The Brattle Group

THE IMPACT OF DYNAMIC PRICING ON WESTAR ENERGY

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Synopsis

First, we develop four time-based rates

- Time-of-use (TOU)
- Critical peak pricing (CPP)
- Peak time rebate (PTR)
- Real time pricing (RTP)

Next, we apply the rates to three customer classes

- Residential
- Small General Service (<200 kW)
- Medium General Service (>200 kW)

Then, we simulate customer response to the rates

- Consumption changes modeled using PRISM software
- Produces estimates of peak reductions, overall consumption changes, and bill impacts

Finally, we model system impacts of the rates

- Construct four scenarios of customer participation
- Quantify financial impacts and system demand impacts

Agenda

- **Review of rate designs**
- **Quantifying customer-level impacts**
- **Projecting system-level impacts**

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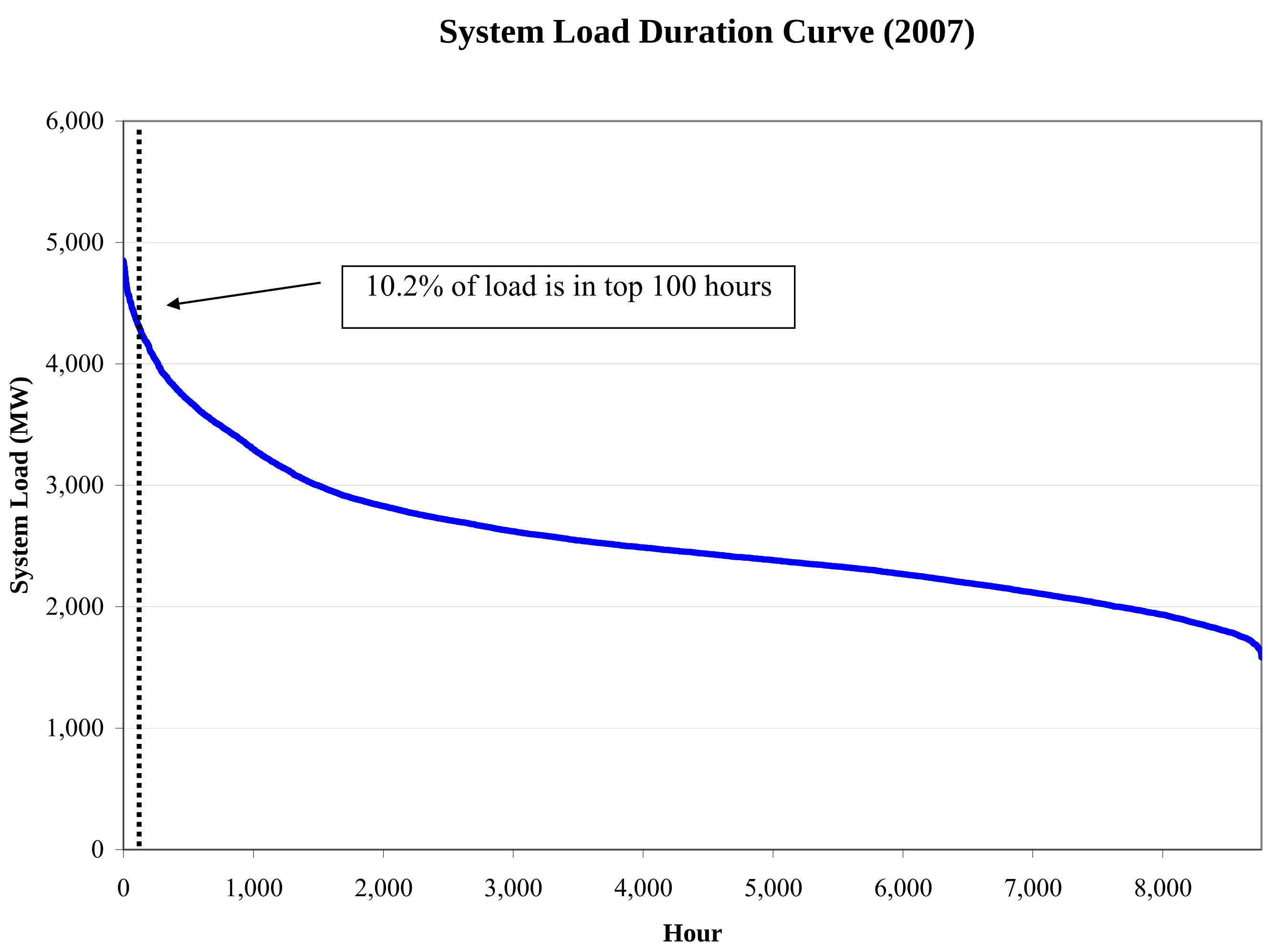
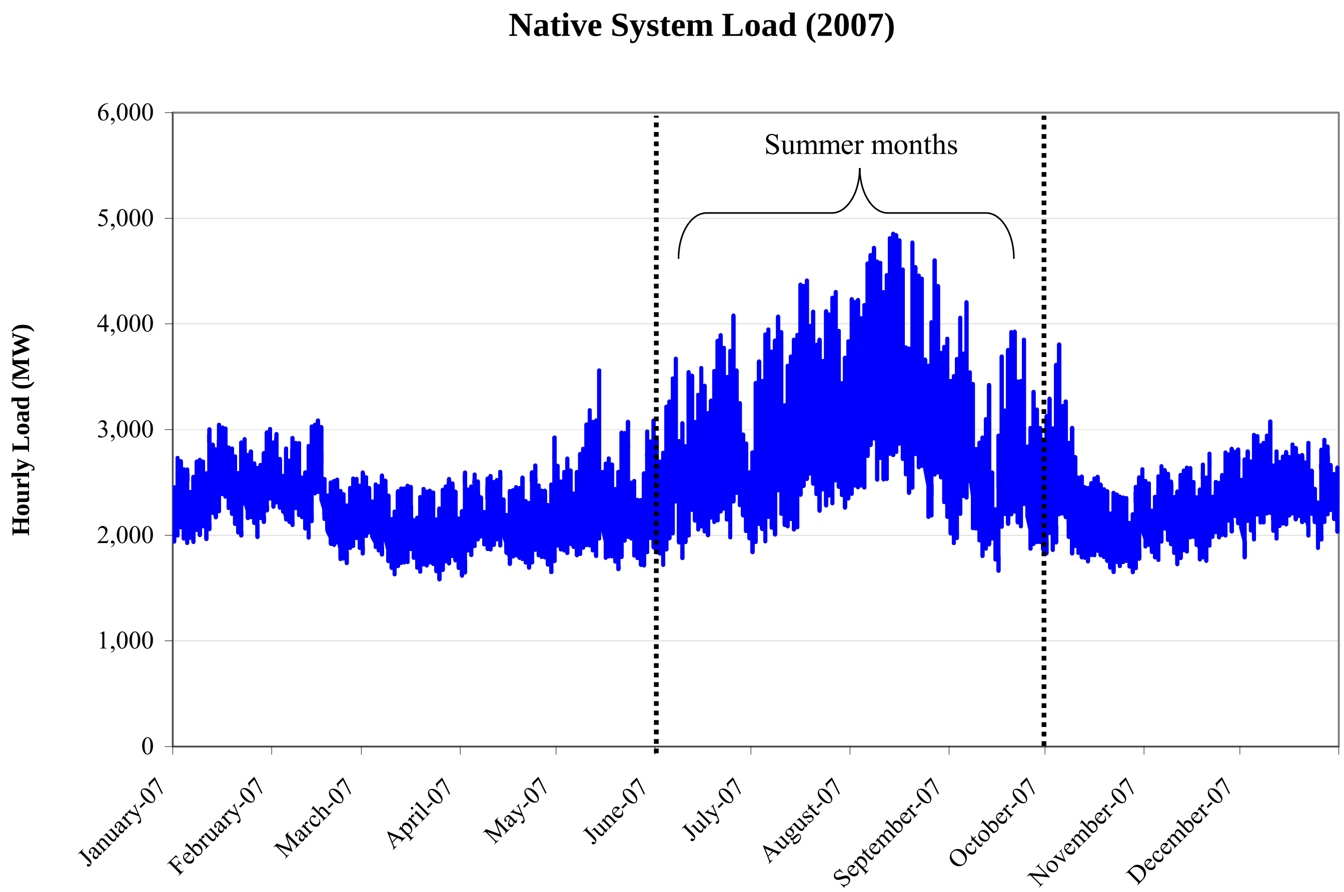
About 10% of the load is in the top 100 hours

