United States Demand Response Coordinating Committee (DRCC)

Regional Meeting

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U.S. DRCC

- U.S. has taken lead among countries on the first demand response project ever undertaken by the International Energy Agency (IEA).
- DRCC is the entity by which U.S. parties are participating.
- Issues to be addressed include
  - Potential
  - Valuation
  - Enabling Technology
  - Funding (U.S.)
  - Barriers
  - State and Regional Cooperation (U.S.)

DRCC Members

- AEP
- National Grid
- NYISO
- Southern Company
- PIER Demand Response Research Center (DRRC)
- NYSERDA
- AREVA
- ISO-NE
- Salt River Project
- PJM
- SCE
- SDG&E
- PG&E
- MISO

DRCC Credits

- Chris King, Chief Strategy Officer, eMeter Corporation
- Steve George, Vice President, Charles River Associates
- Roger Levy, President, Levy Associates
- Chuck Goldman, Lawrence Berkeley Labs

DRCC – Why I Am Here

- DR needs “nourishment” in its infancy
- DR expertise and information is diverse and dispersed
- No natural flow and exchange of ideas and info
- What is known is unknown
- Much is not known
- DR not being recognized as its own discipline
- Some places need/want DR quickly
- Policy makers like it and are looking for assistance

DRCC – Objectives for the Day

- Information dissemination
- Overview of DR developments
- Program snapshots
- DR research highlights
- Information gathering
- Information exchange
- Issues discussion
- Research needs identified

Federal DR Developments

- FERC
  - Using the Bully Pulpit
  - Pushing the ISOs
    - 12/04 Decision on ISO-NE Day Ahead Program
- DOE
  - Stepchild to EE and RE
  - Death by a thousand earmarks
- EPA
  - One eye on DG increasing emissions
  - Other eye on DR decreasing emissions
  - Role for EnergyStar

Federal DR Developments

- Energy Bill had 4 DR Elements
- Federal Buildings
  - FEMP
  - Advanced metering
- Guidance to States and Utilities
  - Time-based pricing offerings by utilities
  - DR and advanced metering investigations by states
  - Requirements to include in regional planning
- Tax Incentive for Advanced Metering
  - Three year depreciation
- DR R&D
  - DR now on the list

State Policy Trends
"Let's have a proceeding"

- This demand response sounds interesting – we had better investigate this
- Round up the usual suspects
- Regulated utility is the focus
- State Examples: OR, PA, NH

State Policy Trends – "Our time is almost up"

- The restructuring transition periods stemming from the statutes are ending
- Most customers are still with their utility
- Focus is on what to do with captive customers and POLR
- Examples: Illinois, NJ, NY, MA, PA

State Policy Trends
"Let's do it!"

- A rebuttable presumption that DR is the way to go.
- Focus in on getting all customers enabled
- Recognition that policy case and business case are multi-faceted and require detailed work
- Example: California, Ontario

State Policy Trends
“Not all demand is demand”

- Policy development/work on demand side management
- Exclusion of DR from definition of Demand Side Management
- Example: AZ

State Policy Trends
"Let's do the regional thing"

- Strong pools with strong DR programs require regional treatment
- States can work together on policies that cut across state lines
  - Interconnection
  - DG Emissions
- Examples: NEDRI, MADRI

State Policy Trends
"Riding on the environmental train"

- Renewable Portfolio Standards (RPS) under development state by state
- DR included in PA
- DR recommended in IL
- Important association for DR
- Measurement and verification a challenge

State Policy Trends
"Why not T&D"

- Moving beyond the generation world
- Addressing problems in getting new infrastructure built
- Examples: New England, Pac NW, CA

DR Snapshots

- ISO-NE
- BPA-Non Wires Solutions
- Puget Sound Energy
- Gulf Power
- California
- Recent Research on Large Customer RTP

DR Program Types

Price-Based vs. Reliability Programs

- Price-based
  - Goal is to provide price signal
  - Demand reductions occur via voluntary end-use customer response
  - Reductions are included in load forecasts
  - Response levels become more predictable as a function of:
    - Transparency/foreknowledge of prices
    - Weather
    - Experience
    - Diversity (number and types of customers)
- Examples: critical peak pricing, real-time pricing

DR Program Types

Price-Based vs. Reliability Programs

- Emergency/reliability
  - Goal is "load acting as a resource"
  - Demand reductions occur via dispatch by system operators
  - Reductions are included in resource/supply portfolio
    - Same as a power plant (with limitations)
  - Response levels more variable
    - Minimal foreknowledge by end-use customers
    - Dispatch reasons varied
    - Less diversity in loads involved
- Examples: interruptible programs or demand bidding programs with penalties

ISO New England – 2004 Program Evaluation

- Required by FERC
- Four Main Elements
  - Market Impacts Evaluation
  - Process Evaluation
  - Customer Satisfaction and Feedback on Product Features
  - Market Potential

ISO-NE Programs - Background

- Programs first introduced in 2001
- Two types
  - Reliability
  - Price Responsive
- Three types of enrollment
  - LDC
  - Competitive Service Provider
  - Independent DR Provider

ISO-NE DR Programs
Load Response – RT

- 30 minute to 2 hour notification
- Participation is mandatory
- Paid greater of LMP or floor price
- Minimum of two hours
- Eligible for ICAP Payments
- Requires 5 minute interval metering
- NEPOOL helps finance equipment

ISO-NE Price Responsive

- Voluntary Reductions
- Day Ahead Notice
  - But rules allow same day or shorter period
- 11 hour period
- Customers notified by email, postings, paging, etc.

ISO-NE Programs – RT Profiled

- Not required to have interval meter
- Need M&V Plan
- Payment of higher of RT LMP or minimum of .10 kwh for reductions per M&V plan
- Qualifies for ICAP

ISO-NE Programs
2004 Reliability Test Impact

- 45.8% Response Rate
  - 349 MW curtailed
  - $169,000 in payments
- 30 minute type provided 61%
- Assets w/o generation provided 33%
- Curtailments reached 90% of enrolled amount in 30 minutes

ISO-NE – Participant Feedback

- Participants like monthly meetings
- Customer implementation reliant on manual methods
- Speed of Payments an issue
- ICAP payments insufficient
- Too many program changes
- DR programs not currently integrated with other LDC offerings
  - Challenge – LDCs say that using efficiency tests for DR result in it showing up less cost-effective

ISO-NE – Customer Feedback

- ISO may be in best position to coordinate marketing with regional and national chains
- Low tech options promote greater participation
- Competitive suppliers are not aggressively marketing due to low profit margins
- Customer satisfaction is just above 50% on a scale of 1-5

ISO-NE – Participant Feedback

- No important distinction that would serve as an indicator of inclination to participate
  - Level of energy use
  - Faciity characteristics
  - Amount of time spent buying and managing energy
  - “Ruling out customers based on conventional rules of thumb historically used to recruit customers to interruptible programs would bypass many good candidates”
  - “Tapping into Residential Sector will require large expenditure in control equipment”

DR for T&D – ISO-NE SW CT

- Southwest Connecticut severely constrained from a transmission standpoint
- Load growth has resulted in reliability being threatened
- Political and community will to add capacity is not existent.

DR for T&D – ISO-NE SW CT

- RFP issued in December 2003 for up to 300 MW of new emergency resources in SW CT for 4 years.
- Eligible resources include:
  - Quick Start Generation
  - Demand Response (both emergency generation and load reduction)
  - On-peak conservation

DR for T&D – ISO-NE SW CT

- RFP Results
  - 34 Proposals received
    - Some offered multiple projects and options
  - 8 suppliers selected
    - Selection Criteria: cost, viability, reliability benefit
  - Contracts executed in April 2004
    - 4 year term with 5th year option
  - Total cost – approximately $128 Million over 4 years
  - All resources selected were either DR or EE
    - 167 MW Emergency Generation; 87 MW Load Reduction
    - Resources must participate in ISO's 30 minute RT program.

