q. Undepreciated net book value

RESPONSE

Prepared By: Jeff Holmes
Title: Manager Trading
Date: October 23, 2019

a. Installed Capacity

Unit	Installed Capacity (MW)
Labadie 1	590.75
Labadie 2	590.75
Labadie 3	621.00
Labadie 4	625.50
Meramec 3	289.00
Meramec 4	326.40
Rush Island 1	669.60
Rush Island 2	669.60
Sioux 1	499.80
Sioux 2	499.80

b. Unforced Capacity

UCAP (MW)	PY 14/15	PY 15/16	PY 16/17	PY 17/18	PY 18/19	PY 19/20
Labadie 1	565.5	546.4	557.9	553.0	555.6	547.9
Labadie 2	569.0	561.8	571.0	578.2	568.4	561.9
Labadie 3	535.8	519.9	546.5	533.7	523.3	533.5
Labadie 4	562.0	540.6	524.5	547.6	556.7	563.4
Meramec 3	211.7	189.8	184.3	190.5	209.9	209.1
Meramec 4	270.6	270.0	275.3	259.3	224.5	233.8
Rush Island 1	564.6	560.7	551.6	538.3	532.5	537.5
Rush Island 2	575.7	557.5	539.4	505.1	515.8	525.5
Sioux 1	441.4	422.4	411.1	412.0	411.2	420.2
Sioux 2	367.5	398.9	400.6	383.3	382.7	436.7

Prepared By: Scott Anderson
Title: Consulting Engineer
Date: October 7, 2019

c. Capacity Factor

NCF	2015	2016	2017	2018
Labadie 1	84.13	73.90	79.00	82.07
Labadie 2	78.47	72.39	79.25	81.59
Labadie 3	63.19	69.80	66.06	52.81
Labadie 4	76.18	61.63	79.54	80.24

Meramec 3	27.42	26.82	15.67	23.25
Meramec 4	34.38	32.35	23.99	25.41
Rush Island 1	68.53	75.05	83.41	62.98
Rush Island 2	72.69	46.21	83.81	84.39
Sioux 1	49.81	41.23	66.27	60.95
Sioux 2	54.35	63.22	49.33	69.92

d. Availability

EAF	2015	2016	2017	2018
Labadie 1	94.47	85.59	89.06	91.26
Labadie 2	90.13	83.29	89.26	90.10
Labadie 3	76.05	82.90	77.68	60.82
Labadie 4	88.56	72.74	92.48	91.06
Meramec 3	71.10	83.39	84.57	60.53
Meramec 4	62.98	66.49	58.57	55.68
Rush Island 1	84.20	90.16	89.87	68.66
Rush Island 2	85.89	58.42	91.07	91.28
Sioux 1	71.35	58.50	86.32	81.62
Sioux 2	79.25	87.76	64.62	92.56

e. Heat Rate

Ameren Missouri does not record an annual heat rate by unit.

Below is the average BTU per KWh Net Generation reported on page 402, line 44 of Ameren Missouri's FERC FORM 1.

	Labadie	Rush Island	Sioux	Meramec
2016	10,123	10,549	10,703	11,849
2017	10,086	9,944	10,347	12,263
2018	10,059	9,864	10,225	11,900

Please note that the values for Meramec include units 1&2 which have been converted to natural gas.

f. Forced or random outage rate (percentage)

FOR	2015	2016	2017	2018
Labadie 1	2.06	9.79	4.34	3.54
Labadie 2	3.47	3.90	4.88	2.90
Labadie 3	7.31	12.68	5.78	4.54
Labadie 4	3.32	2.00	4.14	2.84
Meramec 3	29.39	23.32	17.91	38.56
Meramec 4	19.90	32.59	25.97	14.35
Rush Island 1	3.39	5.23	4.19	7.64
Rush Island 2	6.86	3.94	5.40	1.31
Sioux 1	17.57	19.77	9.85	17.49

Sioux 2	15.29	7.10	12.00	4.31

RESPONSE: (Do not edit or delete this line or anything above this. Start typing your response right BELOW Date.)

Prepared By: Mark J. Peters
Title: Manager, Load Forecasting and Market Analysis
Date:

g. Fixed O&M costs
Ameren Missouri's accounting records do not differentiate between fixed and variable O&M. Please see part h. below
h. Non-Fuel Variable O&M costs
Ameren Missouri's accounting records do not differentiate between fixed and variable O&M. Additionally, O&M is not accounted for on a per unit level.
Below is the non-fuel O&M reported on Ameren Missouri's FERC Form 1 (page 402, line 34 minus line 20)

	Labadie	Rush Island	Sioux	Meramec
2016	48,077,956	27,517,657	36,242,697	20,116,334
2017	43,780,733	25,152,496	39,354,744	19,815,233
2018	60,189,722	35,937,358	36,821,300	19,387,124

Please note that the values for Meramec include units 1&2 which have been converted to natural gas.
i. Fuel Costs
Ameren Missouri's accounting records contain fuel by Energy Center. At Energy Centers with more than one unit, fuel is not separately recorded by unit.
Below is the Fuel cost reported on page 402 line 20 of Ameren Missouri's FERC Form 1.

	Labadie	Rush Island	Sioux	Meramec
2016	332,149,501	152,147,812	103,860,366	44,953,264
2017	353,323,146	183,044,613	106,777,297	30,862,539
2018	301,930,687	158,658,176	111,144,642	31,166,121

Please note that the values for Meramec include units 1&2 which have been converted to natural gas.

Prepared By: Paul W. Mertens
Title: Manager, Plant Accounting
Date: October 15, 2019

j. Environmental capital costs
Please reference part k. below.
k. Non-environmental capital cost

	2016			2017			2018		
	Environmental	Non-Environmental	Total	Environmental	Non-Environmental	Total	Environmental	Non-Environmental	Total
Meramec Energy Center	4,028,645	2,494,053	6,522,698	1,795,684	7,847,990	9,643,674	703,228	2,863,408	3,566,636
Sioux Energy Center	14,677,998	26,425,353	41,103,351	9,907,315	25,935,813	35,843,128	11,124,334	9,409,384	20,533,718
Labadie Energy Center	52,471,962	19,513,932	71,985,894	41,701,199	26,255,296	67,956,495	77,455,584	54,618,596	132,074,180
Rush Island Energy Center	35,390,690	29,322,066	64,712,756	44,140,178	11,233,866	55,374,044	42,839,745	23,930,471	66,770,216
Grand Total	106,569,295	77,755,405	184,324,700	97,544,376	71,272,965	168,817,341	132,122,891	90,821,859	222,944,750

Prepared By: Rozitta Bennett
Title: Supv. RTO Settlements & Trading
Date: October 15, 2019

l. Energy revenues

Please reference response for SC 001.21

m. Capacity revenues

The MISO capacity market utilizes a concept of Zonal Resource Credits (ZRC).
Capacity cleared in the annual auctions is not settled by MISO on a generation unit basis.
Ameren Missouri does not record capacity revenues by unit.
The values below are simply sum annual totals of the cleared ZRCs associated with a given unit multiplied by the applicable auction clearing price multiplied by the number of days in a given month.

	2016	2017	2018
Labadie			
Unit 1	$ 8,885,146.94	$ 6,243,001.80	$ 1,314,238.50
Unit 2	$ 9,095,137.73	$ 6,393,514.20	$ 1,347,338.30
Unit 3	$ 8,695,478.30	$ 6,112,865.70	$ 1,240,745.05
Unit 4	$ 8,367,451.78	$ 5,878,143.60	$ 1,315,369.40
Meramec			
Unit 1	$ 35,341.49		
Unit 2	$ 36,101.52		
Unit 3	$ 2,940,091.01	$ 2,064,860.10	$ 492,334.25
Unit 4	$ 4,384,641.60	$ 3,076,296.90	$ 539,161.45
Rush Island			
Unit 1	$ 8,795,640.67	$ 6,169,789.50	$ 1,261,474.95
Unit 2	$ 8,605,970.40	$ 6,026,493.90	$ 1,218,217.15
Sioux			
Unit 1	$ 6,557,661.50	$ 4,601,731.20	$ 973,286.00
Unit 2	$ 6,383,446.94	$ 4,478,362.50	$ 905,795.45

n. Ancillary services revenues

Please reference response for SC 001.21

o. Any other revenues

Please reference response for SC 001.21

Prepared By: Paul W. Mertens
Title: Manager, Plant Accounting
Date: October 15, 2019

p. Depreciation, excluding Asset Retirement Obligations

	2016	2017	2018
Meramec Energy Center	$ 46,397,888	$ 46,816,907	$ 45,239,524
Sioux Energy Center	$ 54,508,610	$ 55,926,694	$ 56,786,179
Labadie Energy Center	$ 30,861,109	$ 31,996,961	$ 32,393,462
Rush Island Energy Center	$ 16,232,917	$ 17,098,975	$ 18,078,861
Total Depreciation and Amortization by Year	$ 148,000,523	$ 151,839,537	$ 152,498,026

q. Undepreciated net book value

Ameren Missouri			
Net Book Value of Energy Centers as of December 31			
	2016	2017	2018
Meramec Energy Center	268,010,165	238,256,928	198,650,136
Sioux Energy Center	869,469,216	849,393,860	807,427,212
Labadie Energy Center	891,770,230	877,271,605	1,019,513,876
Rush Island Energy Center	452,510,056	442,987,321	552,558,224
Total Energy Center NBV	2,481,761,683	2,407,911,731	2,578,151,466

Ameren Missouri's
Response to Sierra Club Data Request
ER-2019-0335
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.

Data Request No.: SC 001.21

For each of the Company's coal units, please provide the following hourly information for each year from 2015 through 2018 and each month of 2019 through the date of your response. If not available at an hourly scale, explain why not and provide at the most temporally granular scale available.

a. Price ($/MWh) of bids submitted into the MISO market and/or SPP market.

b. Quantity (MW) of bids submitted into the MISO market and/or SPP market.

c. For each bid, whether that bid was accepted by MISO and/or SPP.

d. Whether the hourly decision to dispatch a unit was made by MISO or by Ameren Missouri.

e. Reason for dispatch decision, including "economic," "self-dispatched," "reliability," or other recorded purposes.

f. Fuel costs ($/MWh)

g. Variable costs of production ($/MWh), including fuel, variable O&M, and any other variable operating costs.

h. Net generation (MWh)

i. Locational marginal price received ($/MWh)

j. Energy market revenues ($)

k. Ancillary market revenues ($)

l. Congestion revenues ($)

m. Heat rate (Btu/kWh)

n. Economic minimum/minimum operation level (if this concept varies over time)

RESPONSE

Prepared By: Rozitta Bennett & Neil Graser
Title: Supervisor, RTO & Trading Settlement & Manager, Power & Fuels Accounting
Date: 10/23/2019

Subject to the Company's objection,

1. Generation resources are not bid into the MISO market. To the extent that this request seeks information regarding Ameren Missouri's generation offers, please refer to the attached files SC 1.21 – XXXXX, where XXXXX is the unit designation.

   Please note that unit offers are based on an offer curve.

2. Generation resources are not bid into the MISO market. To the extent that this request seeks information regarding Ameren Missouri's generation offers, please refer to the attached files SC 1.21 – XXXXX, where XXXXX is the unit designations.

   ECON MAX represents the maximum energy offered.

3. Generation resources are not bid into the MISO market. To the extent that this request seeks information regarding Ameren Missouri's generation offers, please refer to the attached files SC 1.21 – XXXXX, where XXXXX is the unit designation.

   DA ENERGY (MW) represents the level at which the unit cleared in the Day Ahead Market. RT ENERGY (MW) represents the integrated hourly total net generation output.

4. Real time dispatch status indicates if a unit was offered with an economic or self-scheduled dispatch status. MISO, as a function of the operation of the market, dispatches units. This dispatch is made above unit ECON MIN (if offered as economic) or above the self-scheduled amount (if offered as self-scheduled).

5. Please refer to the attached files SC 1.21 – XXXXX, where XXXXX is the unit designation.

   Please note, MISO does not have a "self-dispatched" status.

6. Ameren Missouri does not record fuel costs on a per unit level. Nor are they recorded on an hourly basis.

   Please refer to the response to ER-2019-0335 MPSC 0048 for January 2017 through June 2019 and the responses to ER-2016-0179 MPSC 0066, 0066s1, 0066s2, and 0066s3 for January 2015 through December 2016. Refer to attachments "AEEMO_GA19611 – 2019XX" for July through September 2019.

7. Ameren Missouri does not record variable costs of production ($/MWh), including fuel, variable O&M, and any other variable operating costs on an hourly basis. Nor are they recorded on a per unit basis, nor segregated between fixed and

variable. Please reference part f. above for fuel costs by Energy Center, by month.

To the extent that this data request is seeking the Variable O&M proxy utilized by Ameren Missouri in the development of its unit offers to MISO, please refer to the attached files SC 1.21 – XXXXX, where XXXXX is the unit designation.

8. Please refer to the attached files SC 1.21 – XXXXX, where XXXXX is the unit designation.

Real Time Energy (MW) is the hourly net generation settled with MISO.

9. Please refer to the attached files SC 1.21 – XXXXX, where XXXXX is the unit designantion.

10. Please refer to the attached files SC 1.21 – XXXXX, where XXXXX is the unit designation.

11. Please refer to the attached files SC 1.21 – XXXXX, where XXXXX is the unit designation

12. There were no congestion revenues for Ameren Missouri's coal units from January 1, 2015 to September 30, 2019.

13. Ameren Missouri does not record heat rate on an hourly, or per unit basis.

Please refer to the Company's response to SC 1.15, part e.

14. Please refer to the attached files SC 1.21 – XXXXX, where XXXXX is the unit designation. DA ECON MIN

Ameren Missouri's
Response to Sierra Club Data Request
ER-2019-0335
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.

Data Request No.: SC 001.22

Regarding the development of Ameren Missouri's hourly energy market bids and dispatch decisions:

a. Indicate which production costs are considered to be variable on a short-term basis by Ameren Missouri for the purposes of dispatch at its existing coal units (e.g. fuel costs, variable operations and maintenance costs, emissions costs,

effluent costs, etc.).

b. Identify if there are any fuel costs at Ameren Missouri's coal units that Ameren Missouri considers fixed for the purposes of dispatch. Provide a detailed explanation of how the fixed component is determined, and provide a workpaper demonstrating the fixed and variable breakdown.

RESPONSE

Prepared By: Mark Peters
Title: Manager Load Forecasting & Market Analysis
Date: 10.23.2019

1. Ameren Missouri's generation offers are based on incremental cost, including fuel, associated transportation expense, an estimate of variable operations and maintenance ("O&M") costs derived from historical O&M for a given Energy Center, emission control activities (e.g. limestone, urea, activated carbon), variable ash landfill expense (net of revenues from beneficial use sales), variable refined coal credits, and the opportunity cost of emissions allowances. Additionally, a seasonal adjustment to the incremental costs for Meramec Units 3&4 is made to reflect incremental labor expense during non-summer periods when unit staffing is reduced. This adjustment is made to recognize the increased cost associated with overtime labor which would be required as a result of operating the unit above projected levels.

2. None.

Ex. AA-S-1

Ameren Missouri's
Response to Sierra Club Data Request
ER-2019-0335
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.

Data Request No.: SC 001.24

Regarding Ameren Missouri's unit commitment decision process for its coal units:

a. Describe Ameren Missouri's process for determining whether to commit its coal units outside of the MISO or SPP day-ahead energy markets and operate them up to at least their minimum operation levels.

b. Describe Ameren Missouri's process for determining whether to self-schedule its coal units at generating levels above their minimum operation levels.

c. Does Ameren Missouri perform economic analyses to inform its unit commitment decisions (i.e., decisions regarding whether to designate its coal units as must run or take them offline for economic reasons)?

i. If not, explain why not.

ii. If so, provide all such analyses conducted since 2015 in native, machine-readable format.

RESPONSE

Prepared By: Mark Peters
Title: Manager Load Forecasting & Market Analysis
Date: 10/28/2019

1. Ameren Missouri's coal fired units are all registered in the MISO market. They are not committed outside of MISO.

   To the extent that this data request is in regards to Ameren Missouri's use of a must run unit commitment status for its coal fired units, in general, Ameren Missouri utilizes a must run commit status for those units whose operating characteristics, such as high cost to restart, expected increase in forced outages if the units are not placed in must run commit status, and maintenance and capital costs due to unit cycling (again, if not placed in must run commit status), warrant such a designation. These units include all of Ameren Missouri's coal-fired units other than those at the Meramec Energy Center. Must run commit status may also be used for units at the Meramec Energy Center when such a unit is scheduled for testing to ensure that the unit will be in operation for the test, or in instances where the margin on the first day alone would not warrant committing the unit (due to its start-up cost) but where the expected margin over a longer period of time justifies committing the unit.

In making its commit status decisions, the Company's guiding principle is to clear (i.e., sell energy from) its units in the market when doing so benefits customers. Given that the current MISO algorithm for unit commitment only analyzes the 24-hour period of the next calendar day, Ameren Missouri looks past the next 24 hours to make this assessment. This process takes into consideration the costs associated with decommitting a unit, including; total of the expected foregone margins, the cost to restart the unit and the risk of significant maintenance and capital expenses arising from cycling the unit if it is committed and then decommitted and then committed again. Consideration is also given to unit downtime minimums. That is, if a unit downtime minimum is for more than one day, de-committing the unit based only on the next day's MISO model results could mean that the unit will forego margins for the following days when it remains shut-down.

2. Ameren Missouri does not utilize a self-schedule dispatch status for its coal fired units as a matter of course.

3. Ameren Missouri utilizes a combination of quantitative and qualitative analysis to inform its unit commitment decisions.

Each day it performs two separate economic analyses.

First, Ameren Missouri makes an assessment of "generation in the money", by unit, by hour, for each of the next 10 days, utilizing the PCI tool to perform a simulated unit dispatch of each unit based on its incremental production cost, unit characteristics and a forecast of LMPs. The model provides an indication of the level of generation that is "in the money" for a given hour (that is to say that the LMP is in excess of the incremental production cost). Hours for which the unit is not "in the money" do not have values in them.

Additionally, a projection of each unit's energy margin for the next 10 days is separately calculated. This is accomplished by first estimating that amount of energy which could be expected to clear in the MISO energy market, for each hour, based upon each units then current as offered production cost and a forecasted estimated of LMPs. The difference between these LMPs and as offered production costs are then applied to the projected level of unit output to provide an estimate of each unit's energy margin, by hour. This process is repeated by adjusting LMPs up and down by 5%.

For units for whom such indicated margins may be negative, consideration is given to the factors listed in part a above.

Analysis results that informed the commitment decision cannot be provided because the PCI tool overwrites data each day that it is utilized.

Ex. AA-S-1

Status of Residential Time-of-Use Rates in the U.S.

Progress Comes Slowly

BY RYAN HLEDIK, CODY WARNER AND AHMAD FARUQUI

Time-of-use rates, which charge customers a higher price during peak hours of the day and a lower price during off-peak hours, have been a useful addition to the toolkit of electric utility rate analysts for the past several decades.

The Public Utilities Regulatory Policy Act of 1978 launched a national movement toward TOU rates. Several pilots in the late 1970s and early 1980s showed that customers did indeed engage in demand response either by clipping their peak loads or shifting loads to off-peak hours.

Such price-based demand response would lower system peak demands and improve system load factors, thereby reducing average costs for all customers. With the broad deployment of smart metering across North America, TOU rates have increasingly been offered on a large scale to residential customers.

Most recently, TOU rates have been revisited as an option not only for reducing the system peak, but also for addressing operational challenges related to the integration of renewable generation.

In this article, we survey residential TOU rate offerings in the United States and discuss emerging trends in the design of those rates. While our focus is on the United States, it is worth noting that TOU rates were rolled out as the default tariff in Ontario, Canada about a decade ago to some four million customers.

We draw upon data from three sources: EIA-861 data that includes data on the number of utilities offering TOU rates and the number of participants; the OpenEI Utility Rates Database that includes information about the design of existing TOU rates; and Brattle's Arcturus database of more than sixty residential time-varying pricing pilots that has entries from over three hundred tests of various rate designs.

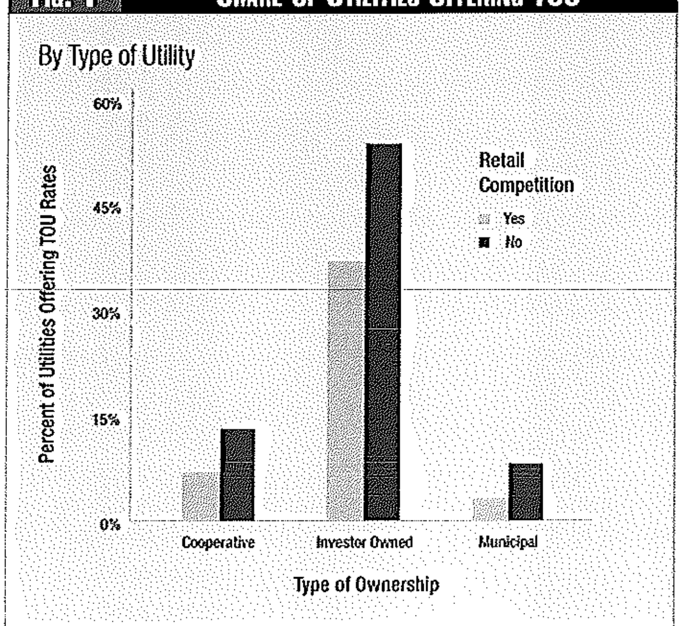
Popularity of TOU Rates

We find that fourteen percent of all U.S. utilities offer a residential TOU rate and that roughly half of all investor-owned utilities offer one. Six percent of all TOU rates include a demand charge in addition to the time-varying volumetric charge. Utilities in states with retail competition are less likely to offer TOU rates, though TOU rate offers are still to be found among those utilities.

See Figure One.

TOU rates have been revisited as an option for addressing operational challenges related to the integration of renewable generation.

FIG. 1 SHARE OF UTILITIES OFFERING TOU



Enrollment

There are 2.2 million residential customers enrolled in TOU rates in the United States. This amounts to 1.7 percent of all residential customers, and 3.4 percent of those customers for which a TOU rate is available.

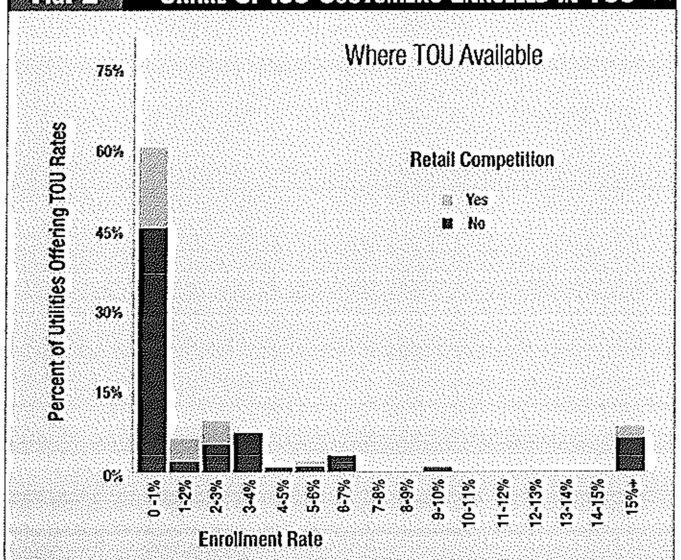
Among investor-owned utilities, sixty percent of the utilities offering TOU rates have enrollment rates of less than one percent. These low enrollment levels among rate offerings that have been in place for decades amount to nothing more than superficial rate offerings.

Ryan Hledik is a principal with The Brattle Group. His consulting practice is focused on regulatory matters related to emerging distributed energy technologies. He has worked with more than fifty clients across thirty states and eight countries.

Cody Warner is a graduate student with the Energy and Resources Group at the University of California – Berkeley. Prior to his graduate studies, Warner was a Senior Research Analyst at The Brattle Group where he modeled rate designs for distributed generation customers in states such as Arizona and Nevada.

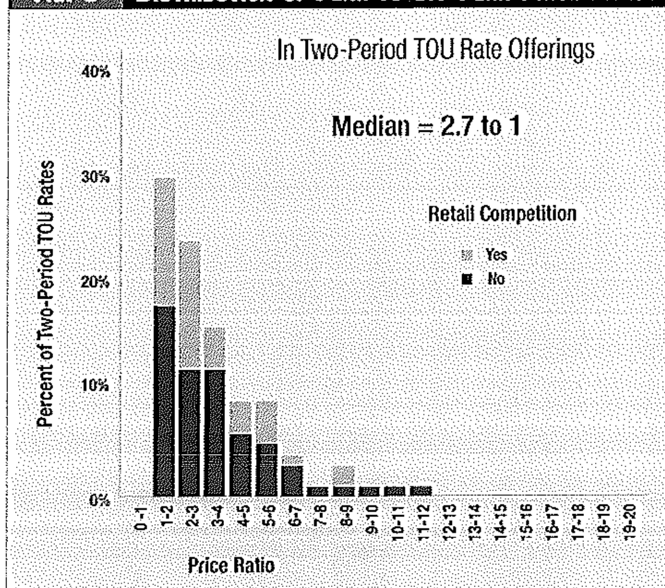
Ahmad Faruqui is a principal with The Brattle Group. He is an energy economist whose career has been devoted to pricing innovations. He has designed and evaluated a variety of pricing experiments in the U.S. and abroad and maintains a global database of more than three hundred tests of time-varying rates. Faruqui has testified on rate-related issues in several jurisdictions and presents frequently on tariff reforms.

FIG. 2 SHARE OF IOU CUSTOMERS ENROLLED IN TOU



Sources and notes: Brattle analysis of EIA-861 data. Data shown for IOUs only. The EIA data does not distinguish between enrollment in static TOU versus dynamic rates, so in some cases TOU participation may be slightly overstated. We have made adjustments for this where apparent, such as, high PTR enrollment for BGE and Pepco.

FIG. 3 DISTRIBUTION OF PEAK-TO-OFF-PEAK PRICE RATIOS



Sources and notes: Brattle analysis of OpenEI Utility Rates Database. Data shown for IOUs only.

However, while the average enrollment level is low, certain utilities have achieved higher enrollment rates. The highest enrollment rate is achieved by Arizona Public Service where nearly sixty percent of residential customers are on a TOU rate and twenty percent of these include a demand charge.

See Figure Two.

There are several reasons why enrollment rates are very low at most utilities. These include customer apprehension about inconvenience ("they will have to do their laundry at two a.m." is a common refrain, but one which is entirely unnecessary), inadequate marketing of the TOU rate, inconvenient rate design (a long peak period that is difficult to avoid through changes in usage patterns), and additional charges to cover the cost of the TOU meter where smart metering has not been deployed.

In cases where TOU deployments have had more success, such as in APS's case, the TOU rate has been designed with customer preferences in mind and the utility has dedicated significant resources to educating customers about their rate options.

Price Ratios and Number of Pricing Periods

Almost three-quarters of TOU rates have only two pricing periods. TOU rates designed recently, such as those developed for pricing pilots and full-scale deployments in the past decade, typically have a peak period duration of six hours or less.

Among older deployments of TOU rates, it is common to have a peak period of ten hours or more and a very modest differential between peak and off-peak rates. Not only does that make it difficult for customers to engage in demand response, it also makes demand response less likely.

TOU rates feature higher peak-to-off-peak price ratios and therefore have a higher potential for customer savings. Seven-tenths of all TOU offerings have a price ratio between peak and off-peak periods of at least two to one, and half have a price differential of at least ten cents per kilowatt-hour between the two periods.

See Figure Three.

Recovery of Utility Costs

TOU rates are designed to capture the time variation in utility costs. Our in-depth survey of a dozen utility TOU rate offerings indicates that generation costs are almost always recovered on a time-differentiated basis, distribution costs are recovered through a time-varying charge in roughly half of the cases, and transmission costs are recovered through a time-varying charge in only one of the twelve cases.

Deployment Scenarios

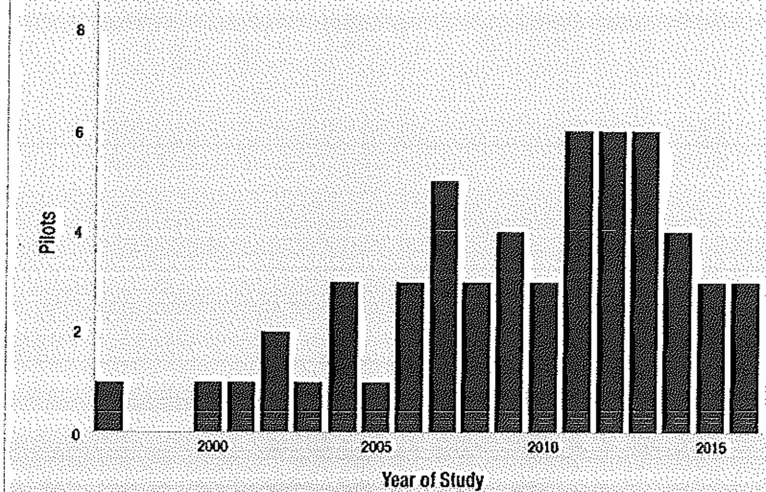
Historically, TOU rates have been offered to residential customers on an opt-in basis. However, with the deployment of smart metering, there has been a gradual shift toward default or mandatory TOU offerings.

Sacramento Municipal Utility District's transition to default TOU rates will be completed by end of 2019. The investor-owned utilities in California will begin transitioning to default TOU rates in 2019. Southern California Edison has proposed an expedited rollout.

The City of Fort Collins, a public utility, introduced mandatory residential TOU rates in October 2018. In Ontario, Canada, province-wide rollout of default TOU was initiated for all utilities in 2012.

In Ireland, TOU variable charges will be a required feature of competitive retail suppliers following the deployment of smart metering by 2020. In Italy, default TOU with a modest price differential has been in place for many years. Spain and the U.S. state of Maryland offer default time-varying rate structures with dynamic price signals.

