The Brattle Group

Evaluating Alternative Dynamic Pricing Designs

Ryan Hledik, M.S.
Ahmad Faruqui, Ph.D.

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What drives rate design?

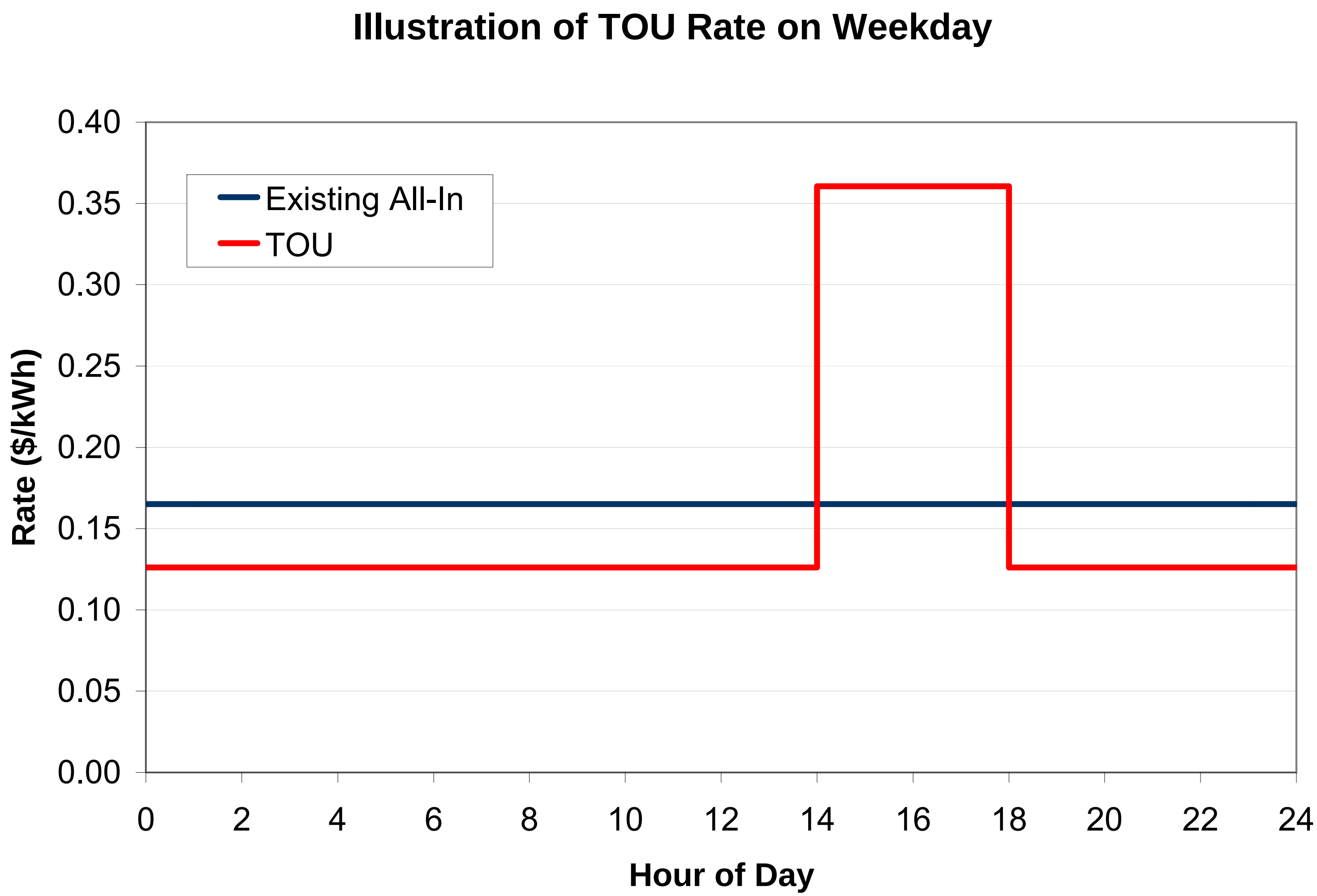
- Several ratemaking objectives
  - Economic Efficiency
  - Equity
  - Choice
  - Simplicity
- In the end, rate designs have to support the state's policy objectives
  - In California, that means encouraging energy efficiency and demand response
  - These are subsumed within the economic efficiency objective

To identify the range of impacts of dynamic pricing, we have developed a set of illustrative rates

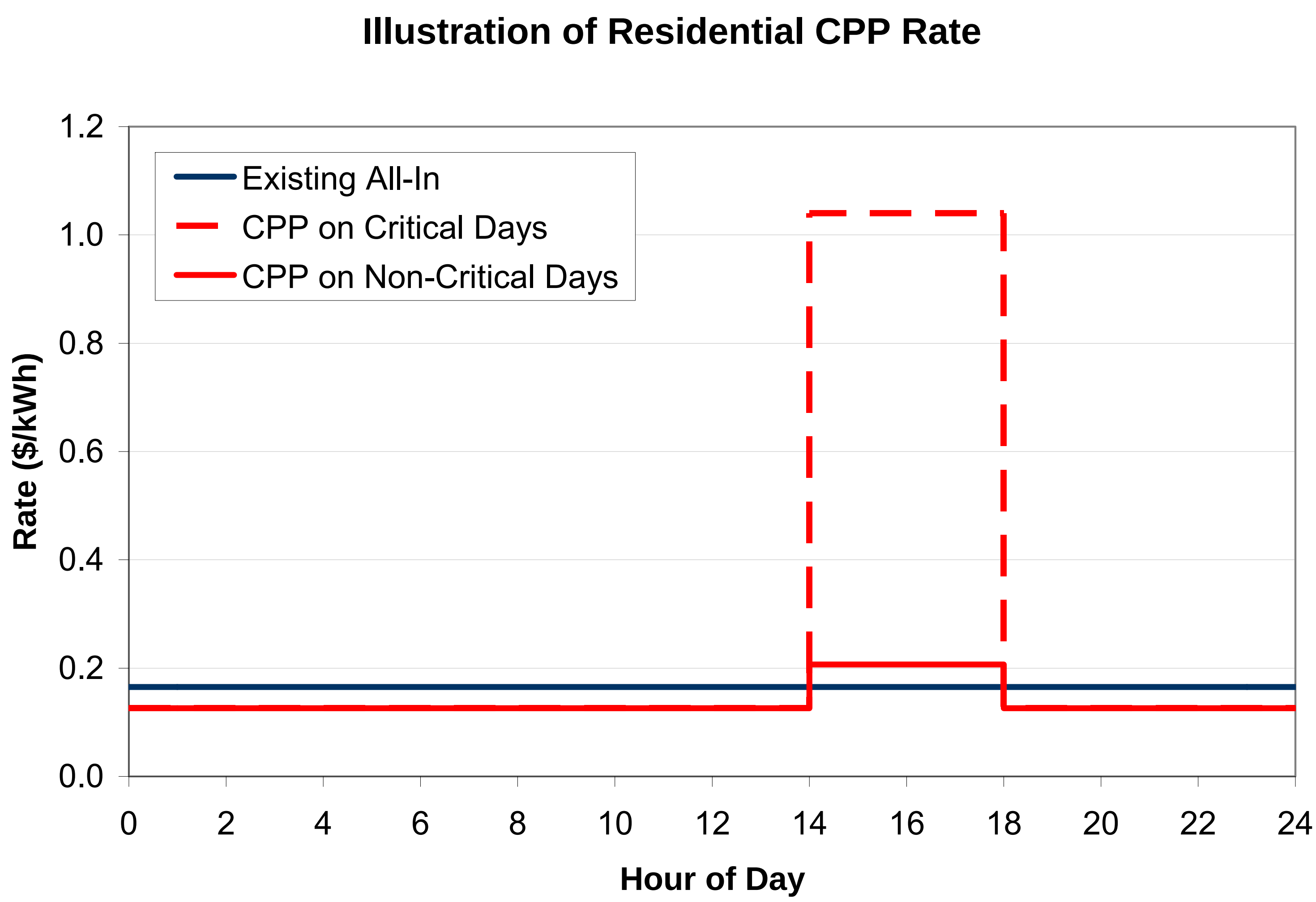
Summary of Illustrative Rates

	Time of Use (TOU)	Peak Time Rebate (PTR)	Critical Peak Pricing with TOU (CPP/TOU)	Real Time Pricing (RTP)
Residential	X	X	X	X
Medium C&I	X		X	X
Large Commercial			X	X
Large Industrial			X	X

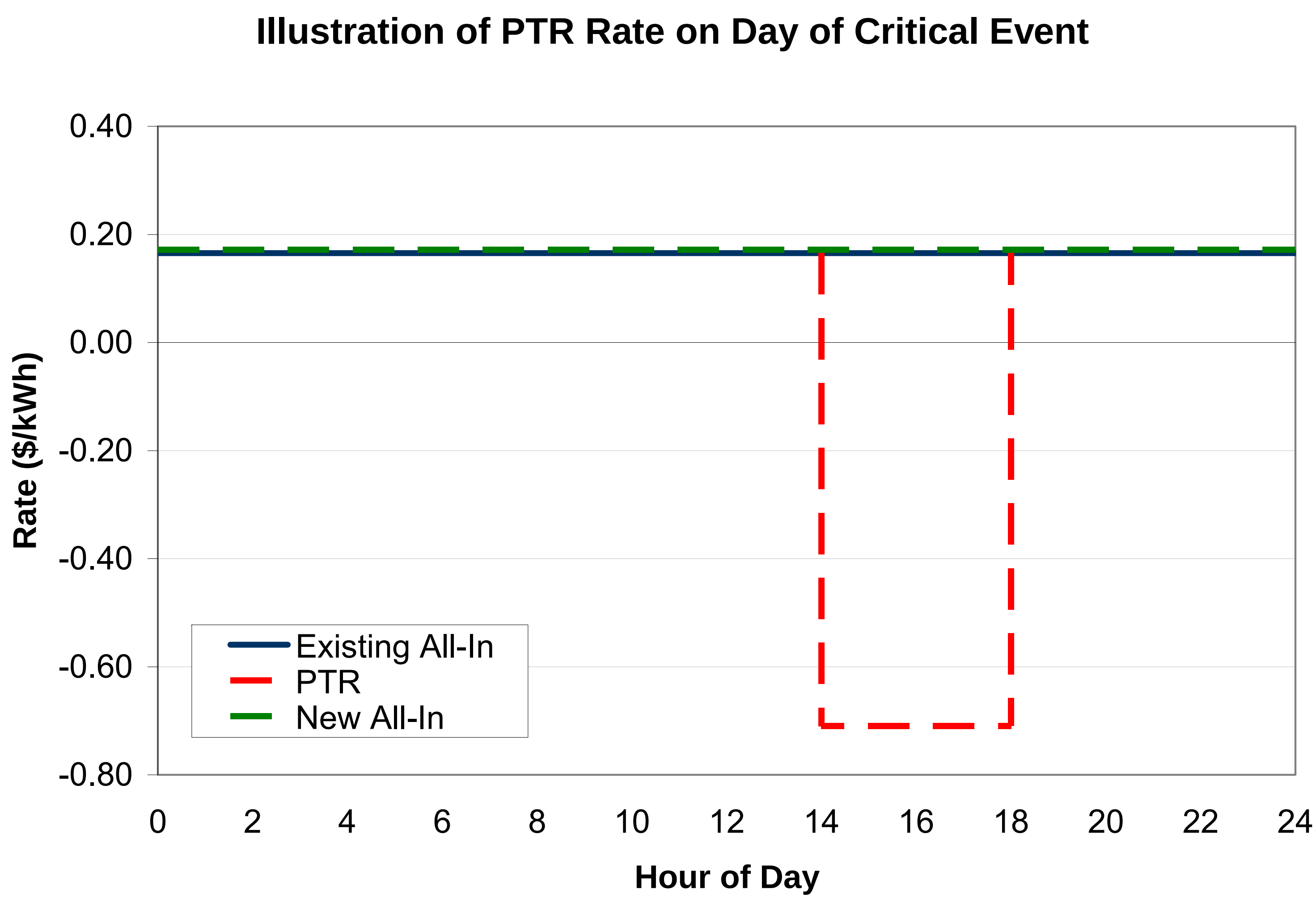
The TOU consists of a higher price during the peak period and a discounted price during the remaining hours



