Using Demand Responsive Loads to Meet California's Reliability Needs

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ABSTRACT

The San Francisco Peninsula experienced rotating outages related to inadequate supply on June 14, 2000, which was followed by days of alerts and blackouts in January 2001. It was apparent that the state needed to take dramatic actions to avoid serious reliability problems in the summer of 2001. This paper reports on California's experience with demand response policies in reducing peak electricity demand and increasing reliability.

During 2001 the state provided almost $1 billion for energy efficiency and demand response programs. Of these funds, about $50 million was spent on creating demand response capability in buildings, and $35 million was spent to install about 23,300 real-time meters for all customers with over 200 kW maximum demand. By the end of 2001, the demand response capability attributable to energy efficiency programs was about 250 MW. In addition, customers with real-time meters, representing about one-fourth (12,000 MW) of the statewide demand, will have meters and communication that will enable their participation in demand response programs. The goal is to obtain about 2,000 MW of demand response (or 17 percent of the air-conditioning and lighting load) from nonresidential customers at the specific times when reliability is threatened.

While the technology exists to create a large amount of demand responsive load, the major barrier is the lack of financial incentives and pricing structures that would reward customers for making investments and efforts to respond to price signals.

The Need for Demand Response in California

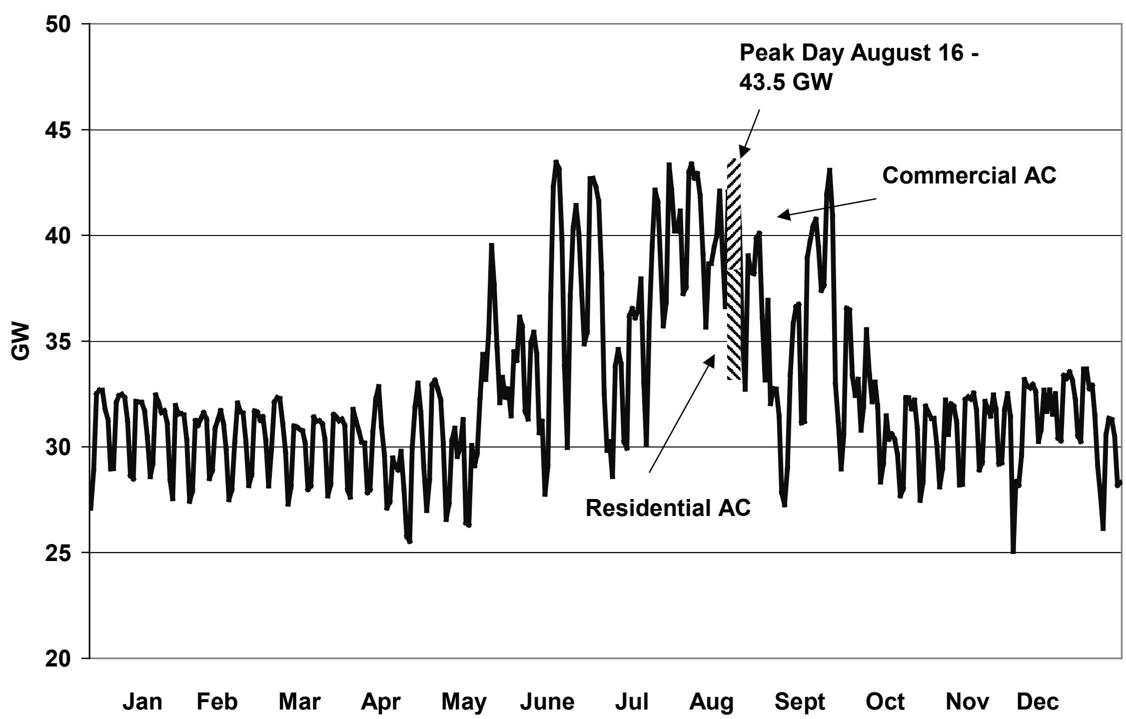
In the early and mid-1990s, as restructuring of the electricity market took shape, there was a sharp drop in the additions to generating capacity due to uncertainties regarding who would be responsible for owning and operating new power plants. In 1999, the California Energy Commission published a report highlighting the potential for reliability problems from inadequate power supplies and the need for demand response programs. (CEC 1999). On June 14, 2000, on an unusually hot day (the temperature reached 103 ° F in San Francisco), the California Independent System Operator (CAISO) was forced to institute rotating outages in the San Francisco Bay Area in order to avoid broader blackouts. The costs in terms of both direct economic losses, especially to high technology companies, as well as threats to public health and safety were enormous.