FIG. 4 NUMBER OF RESIDENTIAL TOU PILOTS INITIATED, BY YEAR



Sources and notes: Chart based on Brattle database of TOU rates tested in recent pricing pilots. Includes international TOU pilots (15 of 38 TOU pilots in the database).

A Glance at The Future

Future TOU-rate offerings are likely to be different from the recent past, and certainly very different from the last five decades. The following trends are already evident and are likely to shape the future.

Historically, the primary motivation for offering TOU rates has been to introduce a more cost-reflective rate that provides customers with an incentive to reduce consumption during higher-cost times of day.

Recently, intervenors in net energy metering rate proceedings have proposed TOU rates as a solution to the challenge of recovering grid costs from customers with rooftop solar. Volumetric TOU rates are commonly proposed by solar industry representatives as an alternative to higher fixed charges or the introduction of a demand charge.

Sometimes the NEM rate proposals include a dynamic price signal combined with the static TOU price signal, such as CPP/TOU combination. Arizona, Nevada, Kansas, and Colorado are a few examples of states where TOU rates have been proposed by intervenors for this reason.

Some future TOU rates designs may feature a low price in the midday hours and a high price in the late afternoon and evening hours.

This brings rate design into harmony with the duck curve phenomenon, which arises from the growing market penetration of solar generation facilities, regardless of whether they are sited on customer facilities, community facilities, or utility facilities. Specifically, this new TOU design will address operational challenges associated with low or negative net load during daytime hours, followed by a rapid increase in net load during late evening hours, when PV output drops and generation must ramp up quickly to balance the system.

In Arizona, APS recently revised its TOU design to include a super-off-peak winter price between ten a.m. and three p.m. and shifted the peak period from noon to seven p.m. to three to eight p.m. In Hawaii, HECO piloted a TOU rate with a discounted midday price – nine a.m. to five p.m. – and delayed peak period – five p.m. to ten p.m.

In California, the peak period will now occur between four to nine p.m. in San Diego, unlike the previous rate in which the peak period began at eleven a.m. As an international point of reference, in Southwest England, a distribution utility has piloted TOU rates with a low midday price to relieve distribution system constraints caused by high PV output.

TOU rates are also receiving support from environmental groups. These groups often present the view that energy-only TOU rates – such as volumetric – will address grid cost recovery issues associated with rooftop PV adoption better than the other solutions that have been proposed by utilities, such as higher fixed charges or demand charges.

TOU rates are experiencing a revival. They are quite different from traditional TOU rates in many respects.

The trend toward deploying TOU rates on a default basis – such as opt-out – for all residential customers appears likely to continue in the future. As discussed above, several states, led by California and Colorado, are considering or are in the process of transitioning toward default TOU offerings.

TOU rates continue to be piloted in North America and internationally. Over the past two decades, thirty-eight TOU pilots have been conducted with a hundred and fifty-three different TOU rates.

There was a surge in pilot studies between 2011 and 2013, driven by U.S. DOE stimulus funding, but TOU rates have continued to be piloted since then. The newest pilots are going to be conducted during the next two years in Maryland and will involve customers of BGE, Pepco, and Delmarva.

See Figure Four.

Early results from this new generation of TOU pilots are

(Cont. on page 70)

an organic part of the market reflecting legitimate customer preferences.

Rather, those efforts are treated as an outside force undermining the ability of markets to promote trade in undifferentiable kilowatt-hours and kilowatts at an efficient price.

The eastern RTOs do not want wholesale providers to compete in both centralized and bilateral markets to provide wholesale customers the products they're looking to buy, subject to the expectations of their retail customers and state regulators. Rather, they're trying to create a single centralized market based solely on marginal cost of energy and capacity. At best, they're trying to accommodate both models to some limited degree by running dual auctions. That's why we're mired in the ongoing debates over minimum-offer price rules, the capacity auction with sponsored policy resources, resilience, and the legality of zero-emission credits.

This is proving to be a futile effort because few others believe there to be a single fungible product. The eastern RTOs are trying to plan their markets around an inaccurate simplifying assumption.

Neither FERC nor the eastern RTOs can stop the federal government from providing support to certain resources based on their individual characteristics or the political effectiveness of their proponents. Recently, the courts have approved state subsidies for nuclear generation. And, even as FERC has argued that some state policies that support specific resources are preempted by the Federal Power Act, it has conceded that others are legally acceptable.

Moreover, the RTOs are increasingly recognizing their evolving operational needs, looking at new ancillary services and new products to help maintain reliability and resilience as the generation fleet transitions. The operators are recognizing the need to perform the very planning functions that some have suggested should be left to the functioning of the invisible hand.

It's time for FERC to finally accept the political, economic, and operational reality that wholesale power is not a fungible commodity. Wholesale-power resources offer a bundle of evolving characteristics and services valued differently by different market participants depending on their operational needs, their evaluation of risk and risk tolerances, the purchasing preferences of local consumers, and the political expectations of local communities.

RTO markets need to respect and reflect that diversity and enable market participants to acquire the collection of attributes that they want and need as efficiently as possible. They should support and facilitate the efficient and non-discriminatory delivery of resources wholesale customers want, whether they were purchased in the centralized or the bilateral markets. They should facilitate both planning and a diversity of choices, not supplant them.

This screed reflects the views solely of its author and does not necessarily reflect the views of NRECA or any of its members.

Residential Time-of-Use Rates

(Cont. from p. 67)

consistent with those found in earlier pilots. As has commonly been observed across these studies, as the peak to off-peak price ratio rises, customer peak demand falls, but at a decreasing rate. The presence of enabling technologies enhances the effectiveness of TOU rates, leading to greater reductions in peak demand and greater bill savings for customers.

To facilitate a greater degree of price responsiveness in the future, in some cases utilities are offering rebates to customers who buy smart digital Wi-Fi-enabled thermostats. In a few cases, utilities are installing the smart thermostats free of charge.

In closing, we note that TOU rates are experiencing a revival. They are quite different from traditional TOU rates in many respects. The number of pricing periods is fewer, the peak period is shorter, and the peak period often occurs in the late afternoon or early evening hours.

In some cases, TOU rates also include a demand charge. In a few cases, they are supplemented with enabling technologies such as smart thermostats to magnify demand response. And more often we see TOU offerings progressing from opt-in deployments to default deployments.

Ameren Missouri's
Response to Sierra Club Data Request
ER-2019-0335
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.

Data Request No.: SC 0002.20

2.20 Refer to Direct Testimony of Steven Wills, page 41, lines 17-18.

a. Please produce any reports or analyses in the Company's possession regarding the response of residential customers' consumption to changes in energy rates resulting from changes in customer charges.

b. Has the Company analyzed the impact of increasing the residential customer charge on customers' payback periods for installing energy efficiency measures? If so, provide all such analyses.

c. Has the Company analyzed the impact of increasing the residential customer charge on its ability to incentivize participation in its energy efficiency programs? If so, provide all such analyses.

d. Has the Company analyzed the impact of increasing the residential customer charge on the cost of its energy efficiency programs? If so, provide all such analyses.

e. Has the Company conducted any analyses of the relative bill impacts of the change in the proposed default residential rate design by income level (e.g. bill impacts for low-income customers relative to other customers)? If so, provide all such analyses.

f. What would the volumetric per-kWh charge be for residential customers if the

Company were to maintain the current customer charge but make no other changes to its proposal in this rate case?

g. Describe the process by which the Company settled on the new proposed residential customer charge of $11.

9

h. Identify which Ameren employee(s) or consultant is responsible for the decision regarding the new proposed customer charge level.

i. Is it the Company's intention to continue to increase the residential customer charge until it reaches its CCOSS-determined value, currently calculated at $24.85? If not, explain the Company's long-term approach to setting the residential customer charge.

RESPONSE

Prepared By: Steven M. Wills
Title: Director, Rates & Analysis
Date: November 12, 2019

CONFIDENTIAL
20 CSR 4240-2.135(2)(A)2

1. See the attached report "Revenue regulation and Decoupling: A Guide to Theory and Application" by the Regulatory Assistance Project from June 2011.
2. The Company has not performed such an analysis for this case. The Company did perform this analysis associated with its proposed rate design in File No. ER-2016-0179, which included a proposed $4.89 monthly Energy Grid Access Charge. That analysis is attached, in a file called "FirstYrSavingsUpdates_2016-06-15.xlsx."
3. Other than the analysis discussed in part B above, no such analysis has been performed.
4. Other than the analysis discussed in part B above, no such analysis has been performed.
5. No such analysis has been performed.

6. Please see the workpaper provided with the direct testimony of Michael Harding called "Jan 2018 to Dec 2018 warehouse bill units Dec 2019 growth delete premeeia formulas jul1.xlsx." See the tab called "Res Rates 9 CC."
7. The Company reviewed the customer-related costs resulting from of the class cost of service analysis prepared for the case, and subjectively weighed other rate design considerations including the principle of gradualism and the objective of bill stability in arriving at a proposed $2 increase in the monthly customer charge.
8. The customer charge proposal was recommended by me and approved by Ameren Missouri's rate case lead team including Tom Byrne, Laura Moore, Mitch Lansford, and myself, with advice from counsel.
9. The Company has described its long term approach to setting rates as a journey, and has not definitively determined the end point of that journey. In my testimony I suggest that the Company may ultimately have a suite of rate offerings, one of which looks like what I have described as the "Cost Based Two Part Rate," with a customer charge at or around the level identified in our class cost of service study, but with other offerings, such as one that includes a demand charge - subject to the results of the pilot study of residential demand rates proposed in this case - with a lower customer charge.

Ameren Missouri's
Response to Sierra Club Data Request
ER-2019-0335
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.

Data Request No.: SC 0002.29

2.29 Refer to Direct Testimony of Steven Wills, page 61, Table 11.

a. Did Ameren consider including a class coincident peak demand charge rather than a non-coincident peak demand charge in its proposed three-part rate pilot? If so, why did Ameren select the non-coincident peak demand charge? If not, explain why not.

b. Did Ameren consider including a system coincident peak demand charge rather than a non-coincident peak demand charge in its proposed three-part rate pilot? If so, why did Ameren select the non-coincident peak demand charge? If not, explain why not.

c. Identify each cost category that Ameren believes is driven by a residential customer's individual non-coincident peak demand as opposed to system-level, class-level, or circuit-level peak demand.

d. How did Ameren decide to apply the proposed demand charge to the hours from 6 a.m. to 10 p.m.? Provide all workpapers used to support this decision, in native format with all formulae intact.

e. Confirm that under Ameren's proposed three-part pilot rate, a customer's monthly demand charge would be based on its non-coincident peak demand level for that month. If not confirmed, explain how any ratchet would be used to determine each customer's demand charge in each month.

f. Identify each type of data Ameren is planning to collect and evaluate as part of its proposed residential three-part rate pilot.

RESPONSE

Prepared By: Steven M. Wills
Title: Director, Rates & Analysis
Date: November 19, 2019

1. Ameren Missouri did not give significant consideration to a class coincident peak demand charge. Class coincident peak times are not known until load research processes are complete months after an operating month, making such a rate not feasible to bill.

2. Ameren Missouri did not give significant consideration to a system coincident peak demand charge. System coincident peaks for a month are only known after the conclusion of the month, meaning it would be impossible for customers to know that their usage at any given time may or may not be used to generate their bill. While it is possible to structure a rate this way, and there are examples that I am aware of where utilities bill larger commercial and industrial customers this way, I believe that it would introduce substantial billing complexity and customer understandability issues in a residential setting. I am not familiar with any examples of a utility billing residential customers with a system coincident peak demand charge. Further, the function of the demand charge is to reflect the costs of the distribution system, many of which are not driven by the system coincident peak load.

3. Specific costs that may be driven entirely or primarily by the individual non-coincident peak demand include the line transformer and service lines. Other distribution costs may be influenced, albeit to some lesser degree, by the individual non-coincident peak demand.

4. See the file attached to DR Sierra Club 2.27 titled "Load Analysis for TOU.xlsx".

5. Confirmed

6. Ameren Missouri will collect hourly customer usage data for participants, as well as for a potential control group that will be used to create a matched control group. Ameren Missouri will also conduct surveys to collect information on customer demographics, appliance ownership, understanding of the rate, and specific actions taken to manage bills while subject to the pilot rate.

Ex. AA-S-1

Ameren Missouri's
Response to Sierra Club Data Request
ER-2019-0335
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.

Data Request No.: SC 0007.4

Refer to the rebuttal testimony of Ahmad Faruqui, page 6, lines 1-7:

a. Is Dr. Faruqui aware of any residential TOU rates in the United States currently in use that have on-peak to off-peak price ratios greater than 4:1? If yes, please list the utilities that currently use such rates.

b. Is Dr. Faruqui aware of any reports, data, or analysis regarding the impact of price ratios on customer willingness to enroll in an opt-in TOU rate? If yes, please provide all such reports, data, or analysis.

RESPONSE

Prepared By: Ahmad Faruqui, Ph.D.
Title: Principal with the Brattle Group
Date: January 31, 2020

a. The three TOU pilots currently running in Maryland all have TOU ratios in excess of 4:1. The ratios for BGE, Delmarva and Pepco are respectively 5.5, 6.2, and 5.0. Additionally, there are at least 47 utilities whose peak to off-peak ratio (excluding the fixed charge) exceeds 4:1:

1. A & N Electric Coop (Virginia)
2. Adams Electric Coop
3. Albemarle Electric Member Corp
4. Appalachian Power Co (Virginia)
5. Baltimore Gas & Electric Co
6. Bedford Rural Elec Coop, Inc
7. Berkeley Electric Coop Inc
8. Central Electric Membership Corporation
9. Central Maine Power Co

10. City of Lakeland, Florida (Utility Company)
11. City of Medford, Wisconsin (Utility Company)
12. City of Princeton, Wisconsin (Utility Company)
13. City of Vernon, California (Utility Company)
14. Consolidated Edison Co-NY Inc
15. Coweta-Fayette El Member Corp
16. Delaware Electric Cooperative
17. Delmarva Power
18. Eau Claire Electric Coop
19. Entergy Arkansas Inc (Arkansas)
20. Entergy Texas Inc.
21. Georgia Power Co
22. Hendricks County Rural E M C
23. Jackson County Rural E M C
24. Kankakee Valley Rural E M C
25. Kentucky Utilities Co
26. Long Island Power Authority
27. Morgan County Rural Elec Assn
28. Mountain View Elec Assn, Inc
29. Nevada Power Co
30. Northern States Power Co - Minnesota
31. Oklahoma Gas & Electric Co
32. Orange & Rockland Utils Inc
33. Piedmont Electric Member Corp
34. Potomac Electric Power Co (Maryland)
35. Prince George Electric Coop
36. Public Service Co of NH
37. Public Service Co of Oklahoma
38. Randolph Electric Member Corp
39. Sawnee Electric Membership Corporation
40. Sierra Pacific Power Co (Nevada)
41. Santee Cooper
42. Surry-Yadkin Elec Member Corp
43. Town of Apex, North Carolina (Utility Company)
44. Town of Sterling, Massachusetts (Utility Company)
45. United Electric Coop Service Inc
46. Virginia Electric & Power Co
47. Wisconsin Electric Power Co (Michigan)

Finally, I refer to Brattle's Arcturus database, which includes a total of 362 treatments, most of which are experimental. The peak to off-peak pricing ratio exceeds 4:1 in 29 cases that involve simple TOU rates. If we expand the sample to include all types of time-varying rates, including peak-time rebates, critical peak pricing rates and variable peak pricing rates, there are a total of 203 rates with a ratio greater than 4:1.

b. I am not aware of any such reports.

Ameren Missouri's
Response to Sierra Club Data Request
ER-2019-0335
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.

Data Request No.: SC 0007.7

Refer to the rebuttal testimony of Ahmad Faruqui, page 6, lines 24-26.

a. Please explain how the Company incorporated hourly variances in the cost of energy and the cost of capacity in its design of TOU rates.

b. Please provide the underlying time-varying cost of energy data the Company relied upon to design its TOU rates in machine readable format.

c. Please provide the underlying time-varying cost of capacity data the Company relied upon to design its TOU rates in machine readable format.

d. Please provide any other time-varying cost data the Company relied upon to design its TOU rates in machine readable format.

RESPONSE

Prepared By: Steven M. Wills
Title: Director, Rates & Analysis
Date: January 27, 2020

1. The Company's analysis relied on traditional embedded cost of service principles, which did not explicitly account for hourly variances in the cost of energy or capacity. Production, transmission, and distribution capacity costs from the embedded cost study were allocated to TOU periods based on hours where incremental usage can drive the incurrence of those costs.
2. No such data is available
3. No such data is available
4. No such data is available

RLW ANALYTICS

Ameren

AmerenUE
Residential TOU Pilot Study
Load Research Analysis – 2005 Program Results

June 2006

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AmerenUE
Residential TOU Pilot Study
Load Research Analysis – 2005 Program Results

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AmerenUE

Residential Time-Of-Use (RTOU) Pilot Study
Load Research Analysis – 2005 Program Results

1 Executive Summary

AmerenUE in conjunction with the Missouri Collaborative launched a Residential Time-Of-Use (RTOU) Pilot study in the Spring of 2004. This report documents the results for the second summer, i.e., June through August 2005, of the Pilot study.

1.1 Overview

The RTOU Pilot study encompassed two innovative rate offerings that provide financial incentives for customers to modify their consumption patterns during higher priced "critical peak periods" (i.e., CPP). Originally, the rate offerings were organized into three treatment groups for the Pilot study and included:

Treatment Group #1 - These customers received a three-tier time-of-use rate[1] with high differentials;

Treatment Group #2 - These customers received the same time-of-use rate as the first treatment group but were also subject to a critical peak pricing (CPP) element; and

Treatment Group #3 - These customers received the same treatment, i.e., TOU rate and CPP, as treatment group number two but had enabling technology, i.e., a "smart" thermostat, installed by AmerenUE. The enabling technology automatically increased the customer's thermostat setting during critical peak pricing events.

For 2005, the first treatment group, i.e., the time-of-use rate only, was dropped from the Pilot Study. The principal reason for dropping the time-of-use only group was that this group failed to display a significant shift in load from the on-peak to the mid-peak or off-peak periods. Therefore, the second year pilot focused on the critical peak pricing element and those customers with "smart" thermostats. Fifteen-minute interval load monitoring equipment was available on the total premise load for a statistically representative sample of customers in each treatment group. In addition to the treatment groups, the Company constructed control groups for use in the analysis. Once again, fifteen-minute interval load monitoring equipment was available on a statistically representative sample of control group customers. Data collection began in the late Spring and continued until mid September.

1.2 Analysis Summary

Table Ex 1 presents a listing of several of the key analysis variables included in the study. These include the average CPP demand, the July 21st demand, the on-peak, mid-peak, off-peak and CPP use during the defined time of use periods and the average summer[2] use. The table presents the information for each treatment group (i.e., rate options) for customers in the control group and the

[1] The TOU rates differ by season (i.e., summer versus winter).
[2] Due to bill cycle issues, the summer 2005 season was defined as June 28, 2005 through August 31, 2005.

voluntary study group (i.e., test group). The table includes the average as well as the achieved relative precision estimated for the sample.

Study Group	Rate Options	Maximum Sample Size	Estimated Average (kW or kWh) and Estimated Relative Precision (%)						
			Average CPP Demand (kW)	July 21st Demand (kW)	Time-Of-Use On-Peak Period #1 (kWh)	Time-Of-Use Mid-Peak Period #2 (kWh)	Time-Of-Use Off-Peak Period #3 (kWh)	CPP Event Use Period #4 (kWh)	Average Summer Use (kWh)
Control Group	Standard Residential Rate	277	5.56	5.71	927	2,054	4,495	252	7,729
			±3.0%	±3.4%	±2.9%	±2.9%	±3.2%	±3.0%	±3.0%
	Standard Residential Rate	211	5.34	5.45	884	1,934	4,147	240	7,205
			±3.6%	±3.9%	±3.6%	±3.6%	±3.4%	±3.6%	±3.3%
Voluntary Study Groups	3-Tier TOU w/ CPP	141	4.84	4.89	896	2,019	4,450	219	7,584
			±6.8%	±5.6%	±5.0%	±4.5%	±5.0%	±5.5%	±4.7%
	3-Tier TOU w/ CPP and Smart Thermostat	104	4.04	4.09	863	1,901	4,017	182	6,963
			±8.6%	±9.6%	±6.3%	±6.1%	±5.4%	±8.7%	±5.5%

Table Ex 1 – Key Summary Statistics

Table Ex 2 presents the T-Test comparisons for the control and voluntary study group (i.e., RTOU Group). The table presents the seasonal average use by time of use period, the absolute difference, the T-value[3] or test result, the probability of getting a higher T-value, and the result of the test. The null hypothesis is that the two test statistics are equal. For both study groups, only the energy consumed during the critical peak pricing event displayed a statistical difference.

Three Tier TOU with CPP (CPP)						
Jun 1 - Aug 31 TOU Period	Control Group (kWh)	RTOU Group (kWh)	Difference Control-RTOU (kWh)	T-Test	Pr>|t|	Ho: Control=RTOU
Seasonal Use	7,729	7,584	145.00	0.58	0.56	Cannot Reject
Off-Peak Use	4,495	4,450	45.00	0.28	0.78	Cannot Reject
Mid-Peak Use	2,054	2,019	35.00	0.54	0.59	Cannot Reject
On-Peak Use	927	896	31.00	0.96	0.34	Cannot Reject
CPP Use	252	219	33.10	3.92	0.00	Reject
Percent Off-Peak	58.2%	58.7%	-0.5%	1.02	0.31	Cannot Reject
Percent Mid-Peak	26.6%	26.6%	0.0%	0.15	0.88	Cannot Reject
Percent On-Peak	12.0%	11.8%	0.2%	(0.72)	0.47	Cannot Reject
Per CPP	3.3%	2.9%	0.4%	4.08	0.00	Reject
Three Tier TOU with CPP and Thermostat (CPP-THERM)						
Jun 1 - Aug 31 TOU Period	Control Group (kWh)	RTOU Group (kWh)	Difference Control-RTOU (kWh)	T-Test	Pr>|t|	Ho: Control=RTOU
Seasonal Use	7,205	6,963	242	0.98	0.33	Cannot Reject
Off-Peak Use	4,147	4,017	130	0.91	0.37	Cannot Reject
Mid-Peak Use	1,934	1,901	33	0.46	0.65	Cannot Reject
On-Peak Use	884	863	21	0.64	0.52	Cannot Reject
CPP Use	240	182	58	5.99	0.00	Reject
Percent Off-Peak	57.6%	57.7%	-0.1%	0.26	0.79	Cannot Reject
Percent Mid-Peak	26.8%	27.3%	-0.5%	1.36	0.18	Cannot Reject
Percent On-Peak	12.3%	12.4%	-0.1%	0.49	0.63	Cannot Reject
Per CPP	3.3%	2.6%	0.7%	(8.18)	0.00	Reject

Table Ex 2 – Seasonal Time-Of-Use Usage Comparisons

Table Ex 3 presents similar findings for the eight critical peak pricing periods. The table presents the average demand for the control and RTOU treatment groups, the absolute difference, the T-value or test statistic, the p-value (i.e., the probability of getting a larger T-value) and whether or not we can reject the null hypothesis that the corresponding demands were equal. In all instances we can conclude that the demands of the RTOU treatment group were statistically lower than

[3] High T-values lead us to reject the null hypothesis that the two statistics are equal.

those of the control group. An additional 0.52 kW on average was achieved by the group with the enabling technology.

Three Tier TOU with CPP (CPP)									
CPP Event			Control Group (kW)	RTOU Pilot Group (kW)	Difference Control-RTOU (kW)	Percent Difference (%)			
Date	Hour Ending Start	Hour Ending End					T-Test	Pr>|t|	Ho: Control=RTOU
30-Jun-05	3:00 PM	6:59 PM	5.35	4.85	0.50	9.3%	2.63	0.0088	Reject
21-Jul-05	3:00 PM	6:59 PM	5.71	4.91	0.80	14.1%	3.75	0.0002	Reject
22-Jul-05	3:00 PM	6:59 PM	5.84	5.05	0.79	13.5%	3.54	0.0005	Reject
26-Jul-05	3:00 PM	6:59 PM	5.98	4.91	1.06	17.8%	5.28	0.0000	Reject
2-Aug-05	3:00 PM	6:59 PM	5.38	4.73	0.65	12.1%	3.24	0.0013	Reject
9-Aug-05	3:00 PM	6:59 PM	5.64	4.74	0.90	16.0%	4.33	0.0000	Reject
10-Aug-05	3:00 PM	6:59 PM	5.01	4.24	0.76	15.2%	4.00	0.0000	Reject
19-Aug-05	3:00 PM	6:59 PM	5.61	4.88	0.74	13.1%	3.54	0.0004	Reject
Average			5.56	4.84	0.72	13.0%	3.90	0.0001	Reject
Three Tier TOU with CPP and Thermostat (CPP-THERM)									
CPP Event			Control Group (kW)	RTOU Group (kW)	Difference Control-RTOU (kW)	Percent Difference (%)			
Date	Hour Ending Start	Hour Ending End					T-Test	Pr>|t|	Ho: Control=RTOU
30-Jun-05	3:00 PM	6:59 PM	5.02	4.30	0.72	14.4%	2.93	0.0036	Reject
21-Jul-05	3:00 PM	6:59 PM	5.37	4.09	1.27	23.7%	5.22	0.0001	Reject
22-Jul-05	3:00 PM	6:59 PM	5.38	4.18	1.20	22.4%	5.39	0.0001	Reject
26-Jul-05	3:00 PM	6:59 PM	5.56	4.38	1.18	21.2%	4.93	0.0001	Reject
2-Aug-05	3:00 PM	6:59 PM	5.23	3.66	1.57	30.0%	6.30	0.0001	Reject
9-Aug-05	3:00 PM	6:59 PM	5.47	4.01	1.46	26.7%	5.76	0.0001	Reject
10-Aug-05	3:00 PM	6:59 PM	4.95	3.82	1.13	22.8%	4.95	0.0001	Reject
19-Aug-05	3:00 PM	6:59 PM	5.38	3.97	1.41	26.1%	5.49	0.0001	Reject
Average			5.29	4.05	1.24	23.5%	6.05	0.0001	Reject

Table Ex 3 – CPP Event Day Comparisons

Table Ex 4 presents the T-test comparisons for the system peak hours in June, July and August. There were no critical peak pricing events called on these days. Interestingly, the demand on Monday, July 25 was lower for the RTOU CPP group when compared to the control group. For all other system peak events, the average hourly demand at the time of the system peak were not statistically different.

Three Tier TOU with CPP (CPP)								
System Peak		Control Group (kW)	RTOU Pilot Group (kW)	Difference Control-RTOU (kW)	Percent Difference (%)			
Date	Time					T-Test	Pr>|t|	Ho: Control=RTOU
29-Jun-2005	5pm	5.60	5.39	0.21	3.8%	1.13	0.258	Cannot Reject
25-Jul-2005	4pm	6.06	5.23	0.83	13.7%	3.60	0.000	Reject
3-Aug-2005	5pm	5.57	5.29	0.28	5.0%	1.33	0.183	Cannot Reject
Three Tier TOU with CPP and Thermostat (CPP-THERM)								
System Peak		Control Group (kW)	RTOU Pilot Group (kW)	Difference Control-RTOU (kW)	Percent Difference (%)			
Date	Time					T-Test	Pr>|t|	Ho: Control=RTOU
29-Jun-2005	5pm	5.32	5.27	0.05	0.9%	0.19	0.848	Cannot Reject
25-Jul-2005	4pm	5.52	5.26	0.26	4.7%	1.01	0.314	Cannot Reject
3-Aug-2005	5pm	5.32	5.04	0.28	5.3%	1.21	0.226	Cannot Reject

Table Ex 4 – System Peak Comparisons

Payback was defined as the three-hour period immediately following the CPP event. Table Ex 5 presents a summary of the payback periods immediately following each of the eight CPP events. In all cases the payback load associated with the RTOU CPP treatment group was not statistically different from their control group counterpart. In contrast, for the RTOU CPP-Therm treatment group all but two paybacks were found to be statistically significant.

