Delivering Cost-Effective Demand Response: A Portfolio Approach

presented by:

Mark S. Martinez
Manager, Program Development
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Agenda

- Background – The “Vision” for Demand Response (DR)
- Building the Portfolio – SCE’s Plan for Achieving Results
- Infrastructure Support
- New DR Initiatives/Feedback
- Next Steps: Evaluation of Advanced Metering Business Case
- Providing DR Value
- The Advanced Load Control Solution
- The Bottom line
The Market For DR In California Today

- Stable Prices Today, But....
  - Transmission Constrained
  - Limited Investment in New Generation
  - No “transparent” prices (maybe in ’06?)
  - Record Setting Peaks This Year (SCE - 20,762 MW; CA - 45,597 MW)
  - 3 Curtailment Events This Year

- New Resource Adequacy Rules Expected to Limit Volatility in the Market (Pending)
  - New Reserve Requirements
  - Significant Procurement Of Resources In Advance
“The Vision”- Demand Response Goals

- From CPUC Decision 03-06-032, dated June 5, 2003 *

  - 2003  150 MW
  - 2004  141 (revised from 400 MW)
  - 2005  3% of Annual System Demand
  - 2006  4% of Annual System Demand
  - 2007  5% of Annual System Demand

  (equates to about 1000 MW)

* Note: Excludes Demand Response From Existing Emergency Programs

- UDC’s ordered to include targets in procurement plans
DR Today vs. 2007 Goals

- **Today**: 1060 MW (5%)
  - Price response (Economic): 855 MW (5% new)
  - Retain Moderate level of Emergency Capacity (approx. 3%)

- **2007 (Goal)**: 1600 MW (8%)
  - Price response (Economic): 1000 MW
  - Retain Moderate level of Emergency Capacity (approx. 3%)
SCE’s Plan for Achieving Goals

- Build robust portfolio of programs to include all customers and all demand response capability (i.e. economic and emergency)
- Expand residential air conditioning load control program
  - Integrate advanced load control technology (i.e. smart thermostats) with existing infrastructure
  - Include an economic trigger
- Support implementation/rollout of dynamic price response where proven feasible and cost-effective
- Implement statewide customer awareness and education campaign
# DR Program Design: A Balancing Act

<table>
<thead>
<tr>
<th>Customer</th>
<th>Planner/Administrator</th>
</tr>
</thead>
<tbody>
<tr>
<td>• No interruptions</td>
<td>• 100% reliability (insurance)</td>
</tr>
<tr>
<td>• Real time visibility</td>
<td>• Real time “verifiable” load*</td>
</tr>
<tr>
<td>• Simple to understand</td>
<td>• Simple to administer</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>Competing Objectives</td>
<td></td>
</tr>
<tr>
<td>• High Incentive (stable price)</td>
<td>• Minimize costs (market price)</td>
</tr>
<tr>
<td>• 24-48 hours notice</td>
<td>• Immediate dispatch*</td>
</tr>
<tr>
<td>• No risk (no penalty)</td>
<td>• Dependable load commitment</td>
</tr>
<tr>
<td>• Customer-specific baseline</td>
<td>• Uniform baseline methodology</td>
</tr>
<tr>
<td>• Long-Term Contract</td>
<td>• Flexibility to respond to market</td>
</tr>
</tbody>
</table>

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**Key Messages:**

* Price drivers = dependable (firm) load, immediate dispatch
# Building the DR Portfolio