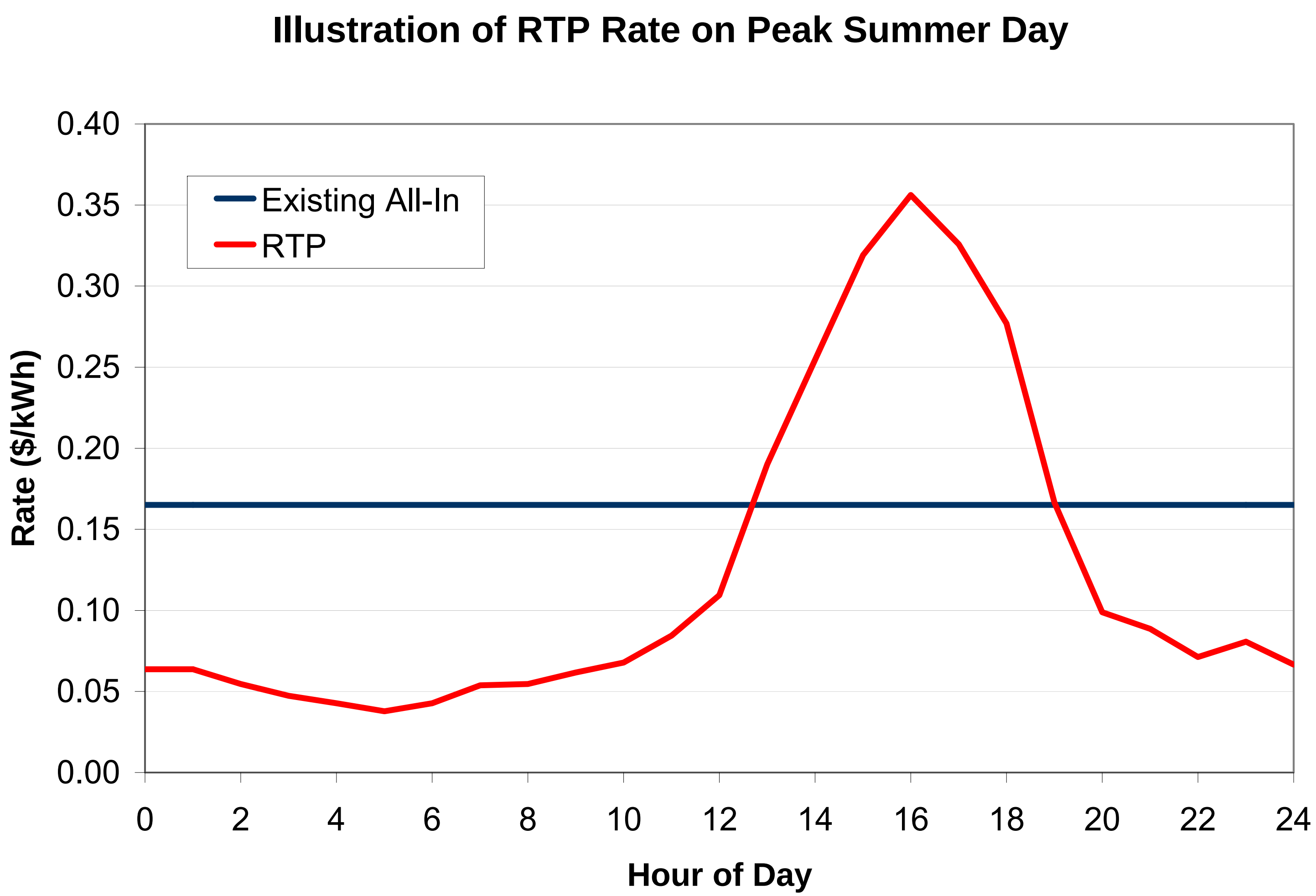
The CPP/TOU is a dispatchable TOU rate



The PTR consists of a credit during critical peak events that mirrors the CPP surcharge



The RTP varies with each hour of the day



Note: We have developed a one-part RTP for this project.

In this presentation, we will summarize the predicted impact of these rates on several variables

- Impact on the average customer
  - Peak demand
  - Monthly energy consumption
  - Monthly bill
- Distribution of bill impacts across customers
- Impact on the California economy
  - System-wide peak demand
  - Total resource cost

We have used two kinds of elasticities to predict demand response

Elasticity of substitution

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

Daily price elasticity

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

To predict demand response to these rates, we have used the following values for the elasticities

- These elasticities are derived from the California SPP and from studies on large C&I customer price response

	Elasticity of Substitution	Daily Price Elasticity
Residential	**-0.08**	**-0.04**
Medium C&I	**-0.05**	**-0.02**
Large Commercial	**-0.05**	**-0.02**
Large Industrial	**-0.05**	**-0.02**

Note:
To predict response to RTP rates, a single price elasticity was used for all customer classes. This elasticity estimate is based on a ComEd study on residential RTP rates and ranges between -0.015 and -0.048 depending on the time of day and day-ahead prices.

We developed four illustrative residential rates

- **Existing Rate (Domestic Non-CARE Five Tiered Rate)**
  - Average = 16.5 cents/kWh

- **TOU**
  - Peak = 36.1 cents/kWh
  - Off peak = 12.6 cents/kWh

- **CPP/TOU**
  - Critical peak = 104.0 cents/kWh
  - Peak = 20.7 cents/kWh
  - Off peak = 12.6 cents/kWh

- **PTR**
  - Existing rate with 87.5 cents/kWh rebate for peak reductions

- **RTP**
  - Generation charge replaced with day-ahead hourly prices

Notes:
Rates are presented on an all-in basis
CPP/TOU, TOU, and PTR are summer-only. RTP applies year-round.

The CPP/TOU rate generates the most demand response

Average Change in Peak
Per Residential Customer

Rate	kWh/hr	%
RTP	-0.06	-4.7%
TOU	-0.10	-7.1%
PTR *	-0.20	-14.5%
CPP/TOU	-0.22	-15.8%

* We assume the same elasticities for PTR and CPP/TOU

Demand response produces small bill savings

Average Change in Monthly Bill
Per Residential Customer

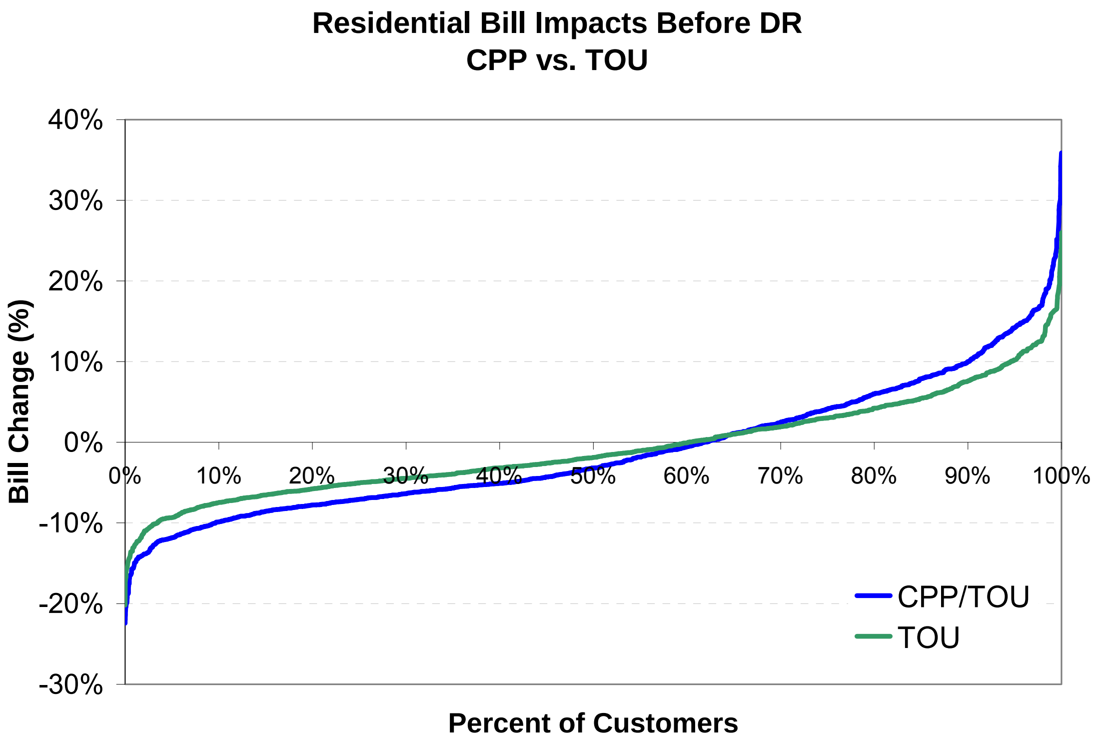
Rate	$/Month	%
RTP	-0.43	-0.5%
TOU	-1.69	-1.5%
CPP/TOU	-2.83	-2.6%
PTR	-3.09	-2.8%
*PTR**	*-1.44*	*-1.3%*

* Reflects a 1.5% rate increase necessary to fund the rebate payments

Notes:
RTP monthly impacts are averaged over the full year. For other rates, they are summer impacts.

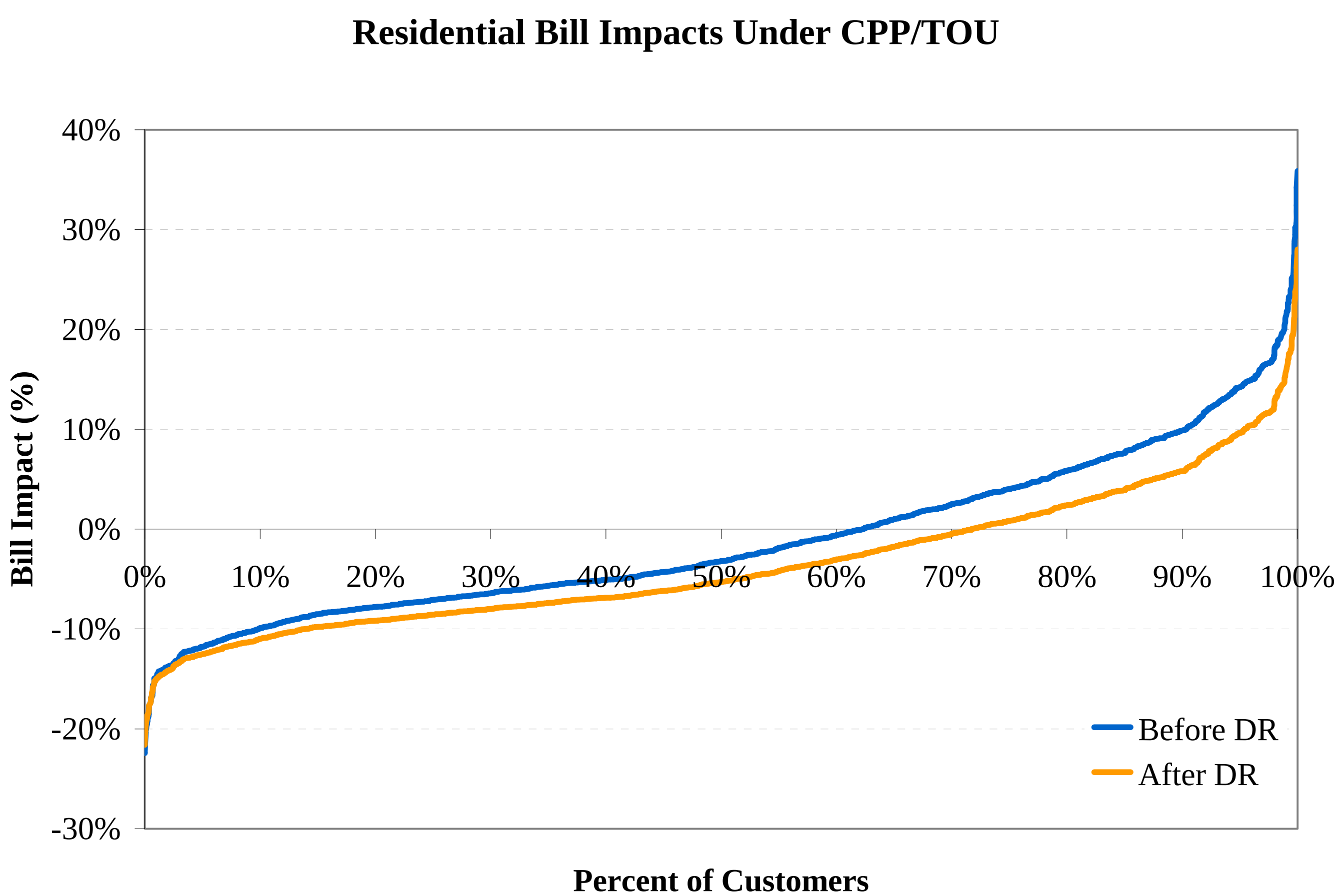
The CPP/TOU rate produces larger bill impacts than the TOU rate

- Before DR, approximately 60 percent of customers experience bill savings under both rates



