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Dynamic Pricing, Advanced Metering, and Demand Response in Electricity Markets

Author:

[Borenstein, Severin](#), UC Berkeley and UCEI
[Jaske, Michael](#), California Energy Commission
[Rosenfeld, Arthur](#), California Energy Commission

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Abstract:

In this monograph, we present an overview and analysis of the possible approaches to bringing an active demand side into electricity markets. In section I, we describe the ways in which economic incentives can be introduced on the demand side. We discuss the fundamental economics of establishing these incentives and the economic loss from systems that lack demand-side participation, and we analyze the effect of these incentives on the efficiency and competitiveness of the market. In section II, we move from the fundamentals to specific issues of implementing time-varying prices. We begin by describing illustrative Realtime Pricing and Critical Peak Pricing tariffs that are in use today. We then address the actual development of dynamic retail prices. In section III, we examine the ways in which customers respond to time-varying and dynamic prices. We discuss both the potential responses that are envisioned by those who study optimization of power use and the actual responses that have taken place in pilot and long-term programs. We conclude in section IV by advocating much wider use of dynamic retail pricing, under which prices faced by end-use customers can be adjusted frequently and on short notice to reflect changes in wholesale prices and the supply/demand balance.





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**Dynamic Pricing, Advanced Metering and
Demand Response in Electricity Markets**

Severin Borenstein, Michael Jaske, and Arthur Rosenfeld

October 2002

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2539 Channing Way, # 5180
Berkeley, California 94720-5180
www.ucei.org

Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets

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Energy Series

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ARTHUR ROSENFELD AND MICHAEL JASKE
CALIFORNIA ENERGY COMMISSION

SEVERIN BORENSTEIN
UNIVERSITY OF CALIFORNIA ENERGY INSTITUTE

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Dynamic Pricing, Advanced Metering, and Demand Response in Electricity Markets

Severin Borenstein
Director,
University of California
Energy Institute

Michael Jaske
Senior Policy Analyst,
California Energy
Commission

Arthur Rosenfeld
Commissioner,
California Energy
Commission

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Severin Borenstein is the Director of the University of California Energy Institute and Professor at the Haas School of Business, U.C. Berkeley. Email: borenste@haas.berkeley.edu.

Michael Jaske is a Senior Policy Analyst in the Strategic Issues Integration Group of the California Energy Commission. Email: mjaske@energy.state.ca.us.

Arthur Rosenfeld is a Commissioner of the California Energy Commission and Professor Emeritus in the Department of Physics of U.C. Berkeley. Email: arosenfe@energy.state.ca.us.

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ACRONYMS

Advanced Meter Reading (AMR)
Air Conditioning (A/C)
Build-Your-Own (BYO) baseline
California Energy Commission (CEC)
California Independent System Operator (CAISO)
California Power Exchange (CalPX)
California Public Utilities Commission (CPUC)
Critical Peak Pricing (CPP)
Customer Baseline Load (CBL)
Demand-Reduction Programs (DRPs)
Digital Control Units (DCUs)
Electric Power Research Institute (EPRI)
Energy Management Control System (EMCS)
Federal Energy Regulatory Commission (FERC)
Gigawatts (GW)
Heating, Ventilating and Air Conditioning (HVAC)
Independent System Operator (ISO)
Kilowatt (kW)
Kilowatt-Hour (kWh)
Los Angeles Department of Water and Power (LADWP)
Megawatts (MW)
Minimum Operating Reserve Criteria (MORC)
Operating and Maintenance (O&M)
Pacific Gas and Electric (PG&E)
Price-Responsive Demand (PRD)
Real-Time Pricing (RTP)
Residential Service Variable Price Option (RSVP)
Sacramento Municipal Utility District (SMUD)
Time-Of-Use (TOU)
Transmission and Distribution (T&D)
Unconstrained Market Clearing Price (UMCP)
Utility Distribution Companies (UDC)
Validation, Editing and Estimation (VEE) protocols
Western Systems Coordinating Council (WSCC)

INTRODUCTION AND EXECUTIVE SUMMARY

Advocates of electricity restructuring have argued that it would increase the efficiency of electricity production and consumption. In many cases, the results so far have fallen well short of this promise, with the California electricity crisis of 2000-01 being just the most publicized disappointment. While there has been heated debate about the reasons for these failings, there is remarkable agreement over at least the broad outline of one response: the demand side of the industry should play a more active role, receiving economic incentives to help balance supply and demand. The way in which this response should be implemented, however, is still the subject of a great deal of debate. In this monograph, we present an overview and analysis of the possible approaches to bringing an active demand side into electricity markets. We conclude by advocating much wider use of dynamic retail pricing, under which prices faced by end-use customers can be adjusted frequently and on short notice to reflect changes in wholesale prices and the supply/demand balance.

We begin in section I by describing the ways in which economic incentives can be introduced on the demand side. We discuss the fundamental economics of establishing these incentives and the economic loss from systems that lack demand-side participation, and we analyze the effect of these incentives on the efficiency and competitiveness of the market. We analyze a number of programs for demand-side participation, including interruptible contracts and paying customers to reduce their demand, as well as static and dynamic time-varying prices. Static time-varying retail prices, generally called Time-of-Use prices are preset for pre-determined hours and days, while dynamic prices are allowed to change on short notice, often a day or less. Static pricing is less costly to implement, but for large industrial and commercial customers, metering and other implementation costs are a negligible share of the electricity bill. Dynamic pricing—whether real-time pricing (RTP) that changes every hour or critical peak pricing (CPP) that allows for the retailer to occasionally declare an unusually high retail price for a limited number of hours—can be more complex than static, but we show that it captures a far larger share of the variation in wholesale price. We conclude that dynamic pricing is most appropriate for large industrial and commercial electricity customers, whether the economic organization is a regulated vertically-integrated utility or relies more on market forces for supply.

We demonstrate that dynamic electricity pricing need not conflict with the goals of customer bill stability and meeting retailer revenue requirements. We then evaluate who the winners and losers would be from greater reliance on dynamic pricing. Customers with flat load profiles or that consume disproportionately at off-peak times are likely to benefit most significantly from such a change. But, even customers whose demand peaks coincide with the systems' could benefit, because the incentives for conservation at peak times would reduce prices at those times, an effect that could outweigh the loss of the cross-subsidy that currently flows to such customers. Finally, we consider whether dynamic pricing should be voluntary. We conclude that voluntary programs are feasible so long as implementation does not include a cross-subsidy to those who remain on flat or time-of-use (TOU) pricing. Nonetheless, we suggest that dynamic pricing as the default for large customers makes the most sense, with customers able to reduce their exposure to real-time prices by entering into forward contracts.