Three-Tier TOU Rate with CPP (CPP)									
CPP Event			Control Group (kW)	RTOU Group (kW)	Difference RTOU-Control (kW)	Percent Difference (%)	T-Test	Pr>|t|	Ho: Control=RTOU
Date	Payback Period Start	Payback Period End							
30-Jun-05	7pm	10pm	4.77	4.74	(0.02)	-0.5%	0.12	0.902	Cannot Reject
21-Jul-05	7pm	10pm	5.56	5.39	(0.18)	-3.2%	0.83	0.408	Cannot Reject
22-Jul-05	7pm	10pm	5.42	5.24	(0.18)	-3.3%	0.85	0.395	Cannot Reject
26-Jul-05	7pm	10pm	5.03	5.01	(0.02)	-0.4%	0.09	0.928	Cannot Reject
2-Aug-05	7pm	10pm	5.02	5.09	0.07	1.3%	(0.35)	0.723	Cannot Reject
9-Aug-05	7pm	10pm	5.14	5.27	0.13	2.5%	(0.65)	0.513	Cannot Reject
10-Aug-05	7pm	10pm	4.63	4.56	(0.07)	-1.6%	0.34	0.735	Cannot Reject
19-Aug-05	7pm	10pm	5.35	5.11	(0.24)	-4.5%	1.08	0.279	Cannot Reject
Average			5.12	5.05	(0.06)	-1.3%	0.34	0.731	Cannot Reject
Three-Tier TOU Rate with CPP and Thermostat (CPP-THERM)									
CPP Event			Control Group (kW)	RTOU Group (kW)	Difference RTOU-Control (kW)	Percent Difference (%)	T-Test	Pr>|t|	Ho: Control=RTOU
Date	Payback Period Start	Payback Period End							
30-Jun-05	7pm	10pm	4.28	5.13	0.85	19.9%	(4.21)	0.000	Reject
21-Jul-05	7pm	10pm	5.21	5.75	0.54	10.4%	(2.55)	0.011	Reject
22-Jul-05	7pm	10pm	5.07	5.73	0.66	13.1%	(2.74)	0.007	Reject
26-Jul-05	7pm	10pm	4.71	5.59	0.88	18.6%	(4.56)	0.000	Reject
2-Aug-05	7pm	10pm	4.89	5.48	0.59	12.1%	(2.79)	0.006	Reject
9-Aug-05	7pm	10pm	5.35	5.39	0.04	0.8%	(0.19)	0.847	Cannot Reject
10-Aug-05	7pm	10pm	4.77	4.89	0.12	2.6%	(0.59)	0.556	Cannot Reject
19-Aug-05	7pm	10pm	4.79	5.63	0.84	17.6%	(3.65)	0.000	Reject
Average			4.88	5.45	0.57	11.6%	(3.05)	0.003	Reject

Table Ex 5 – Payback Comparisons

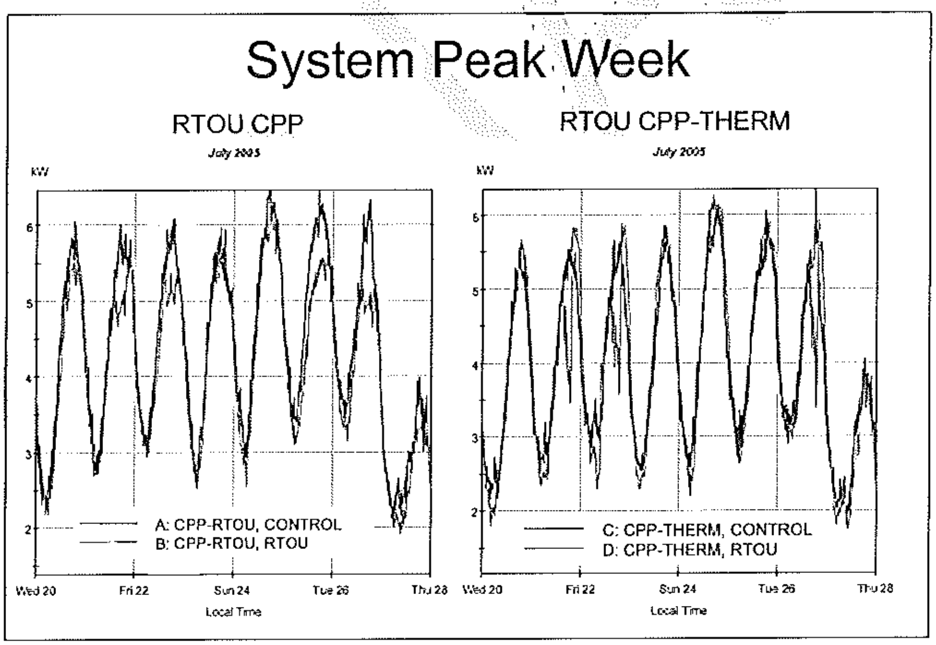


Figure Ex 1 – Summer Peak Week

Figure Ex 1 presents the average 15-minute load shape for each of the treatment groups compared to the single composite control group[4] for the week encompassing the system peak day, i.e., Monday, July 25, 2005. This highlights one of the challenges associated with trying to capture the load reduction on the system peak day. The program had called two events the week leading up to the peak and an event on the Tuesday immediately following the event but missed the system peak. The load associated with each of the treatment groups shows significant load

[4] The composite control group is used for demonstration purposes. In the actual analysis the control group constructed for each treatment group was used in the analysis.

reductions during the event calls. The treatment group receiving the enabling technology displays a substantially different load shape when compared to the CPP only group. The treatment group shows a sharp decrease in load during the event. Interestingly, the RTOU CPP only group shows lower load on the system peak day of Monday, July 25, 2005. Load profiles for all CPP event days that compare the RTOU treatment group load with the individual control group load are included in Appendix A.

To further explore the effects of the time-of-use rate, we examined the average demand during days when the temperature on at least three of the on-peak hours exceeded 90°F. A total of nine days met this criterion. For both groups we could not reject the hypothesis that the two average demands calculated across the on-peak hours were equal.

Three Tier TOU with CPP (CPP)						
Control Group (kW)	RTOU Pilot Group (kW)	Difference Control-RTOU (kW)	Percent Difference (%)	T-Test	Pr>|t|	Ho: Control=RTOU
5.37	5.09	0.28	5.2%	1.61	0.107	Cannot Reject
Three Tier TOU with CPP and Thermostat (CPP-THERM)						
Control Group (kW)	RTOU Pilot Group (kW)	Difference Control-RTOU (kW)	Percent Difference (%)	T-Test	Pr>|t|	Ho: Control=RTOU
5.07	4.99	0.08	1.6%	0.42	0.680	Cannot Reject

Table Ex 6 – Average Demand on Non Event Days over 90°F

1.3 General Conclusions

The study results indicate the following:

- The critical peak pricing component of the time-of-use rate does motivate customers to reduce demand during the CPP event periods.
- The enabling technology was a key component of the offering with the groups receiving the "smart" thermostat displaying much stronger load response (more than double) during CPP events when compared to the CPP only group.
- The RTOU: CPP and the RTOU: CPP-Therm groups did not display a significant shift in load during the on-peak or mid-peak periods to the off-peak.
- The researchers believe that there was insufficient evidence to conclude that the second year CPP: TOU participants substantially improved their load reductions in the second year when compared to their first year of participation. However, the percentage of total use during the CPP period was statistically lower in 2005 when compared to 2004.
- The CPP: TOU-Therm participants displayed an average demand reduction during CPP events that was 0.53 kW greater in 2005 when compared to 2004 on a weather adjusted basis. There was a slight reduction in the percentage of on-peak use in 2005 when compared to 2004 but this difference was not statistically significant.
- Second year control group participants that were moved to the test groups in 2005 confirmed that CPP rate is effective in reducing demand. Both the new CPP: TOU and the CPP:TOU-Therm customers reduced a statistically significant amount of load during the CPP periods when they received the CPP rates. Both groups also had lower CPP period usage after receiving the CPP rates.

AmerenUE

Residential Time-Of-Use (RTOU) Pilot Study

Management Report

2 INTRODUCTION

This document provides a comprehensive review and analysis of the Residential Time-Of-Use (RTOU) Pilot Project conducted by AmerenUE in collaboration with the Missouri Collaborative. The Missouri Collaborative consists of the Office of Public Counsel (OPC), the Missouri Public Service Commission (MPSC), the Department of Natural Resources (DNR) and two industrial intervener groups. AMEREN, the OPC and the MPSC have been the most active parties with regard to the TOU Pilot Study. The data collection period covered in this report is for the 2005 Summer defined as June 28, 2005 through August 31, 2005[5].

2.1 Background

AMEREN is an energy services company providing electricity to 2.3 million customers and natural gas to 900,000 customers in Illinois and Missouri. A map of the AMEREN service territory is presented in Figure 1. The current project is applicable to the AmerenUE's Missouri retail electric service territory.

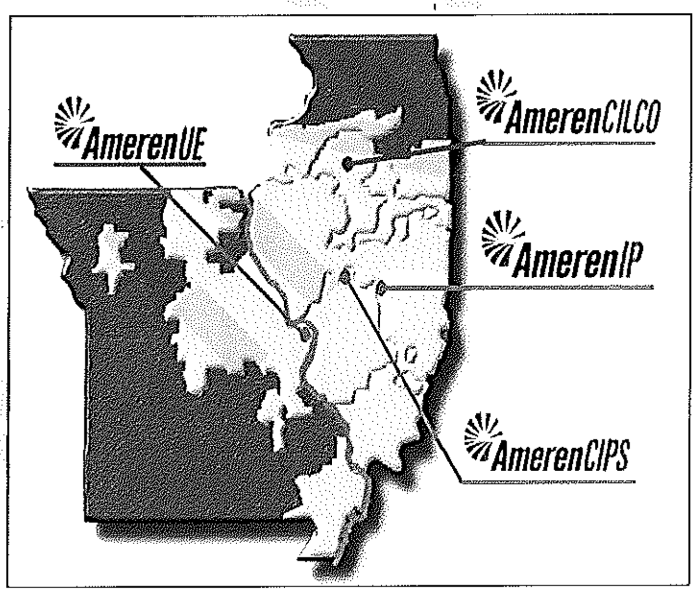


Figure 1 – AMEREN Power Service Territory

The TOU Pilot Study is the result of the July 30, 2002 Missouri Commission Report and Order Approving Stipulation and Agreement that resolved the Case No. EC-2002-1. Public Counsel filed testimony in May 2002 proposing a TOU pilot study in that case. In December of 2003, the Collaborative agreed to a pilot concept. Such agreement laid the foundation for the current project work.

[5] The treatment groups were removed from study during their September bill cycle. This resulted in no data being available after September 22, 2005. Due to bill cycle issues, we have elected to use the period June 28, 2005 through August 31, 2005 as the 2005 analysis period.

During the summer of 2004, AmerenUE implemented a pilot program to test residential time-of-use rates (RTOU), residential time-of-use rates with a critical peak pricing component (CPP), and residential time-of-use rates with a critical peak pricing component and enabling technology. The enabling technology was a programmable thermostat that could be modified during CPP events, e.g., rolled up 1°F each hour during the control.

The results of the 2004 pilot study are documented in "Load Research Analysis – First Look Results," *RLW Analytics*, February, 2005. The 2004 analysis indicated that there was very little to be gained by implementing just the residential time-of-use rate. In addition, the pilot provided results that suggested that the critical peak pricing event was effective in moving load away from the event period. Furthermore, the 2004 results suggested that significant changes were occurring with the introduction of the enabling technology.

At a February, 2005 meeting and subsequent conference call, the collaborative agreed to continue and extend the pilot through the summer 2005. Some changes were recommended and agreed to during these meetings and were documented in the 2005 Project Plan.

2.2 Purpose, Goals and Objectives

Project Purpose: Obtain information needed to determine if and how residential time-of-use rates will be beneficial in Missouri.

2.2.1 Report Goals and Analysis

The primary goals of the 2005 Residential TOU Pilot Study analysis are as follows:

- Confirm that the time-of-use with critical peak pricing (CPP) rate and CPP rate coupled with enabling technology caused a statistically significant change in customers' energy use during periods of potentially high prices;
- Confirm the magnitude of load reduction during on-peak and CPP periods and the amount of energy shift from on-peak to mid-peak or off-peak periods;
- Examine whether or not a second year of participation increases the customer's ability to shift load during CPP events or from the on-peak to mid-peak or off-peak periods;
- Confirm that CPP and/or CPP with enabling technology increases customer awareness and produces positive results in conservation, i.e., reductions in total consumption; and
- Examine the cost-effectiveness[6] of this type of programs.

3 PROJECT DESIGN

3.1 Experimental Design

In addition to the Test/Control experimental design employed in 2004, the 2005 Pilot Study includes a pre/post experimental design component.

[6] Cost effectiveness and cost benefit of the TOU pilot is outside the scope of the Load Research Analysis Plan.

The 2005 Pilot Study continued to follow customers in the 2004 "Test" groups under the RTOU-CPP treatment and the RTOU-CPP with Thermostats (RTOU-CPP-Therm) treatment. In addition to carrying over the existing test/control experimental design, the 2005 Pilot Study recruited "Control Group" customers from the 2004 Pilot Study into the "Test" groups for both RTOU-CPP and RTOU-CPP-Therm. This allows the examination of these customers within a pre/post experimental design[7].

3.1.1 Treatment Groups

For 2005, Four Treatment Groups were formed.

After much discussion, the Collaborative parties agreed to **drop** the residential time-of-use only treatment group. In addition, the parties agreed to construct the following four groups:

Test Group #1 - The customers in test group number one were a continuation of customers from the 2004 RTOU CPP group;

Test Group #2 - The customers in test group number two were a continuation of customers from the 2004 RTOU CPP-Therm group.

Test Group #3 - The customers in test group number three were recruited from the 2004 Pilot Study control group. In 2005, these customers were given the RTOU rate with the CPP element.

Test Group #4 - Finally, the customers in test group number four were recruited from the 2004 Pilot study control group. In 2005 these customers were subjected to the RTOU with CPP and received the enabling technology.

The four test groups were organized into the following two principal treatment groups that were compared to their respective control groups in the primary analysis:

Treatment Group #1 - RTOU customers with a critical peak pricing component; and

Treatment Group #2 - RTOU customers with a critical peak pricing component and the thermostat as the enabling technology.

In addition, supplemental analysis was conducted to examine the impacts associated with the pre/post experimental designs.

3.1.2 Control Groups

Control Groups will be formed for each of Treatment Group.

For 2005, we continue to employ the Test/Control experimental design. Therefore each *Test* group, (i.e., treatment group) is paired with a control group of similar size. In 2004 the parties agreed to select the control groups using daily energy usage, if available, matched to each "test" participant. If daily energy use is not available then summer seasonal use for the pre participation period was used to match the "test" and the "control" group participants. In 2005, some of the control group customers were continued from 2004 while others were recruited new.

[7] The pre/post experimental design is a result of pilot customers recruited into the new treatment groups (groups #3 and #4) come from the 2004 control group sample of 297 customers.

3.1.3 Target Populations

High Summer Use Residential Customers will be targeted.

Once again, only high summer use residential customers will be targeted. Winter use is defined as the billing months December through February and summer is defined as the billing months June through September. The specific definitions used to classify the residential customers are displayed in Table 1. Customers with more than 1500 kWh in the summer are classified as high summer use customers.

Strata	Description	Winter Use	Summer Use
1	Low Winter/Low Summer	0-1150 kWh	0-1500 kWh
2	High Winter/Low Summer	>1150 kWh	0-1500 kWh
3	Low Winter/High Summer	0-1150 kWh	>1500 kWh
4	High Winter/High Summer	>1150 kWh	>1500 kWh

Table 1 – Residential Domains

Table 2 presents updated population characteristics used in the 2005 analysis for the residential class broken down by low/high winter/summer use. Approximately 264,000 customers are classified as high summer use customers.

Stratum	Description	Count	Proportion
3	Low Winter/High Summer	113,110	42.9%
4	High Winter/High Summer	150,602	57.1%
	Totals	263,712	100.0%

Table 2 – AmerenUE Residential Population

3.1.4 Geographical Constraint

The Residential TOU Pilot Study will be geographically constrained to the City of St Louis and St. Louis County.

Here again, to help control the cost and to expedite the implementation of the 2005 Residential TOU Pilot Study, the project team elected to constrain the project to an area that encompasses the City of St. Louis and St. Louis County. Geographically constraining the project provides the following benefits:

- Minimizes the cost incurred implementing the enabling technology, i.e., the "smart" thermostats. The selected "smart" thermostat technology uses a one-way paging strategy to allow for remote programming of the thermostats. Therefore, AmerenUE needs licenses with paging companies to provide the communications backbone. Spreading the project throughout the state increases the number of providers needed.
- By limiting the study to St. Louis City and County, it reduces the training needed of Call Center personnel to implement the program.
- Reduces the cost of installing and subsequent follow-ups (if needed) on the "smart" thermostats.

- Thermostat installers will have less distance between installations by limiting the geographic area, thus expediting the installations.

Figure 2 presents the geographical target area of the City of St. Louis and St. Louis County.

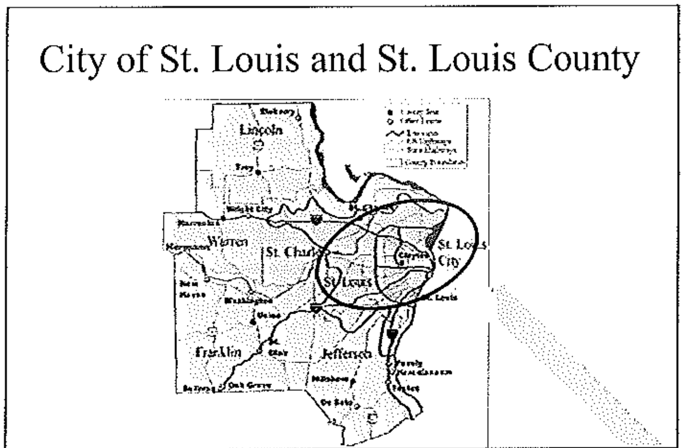


Figure 2 – Geographic Target Area

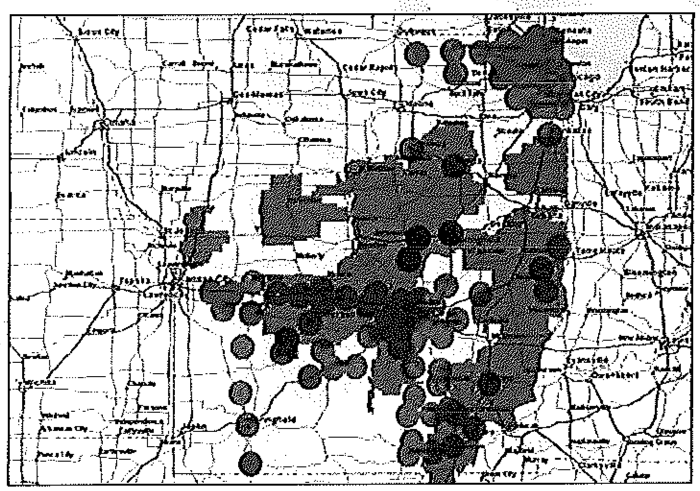


Figure 3 – Paging coverage

Figure 3 presents the paging coverage for the City of St. Louis and St. Louis County area. The paging system has excellent coverage in this area.

3.1.5 Project Duration

AmerenUE agreed to fund the Residential TOU Pilot Study through September 2005.

The agreement was to continue the pilot study through September 2005.

3.1.6 Sample Design

A stratified sample was used to select the "new" program participants.

Focusing on the high use residential customers lends itself to a stratified sample design utilizing the third and fourth strata of the residential cost-of-service stratification. Table 3 presents the distribution of approximately 264,000 customers in our generalized target population. The numbers presented in the table below is updated using the 2005 data.

Stratum	Description	Winter Use	Summer Use	Count	Proportion
3	Low Winter/High Summer	0-1,150 kWh	>1,500 kWh	113,110	42.9%
4	High Winter/High Summer	>1,150 kWh	>1,500 kWh	150,602	57.1%
			Totals	263,712	100.0%

Table 3 – Residential TOU Pilot Sample Design

3.1.7 Sample Sizes

The planned sample sizes provided meaningful results.

The 2004 sample sizes used in the Residential TOU Pilot Study were sufficient to provide meaningful results. Table 4 presents results for the July 13th peak day during 2004. The table includes the achieved precision, the implied error ratio, the required sample size to meet the ±10% precision at the 90% confidence level and the implied precision using the proposed sample of 75. While these results are relative to the system peak day it should be noted that the results do vary for each variable of interest, as well as, for each CPP event day and hour. Following the recommendation in the Project Plan, substantially more customers were recruited into the 2005 sample to allow for additional analysis following the pre/post experimental design.

Study Group	Rate Options	Maximum Sample Size	July 13th System Peak Demand (kW)	Implied Error Ratio (%)	Required Sample Size for 90/10	Implied Precision with Sample of n=75	Actual Installed Sample
Control Group	Standard Residential Rate	89	5.68	42%	47	±8.0%	135
	Standard Residential Rate	117	6.05	36%	34	±6.7%	174
Voluntary Study Groups	3-Tier TOU w/ CPP	87	4.85	50%	69	±9.6%	146
	3-Tier TOU w/ CPP and Smart Thermostat	78	4.07	47%	59	±8.9%	104

Table 4 – Sample Size Requirements and Recommendations

As a result of some preliminary analysis that indicated the control groups were statistically different than their study group counterparts during the pre-participation period (i.e., summer 2003), an alternative control group approach was used. Under the alternative strategy, the full control group was used with replacement to select a 2:1 match for each study group participant based on the customer's pre-period consumption. This resulted in 277 control group customers for the CPP-RTOU group and 211 control group customers for the CPP-THERM group. Table 5 presents the results of a T-Test conducted on the control groups. The T-Test examined whether or not the 2003 seasonal energy use for the control group are statistically different than their study group counterpart. Clearly, the control groups are very similar to their study counterparts with the CPP-RTOU group within 141 kWh or 1.6% and the CPP-THERM group separated by just 6 kWh or less than 1%.

Study Group	Rate Options	Analysis Sample Size	Per-Period Consumption (kWh)	Study-Control Difference (kWh)	T-Test Value	Probability Pr>|t|	Decision Rule on Ho: Study=Control
Control Group	Standard Residential Rate	277	8,423				
	Standard Residential Rate	211	7,955				
Voluntary Study Groups	3-Tier TOU w/ CPP	141	8,564	141	0.478	0.633	Cannot Reject
	3-Tier TOU w/ CPP and Smart Thermostat	104	7,949	(6)	(0.024)	0.981	Cannot Reject

Table 5 – Comparison of Study and Control Groups

3.2 Enabling Technology

The Cannon/Honeywell ExpressGate™ thermostat will continue to be used.

3.2.1 Thermostat Features

The Cannon/Honeywell thermostat selected for use in this project is displayed in Figure 4.

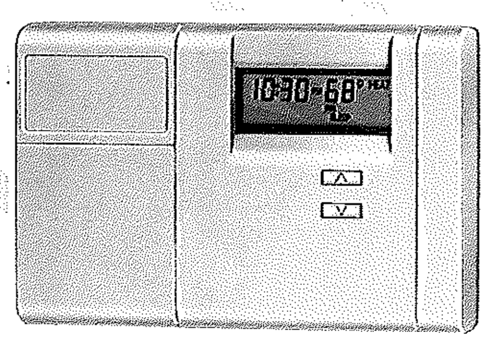


Figure 4 – Cannon/Honeywell ExpressStatThermostat – Settings

The Cannon/Honeywell thermostat is capable of precise temperature control with four time and temperature settings per day. The thermostat has the capacity to handle weekday, Saturday and Sunday schedules. Figure 5 presents the Web screen used to program the thermostat. As evidenced by the figure, the thermostat can be set at different temperatures for waking, leaving, returning and sleeping. Of course, these could be adjusted to correspond with the AmerenUE TOU periods.

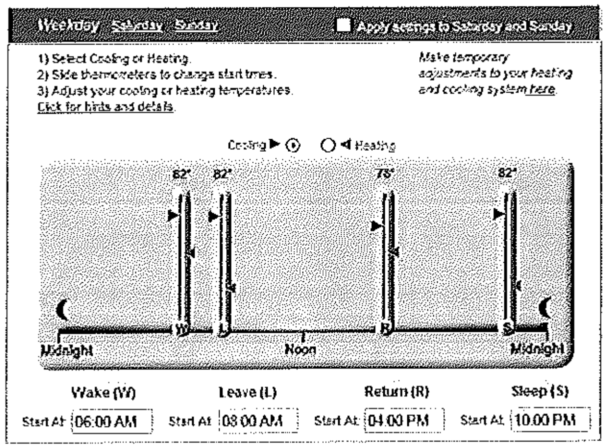


Figure 5 – Thermostat Settings

Thermostat – Control Features

From a control perspective, the thermostat can accommodate simple cycling strategies, cycling strategies with pre-defined limits, ramped temperature control and randomization. The project team has elected to use ramped temperature control allowing the customers to choose their comfort setting by time-of-use period and modify their thermostat during CPP events. Under this customer choice method, the thermostat can be set to roll up a predetermined number of degrees for selected periods. Cannon Technologies Incorporated (CTI) has developed six distinct schedules for customers to invoke during the critical peak pricing period. The offering is presented in Figure 6 and is based on a four hour CPP period.

Degree Per Hour	Maximum Change	Pre Cool (2 degrees)
1	4	No
2	4	No
2	6	No
2	8	No
2	6	Yes
2	8	Yes

Figure 6 – Customer Choice: Degree Roll-Up

Thermostat – Data Logging Capabilities

The Cannon/Honeywell thermostat is capable of securing specific data elements to assist the evaluation. The following elements can be collected on an hourly basis. The thermostat can store up to 90 days of data.

- Temperature,
- Compressor run times, and
- Shed times.

While this information would certainly be beneficial to the evaluation, we do not view it as critical to successfully satisfying the major evaluation objectives, i.e., estimating the demand reduction at system peak, CPP, etc.

3.3 Residential TOU/CPP Rate Design

A three-part time-of-use (TOU) rate with high differentials will be used along with an even more severe critical peak-pricing (CPP) component.

The Residential TOU rate was developed by the AmerenUE Rate Engineering Department. It is important to note that the TOU rates were not based of the true costs of serving loads during the indicated pricing period, but instead designed to gauge customer reaction to "high" prices. In other words, while the average cents/kWh realization resulting from these rates recover the Company's costs of providing service, such costs do not vary as widely by rating period as the TOU prices suggest. The time-of-use rates are detailed below.

The summer billing season uses a four-hour on-peak period defined as hour beginning 3:00PM to hour ending 7:00PM.

Summer: Three-Tier TOU with CPP		Rate
Off Peak	(Weekday 10PM–10AM, Weekends, Holidays)	4.80 cents/kWh
Mid Peak	(Weekdays 10AM– 3PM and 7PM-10PM)	7.50 cents/kWh
Peak	(Weekday 3PM – 7PM)	16.75 cents/kWh
CPP	(Weekday 3PM – 7PM, 10 times per summer)	30.00 cents/kWh

3.4 CPP Customer Notification

Customers were provided day-ahead notification of the Critical Peak Price.

Twenty-four hours before a CPP period was to be called, AmerenUE placed an automated, outbound telephone call to all pilot participants to distribute a pre-recorded notification message. In addition, the notification appeared at the AmerenUE webpage for the TOU pilot program and was emailed to pilot participants requesting email notification.

In addition, the "smart" thermostats were sent a control message to raise temperature to a predetermined level. Customers were able to opt out of a CPP control period by contacting AmerenUE's Call Center or at the Cannon Technologies web site. It is important to note that customers were not able to override the CPP control period directly from the smart thermostat.

3.5 Customer Billing

Customers will be billed from the interval load data collected for the evaluation.

The 2005 stage of the TOU Pilot program was slated to begin June 1, 2005. However, each customer will start being billed under the pilot rates on the first day of their June billing cycle. This means that the participants first TOU bill in the summer of 2005 would come as the July bill for the billing period beginning sometime in June but not necessarily June 1, 2005.

The Pilot participants were billed from their evaluation data. The evaluation data were collected on a 15-minute basis using the Company's CellNet automatic meter reading (AMR) system. After CellNet has collected the data, the data were sent to the ARES Lodestar billing system. The Lodestar system will validate, estimate, and edit the data as necessary. Then, the system summarized the interval data to the Residential Time-Of-Use periods. The TOU information was sent to the Customer Service System (CSS) for billing and the interval load data was sent to the Load Research group for retention and analysis.

3.6 CPP Event Calls

During the pilot test AmerenUE staff put into place an algorithm that was used to call a CPP event anytime the temperature was forecasted to be at least 90° F. In 2005, the temperature was expected to exceed 90°F on 46 days for a total of 326 hours (including weekends and holidays). Table 6 presents a summary by month. The extremely hot summer presented a unique challenge, i.e., determining when to call the CPP event that we did not encounter in 2004.

Month	Number of Days	Number of Hours
June	15	100
July	14	116
August	17	110
Totals	46	326

Table 6 – Count of Days with Temperatures at 90°F or above

AmerenUE staff called CPP events on a total of eight days. The event dates and times are presented in Table 7. All events were called for the full four hour period defined as hour beginning 3pm through hour ending 7pm.

Date	Start Time	End Time	Total Hours
30-Jun-05	3:00 PM	6:59 PM	4
21-Jul-05	3:00 PM	6:59 PM	4
22-Jul-05	3:00 PM	6:59 PM	4
26-Jul-05	3:00 PM	6:59 PM	4
2-Aug-05	3:00 PM	6:59 PM	4
9-Aug-05	3:00 PM	6:59 PM	4
10-Aug-05	3:00 PM	6:59 PM	4
19-Aug-05	3:00 PM	6:59 PM	4
Total Event Hours			32

Table 7 – CPP Event Calls

In 2005, the CPP events missed each of the summer monthly system peaks. The monthly system peak dates and times are displayed in Table 8.

Date	DOW	Time
29-Jun-2005	Wednesday	5pm
25-Jul-2005	Monday	4pm
3-Aug-2005	Wednesday	5pm

Table 8 – System Peak Dates and Times

4 PROJECT ANALYSIS

This section documents the analysis conducted to date for this project. The following analysis elements are explored:

- Determine the significance between the means for the following analysis variables:
  - Demand at the monthly AmerenUE system peaks;
  - Average demand during the critical peak pricing (CPP) periods;
  - Average summer energy use by time-of-use categories; and
  - Average payback for the three-hour period immediately following the CPP periods.

The analysis is conducted for each of the two treatment groups, i.e., CPP, and CPP-THERM.

4.1 Analysis of Treatment Group CPP

This section details the analysis conducted for the treatment group of RTOU pilot participants that were subjected to both the time-of-use rate and the critical peak-pricing component.

4.1.1 Available Sample

The CPP treatment group received the residential time of use rate with the critical peak-pricing component. The "control" group was represented by a sample of 277 customers and the "test" group (i.e., RTOU group) was represented by a sample of 141 customers. The distribution by strata, the population counts and the case weights are displayed in Table 9.

Group	Stratum	Description	Population Size	Sample Size	Case Weight (N/n)
Test-CPP	3	Low Winter/High Summer	113,110	65	1,740.15
Test-CPP	4	High Winter/High Summer	150,602	76	1,981.61
Totals - Test Group			263,712	141	
Control-CPP	3	Low Winter/High Summer	113,110	132	856.89
Control-CPP	4	High Winter/High Summer	150,602	145	1,038.63
Totals - Control Group			263,712	277	

Table 9 – Available Sample: CPP Treatment

In the analysis, the "control" and "test" groups were weighted and extrapolated to represent the full population of stratum 3 and 4 customers. Following the expansion the average demand per customer was calculated by dividing through by the total population size.