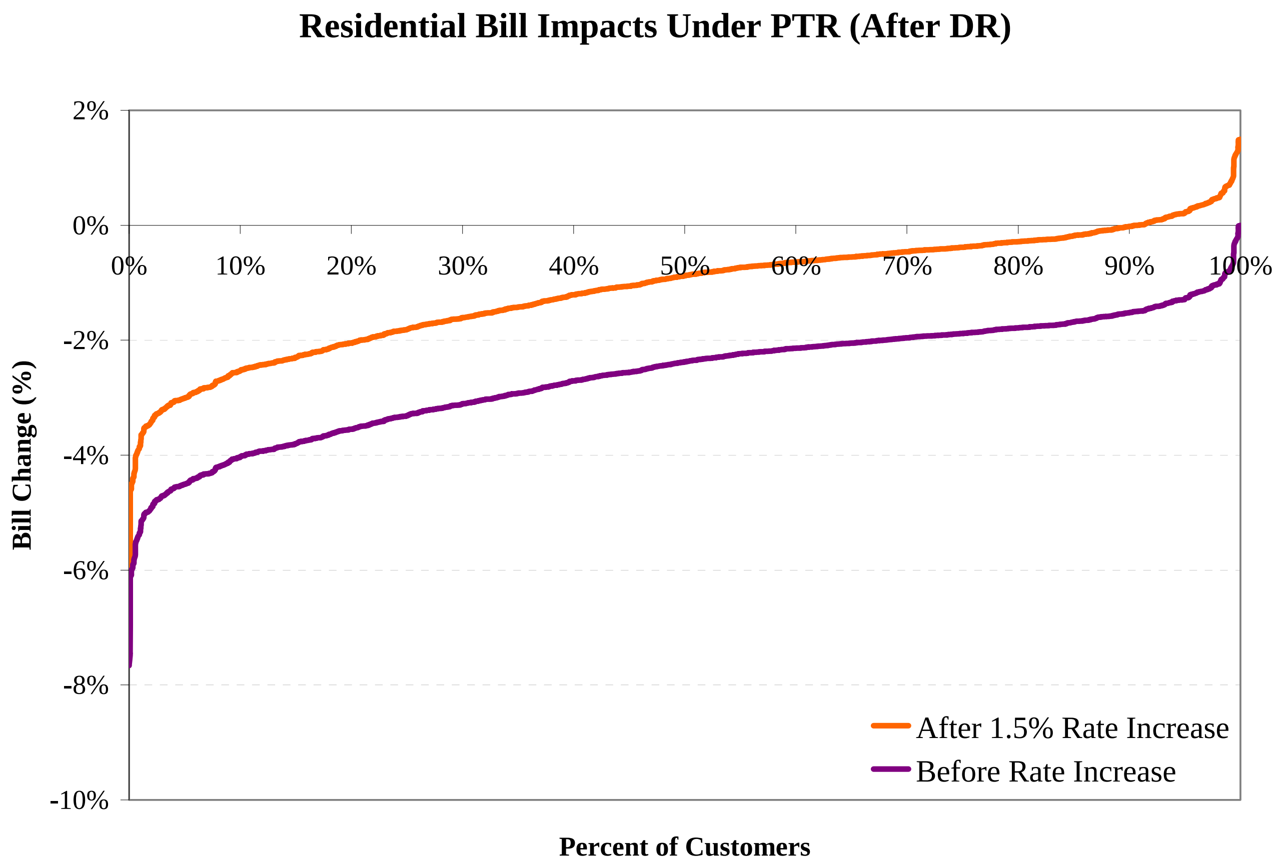
Note: The average rate was used to estimate the bill impacts for all customers in the sample. This would slightly overstate the impacts for large customers and understate the impacts for small customers.

After DR, the share of customers with bill savings under the CPP/TOU rate increases by about 10%



Note: The average rate was used to estimate the bill impacts for all customers in the sample. This would slightly overstate the impacts for large customers and understate the impacts for small customers.

Bill impacts under the PTR illustrate the necessity for a rate increase to fund the rebates



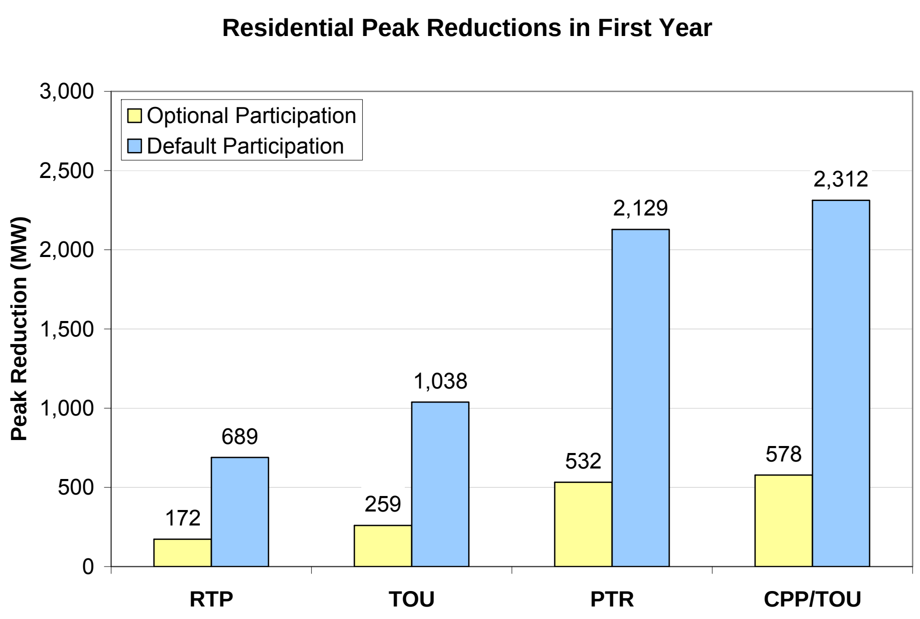
Note: The average rate was used to estimate the bill impacts for all customers in the sample. This would slightly overstate the impacts for large customers and understate the impacts for small customers.

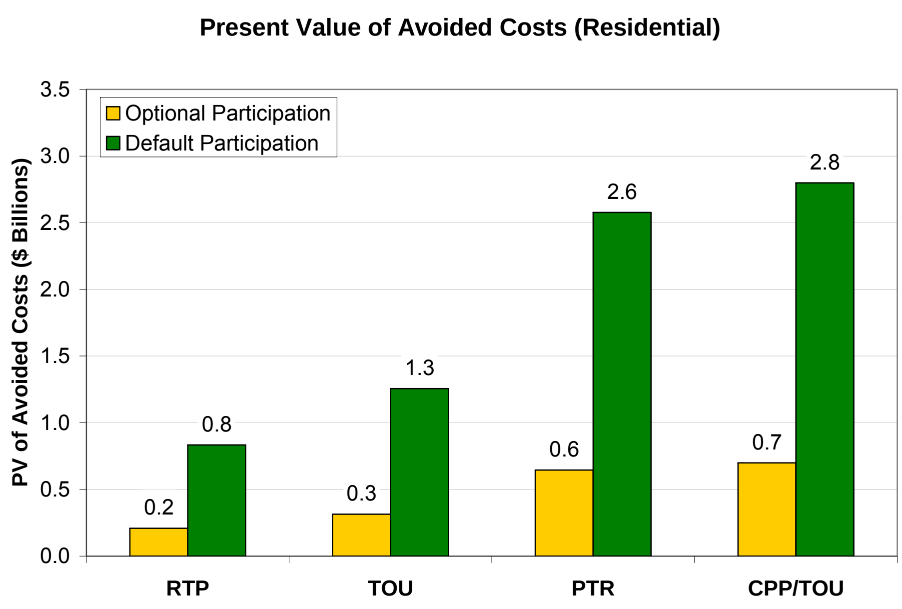
General assumptions in the benefits analysis

- **Forecast Horizon = 20 years**
- **Number of customers in first year**
  - Residential = 9.3 million
  - Medium C&I = 225,000
  - Large Commercial = 5,000
  - Large Industrial = 3,000
- **Annual customer growth rate = 2%**
- **Avoided costs**
  - Capacity = $75/kW-year ($52.5/kW-year after adjustments)
  - Transmission = $15/kW-year
  - Distribution = $12/kW-year
  - Average energy price = $60/MWh
- **Annual discount rate = 8%**
- **Annual inflation rate = 3%**
- **Reserve margin = 15%**
- **Line losses = 8%**

Residential class impacts

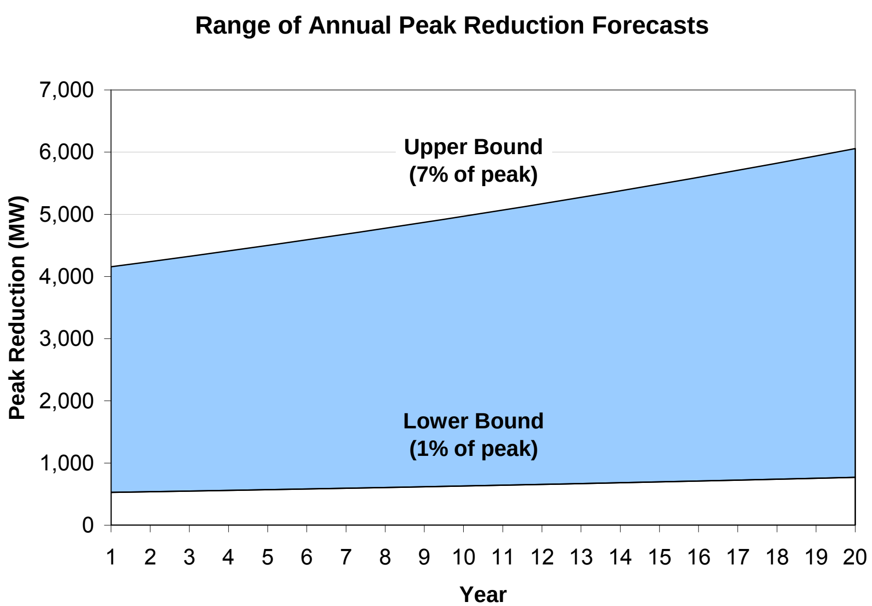
- Annual peak reductions range from 170 MW to 2,300 MW
- This translates into $ 0.2 - 2.8 billion in avoided costs

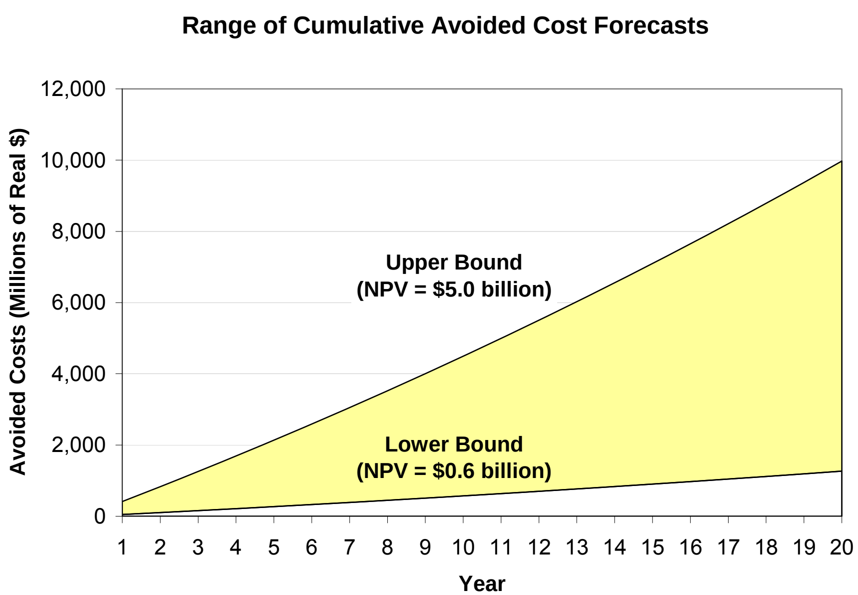




Benefits summary

- The largest impacts are produced by a **default CPP/TOU** for residential and medium C&I customers, and **default RTP** for large C&I customers
- The smallest impacts are produced by an **optional RTP** for all customers





Questions?

Appendix

Additional Detail on Rate Impacts Analysis

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

To account for uncertainty, we have tested the impacts of a range of elasticities for large C&I customers

- **Low elasticities are 50% of the base assumption**
  - Might represent the average elasticity if dynamic rate is offered on a default basis
- **High elasticities are based on results from the Northeast**
  - Might represent the average elasticity if dynamic rate is offered on an optional basis

	Large Commercial		Large Industrial	
	Elasticity of Substitution	Daily Price Elasticity	Elasticity of Substitution	Daily Price Elasticity
Low Case	-0.025	-0.01	-0.025	-0.01
Base Case	-0.05	-0.02	-0.05	-0.02
High Case	-0.05	-0.10	-0.10	-0.05

We developed three illustrative rates for medium C&I customers (20 to 200 kW)

- **Existing Rate (GS-2)**
  - Average = 15.3 cents/kWh

- **TOU**
  - Peak = 31.0 cents/kWh
  - Off peak = 10.0 cents/kWh
  - Note: Generation demand charge is rolled into the peak period

- **CPP/TOU**
  - Critical peak = 98.5 cents/kWh
  - Peak = 32.1 cents/kWh
  - Off peak = 10.0 cents/kWh
  - Note: Generation demand charge is rolled into the critical peak and peak periods

- **RTP**
  - Energy charge replaced with day ahead hourly prices

Notes:
Rates are presented on an all-in basis
CPP/TOU and TOU are summer-only rates. RTP applies year-round.

The CPP/TOU rate produces the largest demand response

Average Change in Peak
Per Medium C&I Customer

Rate	kWh/hr	%
RTP	-1.40	-4.5%
TOU	-1.78	-5.9%
CPP/TOU	-3.00	-9.9%

Bill impacts produced by the CPP/TOU rate are also the largest

Average Change in Monthly Bill
Per Medium C&I Customer

Rate	kWh/hr	%
RTP	-7.03	-0.4%
TOU	-49.05	-1.9%
CPP/TOU	-57.40	-2.2%

Note:
RTP monthly impacts are averaged over the full year. For other rates, they are summer impacts.