In section II, we move from the fundamentals to specific issues of implementing time-varying prices. We begin by describing illustrative RTP and CPP tariffs that are in use today. We then address the actual development of dynamic retail prices. For RTP, the price signal can be released a day or hour ahead of the hour for which it applies (in which case it could be based on a wholesale market for such trades if one exists), a statistical model that forecasts real-time wholesale prices based on information available an hour or day in advance, or a forecast of avoided generation costs. CPP price signals, though less dynamic, still require a sophisticated calculation of the expected real-time supply/demand situation at the time that a critical peak would be called (typically, a day or so in advance). The goal of the RTP (or the CPP call decision) can be to reflect wholesale prices or to transmit even stronger retail price incentives either because the wholesale price is constrained by regulatory price caps or because reduction in retail demand reduces the wholesale price paid for all power bought in the spot market. An RTP price might also differ between locations to reflect local congestion, reliability, or market power factors.

We then move from price development to the metering technology, discussing the options and cost/benefit tradeoffs. For large customers, it is clear that full-capability RTP meters are a minor cost and it makes no sense to replace meters for such customers with meters that have less than full RTP and real-time communication capabilities. The customers have to receive signals of dynamic retail price movements, and we discuss a number of forms of communicating such signals. For large customers, internet communication is likely to be most cost effective. Internet communication also seems to be the best approach to sending real-time usage information to customers. A number of implementations now have private password-protected websites for each customer, which the customer can access at any time to observe its real-time consumption and costs. For smaller customers on a CPP program it may make sense to use TOU-like meters, though with an extra register, if they are already in place, but if a meter is to be replaced, it is likely to be more cost-effective to simply install an interval meter that could also be used for RTP if the opportunity arose. From metering and communication, we turn to the billing and customer service issues raised by dynamic pricing. A change to RTP will require redesign of data collection, validation, and processing systems at the utility. We present some of the bill production and customer service issues that are likely to result.

The value of dynamic pricing will be greatest if the system operator can anticipate the customer responses to price changes. We discuss how the system operator might create and update estimates of these responses, and how this knowledge will over time increase the value of dynamic pricing by reducing the need for reserve generation. Finally, we present some preliminary empirical analysis of the effect that RTP might have had during the California electricity crisis, demonstrating that even relatively small demand response would have yielded very significant reductions in the overall wholesale purchase cost of electricity.

In section III, we examine the ways in which customers respond to time-varying and dynamic prices. We discuss both the potential responses that are envisioned by those who study optimization of power use and the actual responses that have taken place in pilot and long-term programs. We show how customers, and

in particular buildings, can respond to dynamic tariffs. Much of the response will be from commercial air conditioning and lighting, which together account for 26% of California peak load, and from residential air conditioning, which accounts for 14% of peak load. We show that meters and control systems enable customers to respond to price signals and reduce their levels of consumption at times when the system is stressed. Data from simulations and actual experience demonstrate how such response could and does occur. The response comes from a combination of load shifting, moving air conditioning to hours before the system peak, and demand reduction, allowing buildings to get slightly warmer and turning lights slightly lower during peak hours.

In section IV, we discuss the context in which policy changes towards price-responsive demand might take place — the traditional regulated public utility or a restructured market with competition among wholesale generators and possibly also among retail electricity service providers. We point out how the incentives for adoption of these programs will differ between the two institutional settings. We conclude with our long-term vision for the demand side electricity sector: greater reliance on economic incentives for all customers, in particular, dynamic retail electricity pricing along with installation of the necessary metering and communication infrastructure.

I. THE THEORY OF DEMAND-SIDE PRICE INCENTIVES

BY SEVERIN BORENSTEIN

To evaluate the methods for implementing demand-side economic incentives in electricity markets, it is important to understand the fundamental economics of electricity markets. Electricity is not economically storable and production is subject to rigid short-term capacity constraints. Since demand is highly variable, this means there will be times when there is plenty of capacity and the only incremental costs of producing electricity are fuel and some operating and maintenance (O&M) costs. At other times, the capacity constraint will be binding, causing the incremental cost to increase greatly, and wholesale market prices to rise. Supply constraints are even more likely if sellers are able to exercise market power, as we discuss below.

The result of this structure is that the wholesale price of electricity, reflecting the supply/demand interaction, varies constantly. In most markets, the wholesale price changes every half-hour or hour. The end-use customer, however, sees the retail price, which typically is constant for months at a time. The retail price does not reflect the hour-by-hour variation in the underlying wholesale cost of electricity. A number of programs have been implemented or proposed to make the economic incentives of customers more accurately reflect the time-varying wholesale cost of electricity. Such price-responsive demand holds the key to mitigating price volatility in wholesale electricity spot markets.

A. Methods for Achieving Price-Responsive Demand

Depending on one's view, either the most natural or the most extreme approach to price-responsive demand is real-time pricing of electricity (RTP). RTP describes a system that charges different retail electricity prices for different hours of the day and for different days. For each hour, say 4-5 p.m. on June 21, the price may differ from the price at any other hour, such as 3-4 p.m. on June 21 or 4-5 p.m. on June 22. In most other industries that have highly volatile wholesale prices, such as fruits, vegetables, fresh fish, gasoline, or computer chips, retail prices adjust very quickly to reflect changes in the wholesale price of the good. RTP does not mean that customers must buy all of their power at the real-time price. Hedging — purchasing some power through a long-term contract, before a period of system stress is evident — allow customers to stabilize their overall bill while still facing the real-time price for incremental consumption, as we discuss later.

While RTP has not been widely accepted or implemented, time-of-use (TOU) pricing has been used extensively. Under TOU, the retail price varies in a preset way within certain blocks of time. For instance, a typical TOU pricing plan for weekdays during the summer charges 5.62¢ per kilowatt-hour (kWh) from 9:30 p.m. to 8:30 a.m., 10.29¢ per kWh for 8:30 a.m. to noon and 6 p.m. to 9:30 p.m., and 23.26¢ per kWh for noon to 6 p.m.¹ Typically, the weekend and holiday rates are equal to the off-peak weekday rate.