4.1.2 Hourly Load Estimates

Figure 7 presents the results of the analysis. The figure displays the "control" group in blue and the "treatment" group (i.e., RTOU) in red. To the left of the figure are EnergyPrints that display the hourly load in three dimensions. The day of the year is on the y-axis, the time of day on the x-axis and the demand is displayed on the z-axis as a color gradient with low levels of load in the black-blue spectrum and high levels of load in the yellow-white spectrum. The graph shows the "control" group having slightly higher peak demands than the RTOU group.

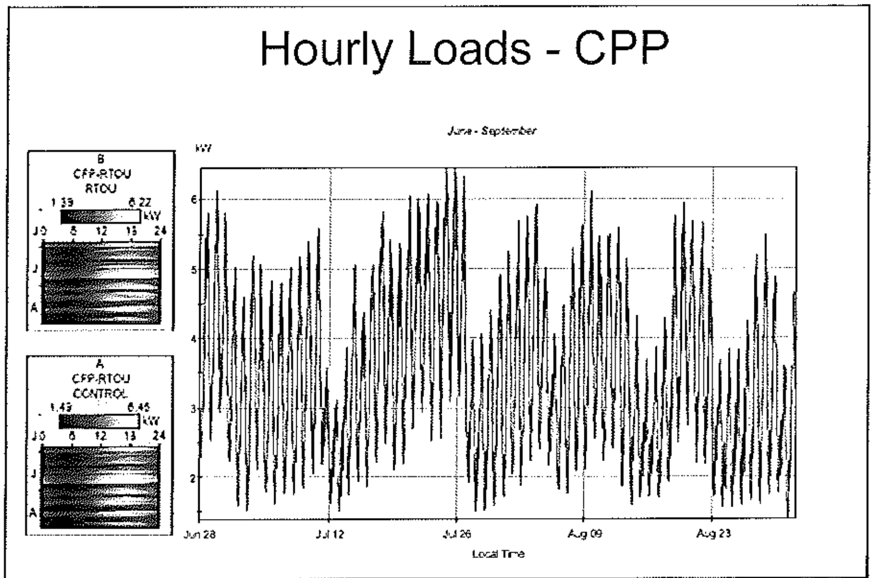


Figure 7 – Hourly Load Estimates: CPP Treatment

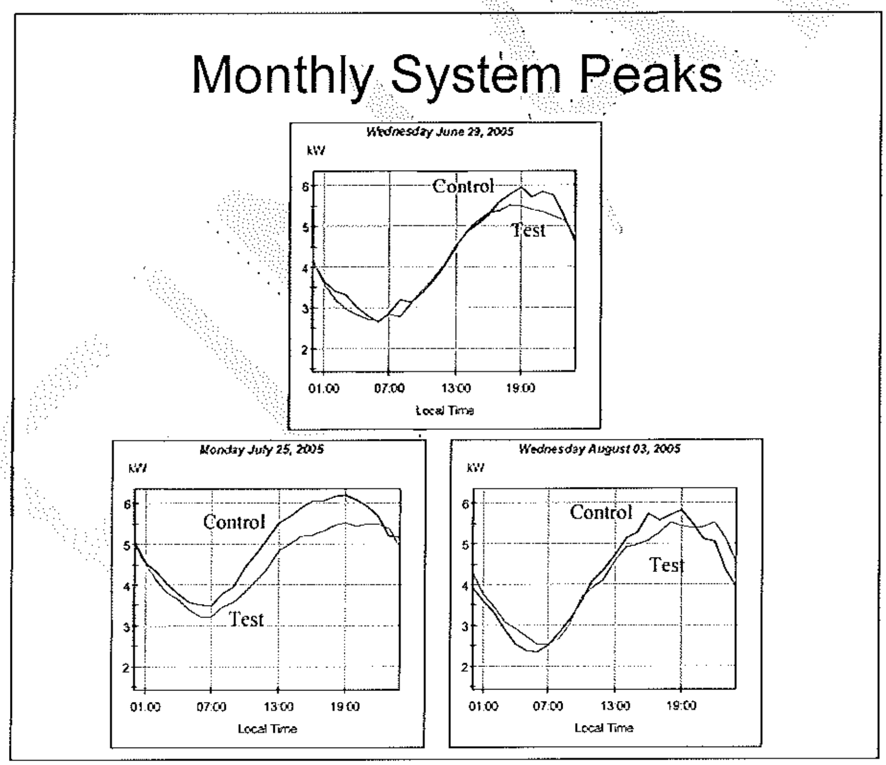


Figure 8 – Monthly System Peaks: CPP Treatment

Figure 8 presents the control group versus the RTOU-CPP group for each of the monthly system peaks. These include:

- Wednesday, June 29, 2005,
- Monday, July 25, 2005, and
- Wednesday, August 3, 2005.

There was insufficient data for the Thursday, September 22, 2005 peak to conduct a comparison.

Three Tier TOU with CPP (CPP)									
System Peak		Control Group (kW)	RTOU Pilot Group (kW)	Difference Control-RTOU (kW)	Percent Difference (%)			
Date	Time					T-Test	Pr>|t|	Ho: Control=RTOU
29-Jun-2005	5pm	5.60	5.39	0.21	3.8%	1.13	0.258	Cannot Reject
25-Jul-2005	4pm	6.06	5.23	0.83	13.7%	3.60	0.000	Reject
3-Aug-2005	5pm	5.57	5.29	0.28	5.0%	1.33	0.183	Cannot Reject

Table 10 – T-Test for System Peak Demand: CPP Treatment

To test whether or not there is a significant difference we conducted a T-test under the null hypothesis that the two means were equal. Since a critical peak pricing event was not called on any of the system peak days, the analysis results test just the impact of the RTOU rate. Table 10 presents the outcome of the analysis. For June and August system peak days, we are unable to reject the hypothesis and must conclude that the time-of-use rate alone does not statistically reduce the demand at the time of the system peak. This is consistent with the findings from 2004. However, there was a statistical difference noted on Monday, July 25, 2005 between the RTOU-CPP group and the control group. On this day, the test group is considerably lower (i.e., up to 0.83 kW) than the control group. If we examine that system peak week more closely (see Figure 9), then we notice that the test group was lower during the Thursday and Friday, which were both CPP days, leading up to the peak Monday. Interestingly, the loads on Saturday and Sunday prior to the peak were nearly identical. Tuesday after the peak Monday was also a CPP day and customers received the CPP notification for the next day around 9am on Monday. Having CPP days on both Thursday and Friday before and Tuesday after the peak Monday may have caused the statistically significant difference on the system peak day.

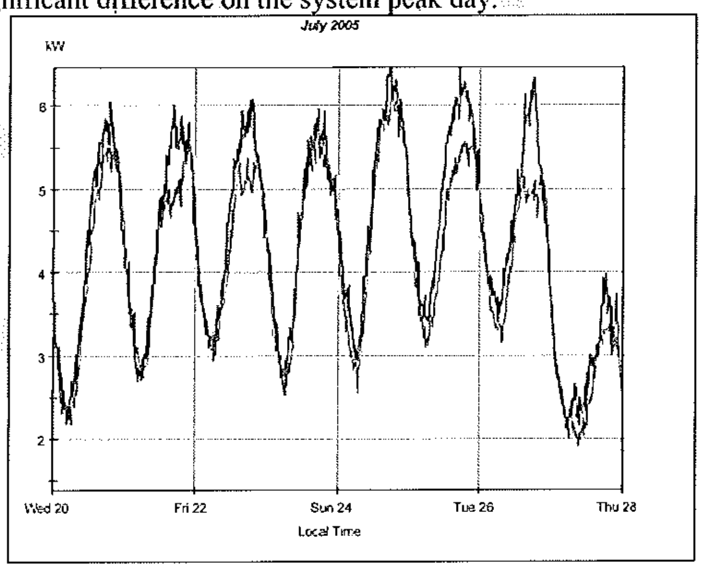


Figure 9 – System Peak Week

4.1.3 Demand on "Hot" Days

To further examine the effects of the time-of-use rate, we examined the demand of the test and control group customers on days where the temperature during the on-peak period exceeded 90°F. CPP event days were separately analyzed and therefore excluded from this analysis. The following dates were included in the analysis:

Non Event Days Over 90°F		
June	July	August
29-Jun-2005	20-Jul-2005	1-Aug-2005
	25-Jul-2005	8-Aug-2005
		11-Aug-2005
		12-Aug-2005
		13-Aug-2005
		18-Aug-2005

Table 11 – Non Event Days Over 90°F

Three Tier TOU with CPP (CPP)						
Control Group (kW)	RTOU Pilot Group (kW)	Difference Control-RTOU (kW)	Percent Difference (%)	T-Test	Pr>|t|	Ho: Control=RTOU
5.37	5.09	0.28	5.2%	1.61	0.107	Cannot Reject

Table 12 – Non Event Days Over 90°F Analysis Results

Error! Reference source not found. summarizes the analysis. The average "hot period" demands of the control group was 5.37 kW compared to a demand of 5.09 kW for the test group. The 5.2% difference was close to being statistically significant.

4.1.4 CPP Event Day Analysis

During the pilot test, a total of eight CPP events were called for a total of 32 hours. The CPP events were invoked on days when the forecasted temperature was expected to exceed 90° F. The CPP event lasted the entire four-hour on-peak period (i.e., hour beginning 3pm to hour ending 7pm. Table presents the dates and times associated with the eight CPP events.

Date	Start Time	End Time	Total Hours
30-Jun-05	3:00 PM	6:59 PM	4
21-Jul-05	3:00 PM	6:59 PM	4
22-Jul-05	3:00 PM	6:59 PM	4
26-Jul-05	3:00 PM	6:59 PM	4
2-Aug-05	3:00 PM	6:59 PM	4
9-Aug-05	3:00 PM	6:59 PM	4
10-Aug-05	3:00 PM	6:59 PM	4
19-Aug-05	3:00 PM	6:59 PM	4
Total Event Hours			32

Table 13 – CPP Event Day Schedule

Figure 10 presents a comparison of the actual hourly load for the RTOU group with CPP versus the baseline load calculated from the Control group. The solid black lines drawn parallel to the y-axis highlight the event period. In this figure, the graph highlights the difference between the RTOU group and the control in yellow. Clearly, the RTOU group with CPP shows a substantially lower level of load during most of the event period. Figures for each of the event days are contained in Appendix A.

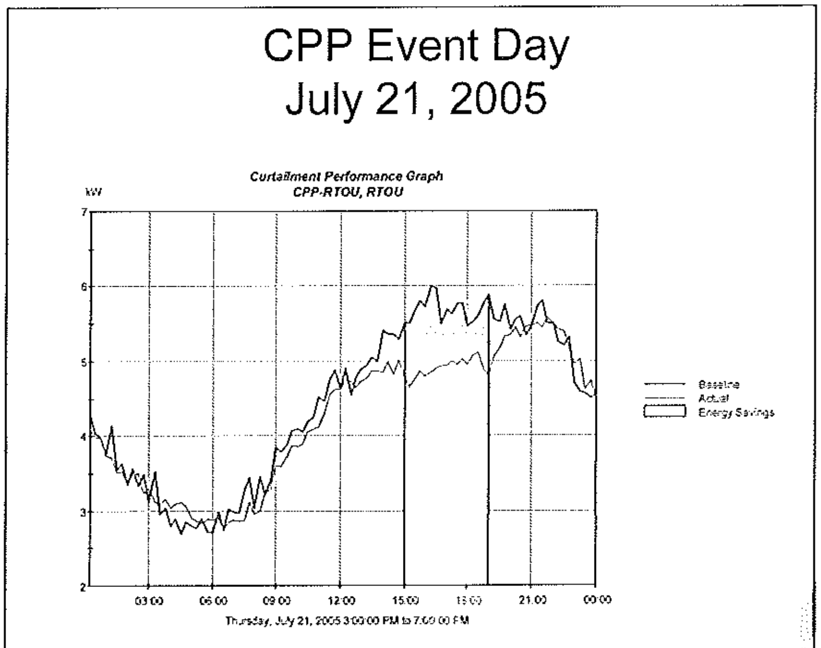


Figure 10 – CPP Event Day: July 21, 2005: CPP Treatment

To determine if there is a statistically significant difference between the RTOU and Control group we set up and conducted a T-Test. For this analysis, we calculate and compare the average demand across the entire CPP event period. The CPP event day analysis results are presented in Table . The RTOU participants demonstrated a statistically lower demand when compared to their Control group counterparts during each of the eight events. In addition, the average demand across all event hours was deemed to be significantly lower.

Three Tier TOU with CPP (CPP)									
CPP Event			Control Group (kW)	RTOU Pilot Group (kW)	Difference Control-RTOU (kW)	Percent Difference (%)	T-Test	Pr>|t|	Ho: Control=RTOU
	Hour Ending								
Date	Start	End							
30-Jun-05	3:00 PM	6:59 PM	5.35	4.85	0.50	9.3%	2.63	0.0088	Reject
21-Jul-05	3:00 PM	6:59 PM	5.71	4.91	0.80	14.1%	3.75	0.0002	Reject
22-Jul-05	3:00 PM	6:59 PM	5.84	5.05	0.79	13.5%	3.54	0.0005	Reject
26-Jul-05	3:00 PM	6:59 PM	5.98	4.91	1.06	17.8%	5.28	0.0000	Reject
2-Aug-05	3:00 PM	6:59 PM	5.38	4.73	0.65	12.1%	3.24	0.0013	Reject
9-Aug-05	3:00 PM	6:59 PM	5.64	4.74	0.90	16.0%	4.33	0.0000	Reject
10-Aug-05	3:00 PM	6:59 PM	5.01	4.24	0.76	15.2%	4.00	0.0000	Reject
19-Aug-05	3:00 PM	6:59 PM	5.61	4.88	0.74	13.1%	3.54	0.0004	Reject
Average			5.56	4.84	0.72	13.0%	3.90	0.0001	Reject

Table 14 – T-Test for CPP Event Day Demands: CPP Treatment

4.1.5 Time-Of-Use Energy Analysis

Time-of-use (TOU) periods consistent with the TOU rate tariff were constructed and analyzed by the project team. These periods and their definitions are as follows:

- Average summer energy use[8]: This value was defined as the average energy use across the periods June 1, 2005 through August 31, 2005.
- Average on-peak summer energy use: This value was defined as the four hour period beginning at 3pm through hour ending 7pm on summer weekdays. Summer weekdays are defined as Monday through Friday excluding holidays.
- Average on-peak summer energy use during CPP events: This value was defined as the four hour period beginning at 3pm through hour ending 7pm during the eight called CPP events.
- Average mid-peak summer energy use: This value was defined as an eight-hour weekday period. The period encompasses the five hours beginning at 10am through hour ending 3pm and the three-hour period beginning at 7pm through hour ending 10pm.
- Average off-peak summer energy use: This value was defined as all weekend hours, all holiday hours (defined as July 4, 2005), and all remaining weekday hours (i.e., the twelve hour period beginning at 10pm to hour ending 10am).

A T-test analysis was conducted for each variable of interest. The results of the analysis are displayed in Table . The test and control groups displayed similar levels (and percentages) of overall, off peak use, mid-peak use and on-peak use. Only for the energy used during CPP periods could the null hypothesis that the two samples displayed equal means be rejected. For this period, the total energy used is estimated to be 252 kWh for the control group and 219 kWh for the treatment group. Dividing the total CPP energy use by the eight control periods yields an average daily CPP usage of 31.5 kWh for the control group or 15% more than the 27.4 kWh used by the treatment group.

Three Tier TOU with CPP (CPP)						
Jun 1 - Aug 31 TOU Period	Control Group (kWh)	RTOU Group (kWh)	Difference Control-RTOU (kWh)	T-Test	Pr>|t|	Ho: Control=RTOU
Seasonal Use	7,729	7,584	145.00	0.58	0.56	Cannot Reject
Off-Peak Use	4,495	4,450	45.00	0.28	0.78	Cannot Reject
Mid-Peak Use	2,054	2,019	35.00	0.54	0.59	Cannot Reject
On-Peak Use	927	896	31.00	0.96	0.34	Cannot Reject
CPP Use	252	219	33.10	3.92	0.00	Reject
Percent Off-Peak	58.2%	58.7%	-0.5%	1.02	0.31	Cannot Reject
Percent Mid-Peak	26.6%	26.6%	0.0%	0.15	0.88	Cannot Reject
Percent On-Peak	12.0%	11.8%	0.2%	(0.72)	0.47	Cannot Reject
Per CPP	3.3%	2.9%	0.4%	4.08	0.00	Reject

Table 15 – T-Test for Average Summer Use by TOU Periods: CPP Treatment

4.1.6 Payback Analysis

Payback is defined as the average demand for the three-hour period immediately following a critical peak-pricing (CPP) event. Table presents the analysis for the payback. The table indicates that the payback for the RTOU group following the CPP event was moderate and not statistically different than the load following the CPP period for the control group. On the eight events the payback averaged approximately 0.06 kW.

[8] Actual data used to estimate the average daily usage was from the time period June 28, 2005 through August 31, 2005.

Three-Tier TOU Rate with CPP (CPP)									
CPP Event			Control	RTOU	Difference	Percent			
	Payback Period		Group	Group	RTOU-Control	Difference			
Date	Start	End	(kW)	(kW)	(kW)	(%)	T-Test	Pr>|t|	Ho: Control=RTOU
30-Jun-05	7pm	10pm	4.77	4.74	(0.02)	-0.5%	0.12	0.902	Cannot Reject
21-Jul-05	7pm	10pm	5.56	5.39	(0.18)	-3.2%	0.83	0.408	Cannot Reject
22-Jul-05	7pm	10pm	5.42	5.24	(0.18)	-3.3%	0.85	0.395	Cannot Reject
26-Jul-05	7pm	10pm	5.03	5.01	(0.02)	-0.4%	0.09	0.928	Cannot Reject
2-Aug-05	7pm	10pm	5.02	5.09	0.07	1.3%	(0.35)	0.723	Cannot Reject
9-Aug-05	7pm	10pm	5.14	5.27	0.13	2.5%	(0.65)	0.513	Cannot Reject
10-Aug-05	7pm	10pm	4.63	4.56	(0.07)	-1.6%	0.34	0.735	Cannot Reject
19-Aug-05	7pm	10pm	5.35	5.11	(0.24)	-4.5%	1.08	0.279	Cannot Reject
Average			5.12	5.05	(0.06)	-1.3%	0.34	0.731	Cannot Reject

Table 16 – T-Test for Payback Analysis: CPP Treatment

4.2 Analysis of Treatment Group CPP-THERM

This section details the analysis conducted for the third treatment group. This group of RTOU pilot participants were subjected to the critical peak-pricing component of the rate but were provided additional enabling technology (see Section 3.2 Enabling Technology for a description of the thermostat) to aid in their load modification. This group is termed the CPP-THERM group.

It is interesting to note that during the test almost all of the customers remained on the default control option (i.e., 1° change per hour with a 4° maximum change). Only four customers elected a control option different than the default setting with three of these customers selecting the highest option (i.e., 2° change per hour with an 8° maximum change).

4.2.1 Available Sample

The CPP-THERM treatment group received the residential time of use rate with the critical peak-pricing component and an ExpresStat thermostat. The "control" group was represented by a sample of 104 customers and the "test" group (i.e., RTOU group) was represented by a sample selected on a 2:1 ratio, or 211 customers. The distribution by strata, the population counts and the case weights are displayed in Table 11. In the analysis each test group was weighted and extrapolated to represent the full population of stratum 3 and 4 customers. Following the expansion the average demand per customer was calculated by dividing through by the total population size.

Group	Stratum	Description	Population Size	Sample Size	Case Weight (N/n)
Test-CPP Therm	3	Low Winter/High Summer	113,110	55	2,056.55
Test-CPP Therm	4	High Winter/High Summer	150,602	49	3,073.51
			263,712	104	
Control-CPP Therm	3	Low Winter/High Summer	113,110	103	1,098.16
Control-CPP Therm	4	High Winter/High Summer	150,602	108	1,394.46
			263,712	211	

Table 11 – Available Sample: CPP-THERM Treatment

4.2.2 Hourly Load Estimates

Figure 11 presents the results of the analysis. The figure displays the "control" group in blue and the "treatment" group (i.e., RTOU) in red. To the left of the figure are EnergyPrints that display the hourly load in three dimensions. The day of the year is on the y-axis, the time of day on the x-axis and the demand is displayed on the z-axis as a color gradient with low levels of load in the black-blue spectrum and high levels of load in the yellow-white spectrum. The graph shows the "control" group having substantially higher peak demands than the RTOU group.

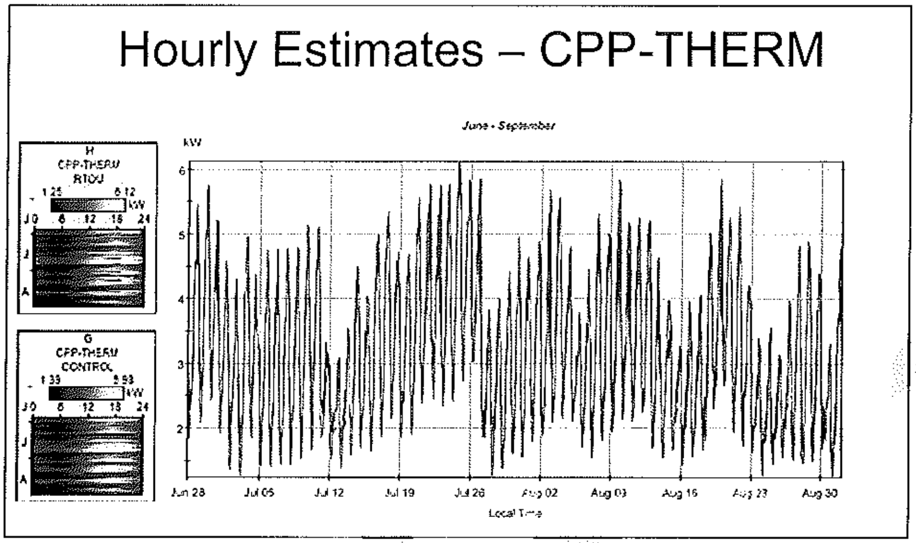


Figure 11 – Hourly Load Estimates: CPP-THERM Treatment

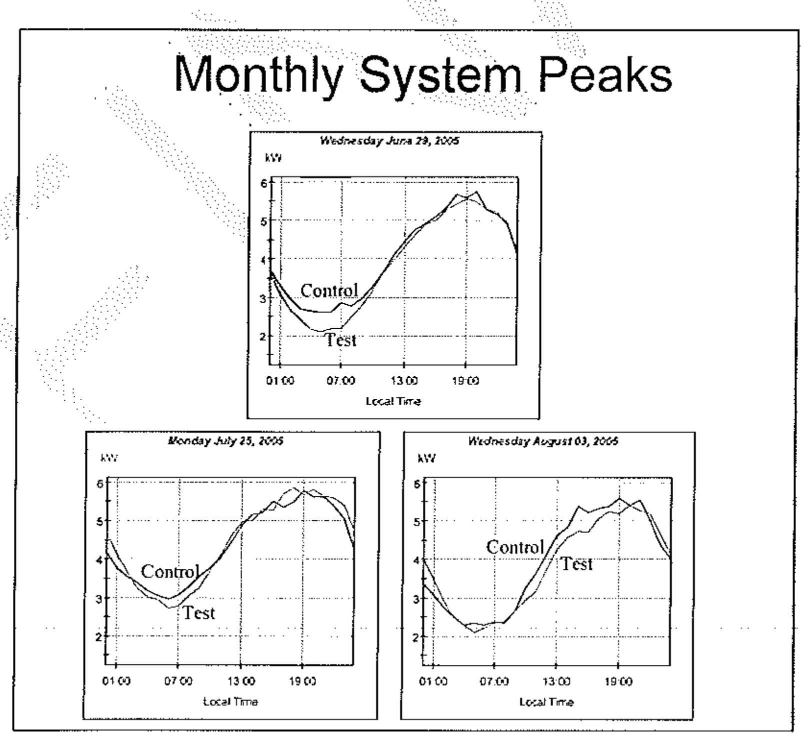


Figure 12 – Monthly System Peaks: CPP-THERM Treatment

4.2.3 Demand at System Peak

Figure 12 displays the hourly demand for the "control" and "treatment" groups on the three summer system peak days. The blue line represents the "control" group and the red line represents the treatment group. Clearly, the loads between the control and treatment groups are very similar. However, to test whether or not there is a significant difference we conducted a T-test under the null hypothesis that the two means were equal. Table 12 presents the outcome of the analysis. The analysis shows that without calling a critical peak pricing event, we are unable to reject the hypothesis that the two means are equal. This is consistent with the 2004 results that indicated the RTOU rate alone was insufficient to cause a statistical difference at the time of system peak.

Three Tier TOU with CPP and Thermostat (CPP-THERM)								
System Peak Date	Time	Control Group (kW)	RTOU Pilot Group (kW)	Difference Control-RTOU (kW)	Percent Difference (%)	T-Test	Pr>|t|	Ho: Control=RTOU
29-Jun-2005	5pm	5.32	5.27	0.05	0.9%	0.19	0.848	Cannot Reject
25-Jul-2005	4pm	5.52	5.26	0.26	4.7%	1.01	0.314	Cannot Reject
3-Aug-2005	5pm	5.32	5.04	0.28	5.3%	1.21	0.226	Cannot Reject

Table 12 – T-Test for System Peak Demand: CPP-THERM Treatment

4.2.4 Demand on "Hot" Days

To further examine the effects of the time-of-use rate, we examined the demand of the test and control group customers on days where the temperature during the on-peak period exceeded 90°F. CPP event days were separately analyzed and therefore excluded from this analysis. The following dates were included in the analysis:

Non Event Days Over 90°F		
June	July	August
29-Jun-2005	20-Jul-2005	1-Aug-2005
	25-Jul-2005	8-Aug-2005
		11-Aug-2005
		12-Aug-2005
		13-Aug-2005
		18-Aug-2005

Table 19 – Non Event Days Over 90°F

Three Tier TOU with CPP and Thermostat (CPP-THERM)						
Control Group (kW)	RTOU Pilot Group (kW)	Difference Control-RTOU (kW)	Percent Difference (%)	T-Test	Pr>|t|	Ho: Control=RTOU
5.07	4.99	0.08	1.6%	0.42	0.680	Cannot Reject

Table 20 – Non Event Days Over 90°F Analysis Results

Error! Reference source not found. summarizes the analysis. The average "hot period" demands of the control group was 5.07 kW compared to a demand of 4.99 kW for the test group. The 1.6% difference was deemed not to be statistically significant.

4.2.5 CPP Event Day Analysis

During the pilot test a total of eight CPP events were called for a total of 32 hours. The CPP events were invoked on days when the forecasted temperature was expected to exceed 90° F. The CPP event lasted the entire four-hour on-peak period (i.e., hour beginning 3pm to hour ending 7pm. Table presents the dates and times associated with the eight CPP events.

Date	Start Time	End Time	Total Hours
30-Jun-05	3:00 PM	6:59 PM	4
21-Jul-05	3:00 PM	6:59 PM	4
22-Jul-05	3:00 PM	6:59 PM	4
26-Jul-05	3:00 PM	6:59 PM	4
2-Aug-05	3:00 PM	6:59 PM	4
9-Aug-05	3:00 PM	6:59 PM	4
10-Aug-05	3:00 PM	6:59 PM	4
19-Aug-05	3:00 PM	6:59 PM	4
Total Event Hours			32

Table 21 – CPP Event Day Schedule

Figure 13 presents a comparison of the actual hourly load for the RTOU group versus the baseline load calculated from the Control group. The solid black lines drawn parallel to the y-axis highlight the event period. In this figure, the graph highlights the difference between the RTOU group and the control in yellow. Clearly, the RTOU group shows a substantially lower level of load during the entire event period. Figures for each of the event days are contained in Appendix A.

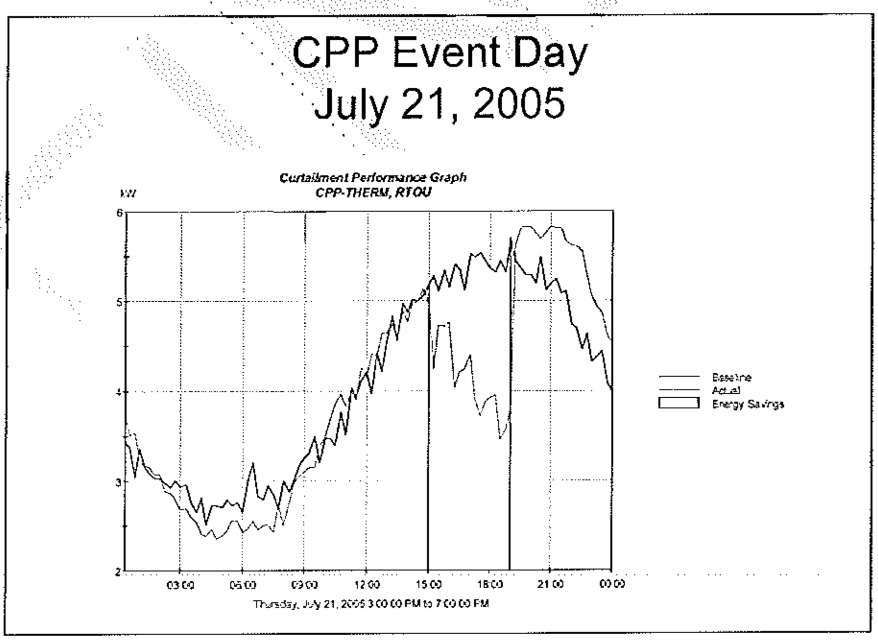


Figure 13 – CPP Event Day July 21, 2005: CPP-THERM Treatment

To determine if there is a statistically significant difference between the RTOU and Control groups we set up and conducted a T-Test. For this analysis, we calculate and compare the average demand across the entire CPP event period. The CPP event day analysis results are presented in Table . The RTOU participants demonstrated a statistically lower demand when compared to their Control group counterparts in all eight events. In addition, the average demand across all event hours was deemed to be significantly lower for the RTOU group.