Two illustrative rates were created for large commercial customers

- **Existing Rate (TOU-8 Secondary)**
  - Average = 13.2 cents/kWh

- **CPP/TOU**
  - Critical peak = 101.2 cents/kWh
  - Peak = 19.7 cents/kWh
  - Mid-Peak = 11.1 cents/kWh
  - Off peak = 8.3 cents/kWh
  - Note: Generation demand charge is rolled into the critical peak and peak periods

- **RTP**
  - Energy charge replaced with day-ahead hourly prices

Notes:
Rates are presented on an all-in basis
CPP/TOU is summer-only and RTP applies year-round

The peak reduction induced by the CPP/TOU rate larger than the RTP-induced demand response

Average Change in Peak
Per Large Commercial Customer

Rate	kWh/hr	%
CPP/TOU (Low)	-25.9	-4.8%
RTP	-26.2	-4.9%
CPP/TOU (Base)	-50.7	-9.5%
CPP/TOU (High)	-77.0	-14.4%

Note: “Low,” “Base,” and “High,” represent the elasticity scenarios described earlier

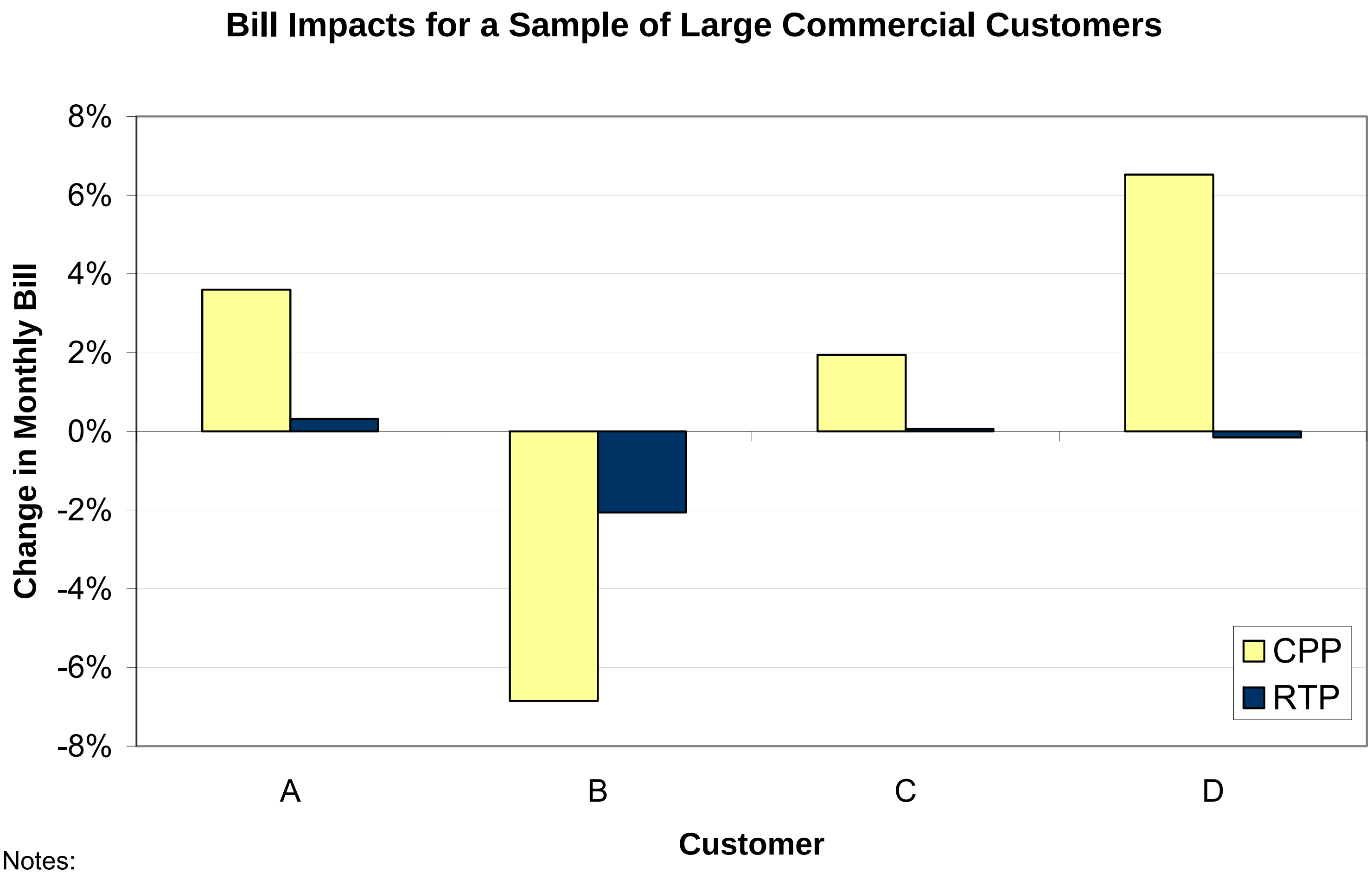
Bill impacts are relatively small for both rates

Average Change in Monthly Bill
Per Large Commercial Customer

Rate	kWh/hr	%
RTP	-148	-0.4%
CPP/TOU (Low)	-357	-0.8%
CPP/TOU (Base)	-700	-1.7%
CPP/TOU (High)	-950	-2.2%

Note:
RTP monthly impacts are averaged over the full year. For other rates, they are summer impacts.

Bill impacts varied for a sample of BOMA's large commercial customers



Notes:
RTP bill change is annual average. CPP bill change is summer only.
Impacts are approximate and are for the period from 11/2006 through 10/2007.

Two illustrative rates were created for large industrial customers

- **Existing Rate (TOU-8 Sub-transmission)**
  - Average = 9.2 cents/kWh

- **CPP/TOU**
  - Critical peak = 99.1 cents/kWh
  - Peak = 14.6 cents/kWh
  - Mid-Peak = 7.8
  - Off peak = 5.6 cents/kWh
  - Note: Generation demand charge is rolled into the critical peak and peak periods

- **RTP**
  - Energy charge replaced with day ahead hourly prices

Notes:
Rates are presented on an all-in basis
CPP/TOU is summer-only and RTP applies year-round

Large industrial peak impacts are greater under the CPP/TOU rate

Average Change in Peak
Per Large Industrial Customer

Rate	kWh/hr	%
CPP/TOU (Low)	-255	-5.4%
RTP	-277	-5.8%
CPP/TOU (Base)	-533	-11.2%
CPP/TOU (High)	-978	-20.6%

Note: "Low," "Base," and "High," represent the elasticity scenarios described earlier

Bill impacts were larger for the CPP/TOU rate

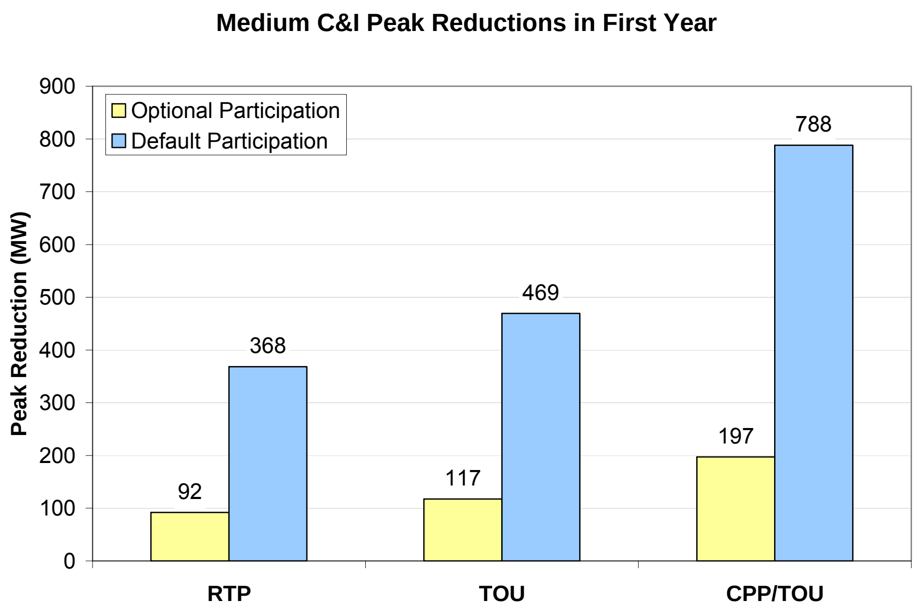
Average Change in Monthly Bill
Per Large Industrial Customer

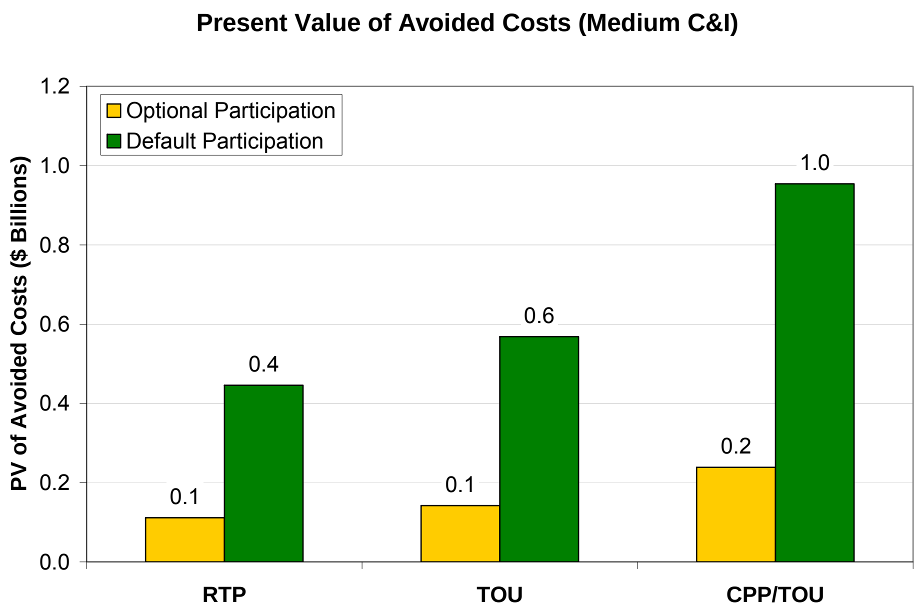
Rate	kWh/hr	%
RTP	-1,283	-0.5%
CPP/TOU (Low)	-3,240	-1.0%
CPP/TOU (Base)	-7,348	-2.3%
CPP/TOU (High)	-12,148	-3.6%

Note:
RTP monthly impacts are averaged over the full year. For other rates, they are summer impacts.

Medium C&I class impacts

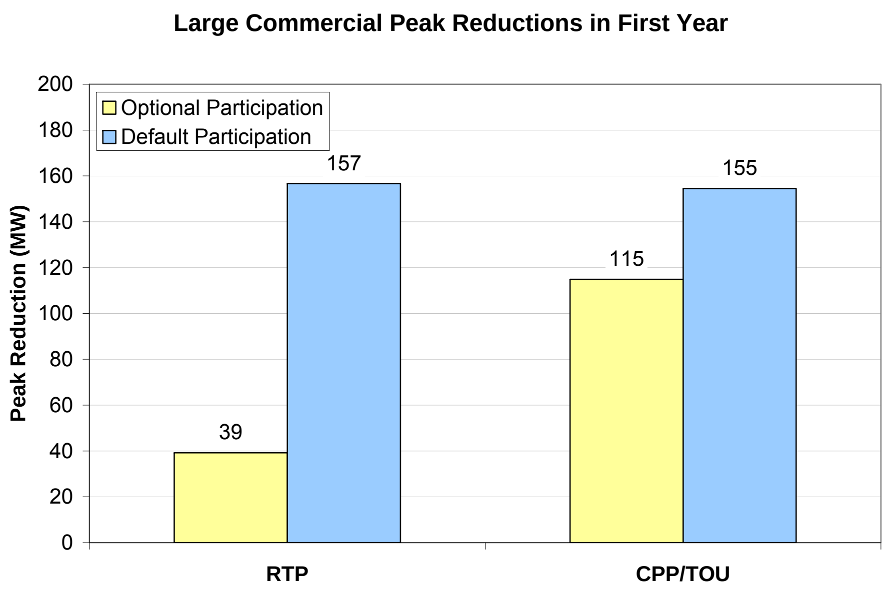
- Annual peak reductions range from 90 MW to 790 MW
- This translates into $ 0.1 - 1.0 billion in avoided costs

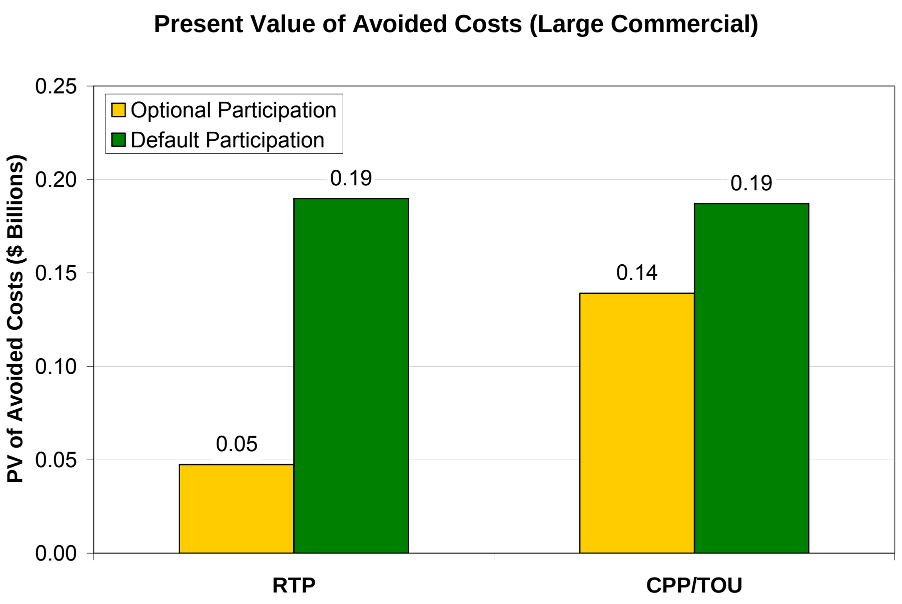




Large commercial class impacts

- Annual peak reductions range from 40 MW to 160 MW
- This translates into $ 50 - 200 million in avoided costs