¹ This is Pacific Gas & Electric's summer commercial TOU rate.

The rates for each time block (usually called peak, shoulder, and off-peak) are adjusted infrequently, typically only two or three times per year. As a result, the price is the same at a given time of day (on a weekday) throughout the month or season for which the prices are set. Thus, for instance, the retail price signal is the same on a very hot summer afternoon, when demand may be at its annual peak, as it is on a mild summer afternoon when demand is much lower.

Because TOU rates don't capture the price variation within a price block, TOU pricing is often combined with a separate charge for peak usage. These "demand charges" are a price per kilowatt for the customer's highest usage during the billing period (usually a month). Demand charges are based on the customer's maximum usage (during a 15 minute interval) regardless of whether that usage occurs at a time when the system as a whole has a tight supply/demand balance or not. Most of the meters that register maximum usage for demand charge billing are not capable of storing information indicating the precise date and time at which that maximum usage occurred.²

At the opposite end of the price-responsive demand spectrum from RTP are interruptible electricity rates. These rates are constant nearly all of the time. When the system operator declares certain potential shortages, however, these customers are called upon to cease electricity consumption. Despite the name, service to these customers is generally not actually physically interrupted. Rather, the price that they face increases dramatically. In one program in California, customers on interruptible rates were required during declared shortages either to stop consuming or to pay \$9.00 per kWh for their continued consumption, a more than 30-fold increase.

A recent innovation in time-varying pricing is critical peak pricing (CPP), which has some attributes of RTP and some of interruptible programs. CPP programs usually start with a TOU rate structure, but then they add one more rate that applies to "critical" peak hours, which the utility can call on short notice. Gulf Power's CPP program in Florida is described in Appendix B.³ CPP programs typically limit the utility to call no more than 50 or 100 critical peak hours per year. CPP is a clear improvement on TOU with demand charges, because the additional charges are based on consumption when the system is actually constrained, rather than when the particular customer's demand peaks. CPP has some of the advantages of RTP, because retail prices are allowed to vary with the wholesale market. Of course, CPP is much more constrained than RTP: the CPP peak price is set in advance and the number of hours in which it can apply is limited. A modification of the single-peak CPP is CPP with two callable peak retail prices, such as 50¢ or \$1.00 per kWh, so that the utility can utilize extremely strong retail price incentives during a few hours per year when the wholesale price might be extremely high.

² Customers that have TOU meters usually face on-peak and off-peak demand charges, with the on-peak maximum usage carrying a much higher price. Within the peak price TOU period (*e.g.*, 9 a.m.-7 p.m. on weekdays), however, the meters do not indicate at what time or day the maximum usage occurred.

³ Also see Faruqui and George (2002) for an analysis of CPP.

While all of the pricing approaches discussed thus far charge customers time-varying prices, demand-reduction programs (DRPs) pay a customer to reduce their consumption at certain times. A customer signed up for a DRP is eligible to be contacted by the utility or system operator with an offer of payment in return for the customer reducing consumption. These programs must first determine a baseline from which demand reduction can be measured. Once the baseline is set, the price offered for demand reduction determines the level of economic incentive to reduce demand when the system operator calls.

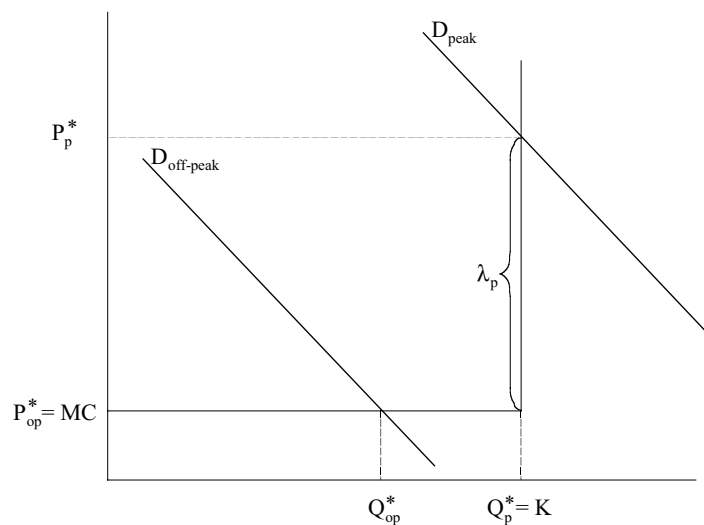


Figure 1-a

B. The Economic Efficiency of Time-Varying Retail Price

For most of the last century, electricity was sold in regulated environments in which the retail price did not vary based on the time it was used. Customers faced a constant price for electricity regardless of the supply/demand balance in the grid. Discussions of changes to greater price-responsiveness in demand have usually focused on who, among customers, would win or lose from such a change. While the distributional impact among customers is certainly important, price-responsive demand is also very likely to affect the total cost of the electricity and, especially, the allocation of the cost between customers and deregulated producers. In this section, we examine the economic impact of moving to a system in which prices more accurately reflect the supply/demand balance.

1. Efficient Time-Varying Electricity Pricing

For illustration, we will assume that there are only two levels of demand, peak and off-peak, as shown in Figure 1-a, and that all producers have the same cost of production up to their capacity. We'll begin by illustrating how this market would operate if different prices were charged during peak and off-peak times and no producer were able to exercise market power. We return to the market power issue below.

If the market were competitive and installed capacity were K , it is easy to see that the prices in the market would be P_p and P_{op} . If any producer tried to charge a price above P_{op} during off-peak, it would be unable to sell its power since there is idle capacity waiting to jump in if price is above the producers' marginal cost. During peak times, no producer would be willing to sell at a price below P_p , because P_p clears the market, i.e., since there is no idle capacity, any producer can sell all of its output at that price, so it would have no incentive to charge less. If any producer tried to charge more than P_p , it would find that its unit sales would decline and it would be unable to earn enough on the power it sold to justify selling less than its full capacity, as it could at P_p . This follows from the assumption that no firm can profitably exercise market power.

