CALIFORNIA'S NEXT GENERATION OF LOAD MANAGEMENT STANDARDS

DRAFT CONSULTANT REPORT

Prepared For:
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Prepared By:
Ahmad Faruqui and Ryan Hledik
The Brattle Group

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Prepared By:
The Brattle Group
Ahmad Faruqui and Ryan Hledik
San Francisco, California
Contract No.700-05-002

Prepared For:
California Energy Commission

David Hungerford
Project Manager

Sylvia Bender
Manager
Demand Analysis Office

Sylvia Bender
Acting Deputy Director
Electricity Supply Analysis Division

B.B Blevins
Executive Director

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ABSTRACT

By reducing system loads during critical-peak times, demand response (DR) can eliminate the need for new peaking generation capacity and associated transmission and distribution capacity. By reducing capacity, generation and infrastructure costs, it can lower total power costs and customer bills. In addition, it can help reduce the threat of brownouts and blackouts. Finally, DR can make organized wholesale power spot markets more competitive and efficient and less subject to the abuse of market power. Consequently, there is agreement among California's energy policy makers, utilities, independent system operator and other interested parties that DR should be a key resource option.

The Brattle Group was engaged by the California Energy Commission—as part of the 2007 *Integrated Energy Policy Report* (IEPR) process—to gather inputs from a broad array of sources and to assess the accomplishments and shortcomings of DR activities in California. This assessment will explore the Energy Commission's "load management" authority as a way to achieve higher levels of cost-effective DR.

The California *Energy Action Plan II (EAP II)* places DR at the top of the resource procurement loading order with energy efficiency (EE). It specifies that five percent of system peak demand should be met by DR in 2007. However, despite significant past and continuing efforts by all of the parties, this goal is unlikely to be achieved.

How soon and whether the goal can be achieved are open questions. Despite California's accomplishments in DR, the question remains: are new policy instruments necessary to expedite, extend and solidify the adoption of DR?

This draft paper, the second deliverable from this project, summarizes the potential for DR in California relative to its current state, provides a history of the Energy Commission's load management authority and the standards that were developed, and lays out ideas for new ways in which load management standards could be used to promote DR going forward.

KEY WORDS

demand response, peak load, load management, electricity rate, electric utility, energy efficiency, economic analysis

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EXECUTIVE SUMMARY

By reducing system loads during critical-peak times, demand response (DR) can eliminate the need for new peaking generation capacity and associated transmission and distribution capacity. By reducing capacity, generation and infrastructure costs, it can lower total power costs and customer bills. In addition, it can help reduce the threat of brownouts and blackouts. Finally, DR can make organized wholesale power spot markets more competitive and efficient and less subject to the abuse of market power. Consequently, there is agreement among California's energy policy makers, utilities, independent system operator and other interested parties that DR should be a key resource option.

This paper builds on the work contained in a preceding paper, "*The State of Demand Response in California,*" April 2007. That paper noted that the projected DR resources for this summer are only 2.2 percent of system peak demand. This leaves a 2.8 percent deficit in achieving the five percent goal for price-responsive "day-ahead" DR. It is important to note that this five percent goal does not apply to day-of reliability-triggered DR programs that predate the DR goal. Those programs provide roughly 3.5 MW in emergency DR.

The paper concluded that this deficit is largely due to the absence of dynamic pricing and enabling technologies that allow customers to respond with little effort to higher prices during critical times. One way to eliminate the deficit is by invoking the authority of the Energy Commission to set load management standards.

This authority was last used in the late 1970s and viewed favorably by the stakeholders. Four load management standards were implemented, involving load control of residential central air conditioners, timers on swimming pools, commercial building audits and marginal cost pricing, which led to time-of-use (TOU) pricing for large customers. Collectively, they were projected to reduce peak demand by seven percent.

The standards were useful in stimulating discussion about innovative ways to reduce peak load and defer or eliminate the need for peaking capacity. Some of these standards, such as mandatory TOU rates for large customers and direct load control of central air conditioners are still around and continue to be refined.

However, since the projected DR deficit is large and persistent, new avenues for managing this deficit must be aired and discussed. Load management standards provide one such method.

To set the stage for evaluating the merits of these standards, it is useful to quantify the potential impact that DR can have on peak demand and to evaluate its financial benefits. An estimate of the **technical potential** of DR is about 25 percent, which represents the most that can be achieved with maximum deployment of the best available technologies. **The economic potential** of DR, which represents the maximum deployment of cost-effective technologies, is estimated at about 12 percent. Finally, the **market potential** of DR, which represents the likely deployment of cost-effective technologies, is estimated at five percent.

If a five percent reduction in peak demand were achieved, it would represent a decrease of about $240 million per year in electricity costs. Over a 20-year time horizon, the present value of benefits could be as much as $3 billion.

Given the state's success with implementing appliance and building standards through Title 20 and 24 respectively, it makes sense to revisit the load management standard-setting authority of the Energy Commission. The next generation of load management standards will differ substantially from the first generation, since much has changed in the last 30 years. To help reinvent the load management standards, it may be useful to engage in a visioning exercise.

To begin that process, this paper provides three strawman proposals that can serve as a springboard for further discussion. The first proposal addresses default dynamic pricing, the second addresses programmable communicating thermostats (PCTs) for residential and small commercial and industrial buildings; and the third addresses automatic demand response software (Automated DR) for medium and large commercial and industrial buildings.

The proposals focus on the two key barriers to the faster deployment of DR in the state: lack of dynamic pricing and lack of enabling technologies. They are designed for use on a day-ahead basis but if necessary they can also be deployed on a day-of basis. From a planning perspective, both triggering strategies are important. The day-ahead strategy decreases the likelihood that emergencies will be encountered, while the day-of strategy provides a mechanism for dealing with the emergency when it does occur. The proposals are designed to enhance the role of pricing mechanisms for managing demand and supply to decrease the role of cash incentives, which are much more expensive and difficult to sustain over the long haul.

These proposals may or may not evolve into the final standards, but they do present a compelling picture of how much additional benefit would be derived by pursuing the Energy Commission's authority to create load management standards. Before any load management standards can be enacted, the Energy Commission must invoke a rulemaking proceeding similar to the ones used to update the appliance and building standards codified in Titles 20 and 24.

In the absence of load management standards, dynamic pricing is likely to remain an optional activity. In that scenario, a drop of about three percent in peak demand can be expected, representing a financial gain of over $1 billion. If dynamic pricing becomes the default tariff as a result of a new load management standard, the impact on peak demand could rise by roughly seven percent. In addition, if programmable communicating thermostats (PCTs) are deployed in all residential and small commercial buildings through load management standards, this would result in an additional reduction in peak demand of around eight percent. Finally, if automatic demand response software is installed in all medium and large commercial and industrial facilities, an additional reduction in peak demand of over two percent might be obtained.

Summing up the numbers, in the absence of load management standards, the state could obtain a load drop of about three percent valued at over $1 billion. With all three load management standards in place, a load drop of roughly 20 percent valued at around $11 billion could be achieved. This sample portfolio of standards could have a financial worth more than $12 billion.

INTRODUCTION

This paper builds on the work that was reported in a preceding paper, "The State of Demand Response in California," April 2007. That paper identified several reasons why the state was unlikely to meets its goals for demand response (DR) and suggested that one avenue for meeting the goals was to invoke the Energy Commission's authority for setting load management standards.

The purpose of this white paper is to explore load management standards as one possible policy tool for promoting DR. The information in this paper is presented in four chapters.

Chapter 1 discusses the state's deficit in meeting its DR goals. The deficit is traced to the lack of dynamic pricing and of enabling technologies that would allow customers to automatically respond to higher prices.

Chapter 2 provides a historical overview of the state's experience with load management standards. It describes the evolution of those standards and summarizes lessons that were learned from the operation of the standards.

Chapter 3 lays out a framework for developing the next generation of load management standards and quantifies their potential benefits. To help envision the future possibilities, it lays out three strawman proposals.

Chapter 4 presents the major conclusions of the paper. The uncertainty in some of the benefit estimates presented in this paper is presented in Appendix A.

CHAPTER 1: THE STATEWIDE DEFICIT IN DEMAND RESPONSE

Demand response (DR) plays a critical role as a resource in California's electricity planning mix. It can prevent brownouts and blackouts during emergency situations. It promotes system reliability by providing the California Independent System Operator (CAISO) with tools to manage demand during peak days. And, coupled with advanced metering infrastructure (AMI), it improves the level of service provided to electricity customers.

In addition to all of these benefits, DR has the potential to cost-effectively provide substantial savings in avoided generating capacity costs, energy production costs, and transmission and distribution (T&D) capacity costs, among others. However, despite its many advantages, price responsive DR is only expected to reduce peak demand by 2.2 percent in the summer of 2007, which is less than half of the goal of five percent laid out in the *Electricity Action Plan II*.[1] This goal does not apply to day-of reliability-triggered DR programs which, when included in the total, would increase the DR impact to roughly 5.7 percent.