The state immediately began planning a massive program to increase efficiency and demand response programs, as well as to speed the licensing of new power plants. In the Fall of 2000 and the Spring of 2001 several bills were passed allocating about $1 billion for such programs, of which about $50 million was spent on demand response capabilities.

In addition, $35 million is being spent to install real-time meters with communication capability for all customers greater than 200 kW. This was a highly unusual program for the state to undertake, but in discussions with the Governor's Office and the utilities, it became apparent that the lack of meters for most large customers was the major barrier to all demand response and real-time pricing options that were being considered. The conclusion was a proposal, accepted by the Legislature, that the state would spend what was a small relatively amount of funds in relation to the potential benefits that could be achieved. So far contracts with the major investor-owned and municipal utilities have been signed to install 23,300 meters, representing about 13,000 MW in peak demand.

Figure 1 shows one year of load data for the CAISO control area (about 80 percent of the total state load). It shows that for three seasons (fall, winter, spring) weekday peaks are about 33,000 MW. This rises to about 38,000 MW during typical summer days, with spikes up to about 43,000 MW on the hottest days. The real challenge is how to reduce demand during the 10 to 15 hottest days of the year. Since building power plants to meet those few hours of "peakiest" load would be very expensive, and the cost of rotating outages even higher, demand response is cheaper, safer and cleaner.

Figure 1. CAISO Daily Peak Loads in 2000



Source: CAISO

Demand Response Programs in California

Most utility-sponsored demand response programs have focused on traditional interruptible programs in which customers are given a lower electricity rate in return for agreeing to be curtailed up to a maximum number of hours per year if called on by the utility.

In recent years about 2,000 MW of interruptible load was available. However, when these programs began to be called upon extensively in 2000 and 2001, it immediately became apparent that many of the customers that had signed up for the discounted rate were not ready to actually be curtailed. In fact, many had loads that were not even appropriate for interruption, like hotels hospitals and prisons. In addition, while many industrial loads can be curtailed at low cost, high tech loads incur large production loses when they are curtailed, and huge costs if they are subject to rotating outages.

Based on these observations, it became apparent that using controls on thermostats and lights to put "shock absorbers" in the demand-side of the utility system made more sense than the "brittle" response of rotating outages. As a result, the CEC began focusing on how buildings could be demand responsive by letting temperatures float up a few degrees and dimming lights without inconveniencing the building occupants or reducing their productivity.

The CASIO Demand Relief Program

The program offered in 2001 that was most well-suited to buildings was the CAISO Demand Relief Program (DRP) , shown in Table 1.

Table 1. CAISO 2001 DRP

Capacity payment	\$80/kW-summer (June – Sept.)
Energy payment	\$.50/kWh curtailed
Program operation	Implemented at Stage "2.9," i.e., before Stage 3 rotating outages. Maximum calls: 24 hrs./mo., 4 calls/mo., 7 calls/yr. Minimum notification time 35 minutes Minimum bid 1 MW (loads can be aggregated) Capacity payment reduced in proportion to nonperformance when called.

Source: CAISO 2000.

For a typical commercial office building, the demand response and financial results shown in Table 2 could be achieved.

Table 2. Payments to a Typical Building from the CAISO DRP

Building characteristics	20,000 sq. feet, 100 kW maximum demand:
Load reductions	A/C 60 kW, save 1/3 = 20 kW Lighting 20 kW, save 1/3 = 7 kW
Financial benefits	Capacity payments = \$80 x 27 kW = \$2,160/summer Energy payments = \$.50 x27 kW x ~42 hrs/yr. = \$567/summer Total = \$2,727 for one summer

The CAISO also offered a Discretionary Load Curtailment Program (DLCP) for customers who did not want to commit to reduce load when called upon, but would be willing to curtail load on a "discretionary" basis. For this the CAISO offered to pay \$.35/kWh with no capacity payment.

The Summer 2001 Experience with Demand Response

The CAISO got significant interest from customers and aggregators to their two requests for bid. By April 2001 the CAISO Board had approved 1,100 MW of demand relief agreements, of which they expected to get about 700 MW of reliable load reduction. (CAISO 2001). As events unfolded in California, the state's investor-owned utilities lost their "credit worthiness" and hence their ability to purchase power, so that responsibility was taken over by the state's Department of Water Resources. As a result, the CAISO had to look to DWR for financial backing for the DRP and DLCP incentive payments. But by May 2001 DWR had entered into many contracts for power, and the market prices for power plunged. This in turn led DWR to conclude that the CAISO's incentive payments were too high relative to power purchases. CAISO had to lower the incentive payments by about one-half, and they lost many customers that had signed up under their programs.