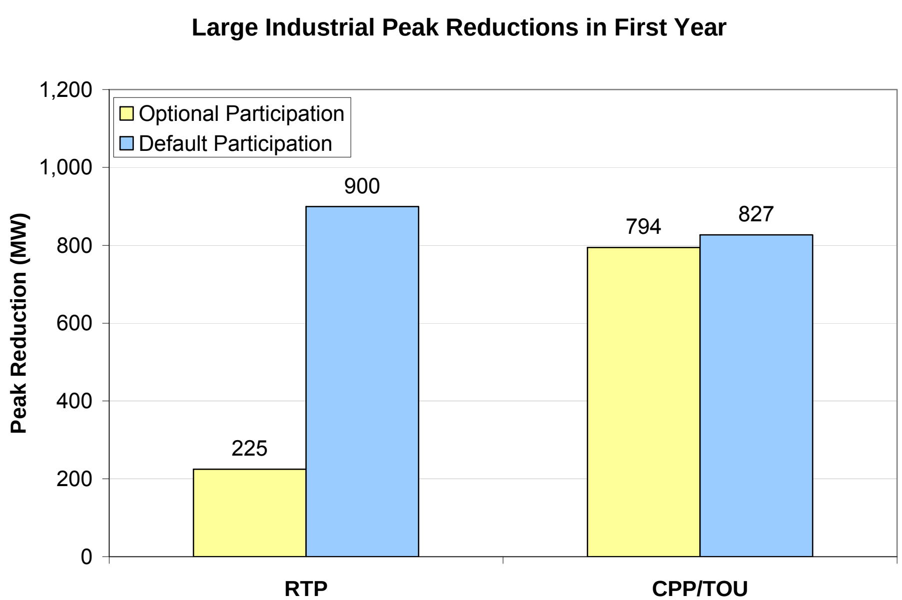


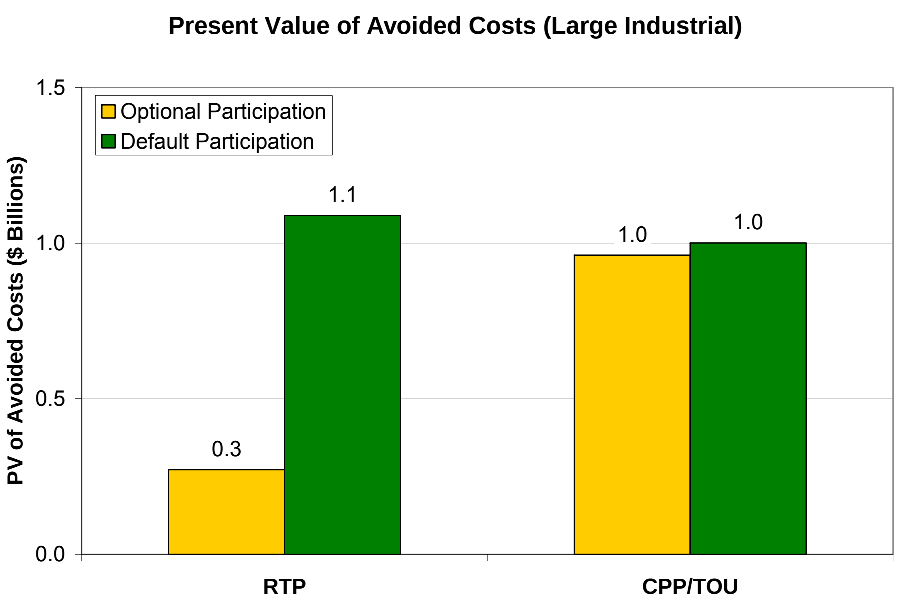


Note: In calculating the CPP/TOU impacts, “high” elasticities are used for the optional participation scenario and “low” elasticities are used for the default participation scenario

Large industrial class impacts

- Annual peak reductions range from 230 MW to 900 MW
- This translates into between $ 0.3 - 1.1 billion in avoided costs





Note: In calculating the CPP/TOU impacts, "high" elasticities are used for the optional participation scenario and "low" elasticities are used for the default participation scenario

Design of the illustrative (strawman) rates

In this appendix, we provide …

1. An overview of the strawman rate development approach
2. A detailed look at the core dynamic pricing rates
3. An assortment of rate sensitivities

Up to four "core" rates were developed for three customer classes

The "core" rate designs

- Time of Use (TOU)
- Peak Time Rebate (PTR)
- Critical Peak Pricing (CPP)
- Real Time Pricing (RTP)

Representative customer classes

- Residential
- Medium C&I (20 kW to 200 kW)
- Large C&I (> 500 kW)

Much of the underlying data comes from Southern California Edison

Strawman Rates Data Sources

	Residential	Medium C&I	Large Commercial	Large Industrial
Rate Class	Domestic Non-CARE	General Service II (20 to 200 kW)	TOU-8 (Secondary Voltage)	TOU-8 (Sub-Transmission)
Hourly Load Profile	2005 SCE load research data	2005 SCE load research data	2006 SCE TOU-8 static load profile	2006 SCE TOU-8 static load profile
Hourly Energy Price	1999 California PX SP15 hourly prices, scaled to today's costs	1999 California PX SP15 hourly prices, scaled to today's costs	1999 California PX SP15 hourly prices, scaled to today's costs	1999 California PX SP15 hourly prices, scaled to today's costs
Capacity Price	$75/kW-yr (2006 SCE GRC)	$75/kW-yr (2006 SCE GRC)	$75/kW-yr (2006 SCE GRC)	$75/kW-yr (2006 SCE GRC)

Nine sensitivities were performed on the core rates

Residential CPP sensitivities

- Capacity price increased to $98/kW-yr
- Capacity price decreased to $52/kW-yr
- 3% hedging cost premium
- “Pure” CPP without TOU layer
- AB 1x compliant
- Extend peak period from four to six hours

Large C&I RTP sensitivities

- Energy price shape: Simulated 2005 prices
- Energy price shape: Scaled 2000 CA PX prices
- 10% hedging cost premium

Each rate is benchmarked against the existing rate

The existing California rate designs

- Residential: Inverted tier rate
- Medium C&I (20 kW to 200 kW): Flat rate with demand charge
- Large C&I (> 500 kW): Time of use rate with demand charge

The matrix of strawman rate designs

		Core Rates	Sensitivities							
			AB 1X Compliant	"Pure" CPP (No TOU layer)	Adjust for hedging premium	Use higher capacity cost	Use lower capacity cost	Longer peak period	Simulated 2005 energy prices	2000 Cal PX energy prices
Residential	TOU	x								
	PTR	x								
	CPP/TOU	x	x	x	x	x	x	x		
	RTP	x								
Medium C&I	TOU	x								
	CPP/TOU	x								
	RTP	x								
Large Commercial	CPP/TOU	x								
	RTP	x			x				x	x
Large Industrial	CPP/TOU	x								
	RTP	x								

x	Indicates strawman rate has been developed

The current residential rate is an inverted tier structure which flows out of AB 1X

Domestic Rate Schedule (Non-CARE)

Average customer consumption	**= 572 kWh/month**	
Generation Charge		
• Baseline	= $0.045/kWh	Protected by AB 1x
• To 130% of baseline	= $0.065/kWh	
• To 200% of baseline	= $0.151/kWh	
• To 300% of baseline	= $0.186/kWh	
• Above 300% of baseline	= $0.221/kWh	
Average Generation Charge	**= $0.090/kWh**	
Average Delivery Charge	**= $0.072/kWh**	
Basic Charge	**= $0.020/day**	
Average All-In Rate	**= $0.163/kWh**	

The current medium C&I rate structure is a flat energy rate combined with a demand charge

General Service II Rate Schedule

Average Customer Usage	**= 15,130 kWh/month**
Average Customer Peak Annual Demand	**= 39.2 kW**
Annual Load Factor	**= 53%**

Average Generation Charge	**= $0.067/kWh**
Delivery Charge	**= $0.015/kWh**
Average Customer Charge	**= $85.75/month**
Average Single Phase Service Charge	**= -$26.65/month**
Average Facilities Demand Charge	**= $8.60/kW**
Average Summer Demand Charge	**= $18.79/kW**

Average All-In Rate	**= $0.121/kWh**

The current large commercial rate structure is a TOU energy rate combined with a TOU demand charge

<u>TOU-8 (Secondary Voltage) Rate Schedule</u>

Average Customer Usage	**= 299 MWh/month**
Average Customer Annual Peak Demand	**= 597 kW**
Annual Load Factor	**= 69%**
Generation Charge*	
• On Peak	= $0.099/kWh
• Mid Peak	= $0.078/kWh
• Off Peak	= $0.050/kWh
Average Delivery Charge	**= $0.014/kWh**
Average Customer Charge	**= $414.98/month**
Facilities Demand Charge	**= $9.71/kW**
Summer Peak Demand Charge	**= $15.37/kW**
Summer Mid-Peak Demand Charge	**= $5.19/kW**

Average All-In Rate = $0.115/kWh

* Blend of URG and DWR. Summer charges are used for illustrative purposes

The current large industrial rate structure is a TOU energy rate combined with a demand charge

TOU-8 (Sub-Transmission Voltage) Rate Schedule

Average Customer Usage	**= 3,393 MWh/month**
Average Customer Annual Peak Demand	**= 5.2 MW**
Load Factor	**= 60%**

Generation Charge*

• On Peak	= $0.077/kWh
• Mid Peak	= $0.061/kWh
• Off Peak	= $0.039/kWh

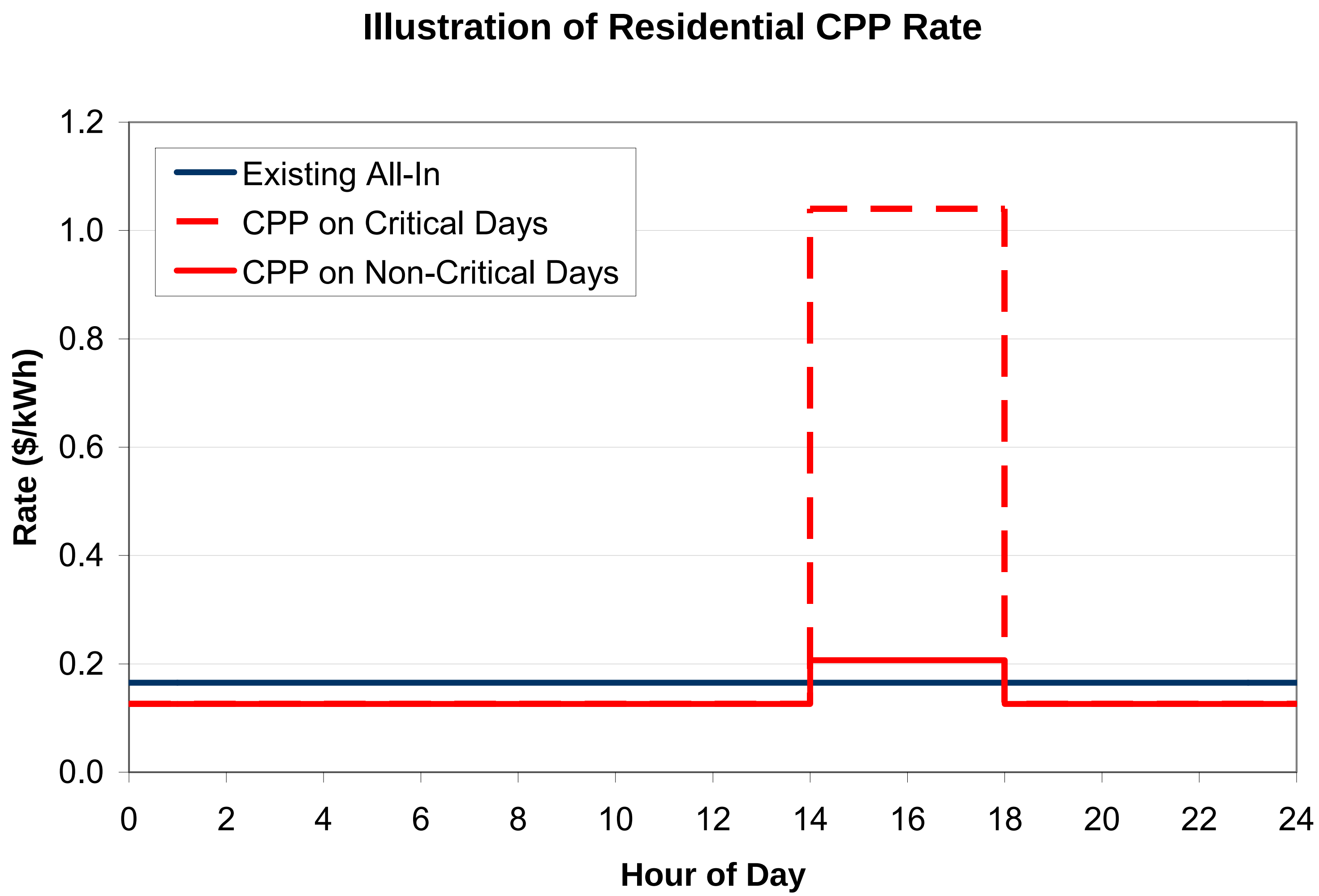
Average Delivery Charge	**= $0.013/kWh**
Average Customer Charge	**= $2,199/month**
Facilities Demand Charge	**= $2.48/kW**
Summer Peak Demand Charge	**= $12.33/kW**
Summer Mid-Peak Demand Charge	**= $4.25/kW**
Average All-In Rate	**= $0.076/kWh**

