The Brattle Group

The Potential Impact of Demand-Side Rates for Ameren Missouri: *Final Report*

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1. Executive Summary

Approach

Our purpose was to develop revenue neutral demand-side rates specific to Ameren Missouri's service territory, and to simulate their likely impact on peak demand and energy consumption

Based on stakeholder feedback, we developed an inclining block rate for residential customers, a time-of-use rate for Residential and Small General Service customers, and a critical peak pricing rate for Large General Service customers

Impacts were simulated using Brattle's Price Impact Simulation Modeling (PRISM) suite

Findings

Projected Peak Reduction by Portfolio

Combination	Participation Scenario	Residential Rate	SGS Rate	LGS Rate	Peak Reduction (MW)	Peak Reduction (% of System Peak)
1	Opt-In	TOU	TOU	CPP	69	0.82%
2	Opt-In	IBR	TOU	CPP	78	0.93%
3	Opt-Out	TOU	TOU	CPP	259	3.07%
4	Opt-Out	IBR	TOU	CPP	294	3.48%

Notes:
(1) Projected system peak in 2034 is 8,440 MW
(2) The Residential, SGS, and LGS classes account for ~79% of system peak

- At the portfolio level, demand-side rates have the potential to reduce Ameren Missouri's system peak by between 0.8% and 3.5%
- Impacts depend in part on whether the rates are offered on an opt-in or opt-out basis
- Under an opt-in offering, customers must proactively sign up in order to enroll in the new rate
- Under an opt-out offering, customers are automatically defaulted on to the new rate, with the option to revert back to the otherwise applicable rate

2. Introduction

Our approach

Using the results of the Rate Survey administered to Ameren employees and stakeholders, we selected a set of new demand-side rates to model for Ameren's Residential, Small General Service (SGS), and Large General Service (LGS) customer classes

We developed the new rates using Ameren's marginal costs and customer load profile data; they are revenue neutral to Ameren's current rates for each class

We then performed a quantitative assessment of the expected peak and sales impacts of the rates using our widely cited suite of price impact simulation tools (PRISM)

The Ameren Rate Survey

- Brattle conducted a brief survey of external stakeholders and Ameren employees connected with ratemaking

- The purpose of the survey was to assist Brattle and Ameren Missouri in selecting appropriate new rates for an impact assessment study

- The survey sought to answer two primary questions
  1. What are the most important rate making objectives/criteria for Ameren and its stakeholders?
  2. How do various candidate rates perform in meeting these objectives?

- A total criteria-weighted score was created for each rate, based on how individuals assessed each rate's performance for each objective, and weighted by the importance they placed on that objective

Based on the results of the survey, we developed four new rates

The Four New Demand-Side Rates

	Residential	Small General Service	Large General Service
Inclining Block Rate (IBR)	X		
Time-Of-Use (TOU)	X	X	
Critical Peak Pricing (CPP)*			X

* A VPP rate was originally selected for the LGS customers. However, due to there being relatively little average energy price variation from one critical event to the next, a CPP was chosen as a simpler, but equally effective, alternative

3. Rate Design

Each of the four demand-side rates were developed using data provided by Ameren

Data used in the development of the rates includes

- Marginal costs
- Existing rates (i.e. the class revenue requirement)
- Class load profiles and consumption distribution

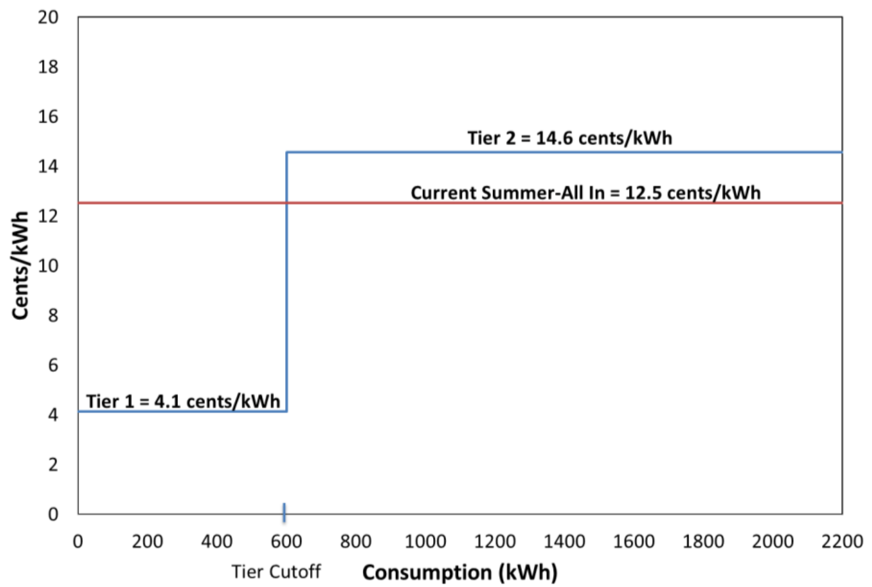
Each rate is revenue neutral, meaning that it will generate the same revenue for the class as the existing tariff (in the absence of a change in the class load profile)

See the appendices for step-by-step detail on how each rates was developed

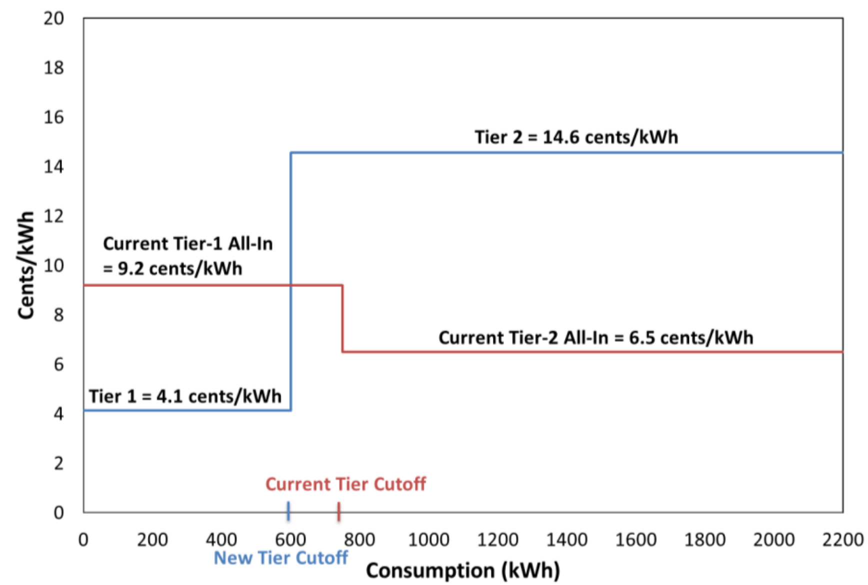
The following slides contain a summary of the key rate design assumptions

The residential IBR has a 10.5 cents/kWh price differential between the two tiers

