



The Brattle Group

THE ECONOMICS OF DYNAMIC PRICING FOR THE MASS MARKET

Ahmad Faruqui, Ph. D.

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Edison Electric Institute

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Précis

- **Utilities are considering the system-wide deployment of smart meters**
 - ▶ They can improve utility operations and the cost savings can cover a substantial portion of the multi-million dollar investment
 - ▶ However, depending on the utility, the “gap” between operational benefits and AMI costs may still be quite large
- **One way of bridging the gap is to use smart meters as a means of providing “smart” prices to customers that would induce demand response (DR), obviating the need for expensive peaking capacity and energy**
- **As a bonus, smart pricing would eliminate an important inequity in existing rate designs**
 - ▶ Consumers who use relatively less power during expensive peak periods subsidize others

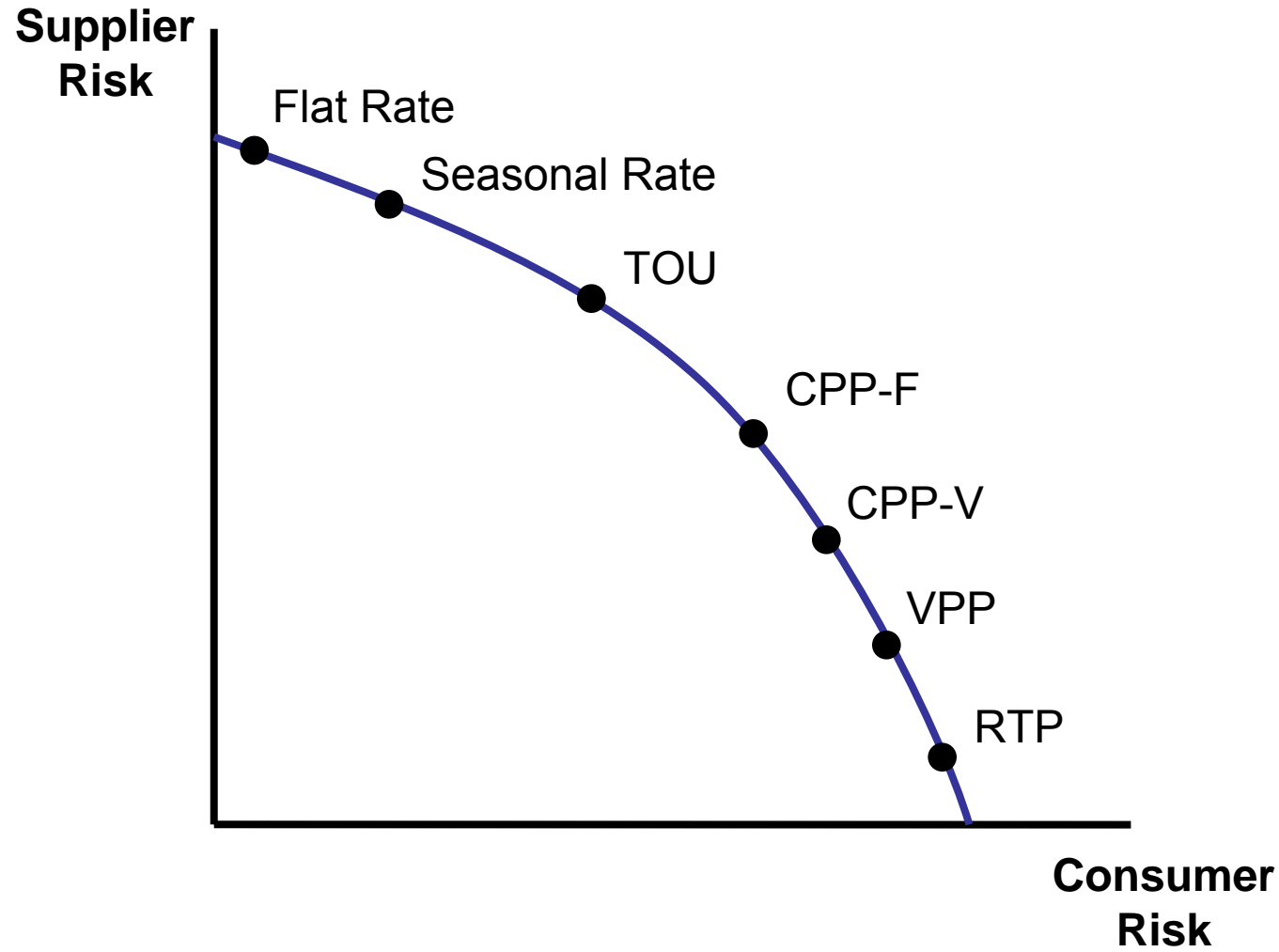
It is important to quantify the costs *and* benefits of smart pricing and smart metering

- Identify and measure costs
 - ▶ Deploying advanced metering infrastructure (AMI)
 - Meters
 - Two-communication links
 - Billing systems
 - ▶ Offering dynamic pricing signals
 - Marketing costs
 - Program administration costs
- Identify and measure benefits
 - ▶ Operational benefits of AMI
 - ▶ DR benefits of dynamic pricing
- Develop a net present value (NPV)

DR has both primary and secondary benefits

- Primary benefits
 - ▶ Quantity of DR (MW) * Value of avoided MW
 - ▶ Quantity of DR = kW reduction per customer * Number of participating customers
 - ▶ Value of avoided load = Cost of peaking capacity net of energy revenues
- Secondary benefits
 - ▶ Reduction in wholesale prices
 - ▶ Enhanced reliability
 - ▶ Environmental improvement