DR for T&D – ISO-NE SW CT

- Supplier Performance – Aug 20th 2004
  - Notice sent at 10:45 a.m.
  - Event started at 11:00 a.m.
  - Resources had 30 minutes to respond
  - All enrolled MW (120 in 2004) responded
  - Load reduction suppliers went above enrolled amounts
  - Event ended at 1:30

DR for T&D – BPA Non-Wires Solutions Initiative

- Before proceeding with construction, determine the most cost-effective solution from an engineering, economic and environmental standpoint.
- Alternatives may include pricing strategies, demand reduction strategies, energy efficiency and strategic placement of generators.
- Goal of identifying and investigating:
  - Least-cost solutions that may result in deferring transmission reinforcement projects
  - Ways to incorporate non-wires options in transmission models.
  - Specific opportunities for integration of options on the system.
  - Feasibility criteria and screening tools

DR for T&D – BPA Non-Wires Solutions Initiative

- 2001 – Expansion of BPA Transmission Planning Capabilities: A Report on Non-Transmission Alternatives
- 2002 – Commencement of Non-Wires Initiative
- 2003 – Non-Wires Solution Roundtable formed
- 2004 – Four Pilot Projects Begun
- 2004 – RFP issued for 2005/06 Pilots
- 2004 – T Plan updated; non-wires included
- 2005 – Update of BPA Business Plan, Including EIS

DR for T&D – BPA Non-Wires Solutions Initiative

- 2004 Pilots
  - Testing technologies
  - Resolving Institutional Barriers
  - Building Confidence in Non-Wires Solutions
  - Special Focus on T-constrained Peninsula
- Technologies/Approaches Being Piloted
  - DG Aggregation via automatic controls (5MW)
  - Hourly pricing for demand reduction (22MW)
  - Internet-based load control – commercial buildings including use of microturbine
  - Remote control of commercial and residential end uses

DR for T&D – BPA Non-Wires Solutions Initiative

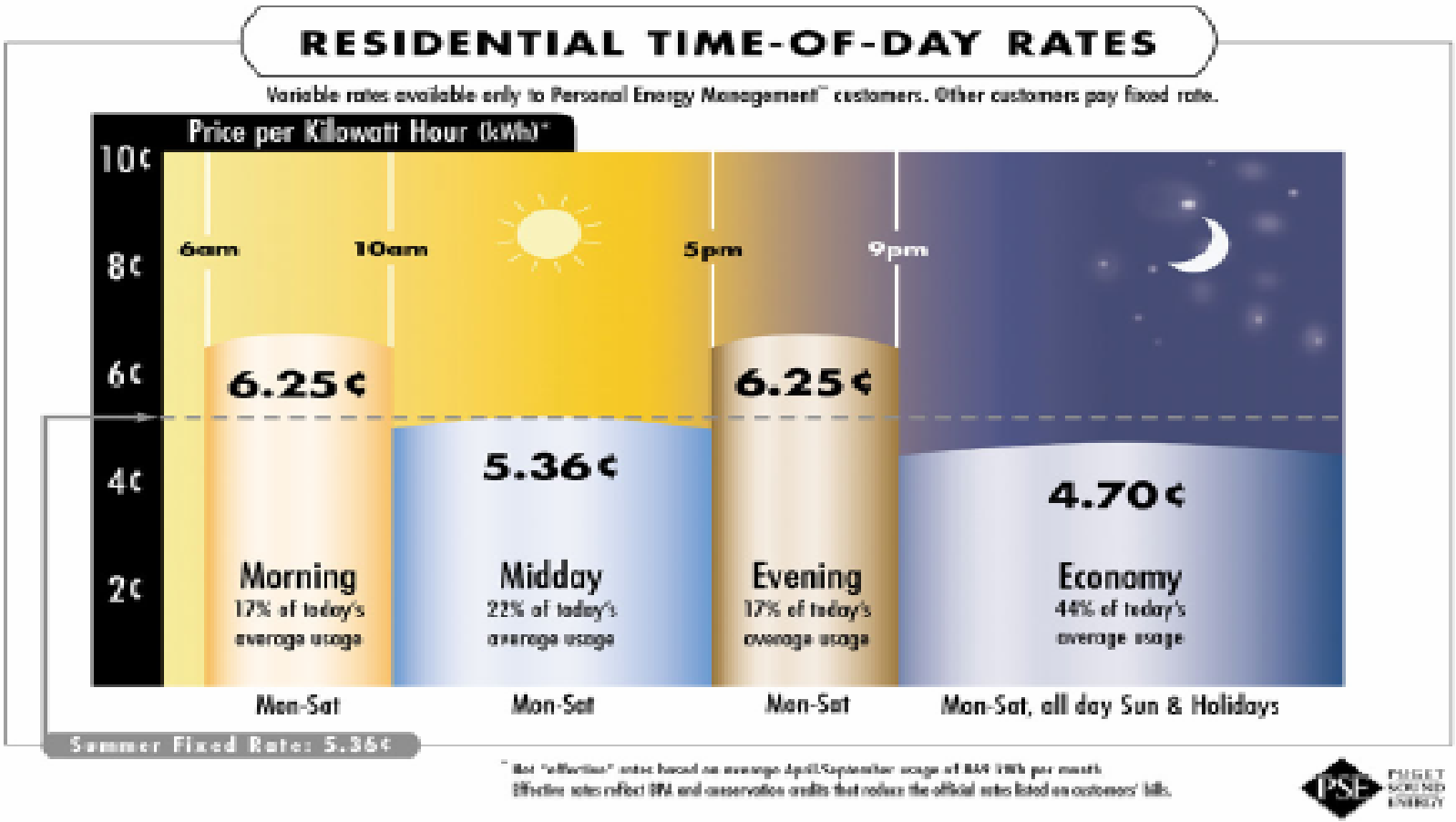
- 2005 Pilots
  - RFP to 135 companies
  - 25 proposals received in September
  - Evaluation underway
  - $1 Million budgeted

Puget Sound Energy

- Puget as “poster child”
  - Advanced meters for all
  - 300,000 on TOU rates
  - Narrow price differential
  - 15 Months of 5% shifts plus a conservation effect
  - Customers loved the program
- Puget as “mug shot”
  - Non-supportive stakeholders
  - Prices narrow
  - Customers surprised
  - Media fans flames
  - Program pulled

Puget Sound Energy

Summer Pricing



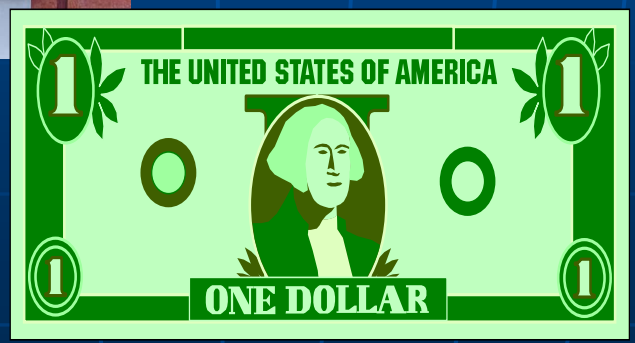
Gulf Power – GoodCents Select

- A residential advanced energy management system that gives customers control over their energy purchases by allowing them to program their central heating and cooling system, electric water heater and their pool pump to automatically respond to varying prices

Gulf Power - Major Components

SuperStat

Communications Gateway



RSVP Rate

New Rate (RSVP)