<table>
<thead>
<tr>
<th>Description*</th>
<th>Incentive Structure (Mandatory or Voluntary)</th>
<th>Resource Value</th>
<th>Customer Profile</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity (or Reservation)</td>
<td>Higher incentives, stringent performance obligation <em>(mandatory)</em></td>
<td>Firm – <strong>high value</strong> <em>(Emergency)</em></td>
<td>High risk, high reward. Ability to curtail load with little notice (30 minutes or less)</td>
</tr>
<tr>
<td>Energy (bidding, pre-scheduled)</td>
<td>Lower incentives; modest or small penalties, “Pay for performance” <em>(voluntary)</em></td>
<td>Non-firm – <strong>lower value</strong> <em>(Economic)</em></td>
<td>Low risk, modest reward. Ability to curtail/shift load with advance notice (DA)</td>
</tr>
<tr>
<td>Load control (automated response)</td>
<td>Customer chooses technology enabled response; up front credit <em>(voluntary)</em></td>
<td>Firm – <strong>high value</strong> <em>(Emergency &amp; Economic)</em></td>
<td>Customer choice up front; good for discretionary loads (eg. a/c)</td>
</tr>
<tr>
<td>Time Varying Rates</td>
<td>TOU, CPP, RTP (e.g. market based price signal and/or super peak charge <em>(voluntary)</em></td>
<td>Non-Firm – <strong>lower value</strong> <em>(Economic)</em></td>
<td>Modest risk; customer chooses to respond during event (or pay premium charge)</td>
</tr>
</tbody>
</table>

*Programs can be combined*
## SCE DR Portfolio Today

<table>
<thead>
<tr>
<th>PROGRAM</th>
<th>Year</th>
<th>FEATURES</th>
<th>ELIGIBILITY</th>
<th>MARKET</th>
</tr>
</thead>
<tbody>
<tr>
<td>Agricultural and Pumping</td>
<td>’87</td>
<td>●</td>
<td>Yes</td>
<td>●</td>
</tr>
<tr>
<td>Interruptible</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Air Conditioner Cycling</td>
<td>’83</td>
<td>●</td>
<td>No</td>
<td>●</td>
</tr>
<tr>
<td>Program – Base</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Air Conditioner Cycling</td>
<td>’01</td>
<td>●</td>
<td>No</td>
<td>●</td>
</tr>
<tr>
<td>Program – Enhanced</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Base Interruptible Program</td>
<td>’01</td>
<td>● ● ● ●</td>
<td>Yes</td>
<td>●</td>
</tr>
<tr>
<td>Large Power Interruptible</td>
<td>’79</td>
<td>● ● ● ●</td>
<td>Yes</td>
<td>●</td>
</tr>
<tr>
<td>Optional Binding Mandatory</td>
<td>’01</td>
<td>● ● ●</td>
<td>Yes</td>
<td>●</td>
</tr>
<tr>
<td>Curtailment</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Scheduled Load Reduction</td>
<td>’01</td>
<td>● ● ● ● ● ●</td>
<td>No</td>
<td>● ● ●</td>
</tr>
<tr>
<td>Program</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SCE Energy $mart Thermostat</td>
<td>’03</td>
<td>● ● ●</td>
<td>Yes</td>
<td>●</td>
</tr>
<tr>
<td>(pilot)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Demand Bidding Program</td>
<td>’03</td>
<td>● ● ● ●</td>
<td>No</td>
<td>●</td>
</tr>
<tr>
<td>California Power Authority</td>
<td>’03</td>
<td>● ● ● ● ● ●</td>
<td>Yes</td>
<td>●</td>
</tr>
<tr>
<td>Demand Reserves Program</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Critical Peak Pricing</td>
<td>’03</td>
<td>● ● ●</td>
<td>Yes</td>
<td>●</td>
</tr>
<tr>
<td>(residential – pilot)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- **Economic (Price Response)**
- **Emergency**
## SCE Peak Reduction Capacity – July ’04