As a bonus, smart prices enable customer choice between various pricing products

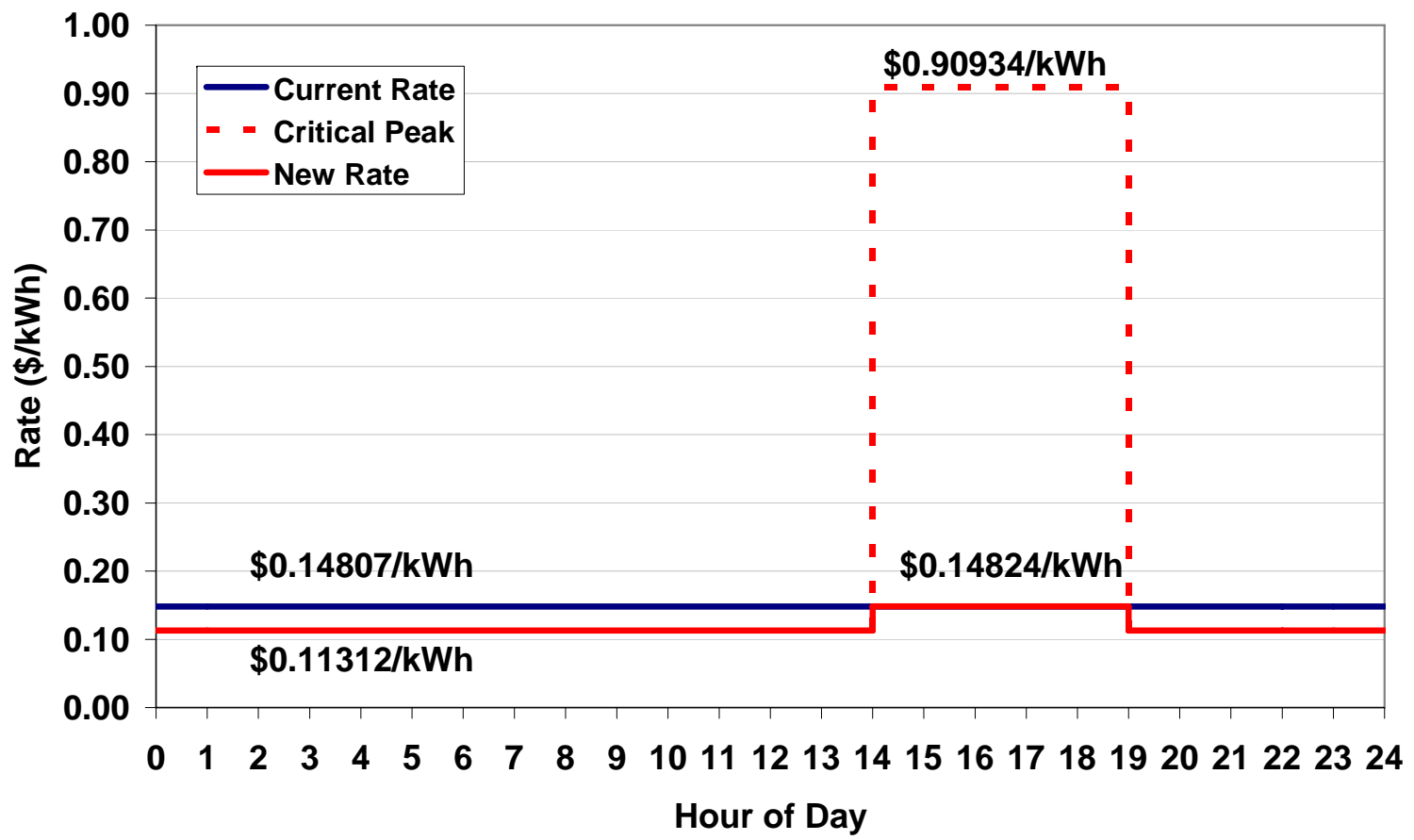


Critical-peak pricing (CPP) is by far the most popular design

- It is essentially a time-of-use (TOU) rate on most days of the year
- When the power system encounters critical conditions, the peak-period price rises to much higher but known levels, either on a day-ahead or day-of basis
- In variable critical-peak pricing (VPP), the critical-peak price rises to an unknown level that reflects actual market conditions
- Both of these rate designs approximate real-time pricing (RTP) rates and are easier for mass market customers to deal with

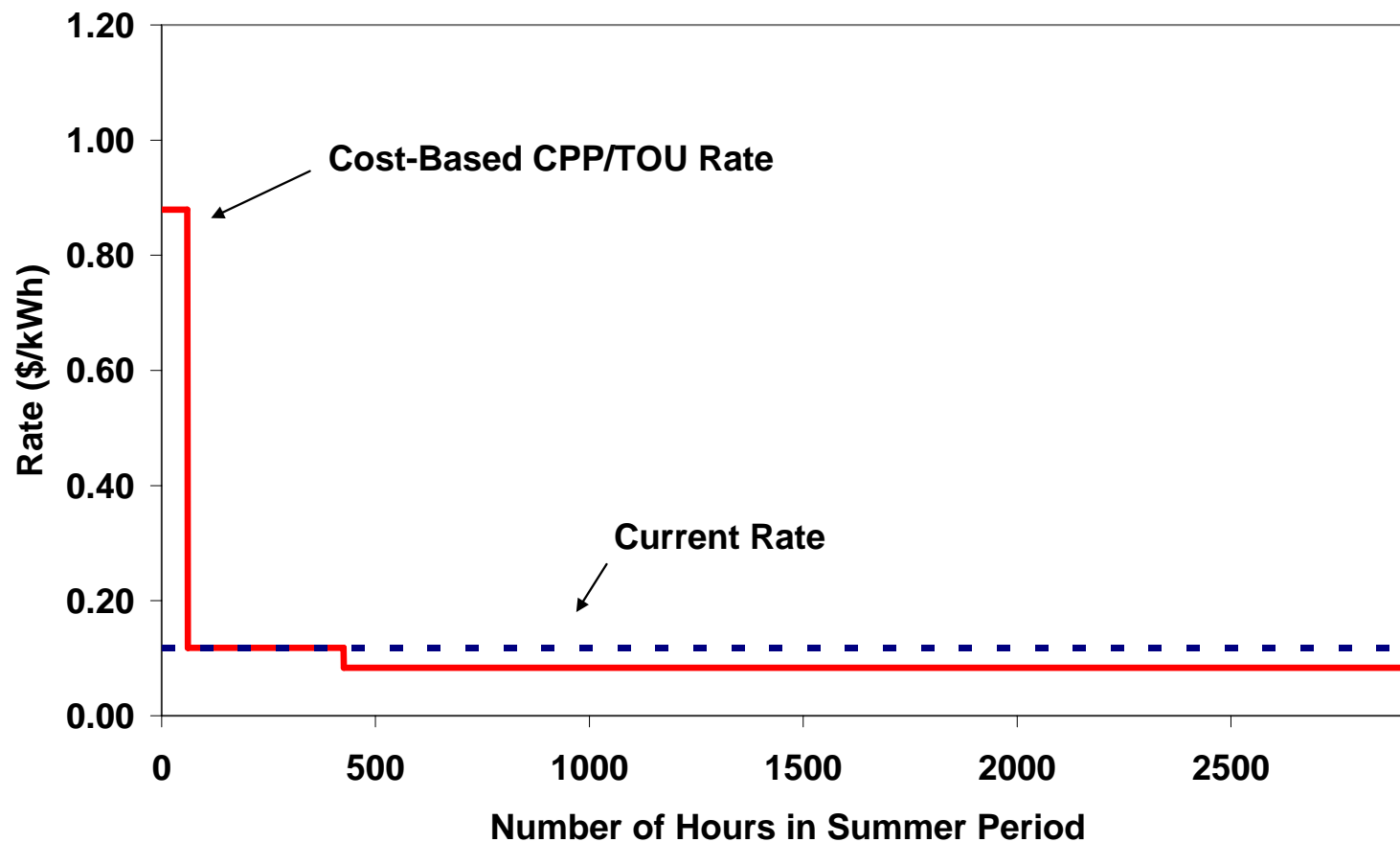
A CPP rate will provide customers with substantial opportunities to save money

Current Residential Rate vs. Cost-Based CPP/TOU All-In Rate



For a vast majority of summer hours, the customer will save money

Price Duration Curve



Peak-time rebates (PTR) represent a variation on this theme

- Customers face their standard rates at all times
 - ▶ In the previous example, that was 14.8 cents/kWh
- However, if they cut their consumption during peak hours, they earn a rebate on every kWh curtailed
- The amount of the rebate is set based on the same principles that were used to set the critical-peak price
 - ▶ In the previous example, that would be 76.127 cents/kWh
- This requires knowing the amount that the customer would have consumed *but for* the rebate
 - ▶ Statistical techniques are available for estimating this amount

Will customers exhibit demand response?