In this chapter, we elaborate upon the benefits of DR, provide descriptions of the barriers to its acceptance as a resource in California, and identify the areas in which new policies could be used to overcome many of these barriers.[2]

The Potential for DR in California

To understand the benefits of DR, it is necessary to first understand its potential impact on the state's peak demand. Projections of the potential reduction in peak demand that can be achieved through price-responsive DR programs depend on the amount of coincident demand that is reduced per customer and on the number of participating customers. It is normal practice to assess three types of impacts: technical potential, economic potential, and market potential.[3] Each of these is briefly discussed below.[4]

It should be noted that these estimates of potential DR are in addition to the peak reductions that are achievable through reliability-triggered programs. All DR estimates are uncertain, since they involve the decisions of multiple customers and technologies. We have performed Monte Carlo simulations to understand the uncertainty in these estimates.[5]

- *Technical potential* measures the outcome if all customers used the best available DR technology. In the residential class, this is the gateway system, which allows homeowners to automatically manage electricity consumption at several points of end-use, including stereos, appliances, and air conditioning units. The gateway system has the potential for lowering peak demand by 43 percent, as demonstrated by the advanced demand response system (ADRS) sub-set of the statewide pricing pilot (SPP). In the commercial and industrial classes, Automated DR programs that control multiple end-use loads and leverage the energy management control system that is installed in most facilities are projected to reduce demand by 13 percent, as demonstrated by work carried out by the Demand Response Research Center. A weighted average over all customer classes leads to an estimate of roughly 25 percent for the technical potential of demand response.[6]

- *Economic potential* measures what would happen if all customers used a cost-effective combination of technologies rather than the best available technologies. This produces an estimate of the economic potential for demand reduction through DR programs of approximately 12 percent. To illustrate this computation for the residential class, recall that customers in the California experiment without an enabling technology lowered their peak usage by 13 percent. Those with a smart thermostat lowered it by 27 percent and those with the gateway system lowered it by 43 percent. If 70 percent of the customers chose no enabling technology, 20 percent chose the smart thermostat and 10 percent chose the gateway system, this would yield a weighted average estimate of approximately 19 percent for the residential class. Corresponding values for the commercial and industrial classes are roughly seven percent and nine percent.

- *Market potential* measures what would happen if a cost-effective combination of technologies is accepted by a realistic number of customers in the market place. It differs from economic potential, which assumes that all customers accept dynamic pricing. Thus, the key unknown in estimating market potential is the number of participating customers. This, of course, depends on the conditions under which dynamic pricing is offered to customers. It is also contingent on the availability of advanced metering infrastructure (AMI) which is currently limited to customers above 200 kW but is likely to be deployed for all customers in the state during the next five years. Under that assumption, if dynamic pricing is made the default rate (as it has been made in restructured states for large customers), a larger fraction of customers would be expected to stay on it than if it is offered on an optional basis. The limited literature on the topic suggests that about 80 percent would stay on dynamic pricing if it is offered as the default rate and that a substantially smaller number, perhaps 20 percent, would select in on a voluntary basis. In our initial analysis, we assume that the actual number is likely to be somewhere in the middle. This yields an estimate of approximately five percent.

The Value of a Five Percent Peak Demand Reduction

If California were to achieve a five percent peak demand reduction, there would be several types of benefits. Three of these can be quantified in a preliminary projection. The first and most significant benefit is the reduction in needed peaking generation capacity. This is a long run benefit and consists of the sum of avoided capacity and energy costs. It can be readily estimated based on the capacity cost of a combustion turbine. The second benefit is the avoided energy cost that is associated with the reduced peak load. Third is the reduction in transmission and distribution capacity. Further detail on the following discussion can be found in Sidebar 1, following this chapter.

To quantify the avoided capacity cost, we first quantify the amount of capacity that will be avoided by a five percent reduction in peak demand and then value it. A five percent reduction in California peak demand of approximately 61,008 MW amounts to 3,050 MW of avoided peak demand. The amount of peaking capacity that is needed to meet this peak demand can be computed by allowing for a reserve margin of 15 percent and line losses of eight percent. This amounts to 3,789 MW or roughly the output of 50 combustion turbines.[7] A conservative value of the avoided cost of generation capacity is $52/kW-year.[8] Thus, the total value of avoided generation capacity costs would be roughly $200 million per year.

Using the relationship that was observed between annual generation capacity and energy benefits in a recent PJM analysis of demand response, the annual value of avoided energy costs is estimated at around $20 million.[9]

In addition, there would be a reduction in transmission and distribution capacity needs. While these are system-specific and depend on the coincidence between system and local area peaks, they are unlikely to be zero. A conservative estimate is 10 percent of the savings in generation capacity and energy costs. Using this estimate, we derive an estimate of roughly $20 million per year for savings in transmission and distribution costs.

Adding up these three components yields long-run benefits of demand response of $240 million per year. The composition of this annual benefit is shown in Figure 1 below. To set these savings in perspective, it is useful to recall that the total cost of electricity in the state of California in 2005 was $34 billion.[10] Over a 20-year time horizon, the present value of DR benefits could reach $3 billion.

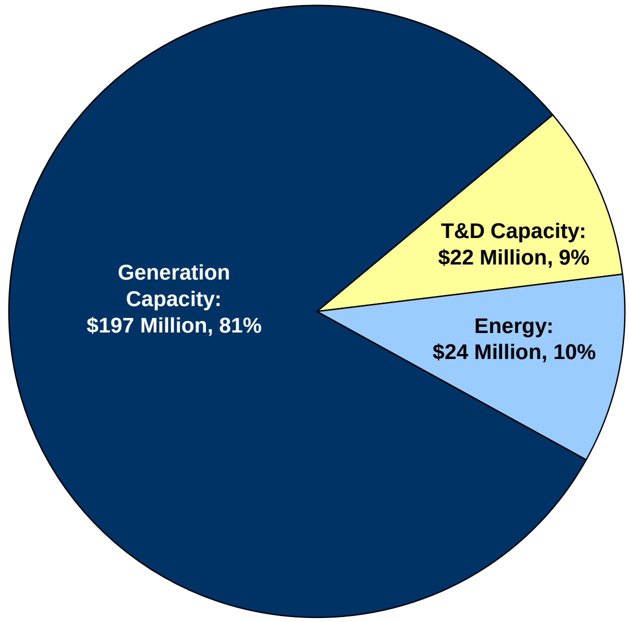

Figure 1: Annual Financial Benefits of a Five Percent Reduction in Peak Demand

Barriers to DR in California

While the benefits of DR (both financial and other) are potentially very large, the state is currently anticipated to achieve only a 2.2 percent peak reduction through price responsive DR in the summer of 2007.[11] This is less than half of the five percent target stated in the *EAP II* (although, while the target does not apply to reliability-triggered programs, their inclusion in the total would bring it to 5.7 percent). This raises the question of why a greater level of peak reduction has not been achieved through price responsive DR. In other words, what factors have slowed the progress of DR in California?

In a recent Consultant Report titled *The State of Demand Response in California* (hereafter referenced as *State of DR)*, 14 barriers were identified. These barriers are listed in Table 1.

Table 1: Barriers to DR

	Barrier	Description
1.	Assembly Bill 1X	AB 1X places a rate freeze on the first 130 percent of baseline consumption for residential consumers of electricity. Most respondents felt that the rate freeze imposed by AB 1X is a serious constraint on the state's ability to replace non time-varying rates with dynamic pricing.

2.	Lack of AMI penetration	Some felt that this was a significant barrier, since AMI was not deployed in the state, while others said it was no longer a barrier since all three investor-owned utilities had decided to pursue AMI.
3.	Lack of cost effective enabling technology	Several respondents identified this as a legitimate barrier. Reasons included low customer awareness, low market penetration, high costs, undeveloped marketing infrastructure, lack of a standard price/event signal for the technology to read, and a lack of automation in buildings and appliances.
4.	Lack of consumer interest	This was cited by all respondents as a "highly significant" barrier. Reasons were that customers feel they have already taken all available measures to become energy efficient (particularly commercial customers already on TOU rates), burdensome administrative requirements , and small bill savings.
5.	Ineffective program design	Most participants agreed that further improvements were needed, since insufficient numbers of customers were enrolled in DR programs. Possible solutions included increased consumer education efforts, integration with energy efficiency programs, and adoption of best practices from energy efficiency in the design of DR programs.
6.	Utility fear of not recovering costs	This was not generally considered to be a problem in California. Many agreed that decoupling had resolved this issue.
7.	Fear of customer backlash	This was cited as a concern by some respondents who felt that heavily-used dynamic pricing could cause customer fatigue, cause them to feel exploited if bill savings were small, or trigger a "revolt" in response to the higher critical peak prices. However, others felt that a well designed program, coupled with effective marketing and educational efforts, would prevent this from becoming a significant barrier.
8.	Confusion with EE	Some felt this was becoming less of an issue, citing the pairing of rebates for new air conditioners with TOU rates. Others felt that the administrative separation of DR and EE programs created redundancies (e.g. unnecessary paperwork) and competition between the two. Program integration and "one stop shop" packaging were suggested to lessen this problem.
9.	Environmental impacts	Many respondents were aware of the concern that DR tariffs and programs may increase load during off peak periods. While they said that this had not surfaced as an issue in California, some felt that environmental impacts should be included in the cost effectiveness tests.

10.	Lack of retail competition	No respondents argued that this was a barrier in California. However, some felt that retail providers understand the customers better than utilities and are better suited to implement innovative rates programs.
11.	Low capacity and energy prices	Some respondents said that it is difficult to build interest in DR during a capacity surplus. However, another respondent argued that this is the best time to promote DR, when the absence of dramatic spikes in the underlying energy prices would decrease the chances of a customer backlash.
12.	No recent blackouts	One respondent said it was hard to get people motivated about DR unless they saw a tangible, immediate benefit from it such as the avoidance of recurring blackouts.
13.	Complicated state-federal coordination	Respondents considered this to be a barrier outside of California, but not within the state.
14.	Retail-wholesale market disjuncture	Lack of a functioning day-ahead market was cited as a major barrier by some respondents, although one commented that the planned creation of the MRTU market next year would solve this problem by providing an accurate reference to wholesale prices when designing the dynamic rates.

Areas for Future Policy Development

These 14 barriers to DR generally fall into one of two broad problem areas requiring future policy development: A lack of dynamic pricing and a lack of enabling technologies.