Three Tier TOU with CPP and Thermostat (CPP-THERM)										
CPP Event			Control Group (kW)	RTOU Group (kW)	Difference Control-RTOU (kW)	Percent Difference (%)			
Date	Hour Ending Start	End					T-Test	Pr>|t|	Ho: Control=RTOU
30-Jun-05	3:00 PM	6:59 PM	5.02	4.30	0.72	14.4%	2.93	0.0036	Reject
21-Jul-05	3:00 PM	6:59 PM	5.37	4.09	1.27	23.7%	5.22	0.0001	Reject
22-Jul-05	3:00 PM	6:59 PM	5.38	4.18	1.20	22.4%	5.39	0.0001	Reject
26-Jul-05	3:00 PM	6:59 PM	5.56	4.38	1.18	21.2%	4.93	0.0001	Reject
2-Aug-05	3:00 PM	6:59 PM	5.23	3.66	1.57	30.0%	6.30	0.0001	Reject
9-Aug-05	3:00 PM	6:59 PM	5.47	4.01	1.46	26.7%	5.76	0.0001	Reject
10-Aug-05	3:00 PM	6:59 PM	4.95	3.82	1.13	22.8%	4.95	0.0001	Reject
19-Aug-05	3:00 PM	6:59 PM	5.38	3.97	1.41	26.1%	5.49	0.0001	Reject
Average			5.29	4.05	1.24	23.5%	6.05	0.0001	Reject

Table 22 – T-Test for CPP Event Day Demands: CPP-THERM Treatment

4.2.6 Time-Of-Use Energy Analysis

Time-of-use (TOU) periods consistent with the TOU rate tariff were constructed and analyzed by the project team. These periods and their definitions are as follows:

- Average summer energy use: This value was defined as the average energy use across the periods June 1, 2005 through August 31, 2005.
- Average on-peak summer energy use: This value was defined as the four hour period beginning at 3pm through hour ending 7pm on summer weekdays. Summer weekdays are defined as Monday through Friday excluding holidays.
- Average on-peak summer energy use during CPP events: This value was defined as the four hour period beginning at 3pm through hour ending 7pm during the six called CPP events.
- Average mid-peak summer energy use: This value was defined as an eight-hour weekday period. The period encompasses the five hours beginning at 10am through hour ending 3pm and the three-hour period beginning at 7pm through hour ending 10pm.
- Average off-peak summer energy use: This value was defined as all weekend hours, all holiday hours (defined as July 4, 2005), and all remaining weekday hours (i.e., the twelve hour period beginning at 10pm through hour ending 10am).

Three Tier TOU with CPP and Thermostat (CPP-THERM)						
Jun 1 - Aug 31 TOU Period	Control Group (kWh)	RTOU Group (kWh)	Difference Control-RTOU (kWh)	T-Test	Pr>|t|	Ho: Control=RTOU
Seasonal Use	7,205	6,963	242	0.98	0.33	Cannot Reject
Off-Peak Use	4,147	4,017	130	0.91	0.37	Cannot Reject
Mid-Peak Use	1,934	1,901	33	0.46	0.65	Cannot Reject
On-Peak Use	884	863	21	0.64	0.52	Cannot Reject
CPP Use	240	182	58	5.99	0.00	Reject
Percent Off-Peak	57.6%	57.7%	-0.1%	0.26	0.79	Cannot Reject
Percent Mid-Peak	26.8%	27.3%	-0.5%	1.36	0.18	Cannot Reject
Percent On-Peak	12.3%	12.4%	-0.1%	0.49	0.63	Cannot Reject
Per CPP	3.3%	2.6%	0.7%	(8.18)	0.00	Reject

Table 23 – T-Test for Average Summer Use by TOU Period: CPP-THERM Treatment

A T-test analysis was conducted for each variable of interest. The results of the analysis are displayed in Table . The test and control groups displayed no statistical differences in load for the seasonal use, off-peak use, mid-peak use, and on-peak use periods. Only the total and percentage of use consumed in the CPP period displays a statistically significant difference. The average energy used in the CPP periods is estimated to be 240 kWh for the control group which is 24% more than the 182 kWh used by the treatment group.

4.2.7 Payback Analysis

Payback is defined as the average demand for the three-hour period immediately following a critical peak-pricing (CPP) event. Table presents the analysis for the payback. The table indicates that the payback for the RTOU group following the CPP event was statistically different than the load following the CPP period for the control group on six of the eight events. On the two days in August, the 7pm to 10pm loads of the two groups were similar.

Three-Tier TOU Rate with CPP and Thermostat (CPP-THERM)									
CPP Event	Payback Period		Control Group (kW)	RTOU Group (kW)	Difference RTOU-Control (kW)	Percent Difference (%)	T-Test	Pr>|t|	Ho: Control=RTOU
Date	Start	End							
30-Jun-05	7pm	10pm	4.28	5.13	0.85	19.9%	(4.21)	0.000	Reject
21-Jul-05	7pm	10pm	5.21	5.75	0.54	10.4%	(2.55)	0.011	Reject
22-Jul-05	7pm	10pm	5.07	5.73	0.66	13.1%	(2.74)	0.007	Reject
26-Jul-05	7pm	10pm	4.71	5.59	0.88	18.6%	(4.56)	0.000	Reject
2-Aug-05	7pm	10pm	4.89	5.48	0.59	12.1%	(2.79)	0.006	Reject
9-Aug-05	7pm	10pm	5.35	5.39	0.04	0.8%	(0.19)	0.847	Cannot Reject
10-Aug-05	7pm	10pm	4.77	4.89	0.12	2.6%	(0.59)	0.556	Cannot Reject
19-Aug-05	7pm	10pm	4.79	5.63	0.84	17.6%	(3.65)	0.000	Reject
Average			4.88	5.45	0.57	11.6%	(3.05)	0.003	Reject

Table 24 – T-Test for Payback Analysis: CPP-THERM Treatment

4.3 Supplemental Analysis

During the planning for the 2005 Pilot Study evaluation, we elected to incorporate existing Pilot study participants into the various treatment and control groups providing a mechanism to examine the pre/post behavior of pilot participants.

4.3.1 Supplemental Groups

Four supplemental test groups were formed including:

Test Group #1 - The customers in test group number one were a continuation of customers from the 2004 RTOU CPP group. The objective of the pre/post evaluation is to see if these customers decreased the amount of load consumed during critical peak pricing periods during the 2005 pilot;

Test Group #2 - The customers in test group number two were a continuation of customers from the 2004 RTOU CPP-Therm group. Here again, the objective of the pre/post evaluation is to see if these customers were successful in decreasing their usage during CPP events in the 2005 pilot;

Test Group #3 - The customers in test group number three were recruited from the 2004 Pilot Study control group. In 2005, these customers were given the RTOU rate with the CPP element. The objective of the analysis is to see if the pre/post experimental design provides any added insight into the performance of the RTOU CPP treatment group;

Test Group #4 - Finally, the customers in test group number four were recruited from the 2004 Pilot study control group. Here again, the objective of the supplemental analysis is to see if the pre/post experimental design provides any additional insight into the performance of the RTOU CPP-Therm treatment group.

The following sample sizes were available in each of the four supplemental analyses.

Group				21-Jul Sample	Population Count	Weight
Test	2004 Pilot	2005 Pilot	Stratum	(n)	(N)	(N/n)
1	Test Group	RTOU with CPP	3	44	113,110	2,570.682
			4	51	150,602	2,952.980
2	Test Group	RTOU with CPP-Therm	3	38	113,110	2,976.579
			4	44	150,602	3,422.773
3	Control	RTOU with CPP	3	34	113,110	3,326.765
			4	42	150,602	3,585.762
4	Control	RTOU with CPP-Therm	3	24	113,110	4,712.917
			4	22	150,602	6,845.545

Table 13 – Supplemental Analysis (Pre/Post)

4.3.2 Challenges

The fundamental challenge associated with assessing the impacts from the pre/post experimental design is properly accommodating for differences in weather related usage

The summer of 2005 was substantially warmer than the summer of 2004. Figure 14 presents the average hourly temperature for the month of July for 2004 versus 2005. Clearly, the 2005 temperatures are substantially higher than those experienced in 2004. Table 14 presents a tabulation of the number of cooling degree hours for June 1 through August 31 periods in 2004 and 2005, the absolute difference and the percentage difference. The summer of 2005 was approximately 33.5% warmer when compared to the same period in 2004.

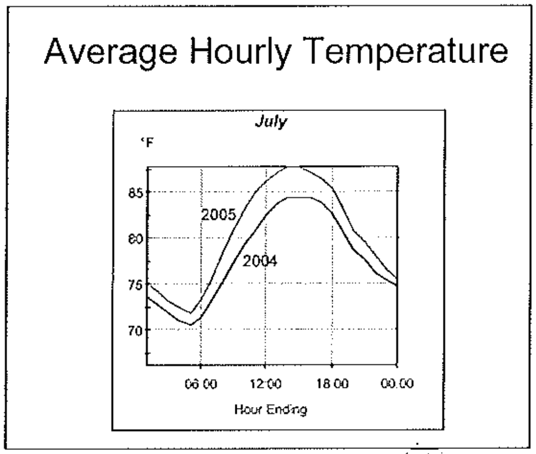


Figure 14 – Average Hourly Temperatures

The challenge is that any modification that we make to the 2004 program year to reflect the higher number of cooling degree hours for 2005 will likely be significantly larger than the impacts we are attempting to measure.

Program Year	Cooling Degree Hours[1]	Difference Absolute	Difference Percent
2004	23,622		
2005	31,540	7,918	33.5%
[1] 65 °F Base			

Table 14 – Cooling Degree Hours

4.3.3 Approach

For this phase of the analysis, the available interval load data for 2004 was used to develop temperature response models for each individual customer. The models focused on summer usage and were developed using data from June 1, 2004 through September 30, 2004. Models[9] were predicted by weekday versus weekend and hour of the day. The actual weather experienced in 2005 was used to "predict" the customer's 2005 load. This predicted "2004" load given 2005 weather conditions was compared to the customer's 2005 actual load in the subsequent statistical analysis.

[9] To optimize the selection of the models, a range of degree-day set points were considered for each customer model. For cooling degree-days the considered set points ranged from 65^0 to 75^0. Mathematically, the models considered can be expressed as follows:

$$BL_{lrid,dow,time} + VL_{lrid,dow,time}$$

$$VL_{lrid,dow,time} = \beta_0 + \beta_1 * CDD(\tau_1)$$

Where

$BL_{lrid,dow,time}$ is the base load of the customer 'LRID', on day of week 'DOW' at hour ending 'Time'

$VL_{lrid,dow,time}$ is the variable load for customer 'LRID', on day of the week 'DOW' at hour ending 'Time'

$CDD(\tau_1)$ are the cooling degree-days with a τ_1 base

4.3.4 Supplemental Findings

The following tables highlight the findings from the analysis following the pre/post experimental design. Table 15 presents the results for the two test groups that were in the program in 2004 and continued in the program in 2005. The top portion of the table is associated with the RTOU CPP group and the bottom half of the table is associated with the RTOU CPP-Therm group. The table presents the results for seasonal energy use[10] defined as June 1, 2005 through August 31, 2005, off-peak energy use, mid-peak energy use, on-peak energy use and usage during the CPP periods. In addition we have provided the percentage of seasonal energy use consumed in each of the time-of-use periods. The table presents the actual usage, the percent difference (i.e., calculated using actual minus predicted), the T-Test statistics, and the probability of getting a large T, and whether or not we could reject the null hypothesis of equal means between the two groups.

Three Tier TOU with CPP (Pre/Post: Test to Test)						
Jun 1 - Aug 31 TOU Period	Predicted Group #1 (kWh)	Actual Group #1 (kWh)	Percent Difference (%)	T-Test	Pr>|t|	Ho: Control=RTOU
Seasonal Use	7,269	7,816	7.5%	1.21	0.229	Cannot Reject
Off-Peak Use	4,289	4,659	8.6%	1.32	0.190	Cannot Reject
Mid-Peak Use	1,922	2,049	6.6%	1.08	0.281	Cannot Reject
On-Peak Use	830	891	7.3%	1.06	0.290	Cannot Reject
CPP Use	229	217	-5.2%	(0.77)	0.443	Cannot Reject
Percent Off-Peak	59.0%	59.6%	1.0%	0.80	0.424	Cannot Reject
Percent Mid-Peak	26.4%	26.2%	-0.9%	(0.45)	0.955	Cannot Reject
Percent On-Peak	11.4%	11.4%	-0.2%	(0.06)	0.653	Cannot Reject
Per CPP	3.2%	2.8%	-11.9%	(2.90)	0.000	Reject
Three Tier TOU with CPP-THERM (Pre/Post: Test to Test)						
Jun 1 - Aug 31 TOU Period	Predicted Group #2 (kWh)	Actual Group #2 (kWh)	Percent Difference (%)	T-Test	Pr>|t|	Ho: Control=RTOU
Seasonal Use	6,492	6,706	3.3%	0.06	0.533	Cannot Reject
Off-Peak Use	3,765	3,797	0.8%	0.16	0.877	Cannot Reject
Mid-Peak Use	1,748	1,873	7.2%	1.28	0.201	Cannot Reject
On-Peak Use	772	855	10.8%	1.82	0.071	Reject
CPP Use	207	180	-12.9%	(1.99)	0.049	Reject
Percent Off-Peak	58.0%	56.6%	-2.4%	(2.14)	0.034	Reject
Percent Mid-Peak	26.9%	27.9%	3.7%	2.06	0.019	Cannot Reject
Percent On-Peak	11.9%	12.7%	7.2%	2.37	0.041	Reject
Per CPP	3.2%	2.7%	-15.7%	(4.23)	0.000	Reject

Table 15 – Comparison of Seasonal Usage: Test to Test Groups

For the RTOU CPP group, the null hypothesis that the means are equal can only be rejected for the percentage of usage consumed in the CPP period. This indicates that there was some additional savings by the test group participants in the second year of program participation. For the RTOU CPP-Therm group, we reject the null hypothesis for the quantity of load consumed in the on-peak and CPP periods. This indicates that during the second year of program participation, the test group increased their on-peak usage but continued to reduce their CPP usage. As a percentage of total load, the CPP-Therm group shows a statistically significant reduction in off-peak use and an increase in on-peak use during the second year of program participation.

[10] The seasonal energy use was calculated using data for the period June 28, 2005 through August 31, 2005 and then normalized the three month seasonal period.

Table 16 presents the same information for the two test groups that started off as control groups but shifted to one of the two treatment groups. Once again, for the RTOU CPP group, we are able to reject the null hypothesis of equality of means for just the CPP usage period. This is further evidence that the only change in load for this group occurs during the CPP period. For the RTOU CPP-Therm group, we see a statistical difference for the amount of energy consumed during the CPP period. In addition, we see a statistically significant increase in the percentage of total energy used during the off-peak period.

Three Tier TOU with CPP (Pre/Post: Control to Test)						
Jun 1 - Aug 31 TOU Period	Predicted Group #3 (kWh)	Actual Group #3 (kWh)	Percent Difference (%)	T-Test	Pr>|t|	Ho: Control=RTOU
Seasonal Use	7,093	7,418	4.6%	0.91	0.366	Cannot Reject
Off-Peak Use	4,081	4,293	5.2%	0.94	0.350	Cannot Reject
Mid-Peak Use	1,889	2,005	6.1%	1.17	0.244	Cannot Reject
On-Peak Use	876	901	2.9%	0.49	0.627	Cannot Reject
CPP Use	247	220	-11.2%	(2.21)	0.029	Reject
Percent Off-Peak	57.5%	57.9%	0.6%	0.40	0.690	Cannot Reject
Percent Mid-Peak	26.6%	27.0%	1.5%	0.84	0.658	Cannot Reject
Percent On-Peak	12.4%	12.1%	-1.7%	(0.44)	0.405	Cannot Reject
Per CPP	3.5%	3.0%	-15.0%	(3.65)	0.000	Reject
Three Tier TOU with CPP-THERM (Pre/Post: Control to Test)						
Jun 1 - Aug 31 TOU Period	Predicted Group #4 (kWh)	Actual Group #4 (kWh)	Percent Difference (%)	T-Test	Pr>|t|	Ho: Control=RTOU
Seasonal Use	7,234	7,264	0.4%	0.06	0.949	Cannot Reject
Off-Peak Use	4,107	4,279	4.2%	0.65	0.515	Cannot Reject
Mid-Peak Use	1,988	1,934	-2.7%	(0.39)	0.699	Cannot Reject
On-Peak Use	891	868	-2.6%	(0.34)	0.738	Cannot Reject
CPP Use	249	184	-26.3%	(3.46)	0.001	Reject
Percent Off-Peak	56.8%	58.9%	3.8%	2.25	0.027	Reject
Percent Mid-Peak	27.5%	26.6%	-3.1%	(1.43)	0.363	Cannot Reject
Percent On-Peak	12.3%	11.9%	-3.0%	(0.91)	0.155	Cannot Reject
Per CPP	3.4%	2.5%	-26.6%	(6.68)	0.000	Reject

Table 16 – Comparison of Seasonal Usage: Control to Test Groups

Table 17 presents the comparisons between the predicted and actual load for the same four test groups. This table presents the predicted and actual average load during the eight CPP events, the absolute load reduction, the percentage reduction, the T-Test statistics, the probability of getting a large T, and the results of the null hypothesis that the two means are equal. It is important to note that the actual load for every group display a lower load than the predicted. For the RTOU CPP group #1, the only statistical difference is calculated for the August 10th event. For the RTOU CPP-Therm test group #2, statistically significant reductions were noted for four of the eight events and in aggregate. For the RTOU CPP test group #3, all but two of the events show a significant load reduction during the CPP event hours. Finally, for the RTOU CPP-Therm test group #4, all but the first event were statistically significant.

Three Tier TOU with CPP (Pre/Post: Test to Test)									
CPP Event			Predicted	Actual	Difference	Percent			
	Hour Ending		Group #1	Group #1	Actual-Predicted	Difference			
Date	Start	End	(kW)	(kW)	(kW)	(%)	T-Test	Pr>|t|	Ho: Control=RTOU
30-Jun-05	3:00 PM	6:59 PM	4.83	4.75	-0.08	-1.7%	(0.23)	0.821	Cannot Reject
21-Jul-05	3:00 PM	6:59 PM	5.57	5.00	-0.57	-10.2%	(1.52)	0.130	Cannot Reject
22-Jul-05	3:00 PM	6:59 PM	4.92	5.01	0.08	1.7%	0.24	0.811	Cannot Reject
26-Jul-05	3:00 PM	6:59 PM	5.14	4.70	-0.44	-8.6%	(0.61)	0.540	Cannot Reject
2-Aug-05	3:00 PM	6:59 PM	4.98	4.59	-0.39	-7.7%	(1.07)	0.285	Cannot Reject
9-Aug-05	3:00 PM	6:59 PM	4.95	4.88	-0.07	-1.3%	(0.18)	0.857	Cannot Reject
10-Aug-05	3:00 PM	6:59 PM	4.90	4.13	-0.77	-15.8%	(2.23)	0.027	Reject
19-Aug-05	3:00 PM	6:59 PM	5.24	4.92	-0.32	-6.1%	(0.86)	0.391	Cannot Reject
Average			5.07	4.90	-0.17	-3.3%	(0.48)	0.456	Cannot Reject

Three Tier TOU with CPP and Thermostat (Pre/Post: Test to Test)									
CPP Event			Predicted	Actual	Difference	Percent			
	Hour Ending		Group #2	Group #2	Actual-Predicted	Difference			
Date	Start	End	(kW)	(kW)	(kW)	(%)	T-Test	Pr>|t|	Ho: Control=RTOU
30-Jun-05	3:00 PM	6:59 PM	4.41	4.05	-0.36	-8.2%	(1.37)	0.172	Cannot Reject
21-Jul-05	3:00 PM	6:59 PM	4.96	4.10	-0.86	-17.3%	(2.58)	0.011	Reject
22-Jul-05	3:00 PM	6:59 PM	4.46	4.24	-0.22	-4.9%	(0.77)	0.443	Cannot Reject
26-Jul-05	3:00 PM	6:59 PM	4.69	4.46	-0.22	-4.7%	(0.67)	0.502	Cannot Reject
2-Aug-05	3:00 PM	6:59 PM	4.49	3.77	-0.72	-16.1%	(2.37)	0.019	Reject
9-Aug-05	3:00 PM	6:59 PM	4.46	4.33	-0.13	-3.0%	(0.39)	0.695	Cannot Reject
10-Aug-05	3:00 PM	6:59 PM	4.47	3.77	-0.70	-15.7%	(2.50)	0.014	Reject
19-Aug-05	3:00 PM	6:59 PM	4.69	3.99	-0.69	-14.8%	(2.26)	0.026	Reject
Average			4.58	4.05	-0.53	-11.6%	(1.93)	0.056	Reject

Three Tier TOU with CPP (Pre/Post: Control to Test)									
CPP Event			Predicted	Actual	Difference	Percent			
	Hour Ending		Group #3	Group #3	Actual-Predicted	Difference			
Date	Start	End	(kW)	(kW)	(kW)	(%)	T-Test	Pr>|t|	Ho: Control=RTOU
30-Jun-05	3:00 PM	6:59 PM	5.23	4.93	-0.30	-5.8%	(1.25)	0.213	Cannot Reject
21-Jul-05	3:00 PM	6:59 PM	6.04	5.67	-0.37	-6.2%	(3.70)	0.000	Reject
22-Jul-05	3:00 PM	6:59 PM	5.30	5.07	-0.23	-4.3%	(0.71)	0.477	Cannot Reject
26-Jul-05	3:00 PM	6:59 PM	5.58	4.89	-0.70	-12.5%	(2.46)	0.015	Reject
2-Aug-05	3:00 PM	6:59 PM	5.37	4.79	-0.58	-10.8%	(2.18)	0.031	Reject
9-Aug-05	3:00 PM	6:59 PM	5.31	4.64	-0.67	-12.6%	(2.59)	0.010	Reject
10-Aug-05	3:00 PM	6:59 PM	5.28	4.36	-0.92	-17.4%	(3.70)	0.000	Reject
19-Aug-05	3:00 PM	6:59 PM	5.65	4.89	-0.76	-13.5%	(2.57)	0.011	Reject
Average			5.47	4.81	-0.66	-12.1%	(2.68)	0.008	Reject

Three Tier TOU with CPP and Thermostat (Pre/Post: Control to Test)									
CPP Event			Predicted	Actual	Difference	Percent			
	Hour Ending		Group #4	Group #4	Actual-Predicted	Difference			
Date	Start	End	(kW)	(kW)	(kW)	(%)	T-Test	Pr>|t|	Ho: Control=RTOU
30-Jun-05	3:00 PM	6:59 PM	5.23	4.60	-0.63	-12.1%	(1.28)	0.205	Cannot Reject
21-Jul-05	3:00 PM	6:59 PM	6.09	4.11	-1.98	-32.5%	(4.38)	0.000	Reject
22-Jul-05	3:00 PM	6:59 PM	5.34	4.11	-1.23	-23.0%	(2.81)	0.006	Reject
26-Jul-05	3:00 PM	6:59 PM	5.53	4.27	-1.26	-22.7%	(2.77)	0.007	Reject
2-Aug-05	3:00 PM	6:59 PM	5.43	3.53	-1.90	-35.0%	(4.33)	0.000	Reject
9-Aug-05	3:00 PM	6:59 PM	5.38	3.64	-1.74	-32.4%	(3.83)	0.000	Reject
10-Aug-05	3:00 PM	6:59 PM	5.29	3.88	-1.41	-26.7%	(3.17)	0.002	Reject
19-Aug-05	3:00 PM	6:59 PM	5.71	3.96	-1.75	-30.7%	(3.76)	0.000	Reject
Average			5.50	4.06	-1.44	-26.2%	(3.45)	0.001	Reject

Table 17 – Comparison during CPP Events

4.4 General Conclusions

The study results indicate the following:

- The critical peak pricing component of the time-of-use rate does motivate customers to reduce demand during most of the CPP events.

- The enabling technology was a key component of the offering with the groups receiving the "smart" thermostat displaying much stronger load response (more than double) during CPP events when compared to the CPP only group.
- The conclusion regarding the load shifted between periods was mixed. Both the TOU: CPP and the TOU: CPP-Therm groups displayed a significant shift in load during the CPP periods. However, only the TOU: CPP group displayed a statistically significant shift in energy use between the on-peak and off-peak periods.
- The researchers believe that there was insufficient evidence to conclude that the second year CPP: TOU participants substantially improved their load reductions in the second year when compared to their first year of participation. However, the percentage of total use during the CPP period was statistically lower in 2005 when compared to 2004.
- The CPP: TOU-Therm participants displayed an average demand reduction during CPP events that was 0.53 kW greater in 2005 when compared to 2004 2004 on a weather adjusted basis. There was a slight reduction in the percentage of on-peak use in 2005 when compared to 2004 this difference but this change was not statistically significant.
- Second year control group participants that were moved to the test group in 2005 confirmed that CPP rate is effective in reducing demand. Both the new CPP: TOU and the CPP:TOU-Therm customers reduced a statistically significant amount of load during the CPP periods when they received the CPP rates. Both groups also had lower CPP period usage after receiving the CPP rates.