Residential Summer All-In Rates



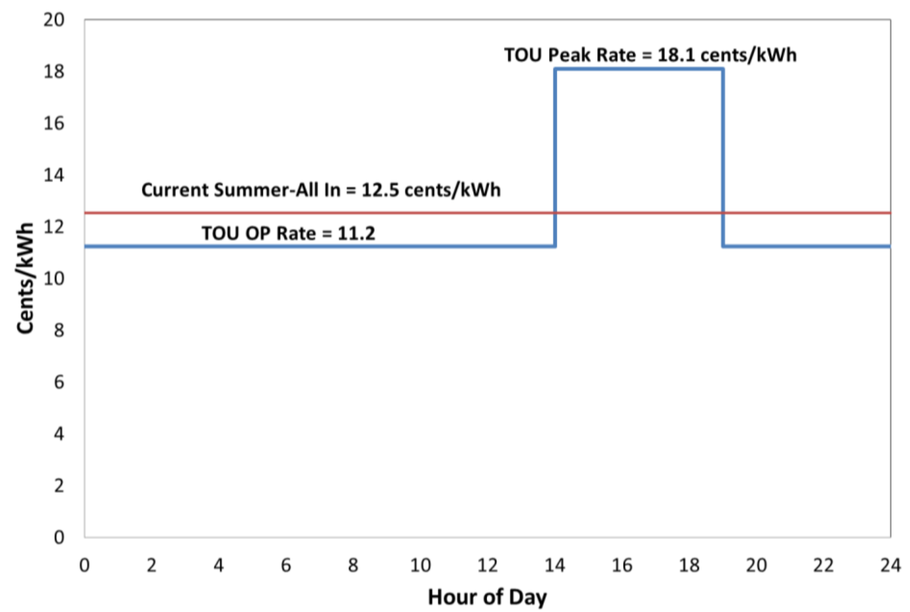
Residential Winter All-In Rates



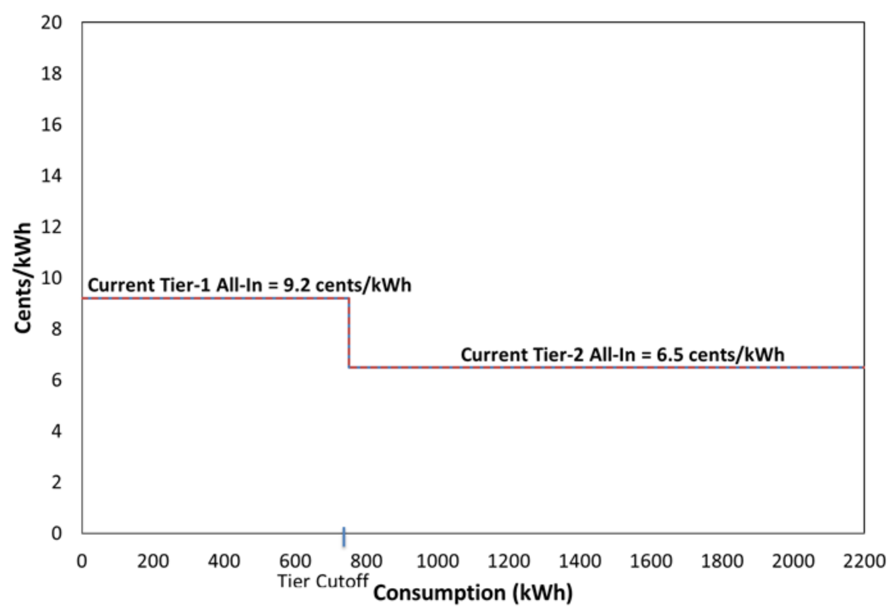
- The IBR is in effect year-round and tier prices do not differ by season
- The tier cutoff in the new rate is 600 kWh, which roughly results in half of annual class sales falling in the first tier, and half in the second tier
- The first tier price is based on Ameren's off-peak marginal costs and the second tier price is solved for revenue neutrality

The residential TOU rate has a roughly 7 cents/kWh price differential between the peak and off-peak periods

Residential Summer All-In Rates



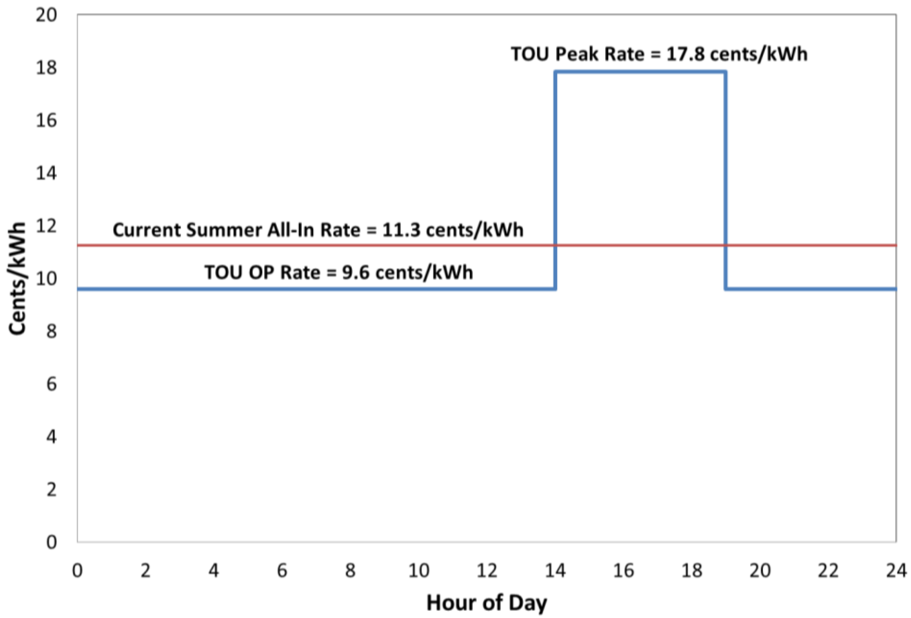
Residential Winter All-In Rates



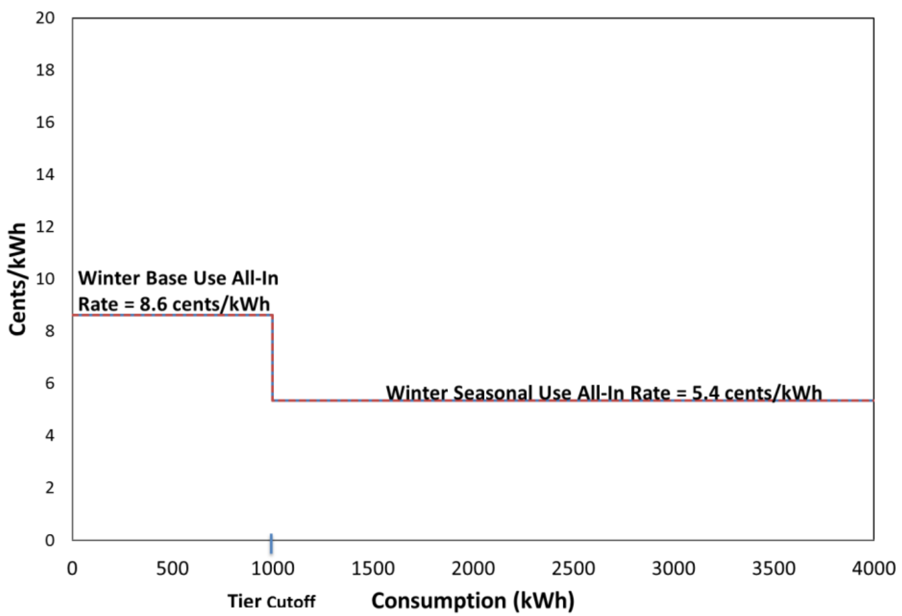
- TOU rate applies only during summer months (June-September)
- For all other months, Ameren's current inverted block rate is in effect
- Peak hours in effect on summer weekdays (non-holiday) from 2-7 PM
- Peak price is set by allocating marginal capacity costs to peak hours, and adding the average peak energy price; off-peak price is solved for revenue neutrality

The SGS TOU rate has a roughly 8 cents/kWh price differential between the peak and off-peak periods

SGS Summer All-In Rates



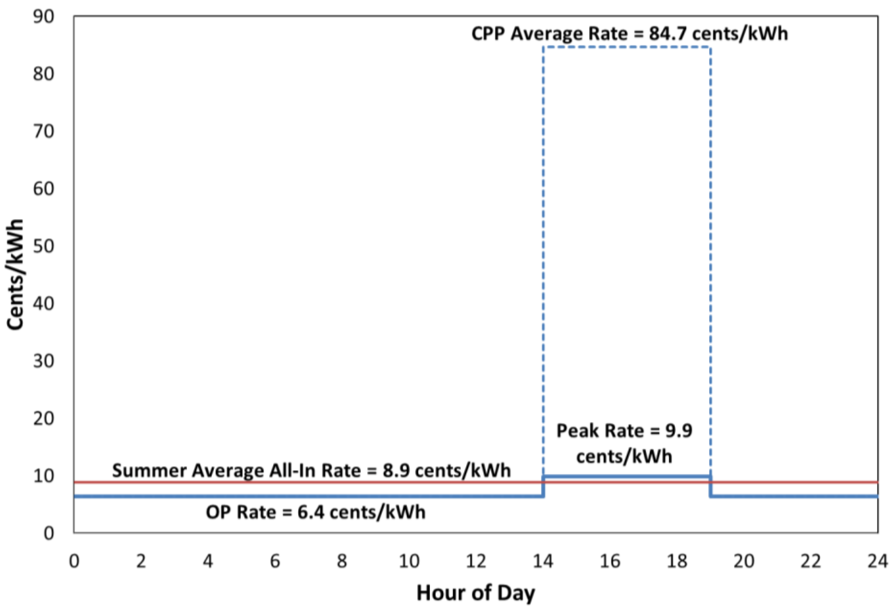
SGS Winter All-In Rates



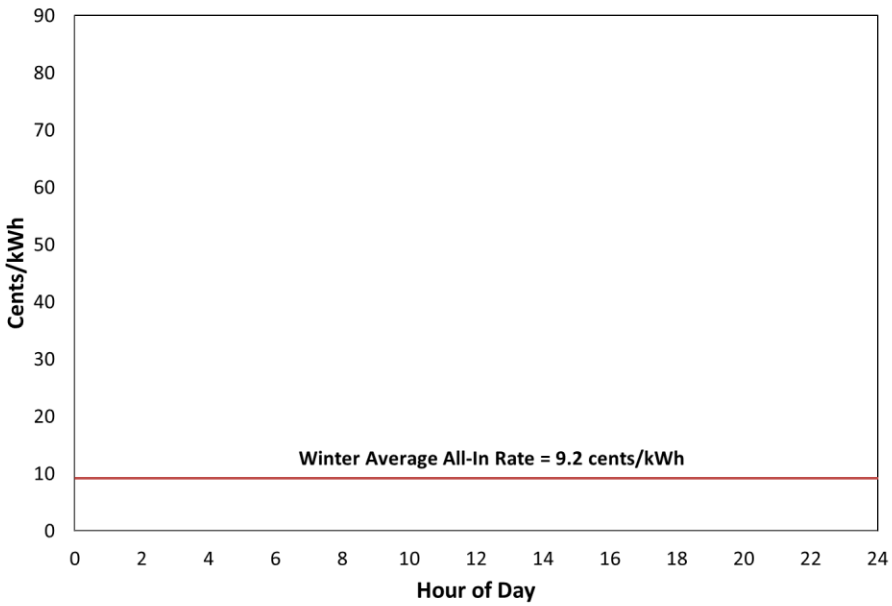
- The SGS TOU is developed using the same methodology as the residential TOU, but is based on the SGS revenue requirement and load profile
- For illustration purposes, the winter tier cutoff in the existing winter rate is shown as 1,000 kWh; it would differ on a customer-by-customer basis depending on historical usage patterns

