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Phase I Results: Incentives and Rate Design for Energy Efficiency and Demand Response - Appendix

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Collaborative Report

Phase 1 Results: Incentives and Rate Design for Energy Efficiency and Demand Response

Appendix

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DR Rate and Program Design
RON-02 Phase 1 Results

Demand Response Research Center

January 13, 2006

Energy and Environmental Economics, Inc.

FREEMAN, SULLIVAN & CO.
A MEMBER OF THE FSC GROUP

UtiliPoint International Inc.

HMG

Orientation

- This document presents the results of work done on DR Rate Design (DRRC RON-02) in Phase I to prepare the Phase 2 research proposal
- The research proposal for Phase 2 is provided in a separate document[1]
- E3 is also submitting a proposal for DR Valuation (DRRC RON-01), with a Phase I results presentation and Phase 2 research proposal, also provided in a separate document.

- *To focus attention on content, this DR Rate Design Phase 1 report is provided in presentation format to allow for more efficient review, discussion and modification prior to the final report in February.*

1. DR RON-02 Phase 2 Research Proposal: “Demand Response Rate Design and Screening Tools.”

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Chapter 1 Introduction

1.1 Objectives

- Project Objectives
  - *develop efficient, implementable rate and program designs to encourage DR*
- Objectives of this Presentation
  - *provide broad review of DR rates and programs*
  - *describe screening methodology to select best options*
  - *describe data gaps requiring further research*
- Proposal Objectives (included as a separate document)
  - *describe research questions*
  - *describe research plan*

1.2 Deliverables

This presentation and the attached proposal constitute the Phase 1 deliverables, as described in E3's Phase 1 proposal:

- *"a methodology for analyzing and developing DR rate designs and programs, including clear definitions and explanations of underlying criteria and models;"*
- *"an evaluation of a representative sample of rate designs to demonstrate the viability of the methodology and the usefulness of its outputs;"*
- *"a report that describes the project results and identifies key gaps in understanding;" and*
- *"a research plan for Phase II."*

1.3 Background

- Federal context
  - *FERC*
  - *2005 Domenici-Barton Energy Policy Act*
- California context
  - *California crisis & policy response*
  - *Regulatory context of DR*
  - *PIER DR research at DRRC and DRETD*
- DR challenges
  - *DR enabling technology & systems integration*
  - *DR valuation*
  - *DR rate design*

The Federal Regulatory Context for DR

- EPACT 2005 contained numerous provisions to encourage DR:
  - *Formally states that it is the official policy of the United States to encourage "time-based pricing and other forms of demand response"*
  - *Requires state utility commissions to conduct investigative proceedings into whether and how to adopt time-based pricing and advanced metering*
  - *Requires DOE to submit a report to Congress on the national benefits of demand response, with recommendations for achieving specific benefit levels*
  - *Requires DOE to conduct consumer education and to work with states to identify and address barriers*
  - *Requires FERC to conduct annual assessments of demand response resources and barriers*
- FERC has encouraged development of DR in wholesale markets through:
  - *Broad policy proclamations – e.g., FERC's current Strategic Plan lists among its objectives: "promote development of policies that accommodate effective demand response programs"*
  - *Regulatory oversight of RTO/ISOs – e.g., directed ISOs to offer programs to allow load to participate in organized wholesale markets (including ancillary services) and to evaluate existing DR programs*

California regulatory context for DR

Regulatory Body	Proceeding/Order/ Publication	Description
California Public Utilities Commission	R0504024 / D0404025	Adopts E3 methodology for the calculation of utility avoided costs for use in energy efficiency programs. Rulemaking looks to adopt consistent methodology across proceedings, including DR.
California Public Utilities Commission	R0206001 / D0501056	Policies and practices for advanced metering, demand response, and dynamic pricing. Sets forth IOU DR goals.
California Public Utilities Commission	R0404003 / D0407028	IOU procurement guidelines regarding reliability, local-area constraints, and RMR contracts, applicable to IOU decisions on DR programs.
California Public Utilities Commission	R0404003 / D0412048	Reinforces IOU DR goals as set forth in D0501056 and emphasizes cost-effectiveness evaluation.

California regulatory context for DR

California Public Utilities Commission	R0404003 / D0410035	Non-dispatchable demand response programs should be treated as debits from load forecasts, while dispatchable demand response programs should be counted as “other resources.”
California Public Utilities Commission	R0110024 / D0406015	MPR decision establishes methodology for determining the long-term market price of electricity from conventional fossil fuel resources to be applied in renewable portfolio standard program.
California Public Utilities Commission	R0404003 / Capacity Markets White Paper	Evaluates capacity markets in other jurisdictions and argues that they may be used to improve resource adequacy in California. DR used
California Public Utilities Commission	Core / Non-Core Electric Market Structure Proposal	Separation of utility customer into “core” and “non-core” still under discussion. One issue with implications for DR is whether non-core customers would be required to purchase ancillary services (AS).

California regulatory context for DR

California Energy Commission	P400-03-001JAF / Building Energy Efficiency Standards for Residential and Nonresidential Buildings	Adopts E3 time-dependent valuation (TDV) method for calculation of avoided costs in 2005 revision of Title 24 building standards.
California Energy Commission	Demand Reponse Evaluation Methodology and Programmable Communicating Thermostat CASE Initiative Activities	Develops valuation methodology for DR for use in 2008 revision of Title 24 buildings standards and evaluation of programmable communicating thermostats for inclusion in the standards.
California Independent System Operator	WECC Minimum Operating Reserve Requirements (MORC)	Sets operating reserve requirement and the type of resources that can be used toward this requirement, including "load which can be interrupted within 10 minutes of notification"
California Independent System Operator	Market Redesign and Technical Upgrade (MRTU) Program	CAISO proposal to institute locational marginal pricing (LMP), day-ahead markets and other fundamental changes in California electricity market.

1.4 E3's Approach to DR Rate Design

- Start from first principles
- Conduct broad review of DR experience and proposals
- Screen potential designs for applicability to California
- Make provisions for future evolution of market and regulatory environments
- Ensure that rate and program design is consistent with DR valuation
- Identify data gaps and research needs
- Obtain input from stakeholders throughout process

1.5 Research Team

E3 Team Qualifications:

- E3 team has broad experience in electric utility rate design
- E3 team has deep knowledge of DR rates and programs in the U.S. and overseas, and has designed well-known DR programs on the East Coast
- E3 team is intimately familiar with California markets and regulatory processes

E3 Rate Design Team

Energy & Environmental Economics, Inc.

Roles	Team
Overall Integration	Ren Orans*
Rate & Tariff Design	Snuller Price
CA Regulatory Context	C.K. Woo
CA Energy Markets	Brian Horii
	Jim Williams

Utilitpoint/Neenan Associates

Roles	Team
U.S. Energy Markets	Bernie Neenan*
Rate & Tariff Design	Donna Pratt
Dynamic Pricing	Peter Cappers
Program Evaluation	Richard Boisvert

Lawrence Berkeley National Laboratory Energy Markets and Policy Group

Roles	Team
RTP Rate Design	Chuck Goldman*
ISO DR Programs	Galen Barbose
Market Penetration	Katie Coughlin
Customer Response	Robert Van Buskirk

Freeman Sullivan & Company

Roles	Team
Consumer Research	Michael Sullivan*
Participation Rates	Grayson Heffner
Program Marketing	Kent Van Liere
	Dan Engel
	Chris Ann Dickerson
	Josh Bode

Heschong Mahone Group

Roles	Team
Building Science	Doug Mahone*
Simulations	Jon McHugh
CA Building Standards	Matt Tyler
Technical Potential	

* team leader

Research Team Experience

(1) **Energy and Environmental Economics, Inc. (E3)**: E3 is an economics, regulatory, and engineering consulting firm serving the electricity and natural gas industries, with clients that include integrated utilities, local distribution companies, owners of transmission and generation, law firms, electricity consumers, government agencies, regulatory commissions, and industry associations. E3 is intimately familiar with existing and proposed California rate structures, and has designed a number of widely-used rates for California and other jurisdictions. E3 will be the project lead and will provide overall integration, in addition to rate design and analysis of the California regulatory framework. E3's work is led by Ren Orans.

(2) **Utilipoint/Neenan Associates (NA)**: NA (now part of Utilipoint) is a national leader in the design, implementation, and evaluation of dynamic pricing systems and demand response programs for electricity markets. NA has designed DR programs for NYISO and ISO-NE, and designed and evaluated rates for utilities in the U.S. and overseas. NA's role in the project will focus on analysis and design of DR rates other jurisdictions and their applicability to California. NA's work is led by Bernie Neenan.

(3) **LBNL Electricity Markets and Policy Group (EMP)**: EMP conducts fundamental research and policy analysis relevant to U.S. electricity markets. EMP's expertise includes power system reliability, DSM, renewable energy, distributed energy resources, and retail services. EMP's role will focus on dynamic pricing and demand response valuation in the Western and Eastern U.S.. EMP's work on this project will be led by Chuck Goldman.

(4) **Freeman, Sullivan & Company (FSC)**: FSC is an industry leader in consumer research, including such key components of rate design as program participation rates, stakeholder analysis, and modeling consumer behavior, attitudes, and preferences. The firm has extensive qualifications in both quantitative and qualitative data collection and analysis, and maintains a 38-station Computer-Assisted Telephone Interviewing (CATI) facility. FSC's role in the project will focus on the consumer dimensions of DR rate and program designs. FSC's Grayson Heffner will also provide economic analysis and expertise on international DR rate designs. FSC's work is led by Michael Sullivan.

(5) **Heschong Mahone Group (HMG)**: HMG is a leader in the field of building energy efficiency in California, and in the related areas of building science and simulation, construction technology, and building standards and policy development. HMG's role in the project will focus on the architectural, engineering, and customer-impact dimensions of DR rate and program designs. HMG's work is led by Doug Mahone.

1.6 Phase 2 proposal summary

Our proposal for Phase 2, “Collaborative Development of DR Rate Design and Screening Tools” will produce screening tools and prototype rate designs that have a strong likelihood of being tested and implemented in California.

Deliverables

- A suite of efficient, implementable prototype demand response (DR) rates and programs for California
- A set of screening tools that can be used to guide and evaluate any potential DR rate or program design from the perspective of market potential, customer acceptance, utility practice, and regulatory policy.

Process

- A consultative process that closely involves utilities, customer groups, regulators, state agencies and other stakeholders in the development of screening methodology and prototype designs.
- The E3 team will be responsible for first drafts, revisions, and final drafts addressing each research question and will give regularly scheduled presentations on the work in progress to facilitate collaboration.

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Chapter 2 Rate design principles

2.1 History of electric rates

- The Early Days
  - *vigorous debate over pricing principles, 1880s-1910s*
  - *early experiments with TOU and demand subscription*
  - *demand charges and declining block rates become the norm*
  - *many non-theoretical factors drive rate design*
- The PURPA Watershed
  - *PURPA calls for cost-based pricing*
  - *new era in pricing philosophy driven by industry cost trends and concerns about environment and resources*

The Early Days

- From the 1880s to about 1910, the electricity industry debated and experimented with a variety of rate structures. (Hausman and Neufeld, 1984)
- Industry and economic journals of the time debated the problem of peak load pricing, the issue of average costs versus marginal costs, and the merits of time-of-day rates and non-coincident demand charges. (Hopkinson, 1892; Gibbings, 1894; Barstow, 1895; Wright, 1896; Doherty, 1900; Insull, 1910; Clark, 1911)
- Time of use rates were not only discussed but offered by such major utilities as Detroit Edison and Chicago Edison to promote off-peak load growth (for example, through special rates for electric trolleys and ice-making factories) (NELA, 1898)
- To support time of use rates, practical TOU meters were available from both General Electric and Westinghouse by 1898. (AEIC, 1898)
- The benefits of time of use pricing were recognized at the time: “The two-rate system seems to produce two desired results… the broadening of the maximum peak, and the increasing of minimum peaks” (AEIC, 1898)

The Early Days (2)

- Another oddly contemporary rate structure of the early days was demand subscription. The industry's first rates were capacity-based, with customer charges based on the number of light bulbs installed.
- The demand subscription idea reached its apex with the "4-C" system proposed in 1900, which required customers to contract in advance for their peak demand ("4-C" was a pun for "foresee," in that it allowed utilities to easily forecast their capacity requirements). (Doherty, 1900)
- Despite early experiments with rate designs that seem advanced today, such as time of use pricing and demand subscription, these had disappeared entirely from the menu of utility rate options by 1920 (Eisenmenger, 1921) and did not re-emerge in the U.S. until the 1970s.
- What emerged instead was non-coincident demand charges for larger customers (Hopkinson and Wright tariffs) and declining block rates for energy for all customers, which became the industry standards for decades.

The Early Days (3)

- In 1910, the threat of monopoly regulation drove IOUs across the country to standardize rates. This effectively locked in demand charges, which had been adopted by industry leaders such as Samuel Insull.
- With continuously declining costs of production for the next half century, rate structures became a non-issue for the industry.
- Technological advances, load growth, and regulatory strategies became much greater concerns to the industry than sending ex ante price signals to customers to encourage efficient consumption.
- This early history demonstrates that marginal cost pricing, time of use rates, and even time of day metering are actually more than a century old. That these were not adopted at the time illustrates the importance of factors other than economic theory in shaping electricity rate structures.

The PURPA Watershed

- Since the early days, there have been two main eras of retail electricity pricing in the US: (1) from the1910s to the1970s, and (2) from the 1970s until the present.
- These two eras are distinguished by dramatically different paradigms regarding industry structure, utility planning processes, and the cost basis and billing components of retail rate design.
- The symbolic watershed separating the two eras was the passage of PURPA in 1978. PURPA's stated goals were to encourage conservation, resource efficiency, and equitable rates.
- PURPA itself reflected a larger transformation in the electricity industry beginning circa 1970, driven by a fundamental change in industry economics from declining to increasing costs, and also by emerging societal concerns with environmental protection and resource conservation. (Hirsh, 2000)

The PURPA Watershed (2)

- PURPA required all 50 state PUCs and all non-regulated utilities to consider adopting 6 ratemaking standards: basing rates on cost of service by class, eliminating declining block rates, introducing time of day, seasonal, and interruptible rates, and offering customers cost-effective load management techniques "that provide useful energy or capacity-management advantages to the electric utility". (PURPA, 1978)
- PURPA had a rapid effect on retail rates. By 1981, over 13,000 large commercial/industrial customers in the U.S. were on TOU rates. (Acton, 1982). Inverted block or tiered rates became the norm for residential customers, replacing declining block rates.
- Although the U.S. had explored TOU rates at the turn of the 20th century, post-PURPA TOU rate design drew primarily on the experience of France, which instituted advanced rate designs years before PURPA.
- The evolution of rates since PURPA has been impacted by other trends begun by PURPA and furthered by the 1992 EPAct, including IRP, DSM, wholesale competition, and industry restructuring.

History of electric rates

1900s to 1970s	→	1970s to present

Industry Trends

1900s to 1970s	1970s to present
declining costs	increasing costs
environment not emphasized	environment emphasized
supply-side planning	conservation, DSM, IRP

Pricing Philosophy

1900s to 1970s	1970s to present
average cost basis	marginal cost basis
volumetric	time-of-use
ratcheted demand	coincident demand
declining block energy	increasing block energy

2.2 Ideal rate design

An ideal rate design would have the following components:

- *monthly customer charge - to recover costs that vary with the number of customers on the system, such as metering, billing, and customer service*
- *distribution facilities charge per kW of design/contract demand – to recover the costs of local distribution facilities*
- *location-specific, time varying energy charge – to recover the time and location differentiated marginal costs of generation, transmission, and high-voltage distribution*

Economic theory of rate design

- Economic theory holds that pricing based on marginal costs leads to efficient consumption and maximizes social welfare.
- A vast body of economic literature has applied marginal cost principles to the question of electricity peak load pricing (Clark, 1911; Boiteux, 1949; Steiner, 1957; Joskow, 1976; Crew and Kleindorfer, 1976) and transmission congestion pricing (e.g., Hogan, 1992).
- Theory also holds that efficiency is maximized when prices are set at short-run marginal cost rather than long-run marginal cost (Kahn, 1970; Vickrey, 1985; Anderson and Bohman, 1985; Della Valle, 1988).