- Yes, according to dozens of experiments that have been carried out over the past 30 years in Europe and North America
 - ▶ Most of these involved time-of-use (TOU) rates but a few involved dynamic pricing
- Key findings
 - ▶ Not every customer will respond
 - ▶ Some will respond marginally
 - ▶ Some will respond a lot
 - ▶ In the aggregate, peak load will drop

The Electricity Council of London ran a pioneering TOU experiment in the early 1970s

- It placed 3,600 customers on a TOU rate
- Experimental prices were revenue neutral with then-prevailing prices
- They showed clearly that customers responded to higher peak prices by curtailing/shifting usage
- However, by the time the experiment ended three years later, the experimental prices were half as high as prevailing prices, invalidating the quantitative findings
- Jim Boggis, Study Director, concluded:
 - ▶ With the aid of hindsight, the experiment might have been better directed to a more primitive problem. What are the price elasticities and cross elasticities of electricity demand by time of day, day of week and season of year?

The US FEA/DOE ran 16 TOU pricing experiments in the late 1970s; five had strong designs

Experiment	Length of peak periods (hours)	Number of test rates	Max. price ratio	Intermediate pricing period		Shoulder or peak price during some weekend hours	Sample size
				Weekday	Weekend		
1. North Carolina	8,10	13	6.2/1	X	X	X	600
2. Connecticut	4	1	16/1	X	X	X	391
3. Los Angeles	3,6,9,12	17	9/1			X	1268
4. Southern California	10	8	9/1				620
5. Wisconsin	6,9,12	9	8/1				674

The LADWP experiment yielded the most comprehensive results

- Customers reduced on-peak usage and increased off-peak usage in response to the TOD rates
- Own-price and cross-price elasticities were successfully estimated using econometric methods and a quadratic functional form for the demand equations
- TOD rates were found to be cost-effective for all customers using more than 1,100 kWh per month, or all customers with swimming pools using more than 800 kWh per month

EPRI proved that results were consistent across the top five experiments

- The average elasticity of substitution was found to be 0.14, suggesting that a doubling of the peak to off-peak price ratio would lead to a 14% drop in the peak to off-peak kWh consumption ratio
- This was a universal result that was transferable across regions, as seen in the next slide

The elasticity of substitution varied across customers and regions

Type of climate	No appliances	Typical appliances	All appliances	Typical appliances except	
				Does not have air conditioning	Has air conditioning
Cool	0.09	0.12	0.16	0.13	0.11
Typical	0.07	0.14	0.21	0.11	0.16
Hot	0.05	0.15	0.25	0.10	0.21

Puget Sound Energy ran a TOU pricing pilot in 2001/02

- It featured several hundred thousand customers on a *mild* TOU rate where peak prices were 15% higher than the average rate and off-peak prices were 15% lower
- Even then, month-after-month, customers lowered peak usage by about 5 percent
 - ▶ Usage reductions were higher in the winter months
- However, the cost of the meters and billing systems was higher than the value of reduced load and the program was discontinued
- Since the experiment involved only a single TOU rate, it did not yield price elasticities
 - ▶ Impacts were difficult to predict for other TOU rates

California created a Working Group in 2002 to study the issue

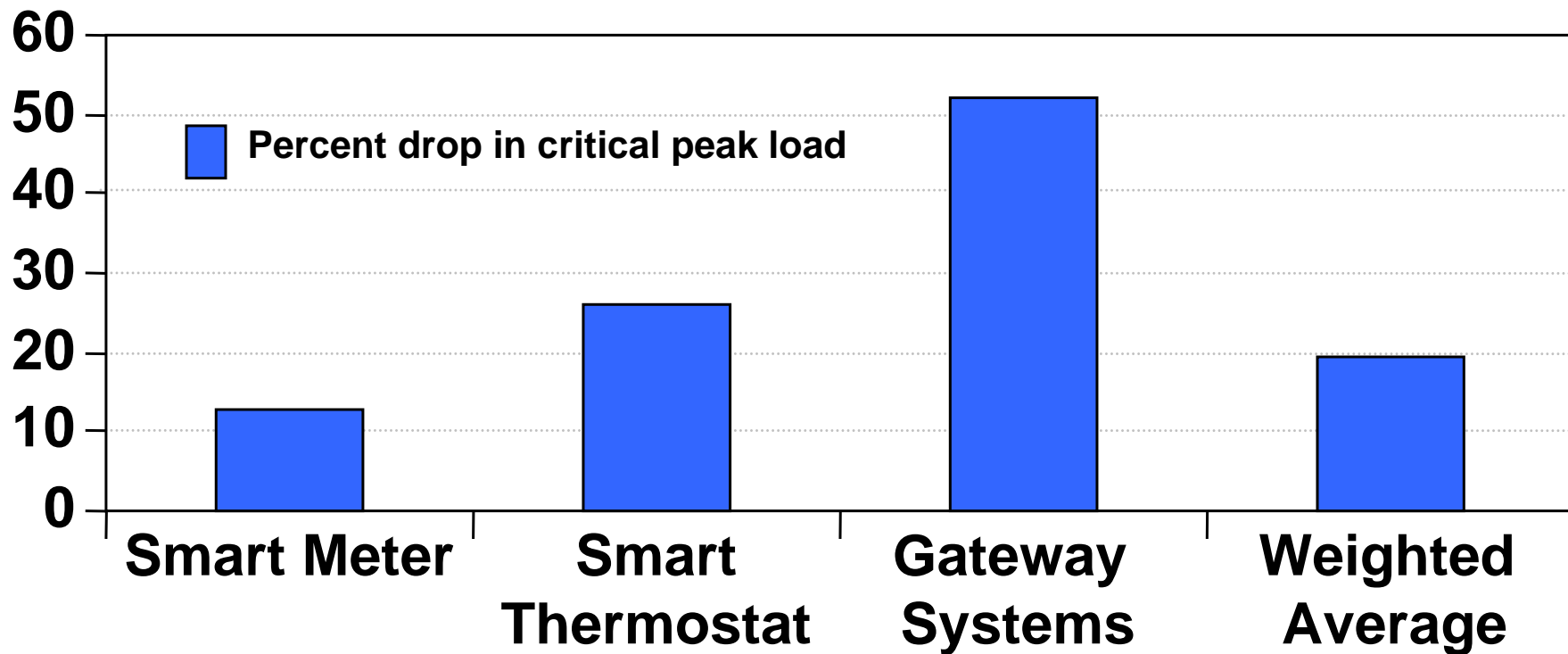
- The energy crisis was accentuated by the lack of demand response
- The CPUC initiated a proceeding on demand response, dynamic pricing and advanced metering
 - ▶ But no one knew whether customers would respond to dynamic pricing by a sufficient margin to offset the costs of AMI
- A preliminary cost-benefit analysis for PG&E revealed that the NPV of benefits could be as low as -\$500 million or as high as \$1,500 million, given that the uncertainty in demand response

This led to a statewide pricing pilot (SPP), “the pilot to end all pilots”

- It involved 2,500 residential and small commercial and industrial customers over 2003-05
- The results were reviewed by staff at two state commissions, three investor-owned utilities, equipment vendors and intervenors
- On average, residential customers dropped peak loads on critical days by 13 percent
 - ▶ Critical period rates were five times higher than existing rates
- Customers with central air-conditioning (CAC) dropped loads by 16 percent while those without CAC dropped loads by 8 percent
- 30% of the customers accounted for 80% of the impact
 - ▶ Not every customer has to respond for dynamic pricing to have a significant impact on system loads