The LGS CPP provides the largest off-peak discount in return for a higher price during a limited number of hours

LGS Class Summer All-In Rates



LGS Class Winter All-In Rates



- Critical events are assumed to be limited to 10 highest load days per summer
- Remaining peak hours are charged at the peak rate of a mild TOU
- Off-peak hours are charged at a 2.5 cents/kWh discount
- The CPP rate maintains the existing demand charge
- The current rate is represented here as a flat average all-in rate; the actual rate includes a demand charge and tiered kWh charges per kW of billing demand

4. The Potential Impact of Demand-Side Rates

The "Green" PRISM is used to simulate customer response to inclining block rates

Model Inputs

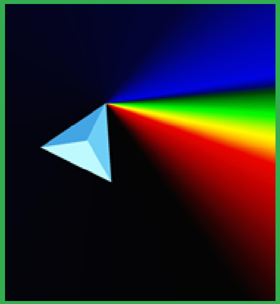
- Customer's usage, by tier
- Original price, by tier
- New price, by tier
- Meta-analysis of price elasticity results as described in Faruqui's August 2008 Public Utilities Fortnightly article, "Inclining Toward Efficiency"

Basic Drivers of Impacts

- Customer's usage, by tier
- Change in price (%), by tier
- Price elasticity, by tier

Usage Changes

- Consumption change, by tier



Energy Consumption Impact

- **Overall change in energy consumption**

The impact on consumption during the peak period is assumed to be equal to the average overall impact on consumption

The "Blue" PRISM is used to simulate customer response to time-varying rates

Model Inputs

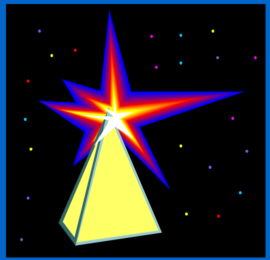
- Customer's peak period usage
- Customer's off-peak period usage
- All-in peak price of new rate
- All-in off-peak price of new rate
- Central air-conditioning saturation
- Weather
- Geographic location
- Enabling technology (e.g. PCT or IHD)
- Load-wtd avg daily all-in price of new rate
- Existing flat rate

Basic Drivers of Impacts

- Peak-to-off-peak usage ratio
- Peak-to-off-peak price ratio
- Elasticity of substitution
- Daily price elasticity
- Difference between new rate (daily average) and existing flat rate

Load Shape Effects

- Substitution effect (i.e. load shifting)



- Daily effect (i.e. conservation or load building)

Aggregate Load Shape and Energy Consumption Impact

Overall change in load shape (peak and off-peak by day)

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The concept of price elasticity

Customer price responsiveness is represented by a factor called “price elasticity”

Price elasticity represents the percent change in quantity consumed for a one percent change in price, everything else constant

A negative price elasticity means that customers will reduce consumption in response to an increase in price

The larger the magnitude of the negative price elasticity, the larger the customer’s reduction in consumption

Price elasticity assumptions are based on the best available information

Residential IBR price elasticities

- IBR elasticities are supported by the findings of a Stanford University researcher who analyzed the impacts of IBRs in California
- Price elasticity in the first tier of the IBR is assumed to be smaller than in the second tier
- Conceptually, the first tier includes necessary end-uses such as lighting and refrigeration; the second tier includes more discretionary end-uses such as air-conditioning and heating

Price elasticity assumptions (continued)

Residential TOU price elasticities

- TOU price elasticities are based on the results of BGE's four-year (2008 – 2011) dynamic pricing pilot
- Elasticities have remained relatively consistent throughout the pilot's duration
- The BGE elasticities come from a utility with a roughly similar climate as Ameren Missouri and have been adjusted to be consistent with Ameren Missouri's weather conditions (as represented by the temperature-humidity index)
- The results of simulations with these elasticities align well with the results of Ameren Missouri's 2005 residential CPP pilot (see slide 22)

Price elasticity assumptions (concluded)

SGS price elasticities

- Supported by research conducted by the California IOUs during the California Statewide Pricing Pilot

LGE price elasticities

- Based on analysis of full-scale rollouts in the Northeastern U.S., as summarized in a study by Lawrence Berkeley National Lab's Demand Response Research Center

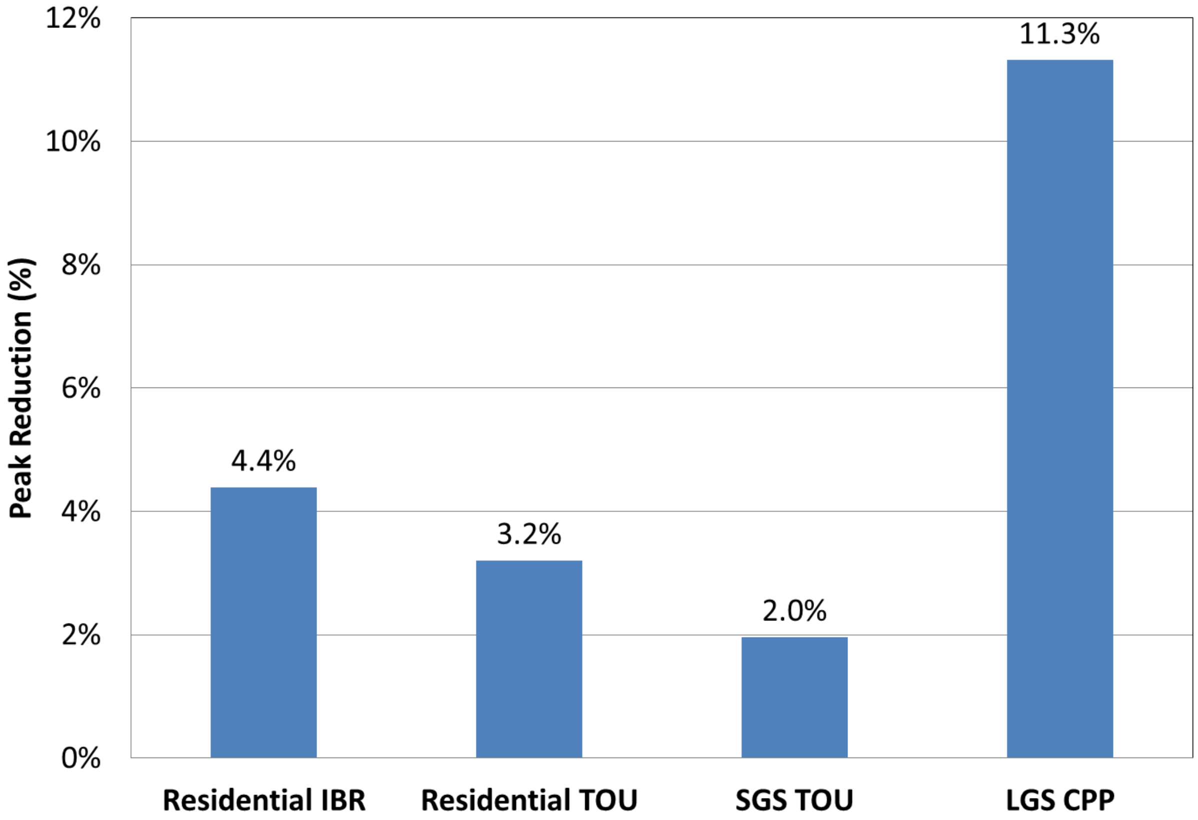
The price elasticity assumptions

	Residential	Small General Service	Large General Service
Critical Day			
Substitution	-0.0864	-0.0412	-0.050
Daily	-0.0522	-0.0250	-0.020
Non-Critical Day			
Substitution	-0.0864	-0.0493	-0.050
Daily	-0.0522	-0.0250	-0.020
Inclining Block Rate			
Tier 1	-0.130		
Tier 2	-0.260		

See appendix for discussion of "substitution" and "daily" elasticities

The strong price signal in the LGS CPP leads to the largest peak demand reduction