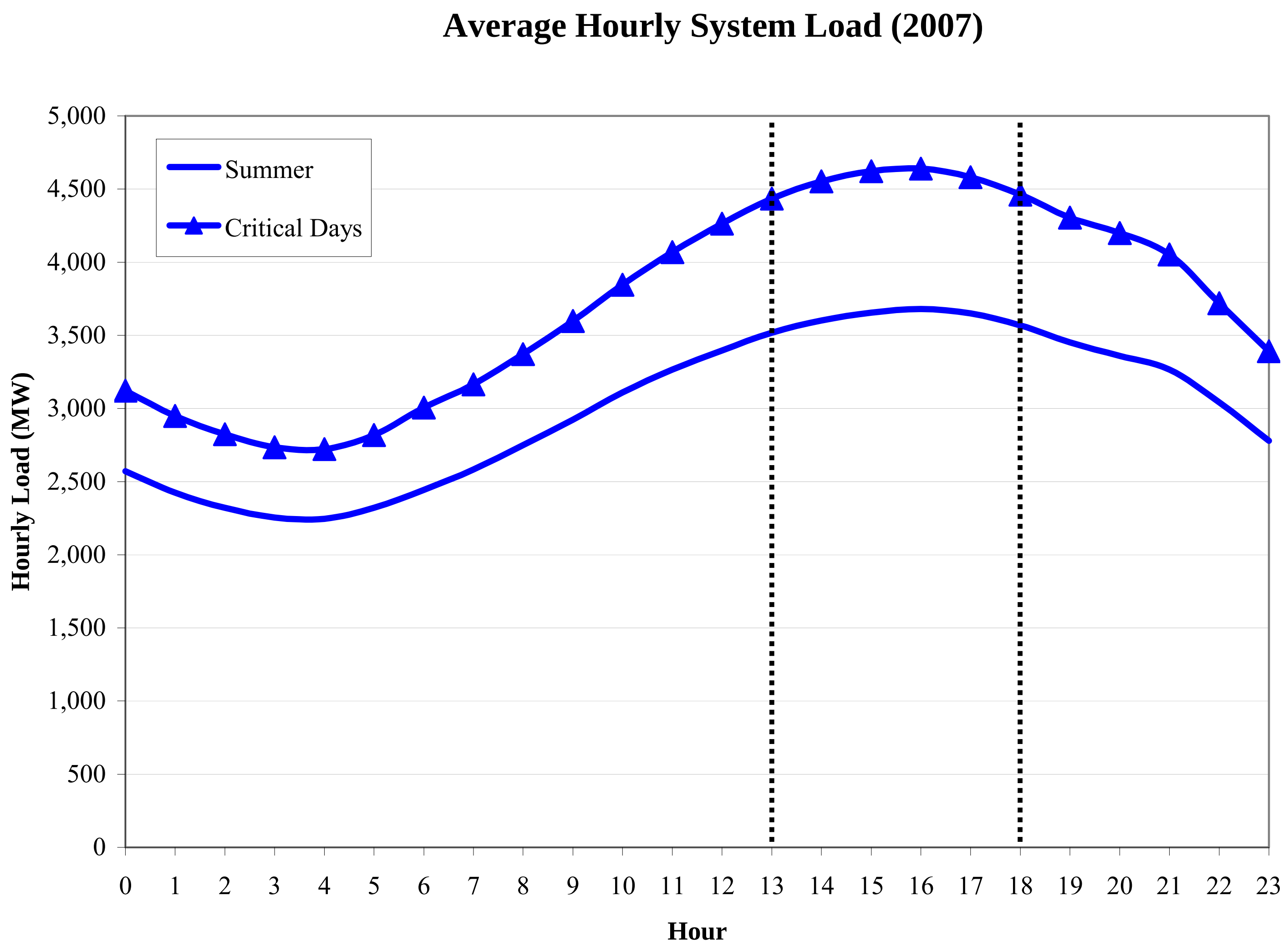


The summer season runs from June through September

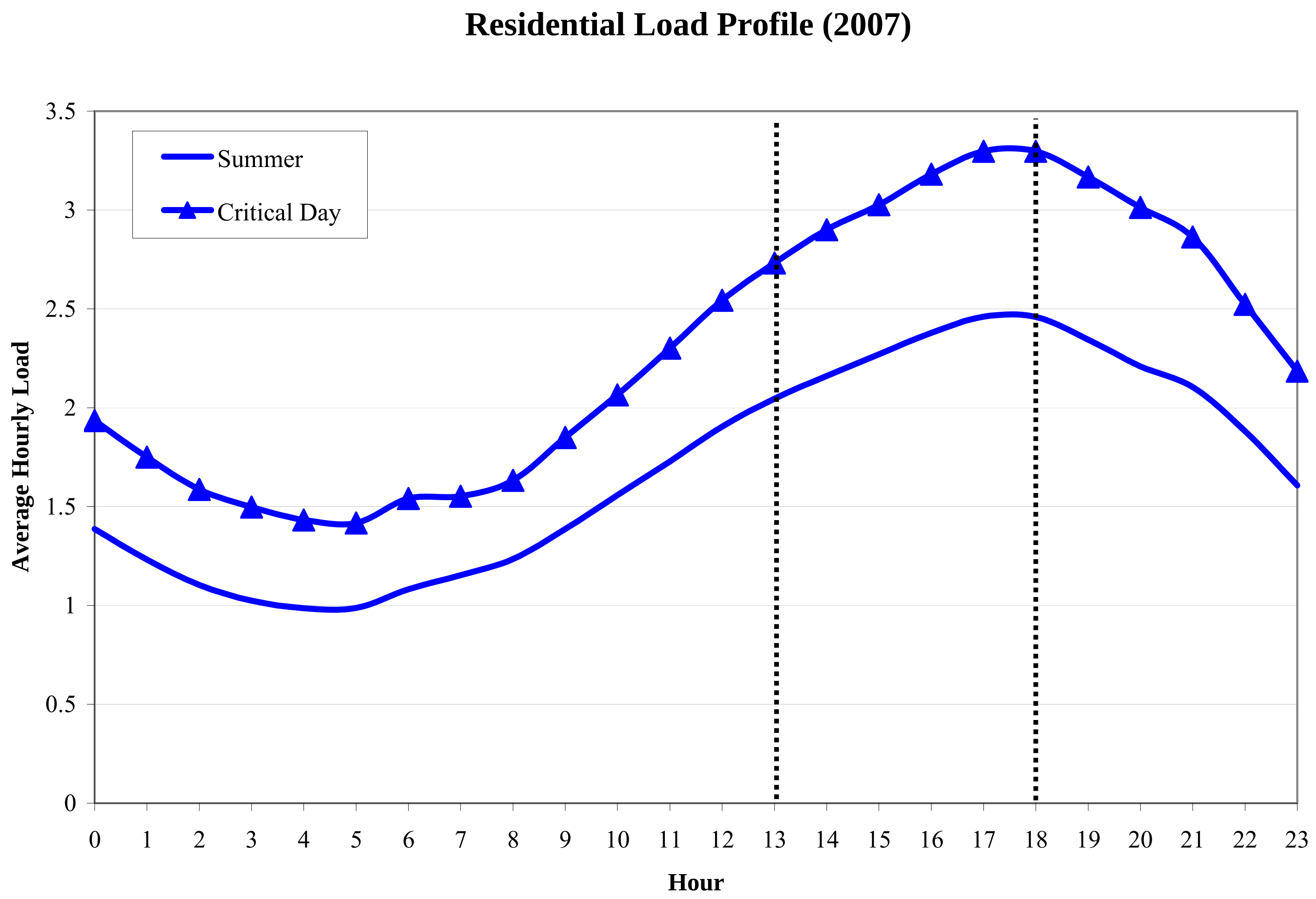


The critical days are the 15 summer weekdays with the highest system load

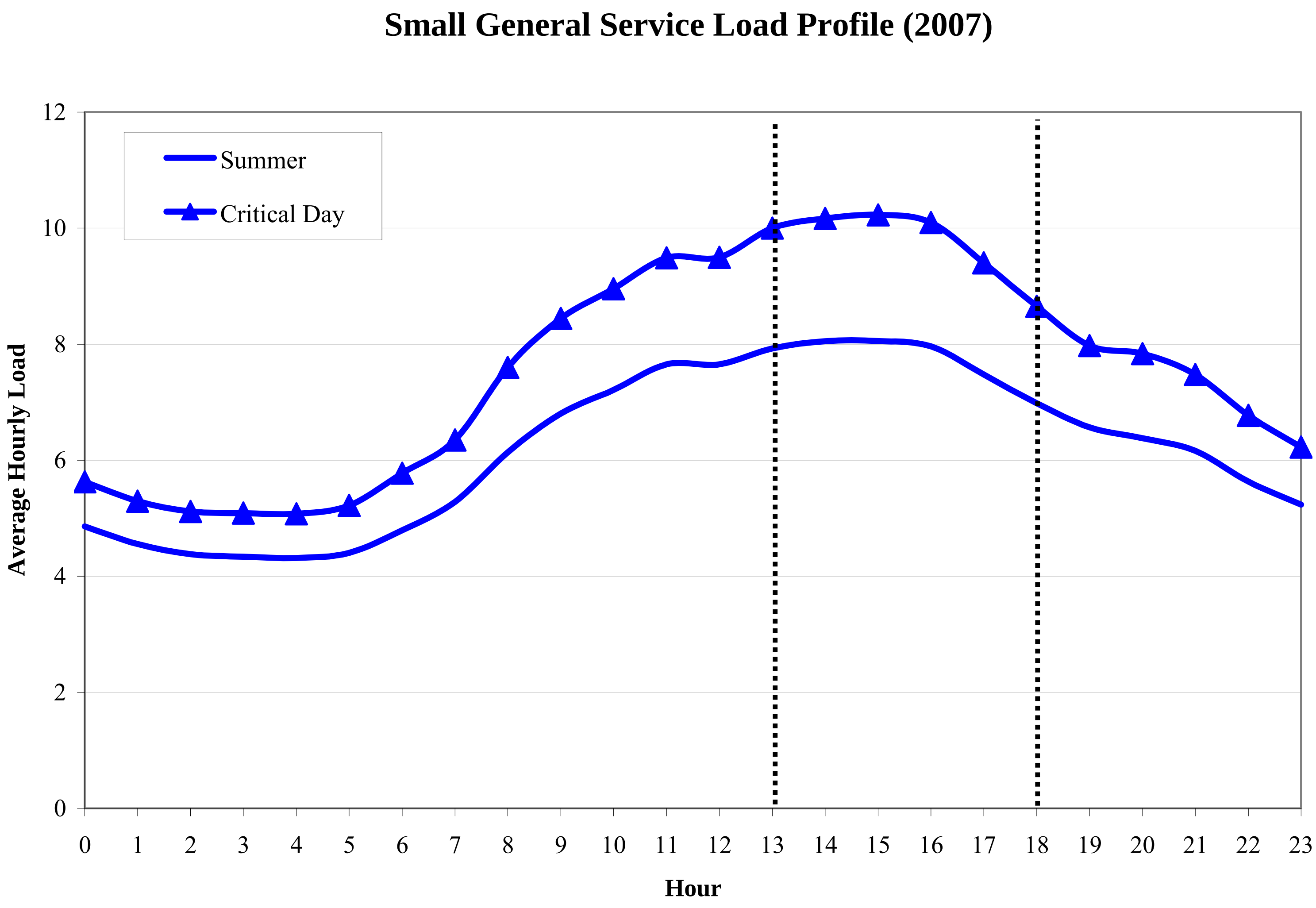
The peak period runs from 1 pm to 6 pm



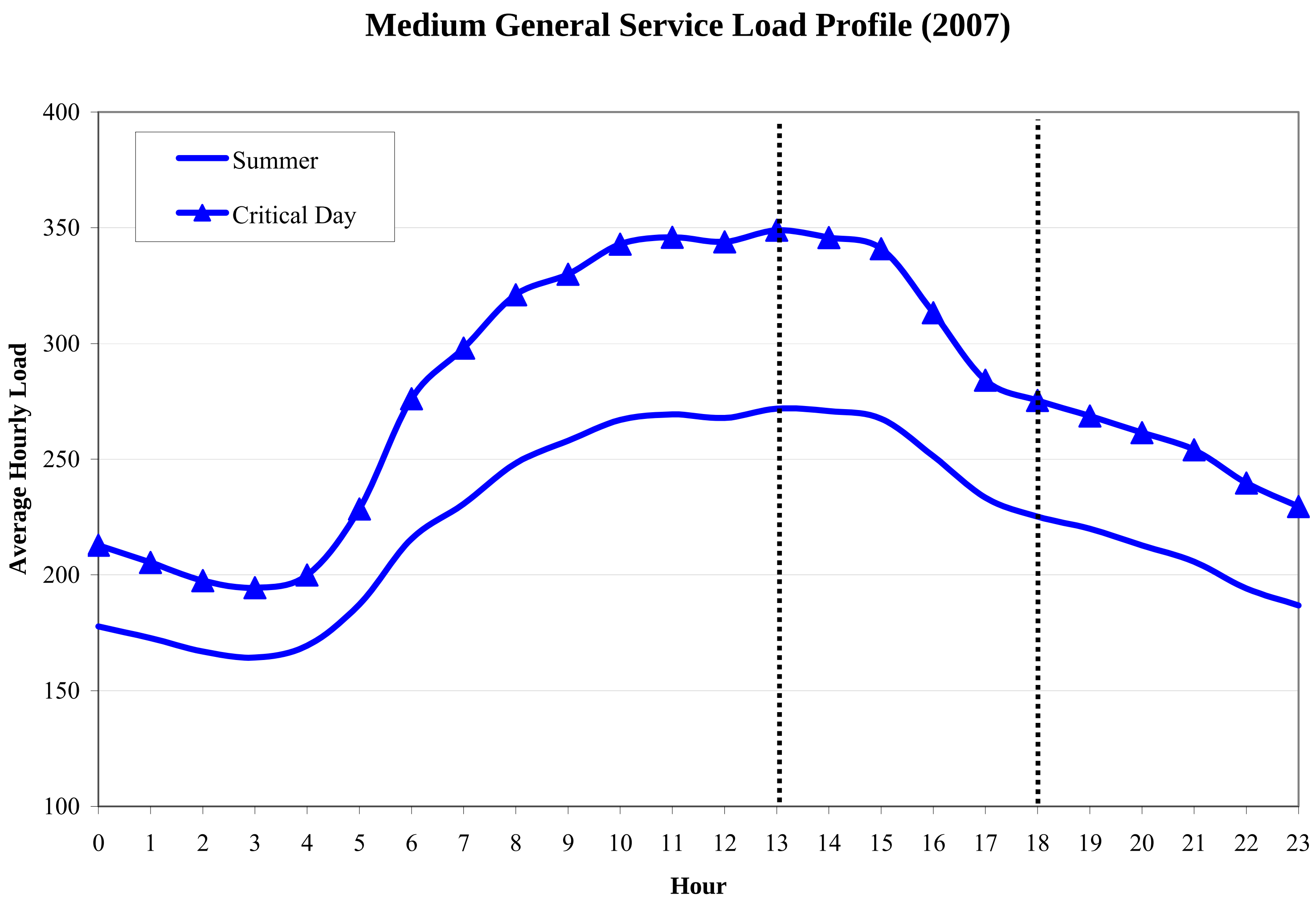
The residential class peaks slightly later than the system



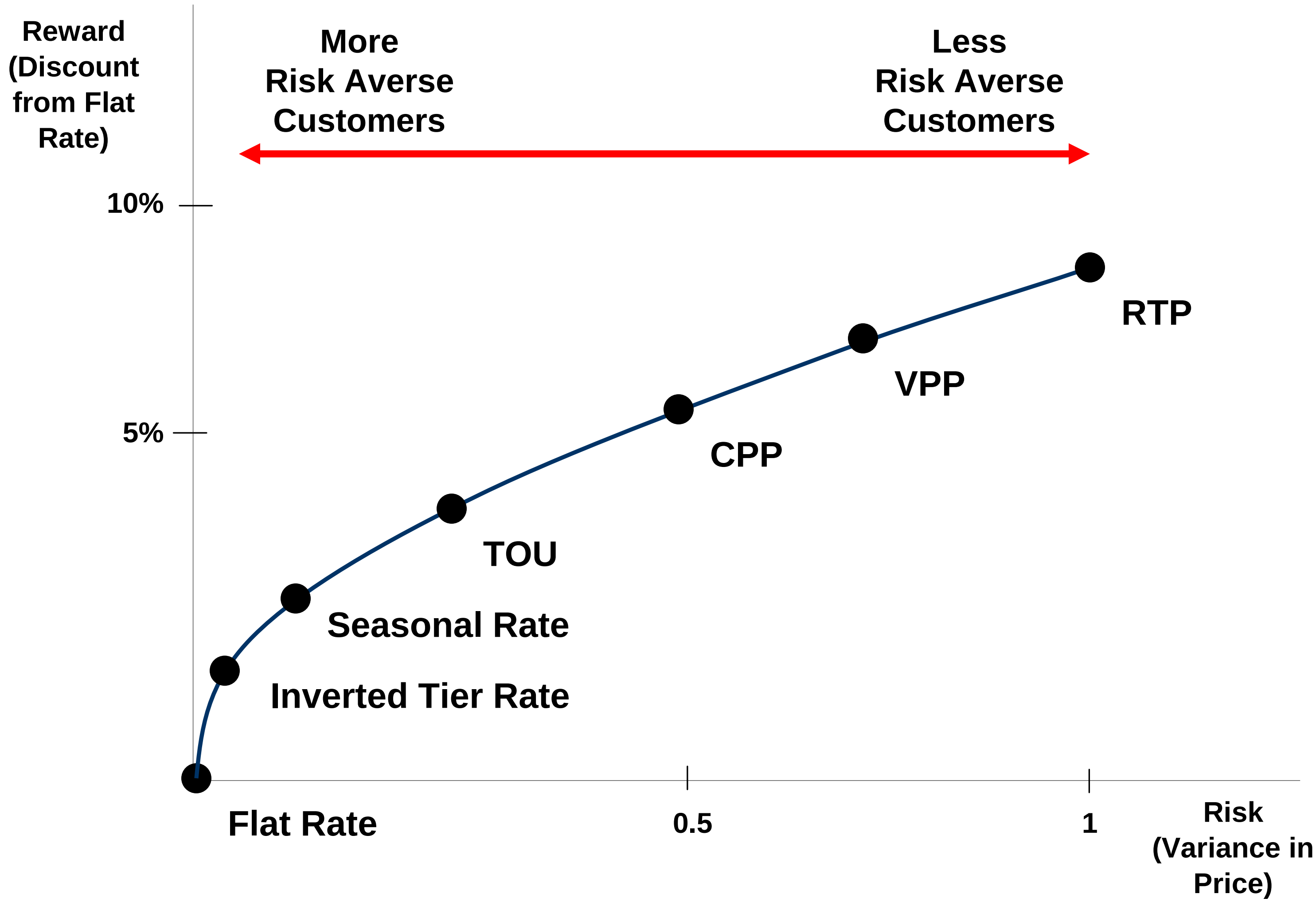
The Small General Service customer class peaks slightly earlier