* Blend of URG and DWR. Summer charges are used for illustrative purposes

THE STRAWMAN

CPP/TOU RATES

The CPP/TOU consists of a higher price during critical peak events and peak periods, and a discounted price during the off peak hours



Steps in calculating the residential CPP/TOU rate

1. **Determine all-in rate in critical peak period:**
   Existing all-in rate + capacity price

2. **Determine all-in rate in off-peak period:**
   Set equal to 12.6 cents/kWh based on off-peak energy and delivery costs

3. **Determine all-in rate in peak period:**
   Solve for peak rate such that the CPP is revenue neutral

Calculation of the C&I CPP/TOU rate is slightly different due to the presence of demand charges

1. **Determine generation rate in critical peak period:**
   Existing peak generation rate + capacity price

2. **Determine off peak and mid-peak generation rates:**
   Both are set equal to existing rates

3. **Determine peak generation rate:**
   Solve for peak rate such that the CPP/TOU rate is revenue neutral without the addition of the generation demand charge (i.e., the new CPP/TOU rate eliminates generation demand charges)

4. **Create an all-in CPP/TOU by converting all remaining charges (such as customer charges and delivery charges, but excluding generation demand charges) to $/kWh rates and adding them to the generation rates**

Summary of strawman CPP/TOU rates

Assumptions

Number of critical days*	= 15
Number of peak days	= 73
Timing of critical event and peak period	= 2 pm to 6 pm
Timing of mid-peak period (large C&I only)	= 7 am to 2 pm and 6 pm to 11 pm
Season	= June - September

All-In Rates (cents/kWh)

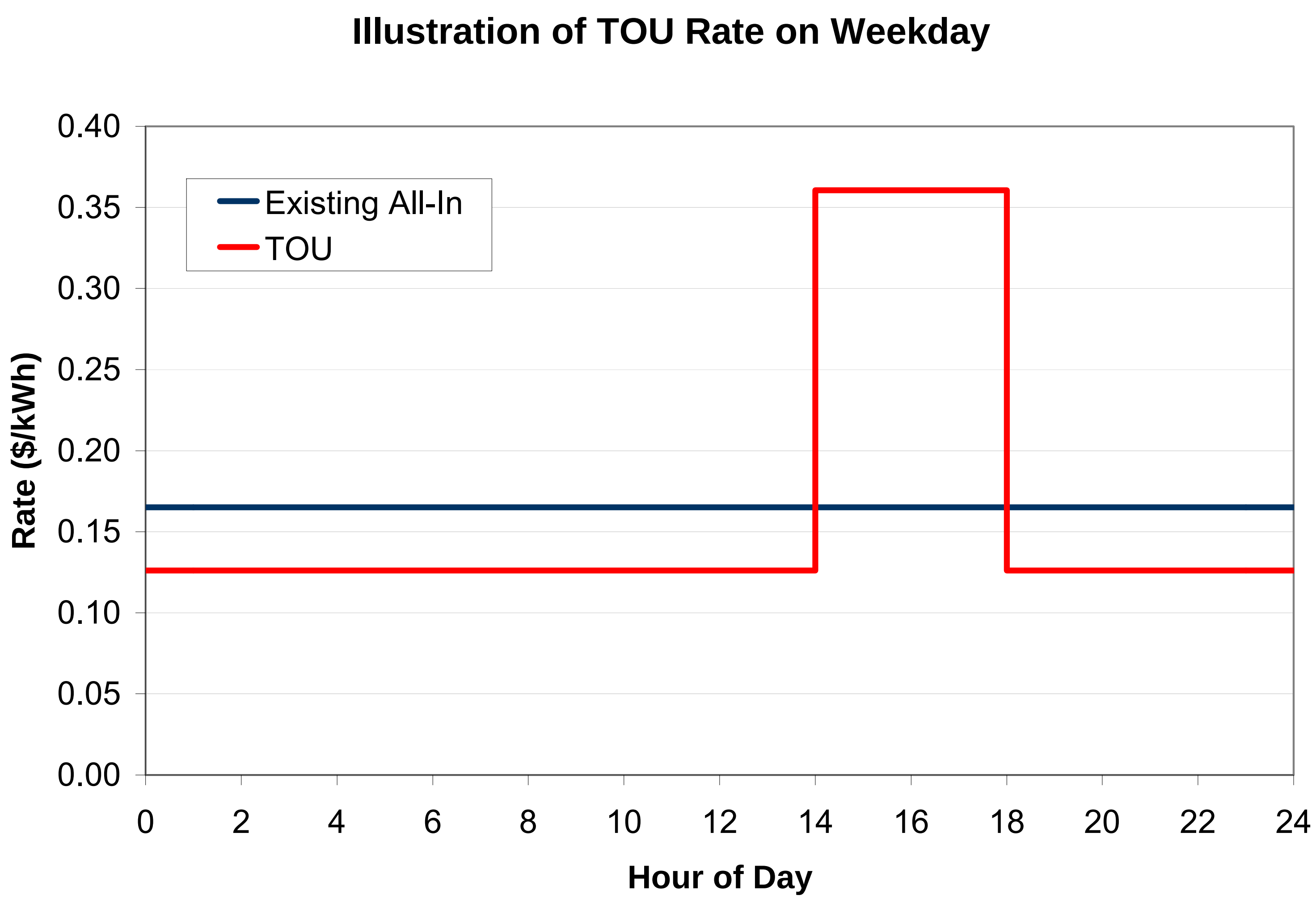
	Residential	Medium C&I	Large Commercial	Large Industrial
Existing All-In Rate (Summer)	16.5	15.3	13.2	9.2
Critical Peak Rate	104.0	98.5	101.2	99.1
Peak Rate	20.7	32.1	19.7	14.6
Mid-Peak	N/A	N/A	11.1	7.8
Off Peak Rate	12.6	10.0	8.3	5.6

* Identified as 15 weekdays with highest maximum energy price

Note that the generation demand charge has been rolled into the critical peak and on-peak periods for medium and large C&I customers

THE STRAWMAN TOU RATES

The TOU consists of a higher price during the peak period and a discounted price during the remaining hours



Steps in calculating the TOU rate

1. **Determine all-in rate for off-peak period:**

   Set equal to all-in off-peak rate determined in the CPP/TOU calculation

2. **Determine all-in rate for peak period:**

   Solve for peak rate to maintain revenue neutrality

Summary of strawman TOU rates

Assumptions

Number of peak days	= 88 (every weekday)
Timing of peak period	= 2 pm to 6 pm
Season	= June - September

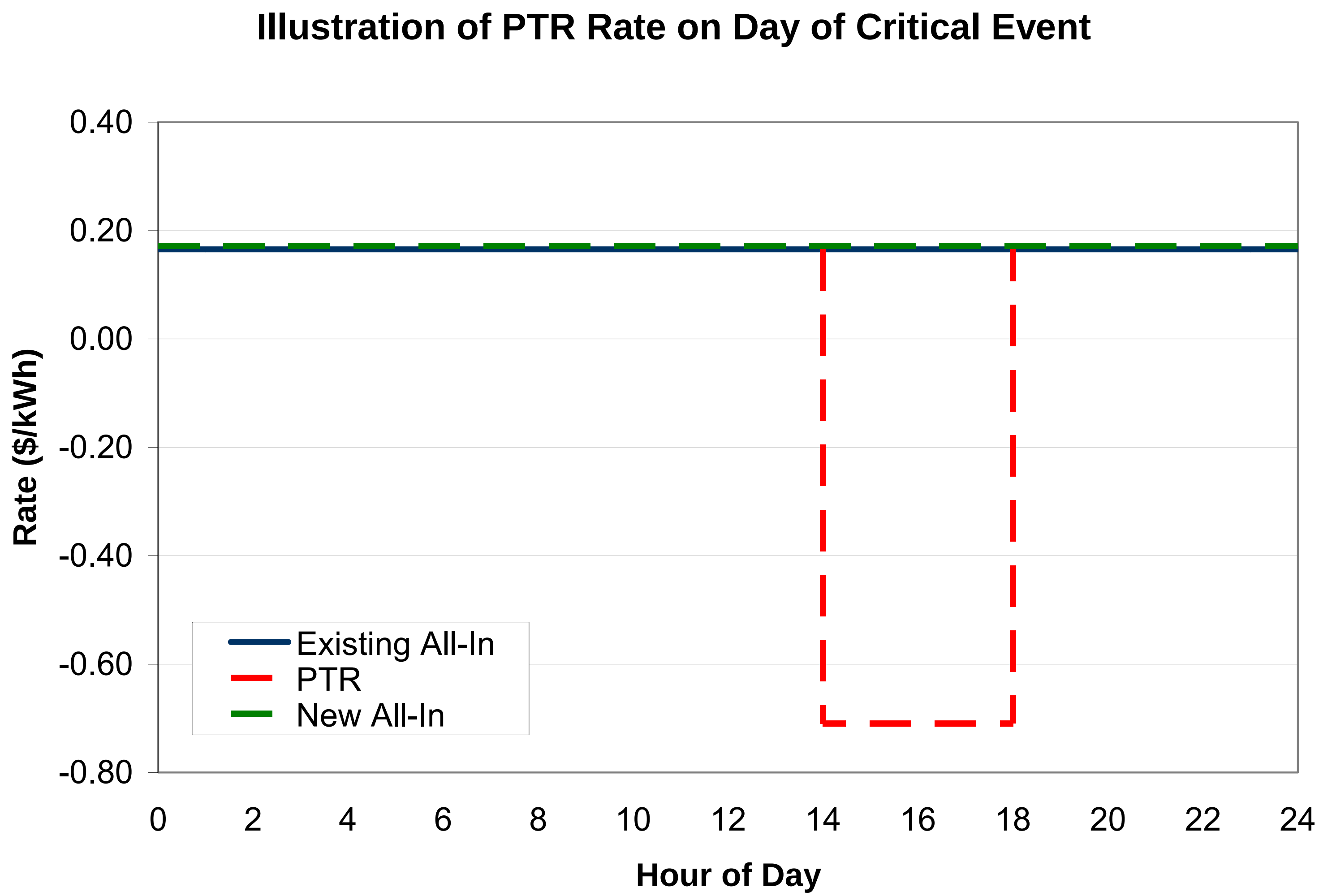
All-In Rates (cents/kWh)

	Residential	Medium C&I	Large Commercial	Large Industrial
Existing All-In Rate (Summer)	16.5	15.3	N/A	N/A
Peak Rate	36.1	31.0	N/A	N/A
Off Peak Rate	12.6	10.0	N/A	N/A

Note that the generation demand charge has been rolled into the rate for medium C&I customers

THE STRAWMAN PTR RATES

The PTR consists of a credit during critical peak events that mirrors the CPP surcharge



Steps in calculating the PTR

1. Determine the level of rebate provided during the critical event. In this case, it is set equal to the surcharge that was calculated for the CPP rate.

2. Raise the all-in rate to reflect the amount of the rebate. Based on information provided by SCE, this is estimated to be an increase of 1.5 percent.