Irrationalities in current rate structures

From the standpoint of economic theory, there are still many irrationalities in current electricity rate structures:

- *Most large customers still pay demand charges for non-coincident demand*
- *Most residential customers still pay only volumetric energy charges with no time of use component*
- *Even TOU rates aggregate hours with different marginal costs into a fixed price, which diffuses the price signal to customers*

Technology and rate design

New technology makes innovative rates possible

- Recent advances in metering and communications technology make it economically feasible to implement rates more reflective of underlying cost structure, even for residential customers
- The Domenici-Barton Energy Policy Act of 2005 requires all state PUCs to consider whether to require utilities to "provide and install time-based meters and communications devices for each of their customers which enable such customers to participate in time-based price structures." (Irastorza, 2005)

2.3 Broad rate design goals

From a public policy perspective, economic efficiency is only one of several goals of rate design. Bonbright (1961) lists eight criteria of a desirable rate structure:

- *Efficient consumption of both total usage and differentiated service such as on-peak electricity*
- *Equitable apportionment of the costs of service among customers*
- *Avoidance of undue discrimination in the relationship among rates offered to different customers*
- *Effective in meeting utility revenue requirements*
- *Utility revenue stability from year to year*
- *Rate stability for customers*
- *Simplicity of implementation and ease of understanding*
- *Wide public acceptance*

2.3 Broad rate design goals (continued)

In practice, these goals can compete with each other and are sometimes in conflict:

- *Short-run marginal cost pricing can fail to yield utility revenue requirements, can cause revenue instability from year to year, and can cause price instability for customers. This is especially true if retail prices are linked to volatile wholesale markets.*
- *SRMC pricing can give inefficient price signals for long-run purchasing decisions.*
- *"Ideal" rates may be administratively infeasible or cost-ineffective to implement, or customers may find them too difficult to understand or too difficult to respond to.*
- *Mandatory imposition of "ideal" rates can result in social welfare losses, while voluntary rates can result in free riders and inequitable transfers among customers.*

2.4 Stakeholder acceptance

- Under current public policy, the conflicting imperatives of rate design are addressed in regulatory proceedings that seek broad stakeholder acceptance.
- The principal stakeholders are utilities, customers, and regulators. Each has different interests with regard to rate design.

Utility's Perspective

From the utility perspective, key rate design goals include:

- *revenue requirements*
- *revenue stability*
- *administrative simplicity and ease of implementation*
- *marketability to customers*
- *consistency with planning, procurement, operations and other utility goals and functions.*
- *improving peak load management*

Customer's Perspective

From the customer's perspective, key rate design goals include:

- *attractive pricing / bill savings*
- *voluntary options / having choices*
- *simplicity of understanding*
- *low "hassle factor"*
- *bill stability*
- *program consistency*
- *minimal inconvenience*
- *environmental benefits*
- *protection from price spikes (if exposed)*

Regulator's Perspective

From the regulator's perspective, key rate design goals include:

- *economic efficiency*
- *equitable cost allocation*
- *program cost-effectiveness*
- *incentives for efficient long-run investment*
- *service to low-income customers*
- *environmental protection*
- *minimizing impacts of system peak demand*

Chapter 3 DR rates and program choices

3.1 Efficient Capacity Rationing

- Issue
  - *There are two different approaches to ration shortages, each with their own body of literature, price-based and quantity-based rationing. The relative efficiency and effectiveness depends on market structure and customer acceptance and response.*
- Price-based Rationing Schemes
  - *Under certain assumptions, mandatory RTP is the most efficient mechanism, since it equates in real time the marginal benefit and marginal cost of electricity consumption. The three main assumptions required are the following;*
  - *1. There is a real-time energy market*
  - *2. Retail end-users will see or face real time prices*
  - *3. Customers make real-time consumption decisions*
- Quantity-based Rationing Schemes
  - *In quantity-based approaches, customers commit to reduce part of their load during a capacity shortage. A recent study found that if there are three reliability classes (i.e., premium, firm and non-firm), mandatory priority service or demand subscription can achieve 90% of the efficiency that can be obtained via mandatory RTP.*

Definitions

- Demand response
  - *We define DR broadly as any mechanism that can be used to ration peak demand*
- Rates
  - *Rates are the pricing arrangements by which a customer is charged for consumption. Ideal rates are voluntary and self-supporting, and do not create transfers.*
- Programs
  - *Programs are arrangements to affect customer behavior. Rates are embedded in programs, which include marketing and non-pricing incentives, for example to reduce consumption or adopt certain technologies. Programs may involve transfers and may not be self-supporting, in which case they should be justified on cost-effectiveness grounds.*
- DR classifications commonly used
  - *DR rates and programs can be divided into two kinds according to the way that it rations capacity: by price and by quantity*
  - *DR can also be classified according to the way it is applied, namely as economic programs and as emergency programs. (These programs themselves employ either quantity or price rationing.)*

3.2 Types of Price-based Capacity Rationing

Price rationing literature

- Static
  - *Mandatory TOU (Chao, 1983; Woo, 1988) under which all customers face posted TOU rates that do not change frequently (e.g., daily)*
  - *Optional TOU (Mackie-Mason, 1990; Woo et al, 1995) under which customer can select TOU as an alternative to the non-TOU default tariff*
- Dynamic
  - *Mandatory RTP (Bohn, et al, 1984) under which all customers face real time MCP that vary by location*
  - *Optional RTP (Woo et al, 1996) under which volunteering customers see day-ahead hourly prices that do not vary by location*
  - *Critical peak pricing (CPP) (Herter et al, 2005) under which participating customers see very high rates during emergency hours. Participation can be mandatory or voluntary (opt-in vs. opt-out)*

Note: Definitions of the rate abbreviations can be found in the appendix.

3.3 Types of Quantity-based Capacity Rationing

Quantity rationing (reliability differentiation) literature

- Priority service (Chao and Wilson, 1987) under which a customer assigns priority to its load segments. In a capacity shortage, low priority loads are cut first before high priority loads. If cutting all low priority loads leads to excess load relief, rotating interruption is used.
- Direct load control programs are a form of priority service. An example is SMUD's AC cycling program.
- Demand subscription (Spulber, 1992; Woo, 1990) under which a customer subscribes to a firm service level (FSL) below which service is not interruptible.
- One type of demand subscription is interruptible and curtailable service for large users offered by UDCs. When FSL = 0, the service is interruptible. If curtailing all non-firm loads results in too much load relief, load curtailed is made proportional to FSL subscribed.
- Though different in theory, priority service and demand subscription are very similar in practice

3.4 Survey of DR rates and programs

- The E3 team conducted a survey of current and past DR rates and programs offered by the 50 largest utilities in the U.S. and 15 large international utilities.
- The goals of the survey were to characterize the prevalence of different DR rates and programs, and to characterize the range of attributes within each type

Residential Rates and Programs offered by US utilities (sample of 50)

US Res	TOU	RTP	CPP	DSS	DLC	CIS	Hybrid
Number	41	2	6	6	15	0	6
Percentage	82%	4%	12%	12%	30%	0%	12%

Non-Residential Rates and Programs offered by US utilities (sample of 50)

US Non-Res	TOU	RTP	CPP	DSS	DLC	CIS	Hybrid
Number	48	24	4	0	6	41	15
Percentage	96%	48%	8%	0%	12%	82%	30%

Residential Rates and Programs offered by International utilities (sample of 15)

Int'l Res	TOU	RTP	CPP	DSS	DLC	CIS	Hybrid
Number	10	0	1	5	0	0	5
Percentage	67%	0%	7%	33%	0%	0%	33%

Residential TOU

Program Designs

Type of TOU Tariff	Number	Percentage (sample of 57)	Example Utility	Example Tariff Name
Energy-only TOU	38	66.7%	Detroit Edison (DTE)	D1.2
Demand-only TOU	2	3.5%	Public Service of Colorado (Xcel)	RT
Energy and demand TOU	4	7.0%	Carolina Power & Light Co	R-TOUD
Energy TOU plus demand subscription	5	8.8%	Electricida de de Portugal	Tarifa Bihoraria
Energy TOU with block pricing	7	12.3%	Long Island Power Authority	Rate 184
Energy TOU with utility-installed load management technology	1	1.8%	Indiana Michigan Power (AEP)	RS-LM-TOD

Program Attributes

Variable	Range	Average
Number of Periods	2-4	2.2
Number of Seasons	1-4	1.7
Duration of Peak Period	4-16 hours	9.9 hours
On-Peak Price (¢/kWh)	1.65-39.37	15.46
Off-Peak Price (¢/kWh)	0.63-13.81	5.91
On Peak/Off Peak Ratio	1.0-29.0	3.5
Monthly Charge ($/month)	0.00-22.39	5.27

Participation Features

Feature	Number	Percentage
Customer Pays to Participate	50	88%
Voluntary Enrollment Only	54	95%
Mandatory for Some Customers	3	5%
Opt-In (vs. Default)	56	98%
Standard (vs. Pilot)	52	91%

Range of program designs and attributes in 57 residential TOU programs found in 50 US and 15 international utilities.

Residential CPP

Program Designs

Type of TOU Tariff	No.	Percentage (sample of 9)	Example Utility	Example Tariff Name
CPP with TOU rates	8	89%	San Diego Gas & Electric	EECC-CPP-F
CPP with flat rates	1	11%	Idaho Power	Energy Watch
CPP + demand subscription	1	11%	Electricitˇ de France	Tempo
CPP + load management	4	44%	Gulf Power	Good Cents Select
CPP + block pricing	6	67%	Southern Cal Edison	TOU-D-CPPF

Program Attributes

Variable	Range	Average
CPP Months Per Year	2-12	10.1
CPP Maximum Days Per Year	10-22	15.3
CPP Maximum Hours Per Day	4-16	6.4
CPP Maximum Hours Per Year	40-352	106.4
CPP Event Advance Notice (hours)	0.5-25	16.1
Number of TOU Periods	2-3	2.1
Number of Seasons	1-2	1.9
TOU On-Peak Price (¢/kWh)	5.1-27.4	15.8
TOU Off-Peak Price (¢/kWh)	3.0-12.1	6.6
CPP Price (¢/kWh)	20.6-84.3	50.5
Ratio of CPP/On-Peak Price	2.4-8.5	3.7
Ratio of CPP/Off-Peak Price	4.1-15.5	8.8
Monthly Charge ($/month)	0-4.95	1.93

Participation Features

Feature	Number	Percentage
Customer Pays to Participate	5	56%
Voluntary Enrollment Only	9	100%
Mandatory for Some Customers	0	0%
Opt-In (vs. Default)	9	100%
Standard (vs. Pilot)	2	22%

Range of program designs and attributes in 9 residential CPP programs (including 7 experimental) found in 50 US and 15 international utilities.

Large Customer RTP

Program Designs and Attributes

Feature	Number	Percentage
One-Part RTP	11	46%
Two-Part RTP	12	50%
Other	1	4%
Two-Part RTP with adjustable CBL	9	75%
Two-Part RTP without adjustable CBL	3	25%
Hourly Price based on system lambda	14	58%
Hourly Price based on pool price	4	17%
Hourly Price based on model	2	8%
Hourly Price based on index	2	8%
Hourly Price based on other/not known	2	8%
Marginal outage or capacity cost adder	18	75%
Interruptible option	13	54%
Interruptible w/ no penalty buy-through	2	15%
Day ahead notification	24	100%
Hour ahead notification	1	4%

Participation Features

Feature	Number	Percentage
Voluntary Enrollment Only	24	100%
Opt-In	23	96%
Default (opt-out)	1	4%
Standard Tariff	11	46%
Pilot	13	54%

Range of program designs and attributes found in 24 non-residential RTP programs (including 13 experimental) in 50 US utilities.

Residential DLC (direct load control)

Program Designs

Type of TOU Tariff	Number	Percentage (sample of 15)	Example Utility Name	Tariff
DLC as rider on flat-rate or otherwise applicable tariff	14	93%	Northern States Power (Xcel)	SaverŜ Switch
DLC with RTP	1	7%	Allegheny Power	Electricity Price Response Pilot Program

Program Attributes

Feature	**Number**	**Percentage**
Year-Round Program	7	47%
Seasonal Program	8	53%
Limited Hours Per Day	9	60%
Limited Days Per Season	2	13%
Limited Hours Per Season	3	20%
Monthly Bill Credit Incentive	12	80%
Per Event Bill Credit Incentive	4	27%
A/C Cycling Only	6	40%
Water Heater Cycling Only	1	7%
Multiple Customer Loads	8	53%
Remote Switches on Individual Loads	11	73%
EMS System Controls Multiple Loads	4	27%

Participation Features

Feature	Number	Percentage
Customer Pays to Participate	1	7%
Voluntary Enrollment Only	15	100%
Mandatory	0	0%
Opt-In (vs. Default)	15	100%
Standard (vs. Pilot)	14	93%

Variable	Range	Average
DLC months per year	4-12	7.9
Maximum DLC hours per day	4-12	7.0
Monthly incentive bill credit ($/month)	0-36.00	9.79
Per event bill credit ($)	0-4	0.54
Customer participation charge ($/month)	0-1.95	0.14

Range of program designs and attributes in 15 residential DLC programs found in 50 US and 15 international utilities.

Residential DSS (demand subscription service)

Program Designs

Type of DSS Tariff	No.	Percentage (sample of 10)	Example	
			Utility	Tariff Name
DSS with physical demand limit	9	90%	Tokyo Electric Power Co	Meter Rate A
DSS with curtailable demand limit	1	10%	SCE	Demand Subscription Service Pilot
DSS + flat-rate tariff	4	40%	ACEA-Electrabel	Uso Abitazione
DSS + TOU	4	40%	Electricidade de Portugal	Tarifa bi-horaria
DSS + CPP	1	10%	Electricite de France	L'option Tempo

Program Attributes

Feature	Number	Percentage
Voluntary Enrollment Only	6	60%
Mandatory/Default Option	4	40%
Customer Receives Incentive Payment	1	10%
Customer Pays to Participate	5	50%
Year Round Program	9	90%
Standard Program	9	90%
Pilot Program	1	10%
Requires Curtailment Notification	1	10%

Range of program designs and attributes in 10 residential DSS programs found in 50 US and 15 international utilities.

Large Customer Interruptible/Curtailable Service

Program Designs and Attributes

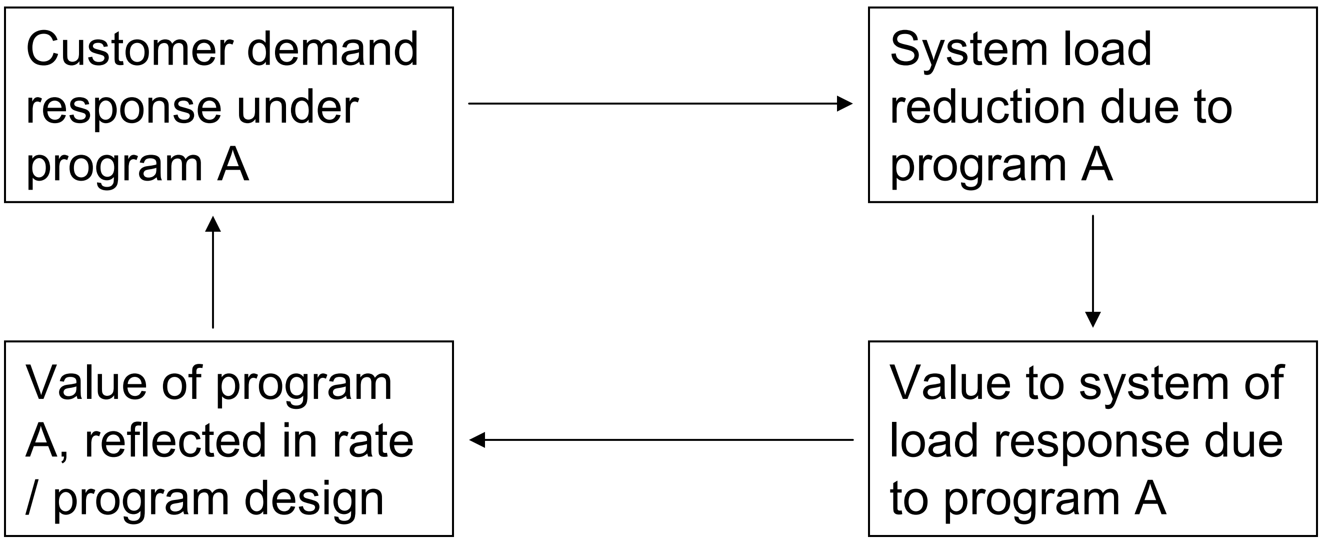
UTILITY OR ISO	PROGRAM OR TARIFF NAME	MINimum CURTAILAB LE LOAD (KW)	INCENTIVE	PENALTY	MAXIMUM CURTAILMENT EVENTS	NOTICE
Duke	Rider IS		$3.50/kW-month	$10/kW-month	10 hours/day, 150 hrs/year	30 minutes
Indianapolis Power and Light Co (IPALCO)	Rider 14	1500	$3/kW-month	$6/kW-month	2 calls/week, 5 calls/month, 8 hours/call, 80 hours/year	10 minutes to 2 hours; larger incentive for shorter notice
Kansas City Power and Light (KCPL)	Peak Load Curtailment Program	200	$10/kW - month	$1.25/kWh + share of utility capacity deficiency payment	25 days/year, 8 hours/day, 120 hours/year	4 hours
Pacific Power (PacifiCorp)	Interruptible Rider	1000	lower kWh rates		2 events/day, 8 hours/day, 10 days/month	10 minutes
Pennsylvania Power and Light (PPL)	IS-T	1000	lower kWh rates	$24.95/kW-month + LMP+tariff for energy	15 days/year, 10 hours/day, 150 hrs/year	
SCE	I-6-BIP	100	$7/kW-month	$6/kWh	4 hours/day, 10 events/month, 120 hours/year	30 minutes

Range of attributes found in 41 non-residential I/C programs (including 13 experimental) in 50 US utilities.

