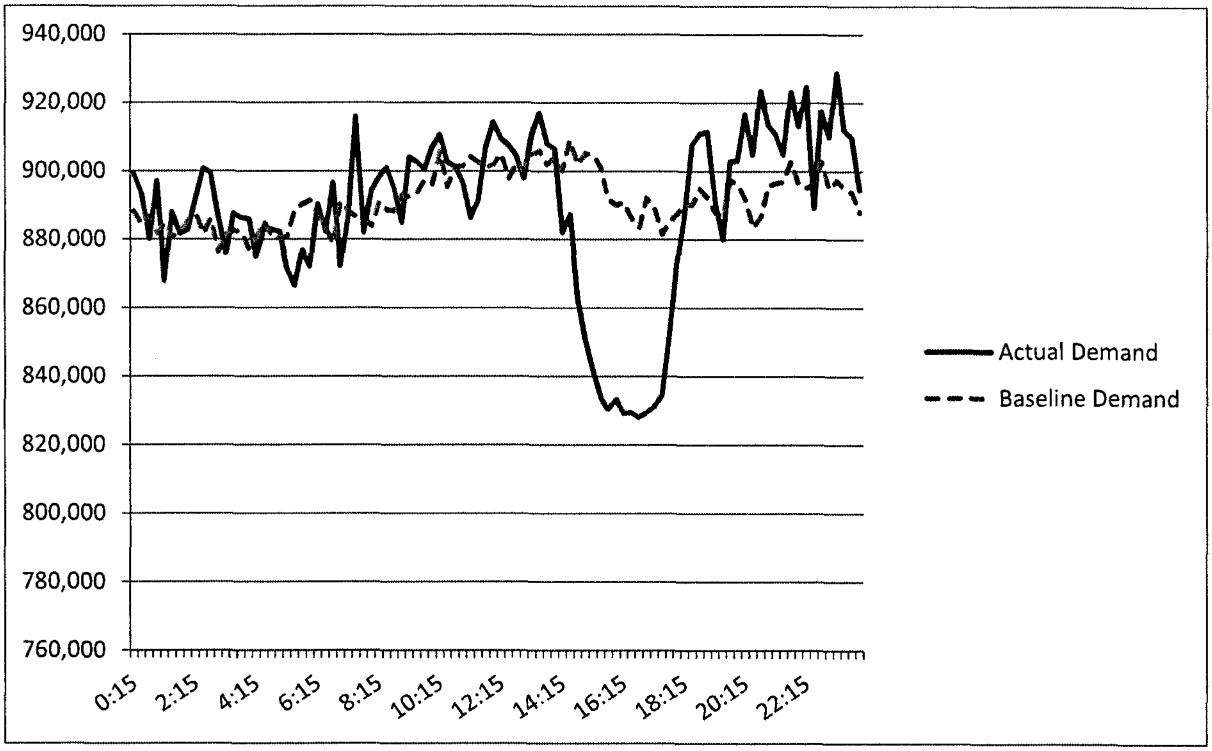

Fig. 2. Energy Consumption (in kWh) by Transmission Voltage Customers on June 26, 2011, Contrasted against Baseline Energy

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.