Dynamic Pricing

Most of the barriers are related to rate design issues and specifically to a lack of dynamic pricing. These barriers include policy issues, such as the need to develop realistic goals for demand response, the need to deal with constraints created by the AB 1X rate freeze and the need to ensure that default rates reflect the traditional rate design objective of cost-based pricing. Solving these issues may require addressing the tension between promoting economic efficiency and fairness and maintaining the current AB 1X subsidies.

There are also analytical issues in this area, such as the need to modify existing cost-benefit methodologies for evaluating demand-side programs, develop protocols for measuring demand response impacts and develop innovative rate designs that incorporate the risks of outages and high peak generation costs. Current efforts by the utilities and commissions to develop workable dynamic rate designs and effective protocols for measuring demand response impacts are steps toward solving these problems.

Additionally, there is a need to develop a consistent message on DR and find ways to better educate customers about the costs embodied in current rates. Customers also need to be educated about the benefits that could come from broad adoption of time-varying and dynamic rates, the true impacts on their electricity costs that would come from such a change and the options they have for responding. This could begin with stressing the simple message that electricity costs more during peak periods, emphasizing the “fairness” of time-varying rates. Many customers assume such rates would amount to rate increases when in fact utility revenue would not change—customers whose consumption patterns reflect below average peak consumption would see bill reductions; those with above-average peak consumption would see increases that reflect the degree to which their peak consumption is currently receiving a hidden subsidy from other customers.

Rate and program designs must be developed that better reflect the value of demand response to the electricity system and the value of consumption to customers. Those designs also must reflect a better understanding of customer perceptions as well as being effectively marketed to customers. There are several ways in which the program design can make the rates more attractive to customers. Examples include limited-term bill protection, cash incentives or credits and two-part rate design.

Enabling Technology

With well-designed rate designs in place, the focus must shift to overcoming the technological barriers to DR. First and foremost is the need to install advanced metering infrastructure (AMI) throughout the state. This is likely to happen over the next five years. To get the most out of the AMI investment, it may be necessary to equip the customer with enabling technologies and automation that take the hassle and fear out of reducing demand during critical-peak times. The use of existing technologies that facilitate and automate demand response should be integrated into program and tariff offerings, while further development of such technologies should continue.

Additionally, rates need to be designed with an understanding of the level of response that customers are capable of providing. Research has shown that customers provide a significantly higher level of demand response when equipped with enabling technologies that automate the response and facilitate the control of electricity consumption at multiple end-use points. Ultimately, these enabling technologies need to be adopted on a large scale for California to approach its potential for demand response.

So what is the best way to overcome these two barriers? One approach that has much to commend itself is the Energy Commission’s authority to set Load Management Standards. These standards were originally created in the late 1970’s to provide the Energy Commission with the ability to develop programs for reducing peak demand and reshaping utility load duration curves. The Commission is authorized to consider the following load management techniques, but its authority is not limited to just these three:

- Adjustments in **rate structure** to encourage use of electrical energy at off-peak hours or to encourage control of daily electrical load. Compliance with those adjustments in rate structure shall be subject to the approval of the Public Utilities Commission in a proceeding to change rates or service.

- **End-use storage systems** which store energy during off-peak periods for use during peak periods, such as thermal storage, pumped storage, and other storage systems.

- **Mechanical and automatic devices and systems** for the control of daily and seasonal peak loads.

The rest of this paper explores the history of the Energy Commission's Load Management Standards and envisions the roles that Load Management Standards may play in the state's energy future. To make the discussion concrete, three strawman proposals are laid out.

SIDEBAR 1: ESTIMATING THE POTENTIAL VALUE OF DR IN CALIFORNIA

This sidebar describes the assumptions and calculations that were used to arrive at the estimate of the potential benefits of demand response in California.

California's residential, commercial and industrial sectors make the following contribution to the state's peak demand. These values are derived from an estimate of a typical peak day demand curve in California.[12]

The penetration rate of enabling technologies within the three sectors is a projection based on general industry knowledge and experience. The average customer-level peak reduction that can be achieved through each of these technologies, when paired with a Critical Peak Pricing (CPP) rate, comes primarily from the Statewide Pricing Pilot (SPP) and studies conducted by the Demand Response Research Center (DRRC)..

The same sectoral allocation was used in all three projections of DR potential (as shown in Table 2). Both the technical potential and economic potential projections assume 100 percent participation by all sectors, while the market potential projection assumes roughly 40 percent participation in each sector.

Table 2: Peak Demand Allocation by Sector

Sector	Peak Demand Allocation
Residential	41%
Commercial	41%
Industrial	18%
Total	**100%**

Customer-level demand response for technical potential is assumed to be based on the technology that allows for the largest response in each sector (Table 3).

Table 3: Demand Response by Sector and Technology

Technology	In-Class Allocation	Customer Response	Source
Residential			
No Technology	70%	13%	(1)
Enabling Technology	20%	27%	(1)
Gateway	10%	43%	(2)
Weighted Avg		*18.8%*	
Commercial			
No Technology	60%	5%	(3)
Enabling Technology	30%	10%	(3)
Auto DR	10%	13%	(4)
Weighted Avg		*7.3%*	
Industrial			
CPP	60%	7%	(5)
Auto DR	40%	13%	(4)
Weighted Avg		*9.4%*	

Note: Sources of customer response are listed at the end of the sidebar.

In estimating the economic and market potential, a weighted average is used, based on the technology market penetration assumptions shown in Table 4. These assumptions lead to the total demand reduction estimate for each sector. Calculating a weighted average using each sector's share of the total population produces the final projections of technical, economic, and market potential for California.

Table 4: Assumptions in Calculation of DR Potential

	Technical Potential	Economic Potential	Market Potential
Sector Allocation to Total Population			
Residential	41.0%	41.0%	41.0%
Commercial	41.0%	41.0%	41.0%
Industrial	18.0%	18.0%	18.0%
Total	**100.0%**	**100.0%**	**100.0%**
Sector Participation Rate			
Residential	100.0%	100.0%	40.3%
Commercial	100.0%	100.0%	40.3%
Industrial	100.0%	100.0%	40.3%
Total	**100.0%**	**100.0%**	**40.3%**
Customer-Level Demand Response			
Residential	43.0%	18.8%	18.8%
Commercial	13.0%	7.3%	7.3%
Industrial	13.0%	9.4%	9.4%
Total	**25.3%**	**12.4%**	**12.4%**
Total Demand Reduction Estimate			
Residential	43.0%	18.8%	7.6%
Commercial	13.0%	7.3%	2.9%
Industrial	13.0%	9.4%	3.8%
Total	**25.3%**	**12.4%**	**5.0%**

As described in Chapter 1 of this paper, the avoided cost of generating capacity, electricity generation, and T&D capacity are all components of the financial benefits of DR. The specific calculations used to arrive at the final estimates of the present value of a five percent peak demand reduction are described in Table 5.

Table 5: Assumptions in Calculation of PV of DR Financial Benefits

	Assumption/Calculation	Value	Units	Source
[A]	California noncoincident peak demand forecast	61,008	MW	Source (6) at end of sidebar
[B]	Market potential of DR	5%	% of peak	Calculation of Market Potential
[C]	Peak demand reduction	3,050	MW	[A] * [B]
[D]	Reserve margin	15%	% of peak	Generally accepted industry practice
[E]	Line losses	8%	% of peak	Generally accepted industry practice
[F]	System-level MW reduction	3,789	MW	[C] * (1 + [D]) * (1 + [E])
[G]	Value of capacity	52	$/kW-yr	Source (7) at end of sidebar
[H]	Value of capacity	52,000	$/MW-yr	[G] * 1,000
[I]	Total avoided capacity cost	197	Million $/year	[F] * [H] / 1,000,000
[J]	Peak demand growth rate	2%	% per year	Assumption
[K]	Annual discount rate	8%	% per year	Assumption
[L]	Study time horizon	20	years	Assumption
[M]	PV of $1 annuity for 20 years	11.58	$	Assumption
[N]	Energy % of generation capacity cost	12%	% of NPV	Source (8) at end of sidebar
[O]	T&D % of energy and generation capacity cost	10%	% of NPV	2006 PG&E AMI Filing
[P]	PV avoided generation capacity cost	2,281	Million $	[I] * [M]
[Q]	PV avoided energy cost	281	Million $	[N] * [P]
[R]	PV avoided T&D capacity cost	256	Million $	[O] * [P]
[S]	PV of total avoided cost	2,819	Million $	[P] + [Q] + [R]

Sources:

- (1): CRA International, *Impact Evaluation of the California Statewide Pricing Pilot*, March 16, 2005.
- (2): Rocky Mountain Institute, *Automated Demand Response System Pilot, Final Report,* March 31, 2006.
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- (5): Quantum Consulting and Summit Blue Consulting, *Evaluation of 2005 Statewide Large Nonresidential Day-Ahead and Reliability Demand Response Programs*, Prepared for Southern California Edison Company and Working Group 2, April 28, 2006.

- (6): CEC Demand Analysis Office, *July 2006 Heat Storm Workshop: Temperature and Other Issues Impacting Load*, presented at the Electricity Committee Workshop, August 29, 2006.
- (7): California Public Utilities Commission, “Final Opinion Authorizing Pacific Gas and Electric Company to Deploy Advanced Metering Infrastructure,” July 20, 2006, No. Decision 05-06-028.
- (8): Newell, Sam and Frank Felder, *Quantifying Demand Response Benefits in PJM*, Study Report Prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI), January 29, 2007.