The Medium General Service class also peaks earlier



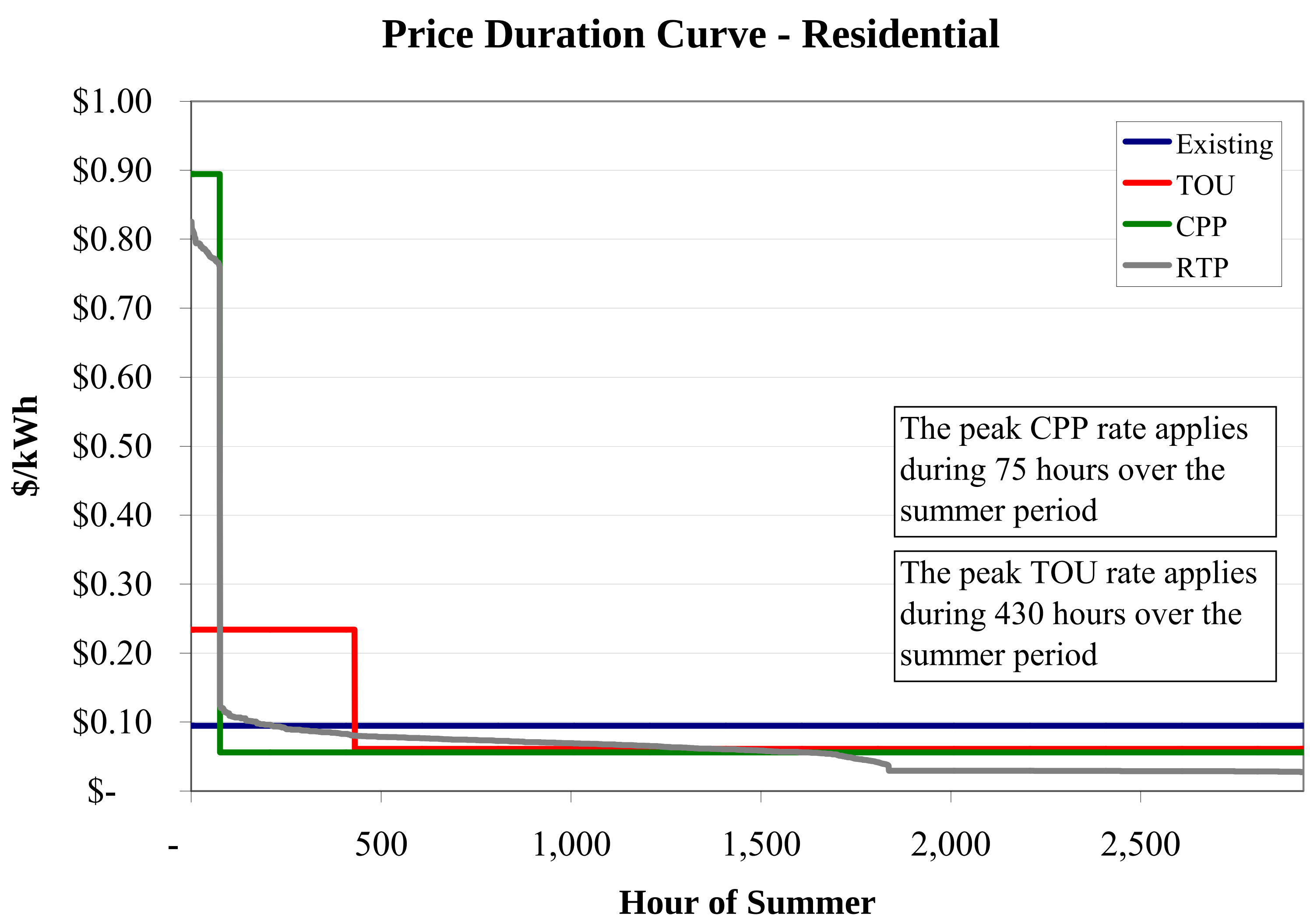
It is best to give choices to customers



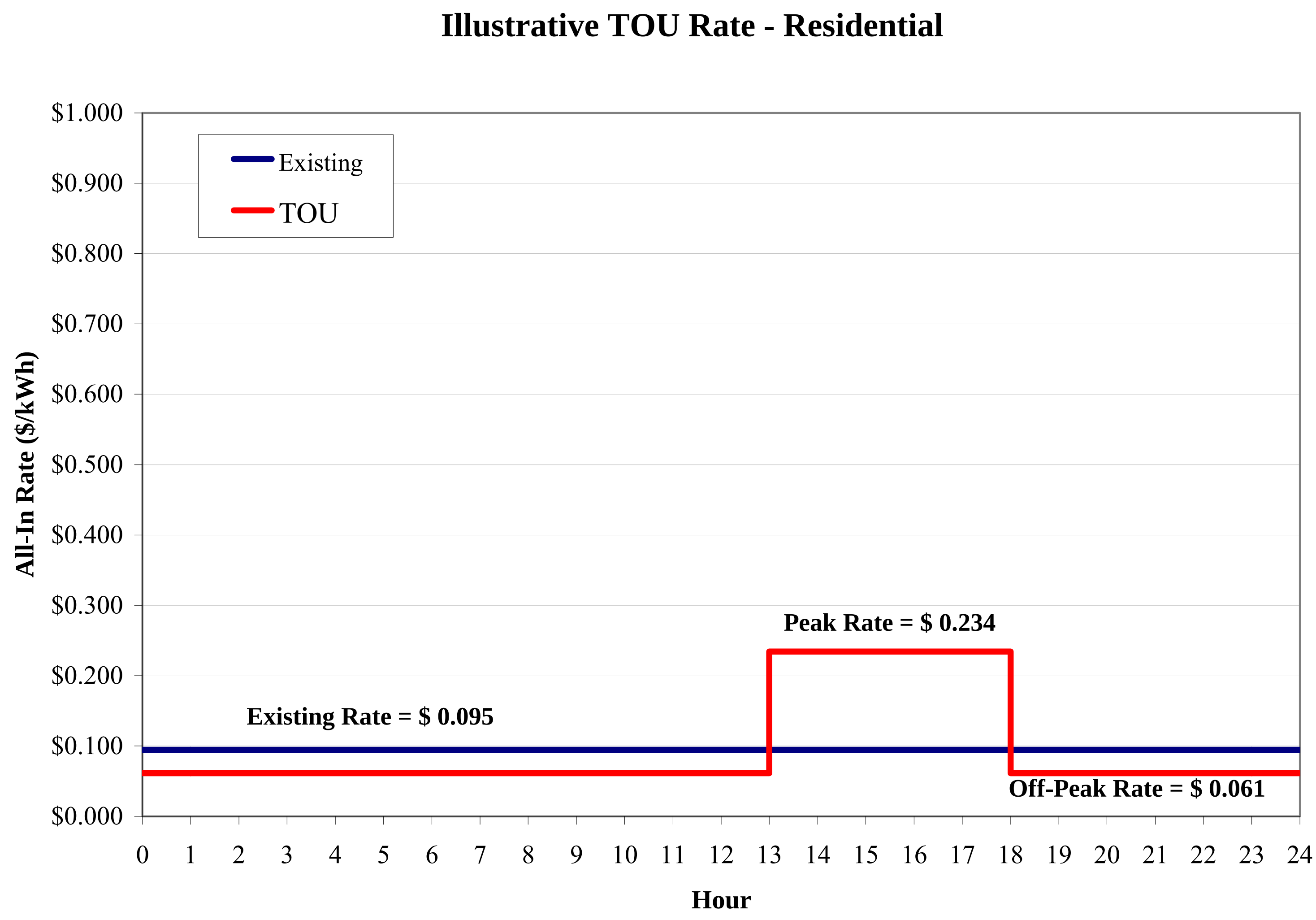
Our rate design principles

- Rates are calculated by allocating the marginal cost of capacity ($60/kW-yr) to peak hours
- The peak period is five hours long (1 pm to 6 pm)
  - For TOU, it applies every weekday
  - For CPP and PTR, it applies on 15 days of the summer
  - For RTP, customers see hourly prices everyday
- Customers receive a discount in the off-peak hours to maintain revenue neutrality and to encourage their participation
  - Revenue neutrality means that Westar's revenues would be unaffected by the new rates in the absence of any change in customer consumption behavior
- Rates apply only during the summer season (June through September)

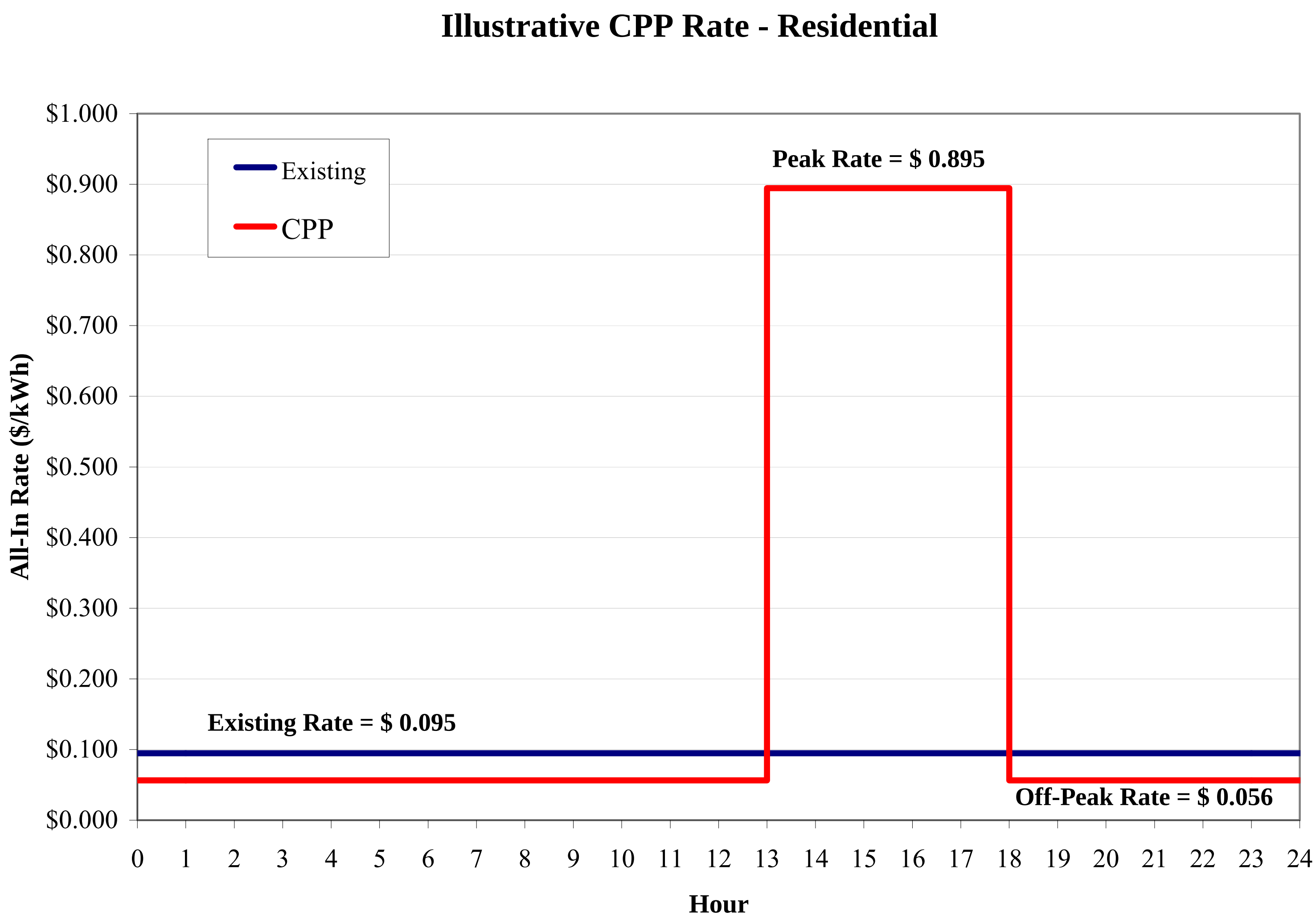
The price duration curves for the rates are very different



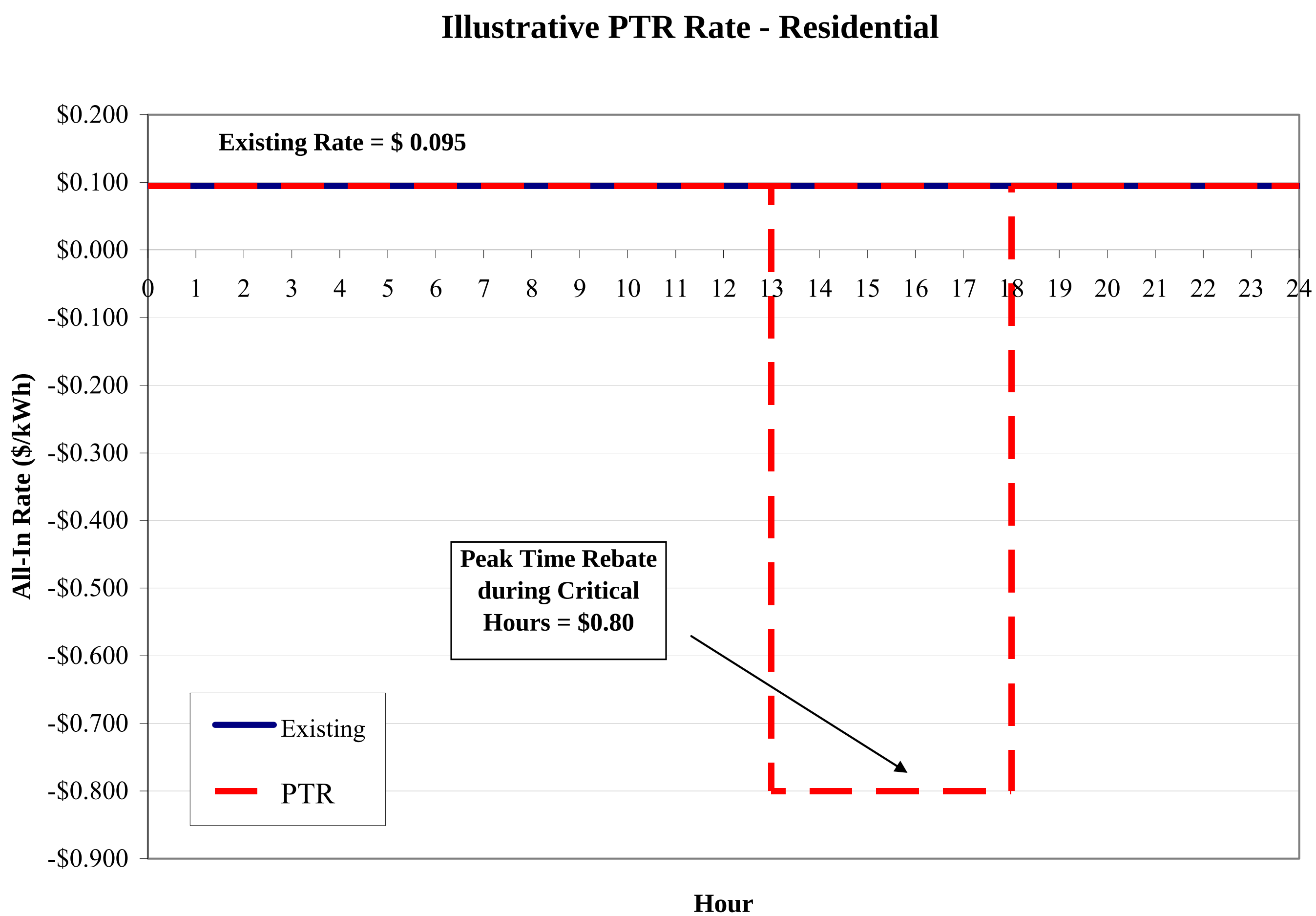
There is a 4:1 ratio between peak and off-peak prices in the TOU rate