In the SPP, enabling technologies boosted the drop in critical peak loads

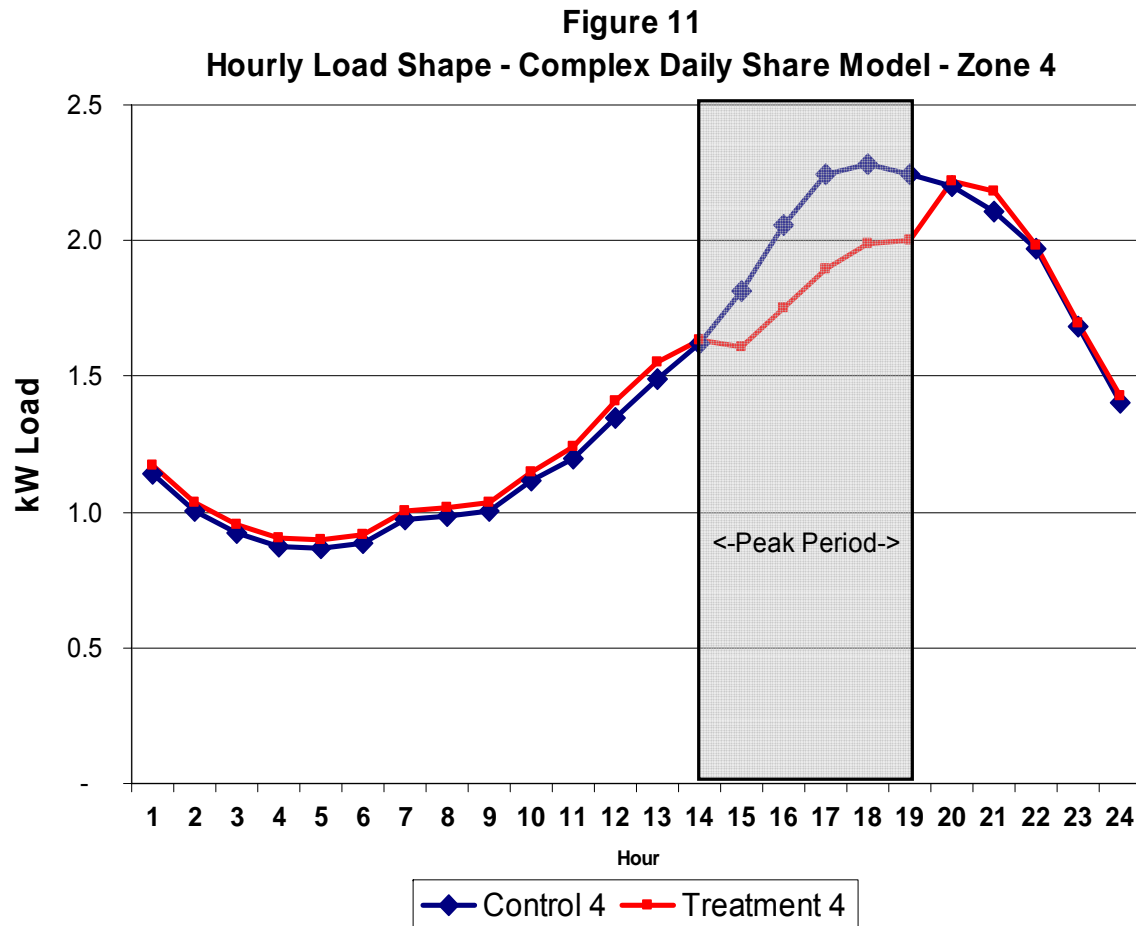
Type of technology



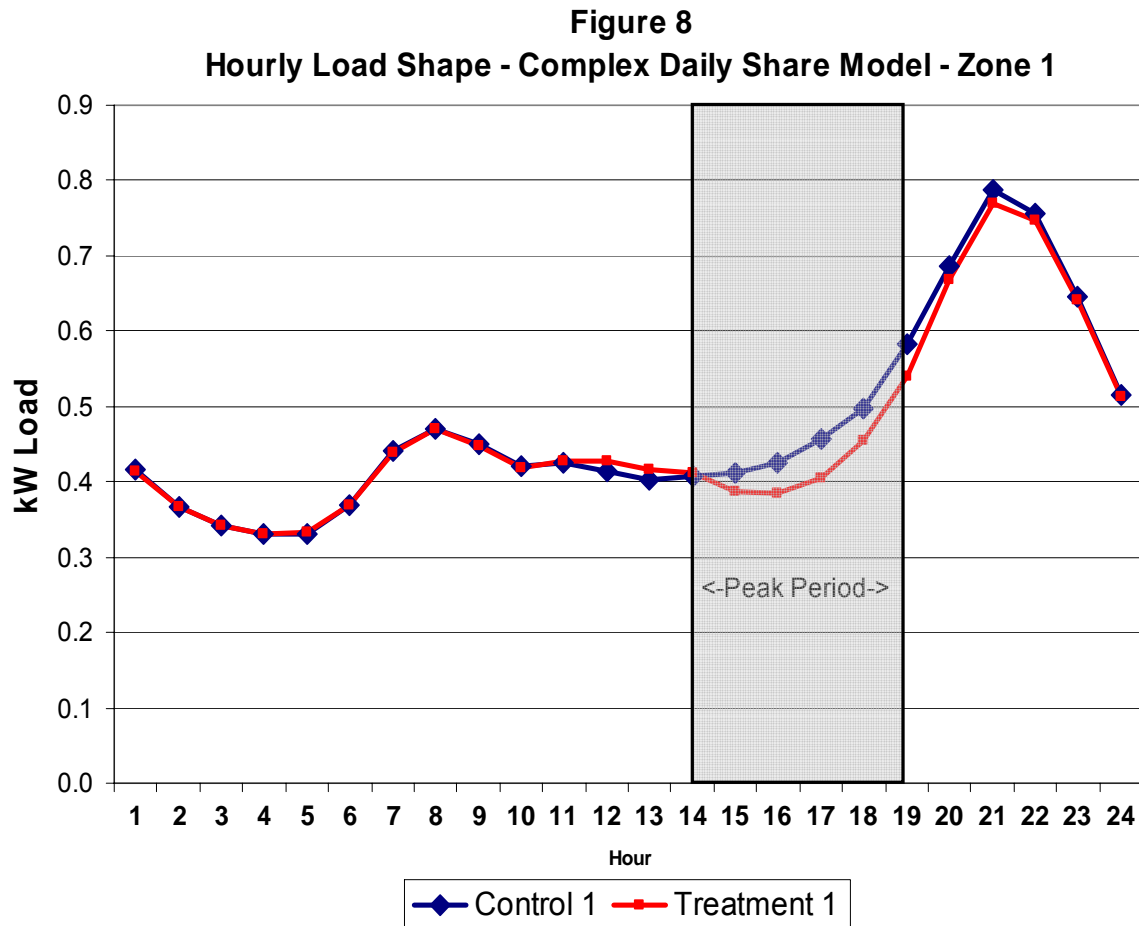
This demand response satisfies the CPUC's “resource adequacy” requirements

- Responses held constant across two and three consecutive critical days
 - ▶ So they are likely to stay constant in a real heat wave
- Responses did not degrade during the second summer
 - ▶ The load impact is not a novelty that wears off
 - ▶ This finding is consistent with results from the earlier 16 experiments, some of which lasted for 3 years
 - ▶ It is also consistent with customer responses observed by Arizona Public Service, Gulf Power and the Salt River Project

Dynamic prices have a substantial impact in a hot climate such as the Central Valley's



They produce an impact even in a mild climate such as San Francisco's



California's utilities have used these findings to develop AMI business cases

- PG&E's \$1.7 billion AMI filing was approved by the CPUC last July
 - ▶ Almost 90% of the benefits come from operational savings
 - ▶ The utility projects more than 500 MW of demand response by 2011, assuming that about a third of its customers with central air conditioning will adopt CPP
 - ▶ It is proceeding to deploy five million electric and four million gas meters
- SDG&E's \$0.6 billion AMI filing has just been approved by the CPUC
 - ▶ The utility intends to deploy the PTR to achieve its DR goals
- SCE has filed a Phase I feasibility report
 - ▶ It plans to file an application later this year
 - ▶ It is also expected to rely on PTR to achieve its DR goals

Can you make use of the SPP results?