CHAPTER 2: A HISTORY OF LOAD MANAGEMENT STANDARDS

In 1976, the California Senate and Assembly unanimously passed a law giving the Energy Commission the authority to implement Load Management Standards.[13] These standards gave the Energy Commission the ability to create and propose programs that California's utilities would employ to reduce peak demand and reshape their load duration curves, thus avoiding the need to invest in new power plants at a time when electricity production was becoming increasingly expensive.[14] When the standards were created, it was estimated that they would reduce peak demand by at least seven percent over the following two decades.

This chapter provides a history of the Energy Commission's load management authority, a description of the standards that it created and a review of the effectiveness of these standards.

The Origin of Load Management Standards

In the early 1970s, oil prices quadrupled in response to the global oil crisis. In addition, there was growing concern about the delays and costs associated with plans for building a new fleet of nuclear power plants. In response to this situation, the Warren-Alquist Act was signed into law in 1974, thereby creating the Energy Commission and codifying energy efficiency and conservation into the state's electricity planning process.

One particular focus of this effort was to reduce the need to build new power plants. As costs and uncertainty in power plant development were rising, so were concerns over their environmental impacts. As a result, in 1976, the Energy Commission was ordered to develop a set of load management standards that would be aimed at reducing demand during peak times. Specifically, the Public Resources Code stated that, "The commission shall, by July 1, 1978, adopt standards by regulation for a program of electrical load management for each utility service area."[15] Three specific ways were suggested for promoting load reduction:

- Adjustments to the rate structure
- Development of end-use storage systems that would shift load from the peak to the off-peak
- Mechanical and automatic devices for controlling peak loads

The law also identified three requirements of the load management standards. The standards must reduce load, be cost effective, and be technologically feasible. Specifically, the act laid out the following:

- **Load Reduction**: Each standard would be designed specifically to change the shape of the load duration curve of the California utilities. In other words, the standard should alter either the time at which electricity is consumed, the amount that is consumed, or both. This change in shape could be either a shift in demand from the peak to the off-peak, or an overall reduction in the total level of demand.

- **Cost Effectiveness**: Any program created by the Energy Commission would need to be cost-effective relative to the cost of new electrical generation capacity. So, while the Energy Commission was authorized to create and propose standards, this authority did not allow it to enforce any standard that would require the utilities to spend additional money. All costs and methods of recovering the costs still had to be approved by the CPUC.

- **Technological Feasibility**: Each standard would need to be technologically feasible. At the time, this was not considered to be an issue for any of the standards under consideration as they were all demonstrated to be achievable using existing technologies.

An additional aspect of the law was the coverage of the Energy Commission's authority. The load management authority extended not only to the three investor-owned utilities (IOUs), but to all "utility service areas." While the original standards proposed by the Energy Commission applied to the three IOUs, the Los Angeles Department of Water and Power (LADWP) and the Sacramento Municipal Utility District (SMUD), the authority is believed to also apply to all (39+) municipal utilities and co-operatives. At the publicly-owned utilities, the board of directors is responsible for approving any costs imposed by the programs as opposed to the CPUC.

In 1976, soon after it was granted authorization to create the standards, the Energy Commission began exploring the specific tools and programs that could be used to carry out load management. Large-scale studies were conducted to gain insights to relevant topics such as customers' willingness-to-pay for air conditioning on peak days and the potential public reaction to new rate structures that would more accurately reflect the true cost of providing electricity. Studies were also conducted to determine the potential impact of load management standards on irrigation practices, to compare load management practices across the US and in other countries and to better understand the load patterns of industrial end-uses of electricity.[16] Ultimately, all of these efforts, including 26 pilot studies, contributed to the development of four load management standards. These studies also produced an estimate of potential load management reductions that were as large as 30 percent of the forecasted capacity needs twenty years in the future.[17]

The Four Original Load Management Standards

By the summer of 1978, the Energy Commission's research led it to develop four load management standards in response to the requirement of the Public Resources Code. These standards are described below, as they were proposed in 1978.

Residential Load Management Standards

For residential customers, the Energy Commission proposed that the utilities develop peak load switching programs which would provide the participating customer with a remote load switch for its space heater, water heater or air conditioner. The program, similar to today's direct load control programs, would provide the utility with the ability to cycle or shut down the customer's heater or air conditioner at peak times, thus reducing system demand when it was most needed to maintain system reliability. In return, the customer would receive a rebate or incentive proportional to the level of interruption they were willing to tolerate. This was not a new concept even back then. At least 3,500 utilities around the world were estimated to already be using remote load switches.

Later, in an amendment to the load management regulations in 1982, the Energy Commission defined three phases for the program's implementation. In the development phase, a plan would be developed including a description of objectives, schedules and budgets. In the testing and evaluation phase, the utilities would have the opportunity to conduct detailed tests to form estimates of the expected impacts of the program. During this phase, a goal was set to install switches on eight percent of residential central air conditioners. After 28 months, the utilities would move to the system-wide implementation phase, during which they would pursue the maximum feasible level of load reduction through the program.

Swimming Pool Filter Pump Load Management Standard

The Energy Commission proposed a large scale effort to educate customers about load management of swimming pool filter pump motors. The purpose of this standard was to encourage customers to install timers that would enable the pump to operate only during designated off peak hours. This would serve to move demand from the peak period to the off peak period and, in some cases, would also lead to an overall reduction in the number of hours the pumps were operating.

At the time the standard was developed, California's utilities already had experience with the program through pilot studies. In an experiment involving over 4,000 customers, it was estimated that 7.7 MW of demand was cost-effectively shifted from the peak to the off-peak. PG&E's pilot program was simply a marketing and educational effort, while SCE's program installed timers on customer's pool pumps. The goal for the proposed pool pump standard was for each utility to have contacted all eligible customers within one year of the standard's approval by the CPUC.

Non-Residential (Commercial) Load Management Standard

The non-residential load management standard was an initiative to audit both small and large commercial customers to identify and present ways in which they could conserve energy and reduce their electricity bills. Thus, the impact of the program would likely produce an overall reduction in load from participating commercial customers (i.e. conservation, as opposed to load shifting). The cost of the audits was to be included as a fixed monthly charge in the customer's bill.

Previous studies had suggested that such audits could result in a reduction in electricity consumption ranging anywhere from 10 to 40 percent. However, initial results from pilots conducted at the five California utilities were showing reductions of less than two percent. Regardless, the goal for the program was a 20 percent improvement in energy efficiency in commercial customers by 1985. This was to be achieved by contacting all commercial customers over a three year period.

Load Management Tariff Standard

This required utilities to provide a marginal cost-based rate to customers. The intent was to design rates that reflected the true cost of providing electricity to the customer. The utilities would file their proposed rates with the CPUC, which would decide whether to allow the rate to be implemented. An early pilot of non-marginal cost-based time-of-use (TOU) rates for large PG&E customers reported a 35 MW reduction in demand, and it was thought that the impact would be even higher if the rates were based on marginal costs. Due to the low implementation cost associated with this standard, it was judged to easily pass the cost-effectiveness test.

As a result of this standard, all load above 500 kW demand was placed on TOU rates.

Impact of the Original Standards

Because of the large research efforts that were required to create full scale utility programs, the initial response to the standards was not instantaneous. In addition, it became clear that the load management standards would play an important role in upcoming years (particularly 1980-83), when the reserve margin in California was expected to be fall substantially. To facilitate program development, two series of workshops were held in September and October of 1979. One was dedicated to load management technology and the other to methods for improving customer participation. Both workshops were intended to provide a forum for exchanging ideas in these areas. Experts outside of California were invited to share their experiences with load management. Managers from Arkansas Power and Light and Detroit Edison spoke at the workshop about their A/C cycling and appliance cycling programs.[18]

In addition to these efforts, a letter jointly signed by the Energy Commission and the CPUC was sent to the California utilities in November 1979 to indicate the need to accelerate load management activities. This need for near term load management was reinforced by a January 1980 report by the Governor's Energy Conservation Task Force. In response, the utilities increased their efforts to develop load management programs, requesting additional budgets to meet the growing expectations.

Despite the short-term push to increase load management activity, many of the load management standards faded away in the years that followed. However, a lasting impact of the load management standards was the institution of mandatory TOU rates for medium and large commercial and industrial customers. After the energy crisis of 2000-01, the threshold for these rates was lowered from 500 kW demand to 200 kW demand through the passage of AB 29X.[19] This legislation authorized the expenditure of $34 million to install some 25,000 digital meters on all customers above 200 kW demand and to upgrade large customer meters that did not have appropriate communication links.

In addition, load control programs for central air conditioners, which were instituted at SMUD and SCE in the early stages of the standards' implementation, continue to this day. However, aside from these impacts, the other standards generally have not played a recent role in today's energy policy.

What can explain the limited success of these load management standards? Through interviews with individuals that were involved in the development of the early load management standards and review of the literature, a few explanations have been suggested.

Advisory nature: Unlike the appliance and building standards that are written in Titles 20 and 24, the Energy Commission does not have independent authority to enforce the load management standards that involve the expenditure of money. Monetary expenditures still have to be approved by the CPUC for the investor-owned utilities and by the Board of Directors for the publicly-owned utilities. As a result, the Energy Commission's ability to effectively ensure that the standards are pursued is largely of a proscriptive nature.

Administrative constraints: The load management standards typically require that both the Energy Commission and the CPUC approve the utilities' proposed programs. Today, the CAISO, which has taken over some of the utilities' grid management responsibilities, would also be involved in this process. This can lead to significant bureaucratic delays as the programs work their way through the multi-agency approval process.