<table>
<thead>
<tr>
<th>PROGRAMS</th>
<th>Service Accounts</th>
<th>Available Power Reduction (MW)</th>
<th>Estimated Peak Response (MW)</th>
<th>Avg. $$ Saved Customer/Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Air Conditioner Cycling Program – Base</td>
<td>89,841</td>
<td>205</td>
<td>164</td>
<td>$110</td>
</tr>
<tr>
<td>Air Conditioner Cycling Program – Enhanced</td>
<td>24,495</td>
<td>50</td>
<td>40</td>
<td>$220</td>
</tr>
<tr>
<td>Agricultural &amp; Pumping Interruptible</td>
<td>350</td>
<td>58</td>
<td>58</td>
<td>$3,200</td>
</tr>
<tr>
<td>Base Interruptible</td>
<td>63</td>
<td>73</td>
<td>58</td>
<td>$82,000</td>
</tr>
<tr>
<td>Large Power Interruptible Programs</td>
<td>512</td>
<td>642</td>
<td>514</td>
<td>$115,000</td>
</tr>
<tr>
<td>Optional Binding Mandatory Curtailment</td>
<td>13</td>
<td>28</td>
<td>8</td>
<td>exempt from rotating outage</td>
</tr>
<tr>
<td>Scheduled Load Reduction Program</td>
<td>15</td>
<td>4</td>
<td>4</td>
<td>$700</td>
</tr>
<tr>
<td>Energy Smart Thermostat Program</td>
<td>2,342</td>
<td>17</td>
<td>9</td>
<td>$150</td>
</tr>
<tr>
<td>California Power Authority Demand Reserves Program</td>
<td>73</td>
<td>117</td>
<td>117</td>
<td>N/A</td>
</tr>
<tr>
<td>Critical Peak Pricing Program</td>
<td>8</td>
<td>1</td>
<td>&lt;1</td>
<td>N/A</td>
</tr>
<tr>
<td>Demand Bidding Program</td>
<td>514</td>
<td>87</td>
<td>87</td>
<td>N/A</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>118,226</strong></td>
<td><strong>1,282</strong></td>
<td><strong>1,060</strong></td>
<td></td>
</tr>
</tbody>
</table>
DR Portfolio Support Requirements

**Program/Ops**
- 13 Programs (3-Pre ‘98)
- About 1000 MW Peak Response (1500 MW in year 2000)
- 70 Curtailment Events (Almost 300 hours)
  - Pre-1998 - 4
  - 1999 - 1
  - 2000 - 21
  - 2001 - 38
  - 2002 - 3
  - 2003 - 2
  - 2004 - 3
- Over 1 million pages and e-mails
- Over 100,000 compliance bills
- Over 1 million mailings annually
- Communications in 5 languages

**Infrastructure**
- Over 250,000 Load Control Switches installed since ’83 (1-way)
- 12,000 Real Time Meters
- 9,000 Smart Thermostats (2 Way)
- 21 VHF Transmitters
- 2 Secure Websites (Internet)
- 3 Auto Dialers (>500 lines)
- Real Time Load Display (Firewall Protected)
- 1200 Load Monitoring/Alert Devices (Large Power)
- Satellite Paging
CUSTOMER DATABASES
Customer/Program Info
Equipment/Maint.
Reporting/Billing

MULTIPLE CONTROL PLATFORMS
Event Launching
Bidding Platform
Notification Platform
Load Verification

MULTIPLE COMMUNICATION PROTOCOLS
FM Radio
Pager/Satellite
Internet
Telephone

END-USER DEVICES AND INTERFACE
Remote Terminal Units
Load Control Switches
Smart T-stat
RTEM Meters
Internet Applications

SCE Demand Response Capability — Infrastructure

AUTO DIALERS
Two external providers
Remotely served
>500 lines

GRID DISPATCH
Redundant rack systems
Firewall protected
Real-time load display
128 telephone lines
21 FM Transmitters(VHF)
5-min to call 1200 RTUs

INTERNET
Secured website (SSL)
Smart T-stat program
Bidding based programs
Near real-time load display
Paging and email notices

AG & PUMPING
Load Control Switch
• 500 DLC Switches
• Radio Controlled
• Regional Load Control

COMMERCIAL/INDUSTRIAL
• 12,000 Real-time energy meters
• Real-Time load display
• 1200 Load monitoring/Alert devices
• 45,000 A/C DLC Switches
• 9,000 Smart T-stats (2-way)
• Satellite Paging

RESIDENTIAL
AC Cycling Load Control Switch
• 200,000 A/C DLC switches
• Radio Controlled
• Regional Load Control
“New” California DR Initiatives

- CPUC Proceeding launched in Summer ‘02 to promote DR as a resource to mitigate procurement costs and enhance reliability
  - **Phase 1 for small customers (<200 kW)** authorized 18 month pilot for 2500 customers of critical peak/TOU pricing to provide demand response input for analysis of deployment of advanced meters in Phase 2 (Approved March 14, 2003).
  - **Phase 1 for large customers (>200 kW)** adopted new Critical Peak Pricing and Demand Bidding Programs (including dispatch of CA Power Authority Programs) (Approved June 5, 2003). Consideration of RTP pricing pending.
  - **Phase 2 (pending)** to address cost-effectiveness of advanced meter deployment based on demand response results developed in Phase 1.
Illustrative CPP Rate Design