Chapter 4 DR design and value

4.1 Link between program and value

- Program designs must be based on the value they provide, otherwise they result in transfers or net social welfare loss.



- This section describes the general methodology used to analyze the value of a rate or program design.
- It connects the market segment, technical potential, and customer acceptance screening methods to the DR valuation methodology developed under RON-01.

4.2 Development of a Value Matrix

- Our approach is to systematically estimate the value that each DR rate and program provide
- We have developed a valuation framework to assess the value of a rate program and design – the ‘valuation matrix’
- Valuation Matrix
  - *For each type of program and control type, the value is computed as the product of the ‘equivalent firm’ load reduction and the value of the benefit defined in the valuation work.*

Control mode of the demand response

- From the standpoint of value to the system, DR programs have two key elements: (1) whether and how peak demand is rationed by price, and (2) who physically controls the load
- Rates = flat (e.g. flat, block, tiered) or time of use (e.g. TOU, CPP, or RTP)
- Control = utility control, customer control, or shared control.
  - *utility control = automated control by utility operator, e.g. A/C cycling switch or non-overridable PCT*
  - *customer control = no utility control, either by automated control or by FSL*
  - *shared control = utility can initiate load reduction but customer has ultimate control, e.g. (1) a utility controlled switch or PCT with customer override (2) a program with a FSL such as demand subscription or interruptible/curtailable service*

Value Matrix: Control method and rate

Programs described by control method and time-dependence of underlying rate

Control	Utility	Utility	Shared	Shared	Customer	Customer
Rate	Flat	Time of use	Flat	Time of use	Flat	Time of use
Emergency	$K_1D_1V_E$	$K_4D_4V_E$	$K_7D_7V_E$	$K_{10}D_{10}V_E$	$K_{13}D_{13}V_E$	$K_{16}D_{16}V_E$
Operating reserve	$K_2D_2V_O$	$K_5D_5V_O$	$K_8D_8V_O$	$K_{11}D_{11}V_O$	$K_{14}D_{14}V_O$	$K_{17}D_{17}V_O$
Planning reserve	$K_3D_3V_P$	$K_6D_6V_P$	$K_9D_9V_P$	$K_{12}D_{12}V_P$	$K_{15}D_{15}V_P$	$K_{18}D_{18}V_P$

Value Matrix: Benefits provided by design

- The value of a DR program depends on the benefits it is capable of providing.
  - *Different program designs deliver different benefits.*
  - *The main value components that DR can provide are the capacity value of emergency, operating, and planning reserves.*

Control	Utility	Utility	Shared	Shared	Customer	Customer
Rate	Flat	Time of use	Flat	Time of use	Flat	Time of use
Emergency	$K_1D_1V_E$	$K_4D_4V_E$	$K_7D_7V_E$	$K_{10}D_{10}V_E$	$K_{13}D_{13}V_E$	$K_{16}D_{16}V_E$
Operating reserve	$K_2D_2V_O$	$K_5D_5V_O$	$K_8D_8V_O$	$K_{11}D_{11}V_O$	$K_{14}D_{14}V_O$	$K_{17}D_{17}V_O$
Planning reserve	$K_3D_3V_P$	$K_6D_6V_P$	$K_9D_9V_P$	$K_{12}D_{12}V_P$	$K_{15}D_{15}V_P$	$K_{18}D_{18}V_P$

Determination of total program benefits

- Total value of a DR program = ∑ emergency, operating, and planning reserve values
  - *Value of each component = V * K * D, value per kW times the number of peak kW enrolled in program times a derating factor for the program*
  - *V_E, V_O, V_P = $/kW of emergency, operating, and planning capacity*
  - *K_X = peak kW enrolled in program X. K is based on technical potential, market segmentation, and customer acceptance*
  - *D_X = derating factor for equivalent "firmness". D is a function of customer response, coincidence of customer peak with system peak, and technical derating factors such as failure rates for enabling technologies.*
- Determination of the quantitative values for V, K, and D by program type is a key part of the Phase 2 research agenda.
  - *V will be evaluated under DR valuation*
  - *K and D will be evaluated under DR rate and program design*

Value Matrix: load, value, and derating factor

For each DR program and type, defined by customer control type, and rate structure, we propose to evaluate the three categories of capacity value

The value is the product of the load reduction, derating factor, and value stream.

Control	Utility	Utility	Shared	Shared	Customer	Customer
Rate	Flat	Time of use	Flat	Time of use	Flat	Time of use
Emergency	$K_1D_1V_E$	$K_4D_4V_E$	$K_7D_7V_E$	$K_{10}D_{10}V_E$	$K_{13}D_{13}V_E$	$K_{16}D_{16}V_E$
Operating reserve	$K_2D_2V_O$	$K_5D_5V_O$	$K_8D_8V_O$	$K_{11}D_{11}V_O$	$K_{14}D_{14}V_O$	$K_{17}D_{17}V_O$
Planning reserve	$K_3D_3V_P$	$K_6D_6V_P$	$K_9D_9V_P$	$K_{12}D_{12}V_P$	$K_{15}D_{15}V_P$	$K_{18}D_{18}V_P$

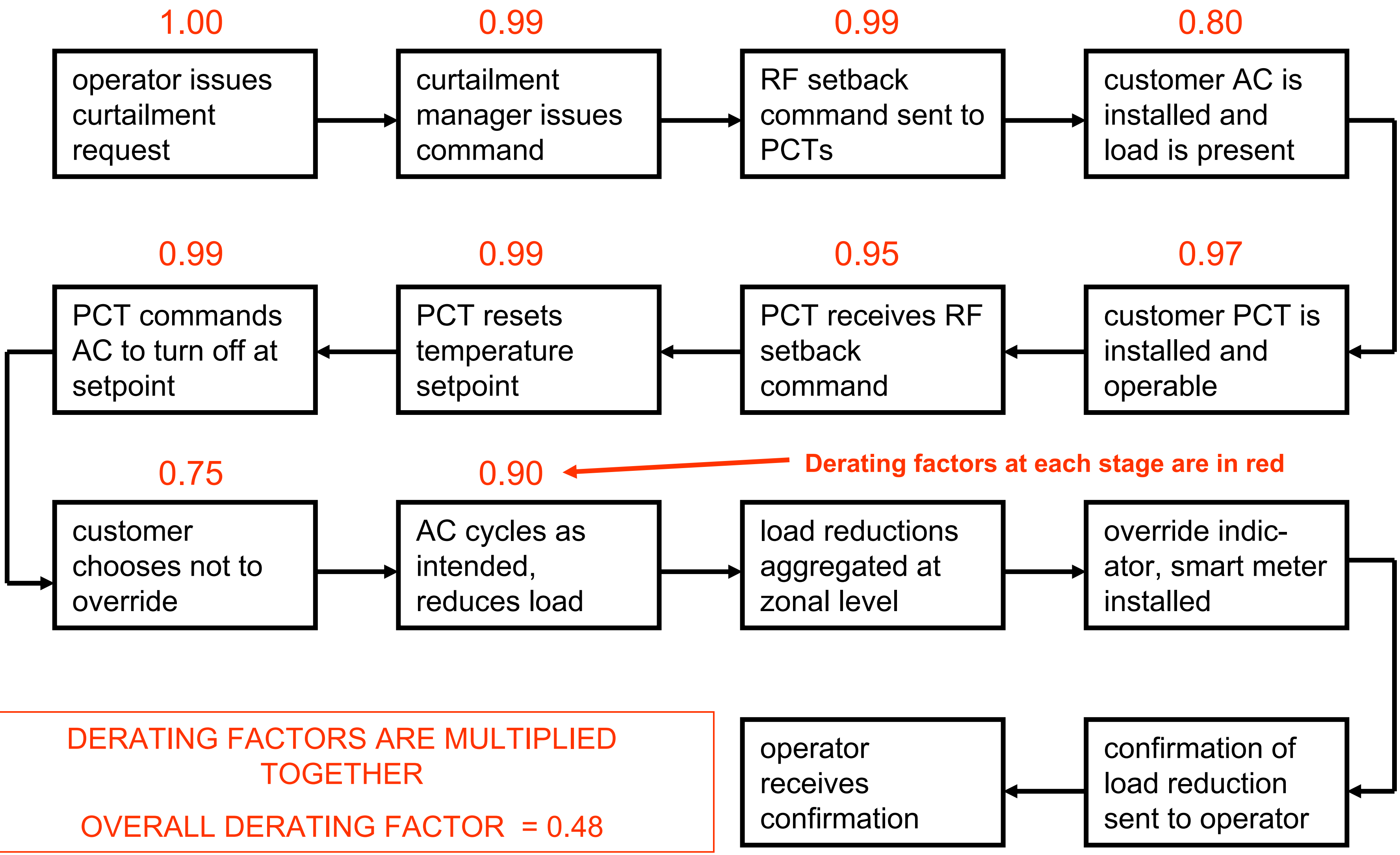
Our proposed DR rate and program work will provide an approach to define load reduction and derating factors (K and D)

The work proposed in the DR valuation will define the value (V)

Equivalent reliability and derating factors

- A key factor in determining the value of a DR program is its equivalent reliability, which is the firm capacity it can be counted on to provide when called.
- To determine equivalent reliability, the nominal curtailable load enrolled in a program must be derated by taking into account any factors that are likely to reduce the actual amount curtailed, whether due to technical reasons or customer behavior.
  - *Example of customer behavior affecting demand response: a customer decides to use the override switch on a PCT after the utility has sent a sent a temperature setback. The utility will not receive the load reduction they had expected from that customer.*
  - *Example of a technical factor: the PCT is not working properly and does not receive the signal or does not set back the temperature. In this case the utility will also not receive the expected load reduction.*
- For each type of load in a DR program, a sequence of automated or human actions is required to reduce the load. The likelihood that each of the actions will occur can be assigned a probability. The total amount by which the nominal load must be derated to obtain equivalent reliability is obtained by multiplying all the probabilities together (note: when probabilities are not independent, the calculation is more complicated, but the principles still applies).
- The derating factor D = prob1 * prob2 * prob3 ... where the probabilities depend on the technology used, failure rates, customer attitudes, weather, performance incentives, and other factors for each action in the sequence.

Example: derating a PCT load reduction



DERATING FACTORS ARE MULTIPLIED TOGETHER

OVERALL DERATING FACTOR = 0.48

Initial program design assessment

Initial assessment, prior to Phase 2 research:

- Highly predictable load reduction
  - *Programs in which the utility controls loads directly are able to provide DR benefits for all three types of capacity, regardless of the rate design*
- Highly unpredictable load reduction
  - *Programs in which the customer completely controls the load, or can override the utility signal, are likely to have little or no emergency capacity value*
  - *Programs with flat rates and customer control are likely to have little capacity value of any kind*
- Very dependent on program design
  - *Programs with shared control, and pricing-only customer controlled programs, are likely of intermediate value for planning and operating reserve capacity, but the value will very strongly depending on design*

Value Matrix: Initial assessment of value

Vx = capacity value $/kW   Kx = enrolled kW   Dx = derating factor

Control	Utility	Utility	Utility w/ customer over-ride	Utility w/ customer over-ride	Customer	Customer
Rate	Flat	Time of use	Flat	Time of use	Flat	Time of use
Emergency reserve	$K_1D_1V_E$	$K_4D_4V_E$	$K_7D_7V_E$	$K_{10}D_{10}V_E$	$K_{13}D_{13}V_E$	$K_{16}D_{16}V_E$
Operating reserve	$K_2D_2V_O$	$K_5D_5V_O$	$K_8D_8V_O$	$K_{11}D_{11}V_O$	$K_{14}D_{14}V_O$	$K_{17}D_{17}V_O$
Planning reserve	$K_3D_3V_P$	$K_6D_6V_P$	$K_9D_9V_P$	$K_{12}D_{12}V_P$	$K_{15}D_{15}V_P$	$K_{18}D_{18}V_P$

Likely high value   Uncertain   Likely zero value

Uncertainty in customer-controlled DR

- ***WECC has stringent standards for counting load resources towards reserve requirements***
  - **WECC Nonspinning reserve currently requires that load be interruptible within 10 minutes.**

WECC Minimum Operating Reliability Standards Standards BAL-STD-001-0-WECC — Real Power Balancing Control Performance

WRS2. Acceptable types of nonspinning reserve. The nonspinning reserve obligations identified in WR1, WRS1.1, and WRS1.2, if any, can be met by use of the following:

(a) load which can be interrupted within 10 minutes of notification

(b) interruptible exports

(c) on-demand rights from other entities or Control Area/Balancing

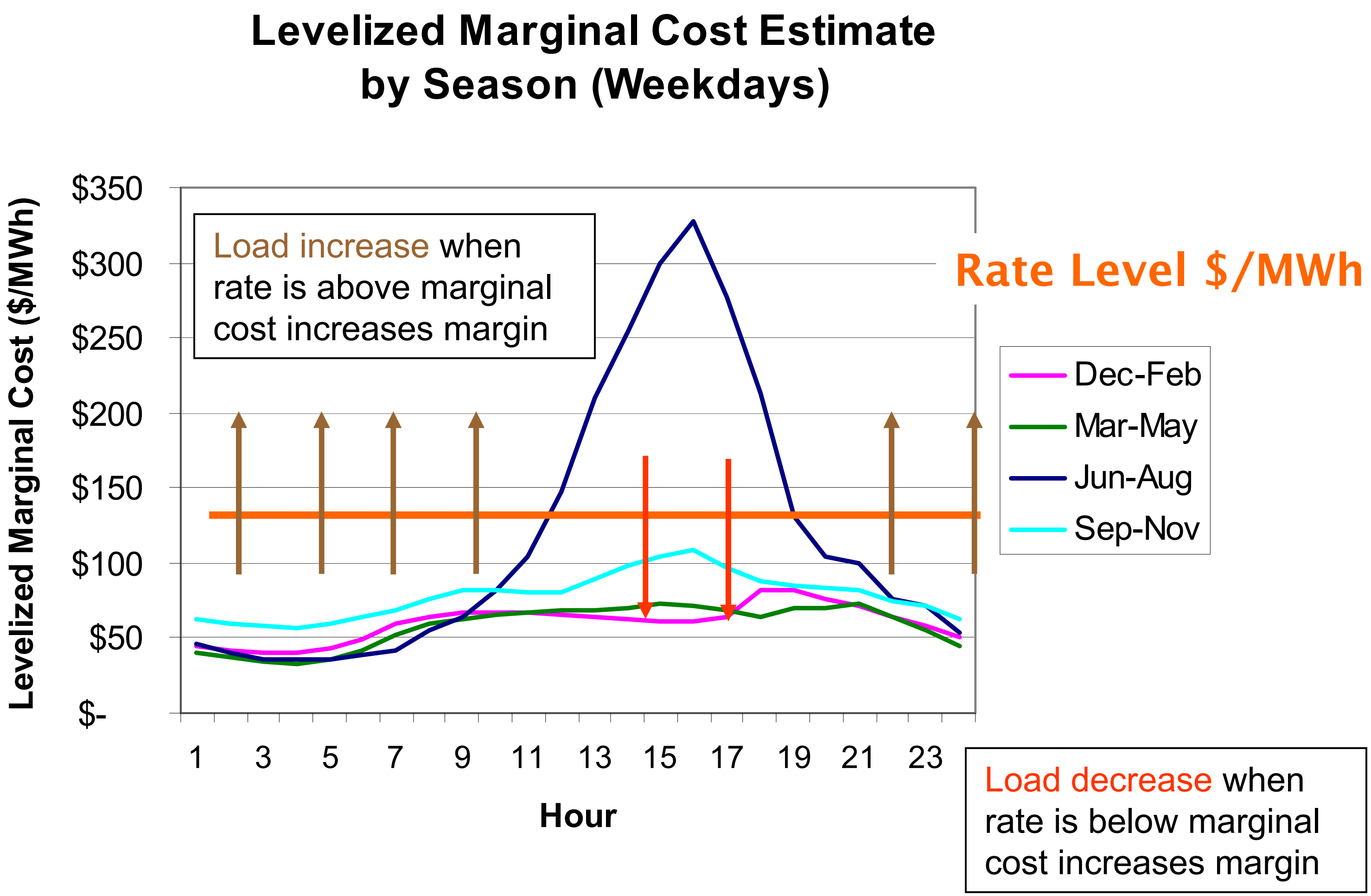
(d) spinning reserve in excess of requirements in WR1

(e) off-line generation which qualifies as nonspinning reserve (see definition)

4.3 Voluntary vs. Mandatory Rates

- Mandatory rates
  - *Issue: mandatory rates definitely increase participation and can improve overall efficiency (= sum over all customers of customer-specific net benefits).*
  - *However, not all customers see positive net benefits under mandatory rates. For example, mandatory TOU rates can harm customers who have relatively more on-peak consumption but cannot reduce on-peak consumption easily, despite the high on-peak rates.*
- Voluntary rates
  - *Issue: voluntary rates always yield a positive net (expected) benefit for participants, as revealed by their rational participation decisions. However, free-riders who see a bill decrease without doing anything can cause revenue loss to the offering utility, thus raising rates for non-participants*
  - *"Self-supporting rate options" are designed to produce a positive margin (= utility cost savings - revenue loss), which can be shared as a benefit (e.g., lower rates) for the non-participants*

Self-supporting Rate Options



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Chapter 5 Illustrative DR design assessment

5.1 Select DR candidates

5.2 Evaluate bill impacts and qualitative summary

5.3 Estimate expected load reduction

5.1 Select DR candidates

- We selected a set of DR rates and program designs to illustrate the screening methodology
- We selected these candidates from a fairly comprehensive list of DR program and rate candidates based on the ideal rate, the rate survey and characterized key attributes
- They provide a broad spectrum of potential rates, customer classes, control methods, enabling technologies, conditions of dispatch, and targeted loads
- There are many other excellent candidate designs that can be analyzed using these screening methods

Initial list of DR Rates and programs

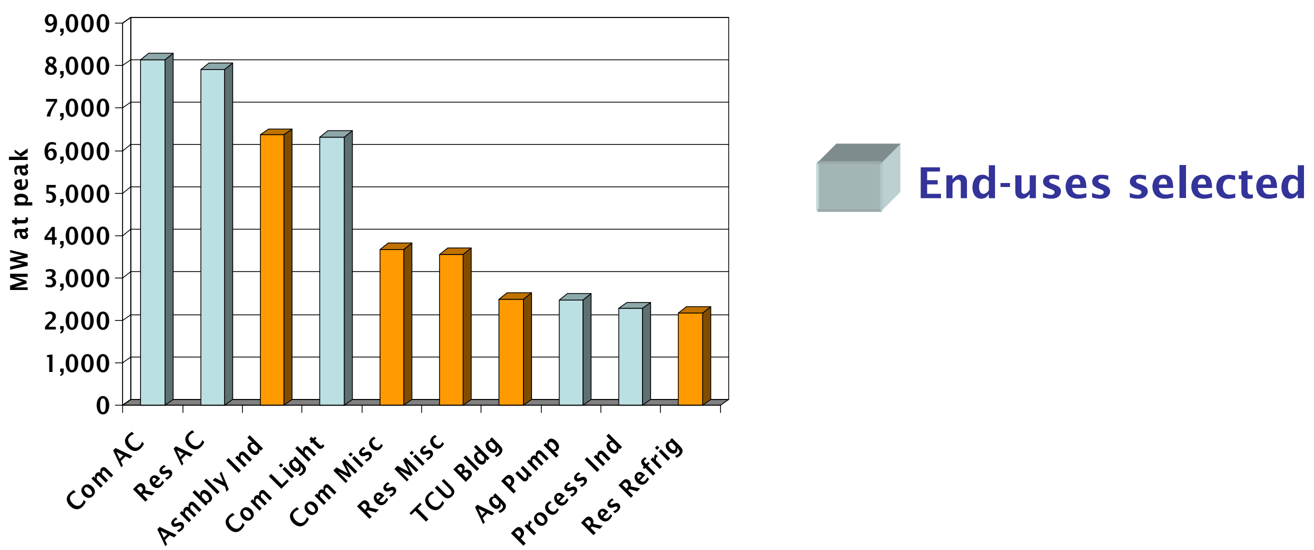
#	type	customer class usually on this rate	peak demand rationing mechanism	customer price established by	time scale on which price level varies	advance notification of price changes	advance notification of curtailment	minimum metering required for settlement	customer receives reservation or performance payment	customer receives penalty for non-compliance	who controls load?
1	flat energy	small	no	tariff	no	no	no	kWh	no	no	customer
2	tiered energy	small	no	tariff	no	no	no	kWh	no	no	customer
3	Hopkinson	large	no	tariff	no	no	no	kWh + kW	no	no	customer
4	TOU	small+large	price	tariff	period	no	no	TOU	no	no	customer
5	TOU + tiered	small	price	tariff	period	no	no	TOU	no	no	customer
6	CPP + flat	small	price	tariff	period	D/H	no	interval	no	no	customer
7	CPP + tiered	small	price	tariff	period	D/H	no	interval	no	no	customer
8	CPP + TOU	small+large	price	tariff	period	D/H	no	interval	no	no	customer
9	RTP no CBL	large	price	market	hourly	D/H	no	interval	no	no	customer
10	RTP w/ CBL	large	price	mkt+tar	hourly	D/H	no	interval	no	no	customer
11	DLC + flat	small	quant	tariff	no	no	D/H/M	kWh	yes	yes	utility
12	DLC + tiered	small	quant	tariff	no	no	D/H/M	kWh	yes	yes	utility
13	DLC + TOU	small	hybrid	tariff	period	no	D/H/M	TOU	yes	yes	utility
14	DLC + CPP buy-thru	small	hybrid	tariff	hourly	D/H	D/H/M	interval	yes	no	utility
15	DLC + RTP buy-thru	small	hybrid	mkt+tar	hourly	D/H	D/H/M	interval	yes	no	utility
16	DSS + flat	small	quant	tariff	no	no	no	kWh	no	yes	either
17	DSS + tiered	small	quant	tariff	no	no	no	kWh	no	yes	either
18	DSS + TOU	small	hybrid	tariff	period	no	no	TOU	no	yes	either
19	DSS + CPP buy-thru	small	hybrid	tariff	hourly	D/H	no	interval	no	no	customer
20	DSS + RTP buy-thru	small	hybrid	mkt+tar	hourly	D/H	no	interval	no	no	customer
21	I/C + flat	large	quant	tariff	no	no	D/H/M	interval	yes	yes	customer
22	I/C + TOU	large	hybrid	tariff	period	no	D/H/M	interval	yes	yes	customer
23	I/C + CPP buy-thru	large	hybrid	tariff	hourly	D/H	D/H/M	interval	yes	no	customer
24	I/C + RTP	large	hybrid	market	hourly	D/H	D/H/M	interval	yes	yes	customer
25	I/C + RTP buy-thru	large	hybrid	mkt+tar	hourly	D/H	D/H/M	interval	yes	no	customer
26	DB	large	hybrid	market	hourly	D/H	no	interval	yes	no	customer

Selection of Illustrative List

- We narrowed the list of initial possible DR programs and rates based on three primary screening criteria
  - *Technical potential*
  - *Customer factors*
  - *Capacity value*
- The illustrative list includes both pricing-based and quantity-based approaches

Top Ten Contributors to System Peak

- For quantity-based programs we focused on major sectors and end-uses in Calfornia.
- Selected sectors are highlighted in the peak load contribution in the State



Data from CEC Demand Forecast Office

Non-time critical customer loads

- In addition to the large end-use segments, there are smaller load segments on less time critical customer loads that have potential for demand response.
  - *Pools*
  - *Electric water heat*

- These are often called the 'low-hanging' fruit.

2001 California Peak Demand		
End Use	Peak Demand (MW)	Pct
Com AC	8,139	15%
Res AC	7,917	14%
Assembly Industry	6,373	11%
Com Light	6,322	11%
Com Misc	3,674	7%
Res Misc	3,556	6%
TCU Buildings	2,508	4%
Ag & Water Pumping	2,487	4%
Process Industry	2,289	4%
Res Refrigerator	2,175	4%
Com Ventilation	1,946	3%
Res Cooking	1,433	3%
Mining and Construction	1,095	2%
Res Clothes Dryers	1,086	2%
Com Refrigerators	996	2%
Res Swimming Pool Pump	588	1%
Res Television	548	1%
Res Single Family Hot Water	409	1%
Res Freezer	400	1%
Res Dishwashing	377	1%
Com Office Equipment	314	1%
Res Spa Pump	270	0%
Res Multi Family Hot Water	209	0%
Res Water beds	162	0%
Res Clothes washer	131	0%
Com Domestic hot water	129	0%
Com Exterior Lighting	111	0%
Com Cooking	102	0%
Res Spa Heater	49	0%
Res Solar Hot Water Pump	36	0%
Res Pool Heating	9	0%
Res Solar Domestic Hot Water	4	0%
Res Solar Pool	0	0%
Total	**55,846**	**100%**

Illustrative candidate DR rates

Sector	Original Rate Type	New Rate Type	Target Load	Who Controls	Enabling Technology Assumed	Control Method	Conditions of dispatch
Residential	Tier (E-1)	Tier (E-1)	A/C	utility	PCT or switch	utility remotely cycles A/C or sets back thermostat, no override	emergency only
Residential	Tier (E-1)	TOU (no tiers)	whole house	customer	optional	elasticity to TOU rate	all hours
Residential	Tier (E-1)	DSS	whole house	utility	optional	firm service level, no buythrough during critical hours	economic ~40 hours per year
Residential	Tier (E-1)	CPP-flat (E-1)	A/C	shared	PCT	thermostat setback w/ override + elasticity to CPP rate	economic ~40 hours per year
Small Office	TOU (A-10)	TOU (A-10)	A/C	shared	PCT	thermostat setback w/override	economic ~40 hours per year
Retail / Large Office	TOU (A-10)	TOU (A-10)	lighting	utility	dimmable ballast	utility remotely controls customer lighting	emergency only
Retail / Large Office	TOU (A-10)	CPP-TOU (A10)	whole building	shared	PCT or EMS	thermostat setback w/ override + EMS + elasticity to CPP rate	economic ~40 hours per year
Industrial	TOU (E-20)	I/C (E-20)	process	shared	optional	curtailment call + energy manager response	economic ~100 hours per year
Industrial	TOU (E-20)	I/C (E-20)	process	utility	switch	utility control of customer load	emergency only
Industrial	TOU (E-20)	DSS + RTP	process	shared	optional	firm service level, RTP buythrough at all hours	all hours

5.2 Bill Impacts and Qualitative Summary

- For each illustrative rate design we have characterized the expected customer bill impact from the rate change.
- We have also developed a qualitative summary of its attributes. **Note that these ratings are preliminary generalizations, and could change as details are fleshed out in the rate forms and in market rules.**

	Simplicity	Avoids free riders	Control		Value		
			Utility	Customer	Planning	Operating	Emergency
Residential TOU Rate	⊙	◉	●	⊙	◉	●	●

○ ⊙ ◉ ◉ ●
Good → Poor

- The attributes are:
  - ***Simplicity****: represents the similarity of the rate form to current customer rates, and the amount of effort required by the customer to control their bill or effect a demand reduction in the time of need.*
  - ***Avoids free riders:*** *indicates the resistance of the rate form to free rider effects. A good rating indicates that there is minimal bill change unless the customer reduces their demand when needed.*
  - ***Control****: indicates how much control each party has over the attainment of demand reduction.*
  - ***Value****:*
    - Planning: provides demand reductions that can be incorporated into resource acquisition decisions.
    - Operating: provides demand reductions that can substitute for operating reserves.
    - Emergency: provides demand reduction at time of system emergencies to avoid or reduce outages.

TOU Rate Qualitative Example

	Simplicity	Avoids free riders	Control		Value		
			Utility	Customer	Planning	Operating	Emergency
Residential TOU Rate	⊙	◉	●	⊙	⦿	●	●

○ ⊙ ⦿ ◉ ●
Good → Poor

- Attributes
  - *Simplicity: In the TOU example, we consider the rate to be simple because it is consistent and predictable.*
  - *Avoids free riders: Depending upon the way revenue neutrality is maintained in the rate, TOU could result in significant revenue shifting even without any changes in customer usage.*
  - *Control: In the TOU example, the utility has almost no control, as the TOU rate does not vary for emergency conditions. The customer has full control over their consumption decisions (even if they may not lead to the best outcome for the utility)*
  - *Value*
    - For planning, TOU is ranked in the middle, as the load reductions will appear in recorded loads and therefore be incorporated into future forecasts, but the load reductions are not "guaranteed."
    - For Operating, the demand reduction cannot be dispatched and could not substitute for operating reserves.
    - For Emergency, the demand reduction cannot be dispatched to avoid outages.

Residential Tier Rate with PCT or Switch for Emergency Events

	Simplicity	Avoids free riders	Control		Value		
			Utility	Customer	Planning	Operating	Emergency
Res Tier w/ PCT or Switch	○	○	○	⊙	●	●	○

○ ⊙ ◉ ⊙ ●
Good → Poor

- This example would be dispatched for emergencies (to avoid outages) only. Other forms could be offered that are dispatched for economic or other reasons.
- Uses current tiered rates, so no rate disruption and no free riders.
- Equipment-based (utility or ISO activated), so minimal customer involvement needed unless override option is offered and exercised.
- Offers high emergency value by replacing full outages with A/C reductions.

Rate Impact of a PCT or Switch Emergency Program

- $5/kWh customer discount when exercised.
- Impact table assumes that A/C accounts for 50% of the customers' demand during the peak
- Bill impact shown for a one hour emergency operation
- Bill reductions can be larger than those achieved under price-based response programs

% Bill Change	Monthly kWh											
Monthly Load Factor	100	200	300	400	500	600	800	1000	1500	2000	2500	3000
10%	-30%	-30%	-30%	-30%	-28%	-25%	-21%	-18%	-15%	-13%	-13%	-12%
20%	-15%	-15%	-15%	-15%	-14%	-13%	-11%	-9%	-7%	-7%	-6%	-6%
30%	-10%	-10%	-10%	-10%	-9%	-8%	-7%	-6%	-5%	-4%	-4%	-4%
40%	-7%	-7%	-7%	-7%	-7%	-6%	-5%	-5%	-4%	-3%	-3%	-3%
50%	-6%	-6%	-6%	-6%	-6%	-5%	-4%	-4%	-3%	-3%	-3%	-2%
60%	-5%	-5%	-5%	-5%	-5%	-4%	-4%	-3%	-2%	-2%	-2%	-2%
70%	-4%	-4%	-4%	-4%	-4%	-4%	-3%	-3%	-2%	-2%	-2%	-2%

Residential TOU Rate

	Simplicity	Avoids free riders	Control		Value		
			Utility	Customer	Planning	Operating	Emergency
Residential TOU Rate	⊙	⊙	●	⊙	◉	●	●

○ ⊙ ◉ ⊙ ●
Good → Poor

- Rate form
  - *Simple form could be 2 periods: Summer on peak, and all other hours*
  - *More complicated form could have tiers within each TOU period. Without tiers, free rider impacts would be severe. Even with tiers, there is free rider risk for customers will relatively low on-peak usage*
- Would rely upon customer price elasticity for price reductions.
- The value of demand reduction could be captured in utility planning.