- Yes, once you adjust the “initial conditions” in the PRISM software to match the conditions of their service area:
 - ▶ Existing rate design
 - ▶ Existing load shape
 - ▶ Saturation of central air conditioning
 - ▶ Weather conditions
- You can then enter a variety of time-varying designs and estimate likely load response to each of them
- This information can be used to carry out a *preliminary* analysis
- For a definitive assessment, you will need to conduct your own pilot (more on this later)

You can use this information to comply with EPACT 2005

- Estimate benefits and costs over the project lifetime and derive the NPV of net benefits
- Analysis should factor in key uncertainties dealing with impact per customer, number of participants, avoided costs and AMI costs
- Analysis should factor in multiple perspectives
 - ▶ Total Resource Cost
 - ▶ Participant
 - ▶ Utility
 - ▶ Society

It is relatively quick to make a first pass at the TRC test

- Develop a dynamic pricing rate and estimate its impact per customer
 - ▶ Ball park estimate: 10-30 percent per customer
- Identify the number of participating customers
 - ▶ Ball park estimate: 10 – 30 percent of the target market
- Compute aggregate DR impact
 - ▶ Ball park estimate: 1 to 9 percent of peak demand
- Estimate value of avoided costs
 - ▶ Ball park estimate of capacity costs: \$52 – 85 /kW-yr
 - ▶ Factor in energy costs
 - ▶ Factor in changes in air emissions
- Combine the last two to come up with an NPV of benefits and compare it with the NPV of costs

But you will have to make many hard decisions

- Dealing with conflicts between multiple perspectives, since the program may look attractive from one and unattractive from another
- Deciding on deployment strategy
 - ▶ Voluntary (opt-in)
 - ▶ Voluntary (opt-out)
 - ▶ Mandatory
- Dealing with customer apprehensions about rate hikes and price instability
- Ensuring regulatory acceptance and cost recovery

Should you do a pilot?

- Probably, since there is much uncertainty about a go/no go decision on AMI/dynamic pricing and not everyone wants to borrow results from California
- How should you proceed?
 - ▶ Plan on letting it run for about a year
 - ▶ Plan on spending real money on it but no more than the value of information you hope to gain from the pilot
 - ▶ If your objective is to estimate customer behavior to dynamic pricing, you will need to do an experiment that follows scientific design principles

Experiments should yield valid results

Internal Validity

- Can a cause-effect relationship be established within the experiment?

External Validity

- Are the experimental findings applicable to other populations in other settings?

But most fail to do so!

No control group

- Cannot measure cause-effect relationship, and ceases to be an experiment

No pre-treatment measurement

- Can't eliminate the effects of weather and other “confounding” variables

Nonrandom sampling methods

- Cannot generalize results

Non-comparable control group

- Becomes a quasi-experiment

Insufficient number of treatments

- Cannot generalize results

Common errors (continued)

Insufficient sample size by treatment

- Leads to statistically-imprecise estimates

Compensatory payments to participants

- Leads to biased estimates

Hawthorne effect

- Leads to biased estimates

Estimating program impacts

	Control Group	Treatment Group
Before Treatment	C_1	T_1
After Treatment	C_2	T_2

I. True Impact Measure = $(T_2 - T_1) - (C_2 - C_1)$

- “Gold standard” for assessing program impacts
- All other variables are held constant
- Random assignment to control or treatment group

II. Alternative Measures of Impact

- (1) $T_2 - T_1$
- (2) T_2
- (3) $T_2 - C_2$

Ongoing pilots that feature dynamic pricing rates

- Ameren, Missouri (TOU, CPP)
- Anaheim, California (PTR)
- BGE (CPP, just approved by the MD PSC)
- Commonwealth Edison, Illinois (RTP)
- Hawaiian Electric, Hawaii (CPP, PTR)
- Hydro Ottawa, Ontario (CPP, PTR)
- Idaho Power, Idaho
- Pepco, District of Columbia (CPP, PTR, RTP)
- PSEG, New Jersey
- SMUD, California

Should you succumb to pilot fever?

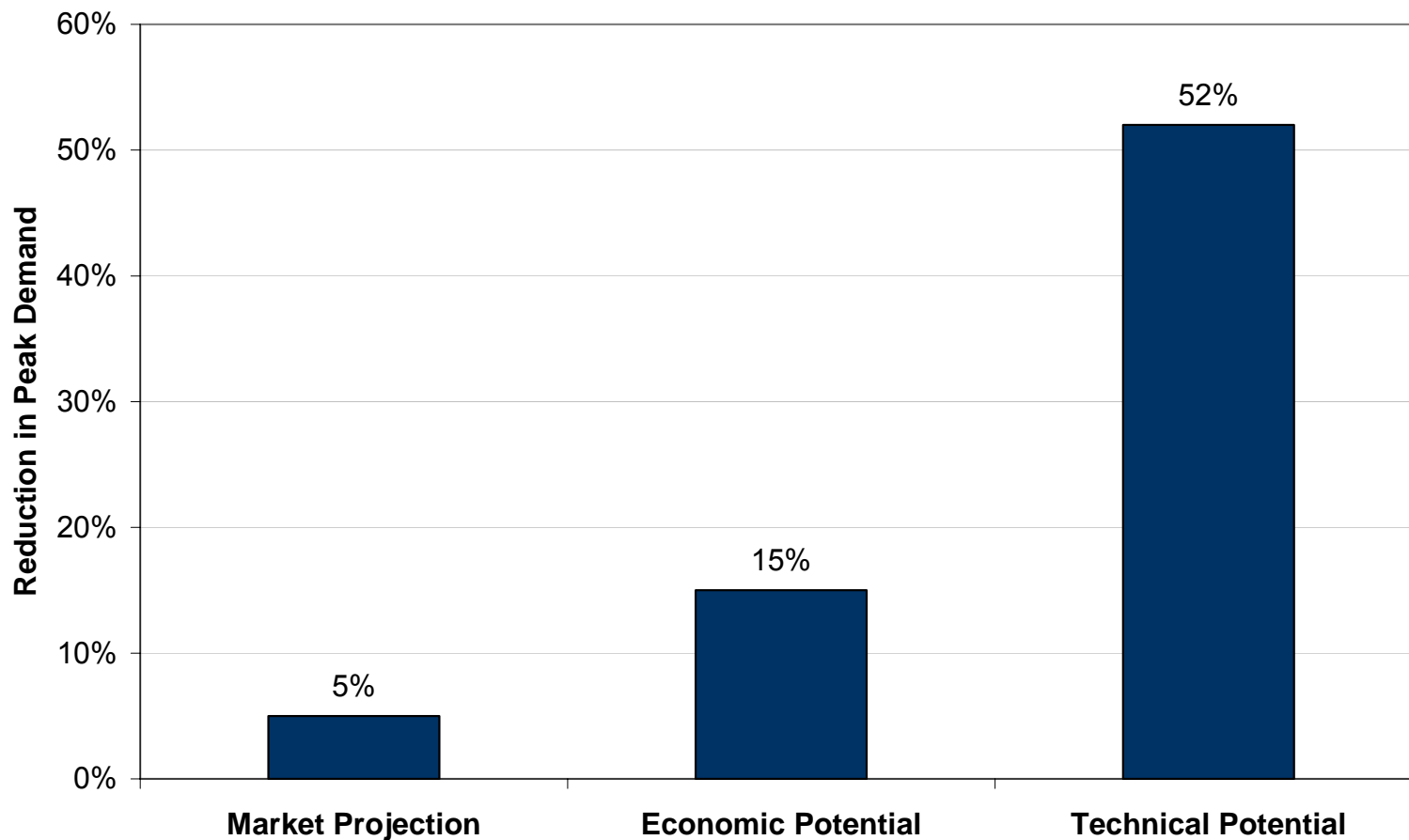
- In the near term, you can borrow results from other pilots to do an initial cost-benefit analysis
 - ▶ This will take you about four to six weeks
- Later on, you may wish to do your own pilot
 - ▶ Should it be an experiment, with control and treatment groups, random selection and random assignment?
 - ▶ What types of rates should you test in the pilot?
 - ▶ Should you also bundle some enabling technologies with the rates?
 - ▶ Would it be useful to also test some pure information treatments?