Technological issues: Some technological issues with the pool pump timers prevented them from working consistently and required significant manual efforts on the part of the customer to maintain their proper operation. It is believed that many customers quit using the timers for this reason. Furthermore, it is not always an option to run the pool pump only during the off-peak. Today, modern pool designs include additional technologies (i.e. waterfalls) that run when the pool is in use, and commercial pools must run for health and safety reasons.

Voluntary participation: Except for the mandatory TOU rates program for medium and large commercial and industrial customers, the Energy Commission and CPUC chose to adopt load management standards that did not require mandatory or default participation. The voluntary nature of the programs may have been one reason for some of the low participation rates.

No market for DR: Because DR programs were under the control of the utilities, there was little private sector involvement in DR. The resulting lack of competition slowed innovation in this area, providing fewer cost effective and creative options upon which to base the load management standards.

Cyclical nature of capacity shortages: The load management standards were created in response to an energy crisis, which was followed by a shortage of capacity in California. As capacity surpluses eventually grew and the need for peak reductions became less critical, load management dropped on the priority lists of policy makers and utility decision makers. It was then difficult to shift attention and resources back to the standards as they lost momentum.

Despite these issues, load management standards do show some promise, as is illustrated in the TOU and direct load control programs that remain. Additionally, the Energy Commission has had great success with its appliance and building standards in promoting energy efficiency, suggesting that there is potential for new load management standards to be effective in the future. This is taken up in the next chapter.

CHAPTER 3: REINVENTING THE LOAD MANAGEMENT STANDARDS

The Energy Commission's load management authority may be a valuable, even necessary, policy tool for the state to bridge the gap between the current level of DR in California and its full cost-effective potential. There are two areas in which this policy tool may be particularly effective. One is modifying the default tariff, which could be changed to a dynamic tariff that reflects the higher cost of using electricity during critical peak hours and lower cost during off-peak hours, and provides a sharply directed signal for lowering peak demand. The other is the adoption of technologies that enable customers to better respond to the opportunities created by dynamic pricing tariffs.

One way to go about reinventing the load management standards is to engage in a visioning exercise where strawman proposals are aired and debated. Toward that end, this chapter lays out three new illustrative load management proposals. One calls for replacing the default rate design with a dynamic pricing tariff, while the other two call for deploying enabling technologies directed at residential and non-residential customers.

The illustrative proposals focus on the two key barriers to the faster deployment of DR in the state: lack of dynamic pricing and lack of enabling technologies. They are designed for use on a day-ahead basis but, if need be, can also be deployed on a day-of basis. From a planning perspective, both triggering strategies are important. The day-ahead strategy decreases the likelihood that emergencies will be encountered while the day-of strategy provides a mechanism for dealing with the emergency when it does occur. The proposals are designed to enhance the role of pricing mechanisms for managing demand and supply and decrease the role of cash incentives, which are much more expensive and difficult to sustain over the long haul.

The strawman proposals are not intended to be definitive, but are intended to simply play a catalytic role in starting an important conversation with the stakeholders in the state's DR process. Other proposals, or modified versions of the three proposals suggested here, may emerge at the June 5 *Integrated Energy Policy Report* workshop on load management standards.

These three items for discussion were identified in Chapter 1 as areas in which particular attention is needed from a policy perspective. However, there are some additional areas in which load management standards could potentially be useful for promoting DR. The standards could be used to encourage permanent load shifting through technologies like thermal storage and pumped storage. It may also be productive to have a statewide standard for communicating technologies that would put in place price/emergency signal protocols, rather than the current situation in which each utility has its own system for communicating with smart thermostats and other DR-enabling technologies. Additionally the load management standards could be used as a premise to hold hearings through which to explore in-depth the barriers that AB 1X poses to DR and ways of addressing this issue. This last issue is discussed in the next section dealing with "New Proposal on Dynamic Pricing of Electricity."

Financial Benefits

Before describing the specifics of the three strawman proposals, it is important to gauge the economic impact they may have in the state. Consider first the case in which no load management standards are in place. In this scenario, dynamic pricing would probably be offered on an opt-in basis by the utilities as AMI is rolled out to customers.[20] Once AMI has been fully deployed, dynamic pricing becomes feasible, but on an opt-in basis may not achieve a participation rate greater than 20 percent. In this scenario, customers would probably not be equipped with enabling technologies such as a smart thermostat. Under these assumptions, using the analytical methodology described in Chapter 1, dynamic pricing could achieve a reduction in system peak demand of around three percent, representing over $1 billion in financial benefits over the next 20 years.[21]

Now consider a second case in which a dynamic pricing standard is adopted in California, requiring that some form of dynamic pricing be offered as the default rate. Under these conditions, the literature suggests that 80 percent of customers are likely to stay on dynamic pricing, with the other 20 percent opting back to their old rate. Assuming that these dynamic pricing customers are not equipped with enabling technology, the peak demand reduction could increase to some 10 percent, representing financial benefits of nearly $6 billion. The incremental benefit of the dynamic pricing standard would be the difference between this and the previous calculation: an increase in peak demand reduction of roughly 7 percentage points and incremental financial benefits of around $4 billion.

Now, if on top of the default dynamic pricing standard, another standard was imposed that requires the installation of programmable communicating thermostats (PCT) in all residential dwellings, the potential benefits would rise even further. The standard could require that all residential customers be equipped with PCTs that can receive price signals from the utilities and/or the independent system operator (CA ISO) so their temperature setback would be raised by a few degrees during critical-priced periods. With this technology installed, the estimated peak reduction potential might increase incrementally by roughly 8 percentage points to around 18 percent.[22] The present value of the benefits would increase incrementally by around $5 billion to $10 billion.[23]

Finally, an automated demand response standard could be included with the PCT standard and the dynamic pricing standard. This could equip commercial and industrial customers with system-wide automation, allowing them to leverage existing energy management control systems and automatically manage lights, air conditioning, and other sources of load during peak times. With this addition, the estimated peak reduction potential could increase incrementally by roughly 2 percentage points to approximately 20 percent. The present value of the benefits could increase incrementally by around $1 billion to $11 billion.

These approximate estimates of the benefits of new load management standards are summarized in Figure 2.

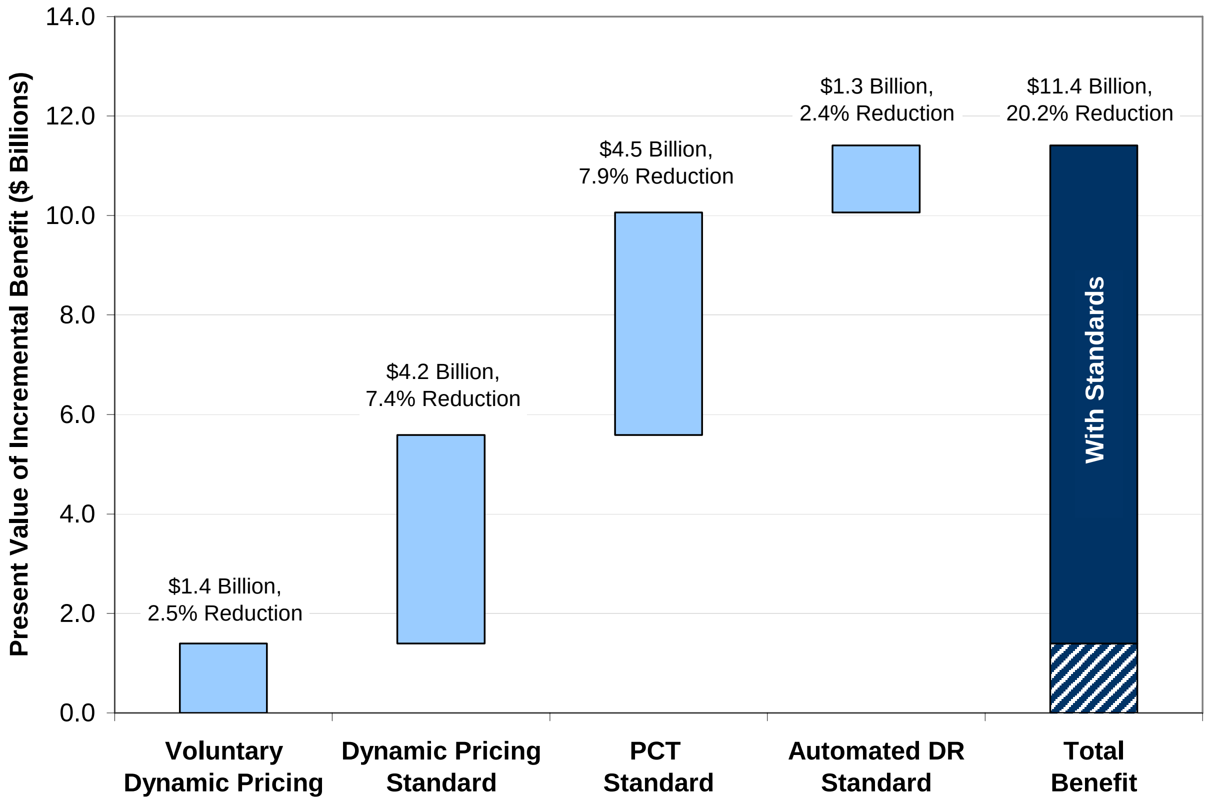

Figure 2: Incremental Benefits of Load Management Standards

In the remainder of this chapter, brief descriptions are provided of the three illustrative load management proposals, including each proposal's intent, provisions, costs and a possible implementation schedule. These strawman proposals are intended to be entirely illustrative and to initiate a conversation with the stakeholders regarding the types of policies that could be pursued through the Energy Commission's authority to set load management standards. These proposals are not intended to automatically become the next generation of load management standards. To implement a load management standard, the Energy Commission would be required to follow a formal rulemaking process as it does with appliance and building standards.