Now consider the outcome if, due to either technological or legal constraints, the firms charged the same price for peak and off-peak demand. If the firms were still to break even overall, the price would lie somewhere between the peak and off-peak price from the previous example, a price we'll call P . This is illustrated in Figure 1-b. For the off-peak demand, this would raise the price and inefficiently discourage off-peak consumption, because the price would exceed the true marginal cost of production. Some consumption that would produce value greater than the incremental cost of production would not take place. This is illustrated by the vertically shaded "deadweight-loss" area.

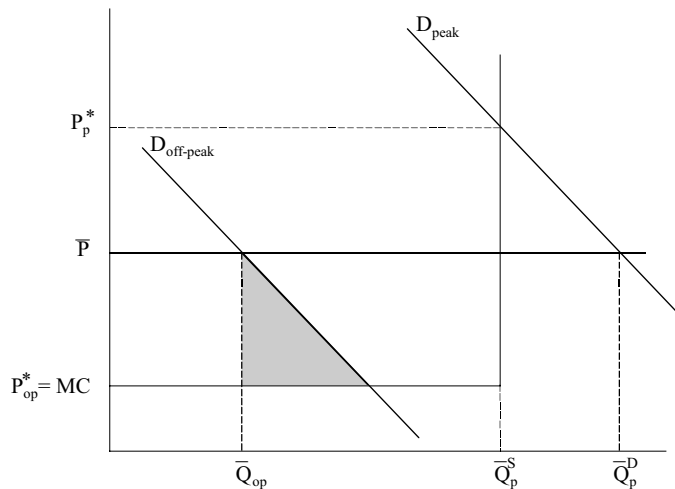


Figure 1-b

A single-price restriction would result in a price for peak demand that is below P_p . This would increase the total quantity demanded above the current market capacity. Absent additional capacity, this would cause a shortage, and would require some sort of rationing, using either economic incentives or some alternate approach. Putting aside, for the moment, the disruption of blackouts, such rationing doesn't even necessarily deliver power to the most valuable use. A use with a value just barely above \bar{P} would be as likely to receive power as a use with a much higher value. When this occurred in natural gas markets in the 1970s rationing was done by grandfathering all who already had gas service and requiring a queue for new hookups.

In reality, of course, the excess demand at peak times is not allowed to cause blackouts. Instead, capacity is expanded to meet the high demand that results at peak times. The question then is whether this is a good use of resources. The answer is almost certainly no, as is explained in the next subsection.

2. Efficient Capacity Investment

To analyze the efficiency of capacity investment with and without time-varying prices, we return to Figure 1-a to illustrate capacity investment with time-varying prices. It is clear in this situation that additional capacity has no value for the off-peak period. Off-peak consumption does not utilize all of the currently available capacity. Additional capacity in the peak period does have value because the marginal value of power to customers is greater than the marginal cost that would have to be absorbed after an additional unit of capacity was built. To be exact, the value of an additional unit of capacity is $P_p - MC$, which is λ_p in the illustration. λ_p is the peak-period shadow value of marginal capacity at the current level, K . The off-peak shadow value of marginal capacity is $\lambda_{op} = 0$.

Assuming for the moment that capacity can be adjusted in very small increments, the per-“day” (where a day includes one peak and one off-peak period) cost of one additional unit of capacity is the fixed operation and maintenance cost plus depreciation and the opportunity cost of the capital investment, *i.e.*, the foregone interest on the funds used for this investment. We will call this full fixed capacity cost r per unit of capacity per day. The efficient criterion for capacity choice is to expand capacity so long as $\sum \lambda > r$ and to stop expanding capacity at the point that $\sum \lambda = r$. In other words, the socially optimal investment in capacity occurs at the point that the sum of the shadow values of capacity is just equal to the cost of capacity. Note that we take the sum of the λ s because the peak and off-peak operation are non-competing uses of the same capacity.

Luckily, this is also the criterion that will determine the competitive level of capacity since each price-taking owner of capacity will receive λ_p above its operating costs in peak periods and λ_{op} in off-peak periods. Thus, a firm will have an incentive to expand capacity so long as the sum of the λ s is greater than the cost of expanding capacity.

Now, let's return to the issue of capacity investment under a single-price retail system. At price \bar{P} , the off-peak demand is well below capacity so the shadow value of capacity for off-peak demand remains zero. In order to meet the peak demand at \bar{P} , however, we have built additional capacity, ΔK . But, it is not efficient to build that capacity: the net value of the additional power produced by the capacity is less than the cost of the capacity. To be concrete, building the extra ΔK of capacity creates deadweight loss equal to the shaded triangle in Figure 1-c because the net value of this additional capacity is less than the cost of holding the capacity, which is $r \cdot \Delta K$.

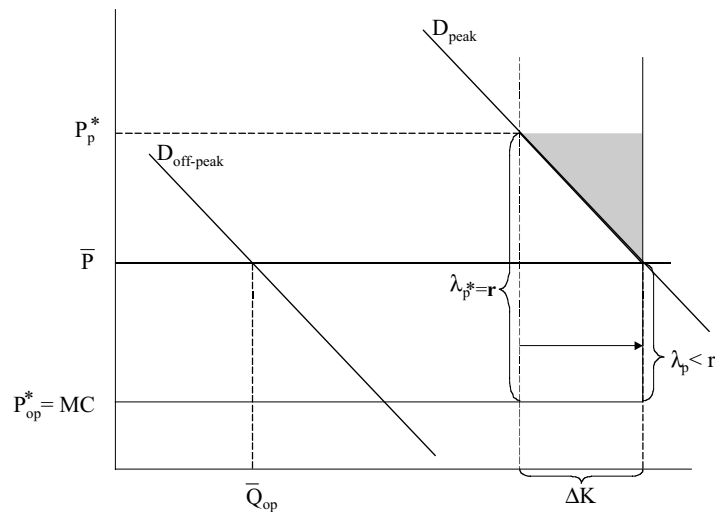


Figure 1-c

In the real world, this inefficiency shows up in the form of excess capacity that is underutilized, but still must be built in order to accommodate the peak demand. The value customers get out of this capacity is not great enough to justify the capital investment. With time-varying pricing of electricity, this excess capacity is not necessary because higher prices at peak times encourage customers to consume less at those times, either by shifting peak consumption to off-peak or by simply reducing consumption at peak times.