The CPP rate has a 15:1 price ratio

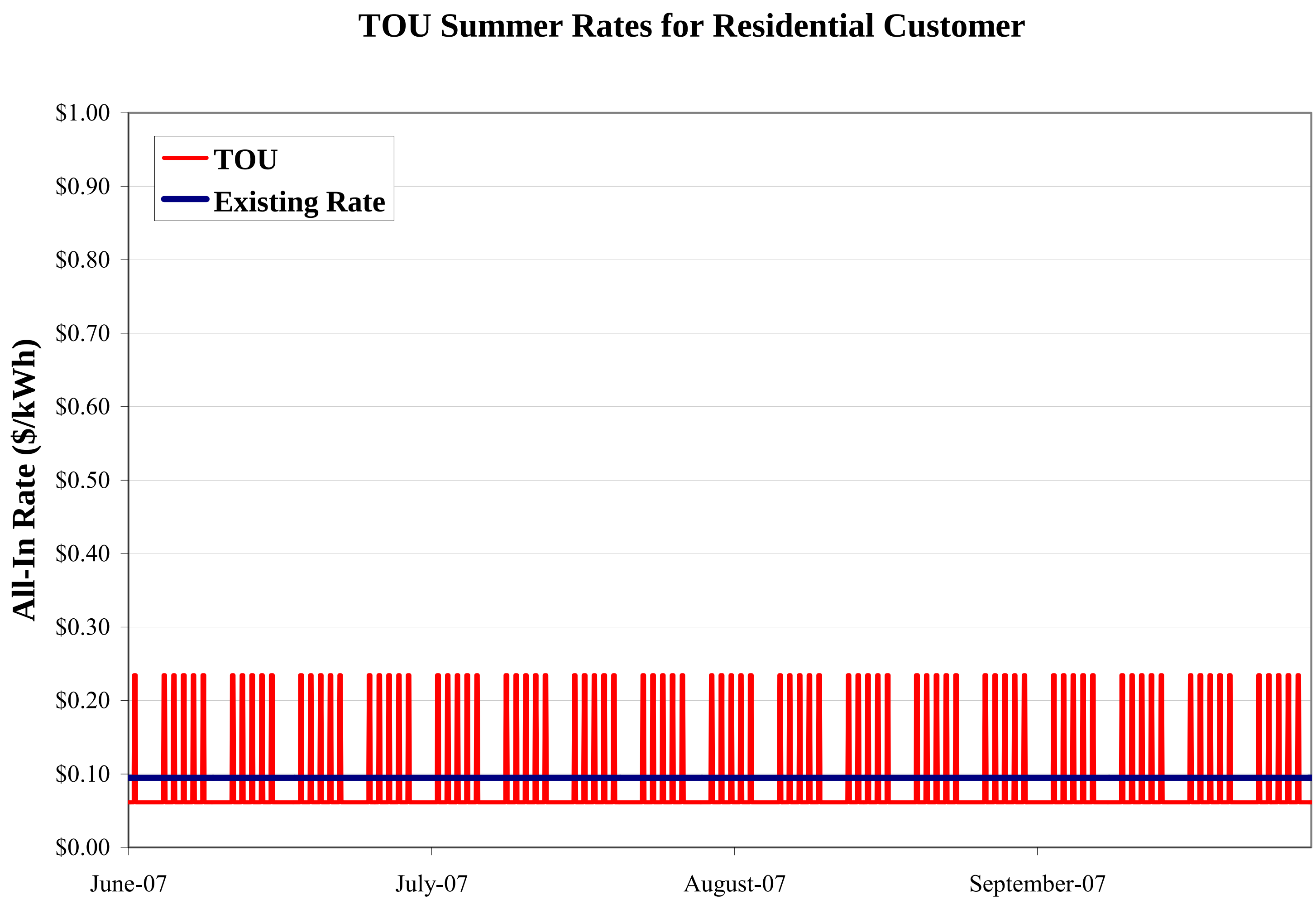


Customers who cut a kWh during the critical peak period save the same amount under the PTR and CPP rates

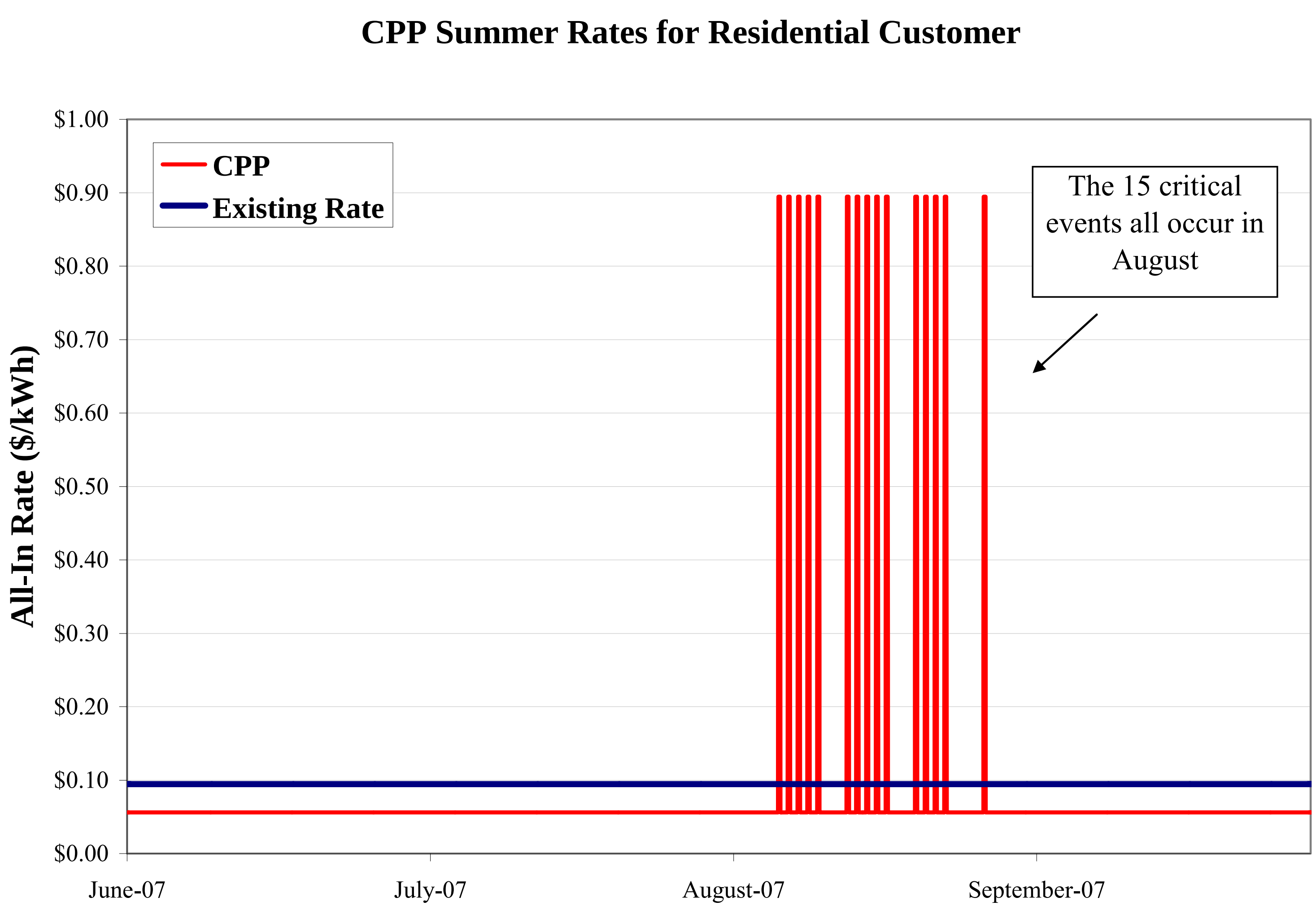


Note: Calculating the rebate amount requires that a baseline consumption level be computed individually for each participating customer

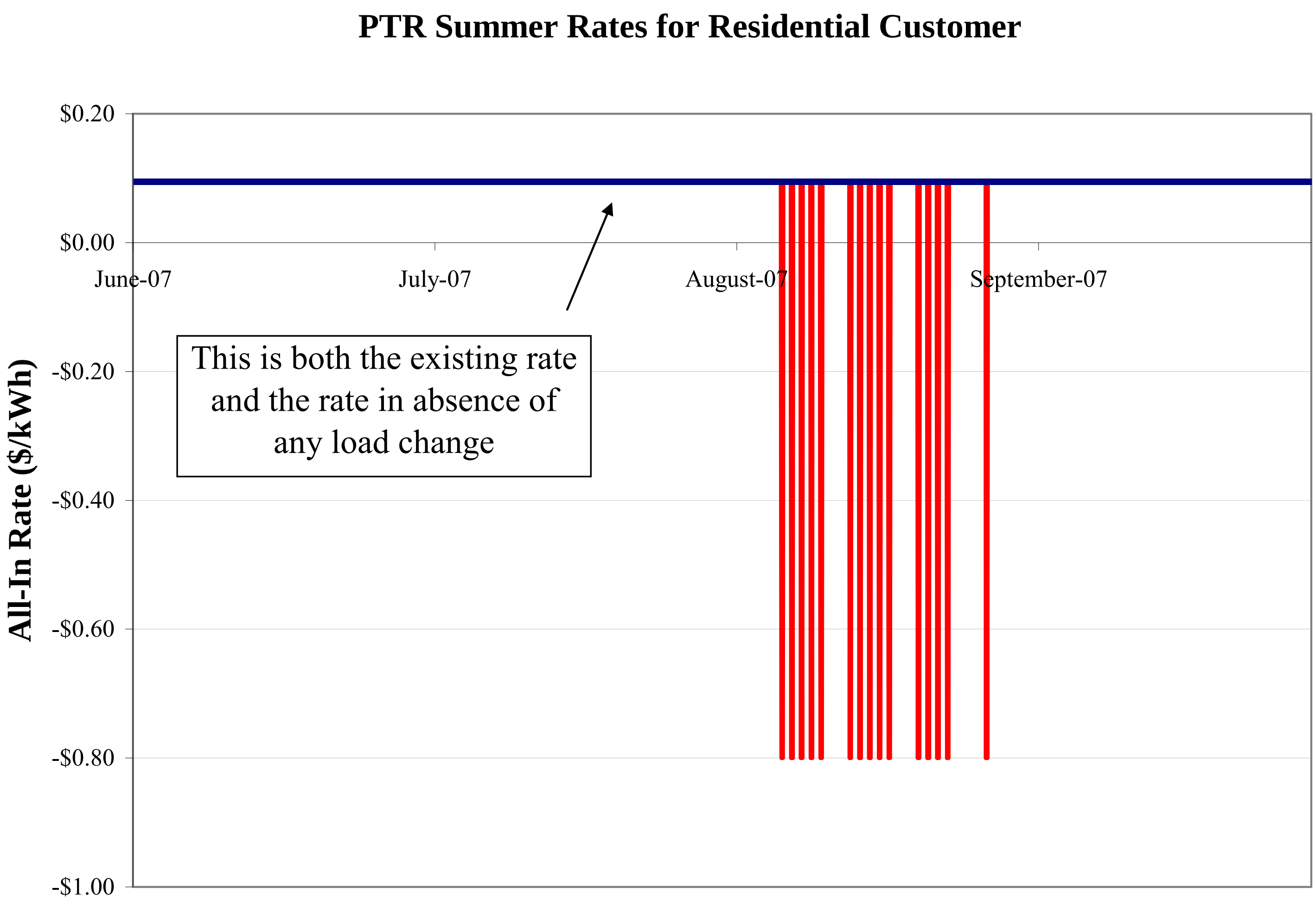
The TOU rate rises and falls every week day relative to the existing rate



The CPP rate has higher peak period rates concentrated in 15 days



The PTR rate offers a rebate for reducing consumption during critical peak hours



The RTP rate allocates capacity costs during the critical peak hours

Features of the RTP rate

- Energy charge varies by hour
- Capacity cost is allocated to 15 five hour critical events
- This produces a “spikier” price during critical peak periods

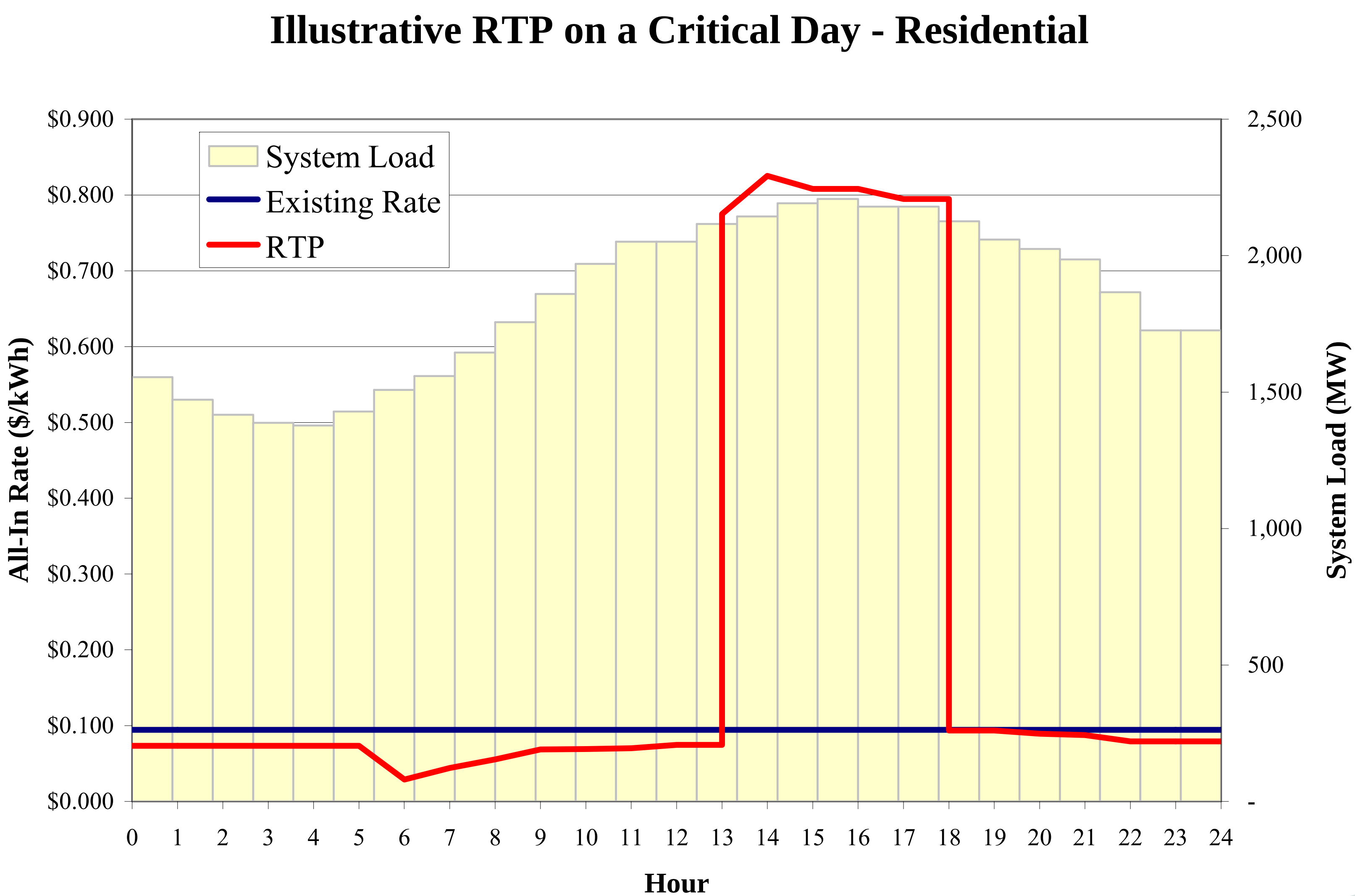
Calculating the RTP Rate

(Hourly system lambda + Critical peak capacity adder) x Scaling factor for revenue neutrality = RTP rate