Average Per-participant Peak Load Reduction



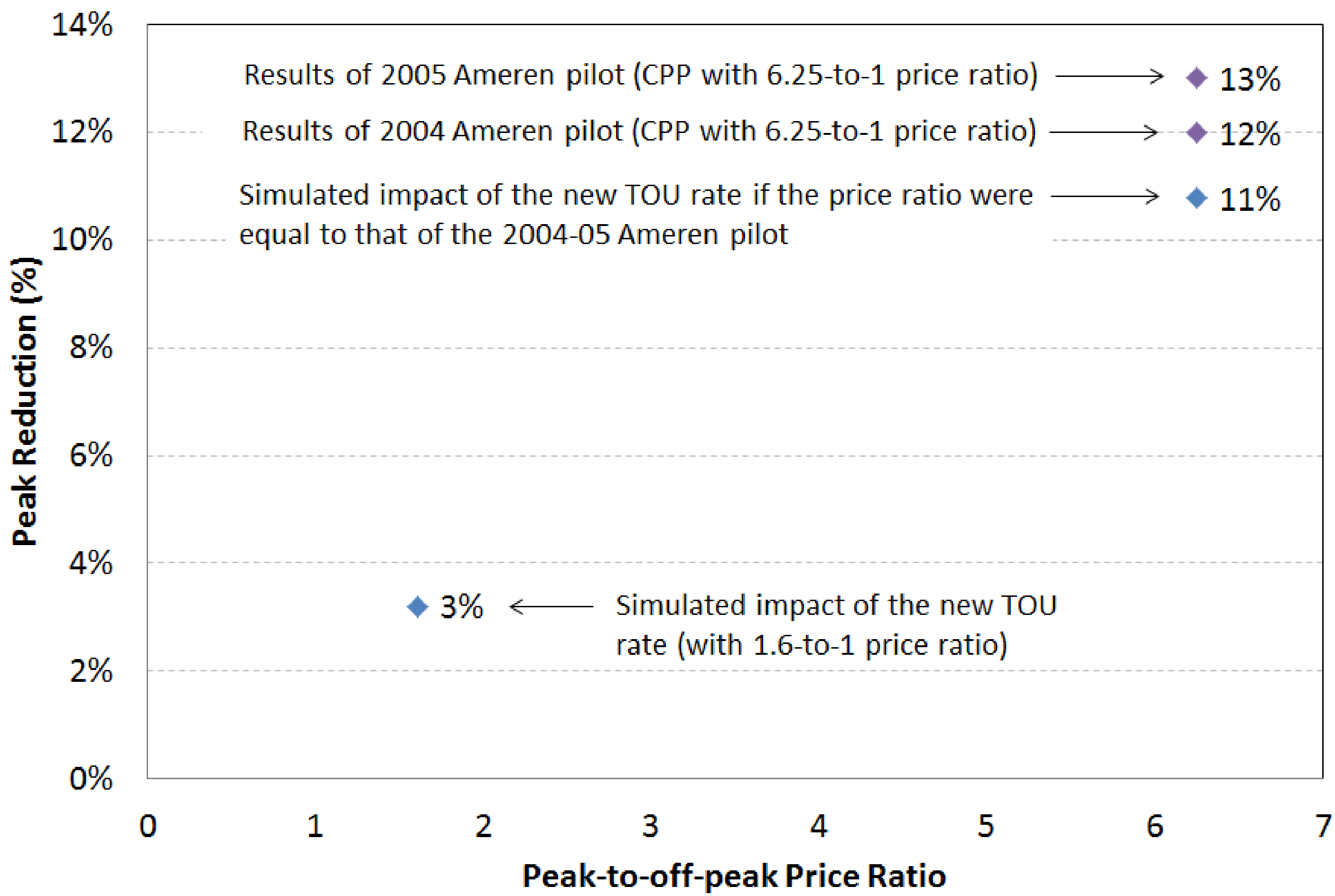
Comments

- The large peak demand reduction among LGS CPP participants is driven by the higher peak-to-off-peak price ratio of the CPP rate, rather than a higher price elasticity among LGS customers

- If the other rate classes also faced a CPP rate, then their peak demand reductions would be higher as well.

The potential impact of residential TOU rates aligns with that of Ameren's 2004-05 dynamic pricing pilot

Results of Brattle Simulations and Ameren Pilot



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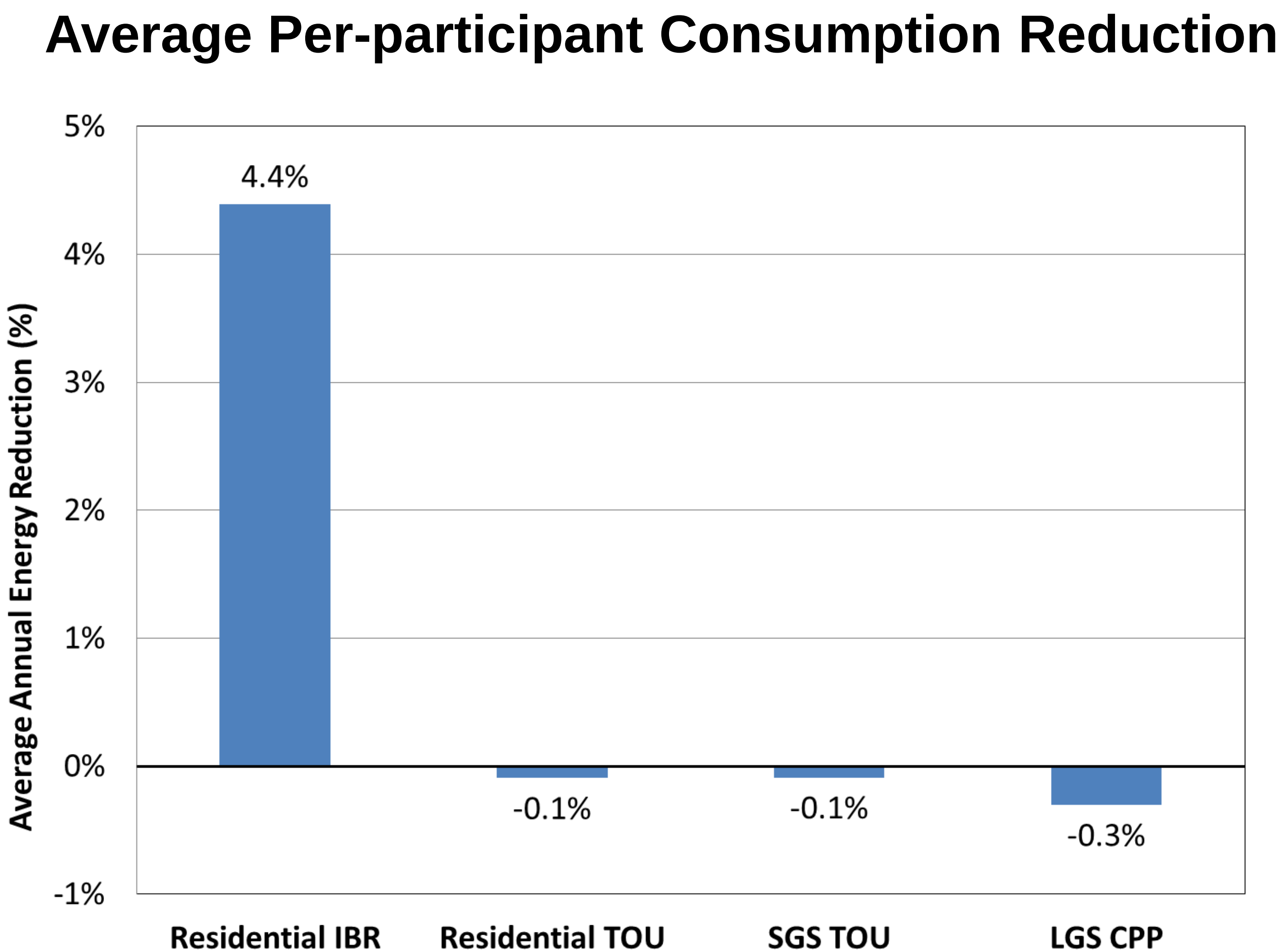
The residential IBR leads to conservation; sales impacts of the other rates are mostly negligible



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To estimate system-level impacts, we model "opt-in" and an "opt-out" rate deployment scenarios

Opt-In Scenario

Class	Rate	First Year of Participation	Steady State Year	Steady State Participation %
Residential	IBR	2015	2019	20%
Residential	TOU	2020	2024	20%
SGS	TOU	2020	2024	20%
LGS	CPP	2020	2024	20%

Assumes that the rate is offered on a voluntary basis, and customers must proactively sign up in order to enroll in the new rate