In May 2001, the Governor's Office directed DWR to create a Demand Bidding Program. Working with the utilities, they created a program with prices established at four levels between \$.10 and \$.70/kWh. The program went into effect on August 1, 2001. However, since then, market prices for power have been below \$.10/kWh most of the time, and hence no demand response offers have been accepted. Since no demand bids to DWR have been accepted, interest in the program has evaporated, no load reductions have been achieved, and none could be expected in the future from the program.

The situation for 2002 therefore, does not look encouraging. The CAISO has stated its intent not to offer any demand relief programs. Utilities have indicated they do not plan to actively market their load management programs. Market prices are likely to stay low, which means the DWR demand bidding program will not be attractive to customers or load aggregators. The result is that there is less demand response capability at the start of 2002 than there was in 2000.

In particular, the prospects for demand response in buildings, a major focus of the CEC, looks bleak. The programs currently offered by the utilities are not conducive to participation by buildings for several reasons. The first is that the minimum curtailment that can participate is 100 kW, which would be nearly impossible for the buildings in the 200-400 kW range to attain. In addition, the programs do not offer the discretionary load curtailment option, which is attractive to buildings that want to provide demand response, but want to retain control over when and how much they curtail.

In October 2001 the CEC made a proposal to the CPUC to address these shortcomings, as shown in Table 3.

DR Technologies: How Buildings can be Demand Responsive and Increase Reliability

Figure 2 shows that commercial and residential air-conditioning, and commercial lighting comprise about 40 percent of peak demand. The air-conditioning contribution to system peak was highlighted in Figure 1.

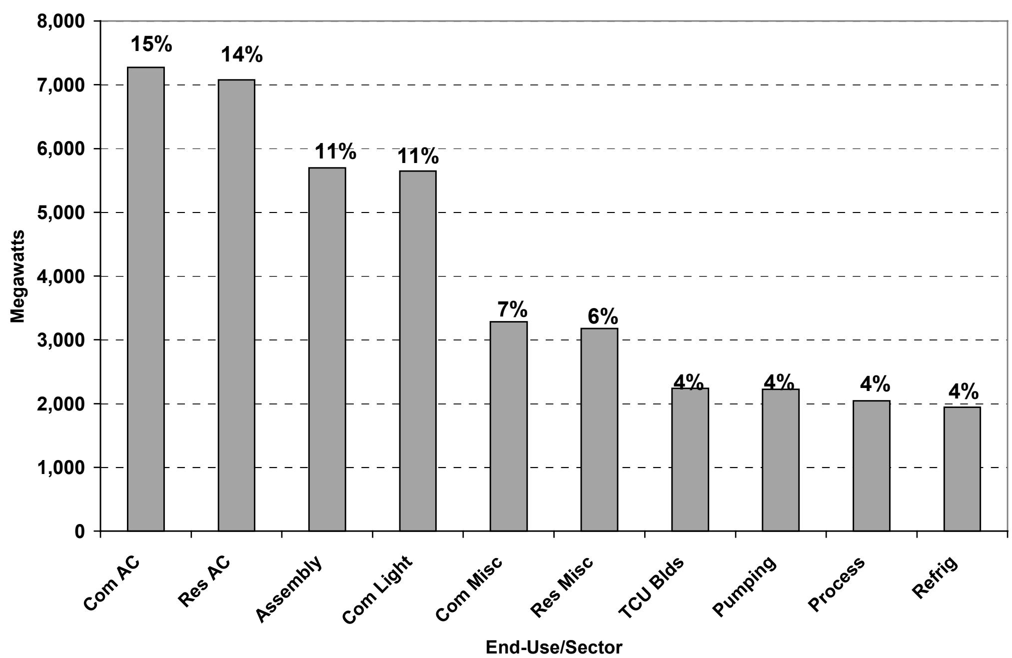
Table 3. Payment Structure for CEC-Proposed Demand Responsive Program

Participant Type	Reservation Payment ($/kW-month)	Performance Payment ($/kWh)	Contract Length (Years)	Maximum Calls
Committed	$10/kW summer mo. + $4/kW other months	$0.20/kWh	3	Up to 40 hrs/month; no more than 3 consecutive days
Discretionary	None	$0.50/kWh	3	Elective when called

Source: CEC 2001b.