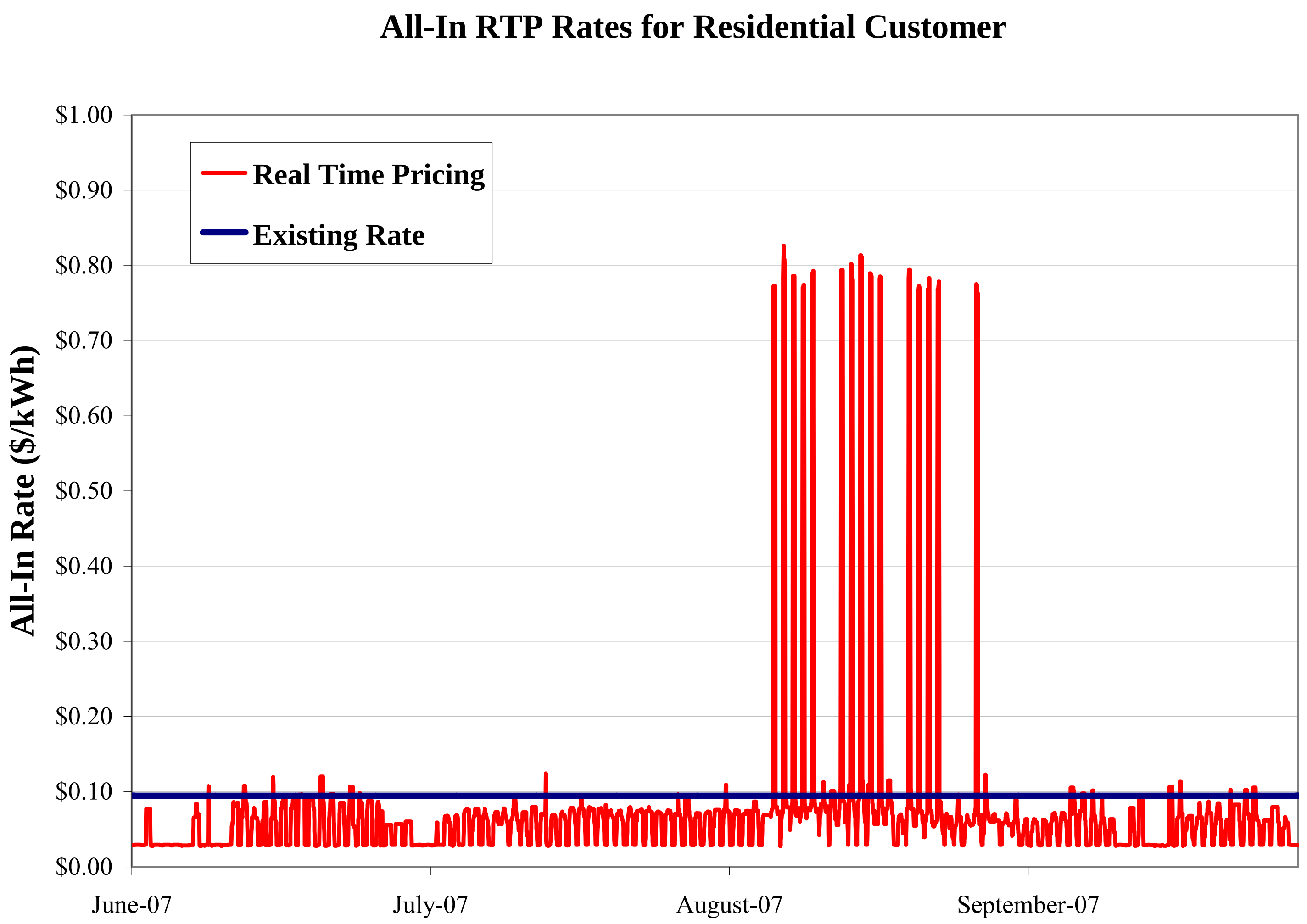
Residential: 0.87
Small GS: 0.77
Medium GS: 0.78

Notes:
(1) Rate is summer-only. Customers would presumably receive 24 hourly prices on a day-ahead basis.
(2) “System lambda” is the marginal cost of energy.

The RTP provides a strong price signal to reduce load during the critical hours



The RTP rate features variation in hourly prices throughout the summer



Agenda

Review of rate designs

Quantifying customer-level impacts

Projecting system-level impacts

We have used two types of elasticities to predict demand response

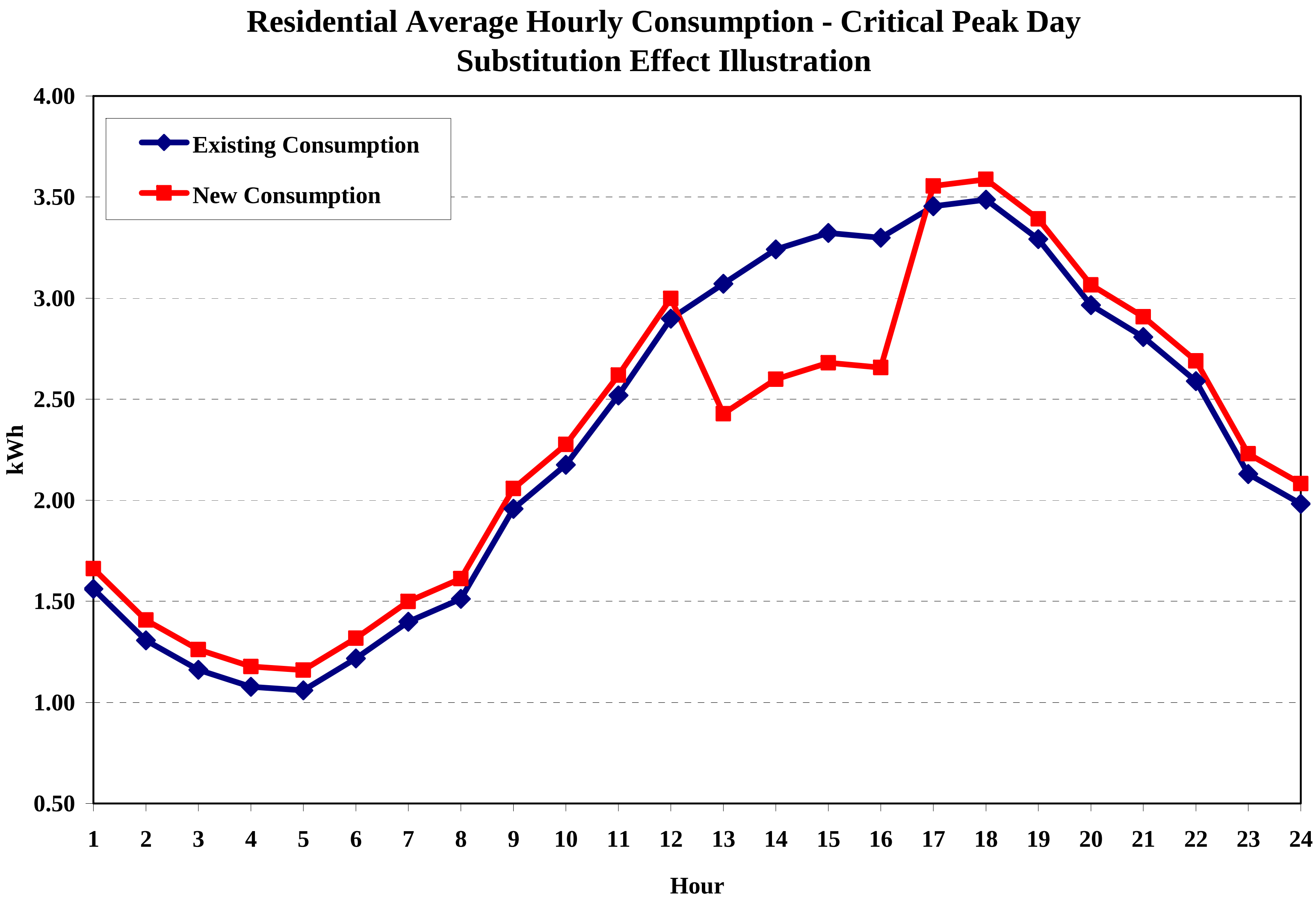
Shift in usage: elasticity of substitution

- This measures the pure change in load shape (i.e. load shifting)

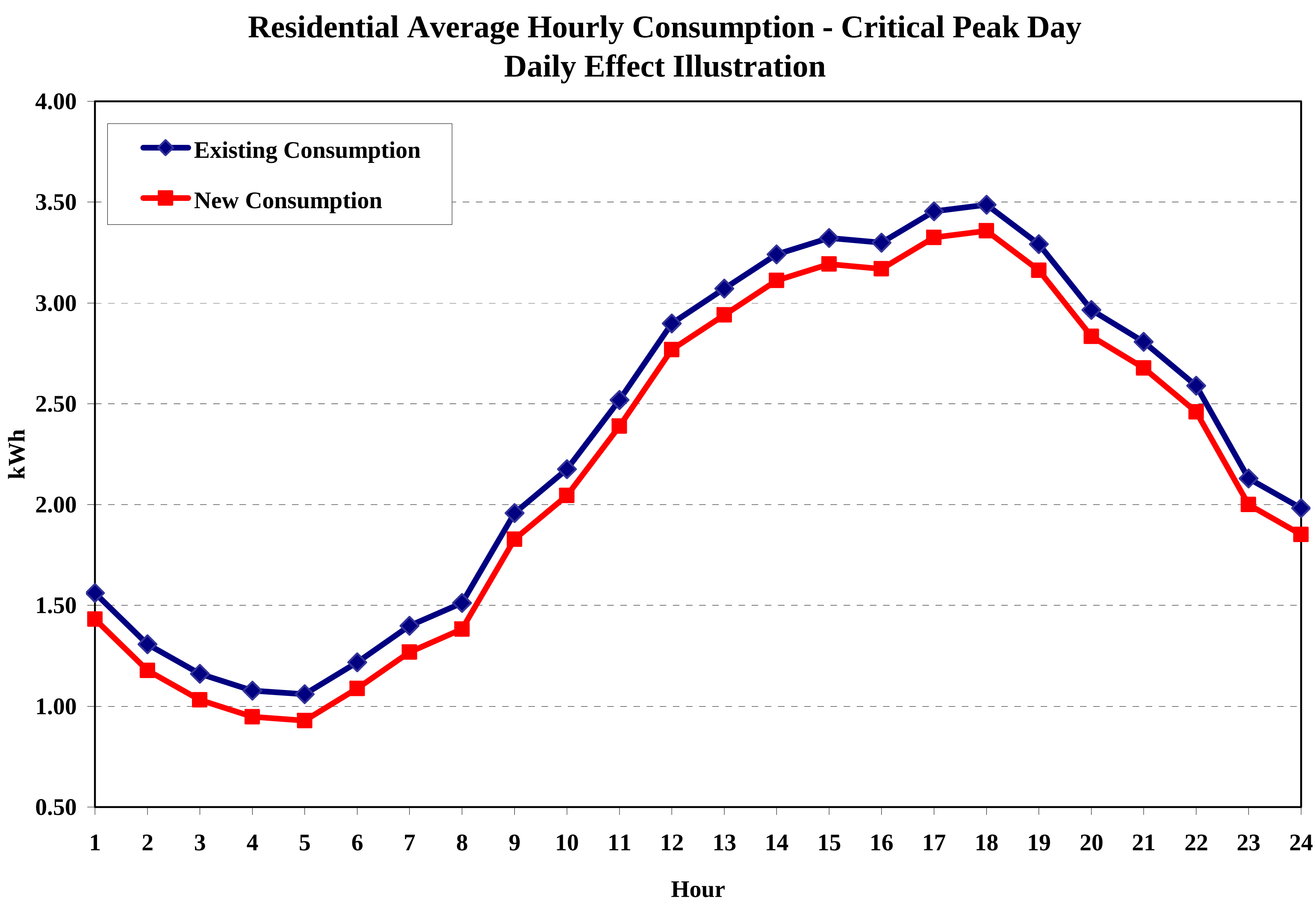
Conservation: daily price elasticity

- This measures the change in the level of the load curve (energy) caused by a change in the price level