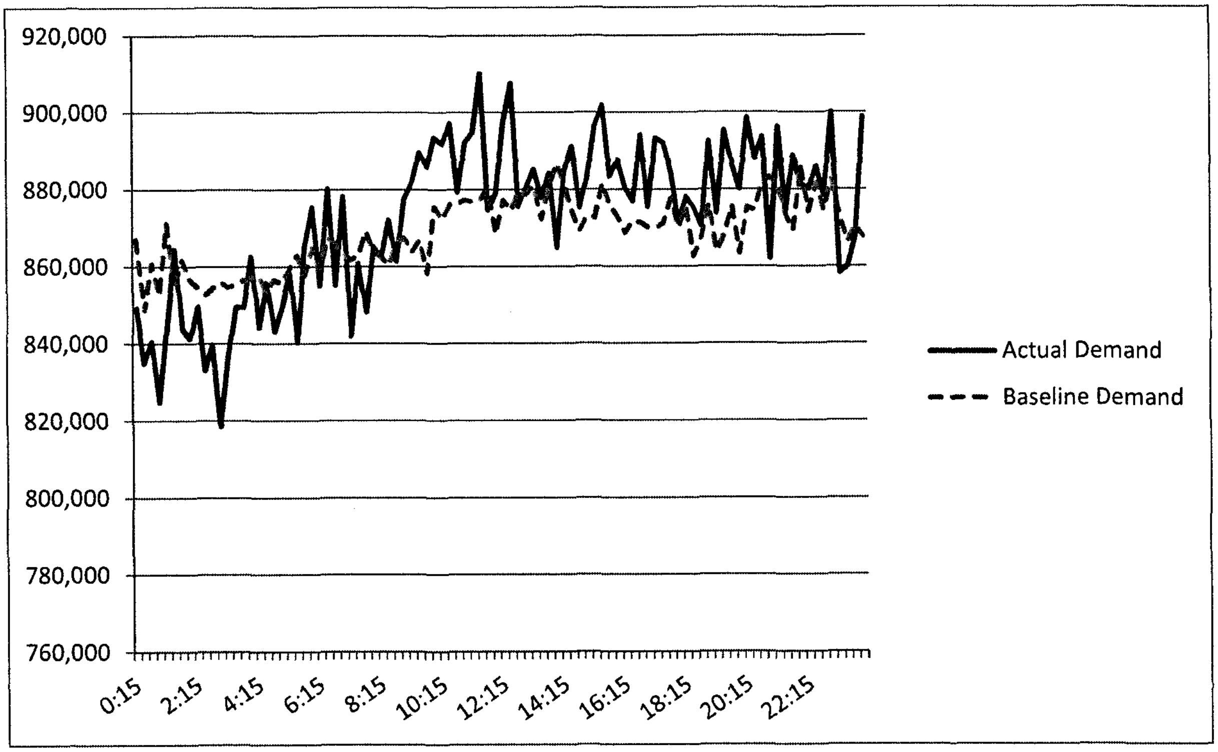

Fig. 3. Energy Consumption (in kWh) by Transmission Voltage Customers on September 2, 2008, Contrasted against Baseline Energy

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.

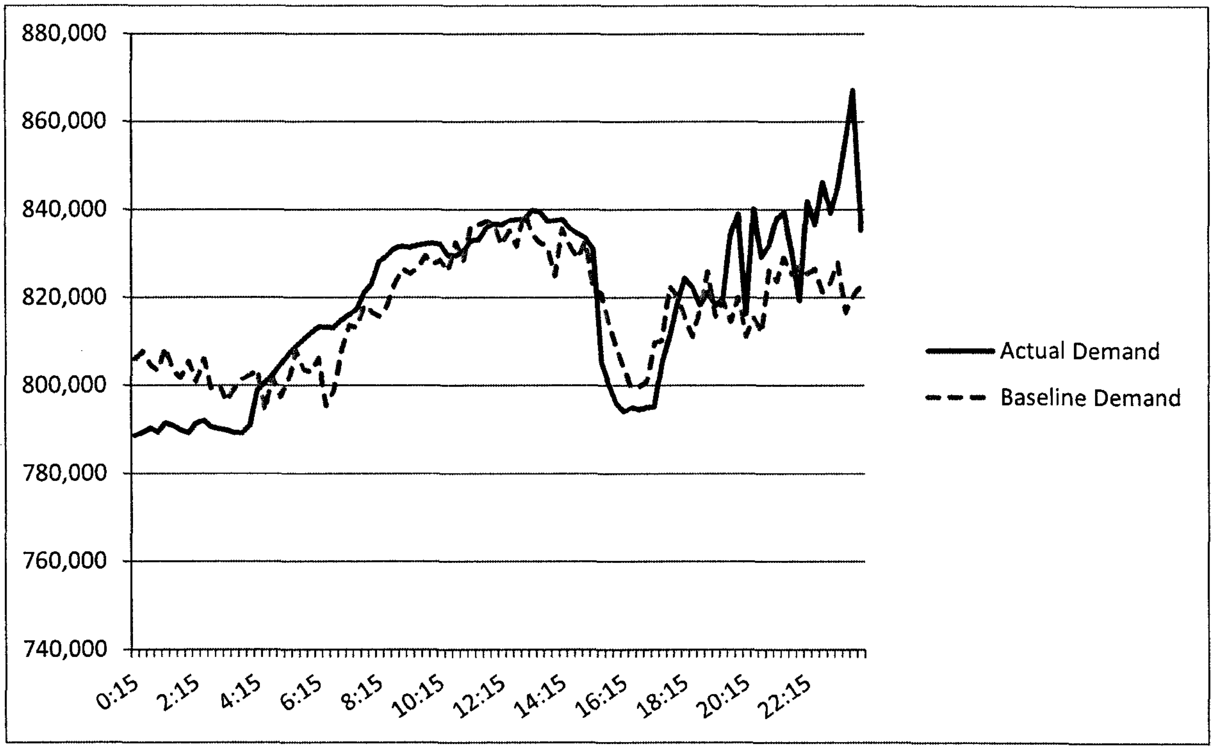

Fig. 4. Energy Consumption (in kWh) by Transmission Voltage Customers on June 21, 2010, Contrasted against Baseline Energy