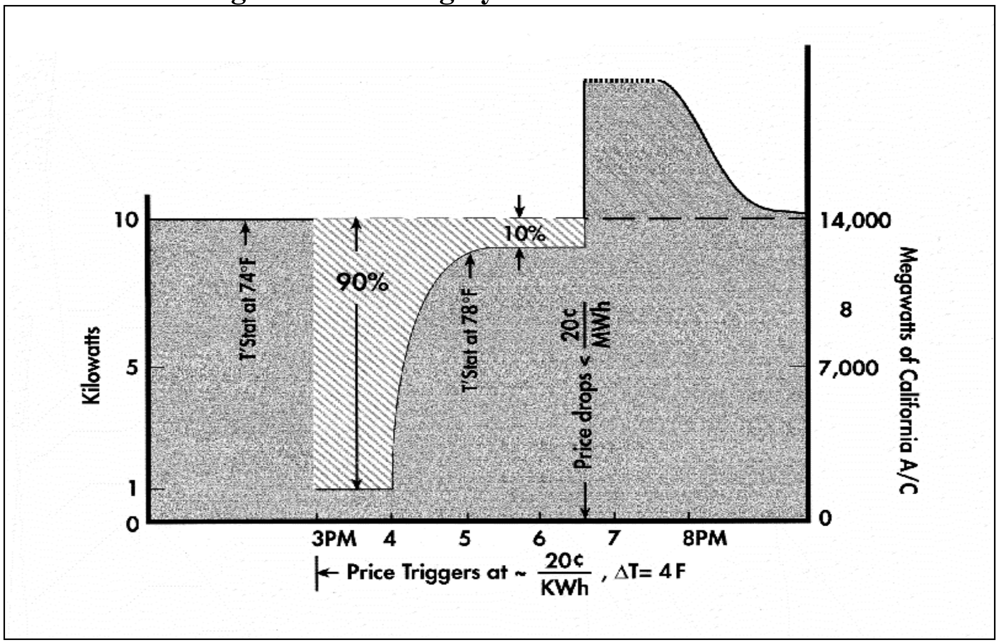
Figure 3 shows an idealized example of the effect of raising the thermostat setpoint about 4˚ F – the air-conditioning system would shut off for about one hour, and after the internal temperature had floated up to the new setpoint, the A/C would come back on, but at a lower average load. While the largest effects are in the first hour when load is reduced 90 percent, over a four hour period the average load is reduced by about one-third. This theory was tested by the Sacramento Municipal Utility District in one of their small office buildings. The result is shown in Figure 4, in which the four-hour average A/C saving of 30% (1W/ft^2) is validated (unfortunately the data logger only had one-hour bins, so the sudden drop at 1 p.m. looks like a slope). Figure 5 shows that dimming lights reduced energy use 40%. (Hamzawi 2000).