New Proposal on Dynamic Electricity Pricing

Intent

California law states that electricity is essential to the health, safety and welfare of the people of this state.[24] The state's experience during the Western Energy Crisis provided evidence that the efficient provision of electricity is conditional on providing customers with accurate and timely information about the cost of electricity and on giving them capability to exhibit what has since become known as demand response.

When prices are hidden from customers and they are not given the opportunity to respond, control of the market is transferred from customers to suppliers resulting in higher prices and costs. Additionally, the risk of brown-outs and blackouts that affect all end-users, regardless of the value they place on them, increases.

Traditional interruptible programs do not provide customers with the ability to take into consideration the value that they place on particular end-uses when controlling their consumption. For example, A/C cycling programs target only one end-use for the reason that it is easy to control, not because it is of low value to the consumer. Dynamic pricing allows consumers to create their own "loading order" of end-uses with which to respond.

Based on these postulates and on the empirical knowledge that has been gained through the Statewide Pricing Pilot (SPP) and numerous workshops that have been held since the passage of R.02-06-001 by the CPUC, a new proposal on dynamic pricing of electricity has been developed.[25]

Provisions

Each electric utility in the state shall bring its default tariffs into conformity with the principles of dynamic pricing. Dynamic pricing tariffs reflect the long run cost of avoided generation, transmission and distribution capacity and the short-run cost of energy. Examples include critical-peak pricing, variable peak pricing and real time pricing. Each utility shall choose one dynamic pricing option from this list. Customers would be given a choice of opting-out to a non-dynamic tariff provided that such tariff is fully burdened with the appropriate costs, including hedging costs as appropriate.

The default dynamic pricing tariff would be designed so that most customers would save money when they receive their electric service under it compared to their existing default tariff. Of course, customers whose load profile is flatter than the average customer's load profile would be the immediate beneficiaries due to the fact that, under their old tariff, they were subsidizing peakier-than-average customers' bills. In addition, the tariff would include a credit equal to the hedging premium that is embodied in the existing default tariff, ensuring that several more customers who are peakier than average will also benefit from it.[26] Finally, as customers curtail their peak load and/or shift it to less costly periods, the number of customers who will lower their bills with dynamic pricing would rise still further. An illustrative analysis cited in *State of DR* showed that 97 percent of customers may be able to benefit from imaginatively designed critical-peak pricing tariffs.

This proposal also requires that electric utilities revamp the mechanisms through which they convey the price of electricity to customers. They would provide clear and simple bills to customers that convey in a transparent manner the price of electricity. Companion standards would ensure that customers are equipped with metering and communications technologies and with energy management equipment to assist them in adapting their consumption patterns to minimize their bills.

Benefits

Default dynamic pricing would ensure equity and efficiency in the pricing of electricity. Customers will pay closer to the actual costs of producing and delivering power at the time that it is used. They would have an incentive to curtail their use when it is expensive and to expand their use when it is less expensive, thus ensuring the fullest utilization of the state's electricity production and delivery infrastructure and lowering energy costs for all Californians.

When dynamic pricing becomes the default tariff, substantial benefits would flow from it to the citizens of the state. As shown earlier in this chapter, if 80 percent of the state's customers stay on dynamic pricing, the market potential impact is estimated at around nine percent, amounting to roughly $5 billion in benefits over the next two decades. Offering dynamic pricing in conjunction with enabling technologies such as PCTs for dwellings, Automated DR for businesses and corresponding technologies for industrial facilities would further increase these benefits. This is discussed in more detail later in this chapter.

Costs

The primary cost of dynamic pricing is the cost of advanced metering infrastructure (AMI) that is not covered by the operational benefits that flow from its implementation.

AMI is already in place for customers above 200 kW demand at the three IOUs, having been installed at a cost of $34 million through special legislation during the energy crisis (AB 29X). SMUD is also known to have AMI installed for at least some of its large customers.

For customers under 200 kW demand, AMI is being deployed by two investor-owned utilities, as they have been given the necessary authorization by the CPUC. The third investor-owned utility is expected to file its application in the summer.

Implementation Schedule

A move toward default dynamic pricing represents a paradigm shift in electric ratemaking practices. As such, it would be important to give customers sufficient time to adapt to the new pricing regime. Anecdotal evidence suggests that while customers have initial misperceptions and fears about dynamic pricing, those fears tend to dissipate once they have some experience on the rate.

One way of doing this might be to gradually phase in the default tariff over a two- or three-year transition period. During the first year of the transition, customers might not be billed any more than they would have been billed on the existing default tariff. In other words, they would be offered a 100 percent bill guarantee. Then, over the course of the following one or two years, the portion of the bill subject to bill protection could be progressively ramped down such that by the third or fourth year there would be no bill guarantee. However, opting out of the tariff would be an option to the customers after the first year.

Issues Arising out of Assembly Bill 1X

Prima facie, Assembly Bill 1X represents a barrier of indeterminate length to the institution of dynamic pricing as the default rate for residential customers. The statute was designed to protect a portion of each residential customer's usage from the costs of reimbursing the state for power purchased during the crisis by capping their rates on the first 130 percent of baseline usage. However, it has had several unintended consequences.

As shown in *State of DR*, this has resulted in cross-subsidies within residential customers that may amount to between $3.0 billion and $10.6 billion since the energy crisis. These cross-subsidies could become even larger as the rates on the uncapped tiers increase. Under the requirements of AB 1X, this would happen under normal inflation, even absent of any increases in the cost of producing and delivering electricity.

In addition, AB 1X has prevented utilities from offering dynamic pricing as a default tariff. It has led to innovations such as peak-time rebates that do not address the fundamental inequities created by the existing tariff regime and whose effectiveness for achieving demand response objectives was not validated in the Statewide Pricing Pilot.

For dynamic pricing to achieve its full potential, the unintended consequences of the act must be corrected. One possible solution would be to progressively phase out the AB 1X rate cap, an approach proposed by SDG&E in a recent rate filing.[27] Or, the amount of electricity consumption that is subject to the rate cap could also be progressively reduced over time. In addition to lessening the impacts of AB 1X, this would provide a smoother, more gradual transition when the rate cap is finally lifted.

Another solution that has been suggested is to make a slight modification to the wording of the act. The relevant language of the act is reproduced below:

“In no case shall the public utility commission increase the electricity charges in effect on … [January 19, 2002] … for residential customers for existing baseline quantities or usage by those customers of up to 130% of existing baseline quantities.”

The proposed alternative language, highlighted in bold, is shown below:

“In no case shall the public utility commission **adopt rates that** increase the **costs based on the** electricity charges in effect on … [January 19, 2002] … for residential customers for existing baseline quantities or usage by those customers of up to 130% of existing baseline quantities.”

This would require that two bills be computed for each residential customer, one with the tariff that was in place on January 19, 2002 and one with the dynamic pricing tariff, and that they will be billed the lower of the two amounts. Since most smaller customers whose usage is confined to 130 percent of baseline are flatter-than-average customers, they are likely to gain from dynamic pricing and would thus be billed on the dynamic pricing tariff. However, while this would correct for the current restrictions on dynamic pricing, it would not resolve the issue of subsidies from high users to low users that is expected to grow as the cap forces rates in the upper tiers to rise dramatically.

While these are not the only options for overcoming the barriers to dynamic pricing that are proposed by AB 1X, they demonstrate two of the possible solutions to a problem that is becoming increasingly important to address.

New Proposal on Programmable Communicating Thermostats (PCTs)

Intent

Since central air conditioning accounts for about 40 percent of peak demand in the state and its share is likely to grow over time, it is important to take measures to control its use. This becomes essential during critical times when power prices are climbing in the wholesale market or when a system emergency is encountered.

Air conditioning use is split roughly equally between residential and commercial buildings. This proposal deals with air conditioning in residential and small commercial buildings. A companion proposal deals with air conditioning use in commercial buildings.

Research carried out in the statewide pricing pilot (SPP) showed that the demand response impact of critical-peak pricing tariffs could be doubled through the use of "smart" thermostats that raised the setback temperature in response to a signal that was communicated to them by the utility. The smart thermostats, by enabling automated response, also ensured actions could be taken in the customer's premise without the customer having to be at home. Thus, it was possible to couple them with day-of price signals in addition to coupling them with day-ahead price signals.

The smart thermostats that were tested in the SPP have since evolved into programmable communicating thermostats (PCTs). PCTs have more features, cost less and are expected to become commercially available to homeowners, contractors and builders in the near future.

Modifications are being made in Title 24 that would require all new and remodeled buildings in the state to be equipped with a PCT beginning in January 2009. At some future date, it is possible that PCTs will be applied retroactively to existing buildings. The presence of PCTs will enhance energy efficiency in residences, since they will come equipped with pre-set timings. However, it will not lower air conditioning use on critical days unless a signal is communicated to a PCT.

Provisions

When the power system encounters critical conditions on a day-of basis, the proposal would require that utilities and the CA ISO send signals to the PCTs that would raise their setpoint by four degrees F. Only if this fails to resolve the system emergency would utilities take recourse to the conventional practice of rotating outages. When the PCTs are operated in this emergency mode, the customer override feature would be disabled. Such operation could be limited to once a year and may be triggered by local or system-wide emergencies.

In addition, the proposal would require utilities to activate the PCTs during critical conditions that are triggered by economic (and possibly reliability) criteria. In the economic mode of operation, the PCTs would not be dispatched by more than the amount that is written into the dynamic pricing tariff. Customers would have the option of overriding the signal if they so wish.