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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UNS ELECTRIC INC.'S SUPPLEMENTAL RESPONSE TO NUCOR'S SECOND SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
April 09, 2013

NUCOR 2.07

Please explain why it costs the utility $436.96 per month to read the meter of a LPS customer, while it costs only $5.18 per month to read the meter of an Interruptible Power Service Customer.

RESPONSE:

The Cost of Service Study ("COSS") identifies certain costs associated with serving the various customer classes based in part on the function served. These costs are then classified and allocated based on the standard assumptions in the COSS. The LPS class is read through interval metering equipment, which feeds into the Meter Management Database system. Because of the magnitude and added complexities of the LPS bills, the LPS reads are verified, validated, and approved before they are entered into the Customer Care and Billing ("CC&B") system, after which the bills can then be generated for the LPS class.

All of these costs are placed in the various components of the customer charge as appropriate. Once various cost levels are determined, they are then used to calculate the weighted component in the unbundled version of the customer charge (since the customer charge does not always collect the exact amount of costs, the unbundled components are arrived at by using a weighted calculation based on the COSS). The LPS meters, equipment and various customer-related services are substantially more involved and more expensive for the LPS class. Therefore, the total dollars associated with the LPS services are higher. These higher costs are then spread over approximately 20 customers resulting in a higher cost per customer than for those classes with less expensive metering equipment and customer-related services and a larger customer base.

The Interruptible Power Service ("IPS") customer charge is calculated on lower cost meters and a less expensive method of generating the meter data. These lower costs are then spread over nearly 1,600 customers. The lower cost spread over a larger population results in a lower cost per customer.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

UNS ELECTRIC INC.'S SUPPLEMENTAL RESPONSE TO NUCOR'S SECOND SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
April 09, 2013

NUCOR 2.08

Please explain why it costs the utility $659.66 per month to provide billing and collection services for a LPS customer, while it costs only $8.48 per month to provide billing and collection services to an Interruptible Power Service customer.

RESPONSE:

Please see UNS Electric's response to Nucor 2.07 to understand why the weighting of these cost are different. The cost is developed based on the data in the test year and the class cost of service study.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

NUCOR 2.09

Please explain why there are differences in the costs of providing other customer-related services or activities between LPS and Interruptible Power Service customers.

RESPONSE:

There are numerous reasons why costs can be allocated differently between Interruptible Power Service ("IPS") customers and LPS customers. The most important are *actual costs*, such as meter costs, and *allocated customer costs*, such as Customer Delivery.

Currently, an IPS customer meter costs $130 to $180; the cost for a LPS customer meter is $612. These costs are shown in UNSE Meter.xls provided in response to UDR 1.1 as support to the cost of service – Schedule G. (The referenced file can be accessed in UNS Electric's electronic data room under UNS Electric Uniform Data Requests\UDR Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support.)

Some customer-related costs, such as Customer Delivery, are allocated based on the weighted number of customers in each class. The IPS Class has 468 annual customers, whereas the LPS class has 260 customers; therefore, more costs are allocated to the class with more customers, the IPS class.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

NUCOR 4.5

Refer to UNSE's response to Nucor 2.09.

a. Please explain the physical differences in the meters used by UNSE to measure usage for IPS customers versus LPS customers. Why are different features or capabilities needed to serve IPS versus LPS customers?

b. Would a customer with an expected billing demand of 5 MW (for example) receive a different meter if it opted for service under the IPS tariff rather than the LPS tariff? If yes, please explain why.

RESPONSE:

a. The primary differences between current meters installed for an IPS customer versus an LPS customer is the measurement level and the modem capability. The meter used for an IPS customer is the standard measurement level 1, which only measures kWh, whereas the measurement level for LPS is measurement level 2, which also measures KVARS. Both the modem and the KVAR measurements are a requirement of the LPS tariff to calculate the billing demand, which includes a ratchet and the power factor adjustment. Neither of these billing requirements are included in the IPS tariff.

b. Yes, a new customer with an expected load of 5MW would receive a different meter for taking service under the IPS tariff than would a new customer opting for service under the LPS tariff, because the tariff requirements are not the same. If an existing LPS customer opted to change service to IPS, then the Company would determine whether or not a meter exchange would be made based on cost and need.