GoodCents *SELECT*

Participation Charge $4.95/Month

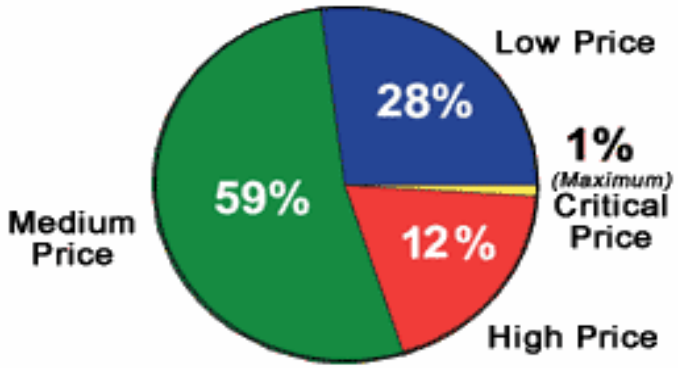
Standard Residential Rate 6.3 cents/kWh

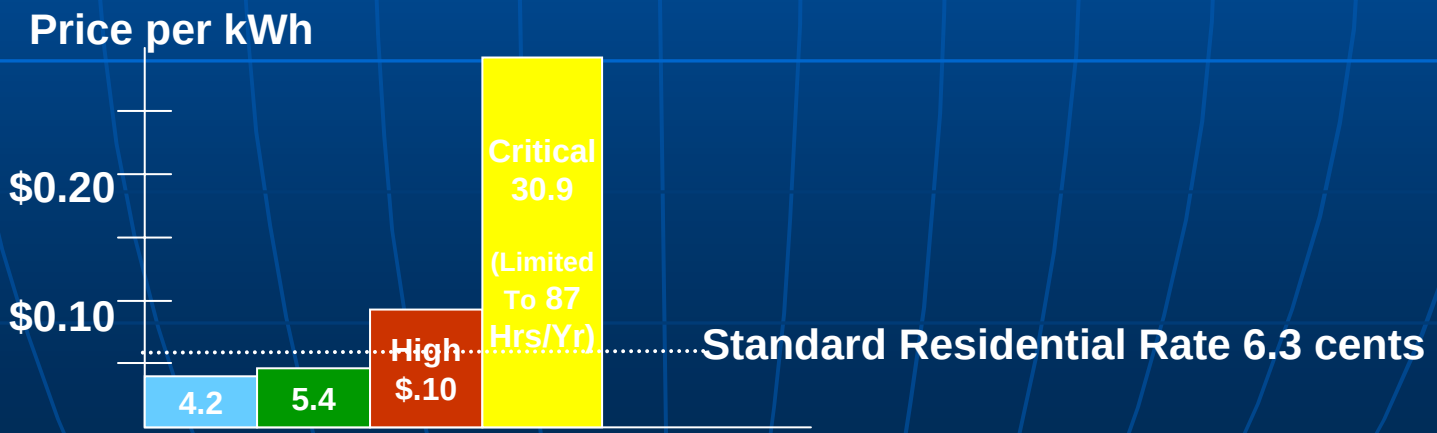
Price Per kWh*	
LOW	4.2 cents
MEDIUM	5.4 cents
HIGH	10.0 cents
CRITICAL	30.9 cents

*All prices are as of 06/07/02, excluding customer and/or participation charges and any applicable taxes. These prices are subject to change.

Residential Service
Variable Pricing (RSVP) Rate

Percent of Annual Hours In Effect





Gulf Power – GoodCents Select

- The Critical Peak Pricing Notion
  - Four Interdependent Components
    1. A time-varying rate design with a near real-time pricing component,
    2. An in-home, customer-programmed, automated energy management (AEM) system,
    3. A way to rapidly communicate rate changes, critical peak conditions, and other messages to program participants, and
    4. A means of recording and retrieving the requisite billing determinants.

Gulf Power – GoodCents Select

- 6000 Current Participants
- 95% Customer Satisfaction Rating
- <2% Churn Rate
- Ability to Install 360 per Month
- 2004 Goal – 3000 installations
- Moving into Multi-Family and Small Commercial in 2005

Gulf Power

- CPP rate plus TOU – 5X differential
- 6000 customers paying $14.95/month
- Peak Reduction
  - Summer 40%
  - Winter 50%
- Overall usage reduction
  - 40% during peak periods
  - 20% and 5% for high and medium TOU
- High customer satisfaction

Gulf Power – GoodCents Select

Residential Service Variable Pricing (Rate Schedule RSVP)

- Standard Residential Customer Charge applies: $10.00 per month
- RSVP Participation Charge: $4.95 per month
- Prices per kWh (includes energy charge, fuel, ECCR, PPCC, and ECRC)

Low	4.7 cents/kWh
Medium	5.9 cents/kWh
High	10.5 cents/kWh
Critical	31.4 cents/kWh

Standard Residential Rate: 6.8 cents/kWh

Gulf Power – Case Study Day

- Case study of January 24, 2003 peak load day.
- Minimum temperature on January 24th was 18 degrees F. Minimum temperature forecast on Gulf's winter peak day is 27 degrees F.
- Gulf Power called a Critical (sent a Critical Price signal to its Good Cents Select customers) on January 24th between the hours of 7a.m. and 9a.m.
- Number of residences receiving the Critical Price signal on Jan 24 (via RF paging signals) = 2,744
- Winter demand reduction per residence at the generator (accounting for losses) = 3.74kW
- Total demand reduction on Jan 24th = 2744 * 3.74 = 10.3mW

Gulf Power – Research Results

- **I pay more attention to my electricity consumption now that I am on the GoodCents Select Program.**

1 Strongly Disagree	15 --- 4%
2 Disagree	37---11%
3 Agree	102 --- 29%
4 Strongly Agree	193 --- 56%
Total	347--- 100%

- **I have NOT had to significantly adjust my lifestyle with the GoodCents Select Program.**

1 Strongly Disagree	16--- 5%
2 Disagree	47 ---14%
3 Agree	140 ---40%
4 Strongly Agree	144 ---41%
Total	347 ---100%

Gulf Power - Research Results

- **Would you recommend GoodCents Select to others?**

Yes	311 ---89%
No/uncertain	37 ---11%
Total	348 ---100%

- **Have you recommended GoodCents Select to anyone?**

Yes	255 ---82%
No/uncertain	56 ---18%
Total	311 ---100%

CA Utility DR Programs
Day Ahead Pricing

- Demand Bidding
- Critical Peak Pricing
- CPA Demand Reserves Partnership
- SF Cooperative
- E-Save
- 20/20

CA Utility DR Programs Reliability

- Base Interuptible Programs
- AC RFP
- Diesel Retrofit “Clean Gen”
- Large Power Interuptible
- Smart Thermostat
- A/C Cycling
- Rolling Blackout Reduction
- Demand Bidding
- CPP
- Residential Smart Thermostat

CA Utility DR Programs Technology Assessment and Incentives

- Technology Equipment Incentives
- Technology Incentives
- Technical Assistance

Education, Awareness and Outreach

- Flex Your Power
- EE/DR Partnership Demonstration
- Customer Education, Awareness & Outreach
- Emerging Markets
- Community Partnerships
- Circuit Savers
- Peak Student Energy Action

CA Large Customers

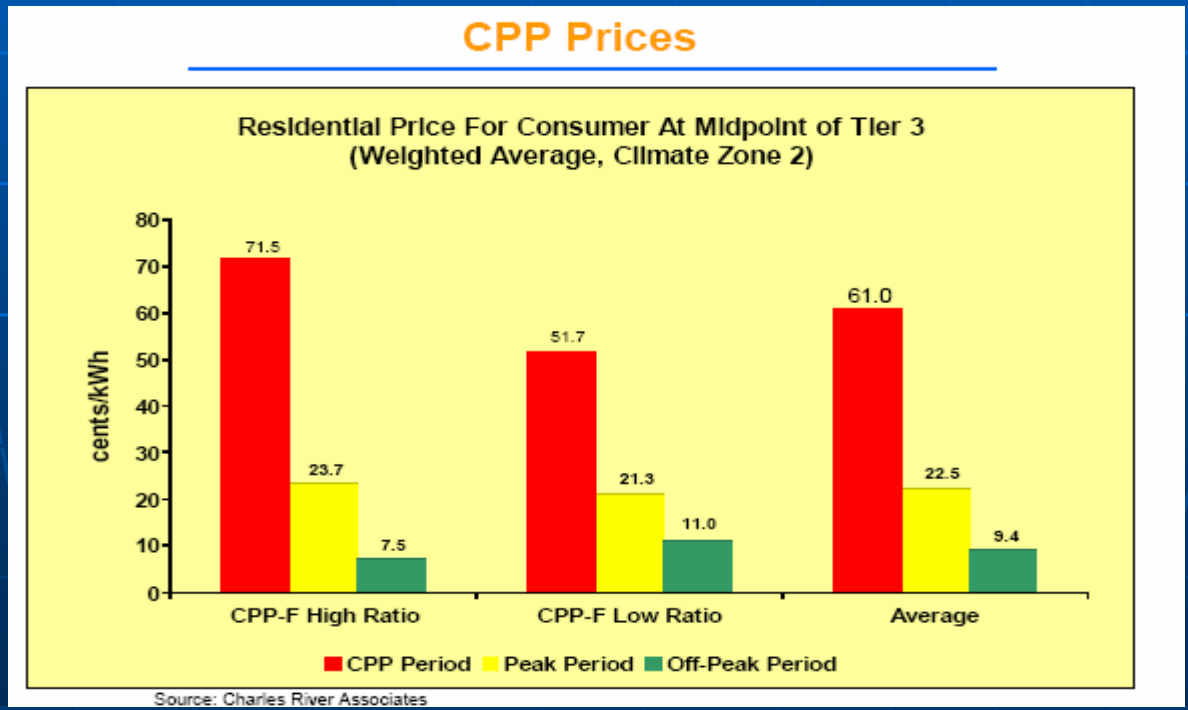
- Interval meters in place for all these customers
- Ultimate goal is two-part real-time pricing (RTP)
  - Model is Georgia Power Company
    - 1,700 customers (80% of those eligible)
    - > 5,000 MW peak load; 500 to 1,000 MW peak reduction
    - Voluntary
    - Day-ahead (75%) and hour-ahead (25%) hourly pricing
    - Prices based on wholesale market with adjustments
  - Features
    - Customer pays for baseline level of usage at standard tariff prices
    - Deviations from baseline –increases or decreases –billed at RTP price