Benefits
It is anticipated that this proposal would yield significant benefits when offered in conjunction with the default dynamic pricing proposal. The incremental load impact that might be expected from this proposal, assuming it applies to all dwellings with central AC in the state, is around 2,300 MW. This is valued at roughly $ 2 billion over the next two decades. The impact will be substantially smaller if it is limited to new construction and remodeling. Currently, Title 24 is limited to new construction and remodeling. However, it is anticipated that utility programs that promote PCTs will eventually transform the energy marketplace, leading to large scale adoption of PCTs in existing housing units.

Costs
The cost of PCTs is coming down rapidly. They are expected to retail at $99 within a year’s time and by the time the proposal would into effect, the cost could be no more than $30 higher than conventional programmable thermostats.

New Proposal on Automated Demand Response (Automated DR)

Intent

Commercial buildings account for some 20 percent of the state's peak load. They are a prime target for dynamic pricing programs. However, without enabling technologies, these buildings find it difficult to respond to higher prices. This is especially true for small commercial and industrial facilities with loads of less than 20 kW (as shown in the SPP) but it also applies generally to all commercial and industrial facilities.

Research carried out with an assortment of 40 buildings in the state over the past four years by the Demand Response Research Center suggests that automated demand response systems (Automated DR) can lower peak demands in commercial and industrial facilities by 13 to 14 percent.[28] Automated DR works in conjunction with energy management and control systems (EMCS) that are installed in many commercial and industrial facilities and with other end-use devices that can receive remotely broadcast signals or signals that can be conveyed through the Internet.

This proposal would help curtail peak loads in commercial and industrial facilities on a day-ahead and day-of basis by instituting Automated DR. It works with a diverse array of DR strategies including pre-cooling on a day-ahead basis and other strategies on a day-of basis such as global temperature adjustment, zonal temperature adjustment, reduced perimeter fan speed, dimming lights, increased chilled water temperature and switched elevator banks.

Provisions

When the power system encounters critical conditions on a day-of basis, the proposal would require that utilities and the CA ISO send signals to all commercial and industrial buildings to activate their Automated DR systems. Only if this fails to resolve the system emergency would utilities take recourse to the conventional practice of rotating outages.

In addition, the proposal would require utilities to activate the Automated DR systems on a day-ahead basis in order to diminish peak demand whenever it is economically called for.

Benefits

It is anticipated that this proposal would yield significant benefits when offered in conjunction with default dynamic pricing for commercial and industrial facilities. The incremental load impact that is expected from this proposal, assuming it applies to all commercial and industrial facilities in the state, is around 1,460 MW. This is valued at over $1 billion over the next two decades. The benefits would be substantially smaller if the proposal is limited to new construction.

Costs

The cost of Automated DR varies by building. An average estimate puts it at around $800. In addition, there would be operating costs associated with running a server. The technology is expected to become commercially available this year.

CHAPTER 4: CONCLUSIONS

There is a currently a deficit of demand response in California. This is largely due to the absence of dynamic pricing and enabling technologies that allow customers to respond to higher prices during critical times with little effort. One potential way of eliminating the DR deficit is by invoking the authority of the Energy Commission to set load management standards.

The earlier experience of the state with load management standards was successful. The standards were useful in stimulating discussion about innovative ways of reducing peak load and deferring or eliminating the need for peaking capacity. Some of these standards, such as mandatory TOU rates for large customers and direct load control of central air conditioners, are still around and continue to be refined. However, the current and projected DR deficit is large and persistent and new avenues for managing it need to be aired and discussed.

Given the state's success with implementing appliance and building standards, it makes eminent sense to revisit the load management standards. Of course, the next generation of standards will differ substantially from the first generation, since much has changed in the intervening three decades. To help in reinventing the load management standards, it is necessary to engage in a visioning exercise.

To facilitate the process, the paper has provided three strawman proposals that can serve as a springboard for further discussion. These proposals may or may not evolve to be the final standards adopted by the Energy Commission. However, despite their illustrative nature, they present a compelling picture of how much additional benefit would be derived by pursuing the Energy Commission's load management standard-setting authority.

The illustrative proposals focus on the two key barriers to the faster deployment of DR in the state: lack of dynamic pricing and lack of enabling technologies. They are designed for use on a day-ahead basis, but if need be, can also be deployed on a day-of basis. From a planning perspective, both triggering strategies are important. The day-ahead strategy decreases the likelihood that emergencies will be encountered while the day-of strategy provides a mechanism for dealing with the emergency when it does occur. The proposals are designed to enhance the role of pricing mechanisms for managing demand and supply and decrease the role of cash incentives which are much more expensive and difficult to sustain over the long haul.

APPENDIX A: MONTE CARLO SIMULATIONS OF DEMAND RESPONSE IMPACT ESTIMATES

In the body of this report, point estimates for the financial value of demand response have been provided to illustrate the magnitude of DR's potential benefits. However, all such estimates are shrouded in uncertainty. To capture this uncertainty, Monte Carlo simulations were used to develop probability distributions around the long-run financial benefits of demand response. Using a software package called Crystal Ball, probability distributions were assigned to each key variable based on expert judgment and prior empirical work. The model was then run 5,000 times by holding random draws for each input variable and re-computing the output. When the outputs are assembled, they yield a probability distribution of benefits. The methodology is described below.

For simplicity, each uncertain variable in the analysis was assumed to be triangularly distributed. The uncertain variables are listed in Table 6, with their assumed minimum, maximum, and mode values.

Table 6: Minimum, Maximum, and Mode Values of Uncertain Input Variables

Variable	Minimum	Mode	Maximum
Value of Capacity ($/kW-year)	$30/kW-yr	$52/kW-yr	$85/kW-yr
T&D % of energy and gen. capacity cost	2%	10%	20%
Energy % of capacity cost	5%	12%	20%
Residential customer-level peak reduction	15.0% (20% reduction from mode value)	18.8%	22.6% (20% increase from mode value)
Commercial customer-level peak reduction	5.8% (20% reduction from mode value)	7.3%	8.8% (20% increase from mode value)
Industrial customer-level peak reduction	7.5% (20% reduction from mode value)	9.4%	11.3% (20% increase from mode value)
Participation level (for market potential estimate)	5%	40%	85%

In a Monte Carlo simulation, a value for each variable is randomly drawn according to the probability distributions defined above. The resulting estimate of financial benefits of DR is calculated using these values and recorded. This process is repeated 5,000 times. The end result is a distribution around the estimate of DR benefits as shown in Figure 3. This figure illustrates the resulting distribution for the value of DR benefits.

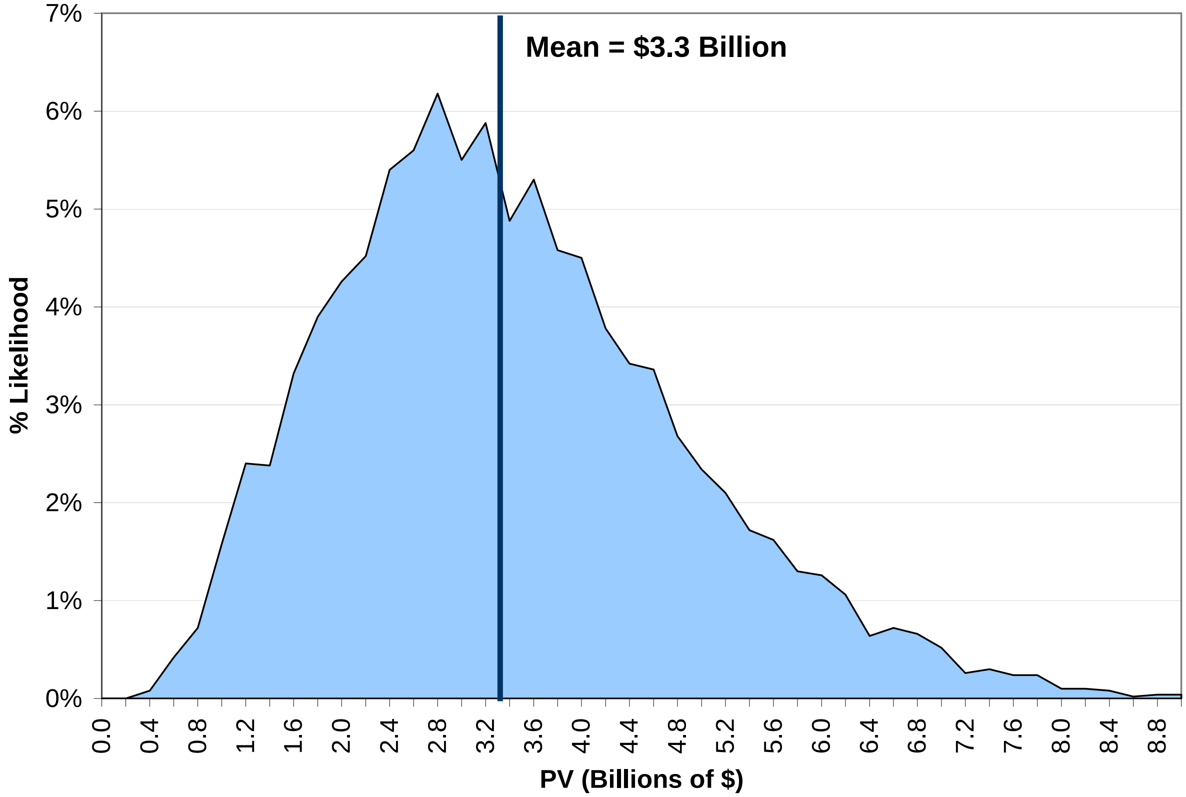

Figure 3: Probability Density Function of PV of DR Benefits in California (Market Potential Projection)

Note that because all of the uncertain variables are not symmetrically distributed, the resulting distribution of the estimate of DR benefits is also not symmetrically distributed. As a result, the mean value of the distribution is not exactly equal to the point estimate provided in Chapter 1 and is actually higher than that estimate ($2.8 billion).