Summary of strawman PTR rates

Assumptions

Number of critical days*	=	15
Timing of critical event	=	2 pm to 6 pm
Season	=	June - September

All-In Rates ($/kWh)

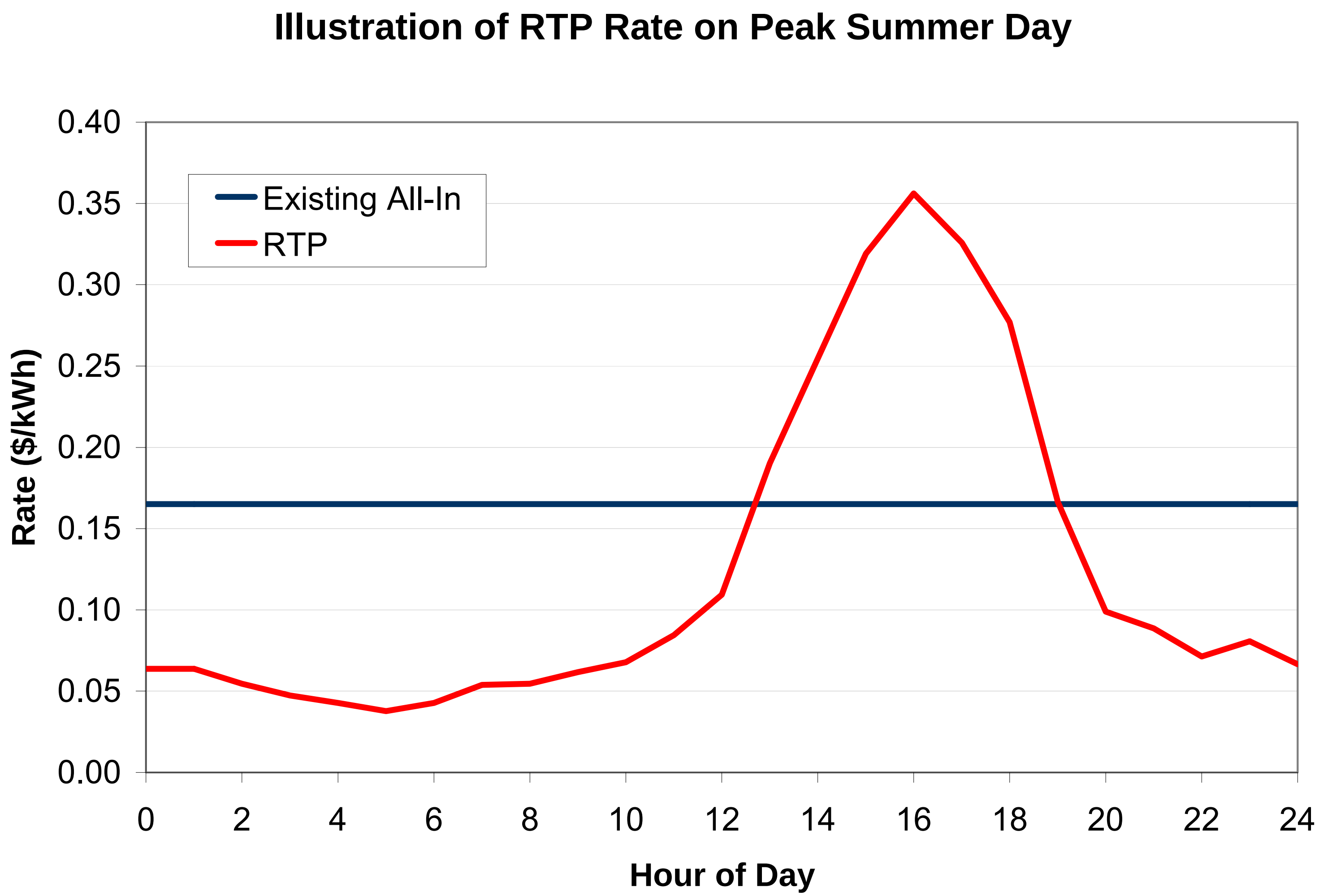
	Residential	Medium C&I	Large Industrial	Large Commercial
Existing All-In Rate (Summer)	0.165	N/A	N/A	N/A
New All-In Rate**	0.168	N/A	N/A	N/A
Peak Rebate	-0.875	N/A	N/A	N/A
Off Peak Change	0.000	N/A	N/A	N/A

* Identified as 15 weekdays with highest maximum energy price

** Assumes 1.5% increase in revenue requirements

THE STRAWMAN RTP RATES

The RTP varies with each hour of the day



Note: We have developed a one-part RTP for this project.

Steps in calculating the RTP rate

1. Determine the ratio of the average historical hourly market price to the existing average customer’s generation charge (energy portion only)

2. Apply the ratio of the bill from step 1 to the hourly market price to calculate the customer’s new generation charge

3. Leave the non-generation portion of the customer’s bill, including demand charges, unchanged

Summary of strawman RTP rates

Assumptions

Historical market prices	=	1999 California PX SP15 day ahead hourly
Application	=	Hourly price replaces $/kWh generation component of bill
Season	=	Year-round

Rates (cents/kWh)

	Residential	Medium C&I	Large Commercial	Large Industrial
Existing All-In Rate (Year-round)	16.3	12.1	11.5	7.6
Scaling Factor*	3.6	2.4	2.4	1.9
Max Hourly Price (cents/kWh)	81.0	54.0	55.4	43.3
Simple Average Price (cents/kWh)	9.5	6.4	6.5	5.1
75th Percentile Price (cents/kWh)	11.4	7.6	7.8	6.1
25th Percentile Price (cents/kWh)	6.7	4.5	4.6	3.6

* Scaling factor is used to gross-up the historical prices to the class average generation cost

RATE SENSITIVITIES

We also examined higher and lower capacity prices

- Due to uncertainty in California's cost of generating capacity and its application in rate design, we tested two alternative capacity prices
  - High price = $98/kW-year
  - Low price = $52/kW-year

- The change in the critical peak rate was offset by a change in the peak rate

All-In Rates (cents/kWh)

	Core Rate (Res. CPP)	High Capacity Price	Low Capacity Price
Critical Peak Rate	104.0	130.8	77.2
Peak Rate	20.7	14.6	26.8
Off Peak Rate	12.6	12.6	12.6

We looked at other approximations of the hourly energy price

- There is uncertainty surrounding the shape of market energy prices that will result from the CAISO's MRTU
- To address this, we tested two other approximations of the hourly market price:
  - A simulated 2005 SP15 hourly price using the Dayzer production costing model
  - The 2000 PX SP15 price, to represent a "crisis" situation
- The simulated price series was much "flatter" than the actual market prices

Rates

	Core Rate (Large Commercial RTP)	RTP with 2005 Simulated Price	RTP with 2000 "Crisis" Price
Scaling Factor	2.4	1.0	0.7
Max Hourly Price (cents/kWh)	55.4	15.4	71.6
Simple Average Price (cents/kWh)	6.5	6.6	6.4
75th Percentile Price (cents/kWh)	7.8	8.1	7.9
25th Percentile Price (cents/kWh)	4.6	4.8	2.2

A “pure” CPP was created, without any TOU charges on non-critical days

- The critical peak rate was unchanged
- The off peak rate was increased to account for the lower rate during the peak period

All-In Rates (cents/kWh)

	Core Res. CPP	"Pure" CPP w/o TOU
Critical Peak Rate	104.0	104.0
Peak Rate	16.5	13.7
Off Peak Rate	13.3	13.7

The "hedging cost premium" was used in the CPP rate calculation

- CPP hedging cost premium = 3%
- The premium is used to decrease the generation component of the new all-in CPP
- This produces a lower peak price

All-In Rates (cents/kWh)

	Core Res. CPP	CPP Adjusted for Premium
Critical Peak Rate	104.0	104.0
Peak Rate	20.7	18.7
Off Peak Rate	12.6	12.6

We also applied the "hedging cost premium" to the calculation of the RTP

- The premium would be larger when the customer is exposed to the full volatility of the hourly market
- RTP hedging cost premium is assumed to be 10%

Rates

	Core RTP (Large Commercial)	RTP Adjusted for Premium
Scaling Factor	2.4	2.2
Max Hourly Price (cents/kWh)	55.4	49.9
Simple Average Price (cents/kWh)	6.5	5.9
75th Percentile Price (cents/kWh)	7.8	7.0
25th Percentile Price (cents/kWh)	4.6	4.1

We created a CPP rate with a longer peak period

- The duration of the critical peak period and the peak period was increased from four hours to six hours
- This lowered the critical peak and peak rates

All-In Rates (cents/kWh)

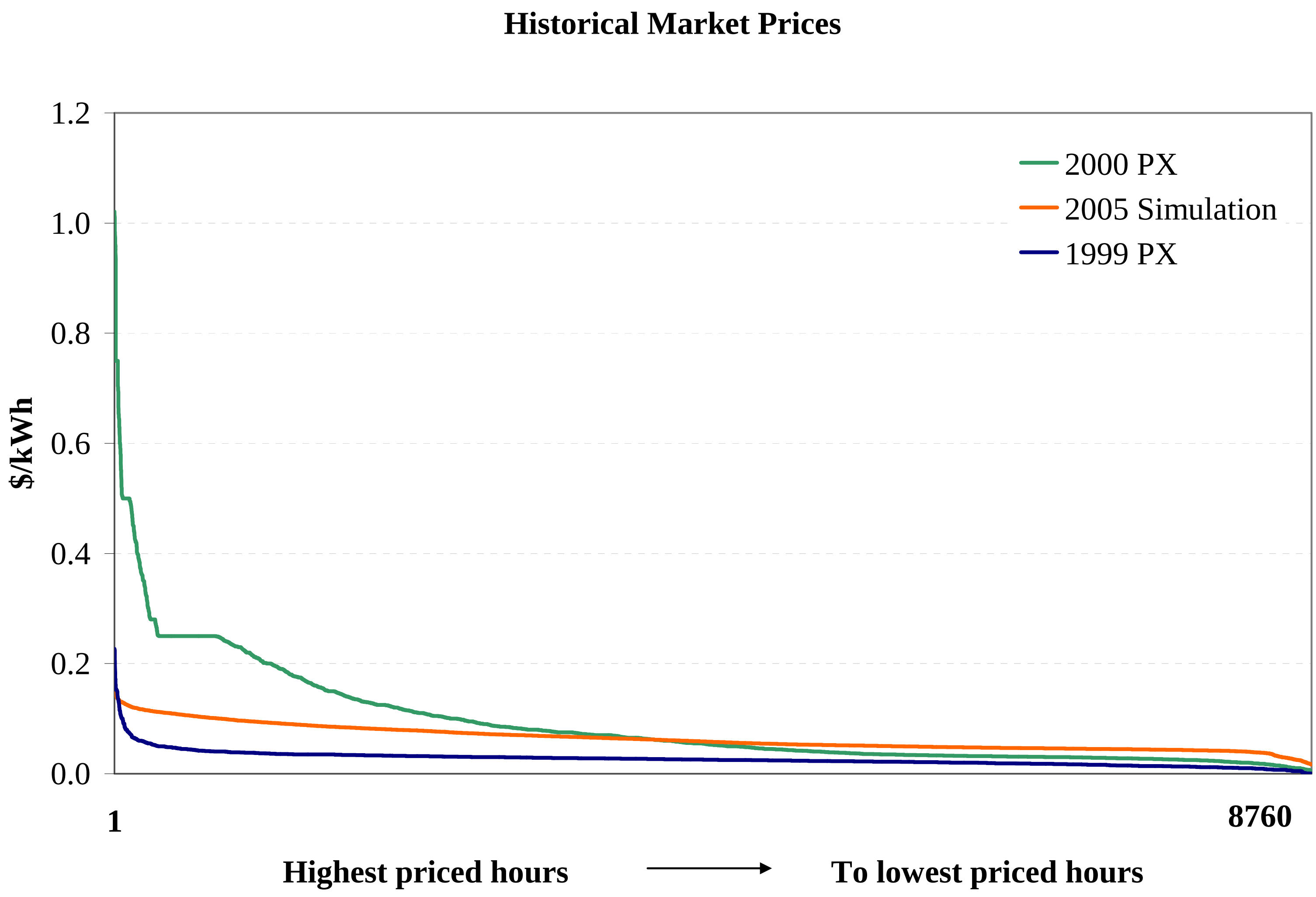
	Core Res. CPP	CPP with Longer Peak
Critical Peak Rate	104.0	74.8
Peak Rate	20.7	18.8
Off Peak Rate	12.6	12.6

An AB 1x compliant residential CPP rate was developed

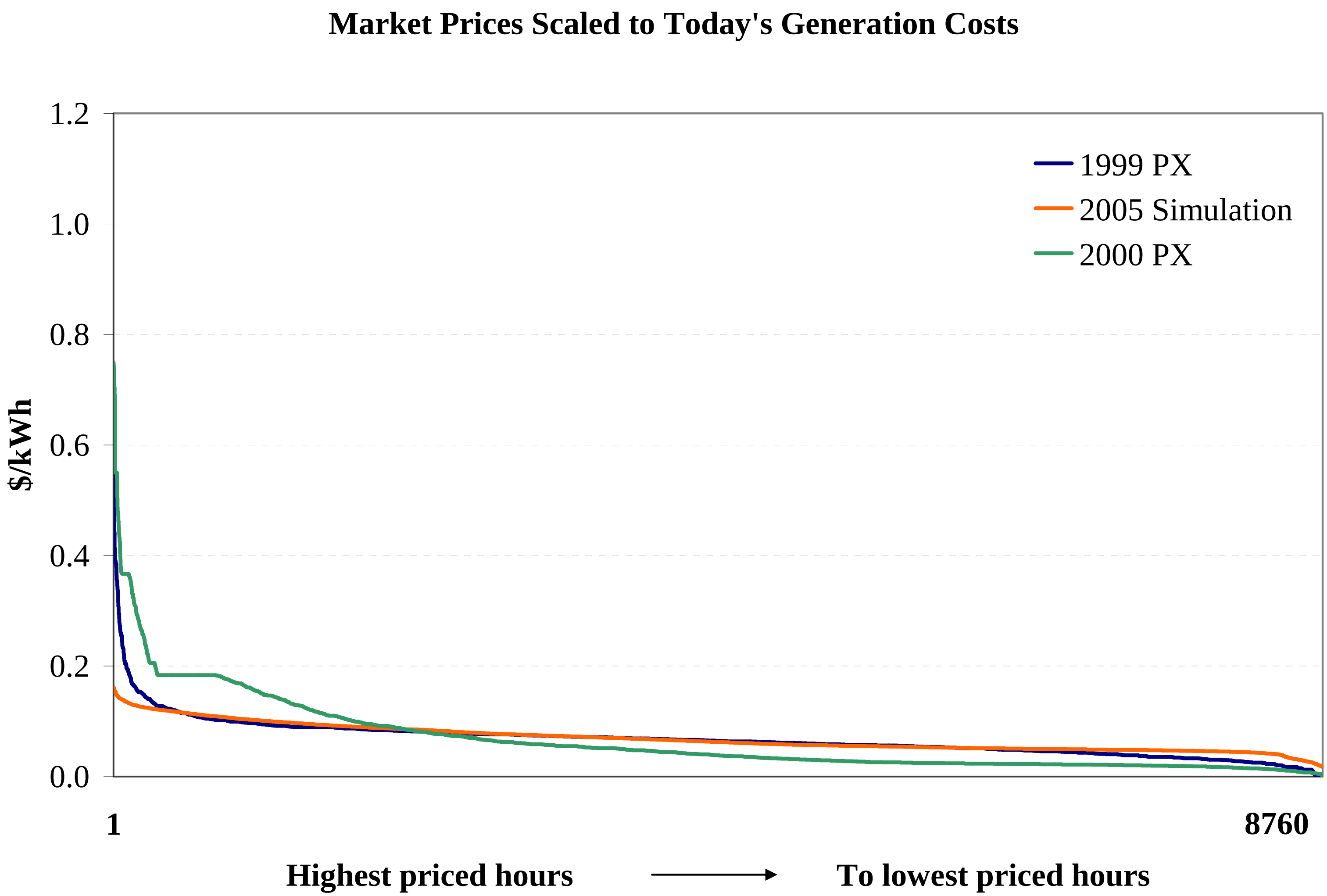
- For compliance with AB 1x, the first two tiers of the residential rate cannot be increased
- As a result, the CPP surcharge and credit are only applied to the share of consumption that exceeds the second tier
- The surcharge and credit do not change from the core rate, but they are applied to a smaller share of the customer’s consumption