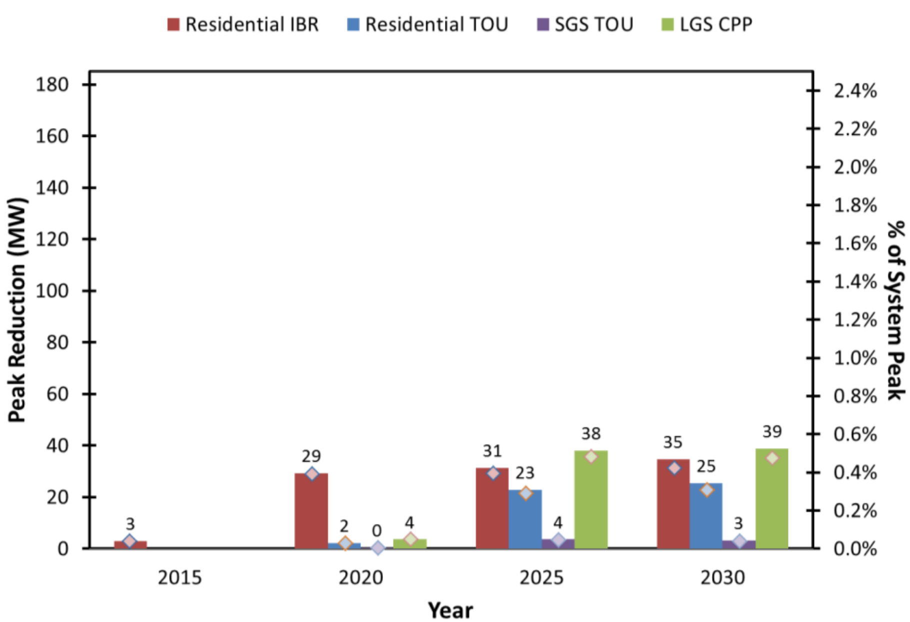
Opt-Out Scenario

Class	Rate	First Year of Participation	Steady State Year	Steady State Participation %
Residential	IBR	2015	2019	75%
Residential	TOU	2020	2024	75%
SGS	TOU	2020	2024	75%
LGS	CPP	2020	2024	75%

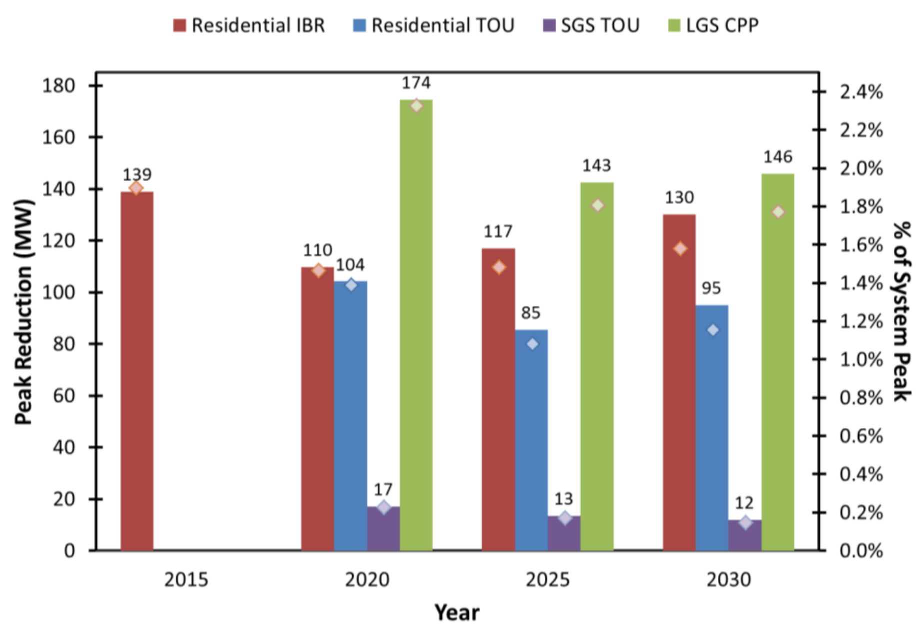
Assumes customers are automatically defaulted on to the new rate, with the option to revert back to the otherwise applicable rate

Higher assumed participation under the opt-out deployment scenario leads to significantly higher impacts

Peak Reduction by Year (Opt-In)

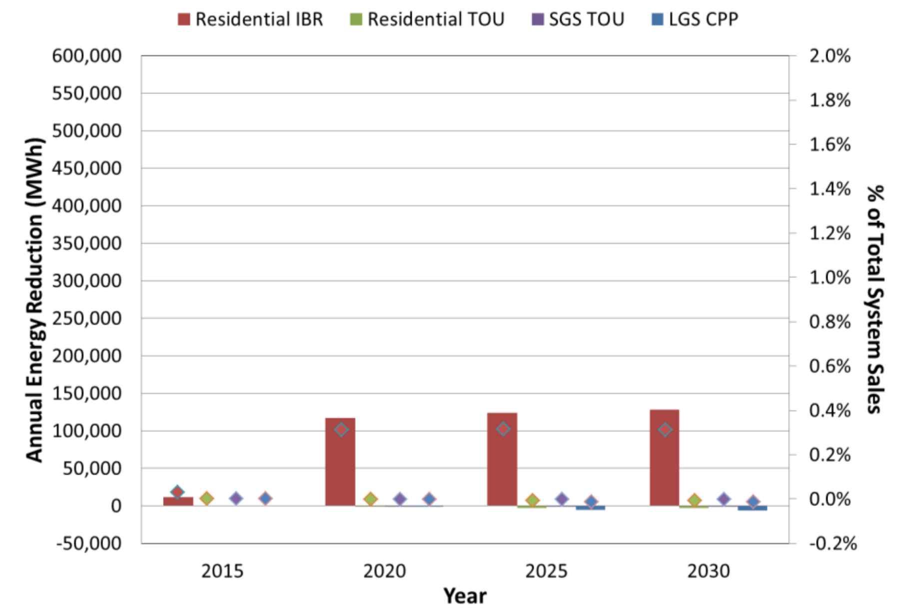


Peak Reduction by Year (Opt-Out)

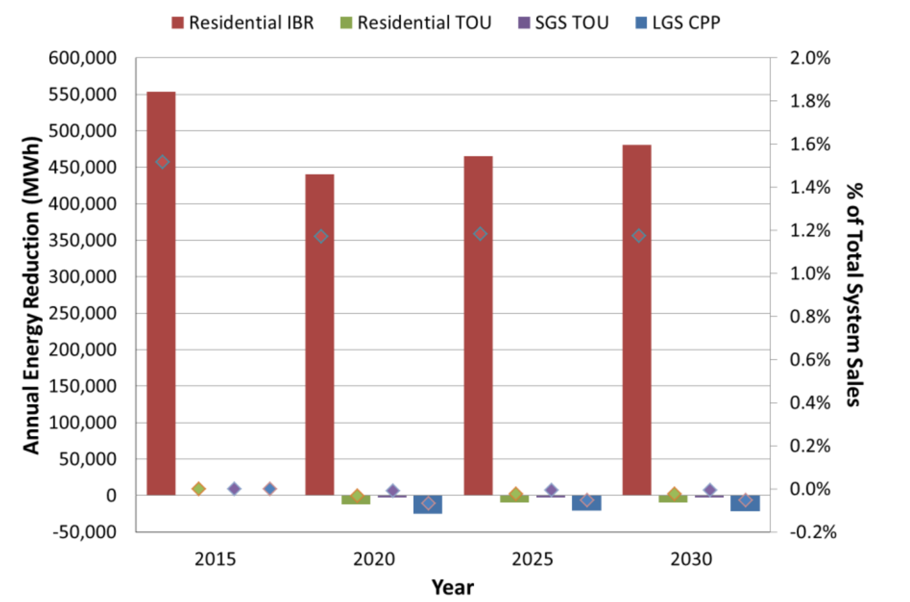


Similarly, the conservation impact of the IBR is significantly higher with opt-out deployment

Annual Energy Reduction (Opt-In)



Annual Energy Reduction (Opt-In)



As a portfolio, the rates have the potential for reducing system peak demand by 0.8% to 3.5%

Projected Peak Reduction by Portfolio

Combination	Participation Scenario	Residential Rate	SGS Rate	LGS Rate	Peak Reduction (MW)	Peak Reduction (% of System Peak)
1	Opt-In	TOU	TOU	CPP	69	0.82%
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Notes:
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Dr. Faruqui has advised more than 50 clients on demand response and dynamic pricing issues, including utilities, transmission system operators, regulatory agencies, governments and international lending agencies.

He has testified or appeared before a dozen state and provincial commissions and legislative bodies in the United States and Canada.

Dr. Faruqui has been involved in the estimation of hourly, daily and monthly demand models in the context of dynamic pricing pilots. Dr. Faruqui has managed the design and evaluation of large-scale dynamic pricing experiments in California, Connecticut, Florida, Illinois, Maryland and Michigan. This work involved the estimation of a variety of econometric models for estimating customer response to prices that varied by time of day.

He has been cited in The Economist, The New York Times, and USA Today and he has appeared on Fox News and National Public Radio. The author, co-author or editor of four books and more than 150 articles, papers and reports on energy efficiency, he holds a Ph.D. in economics from The University of California at Davis and bachelors and masters degrees from The University of Karachi.