CA Statewide Pricing Pilot

- Time-of-Use (TOU)
  - Traditional two-part TOU rate
  - Peak period from 2 pm to 7 pm
  - Rates vary seasonally
- Critical Peak Pricing-Fixed (CPP-F)
  - TOU rate 350 days a year
  - Much higher price during peak period on up to 15 days a year, the timing of which is unknown
  - Day ahead notification
- Critical Peak Pricing-Variable (CPP-V)
  - Similar to CPP-F except notification can be as short as 4 hours ahead
  - Critical peak period can vary in length from 1 to 5 hours between 2 pm and 7 pm
  - Consumers are offered enabling technology to automate demand response

CA SPP Pricing Range

- Off-Peak 7-11 cents
- Peak Period 21-24
- CPP 51 - 72



CA SPP Preliminary Results Residential

Performance Measure	Average from the Literature	California SPP Result
Price elasticity (mean own price)	-0.30	CPP-F: -0.15 CPP-V: -0.22
Peak demand reduction – CPP without automated response	24%	13%
Peak demand reduction – CPP with automated response	44%	35%
Total usage reduction (conservation effect)	4%	0%

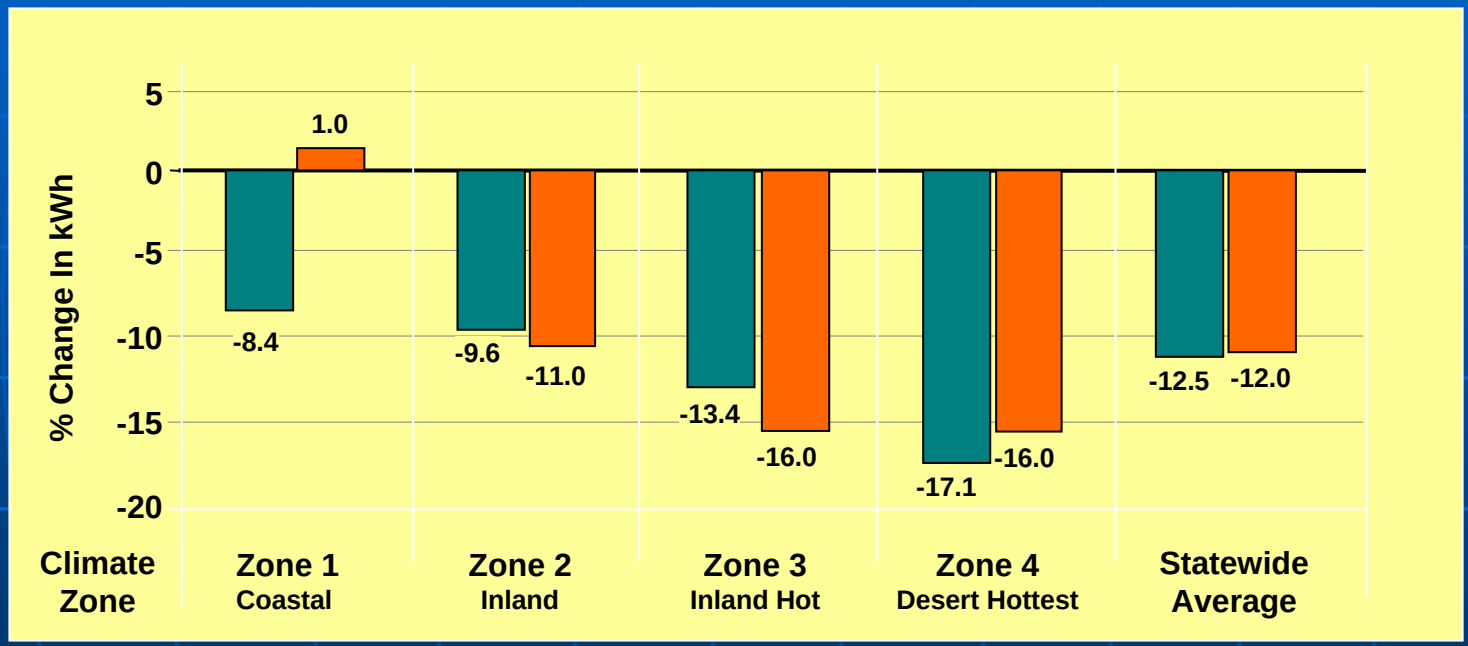
CA SPP Preliminary Results Small Commercial

Performance Measure	California SPP Result
Price elasticity (own-price)	-0.17
Peak demand reduction – CPP with automated response	20%
Total usage reduction (conservation effect)	14%

CA - SPP

Percent Change In Peak Period Energy Use

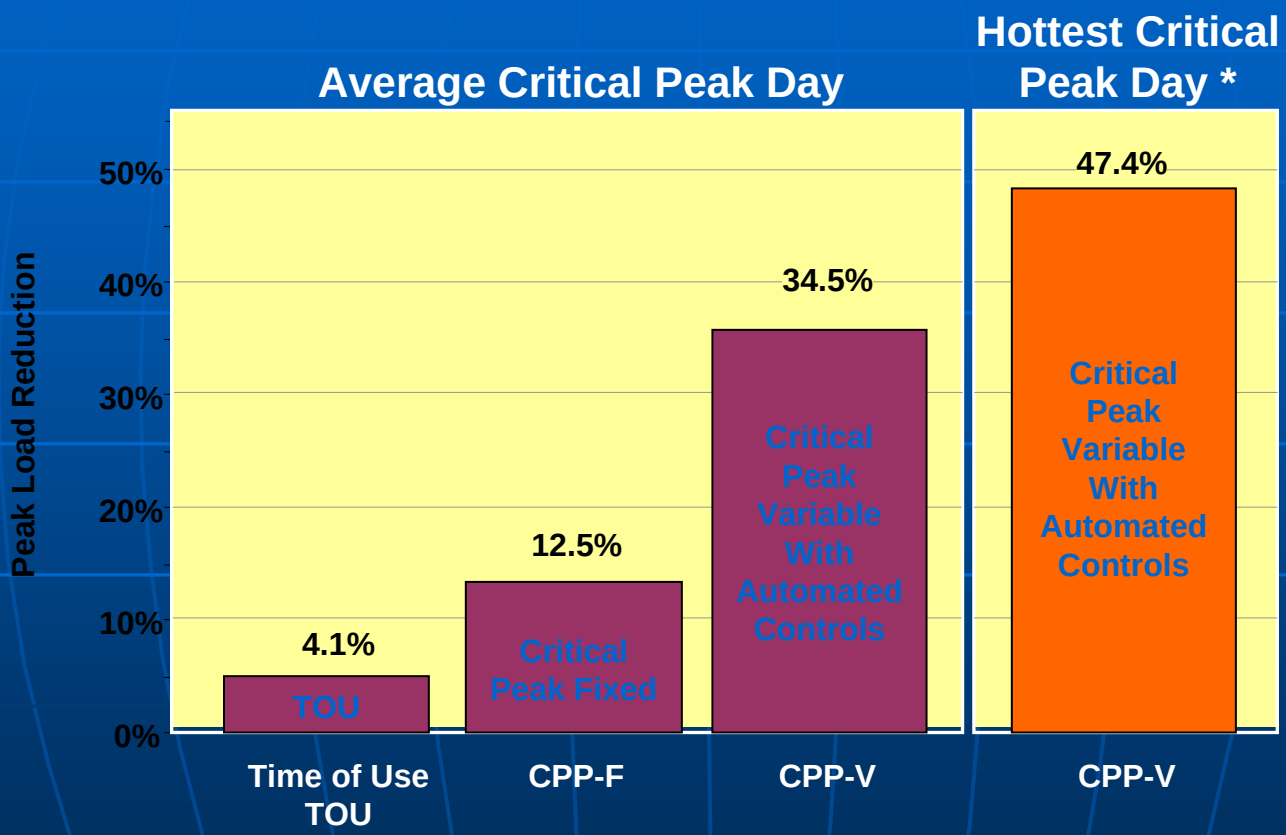
CPP-F Customers on Critical Peak Days By Weather Zone