5 APPENDIX A – CPP EVENT DAY GRAPHS

5.1 CPP Treatment Group

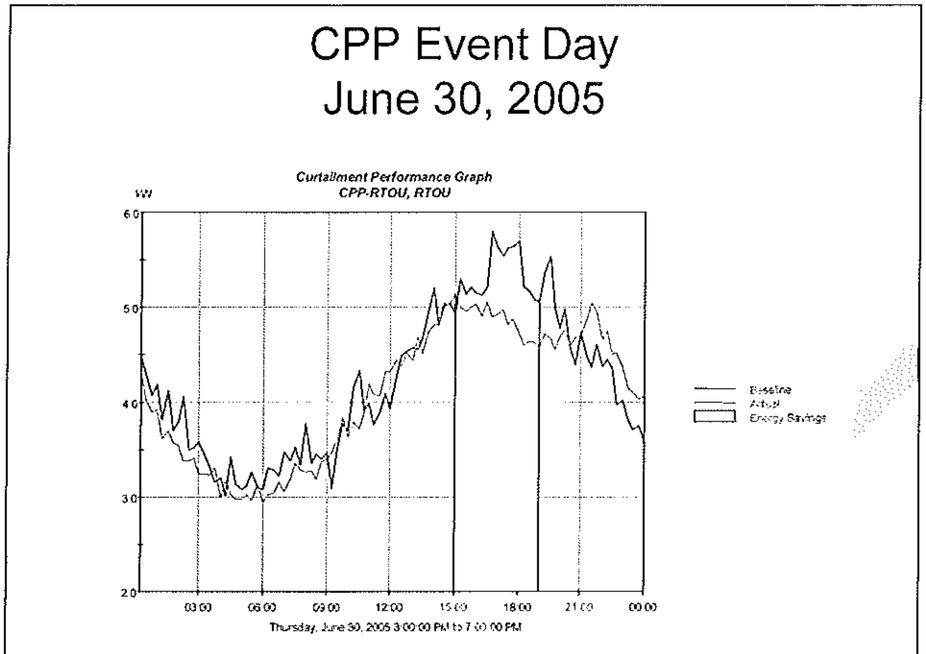


Figure 15 – June 30, 2005: CPP Group

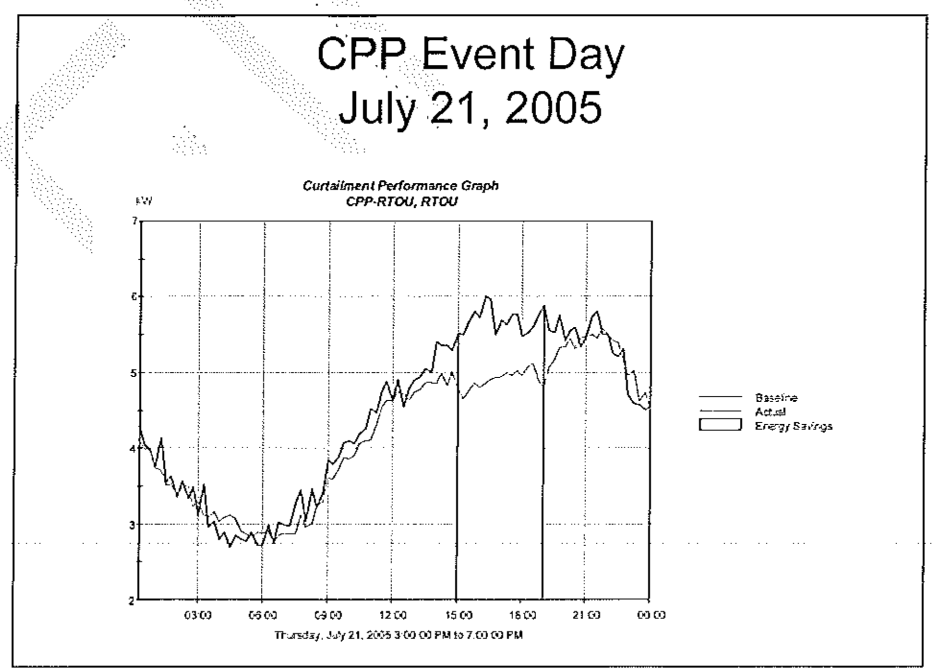


Figure 16 – July 21, 2005: CPP Group

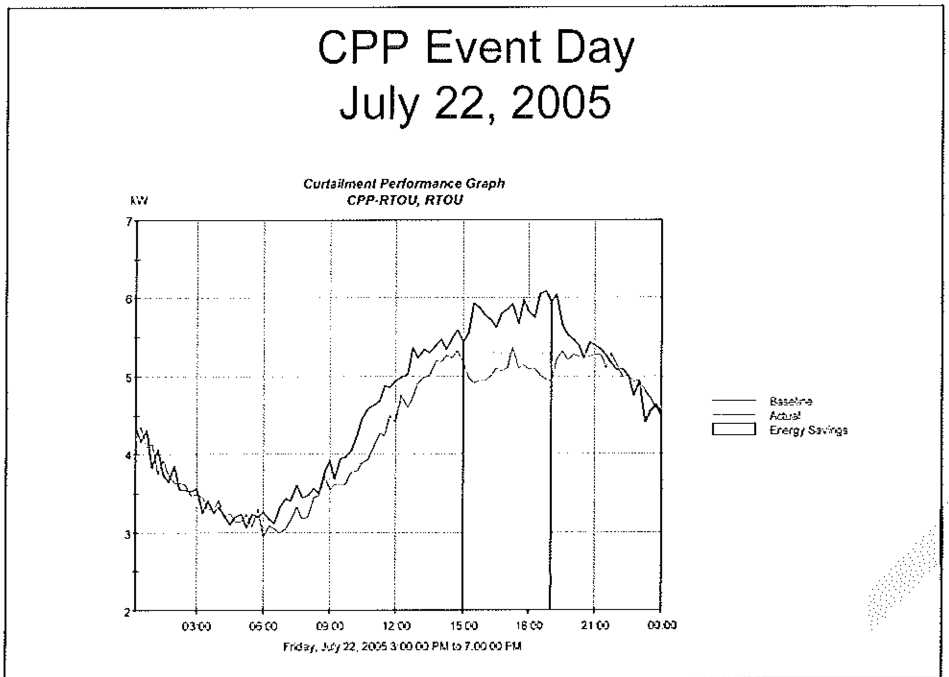


Figure 17 – July 22, 2005: CPP Group

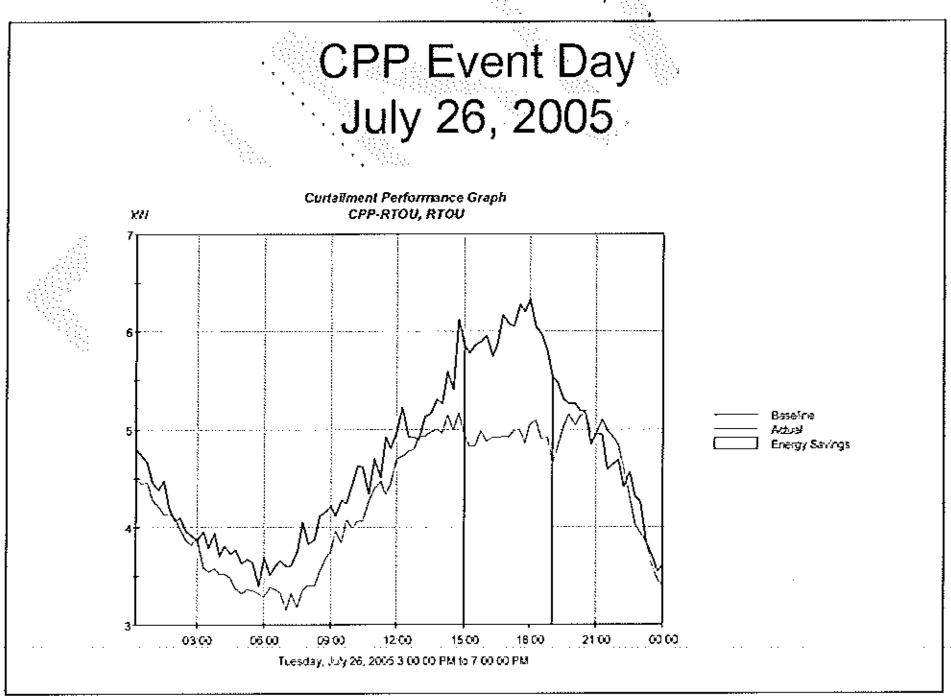


Figure 18 – July 26, 2005: CPP Group

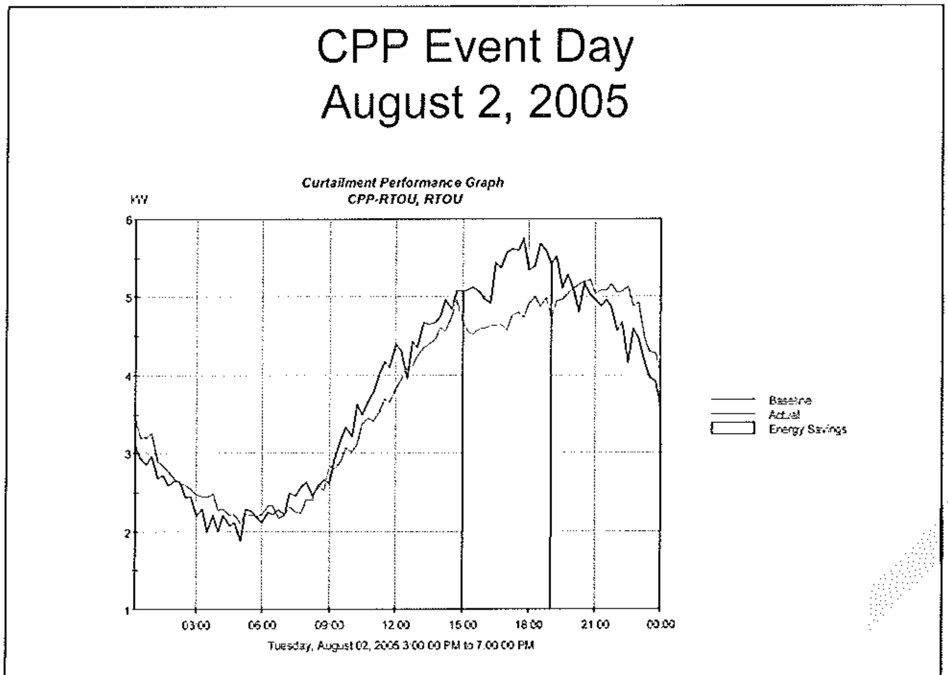


Figure 19 – August 2, 2005: CPP Group

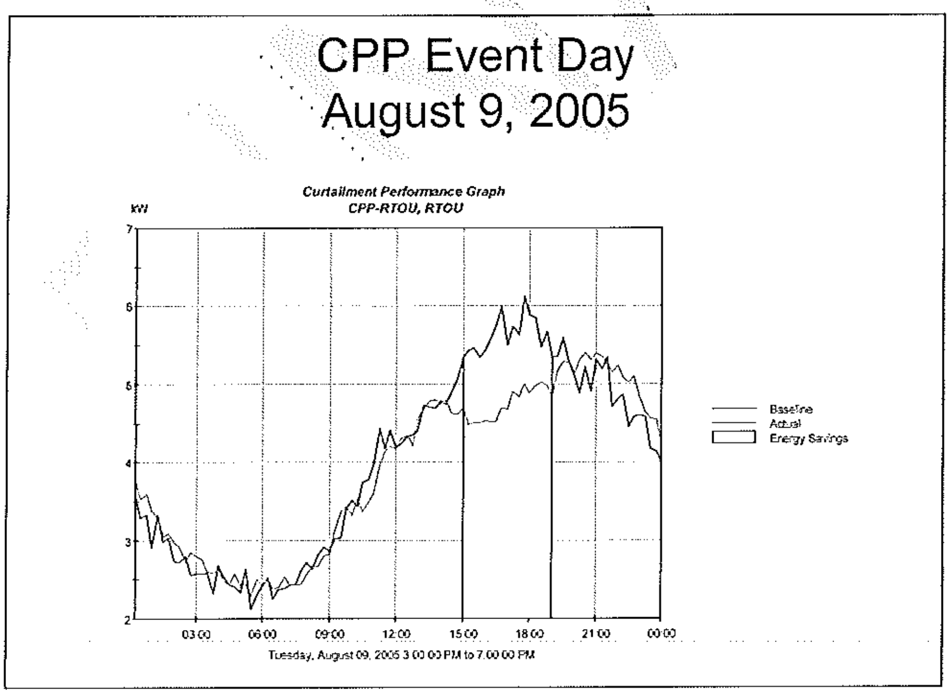


Figure 20 – August 9, 2005: CPP Group

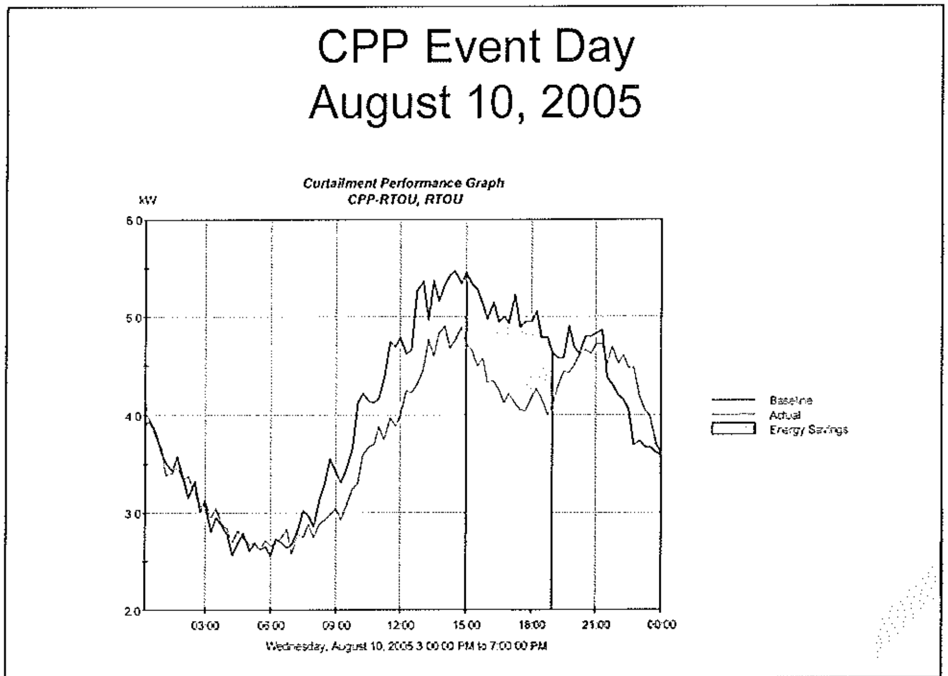


Figure 21 – August 10, 2005: CPP Group

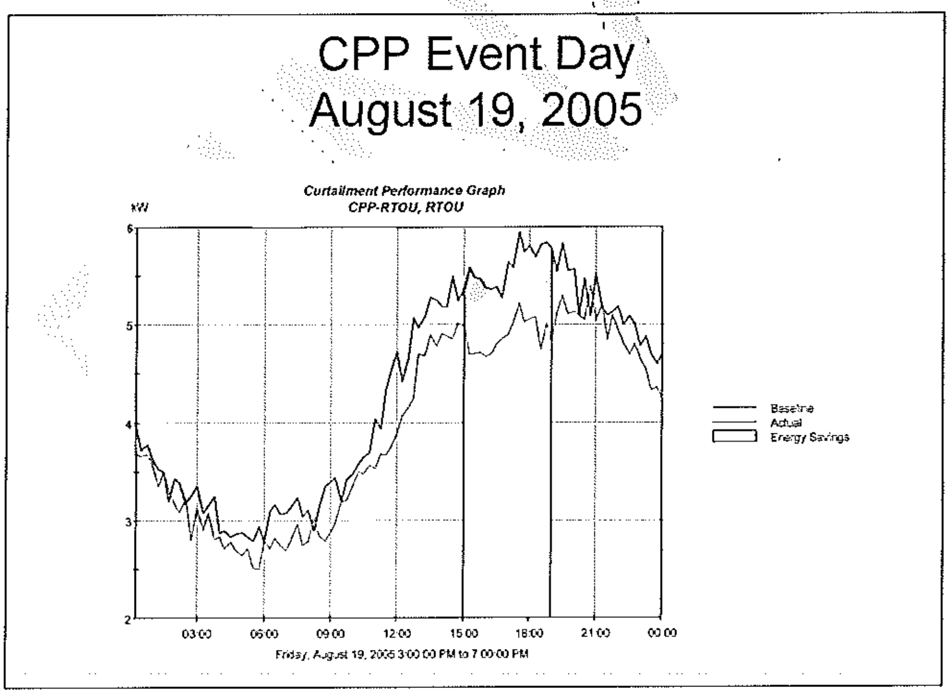


Figure 22 – August 19, 2005: CPP Group

5.2 CPP-THERM Treatment Group

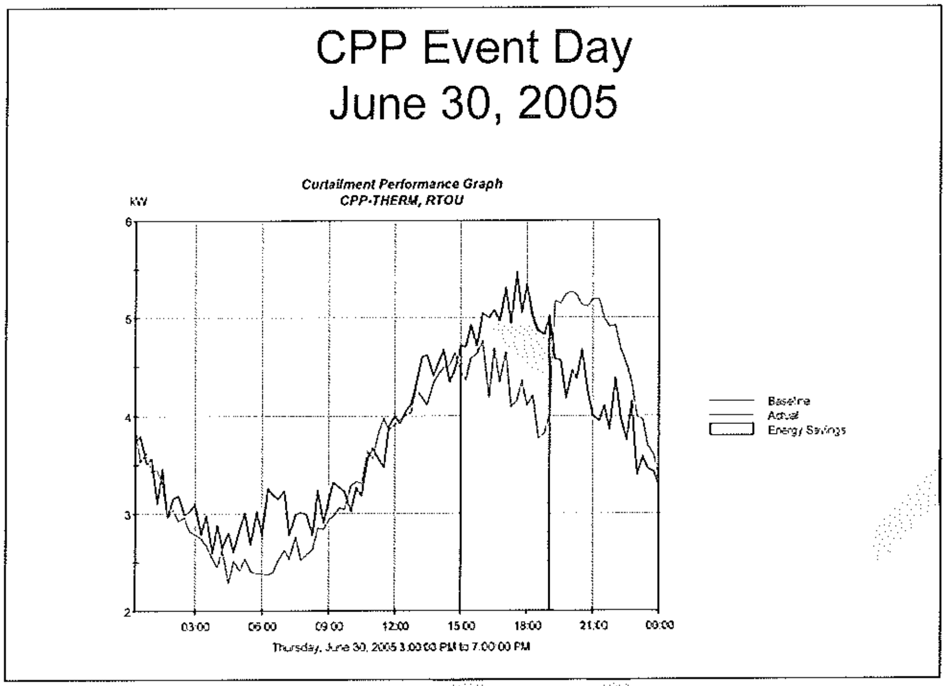


Figure 23 – June 30, 2005: CPP-THERM Group

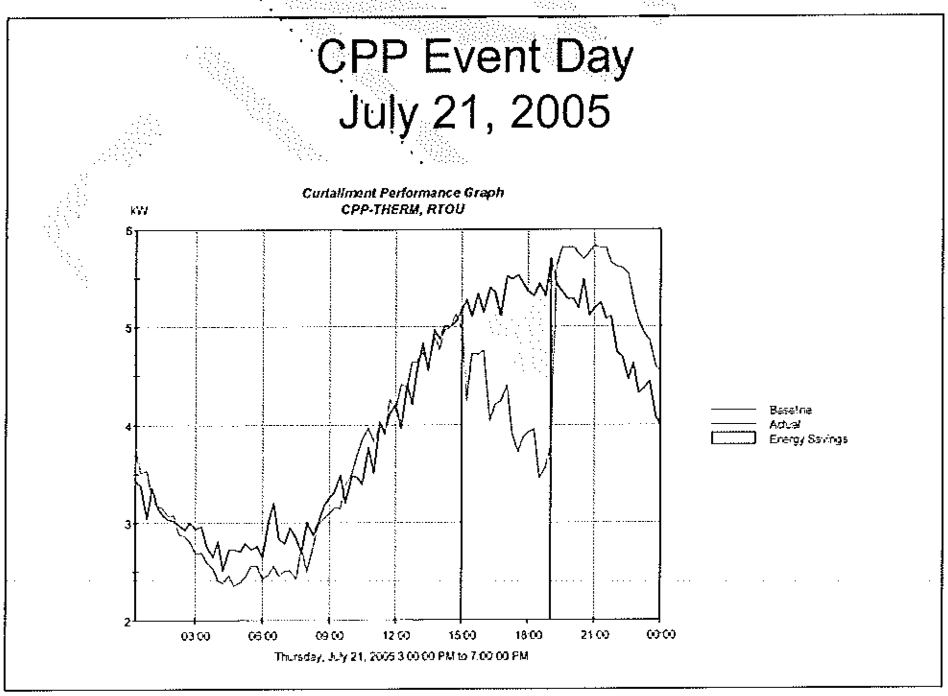


Figure 24 – July 21, 2005: CPP-THERM Group

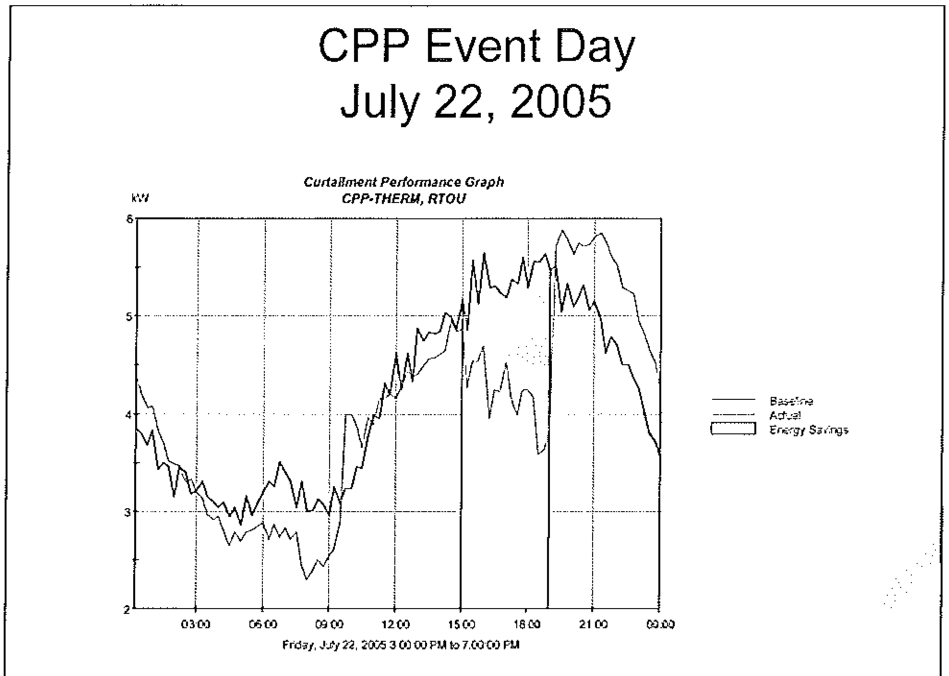


Figure 25 – July 22, 2005: CPP-THERM Group

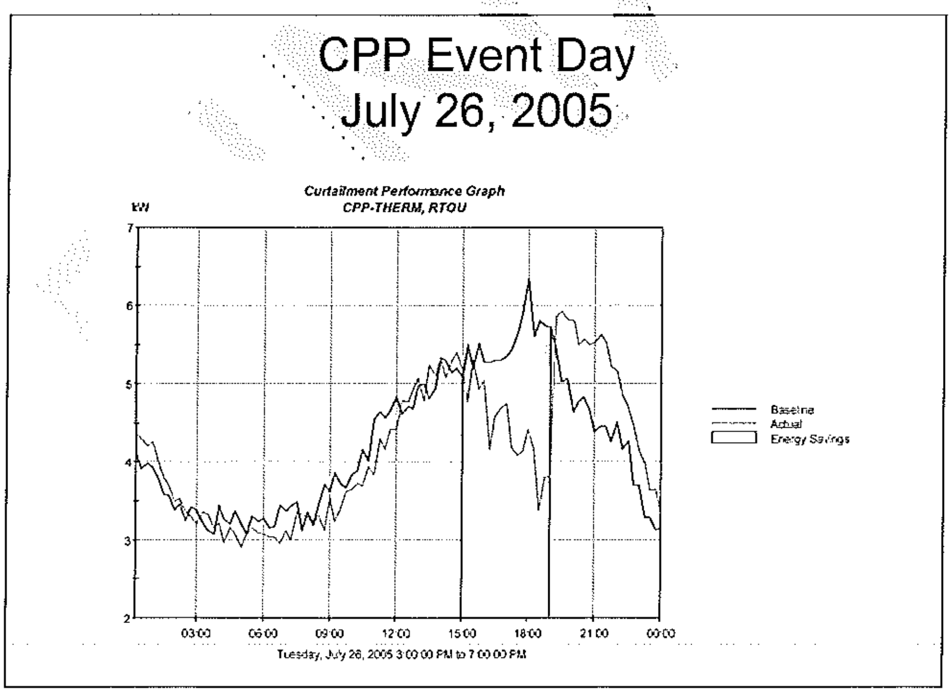


Figure 26 – July 26, 2005: CPP-THERM Group

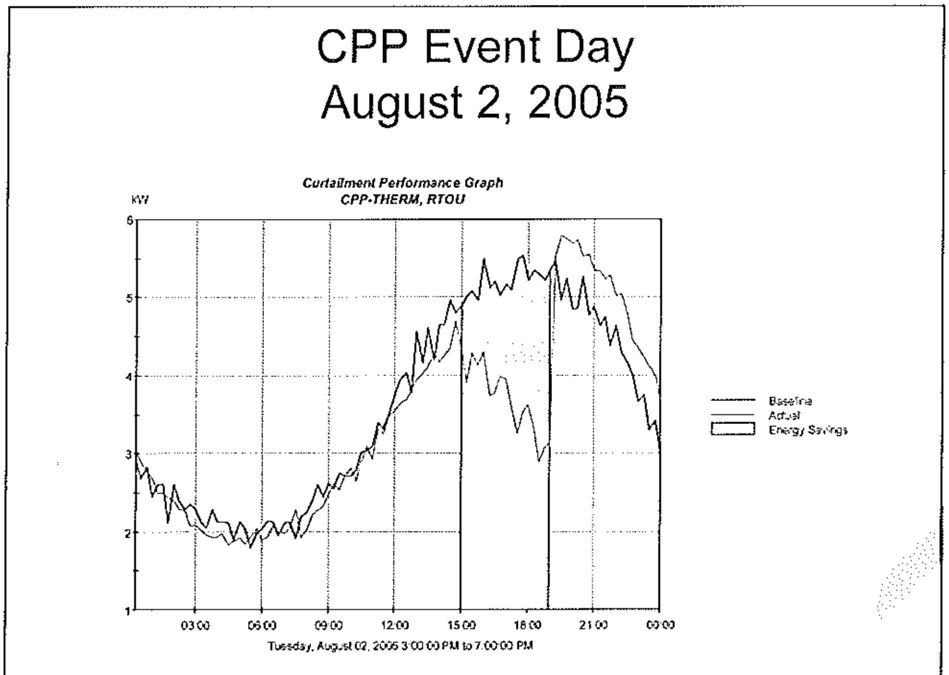


Figure 27 – August 2, 2005: CPP-THERM Group

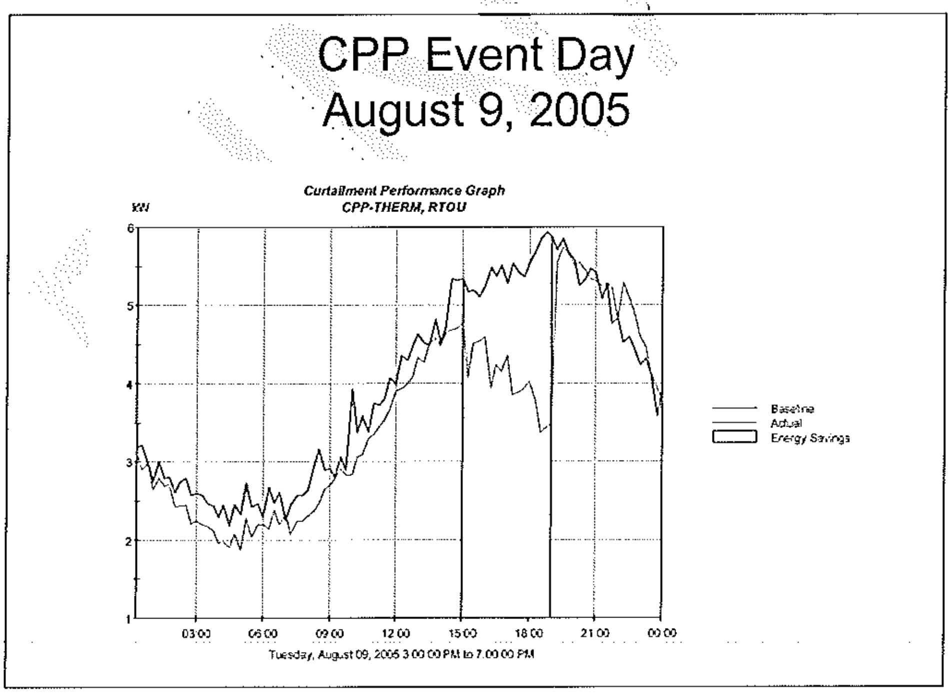


Figure 28 – August 9, 2005: CPP-THERM Group

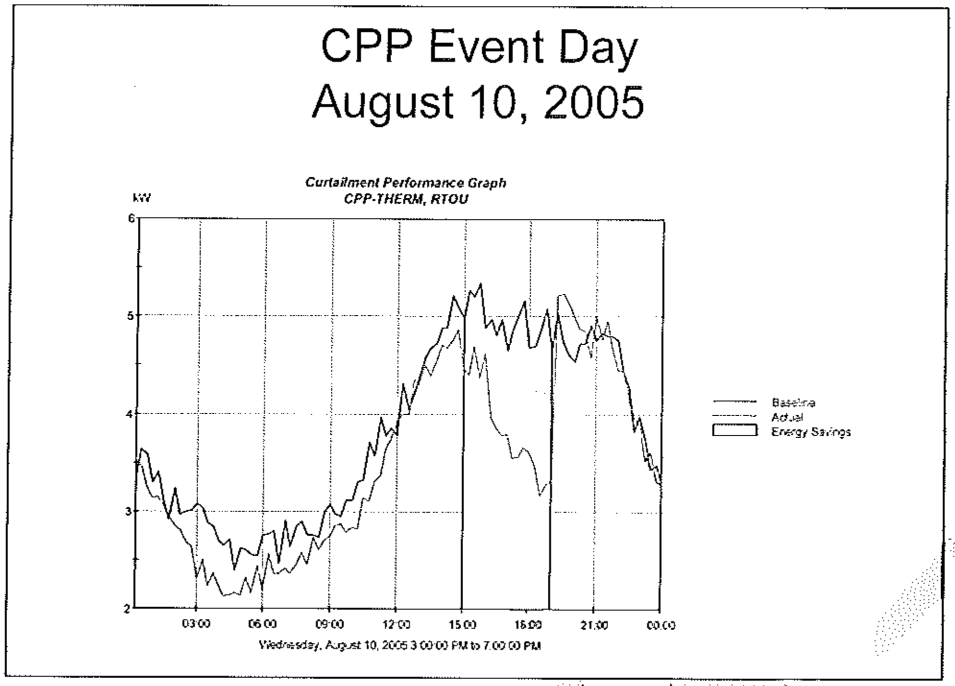


Figure 29 – August 10, 2005: CPP-THERM Group

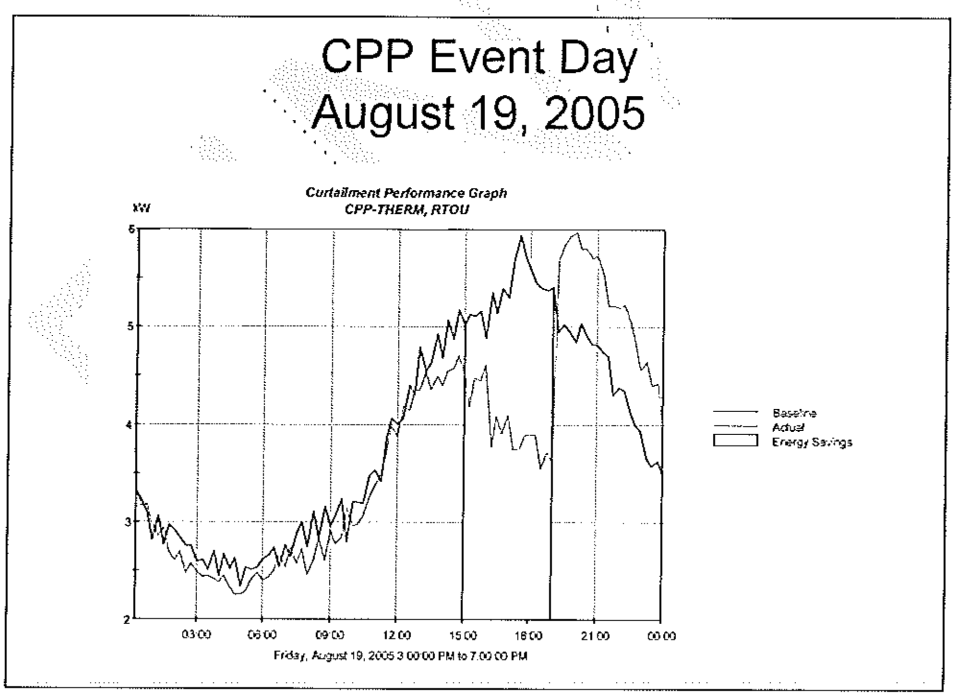


Figure 30 – August 19, 2005: CPP-THERM Group

Ameren Missouri's
Response to Sierra Club Data Request
ER-2019-0335
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.