It is easy to read off the 10^{th} and 90^{th} percentiles of this distribution. The 10^{th} percentile is a value that is likely to be exceeded with a probability of 90 percent. The 90^{th} percentile is a value that is likely to be exceeded with a probability of 10 percent. These values are illustrated in Figure 4.

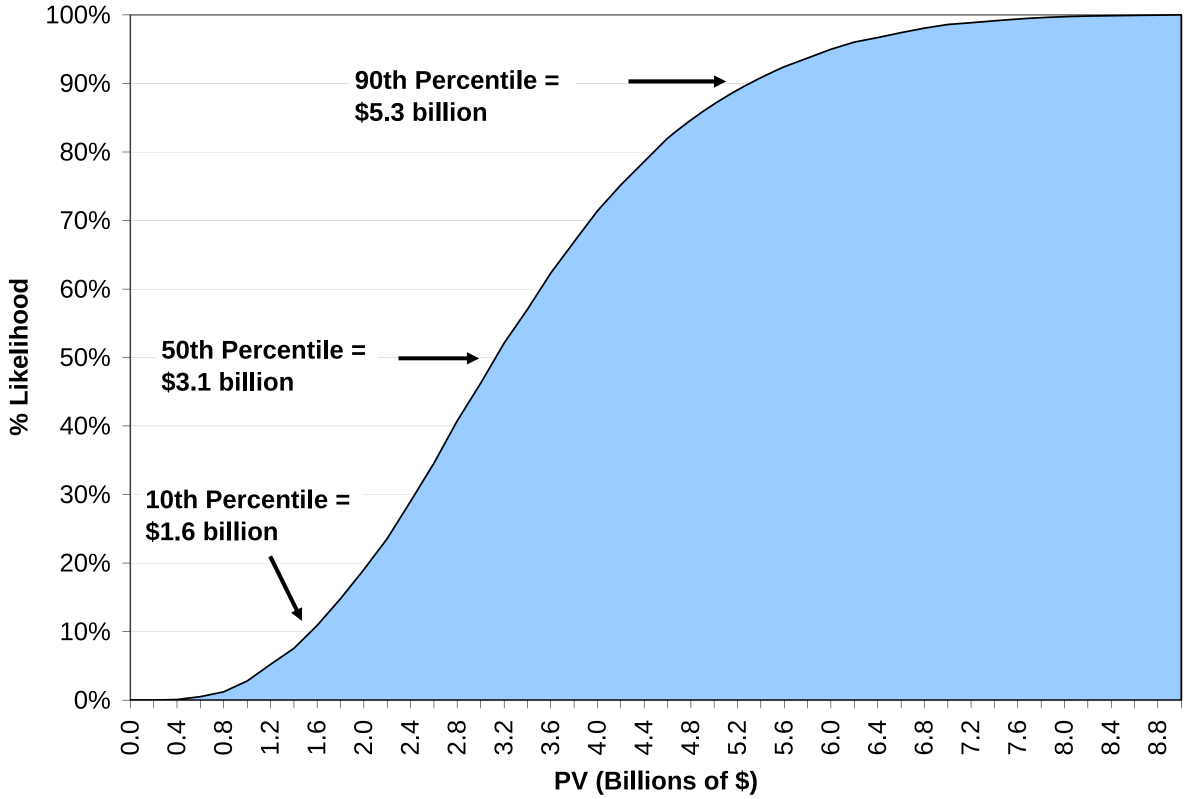

Figure 4: Cumulative Distribution Function of PV of DR Benefits in California (Market Potential Projection)

Based on the Monte Carlo analysis, there is a 90 percent chance that the PV of DR will be greater than $1.6 billion, a 50 percent chance that it will be greater than $3.1 billion, and a 10 percent chance that it will be greater than $5.3 billion. This spread in the possible outcomes illustrates uncertainty in these estimates. Similar ranges would be expected for the other estimates of DR benefits in this paper.

APPENDIX B: LIST OF ACRONYMS

AC	—	Air conditioning
AMI	—	Advanced metering infrastructure
APS	—	Arizona Public Service
BEC	—	Business Energy Coalition
C&I	—	Commercial and industrial
CAISO	—	California Independent System Operator
CARE	—	California Alternative Rates for Energy
CPA	—	California Power Authority
CPA DRP	—	CPA Demand Reserves Partnership
CPP	—	Critical Peak Pricing
CPUC	—	California Public Utilities Commission
DBP	—	Demand Bidding Program
DLC	—	Direct load control
DOE	—	Department of Energy
DR	—	Demand response
DRP	—	Demand Reserves Program
DSM	—	Demand side management
EAP	—	Energy Action Plan
EE	—	Energy efficiency
FERC	—	Federal Energy Regulatory Commission
GWh	—	Gigawatthour
HPO	—	Hourly Pricing Option
IEPR	—	Integrated Energy Policy Report
IOU	—	Investor-owned utility
ISO	—	Independent system operator
kW	—	Kilowatt
kWh	—	Kilowatthour
MRTU	—	Market Redesign and Technical Upgrade
MW	—	Megawatt
MWh	—	Megawatthour
OIR	—	Order Instituting Rulemaking
PG&E	—	Pacific Gas and Electric Company
PTR	—	Peak Time Rebate
RTO	—	Regional transmission organization
RTP	—	Real-time pricing
SCE	—	Southern California Edison
SDG&E	—	San Diego Gas and Electric Company
SPM	—	Standard Practice Manual
SPP	—	Statewide Pricing Pilot
SRP	—	Salt River Project
TOD	—	Time-of-Day Pricing
TOU	—	Time-of-use
VPP	—	Variable Peak Pricing

WG1	—	Working Group 1
WG2	—	Working Group 2
WG3	—	Working Group 3

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ENDNOTES

[1] If reliability-triggered programs are included as well, the utilities are expected to achieve a 5.7 percent reduction in peak demand. However, reliability-triggered programs are not part of the five percent target. This is elaborated upon in *The State of Demand Response in California*, by Ahmad Faruqui and Ryan Hledik, Draft Consultant Report prepared for the California Energy Commission, April 2007. That document is hereafter referenced as *State of DR*.
[2] This Chapter is adapted from *State of DR*.
[3] It should be noted that these projections are in addition to the current peak reductions achieved through reliability-triggered demand response. For a description of the distinction between price-responsive DR and reliability-triggered DR programs, see pp. 8-9 of *State of DR*.
[4] Computational details are provided in Sidebar 1.
[5] See Appendix A.
[6] Much higher responses are possible in specific facilities that have time-flexible production processes, energy storage systems and back-up generation. Since these are highly facility-specific, they have not been included in our estimate of technical potential.
[7] These turbines come in sizes generally ranging from 50 MW to 100 MW.
[8] In R.02-06-001, the CPUC specified a value of $85/kW-year. That value is widely accepted throughout the mainland United States. However, once the revenue stream associated with energy sales from the operation of the turbine is subtracted, a value of $52/kW-year is obtained.
[9] Sam Newell and Frank Felder, "Quantifying Demand Response Benefits in PJM," Study Report Prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI), January 29, 2007.
[10] Assuming 272,385 GWh of consumption times a weighted-average retail rate of 12.45 cents/kWh. For consumption data, see http://www.energy.ca.gov/electricity/consumption_by_sector.html. For electricity rates, see http://www.energy.ca.gov/electricity/statewide_weightavg_sector.html.
[11] Including reliability-triggered DR programs increases the anticipated total peak reduction to 5.7 percent, although these programs are not included in the *EAP II*'s target.
[12] CEC, *California's Electricity Supply and Demand Overview*, California State Assembly Utilities & Commerce Committee Informational Hearing, March 29, 2007.
[13] California Public Resources Code, Chapter 25403.5.
[14] This includes all investor owned utilities, publicly owned utilities, municipal utilities, and co-ops.
[15] California Public Resources Code, Chapter 25403.5.
[16] For an example of one such study, see CEC consultant report, *Analysis of Feasibility of Electrical Load Management for Irrigated Agriculture in California*, April 1979.
[17] Chinbang Chung, John Flory, Richard Foley, Richard M. Hairston, Darwin C. Hall, Roger Levy, Margaret Morgan, Valerie Tamburri, John Wilson, 1978, *Staff Report on Load Management Standards*, California Energy Commission, p. 7.
[18] California Energy Commission, *Proceedings of the Load Management Customer Participation Workshop*, October 1979 and *Proceedings of the Load Management Equipment Workshop*, September 1979.
[19] www.energy.ca.gov/2005publications/CEC-400-2005-021/CEC-400-2005-021.PDF
[20] As proposed by PG&E.
[21] For the methodology behind these computations, consult Sidebar 1. Additionally, Monte Carlo simulations were performed to better understand the range of uncertainty around these estimates. For details, see Appendix A.
[22] Note that this estimate assumes that these benefits will accrue over a 20 year period during which all residential customers have PCTs installed in their homes. There would be an initial period during which the PCTs would need to be rolled out to customers.
[23] Note that some of the figures may not add up due to rounding.
[24] Public Resources Code Chapter 25001.
[25] Public Resources Code Chapter 25403.5
[26] For a more detailed description of the hedging premium, see *State of DR*, page 51.
[27] Direct Testimony of Robert W. Hansen on Behalf of SDG&E. January 31, 2007. A.07-01-047.

[28] Statewide Auto-DR Planning Meeting, November 13, 2006, DRRC. http://drrc.lbl.gov/pubs/StatewideADR07_Nov13_LBNL.pdf.