**Applicable up to 15 days per year (Monday – Friday)**
Small Customer CPP Pilot Rates

Rates were varied by customer groups for purposes of estimating demand function (illustrative)

- CPP-F High Ratio: 71.5 cents/kWh
- CPP-F Low Ratio: 51.7 cents/kWh
- Average: 61.0 cents/kWh

Control Group Average Price: 13.3 cents/kWh

Legend:
- CPP Period
- Peak Period
- Off-Peak Period
Small Customer CPP results (8/9/04 report)

Percent Change In Peak Energy Use Over Time
Period - (Summer '03 Analysis)*

<table>
<thead>
<tr>
<th>Climate Zone</th>
<th>CPP Day</th>
<th>Non-CPP Day</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temperate</td>
<td>-8.35</td>
<td>-9.61</td>
</tr>
<tr>
<td>Moderate</td>
<td>-3.32</td>
<td>-5.59</td>
</tr>
<tr>
<td>Hot</td>
<td>-13.37</td>
<td>-17.13</td>
</tr>
<tr>
<td>Hotter</td>
<td>-6.83</td>
<td>-12.46</td>
</tr>
<tr>
<td>All</td>
<td>-4.78</td>
<td></td>
</tr>
</tbody>
</table>

* CPP impacts do not include enabling technology – average load reduction increases by over 2x with enabling technology (i.e. a/c load control)

** TOU rates were tested but did not yield statistically valid results. For comparison purposes, TOU estimate reflects the results of prior studies validated by EPRI
Large Customer Demand Bidding

- Applicable to utility service customers only (Direct Access Customer participation pending)
  - Minimum bid of 100 kW per hour.
  - Demand reduction must be within +/- 50% (payments based on actual load reduced)

- Price trigger
  - IOUs to forecast hourly price offer on day-ahead basis
  - DBP is triggered when price = or > $.15 per kWh

- Reliability trigger
  - DBP triggered by ISO on day of basis
  - Incentive paid = $.50 per kWh x kWh reduction
Customer Reviews Curtailment Event
1. Receives pager/email notice
2. Reviews event hours and incentive amount
3. Places load curtailment bid

Customer Monitors Performance
1. Baseline Load
2. Target Load
3. Actual Load
CPP / DBP Results to Date

- **Participants**
  - # Participants
  - MWs

- **Participation & Load (MW)**
  - DBP (*Test 2 (Largest number of signups))
  - CPP (*CPP Peak Performance across 4 events*)

- **Enroll**
  - DBP: 21
  - CPP: 8

- **Avail.**
  - DBP: 87
  - CPP: 19

- **Max.**
  - DBP: 1
  - CPP: 1

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* *CPP Peak Performance across 4 events*
Initial Assessment of New DR Programs

- Evidence to support that policy/program changes are necessary to achieve price response goals

- Large Customer Rollout (CPP/DBP) (Phase 1)
  - Successful Rollout and Marketing (i.e. high customer awareness) but limited growth in peak reduction capacity
  - Most customers interested in voluntary (no penalty) DBP
  - Inability to shift load is #1 reason for minimal/non-participation (most customers claim they have already shifted)

- Small Customer Pilot (CPP) (Phase 1)
  - Currently in 2nd summer of 18 month pilot
  - Updated Summer ’03 results (Aug. 9, 2004) show price response however lingering issues as to magnitude, persistence and validity
  - Most significant response achieved with enabling technology
  - Consumer issues: Market research shows mixed response to CPP or “dynamic pricing”
New Innovations In Testing: “The Orb”

What is the impact of…

- Automated control of multiple loads
- Enhanced information
  - User friendly web design with actionable information
- Improved notification
  - Testing effectiveness of visual notification signals (i.e. “the orb”)

“SCE is continuously seeking new and innovative ways to deliver cost-effective DR”

The “orb” changes color based on price
Now What? Phase 2 – AMI Issues

Utilities preparing business case analyses for deployment of advanced metering infrastructure (AMI) to support dynamic pricing to be filed on Oct. 15, 2004

Threshold Question: Do operational benefits of AMI (with demand response) outweigh costs?