3. Time-Varying Prices and Market Power

Thus far, the analysis has considered only the case of a competitive wholesale electricity market. When producers are able to exercise market power, however, the benefit of instituting time-varying prices is greater. In any market, a seller or group of sellers exercises market power by raising price above the

competitive level and reducing sales below the competitive level. The financial attractiveness of this action depends on the tradeoff of higher prices on the sales the firm still makes versus lost sales due to the increased price. It is clear that the payoff to exercising market power is greater if raising prices has a smaller impact on sales.

When the retail price of electricity does not vary over time, a wholesale seller's attempt to exercise market power and raise wholesale prices has no short-run impact on sales since end-use customers do not see a change in the (retail) price they face. This makes it much more profitable for the wholesale seller to exercise market power. With time-varying prices that reflect changes in the wholesale price, an attempt to raise wholesale prices will impact retail prices and thus reduce the quantity of power that customers demand. This customer response reduces the profitability of raising wholesale prices and, thus, discourages the exercise of market power.

To be a bit more concrete, consider a hot summer day when the system is stretched to near its limit, and consider the incentives of a wholesale seller in the market that owns 5% of the system capacity. On such a day, the wholesale seller knows that if it withdraws 1% of the system capacity from production, it will have a significant effect on the wholesale price. If, however, the retail price also increased when the wholesale price rose, then customers would get a signal that they should scale back usage. The resulting reduction in demand means that the withdrawal of production capacity will have less impact on the wholesale price and, thus, will be less profitable for the seller. In contrast, if retail prices are not linked to the wholesale price level, then there is no demand response when the seller withdraws capacity and the wholesale price is more likely to increase dramatically.

Without price-responsive demand, the combination of supply-demand mismatches and the ability of sellers to exercise market power at peak times creates a relationship between price and system load that looks like a hockey stick laid on its side. Figure 1-d shows a price/load scatterplot for California during June 2000 and a polynomial curve fitted to the points. The hockey-stick relationship is a fairly constant price over a wide range of outputs and then steeply upward-sloping price as demand grows closer to capacity. Price-responsive demand would reduce the frequency and degree of price spikes during periods of high system load.

California PX price vs. System Demand
June 2000

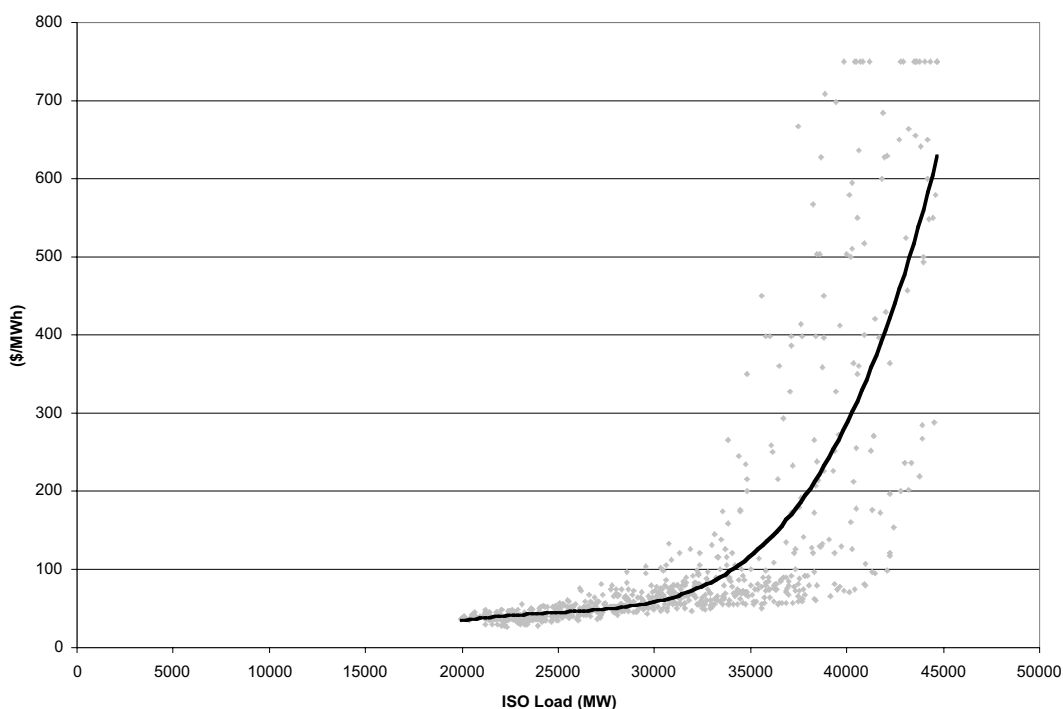


Figure 1-d

C. Comparing the Effectiveness of Different Approaches

Earlier, we presented five types of programs for introducing greater economic incentives into electricity demand: RTP, TOU with or without demand charges, critical peak pricing, demand-reduction programs, and interruptible programs. In this section, we explore the differences among these five approaches. To understand the distinctions among these programs, it is important to first recognize their intrinsic commonality. All of these programs attempt to give end-use customers economic incentives to reduce their demand at times when the supply/demand balance in the system is tight.

1. Comparing Real-Time Pricing and Time-of-Use Tariffs

RTP introduces economic incentives by allowing the retail price to change at fixed time intervals, usually hourly. The real-time price for each hour can be announced at the beginning of (or minutes before) the hour, or it can be announced in advance. RTP programs currently in effect typically announce the prices

for all hours of a day on the previous day. Obviously, a longer lag time between the price announcement and the price implementation will result in prices that less accurately reflect the actual real-time supply/demand situation in the market.

Additionally, the longer lag time means that the prices will be less volatile than, for instance, the real-time wholesale electricity price. Designers of RTP programs face this tradeoff between greater advanced price notification and more accurate price signals. RTP programs that rely on the real-time wholesale price give virtually no advance notification, but use prices that reflect the state of the underlying wholesale electricity market most accurately. At the other extreme, consider what prices would result if the RTP program used prices that were announced a month or more in advance for each hour. In that case, every weekday afternoon hour would have roughly the same prices, because month-ahead forecasts of supply/demand balance in a given hour are simply historical averages, taking into account none of the idiosyncratic weather or plant outage information. The problem with this approach is illustrated by June 2000 in California. In that month, the 3-4 p.m. weekday system load was as high as 44,000 megawatts (MW) and as low as 30,000 MW, with wholesale prices as high as 92.5¢ per kWh and as low as 6.4¢ per kWh.⁴

Yet, RTP with a long lag time between price and implementation is approximately time-of-use pricing. TOU programs set prices months in advance and therefore logically cannot capture any of the shorter-term variation in supply/demand balance. In fact, most TOU programs do an even worse job of reflecting even average wholesale market variation. This is because, first, TOU programs set prices in only two or three blocks — such as peak, shoulder, and off-peak. This means that the 4-5 p.m. weekday price is the same as the noon-1 p.m. weekday price, because they are in the same block, despite the fact that the average wholesale market price is quite different for these hours. Second, TOU programs typically reset prices for each block only two or three times per year. So, the peak, off-peak, and shoulder prices might not change from May to October even though the average demands and costs change in a quite predictable way during that time.