Five questions that will shape the future of dynamic pricing

1. What is the likely impact of dynamic pricing on peak demand?
2. What is the value of this demand response (DR)?
3. How much does customer price responsiveness vary by customer and region?
4. How can we make dynamic pricing more attractive to customers?
5. What is the best way forward?

#1. Dynamic pricing can lower system peak demand by 5 percent but the economic and technical potential is much higher

Estimates of Total Potential Peak Demand Reduction



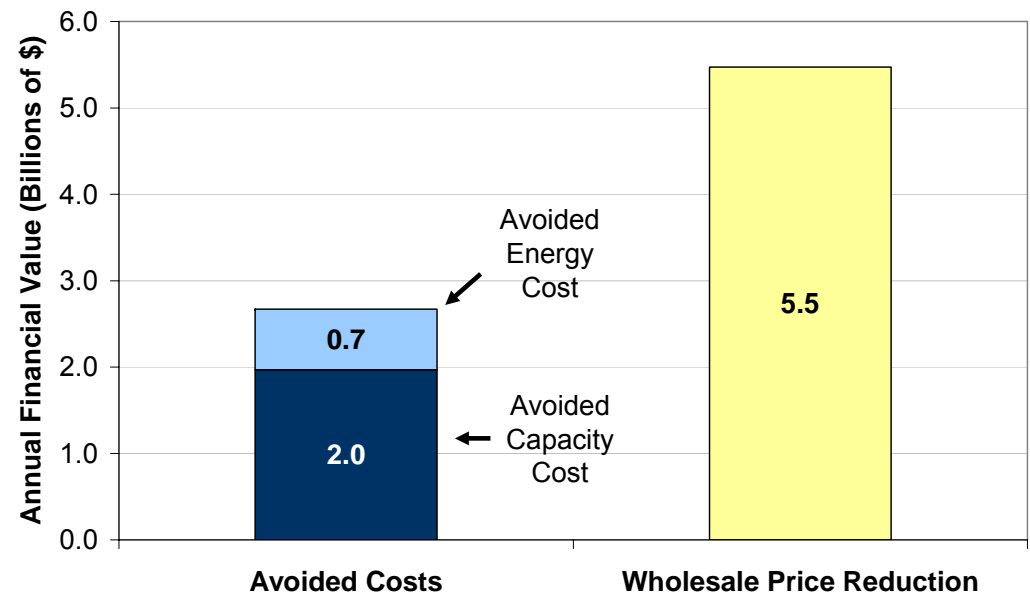
#2. A 5 percent reduction in US peak demand is worth \$31 billion over a 20-year period, just based on avoided costs

Assumptions

- 5% demand reduction in 757 GW
- \$52/kW-year capacity price
- 20 year horizon
- 15% discount rate
- 2% peak growth rate
- Avoided cost of energy is 36% of avoided cost of capacity*
- Value of wholesale price reduction is 278% of avoided cost of capacity*

*Derived from a study on the value of DR in PJM:
The Brattle Group, 2007, *Quantifying Demand Response Benefits in PJM*, Prepared for PJM and MADRI

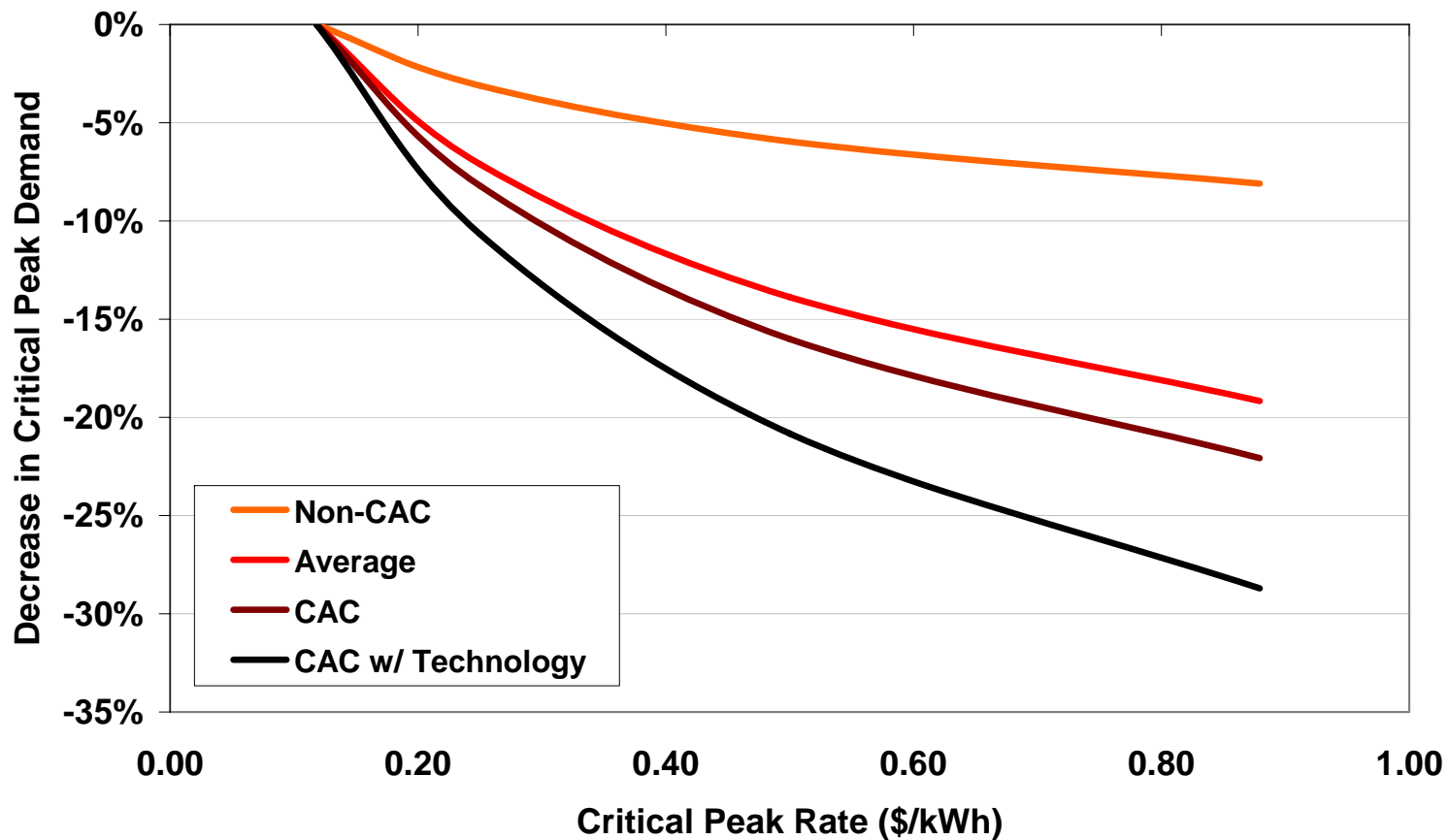
Annual Value of a 5% Reduction in Peak Demand