Example of Bill Impacts of TOU Rate without Tiers

- Residential TOU rate (with no tiers) could drive up bills for small users, so mandatory TOU would face significant opposition
- Abandonment of tier structure also provides windfall savings for the largest consumers

% Rate Increase for Movement from PG&E E-1 to a TOU Rate
(Smr Peak 3 times the rate for all other hours)

% Bill Change	Monthly kWh											
OnPeak %	100	200	300	400	500	600	800	1000	1500	2000	2500	3000
3%	0%	0%	0%	0%	-1%	-12%	-24%	-35%	-47%	-52%	-55%	-56%
4%	1%	1%	1%	2%	1%	-10%	-23%	-34%	-46%	-51%	-54%	-56%
5%	3%	3%	3%	3%	2%	-9%	-22%	-32%	-45%	-50%	-53%	-55%
6%	4%	4%	4%	5%	4%	-8%	-20%	-31%	-44%	-50%	-52%	-54%
7%	6%	6%	6%	6%	6%	-6%	-19%	-30%	-43%	-49%	-52%	-53%
8%	7%	7%	7%	8%	7%	-5%	-18%	-29%	-42%	-48%	-51%	-53%
9%	8%	8%	8%	9%	9%	-3%	-17%	-28%	-42%	-47%	-50%	-52%
10%	10%	10%	10%	10%	10%	-2%	-15%	-27%	-41%	-46%	-49%	-51%
11%	11%	11%	11%	12%	12%	0%	-14%	-26%	-40%	-46%	-49%	-50%
12%	12%	12%	12%	13%	14%	1%	-13%	-25%	-39%	-45%	-48%	-50%
13%	14%	14%	14%	15%	15%	2%	-11%	-24%	-38%	-44%	-47%	-49%
14%	15%	15%	15%	16%	17%	4%	-10%	-23%	-37%	-43%	-46%	-48%
15%	16%	16%	16%	18%	19%	5%	-9%	-21%	-36%	-42%	-45%	-47%

- TOU rates, however, can maintain a tier structure (see PG&E E-7 tariff)

Residential Demand Subscription

	Simplicity	Avoids free riders	Control		Value		
			Utility	Customer	Planning	Operating	Emergency
Res Demand Subscription	◉	⊙	○	◉	○	○	○

○ ⊙ ◉ ⊙ ●
Good → Poor

- Customers subscribe to a firm service level with a monthly $/kW-mo charge. Customers must not exceed this level during notice periods.
- Energy rates are reduced, but can maintain tier structure to minimize free rider bill impacts.
- Customers can reduce their bills by subscribing to a level below their maximum demand
- Subscription level can be enforced with a limiter device, or with a very high price for excess usage.
- If customers subscribe to their maximum demand, they need not later their behavior. For those customers that subscribe to lower levels of demand, however, some education and effort will be required for them to reduce their loads.

Example of Demand Subscription

- Demand subscription charge = $10.92/kW-mo. (30% of total revenues).
- Other residential tier $/kWh rates reduced by 30%.
- Rate is revenue neutral based on average DS of 95% of max demand.
- Large users receive a relative lower % discount because the DS charge in this example is constant ($/kW-mo), while the average rate increases with size.

Load Reduction by Reliability Level (kW) for a 30% annual load factor customers

Demand subscription	Monthly kWh											
level (% of annual max)	100	200	300	400	500	600	800	1000	1500	2000	2500	3000
100%	-	-	-	-	-	-	-	-	-	-	-	-
90%	0.05	0.09	0.14	0.18	0.23	0.27	0.37	0.46	0.69	0.91	1.14	1.37
80%	0.09	0.18	0.27	0.37	0.46	0.55	0.73	0.91	1.37	1.83	2.28	2.74
70%	0.14	0.27	0.41	0.55	0.69	0.82	1.10	1.37	2.06	2.74	3.43	4.11
60%	0.18	0.37	0.55	0.73	0.91	1.10	1.46	1.83	2.74	3.65	4.57	5.48
50%	0.23	0.46	0.69	0.91	1.14	1.37	1.83	2.28	3.43	4.57	5.71	6.85
40%	0.27	0.55	0.82	1.10	1.37	1.64	2.19	2.74	4.11	5.48	6.85	8.22

Bill Discount (for 30% load factor customers)

Demand subscription	Monthly kWh											
level (% of annual max)	100	200	300	400	500	600	800	1000	1500	2000	2500	3000
100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
90%	4%	4%	4%	4%	4%	3%	3%	3%	2%	2%	2%	2%
80%	8%	8%	8%	8%	8%	7%	6%	5%	4%	4%	4%	3%
70%	12%	12%	12%	12%	12%	10%	9%	8%	6%	6%	5%	5%
60%	17%	17%	17%	16%	16%	14%	12%	10%	8%	7%	7%	7%
50%	21%	21%	21%	21%	20%	17%	15%	13%	10%	9%	9%	8%
40%	25%	25%	25%	25%	24%	21%	18%	15%	12%	11%	11%	10%

Customer welfare loss from self-selected reduced reliability is not shown.

Example of Demand Subscription with TOU Energy

- Similar to the prior demand subscription example, but has increased free rider risk and increased planning value.
- Combination of facilities charge and subscription charge
- Usage up to subscription pays TOU
- Usage in excess of subscription pays 125% of balancing energy

Sample Rate Form

Demand Subscription with TOU	Rate	Rate Unit
Demand Charge ($/kW-mo)		
Facilities Charge (T&D, Reg Asset, CTC)	5.45	$/kW-mo
Subscription Charge for Contract Dmd	3.30	$/kW-mo
Energy Charge ($/kWh)		
DWR, Public Goods and Nuclear Decom (all kWh)	0.010	$/kWh
Nonfirm Energy		
Summer On Peak	0.082	$/kWh
Summer Partial-Peak	0.061	$/kWh
Summer Off Peak	0.042	$/kWh
Winter-Partial	0.055	$/kWh
Winter-Off	0.044	$/kWh

Residential Critical Peak Pricing

	Simplicity	Avoids free riders	Control		Value		
			Utility	Customer	Planning	Operating	Emergency
Res CPP	⊙	◉	◎	◉	◎	◎	◎

○ ⊙ ◉ ◎ ●
Good → Poor

- High price signal sent only at times of severe system need (limited to a small number of hours per year).
- There can be a free rider effect, depending upon how the rate is designed for revenue neutrality.
- Primarily relies upon customer price demand elasticity for demand reductions.
- Planning value could increase once experience is gained with the program.
- Could be linked with control devices like PCTs to automatically effect a load drop. This would move the value characteristics closer to that of a PCT or switch program.

Rate Impact of CPP

- 90 cents per kWh CPP rate, and 4 hour CPP event in the month
- Smaller users have less peak usage, but larger % price increase during CPP
- The users that could provide the largest reductions would see small bill changes (because of their large base bill) which questions the likelihood of their participation

Peak kW Change	Monthly kWh											
Monthly Load Factor	100	200	300	400	500	600	800	1000	1500	2000	2500	3000
10%	(0.9)	(1.9)	(2.8)	(3.3)	(2.2)	(2.7)	(2.3)	(2.9)	(3.5)	(4.7)	(5.9)	(7.1)
20%	(0.5)	(0.9)	(1.4)	(1.6)	(1.1)	(1.3)	(1.2)	(1.4)	(1.8)	(2.4)	(3.0)	(3.5)
30%	(0.3)	(0.6)	(0.9)	(1.1)	(0.7)	(0.9)	(0.8)	(1.0)	(1.2)	(1.6)	(2.0)	(2.4)
40%	(0.2)	(0.5)	(0.7)	(0.8)	(0.6)	(0.7)	(0.6)	(0.7)	(0.9)	(1.2)	(1.5)	(1.8)
50%	(0.2)	(0.4)	(0.6)	(0.7)	(0.4)	(0.5)	(0.5)	(0.6)	(0.7)	(0.9)	(1.2)	(1.4)
60%	(0.2)	(0.3)	(0.5)	(0.5)	(0.4)	(0.4)	(0.4)	(0.5)	(0.6)	(0.8)	(1.0)	(1.2)
70%	(0.1)	(0.3)	(0.4)	(0.5)	(0.3)	(0.4)	(0.3)	(0.4)	(0.5)	(0.7)	(0.8)	(1.0)

% Bill Change	Monthly kWh											
Monthly Load Factor	100	200	300	400	500	600	800	1000	1500	2000	2500	3000
10%	-30%	-30%	-30%	-25%	-13%	-12%	-6%	-6%	-4%	-3%	-3%	-3%
20%	-15%	-15%	-15%	-13%	-7%	-6%	-3%	-3%	-2%	-2%	-2%	-2%
30%	-10%	-10%	-10%	-8%	-4%	-4%	-2%	-2%	-1%	-1%	-1%	-1%
40%	-7%	-7%	-7%	-6%	-3%	-3%	-2%	-1%	-1%	-1%	-1%	-1%
50%	-6%	-6%	-6%	-5%	-3%	-2%	-1%	-1%	-1%	-1%	-1%	-1%
60%	-5%	-5%	-5%	-4%	-2%	-2%	-1%	-1%	-1%	-1%	-1%	-1%
70%	-4%	-4%	-4%	-4%	-2%	-2%	-1%	-1%	-1%	0%	0%	0%

Bill changes reflect only the effect of reduced usage in response to the CPP price signal. Higher costs due to remaining consumption under the CPP rate are not shown in the table. Those higher costs would be offset by lower overall rates during non-CPP hours to achieve class revenue neutrality --- but depending upon how the revenue neutrality is implemented, there may be significant bill impacts for individual customers.

Commercial PCT w/ Override

	Simplicity	Avoids free riders	Control		Value		
			Utility	Customer	Planning	Operating	Emergency
Com PCT w/ Override	○	○	○	⊙	●	◉	⊙

○ ⊙ ◉ ⊙ ●
Good → Poor

- Can use current rates, so no rate disruption.
- If a pay for performance incentive form is used, then there free riders are not an issue.
- Equipment-based (utility or ISO activated), so minimal customer involvement needed unless override option is exercised.
- Operating value will depend upon operating rules, which remain in flux.
- Offers high emergency value by replacing full outages with A/C reductions.
- Note that the override option reduces the value provided by the program (compared to a program that does not allow overrides).

Commercial Emergency Program

	Simplicity	Avoids free riders	Control		Value		
			Utility	Customer	Planning	Operating	Emergency
Commercial Emergency	○	○	○	●	●	●	○

○ ⊙ ⊙ ⊙ ●
Good → Poor

- Base rate is standard utility tariff.
- Participation credit for demand reduction during emergency periods, so no free rider issues.
- Equipment-based, such as dimmable ballasts.
- Assuming a credit level based on average customer value for avoided outages (e.g. $5/kWh), a 60% load factor customer could achieve a 3% reduction in their annual bill by shedding 50% of their summer peak load during one 4 hour emergency event during the year

Commercial Critical Peak Pricing

	Simplicity	Avoids free riders	Control		Value		
			Utility	Customer	Planning	Operating	Emergency
Commercial CPP	⊙	◉	◎	◉	◎	◎	◎

○ ⊙ ◉ ◎ ●
Good → Poor

- High price signal sent only at times of severe system need (limited to a small number of hours per year).
- CPP program can also lower the maximum billing demand for the month to offer stronger price incentive.
- Otherwise applicable rate can mimic the current rate forms, but adjustments to maintain revenue neutrality may result in free rider impacts.
- Can be linked with control devices like PCTs or Energy Management Systems to automatically effect a load drop.
  - *Otherwise, relies upon customer price demand elasticity for demand reductions.*
  - *Attribute summary above assumes that control devices are not employed. Use of control devices and non-override conditions would increase the value of the program.*

Commercial Bill Impacts of CPP

- Commercial CPP for Medium Commercial (39,000 kWh-mo usage)
  - *Negative .05 price-demand elasticity*
  - *$0.90/ kWh CPP price, and monthly billing demand lowered to demand during CPP event.*
- Significant bill savings across all load factors. (*Savings are relative to the bill customers would receive if they were to not reduce usage in response to the CPP signal.)*

	Non- CPP		During CPP			
Load Factor	Maximum kW	Avg Rate	Demand Change (%)	Demand Change (kW)	Bill Change ($)	Bill Change %
20%	273	0.2018	-17%	(47)	$ (663)	-8%
30%	182	0.1776	-20%	(37)	$ (519)	-7%
40%	137	0.1656	-22%	(30)	$ (425)	-7%
50%	109	0.1583	-23%	(26)	$ (359)	-6%
60%	91	0.1535	-24%	(22)	$ (311)	-5%
70%	78	0.1500	-25%	(19)	$ (274)	-5%
80%	68	0.1475	-26%	(17)	$ (244)	-4%
90%	61	0.1454	-26%	(16)	$ (221)	-4%

Bill changes reflect only the effect of reduced usage in response to the CPP price signal. Higher costs due to remaining consumption under the CPP rate are not shown in the table. Those higher costs would be offset by lower overall rates during non-CPP hours to achieve class revenue neutrality --- but depending upon how the revenue neutrality is implemented, there may be significant bill impacts for individual customers.

Commercial Demand Subscription

	Simplicity	Avoids free riders	Control		Value		
			Utility	Customer	Planning	Operating	Emergency
Com Demand Subscription	⊙	⊙	◉	◉	⊙	◉	◉

○ ⊙ ◉ ⊙ ●
Good → Poor

- Similar in concept to curtailable rates, but instead of lower demand charge, the billing demand is lowered.
- Customers subscribe to a firm service level with a monthly $/kW-mo charge. Customers must not exceed this level during notice periods.
- Customers can reduce their bills by subscribing to a level below their maximum demand
- If the bill discount is self funded through cost savings, there is no free rider impact.
- Subscription level can be enforced with a very high price for excess usage

Commercial Demand Subscription

- DS can offer significant bill savings for customers willing to contain their usage during periods of system need.
- Example shown for medium commercial (A-10 TOU) summer monthly bill for customer with typical TOU shape and 39,000 kWh usage per month.

Potential Bill Reductions with Reduced Demand Subscription Levels

Demand subscription level (% of Max Demand)	Unsubscribed kW	Bill Reduction ($)	Bill Reduction (%)
100%	-	$ -	0.0%
90%	3.40	$ 35	2.2%
80%	6.80	$ 71	4.4%
70%	10.20	$ 106	6.5%
60%	13.60	$ 142	8.7%
50%	17.00	$ 177	10.9%
40%	20.40	$ 213	13.1%
30%	23.80	$ 248	15.2%
20%	27.20	$ 284	17.4%
10%	30.60	$ 319	19.6%

Assumes demand and energy tariffs remain unchanged. (DSS discount is self funded through cost reductions. No rate redesign is needed).
Example does not include customer welfare loss from reduced reliability.

Industrial Interruptible/Curtailable

		Avoids free	Control		Value		
	Simplicity	riders	Utility	Customer	Planning	Operating	Emergency
Ind I/C - Customer Control	⊙	◉	◉	○	⊙	●	◉
Ind I/C - Utility Control	⊙	◉	○	◉	●	●	⊙

○ ⊙ ◉ ◉ ●
Good → Poor

- Customers required to drop load to firm service level during notice periods
  - *Customer control – customer can elect to consume excessive energy at a high cost*
  - *Utility control – load shedding is automated and not overrideable*
- Predictability and dependability of load shedding will depend upon control mode and how punitive it will be for customers to override.