Market Prices and Load Shapes

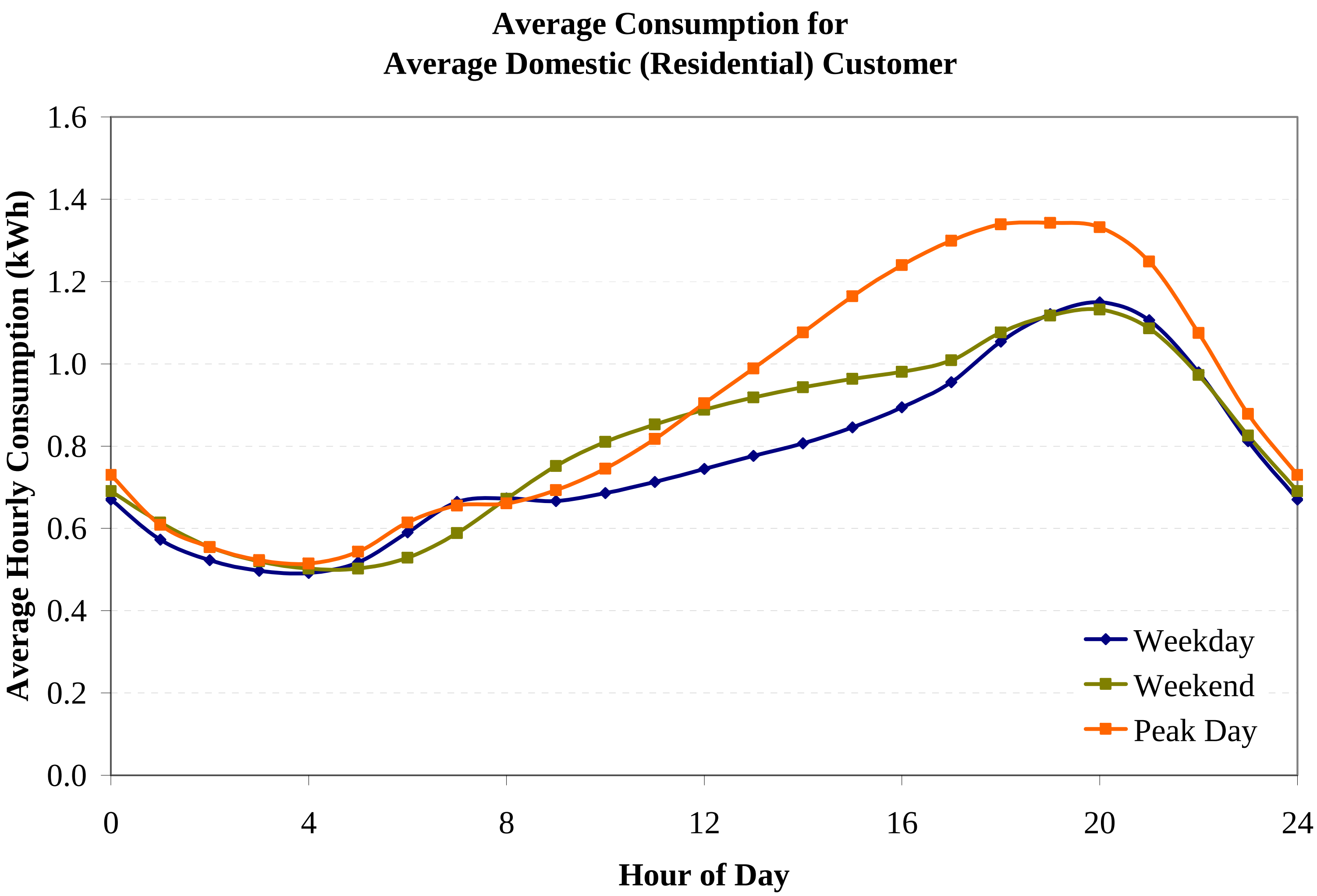
SP15 hourly electricity market prices



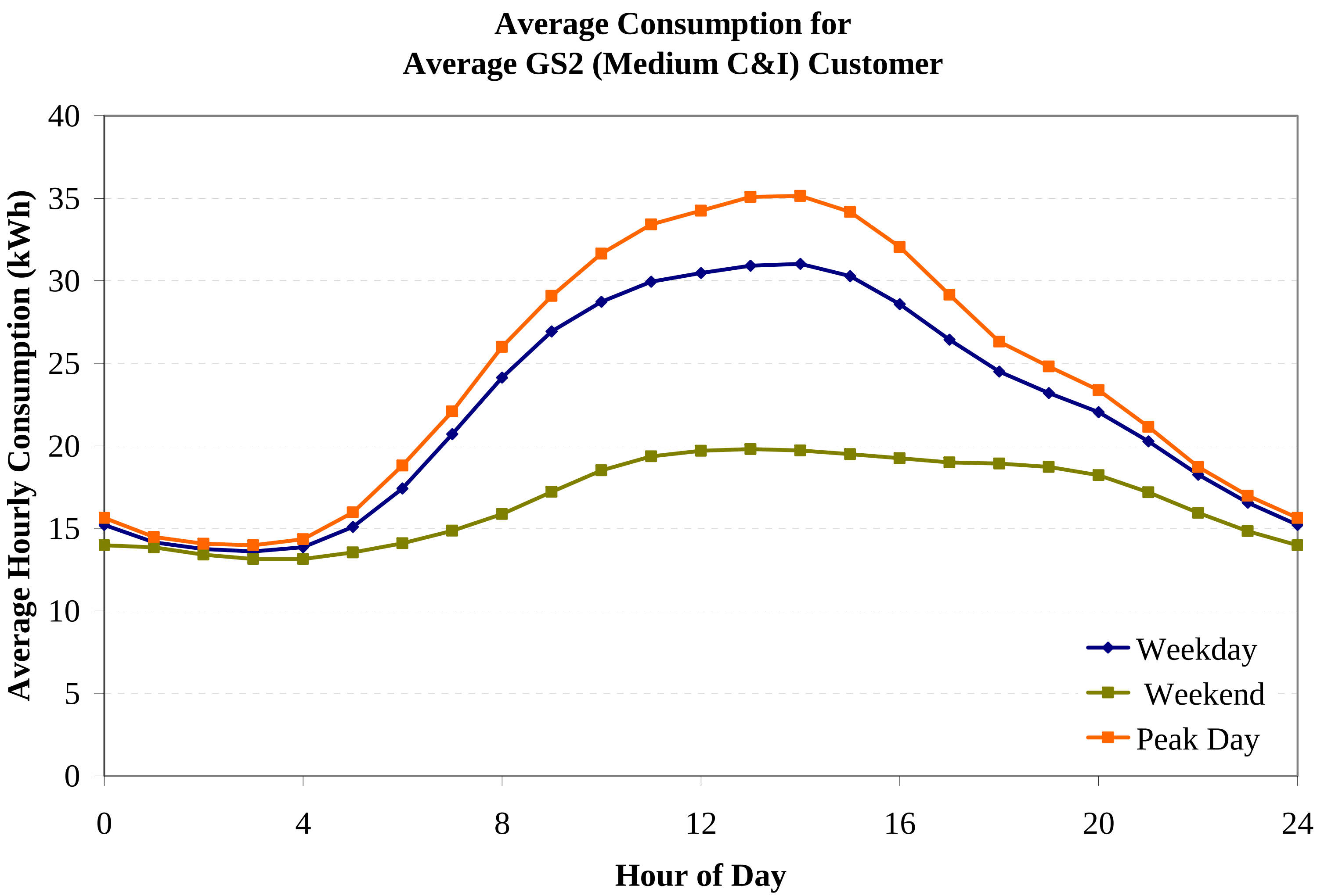
SP15 market prices scaled to today's generation costs



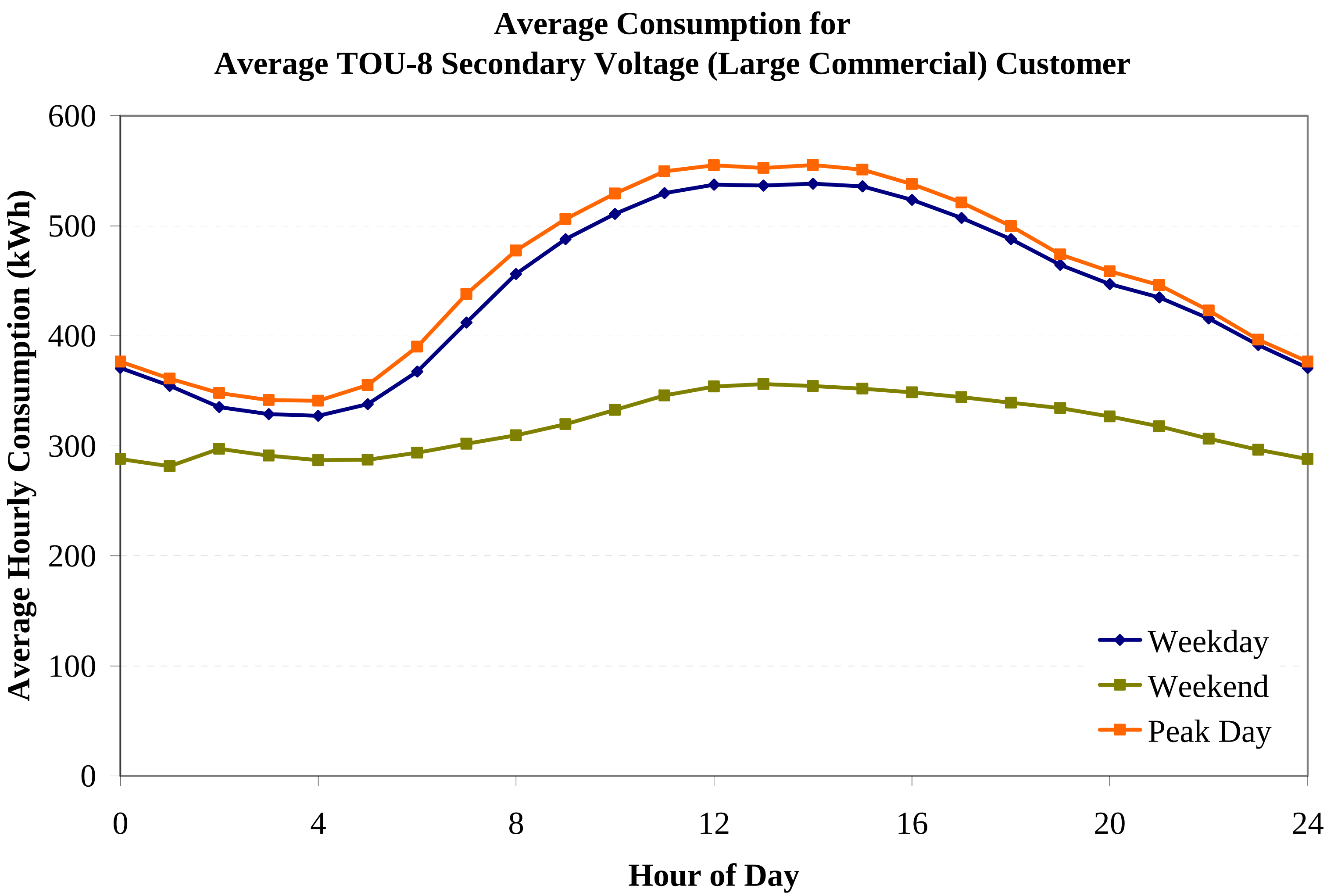
Residential load shape



Medium C&I load shape



Large commercial load shape



Large industrial load shape