NPV of Avoided Costs = \$31 billion

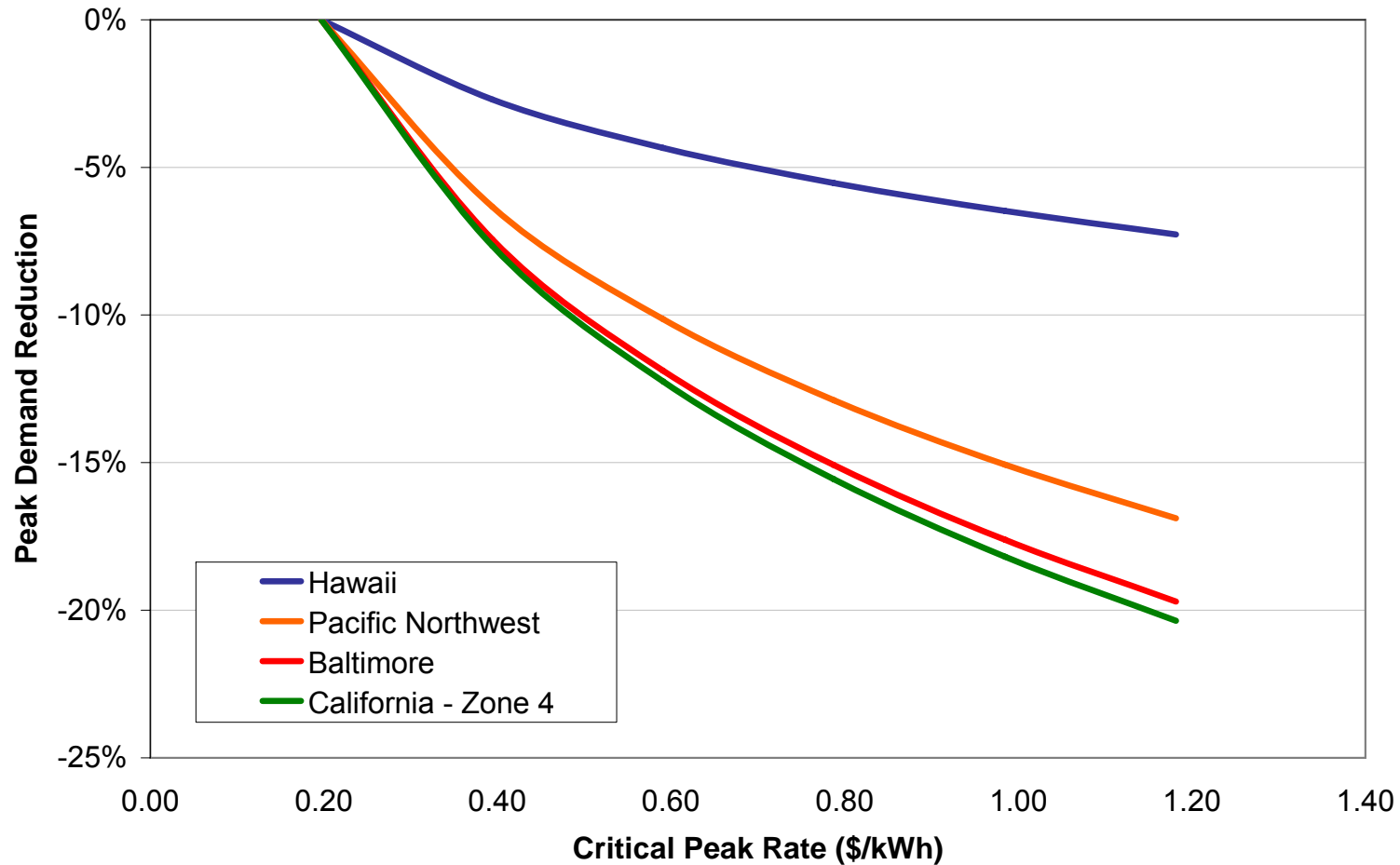
#3. Customer response in the mass market varies by end-use and enabling technologies (source: California's statewide pricing pilot)

Peak Demand Reduction by Customer Type



Applying these relationships, one would expect customer response to vary by region