Source: Statewide Pricing Pilot, Summer 2003 Impact Analysis, Charles Rivers Associates, August 9, 2004, Table 5-4

CA - SPP

Actual Residential Critical Peak Impacts By Rate Treatment

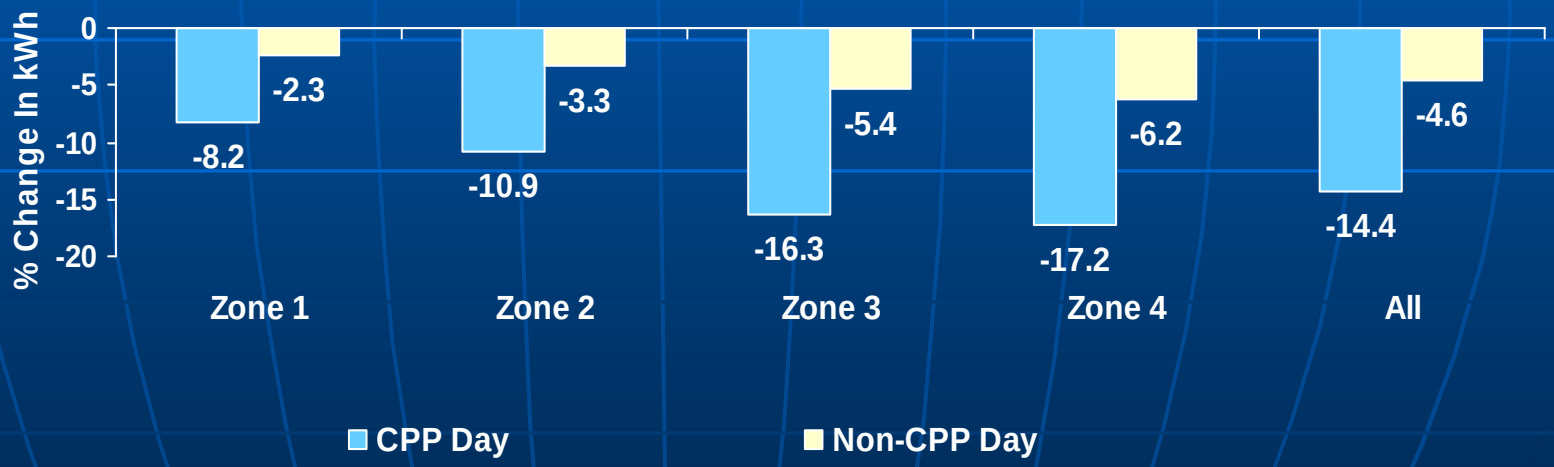


Source: Statewide Pricing Pilot Summer 2003 Impact Analysis, Charles Rivers Associates, Table 1-3, 1-4, August 9, 2004.

* Hottest day impacts discussed on page 105.

CA SPP

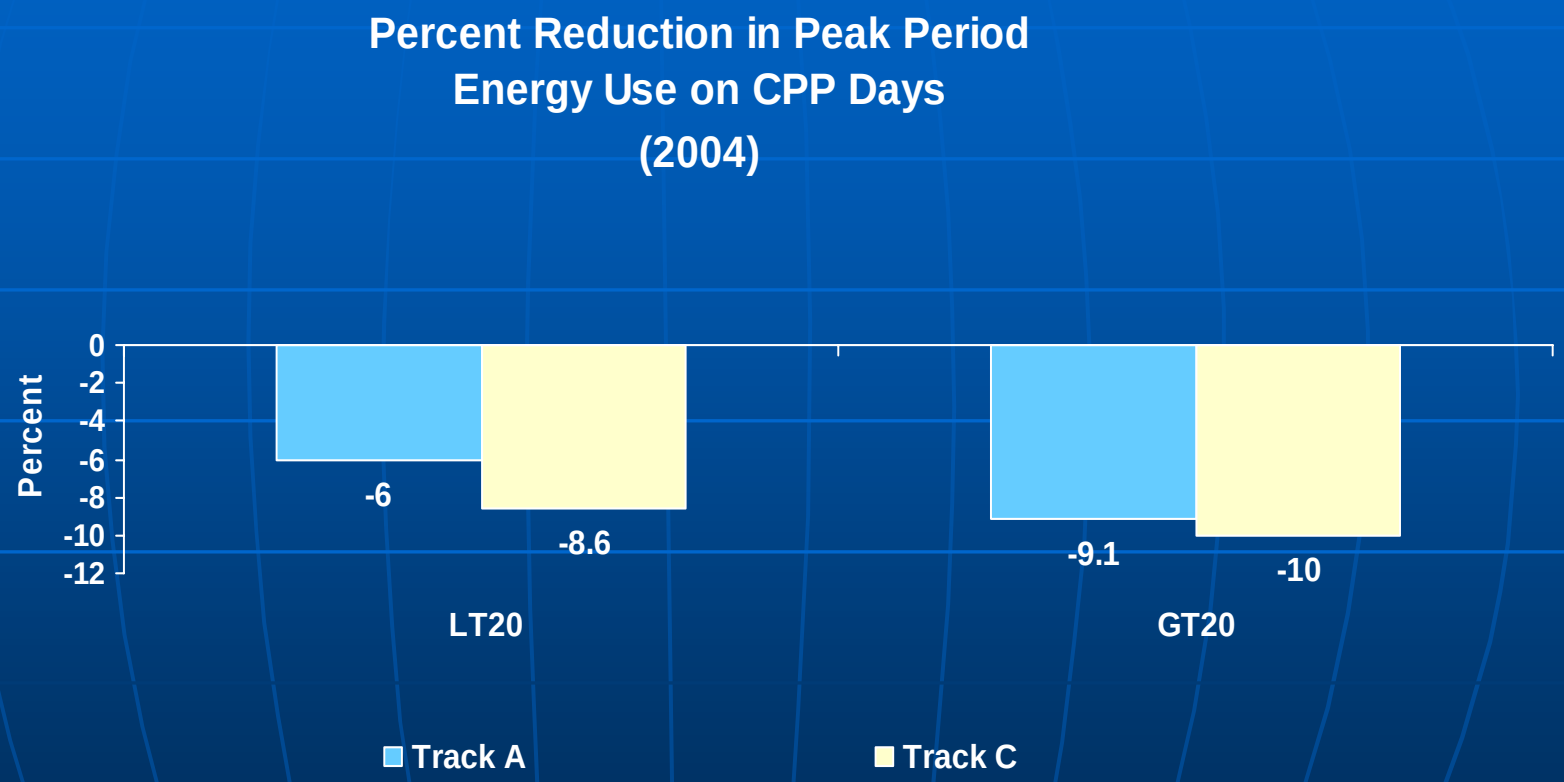
Percent Change In Residential Peak Energy Use for the Inner Summer Months of July through September (Avg CPP-F Prices/Avg 2003/2004 Weather)*