RESPONDENT:

Pricing (Brenda Pries) and Ed Mansfield

WITNESS:

Craig A. Jones and Michael DeConcini

NUCOR 5.2

Please refer to the utility's response to Nucor 2.07.

a. UNSE's response includes the statement: "The LPS class is read through interval metering equipment, which feeds into the Meter Management Database system." Please explain how this differs from the method used to collect data from IPS customers.

b. UNSE's response includes the statement: "[T]he LPS reads are verified, validated, and approved before they are entered into the Customer Care and Billing ("CC&B") system, after which the bills can then be generated for the LPS class." Does the utility verify, validate, and approve metered data obtained from IPS customers? If no, please explain why.

c. Please describe the "added complexities" of LPS bills relative to bills sent to IPS customers.

d. Please provide descriptive statistics (i.e., the mean monthly kWh, mean monthly kW, variance in monthly kWh, variance in monthly kW, median monthly kW, and median monthly kWh) for customers served under the IPS tariff for the past 12 months.

e. Please provide descriptive statistics (i.e., the mean monthly kWh, mean monthly kW, variance in monthly kWh, variance in monthly kW, median monthly kW, and median monthly kWh) for customers served under the LPS tariff for the past 12 months.

f. What is the current per-meter cost of meters used to collect billing data from IPS customers? Please identify the manufacturer and model of these meters.

g. What is the current per-meter cost of meters used to collect billing data from LPS customers? Please identify the manufacturer and model of these meters.

Please describe the "customer-related services" which are more expensive for LPS customers relative to IPS customers.

RESPONSE:

a. The IPS customers are read once a month. A meter reader does a site visit and, using a handheld system, obtains a single monthly read that is used for billing. The LPS customers are read once a day using phone line download. The data is brought into the Company's Meter Data Management System ("MDM") where the 96 interval reads (15 minute increments) are validated by the system. If the reads fall out of tolerance parameters, a task is sent to the validation queue, which is then reviewed by a meter person. If the meter person feels it is necessary, an investigation order will be sent that requires a site visit. The data is verified for accuracy again at time of billing. If accurate, Energy Settlements enters the data into the Customer Care and Billing System, where the bill is generated.

b. IPS customer monthly reads are validated using the Customer Information System's ("CIS") high low algorithms. This is an automated system validation against a single monthly read.

UNS ELECTRIC INC.'S RESPONSE TO NUCOR'S FIFTH SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
May 3, 2013

NUCOR 5.1

Please provide all invoices, purchasing records, contracts, time sheets, other documentation of costs, spreadsheets, and work papers necessary to replicate the utility's calculation of its proposed customer charges for non-residential customer classes.

RESPONSE:

The above requested documents could not be used to replicate the utility's calculation of its proposed customer charges for non-residential customer classes because the utility did not calculate customer specific charges using these specific items. Standard rate making procedures generally support a calculation based on allocations of booked expense accounts based on the results of a Cost of Service Study which uses various methods to allocate costs to each class. These methods include weighting of various cost components based on the classes' utilization of facilities and personnel, general allocators and where appropriate, customer specific data.

The primary work paper to determine the proposed customer charges is Schedule G-6-1 in the class cost of service study. This schedule shows the cost of service on a per unit basis for all charges (demand, energy and customer charges). The rate of return in Schedule G-6-1 in the cost of service is based on class rate of returns based on test year adjusted rate base divided by the test year adjusted operating revenue by class excluding Other Operating Revenue. See response to STF 2.43 for file STF 2.43 G-6-1.xls which provides unit cost based on the Company's requested overall rate of return.

RESPONDENT:

Craig A. Jones

WITNESS:

Craig A. Jones

UNS ELECTRIC INC.'S RESPONSE TO NUCOR'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
July 1, 2013

NUCOR 7.5

How do the Customer Delivery services provided to LPS customers differ from the Customer Delivery services provided to IPS customers?