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Ryan Hledik is a senior associate of The Brattle Group with expertise in assessing the economics of smart grid investments and policies. He has consulted to utilities, policymakers, technology firms, government labs, research organizations, and wholesale market operators. His contributions have included the development of widely cited models for the economic valuation of smart grid programs, serving as a member of a U.S. Department of Energy advisory group to review the activities of Smart Grid Investment Grant recipients, and providing strategic advice to firms implementing new smart grid initiatives.

Additionally, Mr. Hledik has been the lead developer of several energy market simulation tools for the purposes of wholesale price forecasting, asset valuation, and environmental impact analysis. A frequent presenter on the economics of the smart grid, he has recently spoken at events throughout the United States, as well as in Brazil, Canada, Korea, Saudi Arabia, and Vietnam.

Mr. Hledik received his M.S. in Management Science and Engineering from Stanford University, where his concentration was in Energy Economics and Policy. He received his B.S. in Applied Science from the University of Pennsylvania, with minors in Economics and Mathematics. Prior to joining The Brattle Group, Mr. Hledik was a research assistant with Stanford University's Energy Modeling Forum and a research analyst at Charles River Associates.

Appendix A:
Steps in designing the new rates

Steps and assumptions in calculating IBR rate for Residential class

1. **Chose to model a 2-tiered rate for simplicity**

2. **Assumed the IBR rate applies year-round, to encourage year-round conservation**

3. **Defined the tier cutoff such that 50% of class consumption is in tier 1, and 50% is in tier 2; there are many alternative approaches to defining the tier cutoff**

4. **Set the Tier 1 price equal to marginal off-peak costs**
   - ♦ Sum of off-peak marginal energy cost (~$29.67/MWh) and non-generation charges (~$11.67/MWh)
   - ♦ Calculated marginal energy cost using hourly LMP data from 2011

5. **Solved Tier 2 price for revenue neutrality**

Steps and assumptions in calculating TOU rate for Residential and SGS Classes

1. **Chose a TOU rate with two periods (peak and off-peak) for simplicity**

2. **Determined the timing of the peak period by looking at Ameren MO's 2011 average summer weekday system load shape**
   - Chose the five-hour window containing the largest share of high demand hours
   - See Appendix C for details

3. **Modeled the TOU rate for the summer months and kept the winter rate the same as currently specified by Ameren**
   - Focused on summer since Ameren Missouri is a summer-peaking utility
   - Used Ameren's retail tariff definition of the summer period of June through September

4. **Determined the peak price as the sum of the marginal capacity (allocated to peak hours), marginal energy cost in peak hours, and non-generation charges (on a per kWh cost basis)**
   - Full capacity cost ($50/kW-year) allocated evenly across peak hours
   - Marginal energy cost (~$51.68/MWh) calculated using hourly LMP data for 2011
   - Non-generation charges (~$11.67/MWh) taken from Ameren's tariff sheet

5. **Solved off-peak price for revenue neutrality**

Steps and assumptions in calculating CPP rate for Large General Service class

1. **Used 2011 data to pick 10 event days with highest hourly system loads**

2. **Chose peak hour time period consistent with TOU rate methodology**

3. **CPP rate applies to summer months (June-September) only**
   - Existing winter rate in effect for all other months

4. **Assumed critical peak hours on event days are in effect for full five-hour peak period**

5. **Critical peak price calculated by taking the sum of allocated capacity price over critical peak period, marginal energy cost, and non-generation charges**
   - 75% of capacity cost ($37.50/kW-year) allocated evenly across critical peak hours

6. **Determined peak period rate by taking the sum of allocated peak capacity cost, average peak marginal energy cost, and non-generation charges**
   - 25% of capacity cost ($12.50/kW-year) allocated evenly across peak hours
   - Marginal energy cost (~$51.68/MWh) calculated using hourly LMP data for 2011
   - Non-generation charges (~$13.54/kWh**)** taken from Ameren's tariff sheet

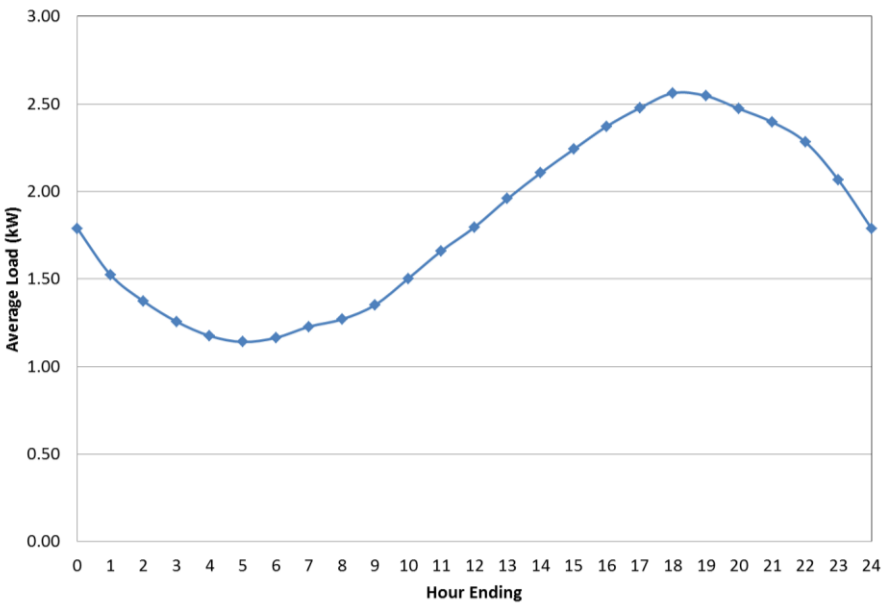
7. **Solved off-peak rate for revenue neutrality**

Appendix B:

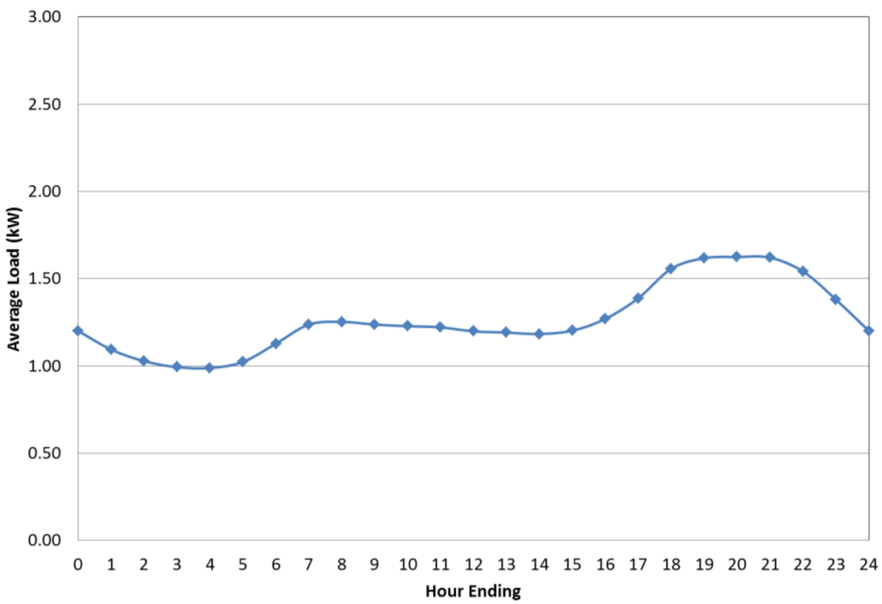
Average customer weekday load by class and season