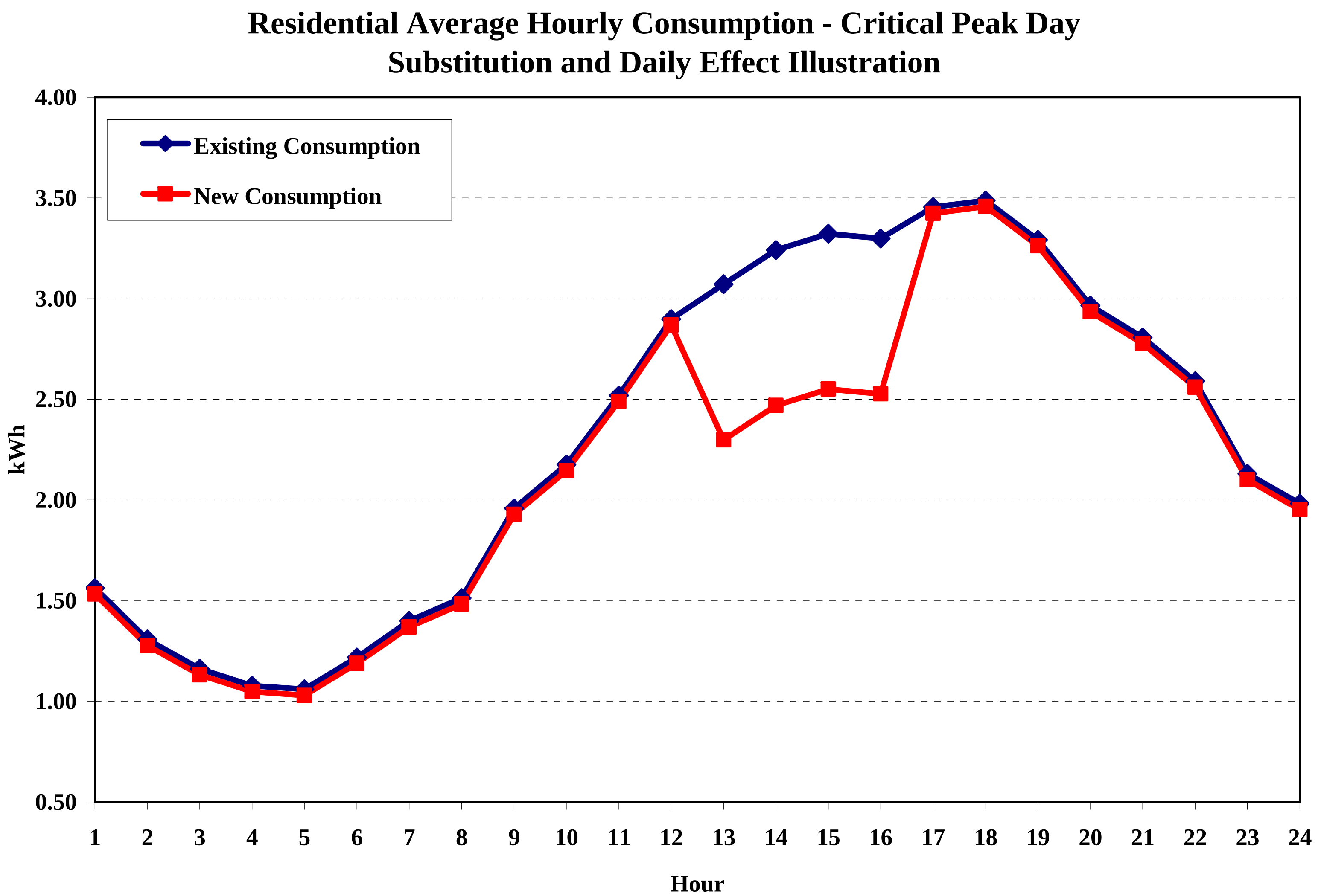
Customers may change their load shape in response to higher peak prices



Higher peak prices may also induce an overall conservation effect



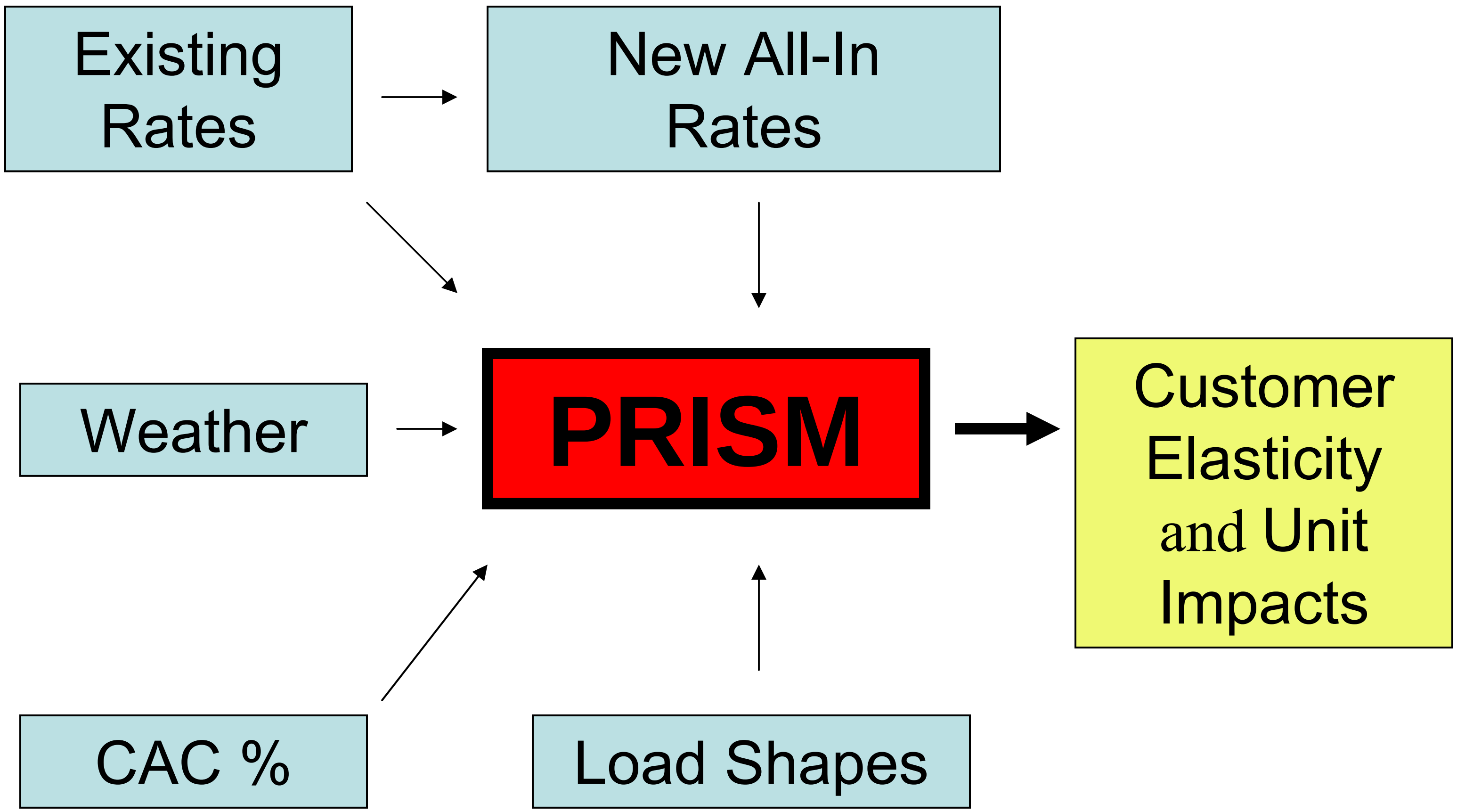
The combined effect can lead to reduced consumption throughout the critical days



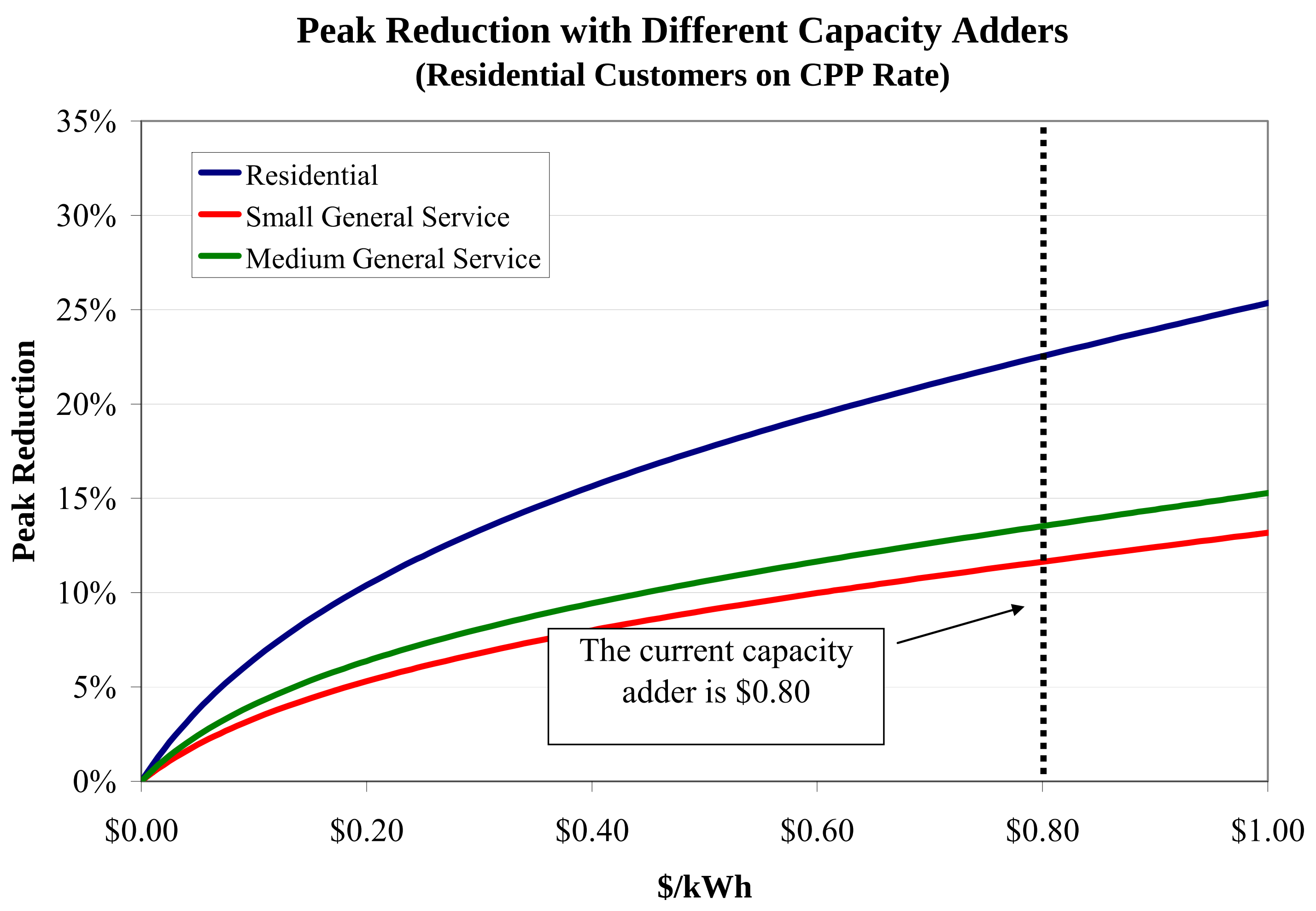
Demand response is predicted using the Price Impact Simulation Model (PRISM)

- PRISM captures the actual responses of thousands of customers during several pricing experiments
- It formed the basis of FERC's National Assessment of Demand Response Potential
- Price elasticities are used to produce a per-customer peak demand reduction
- When multiplied into a forecast of participating customers, the result is a prediction of system-wide peak reduction

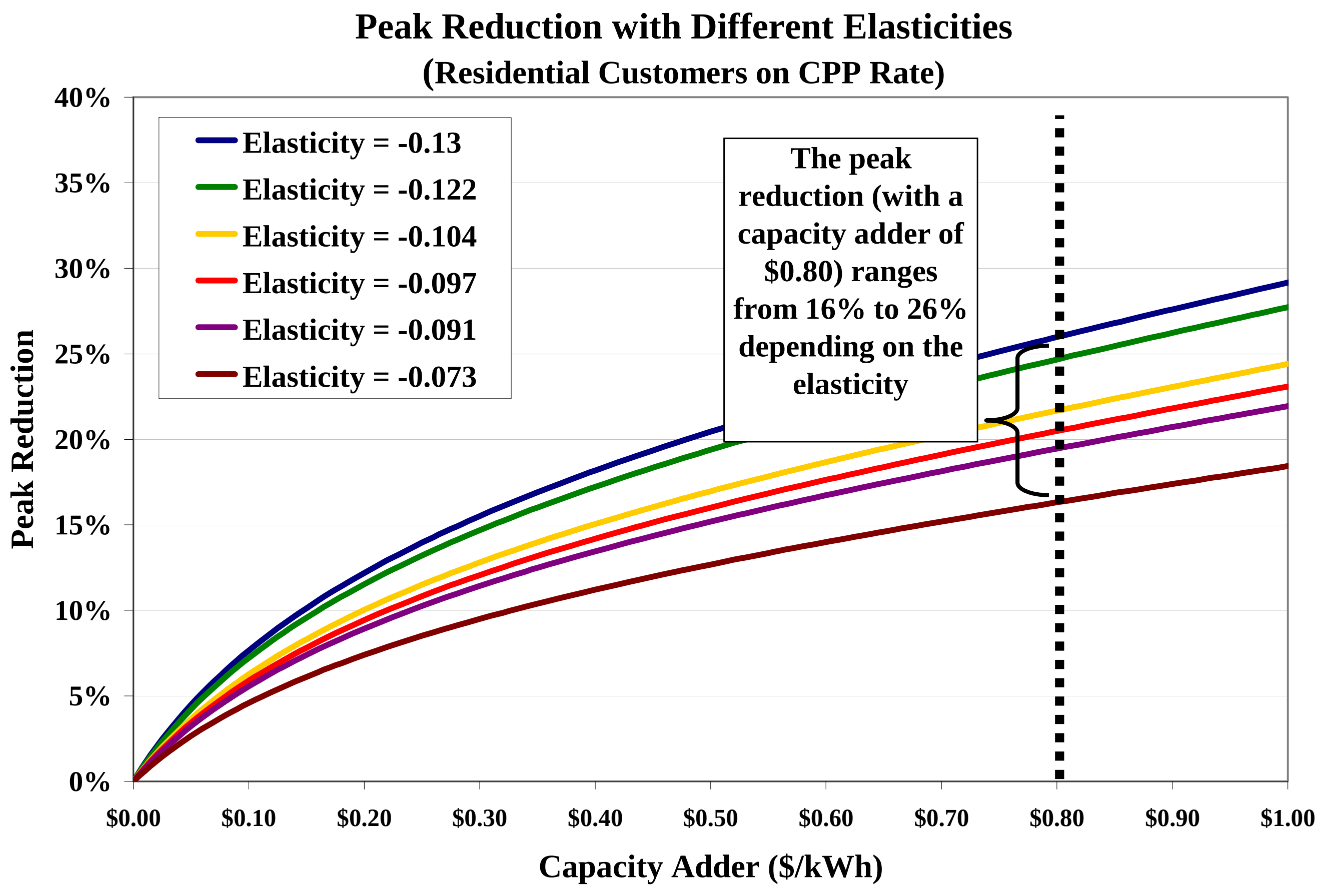
In PRISM, we can tailor customer elasticities to Westar-specific conditions



PRISM yields demand response curves



The assumptions on elasticities greatly affect the magnitude of demand response



More information on Kansas-specific elasticities would allow for more accurate estimates

Our analysis does not reflect all of the inter-temporal effects of dynamic pricing