RESPONSE:

The Company is not aware of any specific services that would differ substantially between the two types of customers. The cost-allocation process, however, incorporates weighting that would likely differ between the classes. For example, the weighted average size of the meters may contribute to a different level of costs being recovered from the different classes. The most likely reason for maintaining some level of rate differential between these customer classes is to mitigate the impact on certain customer classes. Since UNS Electric inherited its rates from its predecessor, the rate differential between customer classes will take time to mitigate in order to gradually move to more comparable charges.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

UNS ELECTRIC INC.'S RESPONSE TO NUCOR'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
July 1, 2013

NUCOR 7.6

How do the Customer Delivery services provided to LPS customers differ from the Customer Delivery services provided to LGS customers?

RESPONSE:

The Company is not aware of any specific services that would differ substantially between the two types of customers. The cost allocation process incorporates weighting that would likely differ between the classes, the weighted average size of the meters may contribute to a different level of costs being recovered from the different classes, but the most likely reason for maintaining some level of difference is customer impact. Since UNS Electric inherited its rates from its predecessor, the rate differential will take time to mitigate in order to gradually move to more comparable charges.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

Arizona Corporation Commission ("Commission")
Nucor Corporation ("Nucor")
Tucson Electric Power Company ("TEP" or the "Company")
Tucson Electric Power Company ("TEP" or the "Company")
UNS Energy Corporation fka UniSource Energy Corporation ("UNS")
UniSource Energy Services ("UES")
UniSource Energy Development Company ("UED")
UNS Electric, Inc. ("UNS Electric")
UNS Gas, Inc. ("UNS Gas")

UNS ELECTRIC INC.'S SUPPLEMENTAL RESPONSE TO NUCOR'S SIXTH SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
June 14, 2013

NUCOR 6.3

Regarding pages 42-45 of Craig A. Jones's Direct Testimony, does UNSE expect that the proposed modifications to the PPFAC calculations will have a material impact on customer bills? Please provide any calculations or projections of the impact of changes to the PPFAC calculation on each rate class.

ORIGINAL RESPONSE: June 13, 2013

UNS Electric is in the process of gathering this information and will provide it as soon as possible.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

SUPPLEMENTAL RESPONSE: June 14, 2013

While bill impact can vary with each individual customer's actual usage habits, it is the Company's opinion that its proposed modifications to the PPFAC calculations will have minimal impact on a customer's bill when compared to the existing method of having multiple base fuel costs and one PPFAC. The total cost of fuel, to the customer, is essentially the same as would be under the current scenario, which uses multiple base fuel costs and a single PPFAC rate.

Company witness Craig Jones' Exhibit CAJ-1 to his direct testimony and Schedule H filed in this proceeding provides multiple levels of impact the customers will experience if the Company's full rate request is granted.

RESPONDENT:

Craig A. Jones

WITNESS:

Craig A. Jones

UNS ELECTRIC INC.'S RESPONSE TO NUCOR'S THIRD SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
April 10, 2013

NUCOR 3.09

Based on 1) the fuel and purchased power costs incurred by the company in 2011 and 2) the utility's proposal to redefine the Summer TOU pricing periods and remove the Summer Shoulder-Peak period, what would have been the On-Peak and Off-Peak Rider-1 PPFAC charges applied to LPS-TOU customers in that year? And what would have been the values of all other energy charges (those that would not have been collected through Rider-1) during that period?

RESPONSE:

The Company objects to this question as being vague and ambiguous and unduly burdensome. Depending on what information is being sought through this request, the Company may need to build a mathematical model not already in existence, and outside the scope of normal business practices. The new model would need to reflect a set of unclear hypothetical assumptions, requiring additional research in order to identify adjustments necessary to be consistent with the test-year adjustments reflected in the Company's proposal in this proceeding. The Company's proposal uses forecasted fuel cost and applies that assumption to the normalized and annualized sales data calculated based on actual test-year data in order to calculate an estimated fuel cost by class that is comparable to the forecasted fuel costs as it would be applied to the adjusted test-year billing determinants. Fuel recovery must be designed to be revenue neutral in any assumption to be in compliance with Commission mandates. Moreover, similar to 3.06 above, the apparent premise of the question is for an "apples to apples" comparison when in fact, it would be an "apples to oranges" comparison.

The Company is also unclear as to what is being requested in the statement; "...what would have been the values of all other energy charges (those that would not have been collected through Rider-1)..."? Without waiver of objection, as the Company understands the question, since the Company's proposal includes the recovery of all fuel in the PPFAC (Rider-1), none of the other energy charges would have been changed since they can only be changed in a rate case.

UNS Electric requests that Nucor rephrase the question or contact UNS Electric by telephone to discuss what information is being sought by this request.

RESPONDENT:

Craig A. Jones

WITNESS:

Craig A. Jones