CA SPP - Conclusions

- Price matters
  - Big price differentials are needed to obtain reductions in the 10 to 15 percent range
  - Appealing for peak reductions in the absence of price incentives doesn't seem to do the job
- Impacts persist
  - Across multiple CPP days
  - Across two years of the experiment
- Residential customers are more price responsive than C&I customers
  - But absolute impacts may be greater for C&I customers
- Central air conditioning ownership and climate are key drivers of demand response for residential customers on CPP-F rates

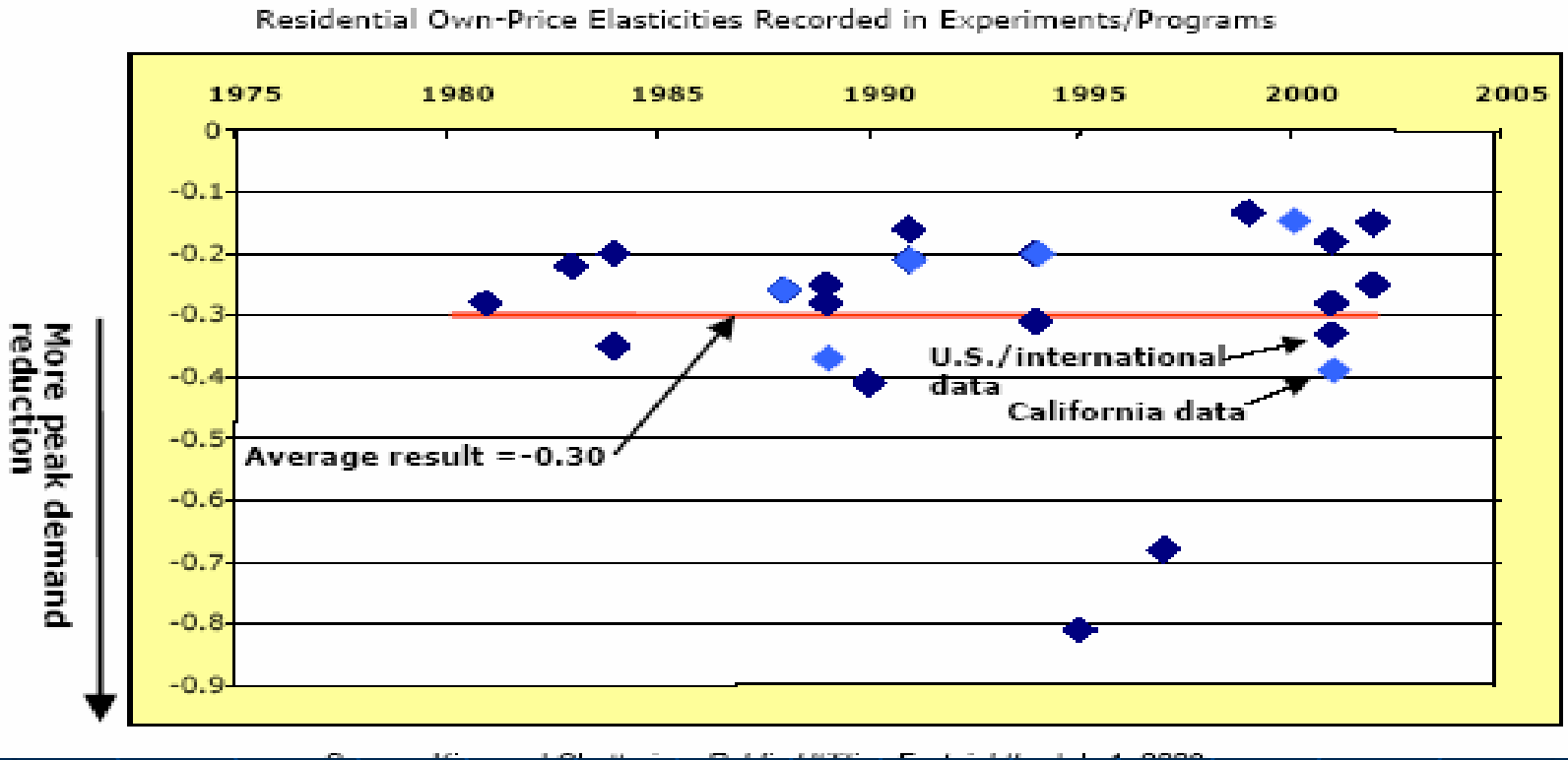
CA SPP – C/I


Percent Reduction in Peak Period
Energy Use on CPP Days
(2004)
Percent
0
-2
-4
-6
-8
-10
-12
-6
-8.6
-9.1
-10
LT20
GT20
Track A
Track C

CA DR – Will Customers Respond?

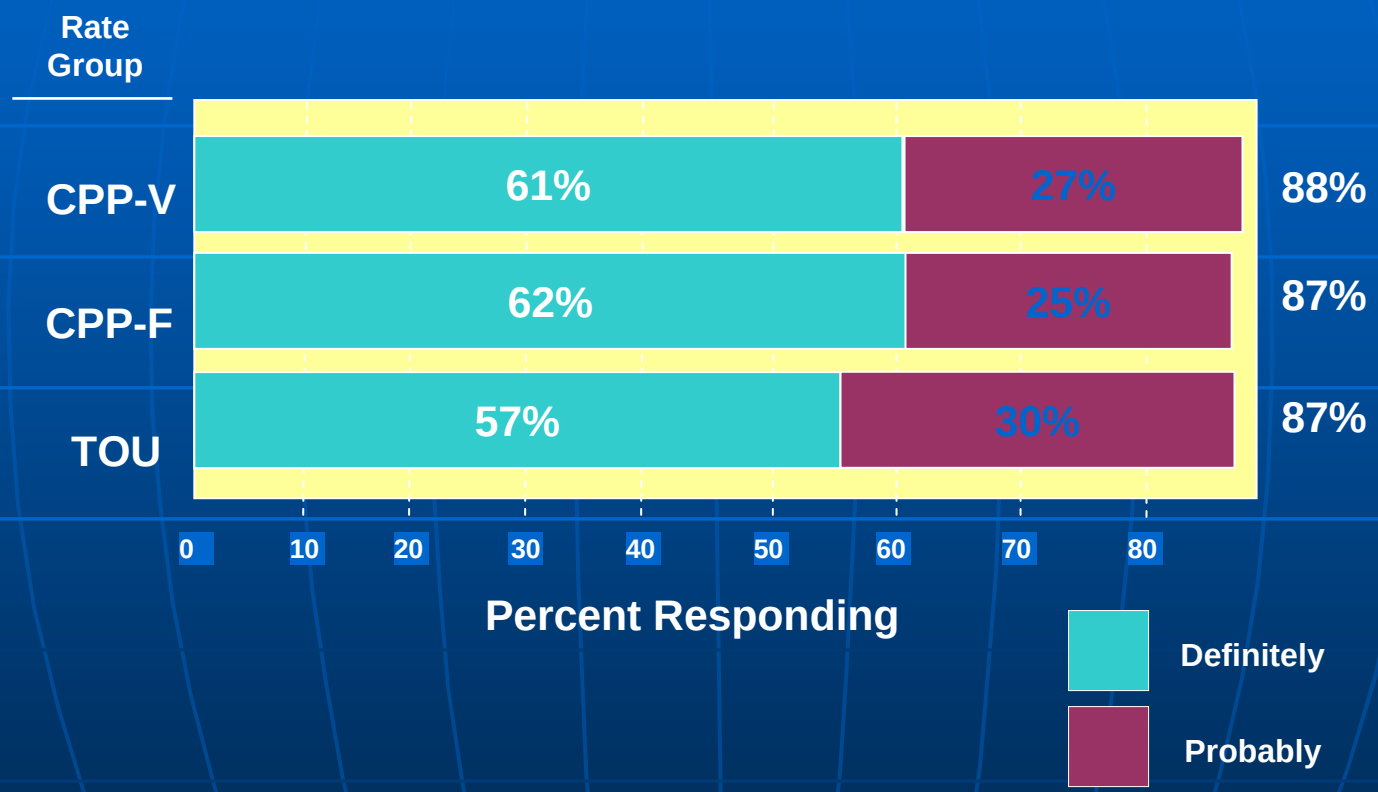
Prior Residential Results: Price Elasticity