Average Residential Customer Weekday Load

Summer

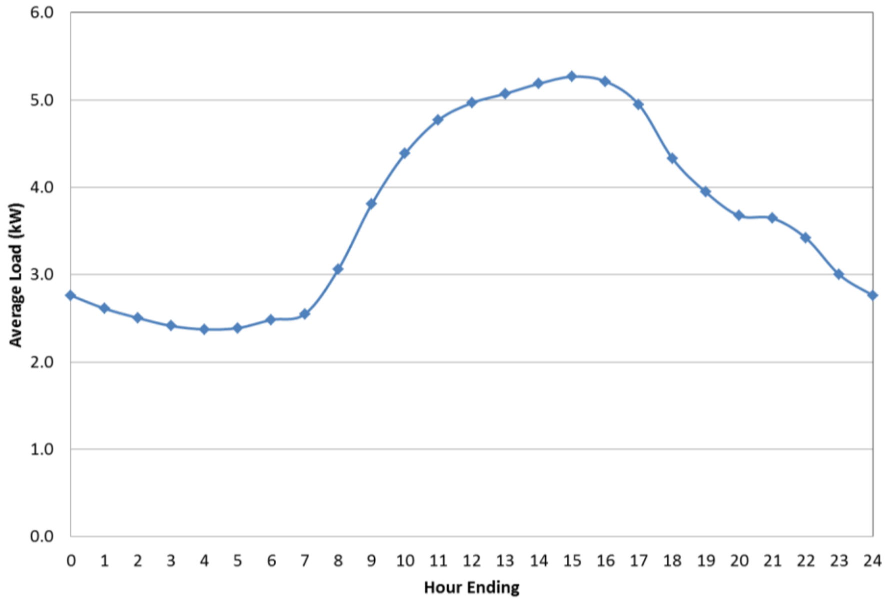


Winter

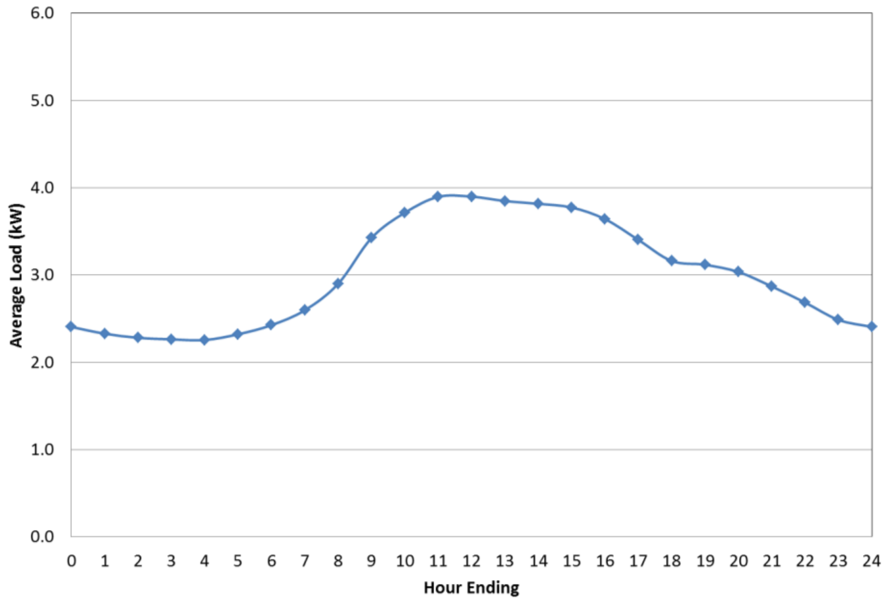


Average SGS Customer Weekday Load

Summer

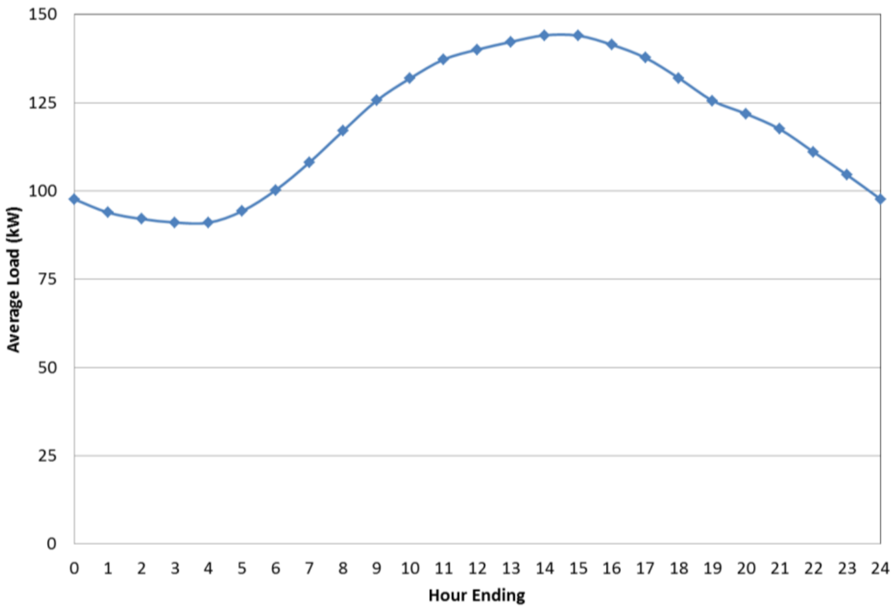


Winter

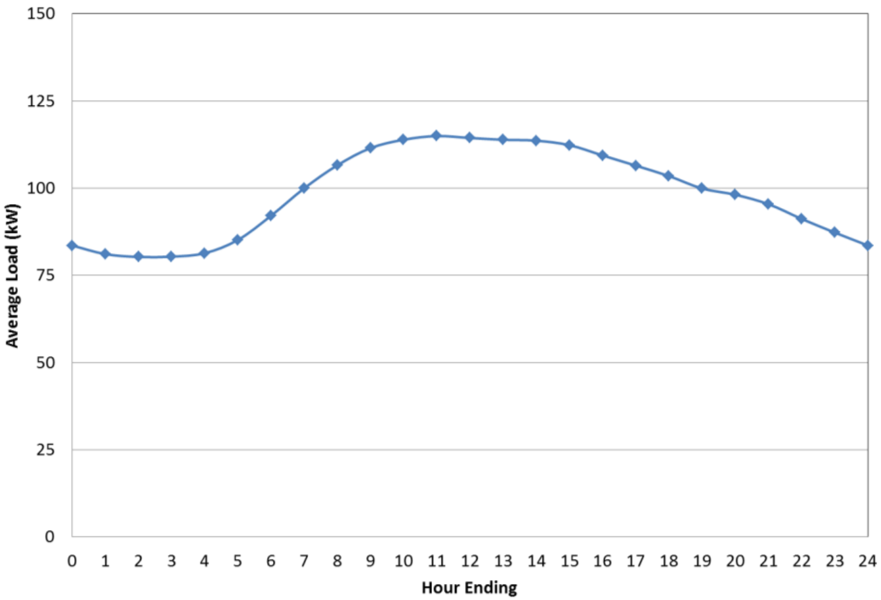


Average LGS Customer Weekday Load

Summer

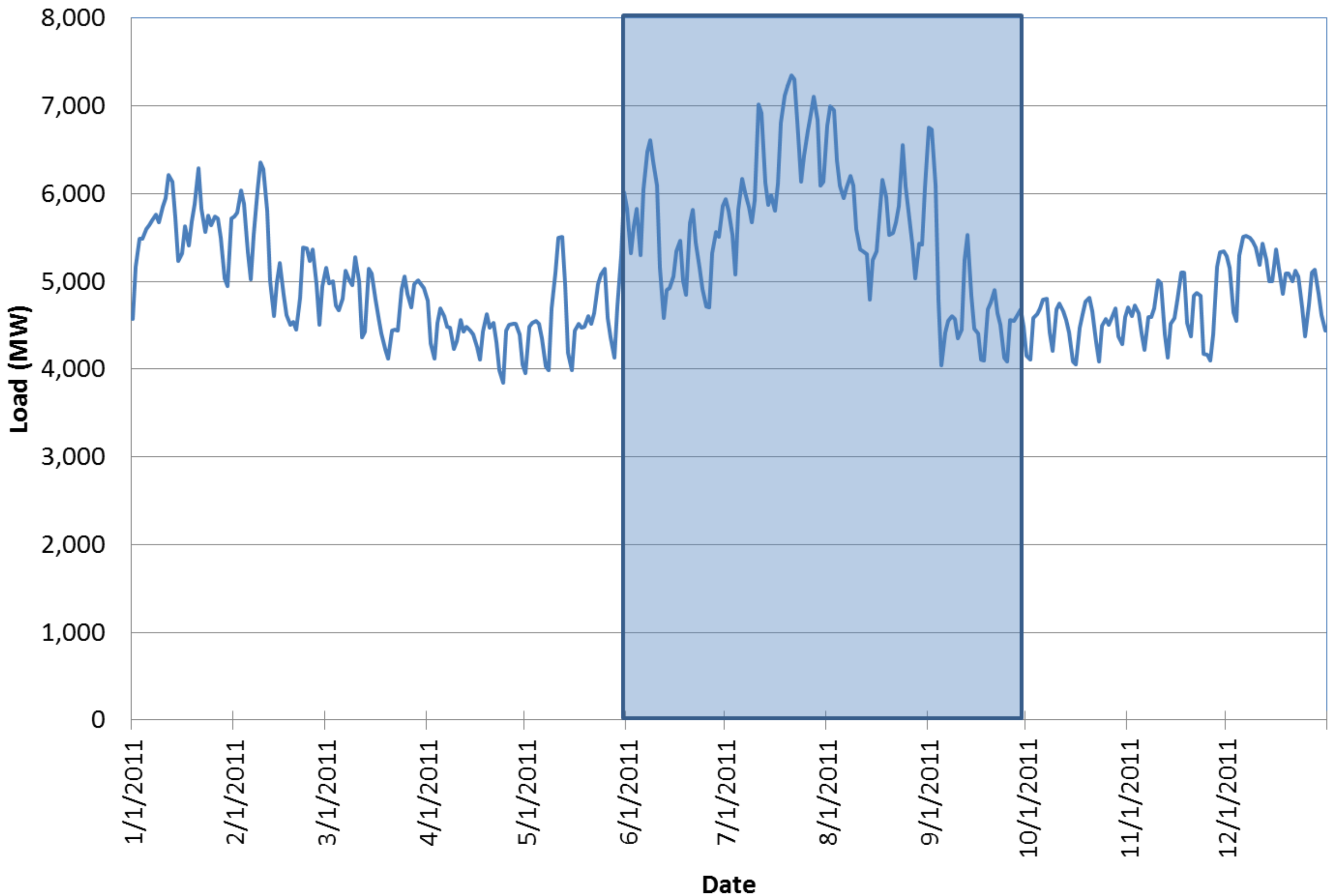


Winter



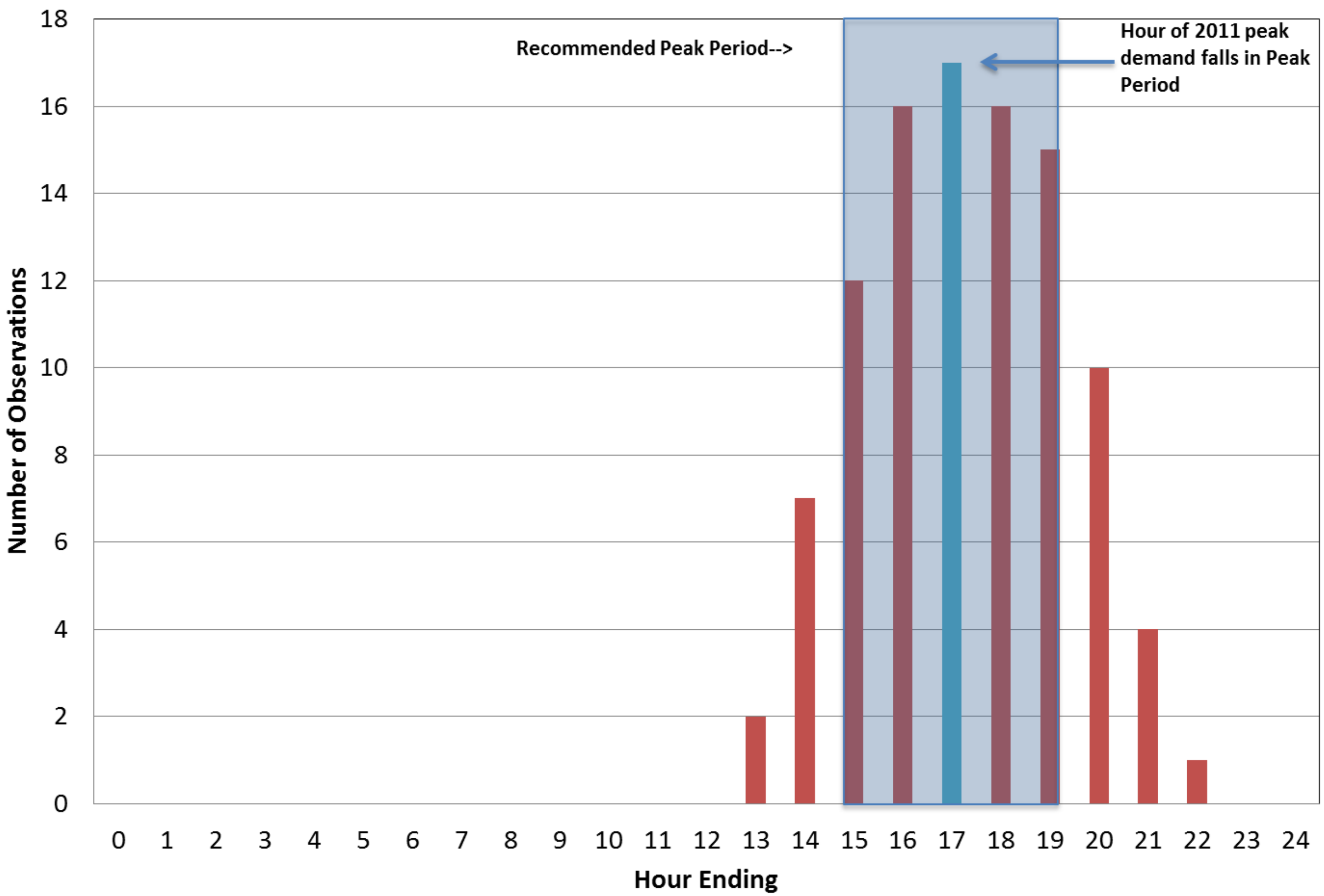
Appendix C:
Choosing the peak period hours

2011 Ameren MO Average System Load per Day

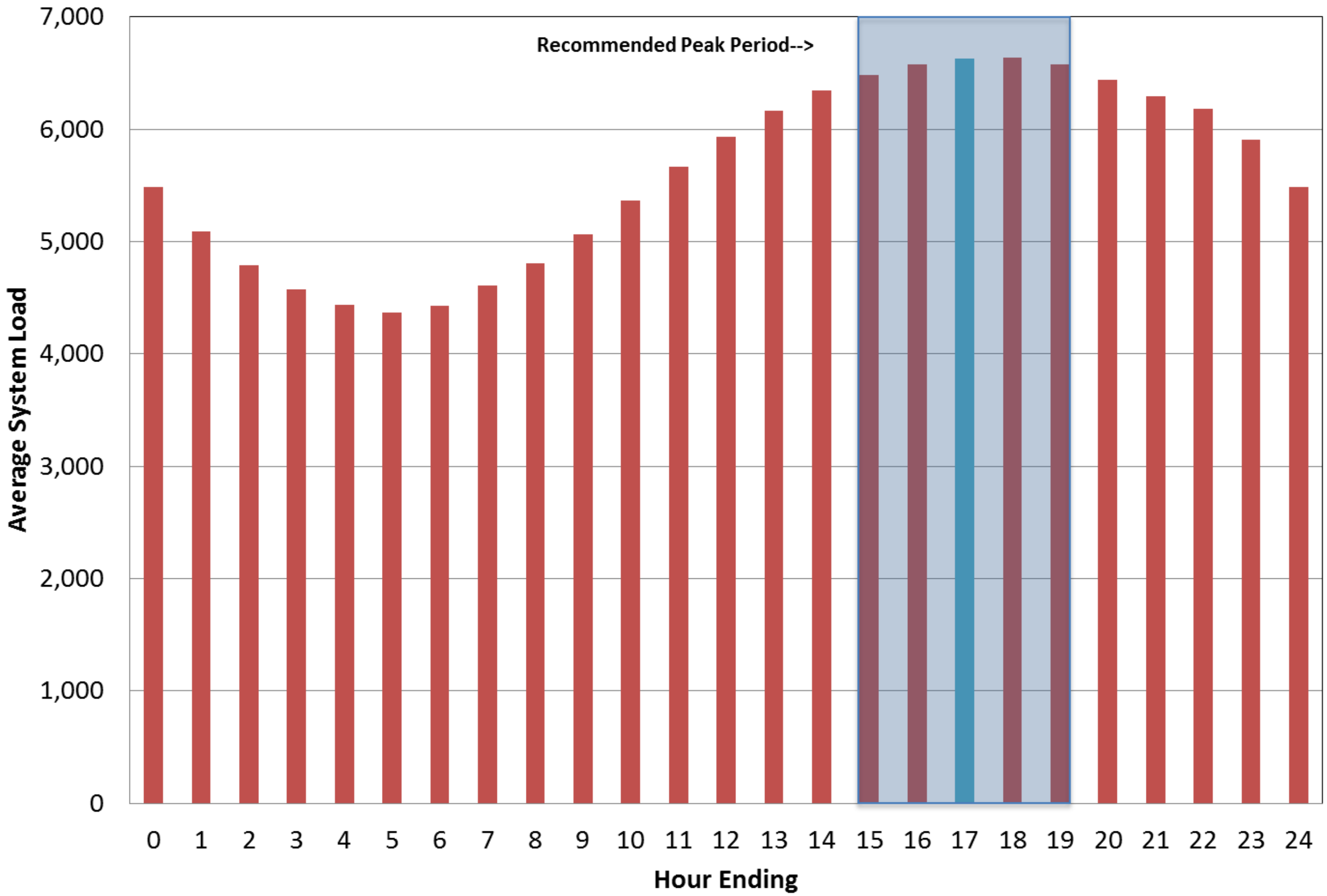


Note: Summer period (June-September) is consistent with Ameren Missouri's optional Time-Of-Day currently offered to customers

Distribution of Timing of Top 100 System Hours in 2011



Average System Load by Hour (Summer Weekdays)



Appendix D:
Types of modeled price elasticities

Two types of elasticities are modeled when simulating response to time-varying rates

Elasticity of substitution

- Represents the degree to which a customer will substitute consumption in a higher-priced period for consumption in a lower-priced period
- This captures the "load shifting" impact of a time-varying rate

Daily elasticity

- Represents the customer's overall change in consumption on a given day, in response to a change in the day's average rate
- With time-varying rates, days with a higher peak price also have a higher daily average price, relative to the otherwise applicable rate; therefore, there is a conservation effect on those days, and a corresponding increase in consumption on days without the higher peak price