Demand Response Comparison Across Regions

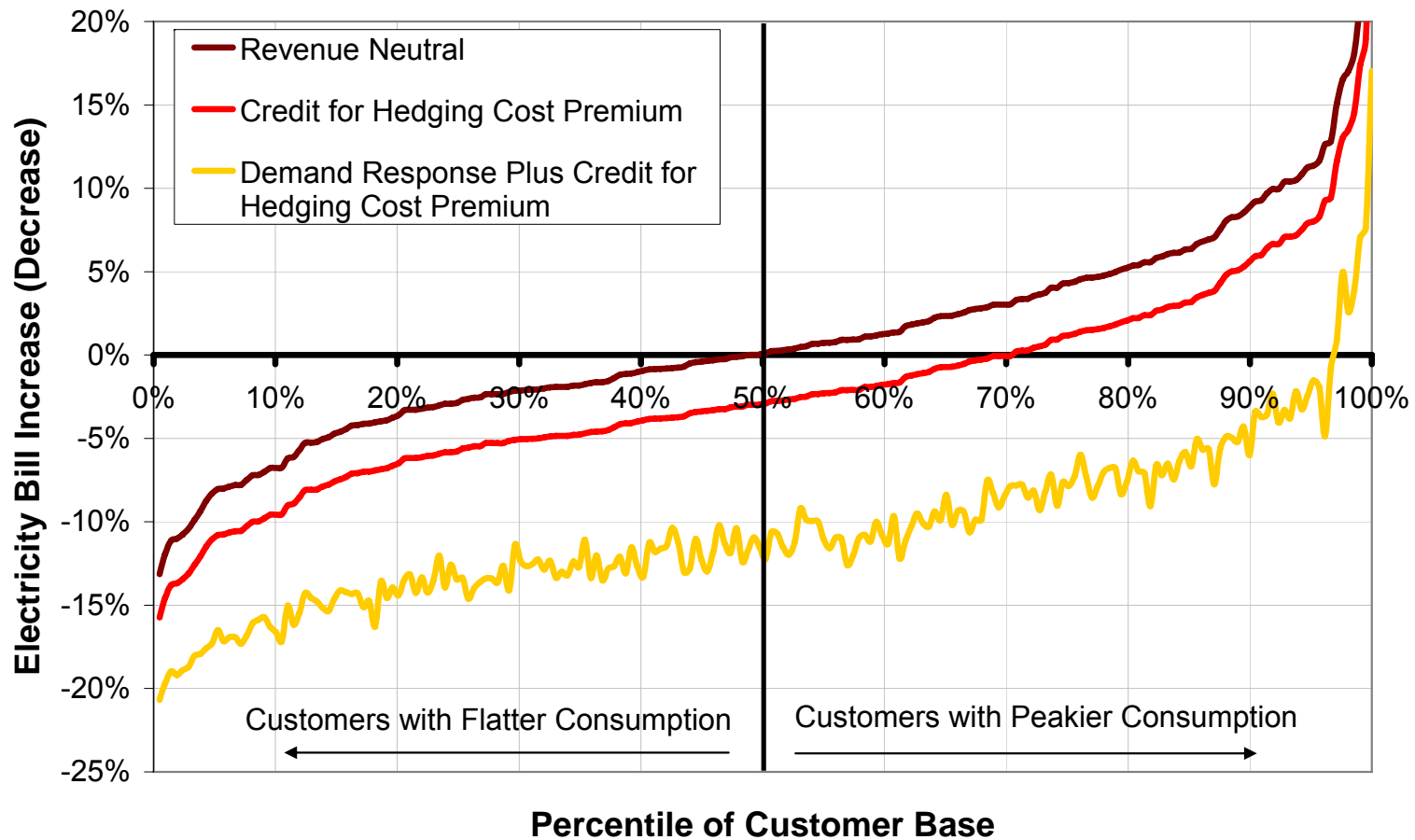


#4. What is the magnitude of the insurance premium that suppliers will need to collect with hedged rates?

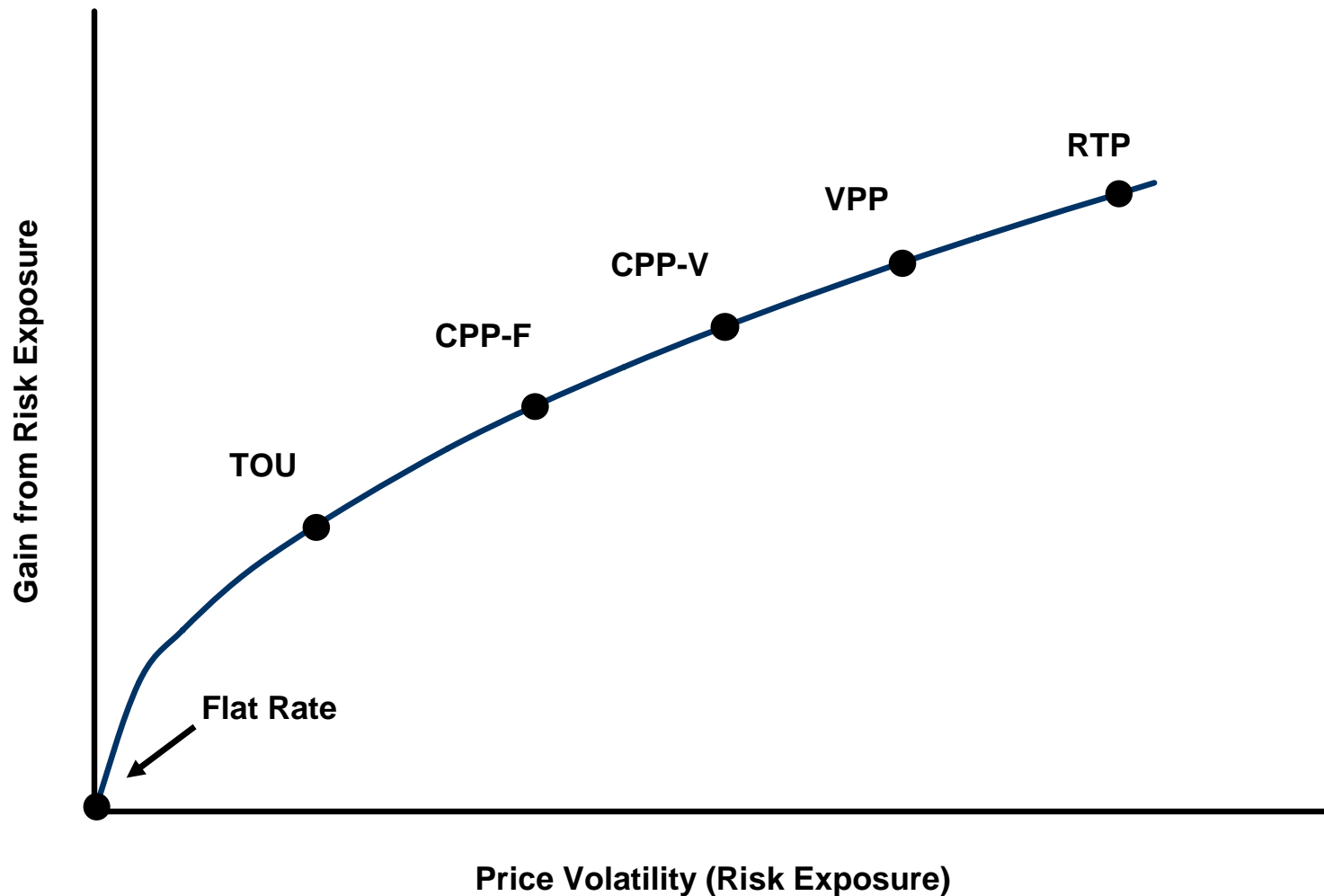
- Empirically, this “insurance premium” ranges from 3 to 13 percent for different types of time-varying rates
- Illinois used a value of 10 percent in its RTP pilot for residential customers
- Monte Carlo simulations with a standard financial equation suggest a mean value of 11 percent
- A very conservative estimate is 3 percent

Even applying a 3 percent credit vastly expands the appeal of dynamic pricing

Distribution of Bill Impacts



#5. The way forward is to offer customers a menu of dynamic pricing options, each of which reflects a credit equal to its hedging premium



Additional reading

- **Brattle Group, The. “Quantifying the benefit of demand response for PJM,” prepared for PJM Interconnection LLC. and MADRI, January 2007**
- **Faruqui, Ahmad. “Breaking out of the bubble: how dynamic pricing can mitigate rate shock,” Public Utilities Fortnightly, March 2007**
- **Federal Energy Regulatory Commission (FERC), The US. “Demand Response and Advanced Metering,” Staff Report, August 2006**
- **North American Electric Reliability Corporation (NERC). “2006 Long-Term Reliability Assessment,” October 16, 2006.**
- **Plexus Research, Inc., “Deciding on Smart Meters,” Edison Electric Institute, September 2006**

Contact information

Ahmad Faruqui, Ph. D.
Principal

The Brattle Group
353 Sacramento Street, Suite 1140
San Francisco, CA 94111
Voice: 415.217.1026
Fax: 415.217.1099
Cell: 925.408.0149
Email: Ahmad.Faruqui@Brattle.Com