1. Customer bills will immediately increase or decrease due to the relative peakiness of their load shapes
2. Bills will decrease as customers shift load in response to the rates

Addressed in this project

3. In the short run, rates will increase to recover these lost revenues
4. In the long run, reductions in capacity costs will cause rates to decrease

Subject to further research

Residential CPP and PTR rates produce the largest peak reduction and bill impact

Residential

Consumption During Critical Hours

	Origional (kWh/hour)	New (kWh/hour)	Change (kWh/hour)	Change (%)
TOU	3.0	2.7	-0.310	-10.2%
CPP	3.0	2.3	-0.682	-22.5%
PTR	3.0	2.4	-0.590	-19.5%
RTP	3.0	2.5	-0.553	-18.3%

Average Monthly Summer Bill

	Origional ($/month)	New ($/month)	Change ($/month)	Change (%)
TOU	$117.46	$113.62	-$3.85	-3.3%
CPP	$117.46	$107.72	-$9.75	-8.3%
PTR	$117.46	$107.81	-$9.65	-8.2%
RTP	$117.46	$110.74	-$6.72	-5.7%

SGS RTP and CPP rates produce the largest peak impact and bill savings

Small General Service

Consumption During Critical Hours

	Origional (kWh/hour)	New (kWh/hour)	Change (kWh/hour)	Change (%)
TOU	10.0	9.5	-0.521	-5.2%
CPP	10.0	8.8	-1.162	-11.6%
PTR	10.0	9.0	-1.018	-10.2%
RTP	10.0	8.8	-1.171	-11.7%

Average Monthly Summer Bill

	Origional ($/month)	New ($/month)	Change ($/month)	Change (%)
TOU	$348	$339	-$9	-2.6%
CPP	$348	$332	-$17	-4.8%
PTR	$348	$331	-$17	-4.9%
RTP	$348	$325	-$23	-6.6%

MGS CPP rates yield the biggest peak reduction but RTP rates yield the biggest bill savings

Medium General Service

Consumption During Critical Hours

	Origional (kWh/hour)	New (kWh/hour)	Change (kWh/hour)	Change (%)
TOU	327	305	-22	-6.6%
CPP	327	282	-44	-13.5%
PTR	327	289	-38	-11.6%
RTP	327	286	-40	-12.3%

Average Monthly Summer Bill

	Origional ($/month)	New ($/month)	Change ($/month)	Change (%)
TOU	$11,271	$10,940	-$332	-2.9%
CPP	$11,271	$10,623	-$649	-5.8%
PTR	$11,271	$10,655	-$616	-5.5%
RTP	$11,271	$10,497	-$774	-6.9%

The overall impact of dynamic pricing on sales is small

- Across all rates, using the elasticities shown earlier, the predicted change in average monthly consumption was negligible
  - **Change in sales typically ranged between -0.7% and +0.8%.**
- This lack of conservation is largely because the rates are revenue neutral
- Higher impacts might occur if new enabling technologies such as in-home displays are used with steeply inclining block rates

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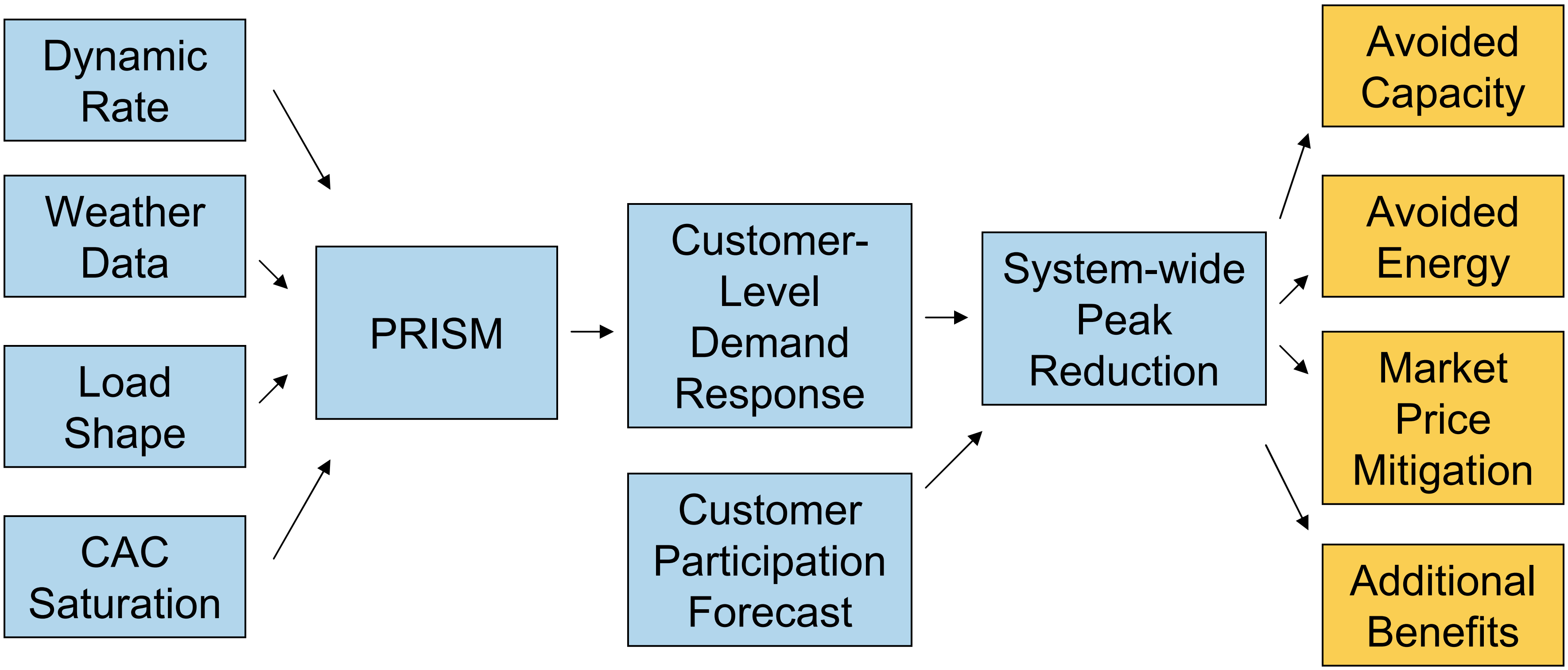
The Zen of PRISMetrics



We have created four scenarios of customer participation

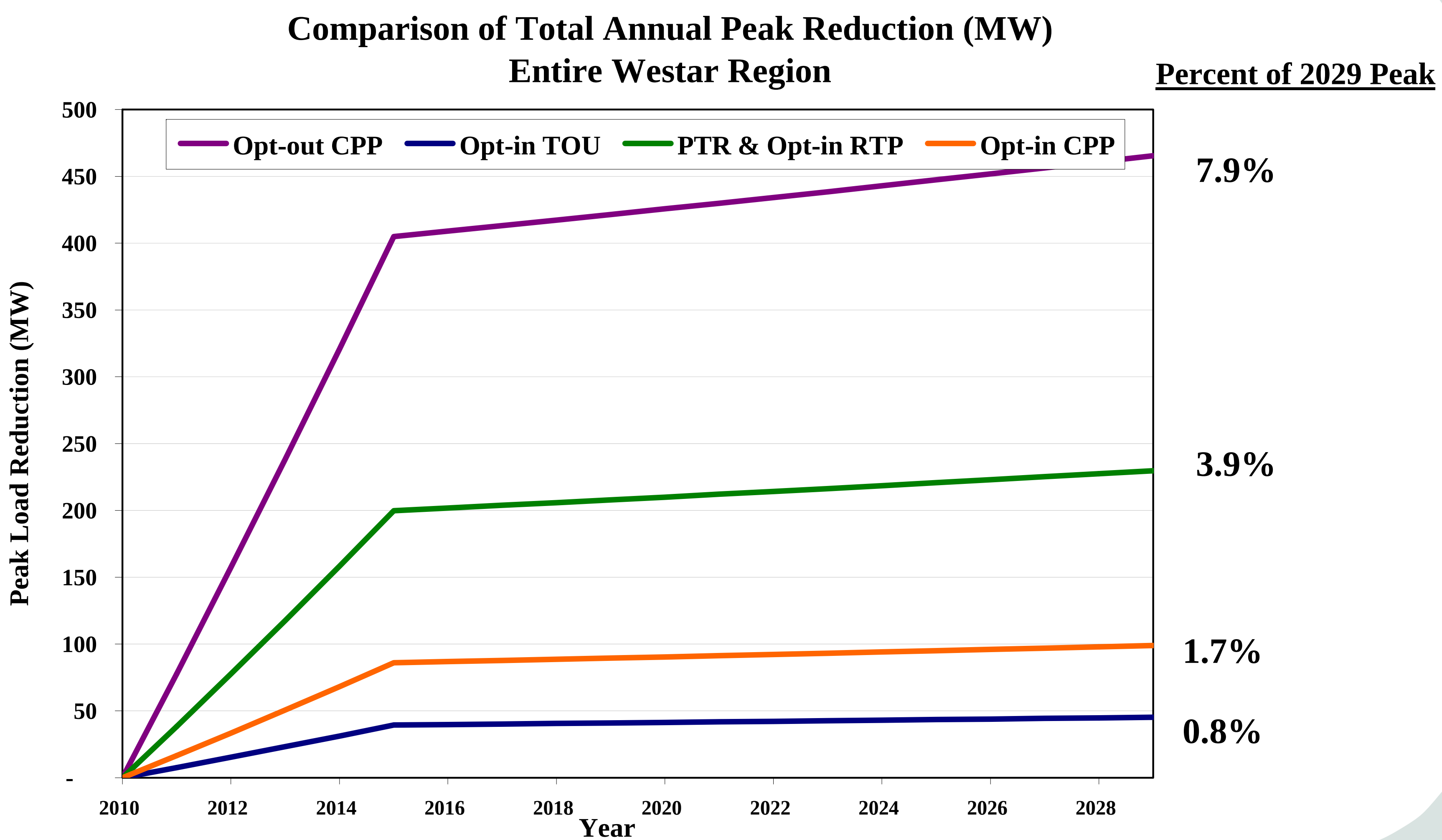
Scenario	Class	Rate	Type	Participation
Opt-out CPP	Residential	CPP	Opt-out	75%
	Small General Service	CPP	Opt-out	60%
	Medium General Service	CPP	Opt-out	60%
Opt-in TOU	Residential	TOU	Opt-in	15%
	Small General Service	TOU	Opt-in	15%
	Medium General Service	TOU	Opt-in	15%
PTR & Opt-in RTP	Residential	PTR	Awareness	50%
	Small General Service	RTP	Opt-in	15%
	Medium General Service	RTP	Opt-in	15%
Opt-in CPP	Residential	CPP	Opt-in	15%
	Small General Service	CPP	Opt-in	15%
	Medium General Service	CPP	Opt-in	15%

- Opt-out participation rates are based on market research
- Opt-in participation rate are based on results of best programs to-date
- Scenarios do not include the impacts of enabling technologies (such as programmable communicating thermostats) which would lead to higher peak reductions if offered to customers

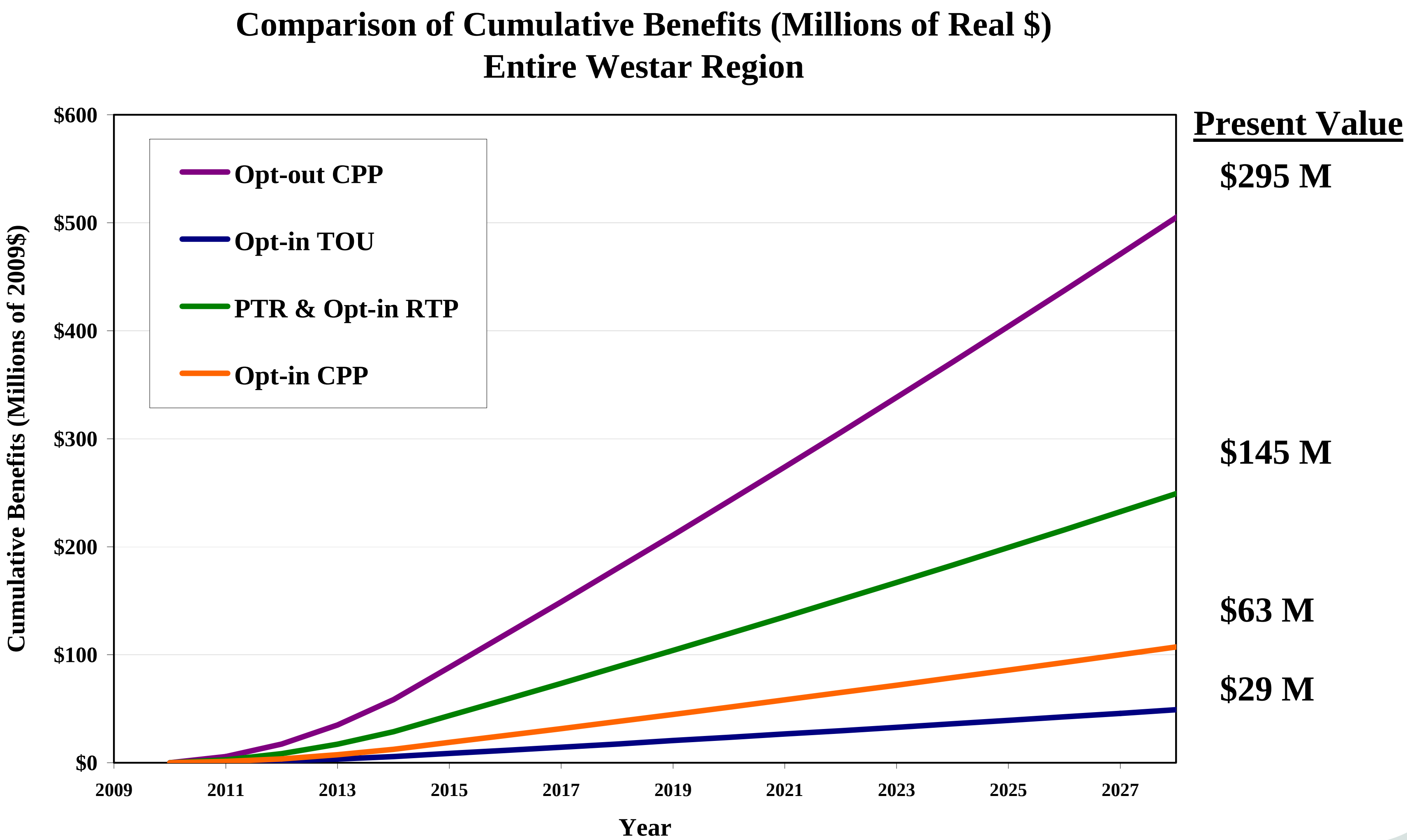
General assumptions in the benefits analysis