Critical Issues:
- How do we recruit over 4 million customers? (Mandatory vs. Voluntary)
- Will customers accept dynamic pricing? If we build it, will they play? How long will they play? Do we need to change “the law”?
- What is the rate impact? What is the cost recovery risk?
- Is the technology proven? What is the risk of obsolesce? What is the standard? Will customers use the data? Who owns the meters?
- Who pays stranded costs? What if the benefits don’t materialize?
- What is a feasible implementation period? 5 years?
- What is the right value to be used for potential capacity and energy benefits from AMI? Can we count on it? Does it meet resource adequacy rules? Will it persist?

Is AMI the most cost-effective solution to achieve DR goals?
Maximizing DR Resource Value

LOW

- Non-Firm
- Advance Notice (Day Ahead)
- Limited Operating History
- Voluntary – Pay for Performance (No Penalty)

HIGH

- Firm (Dependable)
- UDC Dispatch (<10 minutes)
- Real Time Visibility or Statistical Validation
- Mandatory – Guaranteed Payment (Significant Penalty for Non-Performance)
Maximizing Value Thru Advanced Load Control

- Highest value load – can be dispatched in 10 minutes
- Proven load reduction capacity (based on SCE and other UDC experience)
- Utilizes smart thermostats (temperature adjustment is easier to understand vs. cycling)
- Untapped market potential (only 5% residential saturation today; forecast to reach 25% over 7 years)
- Leverages existing infrastructure and labor
- Low acquisition cost for residential customers @ less than $300/kw (equipment plus installation)
- Can be regionally marketed & dispatched for distribution relief
- Demand impact easily validated through statistical sampling
- Residential ALC can yield 700 MW by 2011 (7 years)
Summary of Advance Load Control Plan

Today (a/c cycling) (2 programs)

• 104,000 Domestic
• 175 MW of curtailable load
• Emergency Trigger
• Rarely dispatched (6 hr maximum)

Base available 15 x 6hrs = 90hrs
Enhanced=unlimited

• Premise device is RF remote control switch on a/c

• Program provides CT capacity resource equivalent

Future (Advanced Load Control) - (1 program)

• 500,000 customers (over 7 years)
• 700 MW of curtailable load plus energy
• Economic & Emergency
• Dispatched 70 hrs/yr (4 hour max)

Emergency - 20 hrs
Economic - 50 hrs

• Premise device is smart T-stat and communications module (for multiple loads) or load control switch on a/c unit

• Provides CT capacity resource equivalent plus; plus EE benefits
ALC Can Co-Exist with Dynamic Pricing

- CPUC vision specifies that customers should be able to choose “voluntarily” among 3 basic tariff options: CPP, TOU, and flat rates (w/ hedge)
  - Customers choosing TOU or flat rate can be offered ALC option
  - Existing ALC customers should be offered “choice” of new CPP option or retaining ALC with flat or TOU rate choice
- ALC “enables” load reduction under all tariff options or combinations of options
- Future technology options could involve load control embedded in meters and appliances
The DR Resource Planning Continuum

Regulation / Pre-Deregulation

Recovery

DR programs need to be fully integrated with resource planning NOW!!

Market Failure

Transition

Deregulation

“Over Capacity”
Who needs DR?

Somebody else’s problem!

Where was DR?
We need DR Programs!

We are here!
The Bottom Line:

- Programs **must provide** a balance between both resource planning and customer needs.
- DR Resources **must be** cost-effective when compared to supply alternatives.
- New programs will require time to demonstrate reliable response.
- Build on the infrastructure that works today (e.g. expand advanced load control capability).
- DR isn’t REAL until it becomes a dependable resource **fully integrated** into short and long term resource plans.
Helpful Websites

- Southern California Edison – Demand Response Programs
  - www.sce.com, Demand Response Programs
  - www.sce.com/drp, or