Figure 2. Peak Demand by End Use



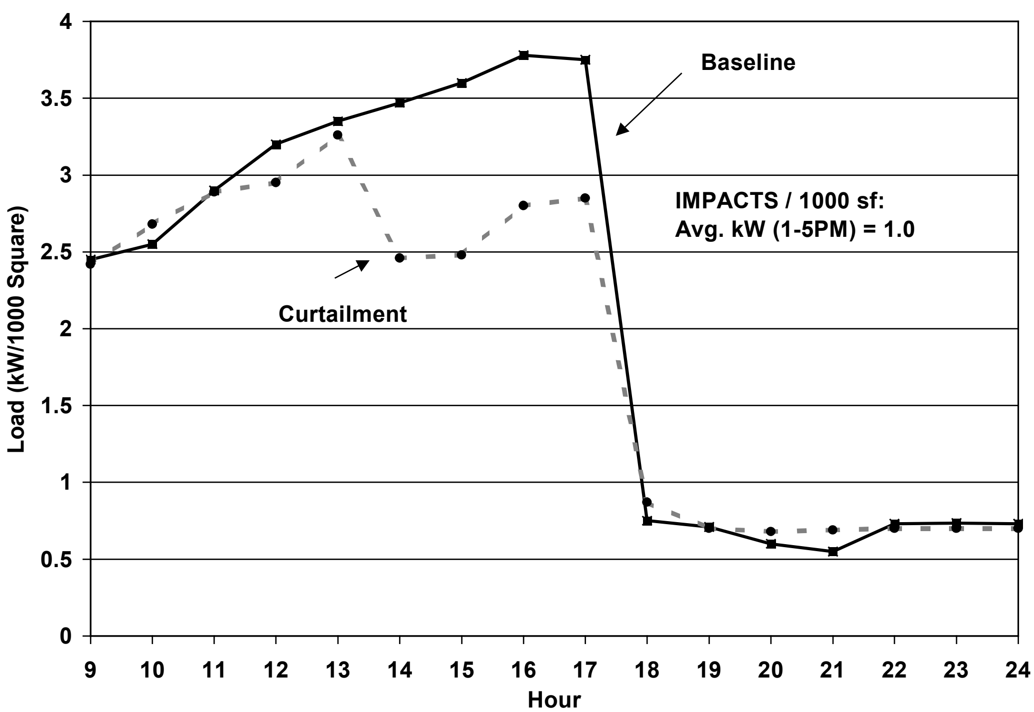
Source: CEC

Figure 3. Idealized Load Data: Raising Thermostat Setpoints Can Reduce a Building's Load During System Peak



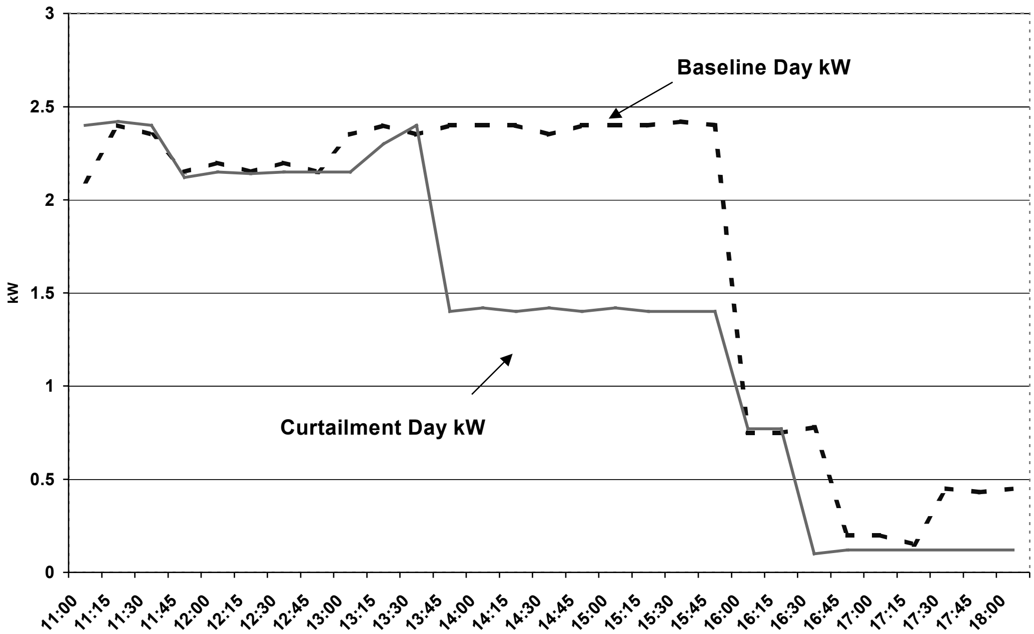
Source: CEC

Figure 4. Actual 30% A/C Load Drop in SMUD Building



Source: Hamzawi 2001

Figure 5. Actual 40% Lighting Load Drop in SMUD Building



Source: Hamzawi 2001

If enough buildings can be controlled in a way to maximize the diversified load drop and mitigate A/C rebound effects on system load (i.e., some means is needed to ensure that all the A/C load does not come back on at the same time), the 12,000 MW of A/C peak load (residential and commercial) and 5,000 MW of commercial lighting peak load could reasonably be reduced by 20 percent, or over 3,000 MW. If only one-third of this potential could be achieved (1,000 MW), the reliability of the state's electricity system would be dramatically increased at a trivial cost (about $100/kW curtailed) compared to the cost of peakers (about $500/kW installed) and the risk of rotating outages (with even higher costs per kW curtailed, especially to high tech companies). (CEC 2002a).

DR Tariffs: Prospects for Real-Time Pricing

Incentive tariffs for demand response have a number of drawbacks that stem from the administrative rules that have to be set in order to determine if a customer has complied with the requirements of the program. The most significant issue has been the determination of the baseline from which the demand reduction is measured. Utilities have to choose between short term actual loads (e.g., average of most recent 10 working days) or long term (e.g., highest or average monthly peak over the last year). But the recent average loads does not take into account the fact that the curtailment is probably for an exceptionally hot day, and the average for the last year does not take into account business growth or shrinkage. Other issues relate to minimum load drop required to be eligible to participate in the programs, penalties for nonperformance, the number and duration of curtailments, and others.