These attributes mean that TOU price variation will reflect very little of the true variation in the wholesale market. Empirically, one can show this by looking at a given time period and asking how much of the wholesale price variation would be reflected in TOU prices, assuming that the TOU price were set optimally to maximize their relationship to wholesale market prices. TOU pricing does not capture this sort of variation in supply/demand balance. For the summer of 2000 in California, even setting TOU prices after the fact to reflect the actual average price in peak, shoulder, and off-peak periods, the TOU

⁴ This is the unweighted average of the NP15 and SP15 California Power Exchange (CalPX) day-ahead zonal prices.

rates would have reflected only about 20% of the variation in the day-ahead market price on average. In comparison to the real-time electricity prices, TOU rates would have reflected only about 14% of the wholesale price variation on average.⁵ The figures are even lower if one examines the entire California market period from May 1998 to October 2000 when the wholesale markets were not as volatile on average. And these numbers assume that the agency setting the rates can forecast the *average* price in each period as accurately before the period as one can do after the fact, which is virtually impossible.

Put differently, TOU prices, in attempting to give greater advanced notice of prices, lose most of their value to reflect variation in wholesale prices. The cost of this loss of information will depend very much on how customers would react if they were given the finer information. For instance, if a factory can react to price changes only by making long-term adjustments, such as changing worker shift schedules that can be made only semi-annually, then the information in TOU prices may be all that the factory can use. In that case, no price-responsiveness is being sacrificed in using TOU prices instead of RTP. On the other hand, if the customer can make such adjustments more frequently, such as weekly or monthly, or can adjust quickly to idiosyncratic supply/demand information, such as by adjusting air conditioning settings and lighting when the system is strained, TOU rates fail to send the information that the customer needs to make these adjustments.

Technology plays a role in this tradeoff, as we discuss at greater length in later sections. Until recently, the cost of TOU metering was substantially less than real-time metering and the ability to send real-time price information to customers was limited. Technology changes of the last decade have virtually eliminated these issues. Technology changes have also enhanced, and continue to enhance, the customer's ability to respond to real-time price changes. Responding to frequent retail price changes does not now require human intervention. Instead, the real-time price is sent electronically to a computer that is programmed to respond. If the price goes above 15¢ per kWh, for instance, the computer might automatically reset air conditioning from 72 to 74 degrees. A computer could also automatically reset lighting and reschedule energy-intensive activities that are time adjustable, such as running a pool pump. Thus, historical measures of firms' abilities to respond to real-time price changes are likely to significantly understate the price-responsiveness that technology and education will evoke in future years.

⁵ These numbers result from a regression of the hourly wholesale price (CalPX day-ahead or ISO realtime) on dummy variables for each of the TOU periods (with observations weighted by quantity demanded, so the resulting TOU rates would exactly meet the retailer's revenue requirements). The R^2 of such a regression is the share of price variation captured by using the TOU periods rather than using a single constant price. Using the day-ahead price, the R^2 was 12% in northern California and 27% in southern California. Using the real-time price, the R^2 was 7% in northern California and 20% in southern California.

2. Augmenting TOU with Demand Charges

Recognizing that TOU pricing doesn't capture superpeak usage, many implementations have accompanied TOU with demand charges. Demand charges are a way to charge for a customer's peak usage, but the economic incentives that they establish are a very imperfect proxy for the real economic cost imposed on the system. First, demand charges are not synchronized to the usage on the system as a whole, so they charge as much for a peak usage that occurs at a lower demand time as at a higher demand time. In fact, this might not be as bad as it seems at first, because air conditioning-driven demand peaks tend to be highly correlated across users within a region. More importantly, however, by charging only for the peak usage, demand charges don't give strong (or potentially any) incentive for a customer to conserve until usage is near the peak level for the period. If a very hot day occurs early in a billing period, the demand charge may give a customer little incentive to conserve after that.

The economics of demand charges made more sense under traditional utility regulation. The concept was to charge customers for their contribution to the need to build additional peaking capacity (though in practice this still suffered from the problem that the customer's peak consumption may not coincide with the overall peak consumption). Apart from the peak, charges varied little. This makes much less sense in a deregulated wholesale market where demand increases result in significant increases in wholesale price even before the system gets right up to its capacity.

In addition, demand charges make no adjustment for the supply side of the market. If an unusually high number of forced outages occurs on a moderately hot day, the system can be more strained than on a very hot day, even if the total system load is lower. Though wholesale prices vary systematically with system demand, many other factors cause wholesale prices to fluctuate throughout the month. Variations in supply availability (and the prices at which that supply is offered) can be as important as variations in demand in explaining fluctuating wholesale prices. Thus, although demand charges do enhance the ability of TOU pricing to reflect true economic costs of service, they still fall well short of RTP.

3. Critical Peak Pricing Programs

CPP Programs are the natural evolution of demand charges when more sophisticated metering is available. Charges increase at critical system peaks rather than at the individual customer's demand peak, which is much more consistent with the true costs of consumption. CPP still has two economic weaknesses, though they may actually be strengths in terms of customer acceptance. First, the prices are limited and levels are preset for the critical peak periods, therefore they can't be calibrated to move with the actual prices in the wholesale market. Second, the number of critical peak hours that can be called in a year is limited. As a result, the utility protects customers against seeing very high prices, even only on marginal purchases, for more than a fixed number of hours. As discussed below, RTP can be designed to offer much the same level of hedging, while still giving the customers strong incentives on the margin to conserve when the market is tight. The key difference is that CPP offers a "requirements contract" at the posted prices, *i.e.*,

buyers can buy as much or as little as they want at that price. In contrast, hedging under RTP would probably involve buying fixed quantities of power at preset prices. Thus, the marginal price for consumption, or reward for forgoing consumption, would still be the real-time price.