- **Forecast Horizon = 20 years**
- **Number of customers in first year**
  - Residential = 565,873
  - Small General Service = 81,935
  - Medium General Service = 1,455
- **AMI deployment (eligibility)**
  - Starts at 0% and increases to 100% over 5 years for all customers
- **Avoided costs**
  - Capacity = $60/kW-year (2009 $, based on 2007 estimate)
  - Transmission and Distribution = No benefits assumed (see appendix)
  - Average energy price = $46.5/MWh in summer (based on system lambda)
- **Annual discount rate = 8.49%**
- **Annual inflation rate = 2.4%**
- **Reserve margin = 13%**
- **Line losses = 8.77%**

A CPP rate with default (opt-out) participation would produce the largest peak impacts



The present value of benefits from the TRC perspective ranges from $29 to $295 million



Appendix A:

Avoided T&D Costs

Estimating avoided T&D costs from dynamic pricing is challenging

Dynamic pricing could defer investment in T&D capacity as peak demand growth is reduced

However, this is a difficult figure to estimate

- It is very system- and geography-specific, so a general industry assumption cannot be used
- It is difficult to estimate the share of T&D investment that is directly tied to peak demand

A survey of recent T&D avoided cost assumptions was conducted to understand the range of publicly available estimates

- See next slide

To remain consistent with publicly available sources, we assume no avoided T&D cost but recognize that it could potentially be an additional benefit

Most utilities have assumed little or no avoided T&D cost from demand response

Xcel Energy (Northern States Power)

- Assumed less than 12.5 cents/kW-month ($1.50/kW year) of transmission cost
- Assumed no avoided distribution cost

Pacific Gas & Electric

- Only included avoided T&D costs in an upper-bound sensitivity discussion
- Total avoided costs ranged around $50/kW-year
- However, the utility does not feel that dynamic pricing can lead to avoided T&D investment, claiming it is too unpredictable as a resource for meeting peak demand

Southern California Edison

- Multiplied forecast of levelized incremental T&D investment by 20% to arrive at share attributable to peak growth
- Actual costs are confidential

Pepco Holdings, Inc.

- Only qualitatively addressed the potential for DR to reduce T&D investment

Baltimore Gas and Electric

- Assumed moderate amount of avoided T&D investment but estimates are confidential

California Independent System Operator

- Believes incorporating avoided T&D costs is a stretch for most, if not all DR programs because utilities generally are unable to define DR program impacts at a sufficient level of granularity

Appendix B:

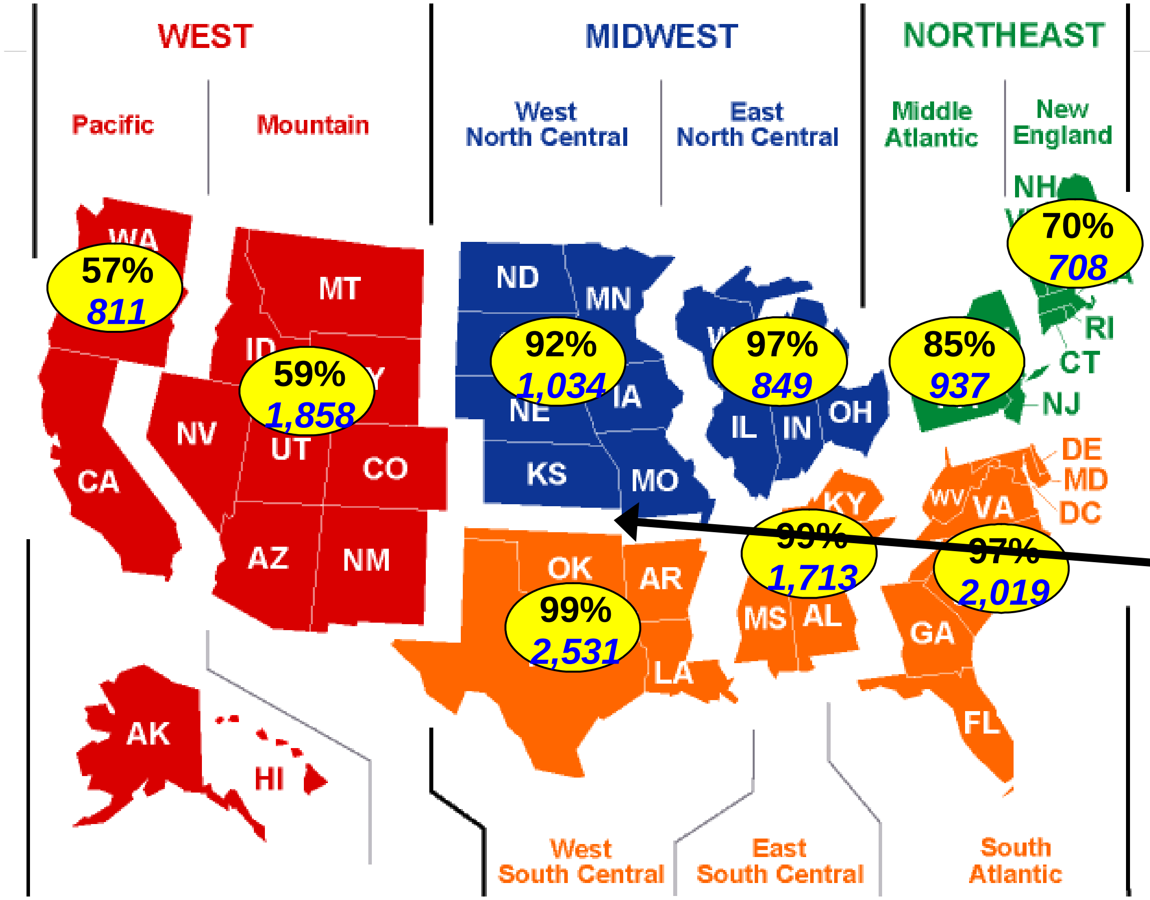
Additional Detail on Modeling Assumptions and Results

The final PRISM elasticities vary by class

- The residential elasticities are derived from a variety of experiments and the C&I elasticities from a variety of full-scale implementations

	Elasticity of Substitution	Daily Price Elasticity
Residential	**-0.1037**	**-0.0342**
Small General Service	**-0.0412**	**-0.0250**
Medium General Service	**-0.0500**	**-0.0200**

Westar's residential CAC saturation is 88%



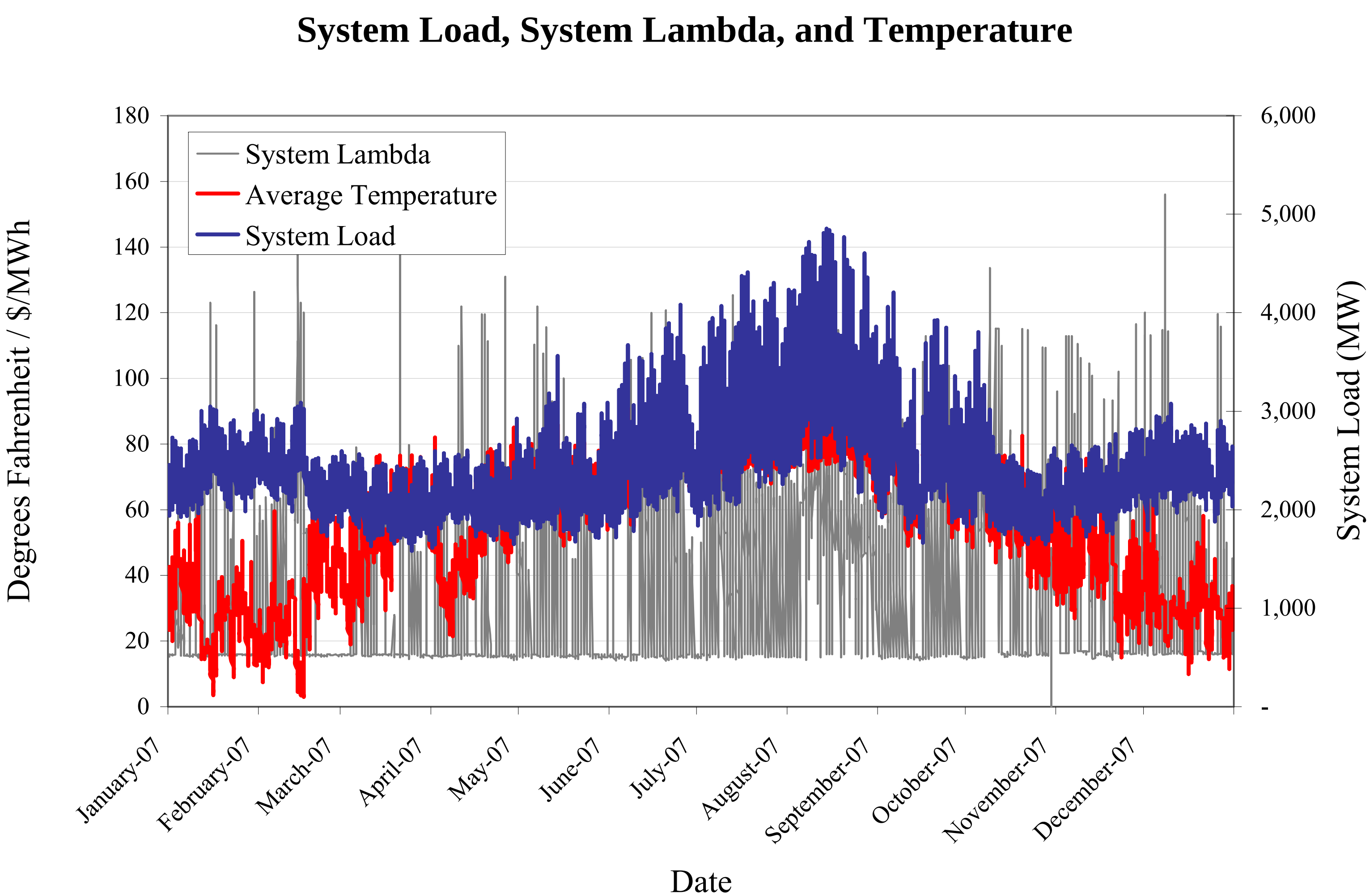
% of Households with Air Conditioning Equipment

Average Cooling Degree Days (CDD)

Westar's CAC saturation = 88%

Source: Compiled from data in 2005 Residential Energy Consumption Survey

The system load is correlated with temperature and system lambda



Summary of final TOU, CPP, and PTR rates

Summer Rate Summary Tables
Entire Westar Region

All-In TOU Rate Comparison (cents/kWh)

	Residential	Small GS	Medium GS
Existing Rate	9.5	7.7	6.9
Peak Rate	23.4	21.6	20.9
Off Peak Rate	6.1	4.2	3.7

All-In CPP Rate Comparison (cents/kWh)

	Residential	Small GS	Medium GS
Existing Rate	9.5	7.7	6.9
Peak Rate	89.5	87.7	86.9
Off Peak Rate	5.6	4.2	3.8

All-In PTR Rate Comparison (cents/kWh)

	Residential	Small GS	Medium GS
Existing Rate	9.5	7.7	6.9
Peak Time Rebate	80.0	80.0	80.0
Off Peak Rate	9.5	7.7	6.9

Summary of final residential RTP rates

Entire Westar Region All-In RTP Rate Comparison (cents/kWh)			
	Residential	**Small GS**	**Medium GS**
Existing Rate	9.5	7.7	6.9
Max Hourly Rate	82.5	73.2	73.3
75th Percentile Rate	7.4	6.3	5.9
50th Percentile Rate	5.9	5.0	4.6
25th Percentile Rate	2.9	2.3	1.9
Min Hourly Rate	2.8	2.2	1.8

The Opt-Out CPP scenario produces the largest benefits

Opt-Out CPP System Level Impacts

Year	Participating Customers	Peak Reduction (MW)	Avoided Capacity Costs (Real $ millions)
2010	0	0	$0.0
2011	95,837	78	$5.7
2012	193,590	157	$11.6
2013	293,289	238	$17.6
2014	394,962	321	$23.7
2015	498,640	405	$29.9
2016	503,626	409	$30.2
2017	508,663	413	$30.5
2018	513,749	417	$30.8
2019	518,887	421	$31.1
2020	524,076	426	$31.4
2021	529,316	430	$31.7
2022	534,609	434	$32.0
2023	539,956	438	$32.3
2024	545,355	443	$32.7
2025	550,809	447	$33.0
2026	556,317	452	$33.3
2027	561,880	456	$33.6
2028	567,499	461	$34.0
2029	573,174	465	$34.3

The Opt-Out CPP and the PTR & Opt-In RTP scenarios produce the greatest benefits

Summary of System Level Impacts

	Percent of Peak Reduction	Present Value of Avoided Capacity Costs ($ millions)
Opt-out CPP	7.9%	$294.5
PTR & Opt-in RTP	3.9%	$145.3
Opt-in CPP	1.7%	$62.6
Opt-in TOU	0.8%	$28.6

Background reading

Faruqui, Ahmad, "Inclining Toward Efficiency," *Public Utilities Fortnightly*, August 2008. http://www.fortnightly.com/exclusive.cfm?o_id=94

Faruqui, Ahmad, Peter Fox-Penner and Ryan Hledik, "Smart Grid Strategy – Quantifying Benefits," *Public Utilities Fortnightly*, July 2009.

Faruqui, Ahmad and Ryan Hledik, "The Power of Dynamic Pricing," *The Electricity Journal*, April 2009. http://ssrn.com/abstract=1340594

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Biography

Ahmad Faruqui is a Principal with The Brattle Group. He led FERC's state-by-state assessment of the potential for demand response which was filed with Congress in June 2009. Last year, he performed a national assessment of the potential for energy efficiency for the Electric Power Research Institute and wrote a report on quantifying the benefits of dynamic pricing for the Edison Electric Institute.

He has assessed the benefits of dynamic pricing for the New York Independent System Operator, worked on fostering economic demand response for the Midwest ISO and ISO New England and assisted the California Energy Commission in developing load management standards. Since the year 2000, he has been assisting utilities and commissions throughout the US and Canada assess the economics of dynamic pricing, demand response and advanced metering. This has often involved the design and evaluation of innovative pilot programs.

His early work on time-of-use pricing experiments is cited in Bonbright's canon. The author, co-author or editor of four books and more than a hundred articles and papers, he holds a doctoral degree in economics from the University of California at Davis. Based in San Francisco, he can be reached at ahmad.faruqui@brattle.com or at (925) 408-0149.