Data Request No.: SC 0007.11

Refer to the rebuttal testimony of Ahmad Faruqui, page 7, lines 19-20. Please provide a list of the 60 demand charges to residential customers that Dr. Faruqui references, with the following information:

a. For each demand charge in the list, please indicate whether or not the demand charge rate was implemented as a pilot only.

b. For each demand charge in the list, please indicate whether the rate is still offered as a rate that new customers can enroll in, or whether it has been closed.

c. For each demand charge in the list, please indicate the customer enrollment levels in the rate (i.e., number of residential customers enrolled, or a relative characterization of enrollment levels).

d. For each demand charge in the list, please indicate the magnitude of the demand charge ($/kW) where possible.

e. For each demand charge in the list, please indicate whether the utility is an investorowned utility, cooperative, municipal utility, or other.

f. For each investor-owned utility demand charge in the list, please indicate the docket in which the demand charge was approved.

RESPONSE

Prepared By: Ahmad Faruqui, Ph.D.	
Title: Principal with the Brattle Group	
Date: January 31, 2020	

Subject to the Company's objection, see Table of Residential Demand Charges, Attachment 1 - SC 7.11.

a. As far as I know, demand rates for the following utilities were implemented as pilots only: Alliant Energy (IPL), Kentucky Utilities Company, Louisville Gas and Electric, Loveland Electric, Santee Cooper Electric Cooperative, Westar Energy, and Xcel Energy.

b. We are aware that the demand rate for Alliant Energy (IPL and WPL) is limited to 100 new customers per month, that the demand rates for Kentucky Utilities Company and Louisville Gas and Electric are limited to 500 customers, that Westar Energy "Restricted Peak Management Electric Service" is closed to new customers, that the demand rates for Xcel Energy were capped at 10,000 customers in 2017, at 14,000 in 2018 and at 18,000 in 2019, and that the demand rate for Loveland Electric has been closed to new customers after December 31, 2014.

c. This information is not available to us.

d. See the Table of Residential Demand Charges.

e. See the Table of Residential Demand Charges.

f. See the Table of Residential Demand Charges.

Ameren Missouri's
Response to Sierra Club Data Request
ER-2019-0335
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.

Data Request No.: SC 0007.23

Refer to the rebuttal testimony of Andrew Meyers, page 28, lines 12-22. Is it Ameren's expectation that each of its Sioux units will experience tube leaks each time it is cycled offline? If so, explain the basis for that assumption. If not, identify for each Sioux unit the percentage of the time that the unit cycles offline that the Company expects that the unit will experience tube leaks.

RESPONSE

Prepared By: Andrew Meyer
Title: Senior Director Energy Management & Trading
Date: 01.31.2020

The Company operates under the assumption that each time a Sioux unit comes offline and the boiler returns to normal ambient temperatures, tube leaks will be identified that must be repaired before the unit can enter startup. This assumption is based on conversations with energy center personnel and extensive operational experiences in which the Sioux units identified had tube leaks after coming offline.

Ameren Missouri's
Response to Sierra Club Data Request
ER-2019-0335
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.

Data Request No.: SC 0007.28

Refer to the rebuttal testimony of Andrew Meyers, page 31, lines 6-9. Is it Ameren's contention that the MISO IMM reviews or has reviewed Ameren's self-commitment practices? If so, explain the basis for that contention, and provide any supporting documents.

RESPONSE

Prepared By: Andrew Meyer
Title: Senior Director Energy Management & Trading
Date: 01.31.2020

Ameren Missouri's contention, based on the above referenced lines of the Andrew Meyer rebuttal testimony, was that the MISO-IMM has indicated to Staff that market forces will likely discipline the market. Staff proceeded to state in its findings in the Commission's unit commitment docket, File NO. EW-2019-0370, "the MISO-IMM looks for abuses of power and whether behavior is justified".

Ameren Missouri is not aware of the MISO-IMM reviewing the Company's unit commitment practices to the level of detail performed by Staff or Sierra Club in either this docket, ER-2019-0335, or in docket EW-2019-0370.

Ameren Missouri's
Response to Sierra Club Data Request
ER-2019-0335
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.

Data Request No.: SC 0007.31

Refer to Schedule JLW-R1. For each expenditure listed in this exhibit, identify the latest unit retirement date under which the expenditure would not be needed.

RESPONSE

Prepared By: James Williams
Title: Sr. Director, Operations Excellence Support
Date: January 28, 2020

Subject to the Company's objection,

Schedule JLW-R1 included a listing of steam plant projects in excess of $500,000 that went in-service in 2018 and 2019. This post implementation project review was prepared by Mr. Williams to confirm that all projects were required should plants be shut down shortly after 2024.

Data on individual project basis, evaluating a hypothetical ***latest unit retirement date under which the expenditure would not be needed***, does not exist.

2019 OMS MISO Survey Results

Furthering our joint commitment to regional resource assessment and transparency in the MISO region, OMS and MISO are pleased to announce the results of the 2019 OMS MISO Survey

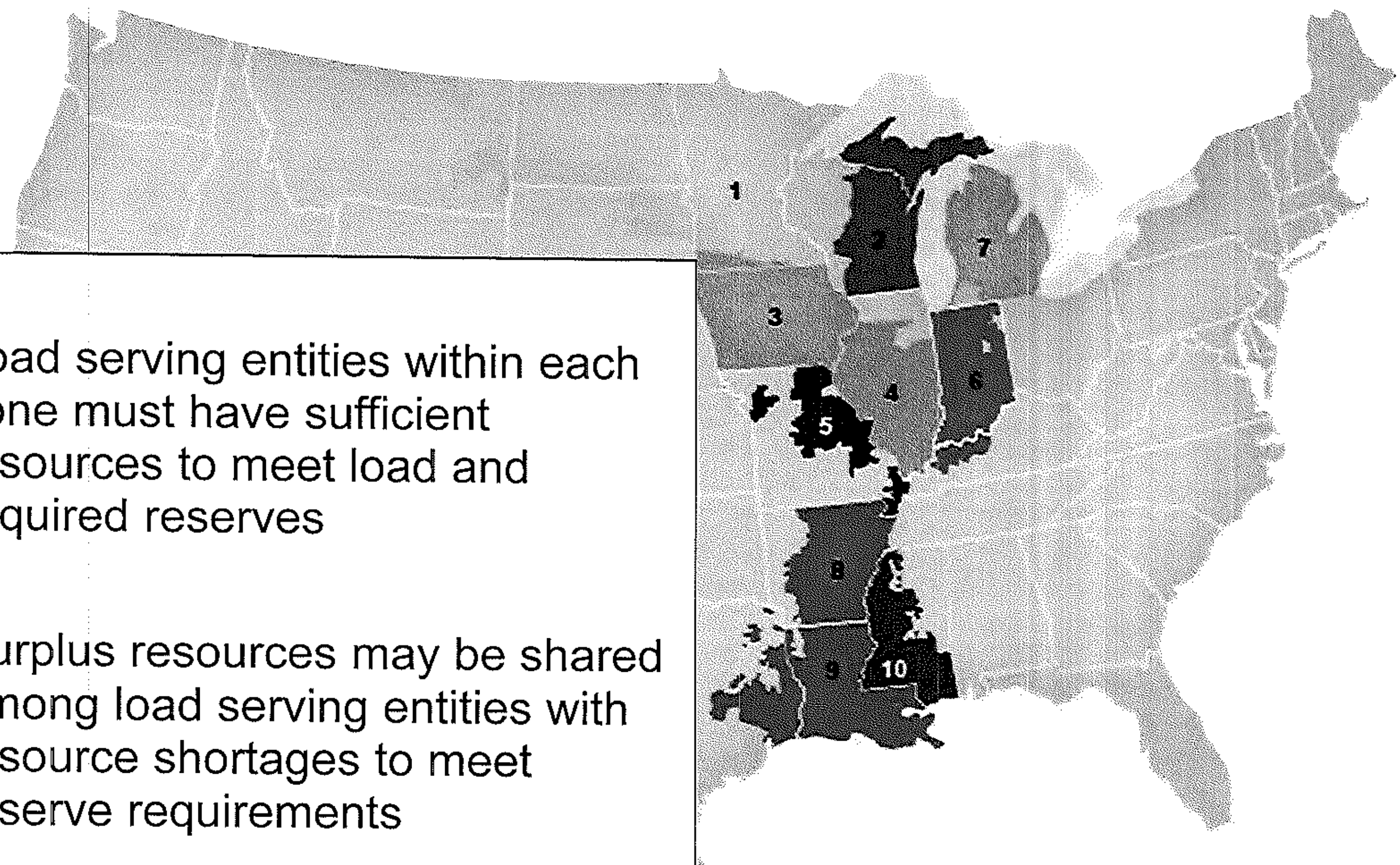
June 2019

Updated Aug 2019: added "1 Day in 10 PRM" labels to several chart axis

MISO Region is projected to have adequate resources to meet its Planning Reserve Requirement for 2020; continued action will be needed to ensure sufficient resources are available going forward

- The region is projected to have 3.0 GW to 5.8 GW resources in excess of the regional requirement, based on responses from over 97% of MISO load and additional non-LSE market participants
- Resources have been firmed up since 2018 survey, improving the regional snapshot, however certain zones continue to show potential risk
  - Lower resource commitments are mainly focused in Zones 4, 6 and 7
  - Some committed capacity depends on the construction of transmission projects
- Demand growth rate forecast continues to decrease similar to previous projections
  - Regional 5 year growth rate is 0.2%, down from 0.3% last year

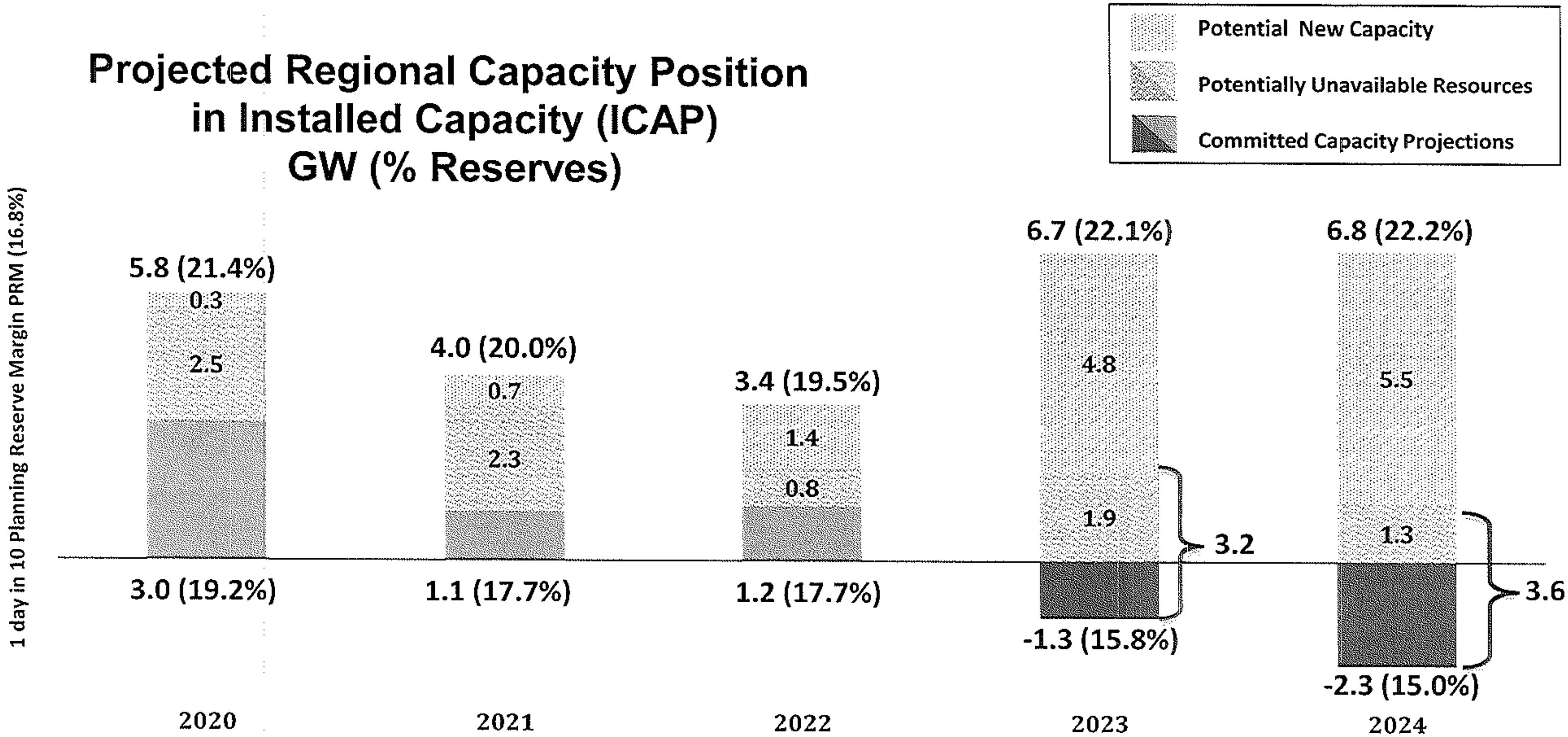
Understanding Resource Adequacy Requirements



- Load serving entities within each zone must have sufficient resources to meet load and required reserves
- Surplus resources may be shared among load serving entities with resource shortages to meet reserve requirements

OMS MISO

Existing resources, potential retirements, and new resources create a range of resource balances

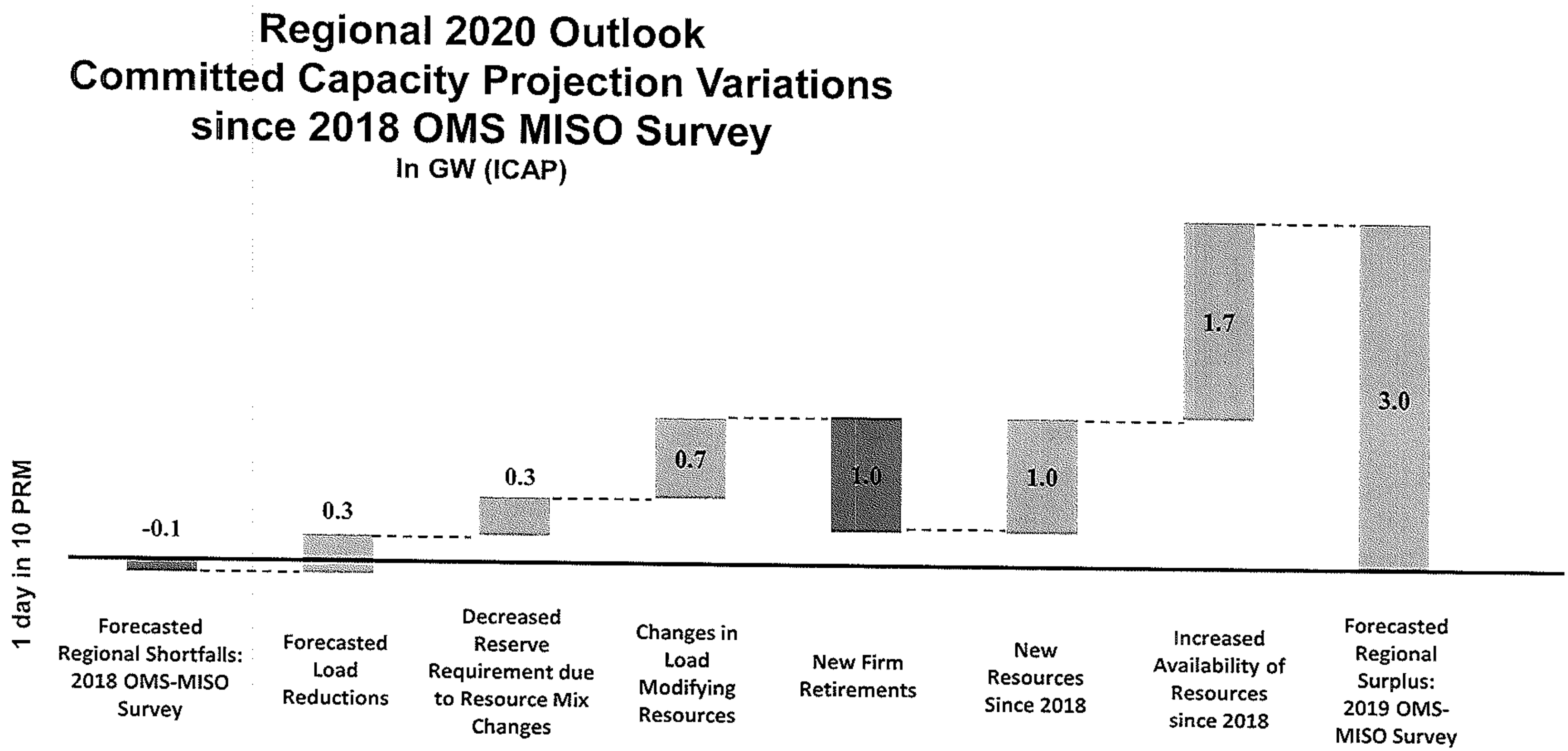


- Regional outlook includes projected constraints on capacity, including the Sub-regional Power Balance Constraint
- These figures will change as future capacity plans are solidified by load serving entities, state commissions, and local regulators
- <u>Potential New Capacity</u> represents the capacity in the MISO Generator Interconnection Queue at their projected queue certainty factors (see slide 14), as of May 28, 2019
- <u>Potentially Unavailable Resources</u> includes potential retirements and capacity which may be constrained by future firm sales across the Sub-regional Power Balance Constraint

OMS MISO

Ex. AA-S-1

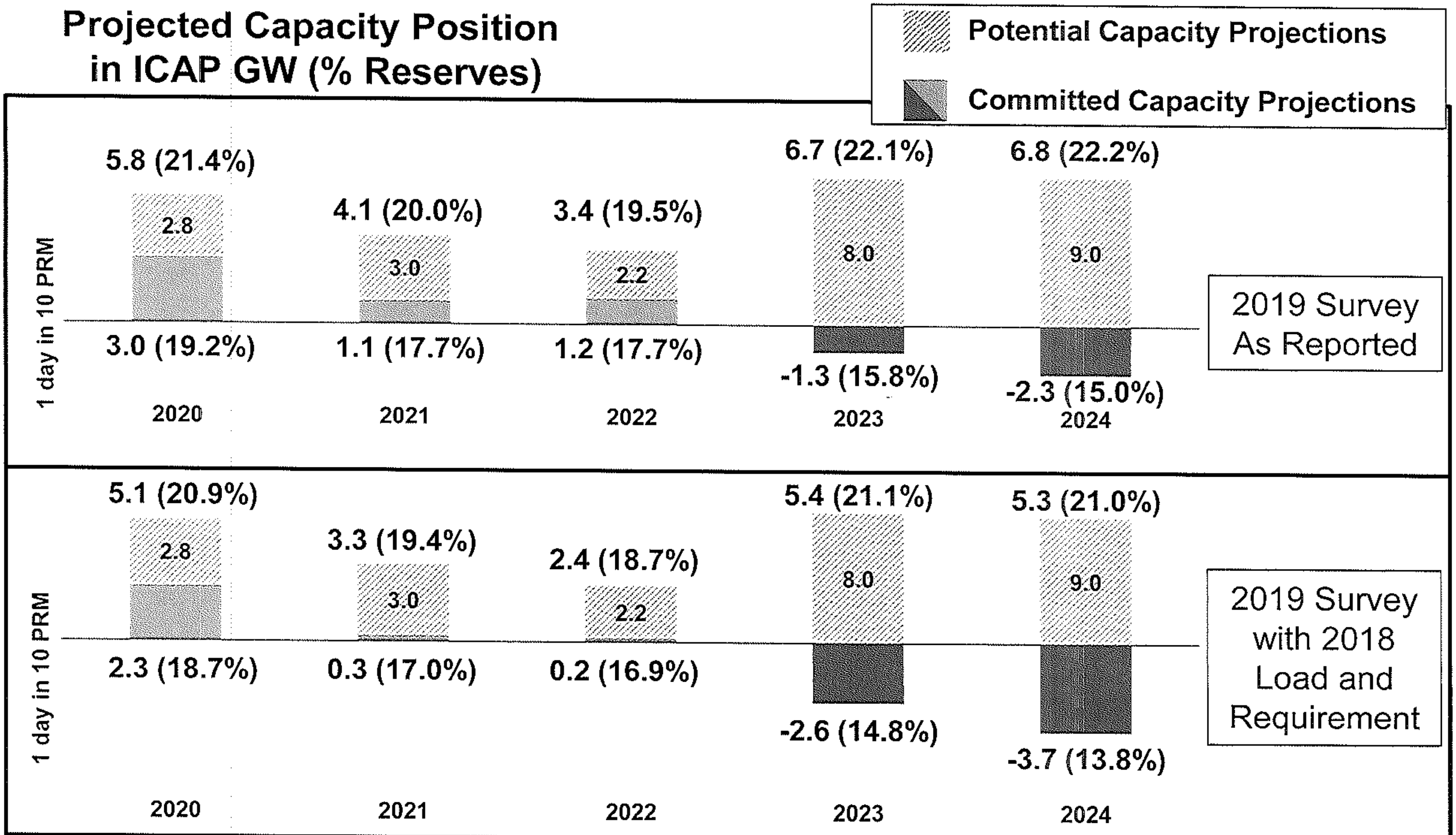
Regional capacity balance increased largely due to confirmed availability of existing and new resources



<u>New resources</u> include resources with newly signed Interconnection Agreements

<u>Increased availability</u> results from potential resources from 2018 survey that are now committed resources

Demand forecast variation creates risk for forward-looking resource adequacy projections

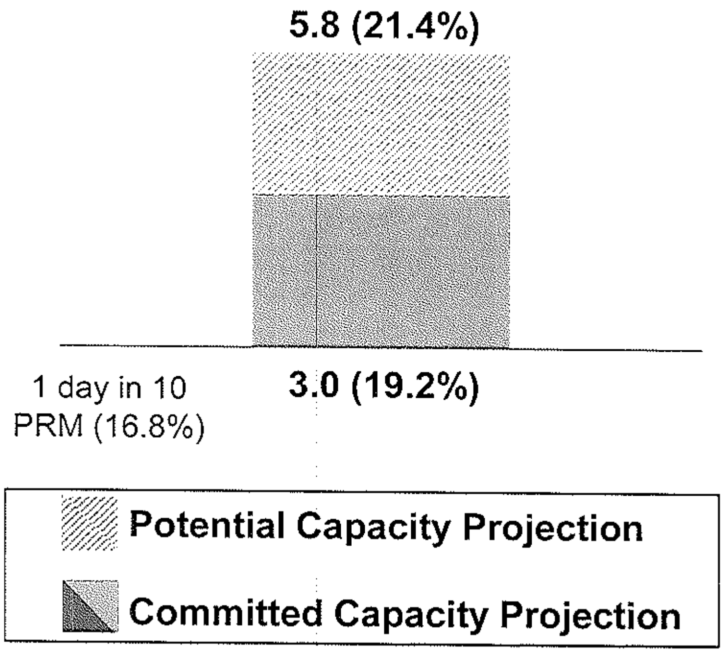


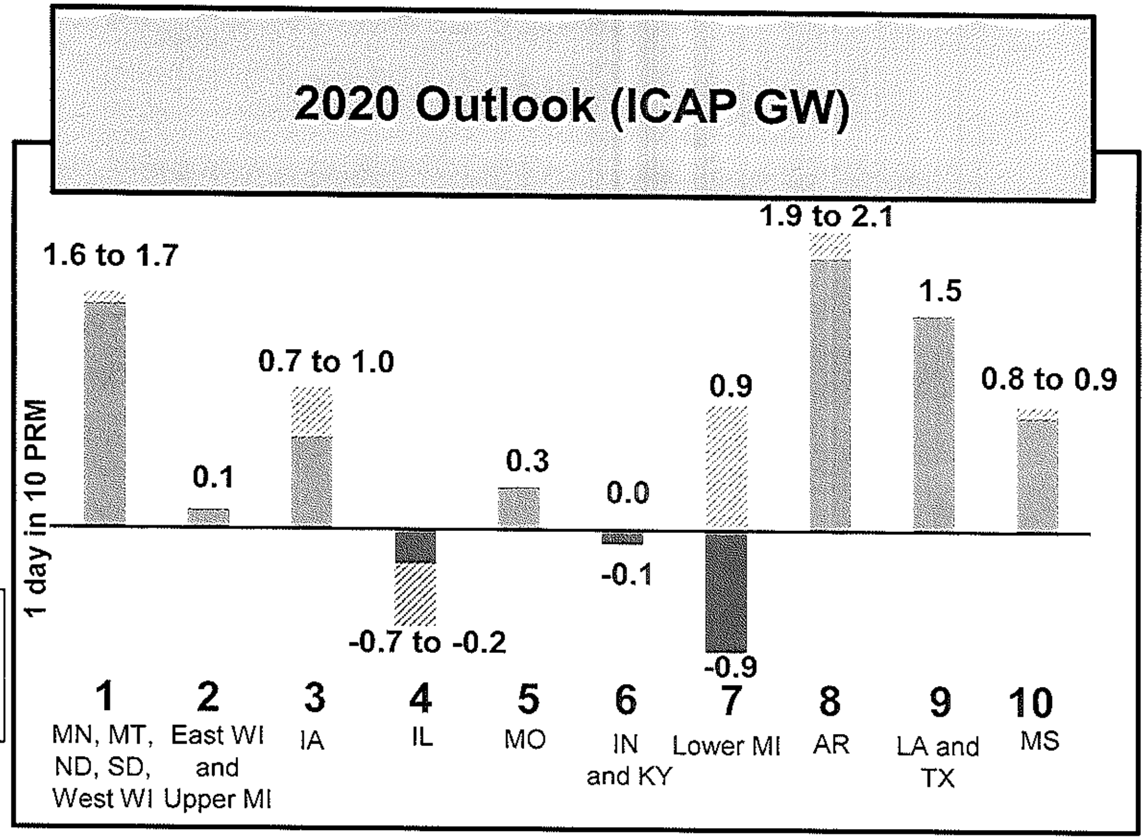
 Potential Capacity includes potential new capacity and potentially unavailable resources

OMS MISO

In 2020, regional surpluses are sufficient to cover areas with potential resource deficits

2020 Outlook, ICAP GW (% Reserves)

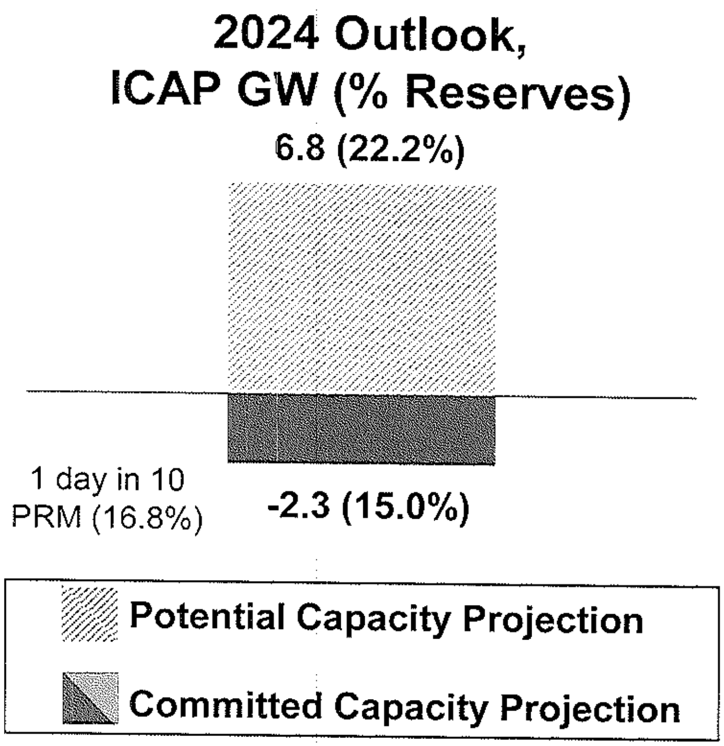


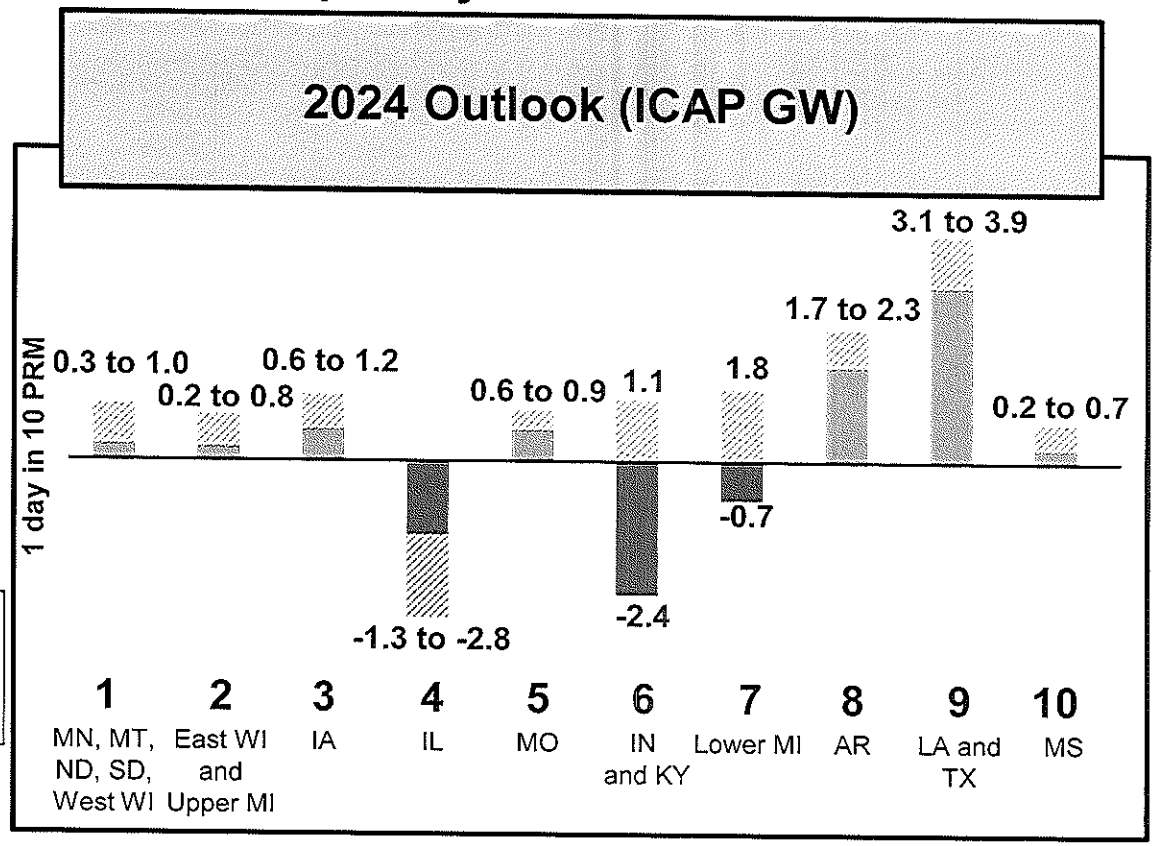


- The Michigan Public Service Commission Staff recently filed a report finding that the Michigan LSEs have adequate owned or contracted resources to meet projected resource adequacy requirements through 2022, this aligns with the OMS MISO survey projections for Zone 7
- Regional surpluses and potential resources are sufficient for all zones to serve their deficits while meeting local requirements
- Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones
- Exports from Zones 8, 9, and 10 were limited by the Sub-regional Power Balance Constraint