- Fifty-six analyses and projects in the past 25 years
- California's pilot providing one more data point



CA SPP Customer Satisfaction

Rates Should be Offered to All Residential Customers



Source: SPP End-of-Summer Survey Report, Momentum Market Intelligence, WG3 Report, January 21, 2004

LBNL Study of NiMo RTP

- In 2003, at least 65% of customers fully exposed to RTP
- Why do customers not hedge more? Possible explanations:
  - – Customers are sophisticated – they understand risks and still choose not to hedge
  - – Customers are discouraged – retail market offers are hard to find or too expensive
- Customers are not fully aware of the risks – declining volatility in recent years
- Customers have chosen not to choose – default RTP service
- Tariff Design and Retail Competition
  - Unbundled RTP tariff design is appropriate for a competitive market structure, so long as there is a robust market for hedges
  - A utility-offered hedge (e.g., Option 2) is an appropriate transition strategy

LBNL Study of NiMo RTP

- 31% say they FOREGO usage (mainly government/education customers)
- ~15% say they can SHIFT from on-peak to off-peak
- 54% of survey respondents claim they CANNOT CURTAIL
  – but 30% of them were enrolled in NYISO DR programs
- Observation: Customers may make a distinction:
  – RTP is price response
  – ISO programs are a call to keep the lights on (civic duty)

LBNL NiMo - Findings

- Customers generally satisfied with default Day Ahead RTP
- Despite views expressed by some that hedging options are expensive relative to perceived risks
- ~45% of customers remained on default RTP; many others fully or partially exposed to day-ahead prices
- Price response is modest overall
  - Government/educational customers are most responsive
  - Average elasticity (0.15) comparable to other studies' results
  - Aggregate DR potential is ~100MW at high prices
  - Most response involves reducing discretionary loads - technology has a limited impact
- ISO DR programs complement RTP
  - Industrial customer response to DR programs is greater than for RTP

LBNL – Implications for Others

- Results challenge conventional wisdom about which customers are most likely to respond
  - Institutional customers can provide significant price response
  - Some customers respond to *day-ahead* hourly prices
- RTP is best implemented as part of a portfolio of options
  - Emergency DR programs can complement RTP
  - Ensure adequate hedging options exist, at least initially
- Targeted customer education and technical assistance are needed to realize customers' inherent price response potential
  - Many customers are not aware of available price response technologies and strategies
  - Even more important if RTP is extended to smaller customers

LBNL – Implications for Others

- It will take time to develop RTP price response

  – Initial response for most customers is discretionary (not shifting), which limits:
    - The number of customers willing to participate
    - The amount of peak demand participants will curtail

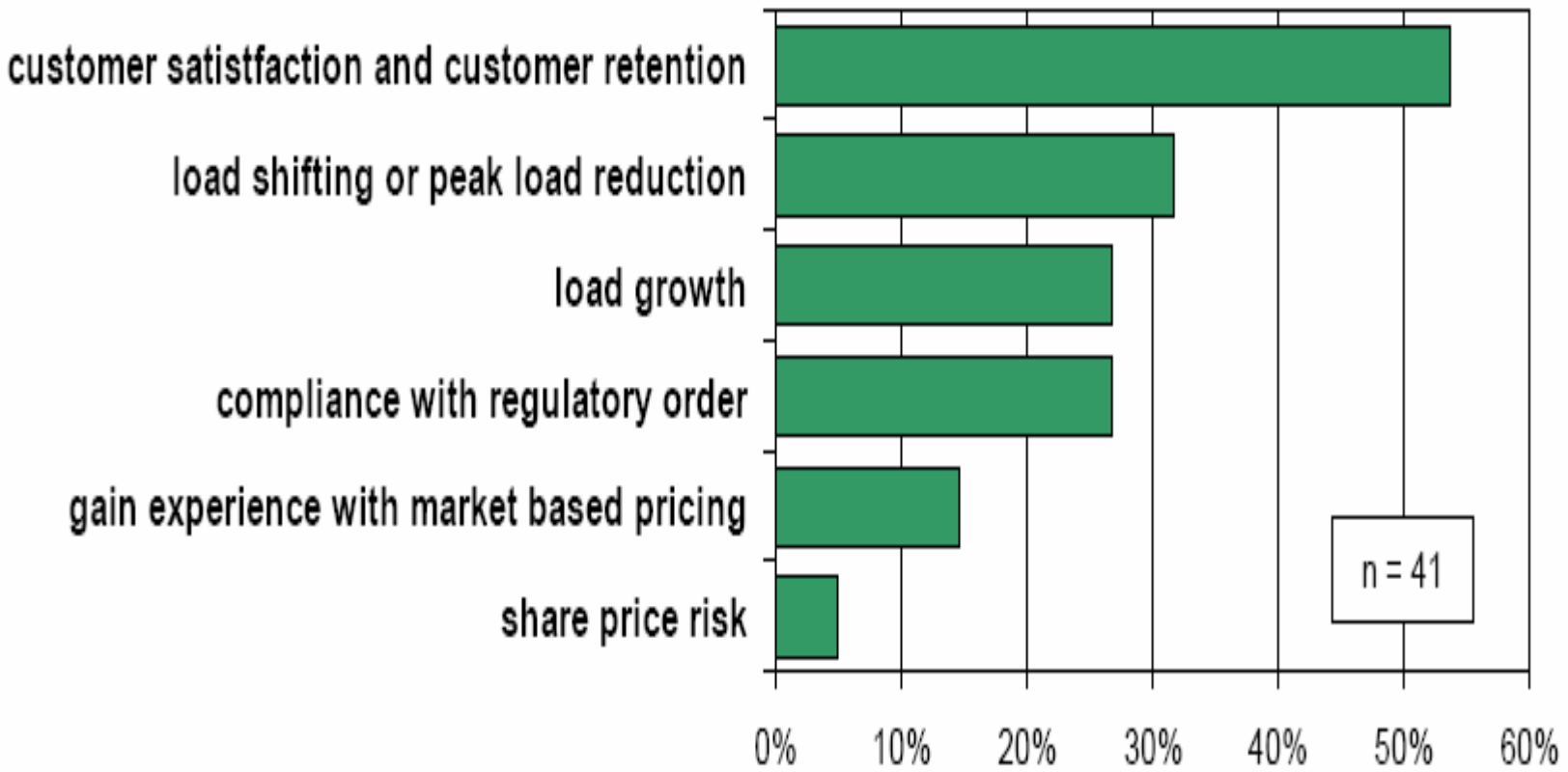
  – How many customers already have the capability to shift load? At what price?
    - Probably quicker to build DR capability with utility or ISO DR programs