One way to by-pass the problems associated with demand response incentive programs would be to offer real-time prices (RTP) that reflect the time-varying cost of power, plus an adder for the reliability benefits that demand response can achieve. RTP charges customers prices that can vary hour-to-hour, thus encouraging conservation and demand response exactly at high-demand times. Prices could be "real-time" every ten minutes, or day-ahead estimates of 24 hourly prices.

RTP is superior to time-of-use prices, which do not distinguish hot days from cool summer days. For example, while PG&E had one fixed peak period price of 18 cents/kWh, wholesale prices varied in June 2000 from $.06 to $.93/kWh, and thus customers were charged far less than actual costs during the hours when demand response was needed most, but much more than costs in many other hours. (Borenstein 2001).

RTP has additional broader beneficial effects on the wholesale electricity market by reducing the ability of generators to charge prices far above their marginal costs, and instead rewarding loads for reducing demand rather than paying higher costs to generators. At the same time RTP and demand response reduces the cost of all kWh sold in the market, lowering the bills of all customers.

Utilities have offered different kinds of RTP programs over the last 15 years. They have been marketed primarily to industrial customers wanting to take advantage of cheap power during time of surpluses (e.g., in California in early 1990s) and faded when power supplies became more expensive and less reliable. Georgia Power has offered a successful program for over 10 years that combines the attributes of an economic development program and demand response.

Georgia Power's RTP Program

Georgia Power Company has offered its large customers voluntary RTP for 10 years. They have 1,600 customers signed up, representing 5,000 MW of peak load. The RTP is a "two part" tariff: (1) customers pay regulated, pre-set rates for their "baseline" load, which is a load profile based on historical usage, and (2) customers pay or are rewarded for *deviations* from the baseline load profile. The result is that customers are paid for load reductions when prices are high, but they can also take advantage of low prices by increasing electricity use during periods of low prices. Customers can chose between day-ahead or hour-ahead prices (day ahead prices are slightly higher because GPC is taking some risk in guaranteeing the day ahead price). When GPC charges their highest prices, about $1/kWh, they get about an 18 percent load response, or 800 MW, compared to the customers' baselines. The $1/kWh price is based on their short-run marginal cost, plus a "reliability adder" which they adjust in real-time to achieve the desired demand response. They actively use this demand responsiveness to provide shock absorbers on their electricity system.

An example of GPC's two part RTP tariff is shown in Figure 6. Two sets of prices are shown: the first part (based on a regulated time-of-use rate), and the real-time second part. The firm's baseline load is shown, as well as their response to the RTPs: the customer is rewarded for reductions from the baseline load at the high RTP, and is able to buy more power at a low RTP, especially when it is less than the TOU rate.

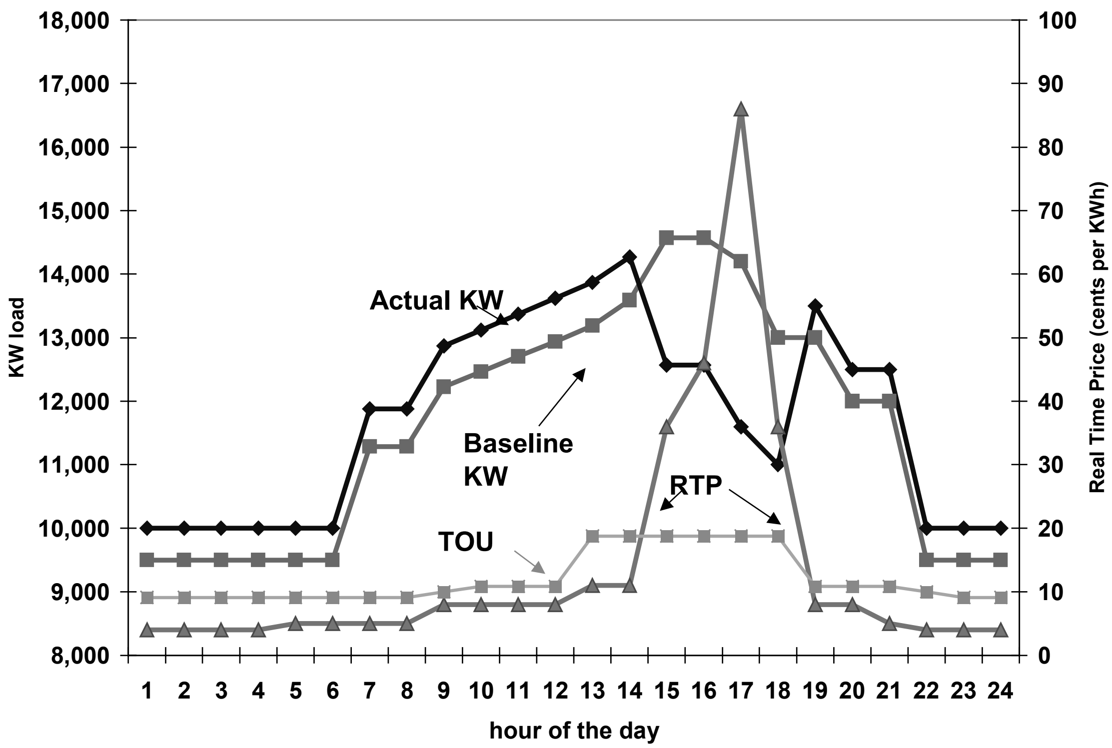
The CEC's Failed Real-Time Pricing Proposal