4. Real-time Demand-Reduction Programs

Much like CPP and unlike TOU, real-time demand-reduction programs attempt to recognize the idiosyncratic daily and hourly variation in system stress and give customers incentives to respond. Demand-reduction programs are activated by the system operator when grid conditions meet certain pre-determined criteria that indicate that the supply/demand balance is likely to be very tight over some ensuing period of time. The operator then offers to pay participating customers to cut back their usage. In general, these programs are fairly blunt instruments; the system operator simply announces when the program is in effect. The price offered is usually pre-determined and does not vary with the tightness of supply.

The fundamental weakness with demand-reduction programs is that there is no reliable baseline from which to pay for reduction. With most goods, the natural baseline is zero: you start with none of the good and pay more as you consume more. Programs that pay for demand reduction generally set a baseline that comes from the past behavior of the customer. This sets up two serious problems.

First, if the program is voluntary, it will be joined disproportionately by the customers that already know they will have lower consumption. For instance, if the program uses last year's consumption as the baseline (perhaps with an adjustment for weather), the companies that have shrunk since last year will be the first to sign up. Their electricity consumption has fallen compared to the baseline for reasons having nothing to do with the program. The operator ends up paying for "conservation" that would have occurred anyway. Meanwhile, the companies that have grown rapidly since last year simply won't sign up. This phenomenon is known as "adverse selection."

Second, if the baseline that is used can be affected by the customer, it will probably discourage conservation during times when the payments are not in effect, a "moral hazard" problem. For instance, consider a plan that sets the baseline at the level of consumption the customer had on the previous day. Then on days when the payments are not in effect, customers would be foolish to conserve at all since that would just lower their baseline. Californians saw this effect in the 1970s with water rationing. Many users figured out that they were better off being wasteful in normal-rainfall years so that they would have a higher baseline if a drought hit.

To overcome these problems, there could be a program that uses a baseline from an earlier period and is not voluntary. However, this would raise serious equity concerns. Shrinking companies would reap a windfall and expanding successful companies would be penalized.

Ultimately, real-time demand-reduction programs are very imperfect substitutes for critical peak pricing or RTP. They require the same metering technology as critical peak pricing and approximately the same level of information transmission from the system operator. Demand-reduction programs limit the customer's liability by starting from a flat rate and reducing bills from there, but that can be done easily within a CPP or RTP program, as described in the next section. Unlike CPP or RTP, demand-reduction programs suffer significant problems and potential conflicts in setting baselines. Lastly, although demand-reduction programs are often favored as a positive reinforcement mechanism, in contrast to RTP, all the money that is paid out in positive reinforcement has to come from somewhere. Paying for demand reduction is not a free lunch. It most likely comes from higher general rates than would be necessary to reach the same revenue requirement under CPP or RTP.⁶

5. Interruptible Demand Programs

The physical attributes of electricity systems imply that excess demand cannot be rationed using the standard non-price mechanism: queuing. Instead, a systemwide excess demand can lead to a collapse of the entire grid, cutting off supply to all users. Thus, if for some reason economic incentives fail to equilibrate supply and demand for even a brief period, the system operator must have the ability to curtail usage by some customers. The response has been interruptible demand programs and demand-reduction contracts, which give the system operator the right to instruct the customer to cease or reduce consumption on very short notice. In return, the customer usually receives a reduction in its flat (or TOU) electricity rate or it receives a periodic fixed payment.

Interestingly, although these programs appear at first to be a departure from using a price system to allocate scarce electricity, in fact most programs are simply a crude form of RTP or CPP. The customer on an interruptible program retains an option to continue to consume after being instructed to discontinue usage, but at a greatly increased price. In one California program, for instance, the industrial and commercial customers on an interruptible program pay approximately 20¢ per kWh during TOU peak demand periods, but if they decline to discontinue when requested by the system operator, their rate increases to \$9.00 per kWh.

⁶ The rates might still be lower than under flat pricing since the reduced demand might lower the wholesale market price sufficiently to more than cover the cost of payments for demand reduction. Nonetheless, the revenue requirement implies that overall average rates will not be lower with demand reduction programs than with CPP.

Seen in this light, interruptible and demand-reduction contracts are RTP (or CPP) with very blunt price changes: a constant rate unless a system emergency occurs, in which case the rate increases so much that nearly all contracted customers choose to stop, or drastically reduce, consumption.⁷ As with demand response programs and CPP, interruptible programs and demand-reduction contracts offer a certain amount of insurance to customers: those on interruptible programs are told that they won't be called more than a pre-specified number of times during a year. As we discuss below, however, price protection products can supplement RTP to offer at least as much insurance.

6. Using Demand to Meet Reserve Requirements: Economics Meets Engineering

Administrators of nearly all restructured electricity markets, and of many that are still fully regulated, have suggested that demand responsiveness could be used to help meet reserve requirements. The Federal Energy Regulatory Commission (FERC) has endorsed this concept in its draft Standard Market Design. Implementation of this approach, however, exposes a conflict between the economic analysis of electricity markets and the operating procedures that electrical engineers use in operating the grid. The grid operator wants to have resources that it knows with near-certainty it can call on to increase supply or reduce demand.⁸ Grid operators tend to be resistant to the idea of equilibrating supply and demand by increasing the price in a spot electricity market and hoping that demand in aggregate will respond.

The grid operators' concerns are understandable since any supply/demand imbalance that lasts more than a split second can be catastrophic. They are less attracted to the idea of balancing supply and demand through price adjustments that yield small quantity changes from thousands of customers, because none of those customers pre-commits to make a specific change under specific conditions. Rather, the responses to price changes are probabilistic, and the reliability of the aggregate response is due only to the law of large numbers applied to many independent buyers. To be concrete, if demand is exceeding supply and adjustment is supposed to occur through a price mechanism, a grid operator has no one to call to assure that demand response occurs.

It is for this reason that grid operators tend to be much more supportive of interruptible demand and contracts for pre-specified demand reduction than they are of critical peak or real-time pricing as a method for balancing supply and demand. Grid operators, however, can be satisfied while still allowing price

⁷ We ignore in this discussion the widespread view that many interruptible customers believed when they signed up that they were simply getting a price break and would never actually be called to stop usage.