  – Limited, voluntary exposure is a big plus to many customers

  – Easier to sell because of public duty aspect of ISO declared events

LBNL Study of Utility RTP

Why the Program Came About

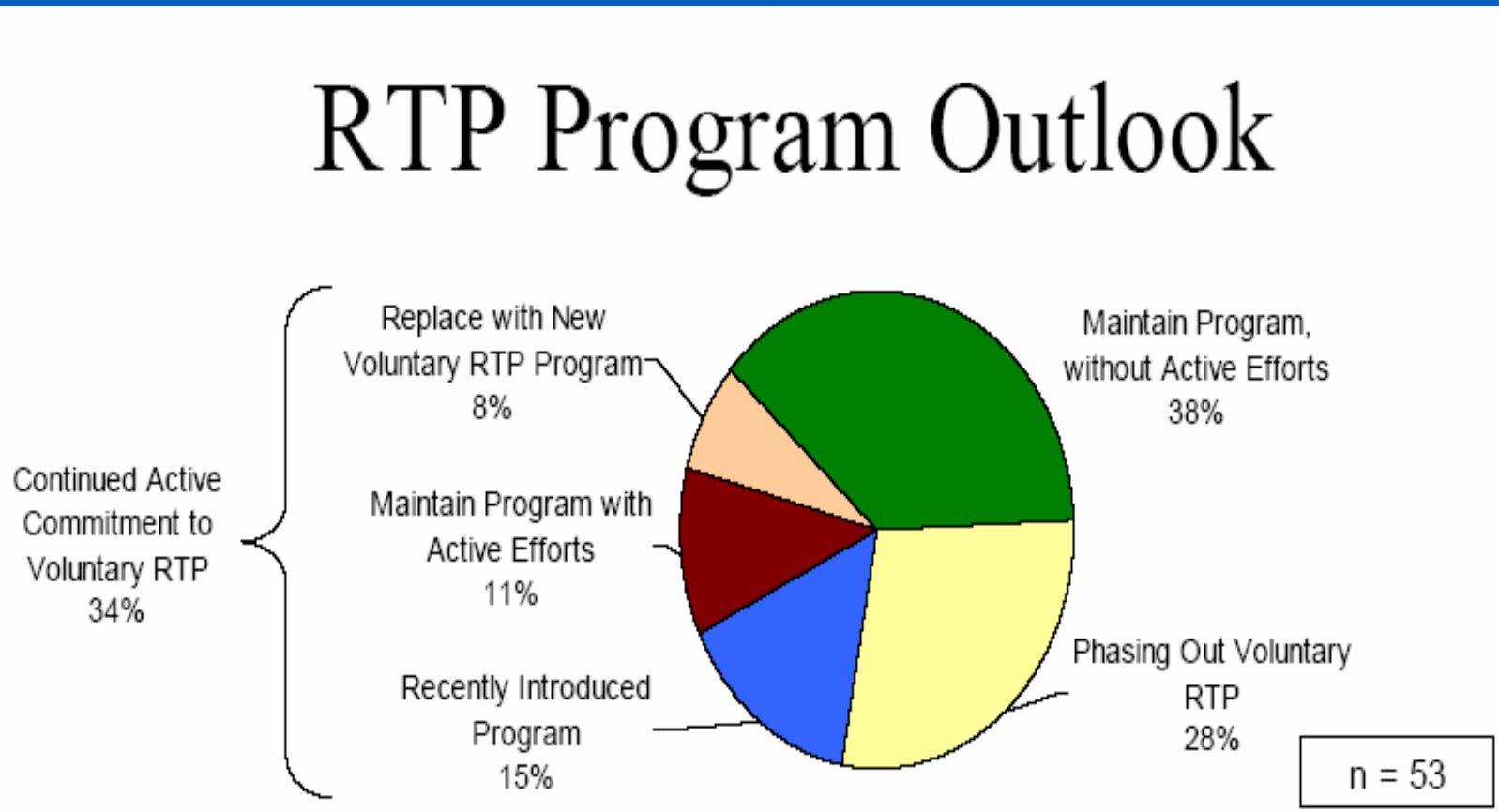


** Some utility program managers identified multiple motivations; thus, percentage values for all categories add to more than 100%*

LBNL Study of Utility RTP

- Concern about customer satisfaction/retention driven by competitive pressures in the early- and mid-90s
- Competition from other utilities (electric and gas), onsite generation, unregulated suppliers
- Give large customers “early access” to the market
- Reducing peak demand rarely the sole motivation
  – Often an alternative to interruptible rates, allowing customers to “buy through”
- Load growth achieved by providing low prices in off-peak periods AND by allowing customers to add load without incurring additional demand charges

LBNL Study of Utility RTP



LBNL Study of Utility RTP

- 2,700 non-res customers and 11,000 MW enrolled in 2003
- Although several programs have achieved a significant level of participation, most have not.
- Three programs account for 80% of customers and 80% of load enrolled
- One-third of programs had no participants, and another third had <25
- Low market penetration for most programs: only two have >25% of eligible customers enrolled
- RTP tariffs typically restricted to non-residential customers larger thana specified size
- 50% of programs restricted to customers > 500 kW
- Most programs not pro-actively marketed, or targeted to narrow sub-set of eligible customers (typically largest industrials)

LBNL Study of Utility RTP

- Among programs with >20 participants, most have achieved maximum load
- reductions of 12-22% of participants' combined load
- Higher prices did not necessarily correspond to larger percentage load reductions across RTP programs
- Aggregate load reductions are modest for nearly all RTP programs
- Only two programs (Duke and Georgia Power) reported load reductions > 100 MW
- All other programs with load reduction data had < 60 MW enrolled

LBNL Study of Utility RTP

- Among programs with >10 participants, typically <60% of participants

  are price responsive
- Many customers enrolled expecting to save on their energy costs without responding on a daily basis
  - Arguably a consequence of marketing strategies and program goals

LBNL Prospects for RTP as DR

- Two essential elements to success:
  - Customers must enroll
  - And must respond “significantly” in aggregate
- Several programs have successfully enrolled a sizeable number of customers, but most have not.
- This could be indicative of customers’ calculated choices: too much risk for the potential benefit
- But customer acceptance not yet thoroughly tested
- Existing programs have also demonstrated that, in aggregate, customers on RTP can drop load by 20-30%
- Difficult to extrapolate from demonstrated levels of price response:
  - Small populations of quite large industrial customers
  - On-site generation a significant fraction of load response in most programs
  - Low-tech response strategies
  - Many customers enrolled without intending to monitor or respond to hourly prices

LBNL Recommendations

- Sufficient resources must be devoted to developing and implementing a customer education program
- Customers need help understanding and managing price risk (e.g. risk management products, two-part CBL)
- Coordinate RTP implementation with other demand-side activities
- Include provisions for rigorous analysis of customer acceptance and price response

LBNL Recommendations

- Utilities interests must be aligned with program goals
- Costs and benefits of obtaining incremental amounts of price responsive load from RTP must be weighed against those of other types of DR programs
- Account for the potential environmental and market impacts of the increased use of on-site generation resulting from RTP

Demand – An Evolutionary Perspective

- Conservation
  - Response to energy supply and environmental problems
- Load Management
  - Curtailment and Control
- Efficiency – Phase 1
  - Get the same benefit with less energy
- Demand Side Management
  - Utility-oriented; IRP
- Efficiency – Phase 2
  - Beyond the end use
- Demand Response
  - Dynamic, communication and price-based
- Optimization (Smart Age)
  - Systems approach: Smart Grid, Smart Homes, Smart appliances

Load Management
Then and Now

- Emergency-driven
- Blackout-avoidance
- Reliability-focused
- Old Technology
- Blunt Instrument
- One size fits all
- Opt-in

- Customer choice
- Optimize Efficiency
- Mass Mkt Capability
- New Tech; Internet
- Tie to Mkt Dynamics
- Risk/Reliability tool
- Smart Bldgs & Appl.
- Opt-out

DR – Why Policy Makers Like It

- Optimize the system between supply and demand
- Moderate price spikes during peak period
- Mitigate market power of suppliers
- Avoid unnecessary supply/T&D investment
- Improve reliability of grid
- Solve specific geographic congestion
- Create a smart grid
- Outage management and restoration
- Providing customers with new options

DR - Issues for Policy Makers

- State vs Federal Jurisdiction
- Tie to Deregulation
- Competitive Metering and other services
- Who pays for the Technology
- Need for Pilots
- Cost Recovery and Stranded Costs
- Use of System Benefit (wires) Charges
- Chicken and Egg
- Opportunity Costs
- Lost revenues
- Cheese for the Rat

DR Myths and Misconceptions

- It’s all about real time
- Negative environmental impact
- Technology costs are too high
- No efficiency/conservation effect
- Customers don’t want or won’t accept
- DR is bad for low-income consumers
- Competitive Market will eagerly supply it

DR – A chicken and egg situation

- DR requires enabling technology
- Enabling technology provides benefits outside of demand response
- Enabling technology provides benefits to different parties in different places
- Enabling technology is more cost-effective with DR benefits
- Multiple stakeholders and decision pockets
- Case specific, comprehensive analysis is required

Discussion Items

- Cost-Benefit Analysis
- Reasons to do it
- How much to expect
- How customers will respond
- What kind of technology is needed – if at all
- Will the market provide
- What needs to be known
- What are the regional differences
  - Customers?
  - Markets?
  - Supply and Demand
  - Capacity situation
  - Peaking drivers
- Is it a fad
- Is it just supply programs in drag
- What is its relationship to efficiency/conservation
- Who is best suited to deliver it
- Can you depend upon it
- How should you integrate it into planning and operations
- What is the role of government and policy makers
- Direct vs Indirect Benefits