California's wholesale price frenzy started in June 2000 and lasted until FERC imposed a cap starting June 2001 (scheduled to end September 30, 2002). During the crisis, when wholesale prices were often far above retail, RTP was of high interest, particularly to the utilities, who were facing impossible losses from "buying high and selling low." It was during this turbulent time that the CEC submitted to the CPUC a voluntary RTP proposal based on Georgia Power's approach

But, before the CPUC responded, there were three dramatic changes. The first two forced wholesale prices to fall below retail; the third "hid" the wholesale price:

- In a last-ditch effort to save the utilities from bankruptcy, the CPUC raised retail rates.
- The FERC wholesale price cap took effect.
- Transparent wholesale prices disappeared when the California Power Exchange was abolished by a decision by FERC in January 2001, and since then market clearing prices have not been made public, and indeed are hard to estimate because the market was not working very well.

Figure 6. Georgia Power's RTPs and Load Response by a High Tech

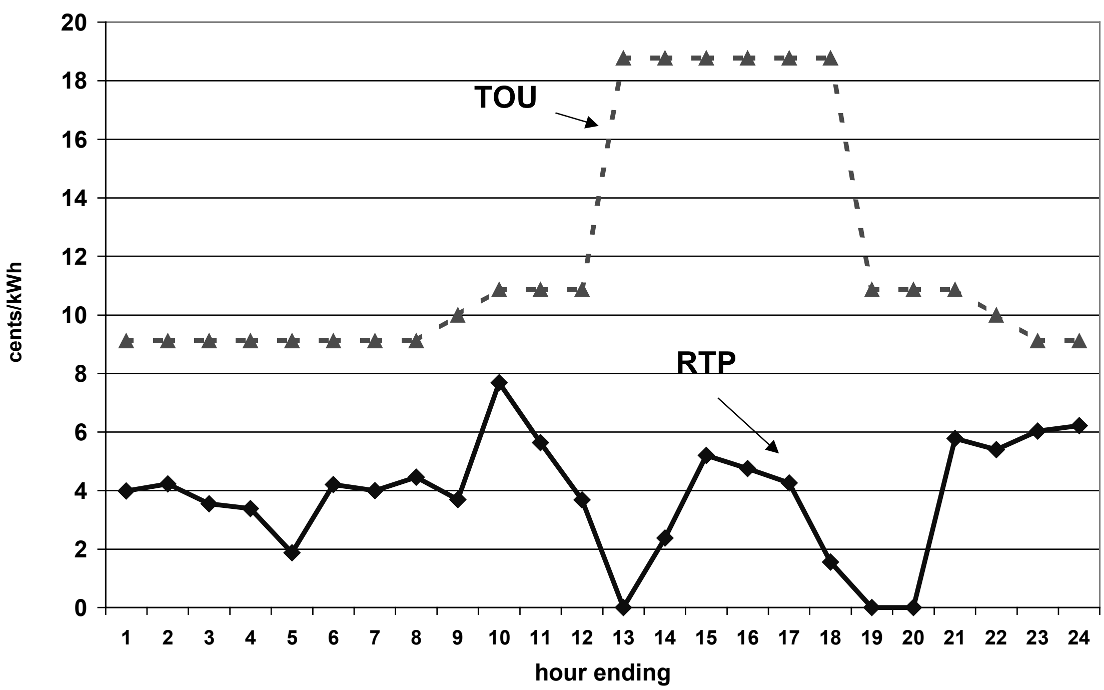


Source: CEC

The effect of these factors are summarized in Figure 7, which shows the new time-of-use rates are about 18 cents/kWh on-peak, while real-time wholesale prices are about 5 cents.