Real Time Pricing

	Simplicity	Avoids free riders	Control		Value		
			Utility	Customer	Planning	Operating	Emergency
Real Time Pricing	●	⦿	◉	◉	⊙	◉	●

○ ⊙ ◉ ⦿ ●
Good → Poor

- Hourly varying energy price based on the balancing energy price in the market.
- Fixed or demand-based charges collect remaining revenue requirement.
- Can have significant free rider impacts.
- Utility has limited control through price signals, and customer has limited control over their bill because they may not be able to respond appropriately to all the varying price signals.
- Relies upon customer elasticity (and customer attention to varying prices) for demand response.

Demand Subscription with RTP

	Simplicity	Avoids free riders	Control		Value		
			Utility	Customer	Planning	Operating	Emergency
Dmd Subscription w/ RTP	●	⊙	○	⊙	⊙	⊙	⊙

○ ⊙ ⊙ ⊙ ●
Good → Poor

- Same complexity and free rider issues as regular RTP, but improves upon the control and value to the utility.
- Subscription charge collects all energy costs for the contract demand block of power.
- Deviations from the contract demand are billed/credited at the balancing energy price

Sample Rate Form

Demand Subscription with RTP	Rate	Rate Unit
Demand Charge ($/kW-mo)		
Facilities Charge (T&D, Reg Asset, CTC)	13.80	$/kW-mo
Facilities Charge to Maintain Revenue Neutrality	8.61	$/kW-mo
Subscription Charge for Contract Demand & Block Energy	36.69	$/kW-mo
Energy Charge ($/kWh)		
DWR, Public Goods and Nuclear Decom (all kWh)	0.033	$/kWh
Deviations from contract demand gets balancing energy price	*Varies*	$/kWh

Industrial Emergency Program

	Simplicity	Avoids free riders	Control		Value		
			Utility	Customer	Planning	Operating	Emergency
Commercial Emergency	○	○	○	●	●	●	○

- Same attributes as Commercial Emergency program.
- Base rate is standard utility tariff.
- Participation credit for demand reduction during emergency periods, so no free rider issues.
- Equipment-based, such as dimmable ballasts.
- Assuming a credit level based on average customer value for avoided outages. (e.g. $5/kWh), an 80% load factor customer could see a 1.5% annual bill reduction for shedding 50% of their summer peak load for one 4 hour event during the year.

Industrial Bill Impacts of CPP (1)

	Simplicity	Avoids free riders	Control		Value		
			Utility	Customer	Planning	Operating	Emergency
Ind CPP	⊙	⊙	⊙	⊙	⊙	⊙	⊙

- Industrial (E-20) customer (648,000 kWh-mo usage)
  - *Negative .05 price-demand elasticity*
  - *$0.90/ kWh CPP price, and monthly peak billing demands lowered to demand during CPP event.*
- Significant bill savings across all load factors. (*Savings are relative to the bill customers would receive if they were to not reduce usage in response to the CPP signal.)*

	Non- CPP		During CPP			
Load Factor	Maximum kW	Avg Rate	Demand Change (%)	Demand Change (kW)	Bill Change ($)	Bill Change %
20%	4,498	0.1905	-19%	(838)	$ (15,060)	-12%
30%	2,999	0.1572	-24%	(708)	$ (12,737)	-13%
40%	2,249	0.1406	-27%	(607)	$ (10,923)	-12%
50%	1,799	0.1306	-29%	(530)	$ (9,530)	-11%
60%	1,499	0.1239	-31%	(469)	$ (8,441)	-11%
70%	1,285	0.1192	-33%	(421)	$ (7,570)	-10%
80%	1,124	0.1156	-34%	(381)	$ (6,859)	-9%
90%	1,000	0.1128	-35%	(349)	$ (6,269)	-9%

Bill changes reflect only the effect of reduced usage in response to the CPP price signal. Higher costs due to remaining consumption under the CPP rate are not shown in the table. Those higher costs would be offset by lower overall rates during non-CPP hours to achieve class revenue neutrality --- but depending upon how the revenue neutrality is implemented, there may be significant bill impacts for individual customers.

Industrial Bill Impacts of CPP (2)

- Prior slide assumed that peak demand billing determinants are reduced for load reductions during CPP event.
- If peak demands remain unchanged, then bill savings are significantly lower

	Non- CPP		During CPP			
Load Factor	Maximum kW	Avg Rate	Demand Change (%)	Peak kWh Change	Bill Change ($)	Bill Change %
20%	4,498	0.1905	-19%	(3,350)	$ (3,015)	-2%
30%	2,999	0.1572	-24%	(2,833)	$ (2,550)	-3%
40%	2,249	0.1406	-27%	(2,430)	$ (2,187)	-2%
50%	1,799	0.1306	-29%	(2,120)	$ (1,908)	-2%
60%	1,499	0.1239	-31%	(1,878)	$ (1,690)	-2%
70%	1,285	0.1192	-33%	(1,684)	$ (1,516)	-2%
80%	1,124	0.1156	-34%	(1,526)	$ (1,373)	-2%
90%	1,000	0.1128	-35%	(1,395)	$ (1,255)	-2%

Summary of Qualitative Assessment

	Simplicity	Avoids free riders	Control		Value		
			Utility	Customer	Planning	Operating	Emergency
Residential TOU Rate	⊙	⦿	●	⊙	◉	●	●
Res Tier w/ PCT or Switch	○	○	○	⦿	●	●	○
Res Demand Subscription	◉	⊙	○	◉	○	○	○
Res CPP	⊙	◉	⦿	◉	⦿	⦿	⦿
Com PCT w/ Override	○	○	○	⊙	●	◉	⊙
Commercial Emergency	○	○	○	●	●	●	○
Commercial CPP	⊙	◉	⦿	◉	⦿	⦿	⦿
Com Demand Subscription	⊙	⊙	◉	◉	⊙	◉	◉
Ind Emergency	○	○	○	●	●	●	○
Ind CPP	⊙	◉	⦿	◉	⦿	⦿	⦿
Ind I/C - Customer Control	⊙	◉	◉	○	⊙	●	◉
Ind I/C - Utility Control	⊙	◉	○	◉	●	●	⊙
Real Time Pricing	●	⦿	◉	◉	⊙	◉	●
Dmd Subscription w/ RTP	●	⦿	○	◉	⊙	◉	◉

○ ⊙ ◉ ⦿ ●
Good → Poor

5.3 Sample Designs Participation Rates: Calculations

- We use the estimated bill impacts and qualitative factors to estimate rates for the sample of rate and program designs, we chose to bound the estimates
  - *On the high end, we used a customer preference model, based on data contained in the WG 3 Momentum report*
  - *On the lower end, we used a transferability methodology based on our exhaustive literature search, program data as presented in the WG 2 reports (Quantum/Summit Blue et al), and our expert judgment*
- For voluntary, quantity-based programs, participation estimation is a critical component in deciding which programs to develop.
- We provide a detailed primer on approaches for participation estimation, and literature review in the appendices.

Sample Designs Participation Rates – Calculations (cont'd.)

Quantifying Participant Enrollment Rates I

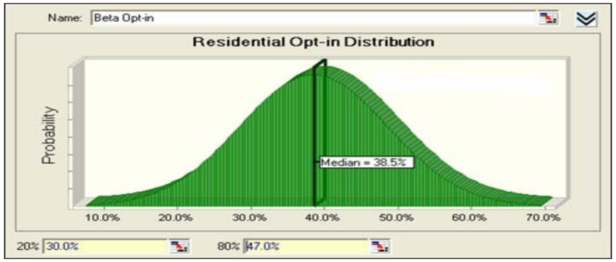
- What does the most relevant and recent research on participation rates tell us?
  - *WG3 Momentum Intelligence Customer Preference Market Research*
    - Specific to California
    - Surveyed residential and small/medium businesses
    - Tested customer preferences for different time-varying rates
    - Looked at how different rate design attributes influence the attractiveness of the offering
    - The market share estimates in the Momentum report can be considered an upper limit on participant enrollment rates. They may act as rough proxi for the share of individuals benefitting from the rates
    - Can be used to develop systematic methods to apply Momentum's results to rate designs, and enrollment rate drivers which were not tested in the study
- What are the limits?
  - *The report measures what customers prefer; it does not measure how they will behave when faced with a real option*
    - It does not measure the share of individuals who intend to switch rates
    - It does not measure the share of individuals who would follow through with intentions
  - *Customers are unfamiliar with the rates tested and often don't understand their current rates. Their decision is based on a cursory understanding not on concrete products, experience, or recommendations*
  - *The research does not account for the fact that some customers will automatically benefit from time-varying rates, regardless of effort, based on their usual daily consumption habits and load shapes.*

Sample Designs Participation Rates – Calculations (cont'd.)

Quantifying Participant Enrollment Rates II – based on Momentum Data

- We used the WG3 Customer Preference Research to systematically quantify rates and programs that were not tested in the Momentum study
  - *The study tested a range of time varying rates and design attributes. While they cover the gamut from good to bad, the range of rates and attributes is fairly broad*
  - *We used the lower and upper end estimates from the Momentum report to index the data. This was done for both opt-in and opt-out designs*
  - *We applied the information about how rate/program attributes and customer characteristics affect customer preferences to rank the rate and program designs (1-5) in relation to the designs tested in the Momentum study*
  - *We tied the rankings to the distribution, to provide a consistent quantification*
  - *The results are an estimated range for the participant enrollment cap*

- Limitations
  - *This does not take us from what customer prefer to how they'll behave*
  - *The share of customers who prefer options must be de-rated to account for the fact that*
    - not all who prefer a product intend to purchase it, and
    - not everyone carries through with their intentions.
  - *It is not clear whether the estimates of how many customers prefer a rate/option is a good proxy for the share who economically benefit from the rate/program*



Sample Designs Participation Rates – Calculations (cont'd.)

Quantifying Participant Enrollment Rates III – based on Actual Program Experience

- We used information about actual program experience to infer alternative participation rates
  - *Based on the exhaustive review of literature (most specifically the reports tied to the WG 2 initiatives, and extensive experience with DR programs*
  - *Identified the factors that make rates and DR rates/programs more attractive*
  - *Bound the default enrollment share and response with information about tested rates/programs that are more and less attractive based on their design*
    - Analysis of transferability of results
    - Calibration for the differences in quality of implementation and design
    - Expert judgment and experience

Sample Designs Participation Rates – Calculations (cont'd.)

Steady State Participation Rates for Sample DR Rate/Program Offerings

		Momentum Based (Assumes 100% awareness, 0 Transaction Costs, No Measurement of Intention)		Actual Program Experience	
Sector	**Rate/Program Design**	**Lower Bound**	**Upper Bound**	**Lower**	**Upper**
Residential	TOU Rate	33.0%	47.0%	6%	10%
Residential	Tier w/ PCT or Switch	41.0%	47.0%	5%	15%
Residential	Demand Subscription	34.0%	47.0%	5%	10%
Residential	CPP-F	34.0%	47.0%	5%	10%
Commercial	PCT w/ Override	37.0%	47.0%	3%	10%
Commercial	Emergency - utility control	37.0%	47.0%	Unknown	
Commercial	CPP	34.0%	39.0%	5%	10%
Commercial	Demand Subscription	34.0%	39.0%	5%	10%
Industrial	I/C - Customer Control			5%	20%
Industrial	I/C - Utility Control			0%	10%
Industrial	Real Time Pricing			1%	3%

Technical potential of end-use programs

- We developed an estimate of the technical potential of select end-uses and sectors and applied them to estimate state-wide reductions
- These results are aggregated from an estimate by utility and climate zone.
- Details, data sources and approach are described in the appendices.

Illustrative Sector Definition	End-use, or Technology	Commercial square feet or homes	Appliance Stock	kW per Unit Savings	Coincident Peak kW	Total technical response kW/sector
Single Family Residential	A/C PCT	7,769,887	2,905,338	0.87	2,541,319	1,945,859
Single Family Residential	A/C cycle off	7,769,887	2,905,338	2.37	6,895,801	2,744,013
Single Family Residential	Pool Pump	7,769,886	1,127,455	1.27	1,431,868	1,431,868
Small Office	A/C PCT	359,360,500	359,360,500	1.54	551,791	551,791
Small Office	Lighting	354,885,500			414,264	207,132
Retail	Lighting	890,285,500		1.61	1,433,955	716,978
Colleges	Lighting	269,290,000		0.72	193,614	96,807
Industrial Sector	Existing Control				6,201,000	306,022

Note that not all programs are additive, and the list is by no means exhaustive.

Total Penetration Assumptions

- With the estimation of participation rates, technical potential, and a high-level estimate of deration factors, we estimated the range of impact for state-wide deployment of resources.

Rate Scenario	Low Case Middle Range of Actual Program Experience	High Case Low Range of Momentum Study	Response rate (1-overrides)	Low Estimate On-peak System Demand (kW)	High Estimate On-peak System Demand (kW)
Residential PCT	10%	41%	50%	97,293	398,901
Residential A/C Cycling	10%	41%	100%	274,401	1,125,045
Residential Pool Pump	10%	41%	100%	143,187	587,066
Small Office PCT	7%	37%	50%	19,313	102,081
Small Office Lighting	7%	34%	50%	7,250	35,212
Retail Lighting	7%	34%	50%	25,094	121,886
Colleges Lighting	7%	34%	50%	3,388	16,457
Industrial Sector	5%		50%	7,651	

Appendices

- Section 1: Technical potential estimates
- Section 2: Primer on customer acceptance
  - *Methodology and approach*
  - *Literature review*
- Section 3: Bibliography and definitions

Section 1: Technical potential

Technical potential is an input to the market potential estimates of savings

1. Tech potential - Maximum savings based on engineering estimate of savings from measure and total size of market segment affected.
2. Market potential – fraction of technical potential based on how much of the market one can induce to participate

Technical potential as screening tool

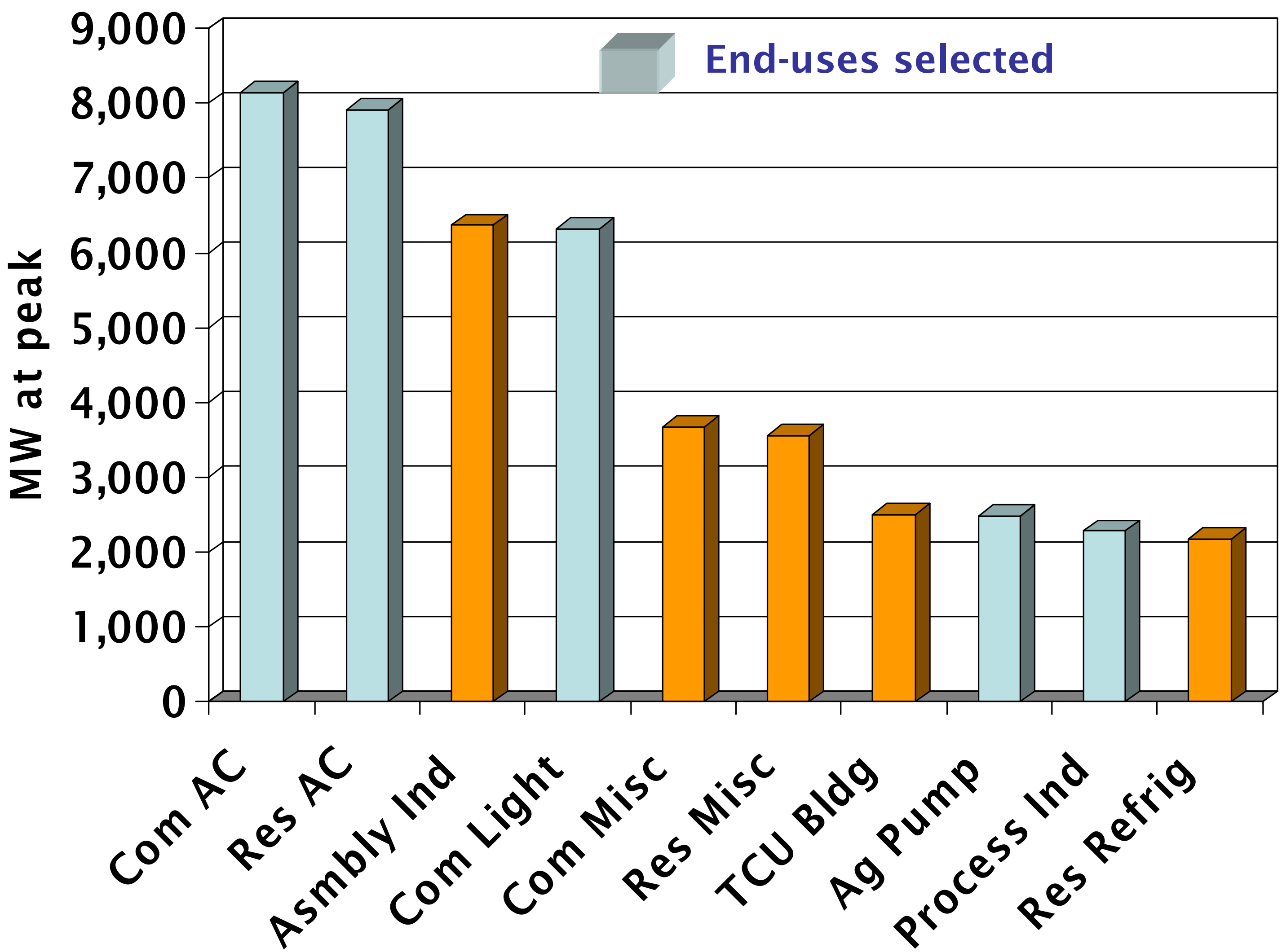
- Identifying the technical potential by segment helps target end-uses and customers with the most possible savings
- Our team developed a first order screening of California market segments, from existing sources.