Ex. AA-S-1

Continued focus on load growth variations and generation retirements will reduce uncertainty around future resource adequacy assessments





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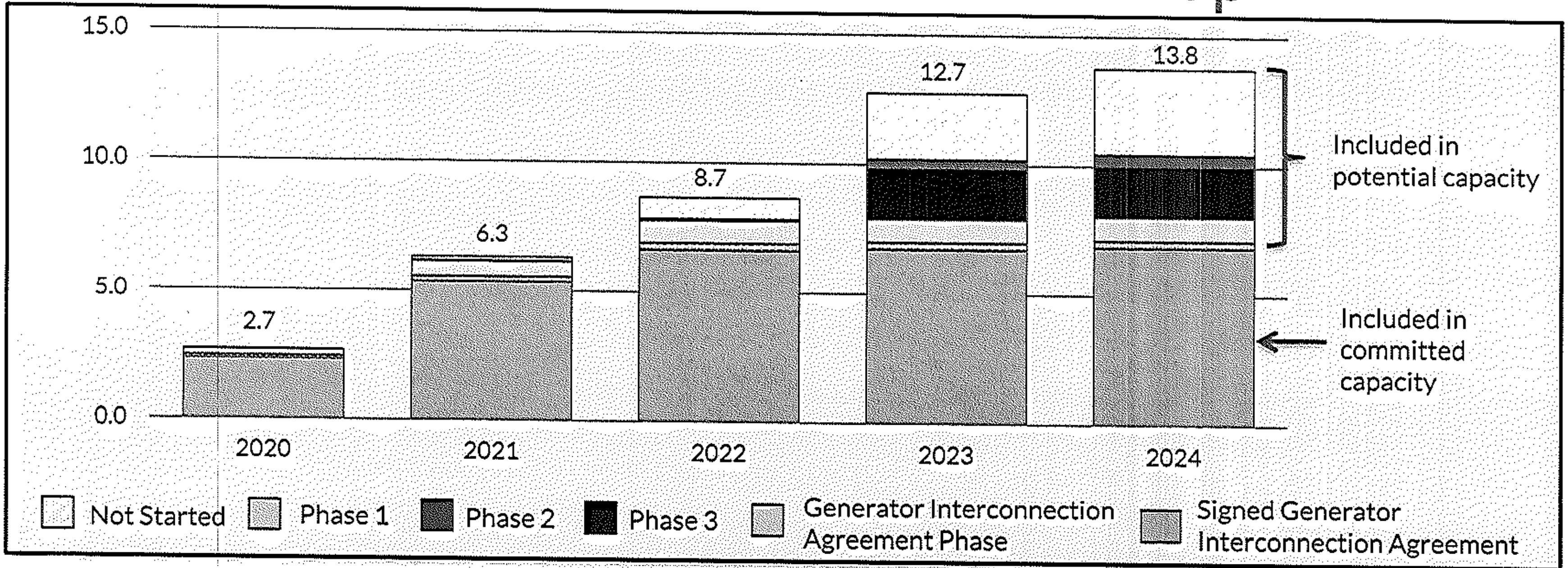
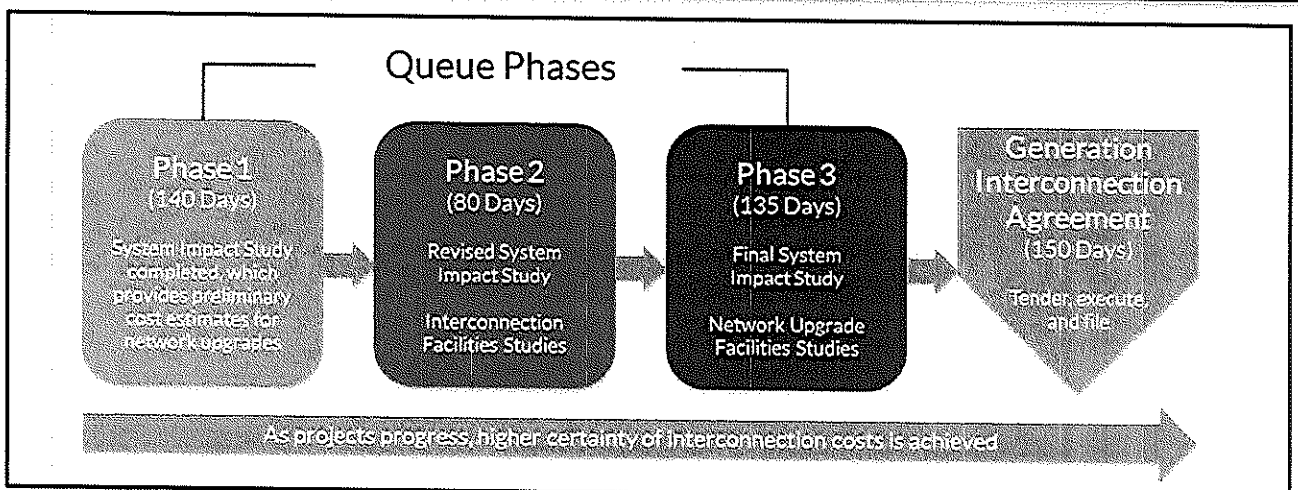
- Regional surpluses and potential resources are sufficient for all zones to serve their deficits while meeting local requirements
- Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones
- Exports from Zones 8, 9, and 10 were limited by the Sub-regional Power Balance Constraint

OMS MISO

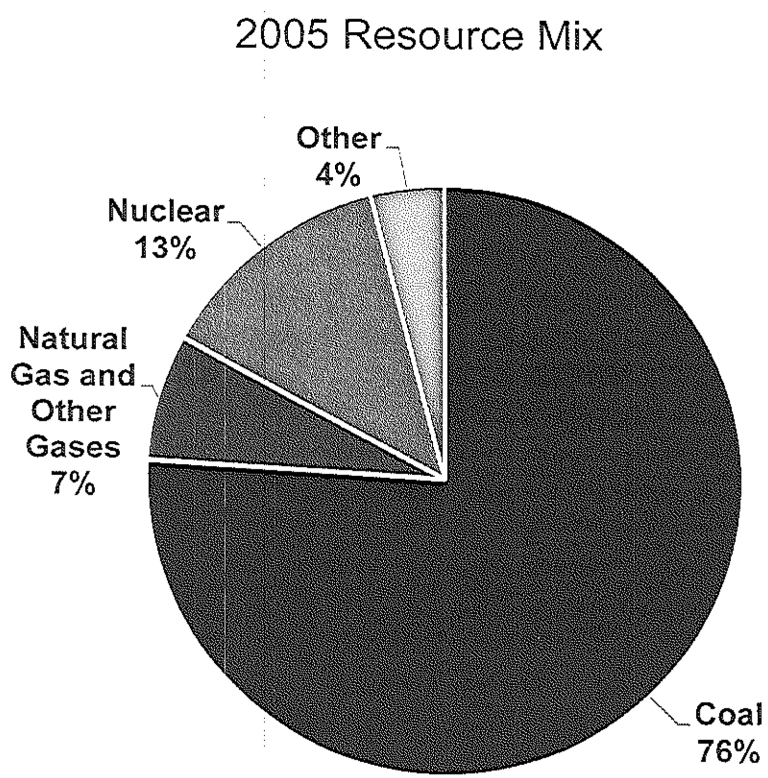
Future resource ranges will shift as planned generation interconnections are firmed up

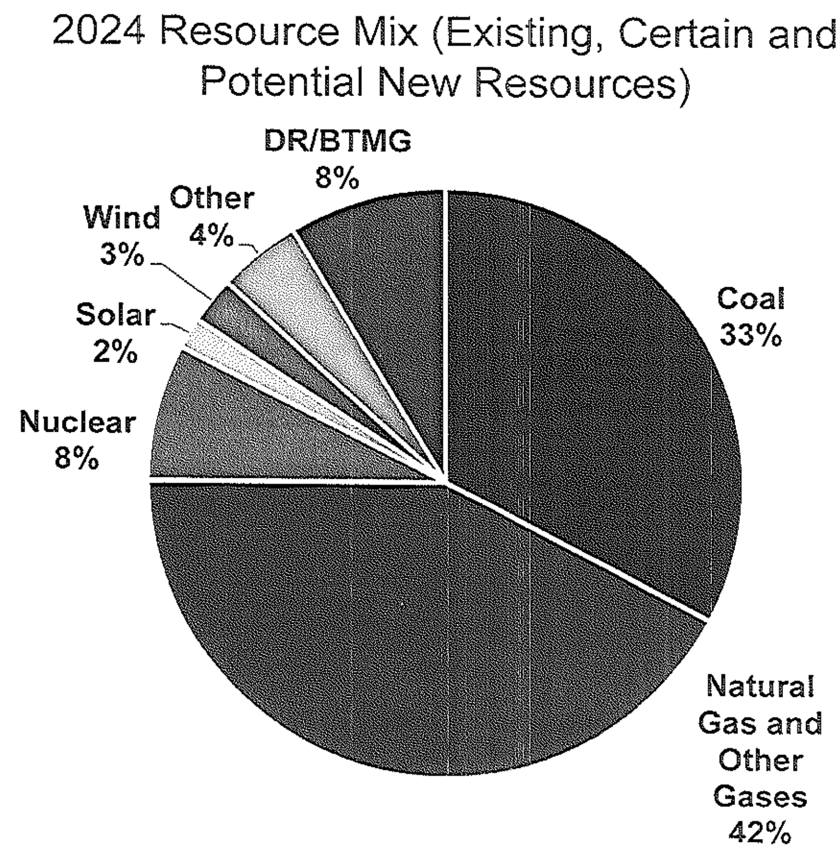




- Potential New Capacity represents the capacity in the MISO Generator Interconnection Queue at their projected queue certainty factors as of May 28, 2019. Wind and solar resources are modeled at their expected capacity credit

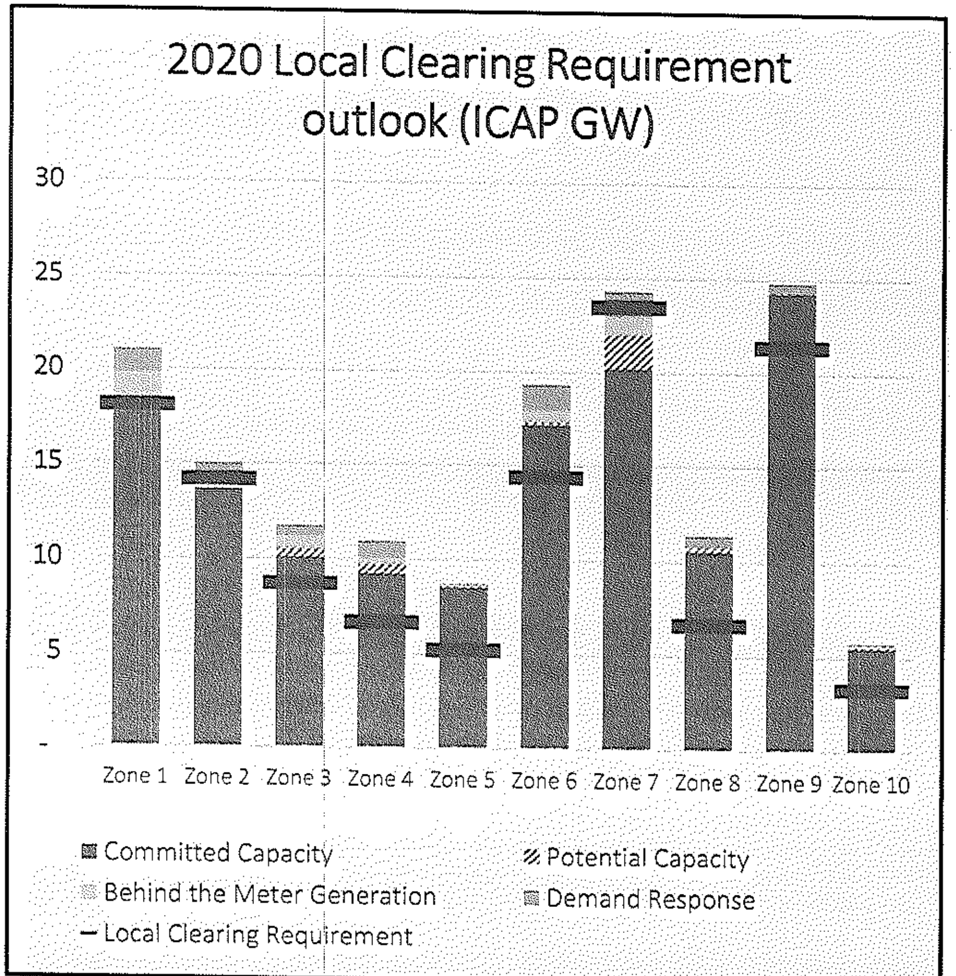
Forecasted resource mix changes continue to underpin a number of initiatives currently in the stakeholder process

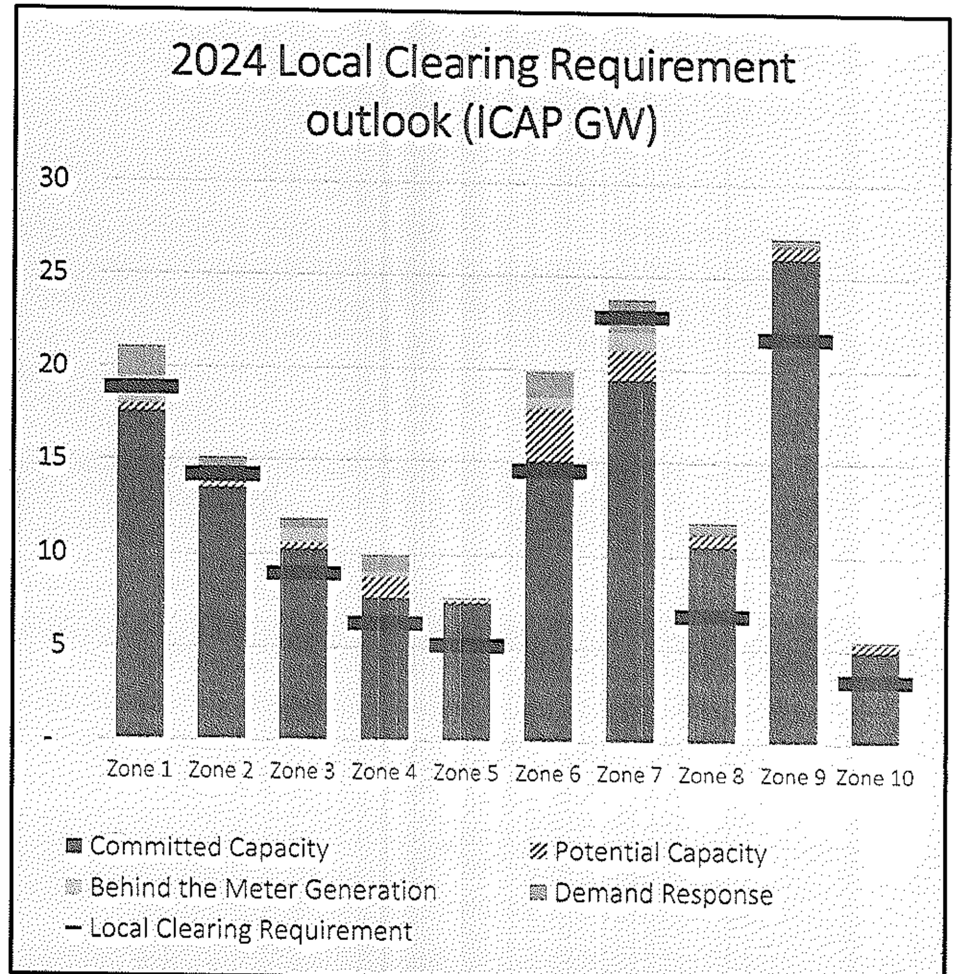




- Wind and solar resources shown at their expected capacity credit
- Potential New Capacity represents the capacity the MISO Generator Interconnection Queue at their projected queue certainty factors (see slide 14), as of May 28, 2019

New generation and load modifying resources continue to be important in meeting local resource needs





- Potential Capacity includes both new generation and potential retirements
- Load Modifying Resources include Demand Response (DR) and Behind the Meter Generation (BTMG)

OMS MISO

Appendix

Understanding Resource Projections

- **Committed Capacity Projections** - resources committed to serving MISO load
  - Resources within MISO utilities' rate base
  - New generators with signed interconnection agreements
  - External resources with firm contracts to MISO load
  - Non-rate base units without announced retirements or commitments to non-MISO load
- **Potential Capacity Projections** - resources that may be available to serve MISO load but do not have firm commitments to do so
  - Potential retirements or suspensions
  - Capacity in the MISO Generator Interconnection Queue at their expected capacity credit and projected queue certainty factors
- **Unavailable resources** are not included in the survey totals
  - Resources with firm commitments to non-MISO load
  - Resources with finalized retirements or suspensions
  - Potential new generators without a signed Generator Interconnection Agreement or generators which **have not entered** the MISO Generator Interconnection Queue

2019 OMS MISO survey results consider new generator interconnections as potential capacity

Apply Capacity Credit

- Wind 15.7%
- Solar 50%
- All other 100%

Apply Study Phase Weighting

- Not Started = 10%
- Phase 1 = 10%
- Phase 2 = 50% Non-Intermittent, 25% Intermittent
- Phase 3 = 75% Non-Intermittent, 50% Intermittent
- GIA in Progress = 90%

Requested In-Service Date

If requested in-service date is prior to 2018, projects would be moved to their study cycle end date, unless an updated date is provided in the OMS-MISO Survey

Study Cycle Not Started

If the Study Cycle hadn't started, then project requested in-service dates would be moved to their study cycle end date plus 2 years, unless an updated date is provided in the OMS-MISO Survey

- Study Phase Weighting is applied to recognize that as projects move through the queue process they generally become more certain
- In-service adjusted if the Study Cycle Not Started to recognize that a project likely can't get capacity credit until at least the end of the study cycle and additional 2 years to reflect expected GIA dates and possible construction timelines
- Methodology review at Feb. RASC: https://cdn.misoenergy.org/20190206%20RASC%20Item%2007%202019%20OMS-MISO%20Survey315955.pdf

Ameren Missouri's
Response to Sierra Club Data Request
ER-2019-0335
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.

Data Request No.: SC 0007.38

Refer to the rebuttal testimony of Todd Schatzki, page 15, line 17 through page 16 line 1. Has Mr. Schatzki reviewed any examples of the referenced 10-day forward-looking analyses performed by Ameren? If so, identify and provide each such analysis reviewed by Mr. Schatzki.

RESPONSE

Prepared By: Dr. Todd Schatzki
Title: Principal, Analysis Group
Date: February 3, 2020

No. See the response to Data Request No. SC 7.37.

Ameren Missouri's
Response to Sierra Club Data Request
ER-2019-0335
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.

Data Request No.: SC 0007.39

Refer to the rebuttal testimony of Todd Schatzki, page 16, lines 8-12.

a. Is Mr. Schatzki aware of any instances in which the MISO IMM has evaluated or audited self-commitment decisions made by Ameren? If so, identify each such instance, and provide any associated documentation.

RESPONSE

Prepared By: Dr. Todd Schatzki
Title: Principal, Analysis Group
Date: February 3, 2020

No. See the response to Data Request No. SC 7.37.

Ameren Missouri's
Response to Sierra Club Data Request
ER-2019-0335
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.

Data Request No.: SC 0008.9

Refer to the rebuttal testimony of Andrew Meyers, page 24, line 23 to page 25, line 3

a. Has the Company ever chosen not to accept delivery on a coal contract? Please explain.

b. Has the Company ever sought to renegotiate its fuel contracts? Please explain.

c. Has the Company ever discussed with a supplier not accepting delivery on a coal contract for economic reasons? If yes, please provide and explain. If no, why not?

d. Has any supplier informed the Company that it will not enter into at-market replacement fuel contracts if the Company declines to accept a delivery? If so, please provide any communications.

e. Has the Company ever discussed with a supplier not accepting delivery on a coal contract for economic reasons?

f. Has the Company evaluated the costs and benefits of canceling any coal contract, or declining to take receipt of any coal deliver under the contract? If so, please provide all such analyses, in native format. If not, please explain why not.

RESPONSE

Prepared By: Andrew Meyer
Title: Senior Director Energy Management & Trading
Date: 01.29.2020

1. The Company has exercised our rights under a given contract to not accept delivery of a portion of the contracted volume due to quality parameters not being met and events related to transportation disruptions.
2. Yes. The Company has sought to renegotiate fuel contracts for multiple reasons including price, credit, and optimization of shipment schedules. Not every renegotiation attempt results in a contract amendment. The Company is always monitoring coal contracts for optimization potential.

3. Please reference part b. above. Ameren Missouri has not discussed defaulting on its contracts based on the price of the contract being above current market. Economic matters, i.e. the comparison of coal contract price to the spot market, are discussed with the suppliers but have not resulted in any contract amendment that relieves the Company of paying the non-receipt damages.
4. The referenced testimony was specific to the issue of Ameren Missouri refusing delivery under an above-market fuel contract. Ameren Missouri has not refused delivery on such a basis, and therefore there is no supplier communication stating reaction to this event.
5. See response to c.
6. The Company cannot unilaterally cancel contracts, as such there would be no basis upon which to perform an analysis of canceling a contract. As noted in part b. above, the Company has sought to renegotiate coal contracts. The Company is aware of the mark-to-market comparison of its coal contracts. The mark-to-market is an indication of the non-receipt damages to which the Company would be exposed if it did not ship the contracted coal. Further, as the Company has noted in the response to data request SC 1.22, Ameren Missouri's generation offers are based on incremental cost. As such, through the development of these offers and the operation of the MISO market, the cost and benefit associated with the opportunity cost of the coal, which would arise if non-delivery were to occur, has been taken into consideration.

Ameren Missouri's
Response to Sierra Club Data Request
ER-2019-0335
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.

Data Request No.: SC 0008.11

Refer to the rebuttal testimony of Andrew Meyers, page 29, line 3. Please provide all workpapers and analyses used to calculate the $87,000 value.

RESPONSE

Prepared By: Andrew Meyer
Title: Senior Director Energy Management & Trading
Date: 01.29.20202

The calculation of the $87,000 value is based on two parts, startup costs and anticipated cycling O&M. For startup costs, please refer to the Company's response to data request SC 7.18. For the cycling O&M, the value is based on discussions with the energy center relating to expected tube leak repair costs that will be incurred when the units are cycled.

Expenditure	Project	Reason
605,451	MR U3 Transformer Explosion Protect	GSU Transformer Upgrade (safety)
569,054	Meramec Drainage Improvements	Facility upgrade
1,971,485	SX DRY FLY ASH CONVERSION	ELG/CCR
1,897,520	SX Dry Bottom Ash Conversion	ELG/CCR
1,611,152	SX Wastewater Treatment ELG	ELG/CCR
1,210,347	SX Coal Dust & Slurry Proce	ELG/CCR
1,131,982	SX NERC CIP 5 Physical Security	Security
963,944	Sx1 Absorber Oxidation Air Agitator	Component Replacement
896,931	SX 800xA HMI LIFECYCLE UPGR	Component Replacement
859,791	SX - 1A ID Fan Hub Replacement	Component Replacement
542,259	SX Wi Fi Expansion	Communication Upgrade
21,839,107	LBD Wastewater Treatmen ELG	ELG/CCR
18,479,420	LBD U3 DRY BOTTOM ASH CONVERSION	ELG/CCR
16,254,735	LBD DRY FLY ASH CONVERSION	ELG/CCR
12,065,726	LBD U3 Reheater REPL	Component Replacement
6,751,395	LBD U3 LOWER SLOPE REPL	Component Replacement
6,572,174	LBD U1 Dry Bottom Ash Conv	ELG/CCR
3,905,704	LBD PLANT 316 COMPLIANCE	Regulatory
3,709,985	LBD U3 ID Fan Rotor Repl	Component Replacement
3,673,433	LB-RI Critical Spare GSU	Critical spare part
2,383,697	LBD U3 Coal Mill Transport Pipe Rep	Component Replacement
1,738,681	LBD - U3 BCP Casing/Suction Valve R	Component Replacement
1,686,438	LBD U2 DRY BOTTOM ASH CONV	ELG/CCR
1,649,041	LBD U3 K LINE BREAKER REPL	Component Replacement
1,483,948	LBD U3 AUX COOLING H2O COOLERS REPL	Component Replacement
1,465,257	LBD U3 &4 Gas Conditioning	Component Upgrades
1,414,583	LBD3 Valve Component Replacement	Component Replacement
1,370,302	LBD U4 DRY ECON ASH CONVERS	ELG/CCR
1,124,233	LBD U1 LOWER SLOPE REPL	Component Replacement
1,084,493	LBD Fly Ash Pond Closure	ELG/CCR
1,022,210	LBD - 1A&D BCP Casing&Suct Vlv Repl	Component Replacement
985,160	LBD U3 Air Preheater Basket Repl	Component Replacement
918,323	LABADIE U3 125 V DC System Repl.	Component Replacement
881,372	LBD U1-4 HMI LIFECYCLE UPGR	Component Replacement
857,004	LABADIE WATER TREATMENT CNTRLS	Component Replacement
789,163	LBD NERC CIP 5 Physical Security	Security
736,072	LBD U3 Instal 2 New Lances in HorSh	Component Upgrades
704,461	LBD - U3 Repl C ID Fan Inlet Vanes	Component Replacement
704,231	LBDS - U3 A&B FD Inlet Vanes	Component Replacement
650,115	LBD U3 Transformer Explosion Protec	GSU Transformer Upgrade (safety)
648,071	LBD U3 ADDL BLR CLNG DOORS	Component Upgrades
647,883	LBD - U3 CRH Safety Vent Stack Mods	Component Upgrades
617,311	LBD - U1 APH Hot Basket Repl	Component Replacement
568,517	LBD - U2 LOWER SLOPE REPL	Component Replacement
16,926,950	RI - Wastewater Treatment ELG	ELG/CCR
11,934,014	RI Dry Ash Handling System Retrofit	ELG/CCR
8,578,261	RI U1 BOTTOM ASH MODS-SC	ELG/CCR
3,935,324	RI-LB Critical Spare GSU	GSU Transformer Upgrade (safety)
3,385,407	RUSH ISLAND U1 ESP REBUILD	Component Replacement
2,390,491	RI U1 Economizer Strap Addition	Component Replacement
2,123,048	RI 1 Valve Component & Actuator Rep	Component Replacement

1,767,999	RI-Marketing Silo Ash Transfer Sys	Component Replacement
1,064,662	RI U1 AUXILARY COOLERS	Component Replacement
972,704	RI U1 Air Preheater Basket Replacem	Component Replacement
938,443	RI Coal Receiving Electrical Racewa	Component Replacement
895,275	RI U1 Replace Blr Steam Cooled Spac	Component Replacement
868,168	RI Coal Dusting and Spillage Improv	Component Upgrades
828,846	Rush Island Wi Fi Expansion	Communication Upgrade
720,187	RI U1 BURNER REPLACEMENT (24)	Component Replacement
509,087	RI U1 TRB FOAM CLEANING SYS	Component Upgrades

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **DTE ELECTRIC COMPANY** for approval of certificates of necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.	)	Case No. U-18419

At the April 27, 2018 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Sally A. Talberg, Chairman
Hon. Norman J. Saari, Commissioner
Hon. Rachael A. Eubanks, Commissioner

OPINION AND ORDER

I. HISTORY OF PROCEEDINGS

On June 30, 2017, DTE Electric Company (DTE Electric) submitted a notice of intent to file an application requesting approval of certificates of necessity (CONs) pursuant to MCL 460.6s and the May 11, 2017 order in Case No. U-15896 (May 11 order). On July 12, 2017, the Commission issued an order in this case (July 12 order), providing guidance to the Administrative Law Judge because: "MCL 460.6s, as amended by Act 341, has not yet been subject to scrutiny or interpretation by the Commission . . . and because certain provisions of the amended version of MCL 460.6s involve novel procedural requirements." July 12 order, p. 2.

On July 31, 2017, DTE Electric filed an application, with supporting testimony and exhibits,