Accordingly the CPUC rejected the CEC RTP proposal and it is only now (May 2002) regaining their attention. Meanwhile an alternative which is simpler (at least for homes and small commercial buildings) is attracting attention – this is Critical Peak Pricing, which is described next. (There remains the interesting question of how to offer real time prices when we return to a world where the average wholesale price is well below retail, but spikes occasionally. These matters are discussed by Borenstein et al. (2002).)

Figure 7. RTP and Retail Rates in California Today

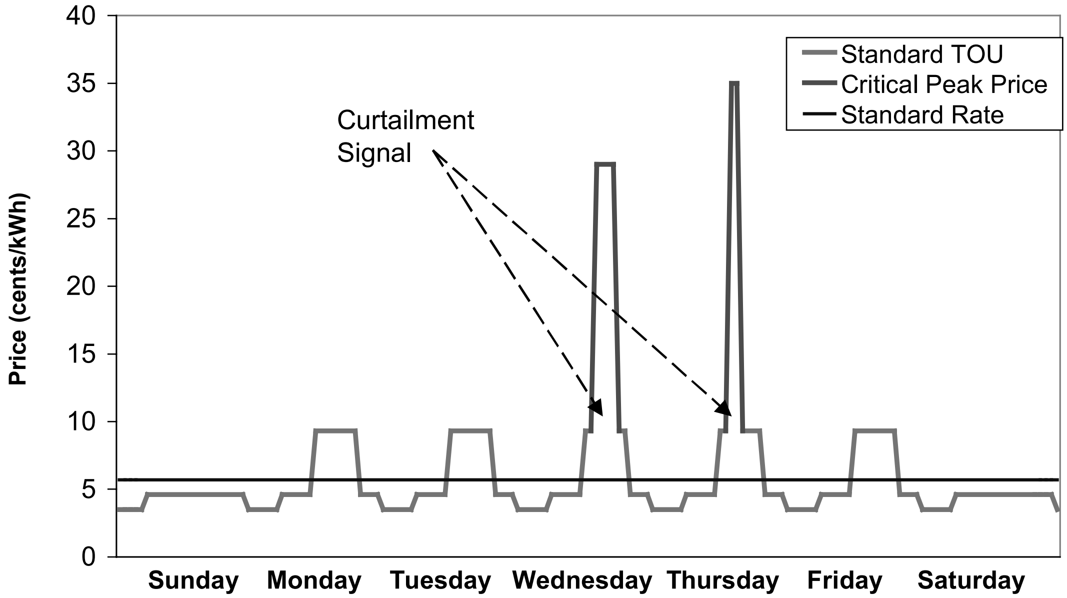


Source: CEC

Critical Peak Pricing (CPP)

This simpler approximation to RTP (with a reliability adder) is to augment existing TOU rates with a dispatchable "critical-peak" price (CPP) that reflects the added value of reliability when electricity supplies are short (much like GPC's reliability adder). An example of this is Gulf Power's "RSVP" program (Residential Service Variable Pricing), which offers rates exemplified in Figure 8 (Gulf Power 2002). The CEC is working with SCE and SDG&E to demonstrate the feasibility of a CPP for homes and small commercial buildings equipped with interval meters and communicating thermostats. (Herter et al. 2002).

Figure 8. Example "Critical-Peak" TOU Rates



Conclusion

In many regards the near term results of the state's demand response efforts over the last year are disappointing. About $80 million was spent on demand responsive technologies ($45 million for recruiting customers to install communication networks and upgrade their energy management system controls, and $35 million for real-time meters), and today most of the installations do not have an incentive or pricing program that will reward their response when load reductions are needed.

On the other hand, installing this equipment and giving customers access to information on their own electricity use will probably have a useful market transformation effect on energy conservation and management. In addition, there are hopeful signs that useful demand response and pricing options will exist in the relevant future, including the pilots of a residential controllable thermostat combined with a critical-peak rate, continuing policy support from a broad range of influential consumer groups (California Manufacturing and Technology Association, TURN, Silicon Valley Manufacturing Group, Environmental Defense), and interest from the new California Power Authority to support installation of more real-time meters and develop demand response programs. More recently, legislation has been introduced directing the CEC to prepare a report to the Legislature on the feasibility of implementing real-time pricing (SB 1976, Senator Torlakson), and the PUC has proposed (May 2002) a rulemaking on real-time pricing and demand response. So progress is being made in a market transformation effort of the most fundamental kind—to actually create a new retail environment for electricity that allows customers to actively participate in ensuring the system's reliability as well as managing their energy bills.

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