Technical potential input data sources

- **Surveys and existing literature that are available on California technical potential. Those in bold were used in the development of our technical potential.**

- **CEC Demand Forecast Division - end-use coincident peak forecasting database**
- **RASS – Residential Appliance Saturation Survey**
- NRNC – Nonresidential New Construction Database
- CEUS – Commercial End-Use Survey
- **SCE/PIER PCT simulations for PCT CASE**
- CALMAC technology evaluation reports
- DEER – database of energy efficient resources
- **Nonresidential Market Share Tracking Study**

Top Ten Contributors to System Peak



Data from CEC Demand Forecast Office

Non-time critical customer loads

In addition to the large end-use segments, there are smaller load segments on less time critical customer loads that have potential for demand response.

These are often called the 'low-hanging' fruit.

2001 California Peak Demand		
End Use	Peak Demand (MW)	Pct
Com AC	8,139	15%
Res AC	7,917	14%
Assembly Industry	6,373	11%
Com Light	6,322	11%
Com Misc	3,674	7%
Res Misc	3,556	6%
TCU Buildings	2,508	4%
Ag & Water Pumping	2,487	4%
Process Industry	2,289	4%
Res Refrigerator	2,175	4%
Com Ventilation	1,946	3%
Res Cooking	1,433	3%
Mining and Construction	1,095	2%
Res Clothes Dryers	1,086	2%
Com Refrigerators	996	2%
Res Swimming Pool Pump	588	1%
Res Television	548	1%
Res Single Family Hot Water	409	1%
Res Freezer	400	1%
Res Dishwashing	377	1%
Com Office Equipment	314	1%
Res Spa Pump	270	0%
Res Multi Family Hot Water	209	0%
Res Water beds	162	0%
Res Clothes washer	131	0%
Com Domestic hot water	129	0%
Com Exterior Lighting	111	0%
Com Cooking	102	0%
Res Spa Heater	49	0%
Res Solar Hot Water Pump	36	0%
Res Pool Heating	9	0%
Res Solar Domestic Hot Water	4	0%
Res Solar Pool	0	0%
Total	**55,846**	**100%**

CEC End-use forecasting database

- Geographical – 16 demand forecast zones
- Utility – by major utility service
- Commercial - 9 end-uses and 12 building types
- Residential – 18 end-uses
  - *Residential AC segments*
    - Single family vs multi-family
    - Central systems versus room A/C
- Industrial – 19 groupings by 2 digit SIC
  - *End-uses not divided*

Technical potential estimation

Product of:

- Population of: building sf, homes, acres of irrigated land and kWh of various sectors
- Technology saturation - estimation of fraction of population or fraction of electricity consumption by a given technology
- Estimate of fraction schedules to be active during peak (i.e. res A/C in mild climates)
- Engineering or other estimates of unit potential sheddable load, W/sf

Population data

- Utility information – total electricity consumption data
- Electric consumption mapped to sectors
  - *billing information cross-referenced with data from tax assessor's info about SIC, business type etc.*
  - *prior work contained in various databases such as Nonresidential Market Share, CEC Demand Forecast, Residential Appliance Saturation Survey (RASS)*
- New construction databases
  - *McGraw-Hill Dodge database*
  - *CA Department of Finance – construction activity*
  - *CIRB – Construction Industry Research Board*

Technology saturation data

- Often generated by surveys or interviews
  - *Nonresidential Market Share,*
  - *Residential Appliance Saturation Survey (RASS)*
  - *Nonresidential New Construction (NRNC) Database*
  - *Commercial End-Use Survey (CEUS)*
- Product sales info
  - *Various market survey companies*
  - *Some manufacturer organizations publish sales data*

    ARI – air conditioner sales

    AHAM –home appliances – room air conditioners, dishwashers etc

Coincidence of equipment schedule with peak

- Affected by occupant schedules
  - *Nonresidential – low variability*
  - *Residential – higher variability*
  - *Industrial – moderate variability*
- Schedules collected by:
  - *interviews,*
  - *site surveys of control or time clock settings*
  - *field monitoring, data logging*
- Schedules can be modified by calibrated energy simulations

Engineering model

- Detailed hourly energy simulation
- Accounts for all sources of energy consumption and thermal loads
  - *Internal - People, lighting, equipment,*
  - *External – conduction, solar gains, ventilation, infiltration*
- Includes model of thermal capacitance
  - *Prior thermal conditions effect the loads of current hour. Stored cooling in thermal mass*
  - *Space temperature modeled while “floating” up to higher temperature setpoint without cooling. Duration of float period and reduction of loads at higher setpoint key to estimate of savings.*
  - *Consumption rebound modeled when temperature setup is released after curtailment period*

Examples for selected end-uses

- Residential PCT
- Residential A/C cycling
- Non-residential PCT
- Commercial lighting
- Industrial process

Programmable Communicating Thermostat Technical Potential Example

- Enabling technology – Communicating Thermostat receives emergency or economic signal from utility
- Physical activity – thermostat increases setpoint by 4ºF triggered by signal
- Technical demand savings only if:
  - *Air conditioner exists (technology saturation)*
  - *Air conditioner is ON*
  - *Signal received (100% reception assumed)*
  - *Room temperature is within 4ºF of setpoint*

Population of Homes and Technology Saturation

- Residential Appliance Saturation Survey (RASS).
  - *Stratified sample of 21,920 homes and dwelling units throughout California*
  - *Information collected on energy consuming appliances in each dwelling unit*
  - *Information collected on energy consumption, thermostat setpoints etc.*
- Appliance saturation – from surveys
  - *Example: air conditioner saturation*

    37% of single family homes have central air conditioning

    Fewer homes with A/C in mild climates

    More homes with A/C in Central Valley
- Saturation derates estimate of technical potential

Specifics for PCT engineering simulation

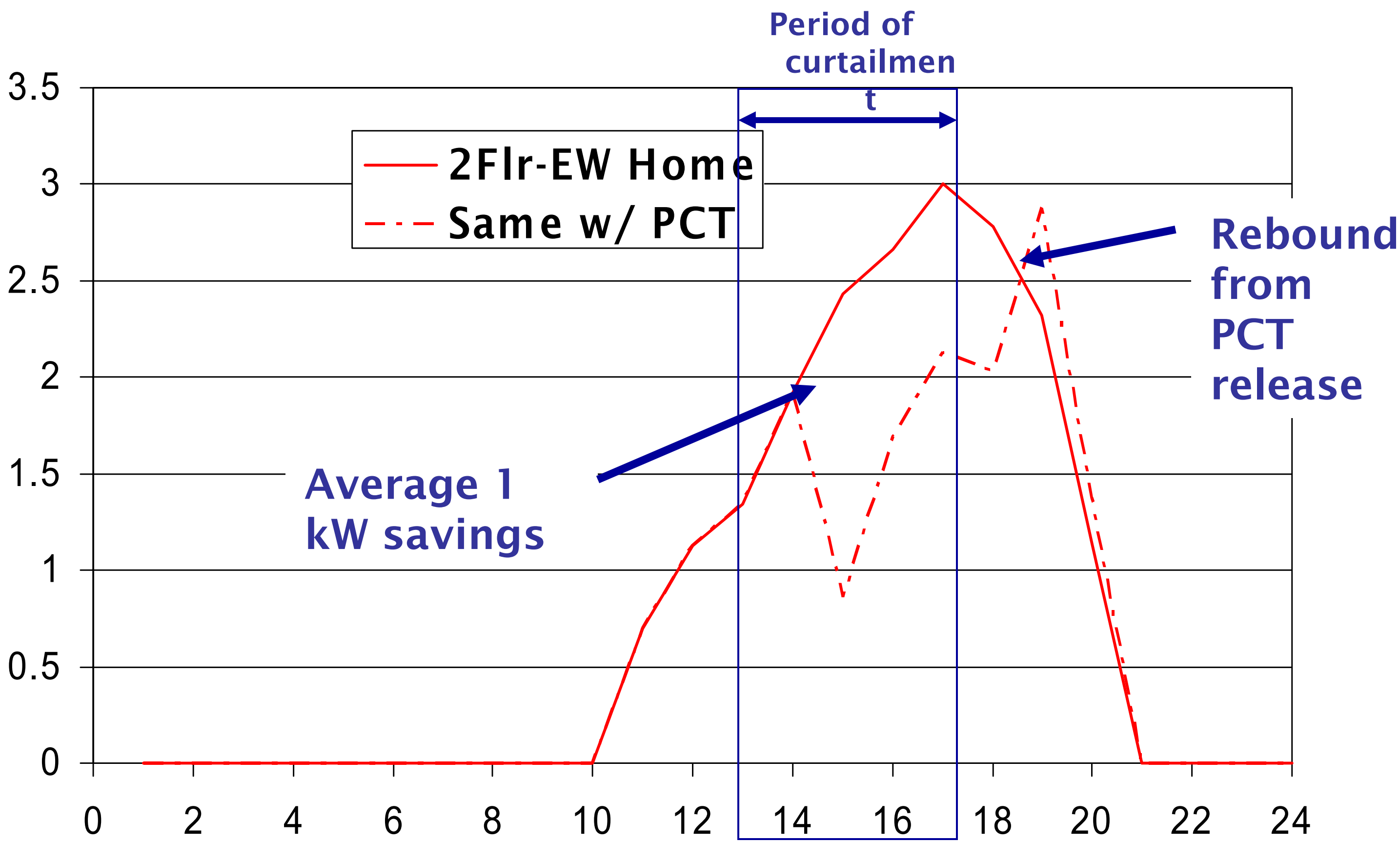
- Home simulation models for each cardinal orientation
- Two story and single story models
- Three different vintages of construction
  - *Different insulation and window properties*
- Results averaged
- 21 different t-stat schedules of load control
  - *Different start and end times between noon and 6 pm*
  - *Duration from 1 to 4 hours*
- Different base t-stat schedules
  - *T-24 schedule, constant 72°F, constant 74°F*

Example: Residential Thermostat Operation

- Data from RASS
- Survey of how residential programmable thermostats operated
- Thermostat turned off 9am – 5pm by 14% to 31% of sample
- More turned off in mild climates
- Thermostat operated like a switch

Region	Residential Programmable Thermostats turned to OFF
North Coast	31%
South Coast	37%
South Inland	20%
Central Valley	15%
Desert	14%

PCT DOE-2 results 2 – 6 pm control



Analysis Repeated for Each of the Dispatched Days

Technical potential spreadsheet for Res PCTs

Building Type	Technology	Comm. SF or dwell. units	Appliance Stock	W/sf or kW/unit savings	Total Peak kW	Technical Savings multiplier	Total technical response kW/sector
Residential Sector							
Single Family Residential	A/C PCT	*7.77E+06*	*2.91E+06*	0.9	*2.54E+06*		*1.95E+06*
PG&E							
2003	A/C PCT	*3.17E+06*	*1.03E+06*		8.30E+05		*6.40E+05*
Forecast Zone 1			7.95E+04	0.5	3.98E+04	0.69	2.74E+04
Forecast Zone 2			1.62E+05	0.8	1.30E+05	0.85	1.10E+05
Forecast Zone 3			3.22E+05	0.9	2.90E+05	0.85	2.47E+05
Forecast Zone 4			4.08E+05	0.8	3.27E+05	0.69	2.25E+05
Forecast Zone 5			5.42E+04	0.8	4.34E+04	0.69	2.99E+04
SMUD							
2003	A/C PCT	3.47E+05	2.51E+05		2.26E+05		*1.92E+05*
Forecast Zone 6		3.47E+05	2.51E+05	0.9	2.26E+05	0.85	1.92E+05

Approximately one third A/C saturation in PG&E territory

Fraction of A/C on during peak is climate dependent

Savings per home are climate (forecast zone) dependent

More Utilities and forecast zones below

Residential A/C duty cycling program

- Program curtails air conditioner consumption for a fixed period (2 hr)
- Enabling technology – radio controlled switch
- To capture entire peak two control groups are used and therefore we reduce the expected achieved savings for each group
- Estimate based on prediction of A/C load during peak.
- Same fractions of A/C OFF used as for PCT
- If passes technology screen, can use results of pilot projects or detailed engineering model

A/C cycling program

Building Type	Technology	Comm. SF or dwell. units	Appliance Stock	W/sf or kW/unit savings	Total Peak kW	Technical Savings multiplier	Total technical response kW/sector
SF Residential	**A/C cycle off**	***7.77E+06***	***2.91E+06***	2.4	***6.90E+06***		***2.74E+06***
PG&E							
2003	**A/C cycle off**	3.17E+06	1.03E+06	0.93	**2.96E+06**		***1.19E+06***
Forecast Zone 1					1.59E+04	0.35	5.48E+03
Forecast Zone 2					3.13E+05	0.43	1.33E+05
Forecast Zone 3					1.82E+06	0.43	7.74E+05
Forecast Zone 4					7.51E+05	0.35	2.59E+05
Forecast Zone 5					5.50E+04	0.35	1.90E+04
SMUD							
2003	**A/C cycle off**	3.47E+05	2.51E+05	2.17	**7.52E+05**		***3.20E+05***
Forecast Zone 6					7.52E+05	0.43	3.20E+05

Same appliance saturation as PCTs

Higher unit savings, A/C is turned completely off

Lower unit multipliers, ½ that of PCT's to account for two control groups

Nonresidential PCT Program

- Similar to residential A/C program
- Greater savings per thermostat due to greater internal loads, and tonnage.
- Assumed that all systems would be ON during peak

Commercial lighting demand response

- Segmented by occupancy type
  - *Office*
  - *Retail*
  - *College (K-12 not considered since often closed during summer)*
- Not disaggregated by climate as no climate effect on lighting
- Assumed 50% reduction in lighting

Industrial process DR

- Segmented by SIC (Standard Industrial Classification) No.
  - *Different types of industry have different mix of end-uses*
- Fairly low technical savings multiplier
  - *Based on Aspen Systems survey of industries*
    - Fraction with electronic controls that can unload of turn off equipment
    - kW of equipment that was controlled
    - kW of equipment that could be controlled
- Segment industrial market by consumption.
  - *80% of consumption by large industrial*
  - *Sophisticated user with large financial incentive*

Aspen Systems control survey in Nonresidential Market Share Tracking Study

Questions	SIC 20	SIC 35	SIC 36	SICs 20, 35, 36	SICs 21-34. 37-39
Fraction with electronic controls that turn off or unload equipment	19.7%	7.8%	20.3%	13.2%	5.1%
Total demand of controlled processes	357	131	542	320	499
Demand that can be controlled to save energy	286	79	244	201	228
Fraction of total demand available for control	**15.78%**	**4.70%**	**9.14%**	**8.29%**	**2.33%**

Weighted average savings was 5% of total demand

Industrial segmentation by size (SCE)

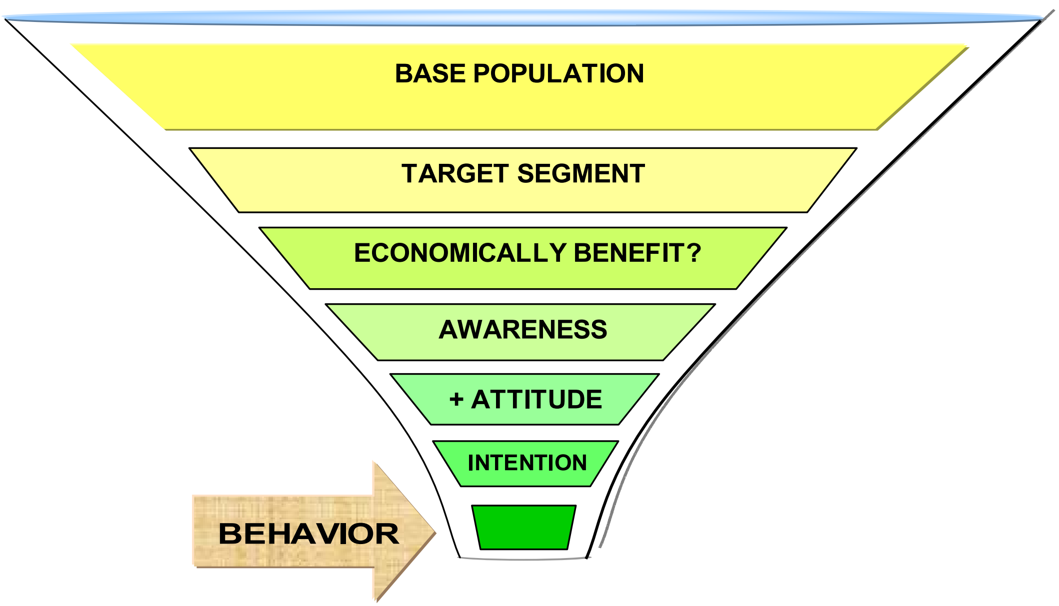
SIC	Size Class	N	Average Consumption (kWh)	Percent of Total	Cumulative Percent
	Largest	7	40,373,739	21%	21%
	Very Large	28	12,450,096	25%	46%
	Large	97	4,733,438	33%	80%
	Medium	122	1,430,133	13%	92%
20	Small	692	153,141	8%	100%
Total		946	1,449,061		
	Largest	7	16,371,094	16%	16%
	Very Large	28	4,451,798	17%	33%
	Large	144	1,424,230	28%	61%
	Medium	475	343,705	22%	83%
35	Small	3,304	38,085	17%	100%
Total		3,958	185,303		
	Largest	7	85,131,802	37%	37%
	Very	28	12,799,394	22%	59%
	Large	80	4,002,070	20%	79%
	Medium	204	1,092,369	14%	93%
	Small	363	241,908	5%	98%
36	Very Small	742	33,741	2%	100%
Total		1,424	1,130,732		
Grand Total		6,328	586,979		

From Nonres Market Tracking Study

Section 2: Customer Acceptance Primer

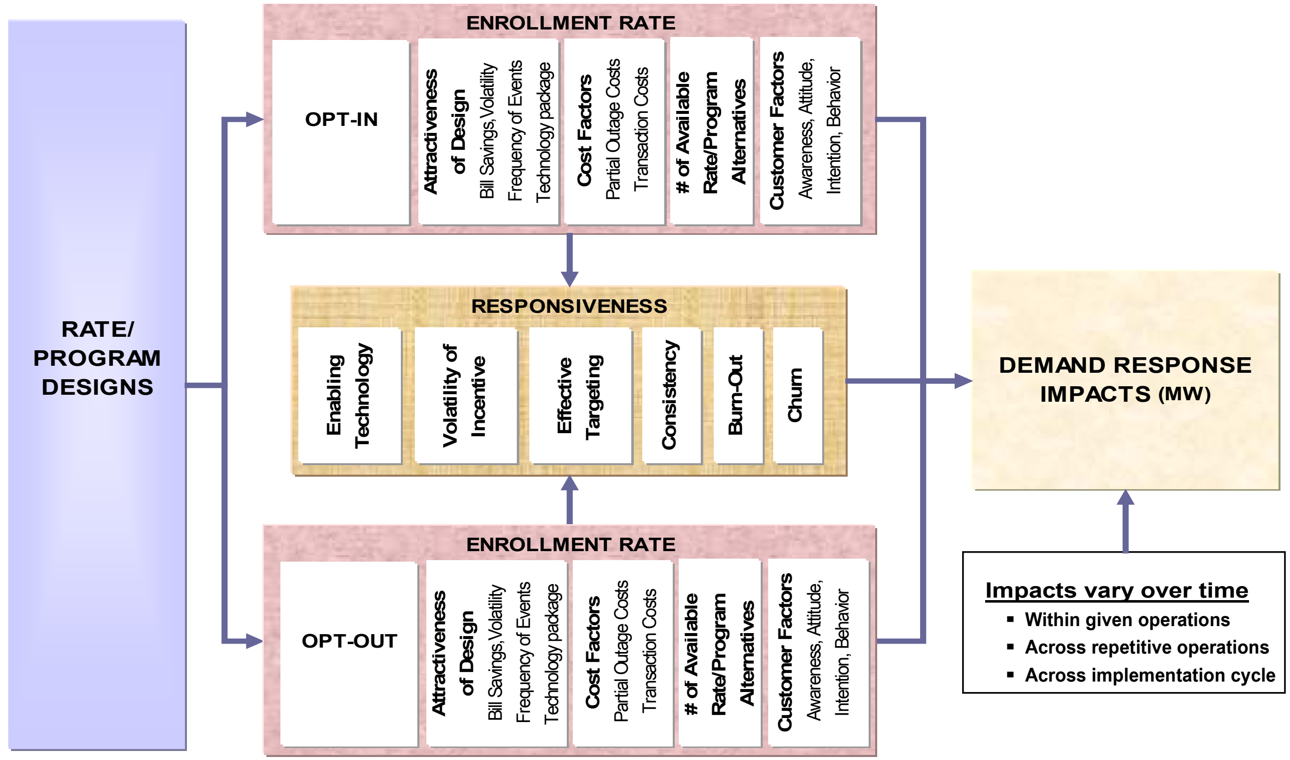
Participant and Response Estimation Framework

Impact of Participation Rate Drivers



Participant and Response Estimation Framework

- The following framework was developed to help assessment of the demand response impacts



Participation and Response Driver Primer

- Participation rates (and resultant response rates) are impacted by a panoply of drivers
  - *Rate design considerations that influence the attractiveness of the offering (for more detail, see prior slides on rate design components)*
  - *Mode of the offering (opt-in versus opt-out) has a significant impact on expected participation and response on the offering*
  - *Enrollment rate factors such as cost (operational and real) to participate as well as hassle implications*
  - *Participant ability and willingness to be responsive to the rate/program guidelines based on various factors*
  - *As for response impacts, they vary over time within a given operation, across repetitive operations, across the implementation cycle of the program*

Primer – Rate/Program Design Attributes

- How is the rate or program offered; mandatory vs. voluntary…opt-in vs. opt-out
- What type of peak load rationing is used
- Are energy retail prices set by the market or by inflexible tariff
- Based on energy consumption or demand on the infrastructure
- Who controls operations on the customer's responsive load
- Do retail prices change as a function of time
- What are the price differentials that have been incorporated
- How are the tariff's structural benchmarks established (e.g. baseline, firm service level, demand subscription level, etc.)
- What are the likely bill impacts or incentives (both positive and negative…for non-compliance)
- Mandatory (i.e., penalized for non-compliance) or voluntary responsiveness
- Are price signals (or curtailable signals) dispatched to the participant
- What pricing or DR operational constraints are in place (season, period, frequency, duration, longevity, etc.)
- Customer cost to participate in the offering
- What kind of metering is required and who pays for it
- Level and stages of advanced notice relative to impactful price or curtailment signal
- What triggers the rate or program operations – economic price signals or reliability concerns

Primer – Participant Enrollment Rate Issues – customer factors

- How the offering is packaged – think of OBMC versus Real-Time Pricing
- Clarity of offering – rate options versus simplicity analogy of cell phone plans at a set price with unlimited minutes per month
- Ease of participation – do you have to buy your own metering and sign a 40 page contract or sign up on the web
- Tenure/consistency of the offering – has there been or will there be annual changes to the structure thereby disabling customers to reasonably assess their financial investment or risk over time
- Program participation caps – have a definite impact on assessing a steady state participation level

Primer – Participant Enrollment Rate Issues – marketing approach factors

- Linked with other program opportunities – or offered as a "one-off"
- Marketing tactics utilized – door to door results versus marketing through bill inserts or "bang tags"
- Marketing delivery channel – whether it is offered through the utility, third party implementers, or CBOs, the key is whether the channel is viewed as a credible resource by the targeted customer base
- Timing of the marketing effort – needs to be tied to the target market's purchasing or decision cycle; example of marketing A/C DLC in the spring versus fall seasons
- Degree of effective targeting – peanut butter offerings improve awareness but are often not as impactful or cost-effective as effectively targeted programs. Example A/C DLC targeted on Central Valley SFDs with A/C tonnage of 5 tons.
- Targeted participation ramp up rates – if overly aggressive, can sentence the effort to failure due to inability to fulfill program obligations for the participants

Primer – Participant Enrollment Rate Issues – awareness and historic landscape factors

- History of rate or program option availability within a service territory and/or targeting the selected customer base
- Overall climate of public awareness – think back to the California Energy Crisis and the level of awareness
- Customer satisfaction with the energy provider – if they are not viewed as a credible resource/provider who is looking to "partner", enrollment rates will suffer
- Are there allied or supportive efforts underway – including co-branding (think of the Chicago-based Energy Cooperative)

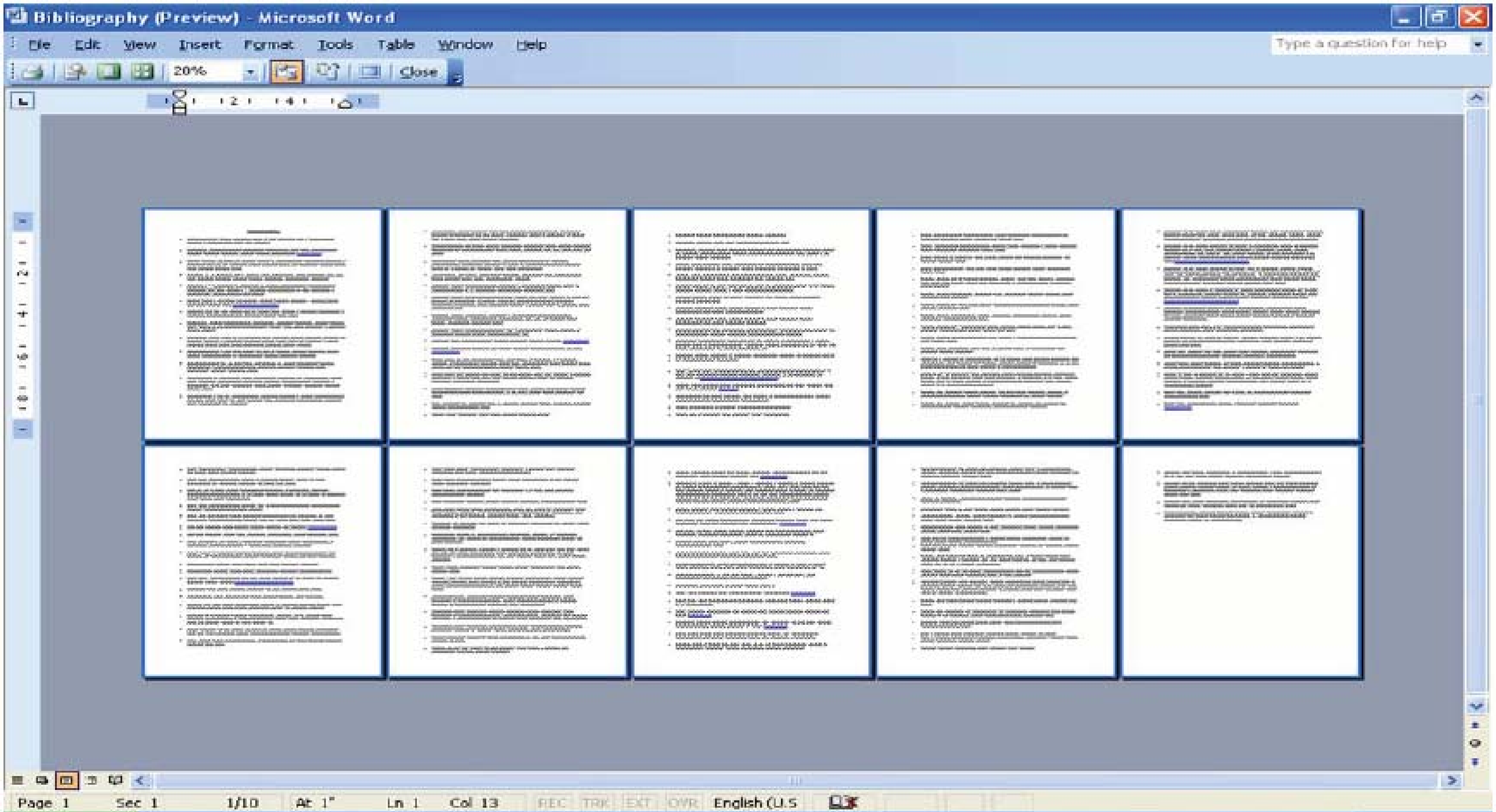
Primer – Participant Enrollment Rate Issues – participant cost factors

- Involved operational cost impacts – thought of as the hassle factor relative to customers wanting to “stick to their knitting”
- Involved capital cost impacts – in times of tight capital for business customers, how does the cost to invest in enabling technologies stack up with other corporate priority projects
- Involved DR outage cost impacts – is the incentive provided sufficient to offset the partial outage cost incurred by the participant
- How is the financial incentive fulfillment transacted – one approach (such as bill credits) will only be attractive to a subset of the target market

Primer – Responsiveness Issues

- Are there enabling technologies commercially and readily available to assist participants in seamlessly participating
  - *Are they incented for inclusion in the participant's decision process*
- Volatility of the incentive or bill impacts
- Effective targeting – focusing on participant subsets with higher propensities for actual compliance and impacts is important to garnering results
- Will the participant responsiveness fade over the duration of an operation
- Participant burn-out – has the rate or program been over-extended (from the participants' perception, not the utility's)
- Churn – what level of participant turn-over is expected and how difficult will it be to backfill behind departing participants

Extensive Literature Review



Literature search

- Over 100 sources were reviewed and assessed
  - *List subcategories of materials and number of citations*
  - *For a full delineation of sources, see the bibliography*

- These resources were viewed through the prism of 80 person-years of DSM/pricing rate and program design and implementation experience among the FSC team members

Develop participation rate estimates for the sample of rate/program alternatives selected to demonstrate the team's methodology

- A significant literature search focused on;
  - *Historic DSM participation rates*
  - *Price elasticity estimates*
  - *Customer participation research*
  - *Inputs for estimation modeling for both pre-tested pilot rates/programs, as well as non-tested alternatives*

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Definitions

- Price rationing rates/programs
  - *TOU = time of use*
  - *CPP = critical peak pricing*
  - *RTP = real-time pricing*
- Quantity rationing rates/programs
  - *DLC = direct load control*
  - *I/C = interruptible and curtailable (also CIS, curtailable-interruptible service)*
  - *DSS = demand subscription service*
- Hybrid rates/programs
  - *DB = demand bidding*
  - *combinations of the basic price and quantity rationing types, e.g.*
  - *RTP + I/C*
  - *TOU + DLC*
  - *many other possibilities*
- Non-DR rates/program
  - *flat = flat*
  - *tiered = inverted block*
  - *Hopkinson = energy + non-coincident demand*