⁸ Though many interruptible customers cannot actually be physically interrupted, as discussed above, the programs usually involve small number of large customers so it is feasible for the system operator to contact each by phone to see how they will respond to the call for demand reduction (and the extremely high retail price that accompanies the call).

response to play a major role supply/demand balancing. Interruptible and demand-reduction contracts will still have a role to play as a backup mechanism. Given the engineering realities of electricity systems, the system operator has to have some ability to cut off customers when the system is nearly overloaded and normal market processes either have failed or cannot respond quickly enough. It makes much more economic sense to establish priorities for such situations in advance and compensate those who volunteer for curtailment, rather than choose customers or areas randomly, as was done in California during early 2001.

Still, it is important to recognize that reducing demand through customer interruption or large pre-specified demand reductions is likely to take a much larger economic toll than is price-responsive demand: forcing 100 customers to reduce consumption by 100% will be much more costly than inducing 10,000 customers to each reduce consumption by 1%, on average. Grid operators have long recognized that it isn't practical to enter into thousands of contracts for small demand reductions, or to call each customer to ask for reduction, but the price mechanism is the tool that can achieve that outcome without formal contracting. If market processes are allowed to operate effectively, interruptible programs and demand-reduction contracts will be an absolute last-ditch mechanism that will hardly ever be used.

Currently, reserve requirements are established based on forecasts of system peak demands that do not take into account demand's response to price changes. Implicitly, demand is assumed to be completely price-inelastic and system reserve requirements are set to be some percentage, usually between 10% and 20%, above the forecast system peak. Contracts for demand interruption or reduction fit easily into that paradigm. Incorporating the price-responsiveness of demand under RTP or CPP requires a change in the paradigm. It overstates the effect of RTP to say that no reserves are needed once RTP is implemented, but it understates the impact to say that RTP would simply reduce the system peak so the same reserve requirement should be applied to a somewhat lower peak forecast. Price-responsive demand will mean not only that the system peak will be lower, but also that the necessary percentage reserve level will be reduced, because an unexpected system shortage will be addressable in part through the response to price increases. When it is first implemented in a system, the reliability of price response will be unproven, so the operator will rely very little on it to meet reserve requirements. Over time, however, the response will be more reliably forecast and price-responsiveness will be able to take on an increasing role in assuring system reliability. Though it will never fully replace other forms of reserves, price-responsive demand will eventually cut the necessary reserve levels substantially.

D. Issues in Implementing Real-time Pricing

We will now focus on real-time pricing in discussing three important issues in implementation: customer price risk, mandatory versus voluntary implementation, and distributional impacts of adoption. TOU pricing already exists and is used widely, but does not give economic incentives that are particularly

accurate, as discussed above. Much of the discussion that follows applies to other demand response programs, including critical peak pricing and pay for demand reduction. (In fact, demand-reduction programs can be seen as critical peak pricing programs with an additional baseline-setting problem.) As discussed in the prior section, interruptible programs are extreme and extremely blunt versions of RTP whose usage would be minimized in a well-functioning electricity system.

1. Mitigating Customer Price Risk

Under the simplest RTP system, the customer is billed the real-time price of electricity on an hourly basis (or some other frequent interval) for all power the customer consumes during that hour. Because the real-time or day-ahead price can be quite volatile, many customers have balked at such a program for fear that they could find themselves paying astronomical prices for their consumption during any given hour. TOU programs limit this risk by drastically reducing the volatility of retail prices. Because prices under TOU are requirements contracts, however, they also drastically reduce the efficiency of the resulting economic incentives. Demand response programs limit this risk by guaranteeing that the customer never faces a price above the posted tariff, only below.

Many RTP programs have limited this risk by assigning customers a baseline consumption that they purchase at the regulated rate during each hour. The price for purchase of power at the baseline consumption is usually the TOU rate that a customer would otherwise face. Then the customer pays the real-time price for any consumption above its baseline level *and* receives a rebate based on the real-time price if its consumption falls below its baseline level. In financial terms, the baseline is just a forward contract for a quantity equal to the customer's baseline level, which the customer has purchased at a price set by the regulatory process. Such programs are generally called two-part RTP programs with a customer baseline load (CBL).⁹

The California crisis, however, made clear a significant problem with the CBL approach. If the customer buys the baseline at a price unrelated to the expected market price, purchase of the baseline quantity amounts to either a subsidy or a tax depending on whether the regulated price is above or below the expected market price. That alone would create an equity issue, but in practice it also creates a significant influence and lobbying problem. An RTP plan with a CBL was proposed in California during the spring of 2001. At that time, the real-time price was expected to be well above the regulated price at which customers would purchase their RTP. Once companies understood this (the plan was to be only for large customers), their focus turned almost entirely to lobbying for a high CBL for themselves. Though the California economy was clearly entering a recession and the dot-com economy was declining, many companies still claimed that they were growing at phenomenal rates and therefore needed a CBL well

⁹ See Ahmad Faruqui, Joe Hughes, and Melanie Mauldin. "RTP in California: R&D Issues and Needs," report prepared by the Electric Power Research Institute for the California Energy Commission; February 2002.

above their past usage. Any RTP program with a CBL will include an implicit transfer payment to or from the customer so long as the regulated price differs from the expected real-time price. Thus, baselines set by any regulatory process will be subject to intense lobbying and related influence activities.

Luckily, there is a device similar to the CBL that can avoid this problem: the forward contract that the CBL itself was meant to mimic. One way to think of this is as real-time pricing with a build-your-own (BYO) baseline. Rather than assigning the customer a baseline level, the customer can purchase a baseline, *i.e.*, a forward contract, to hedge as much price risk as it wants. The key would be to offer the baseline or forward contract at a price that equals the best forecast of the future spot price. Georgia Power, one of the first users of the CBL, now offers such a futures contract as an enhancement. They refer to these as price protection products. The advantage of this approach is that because the BYO baseline is purchased at a price that reflects the expected real-time price, unlike the CBL, it contains no subsidy or tax on average. It is simply a risk-hedging device.

It is worth pointing out, however, that while the CBL approach creates incentives for lobbying because the baseline contains a subsidy or tax, the same characteristic can be advantageous. The retailer nearly always needs to impose charges that are not directly related to the incremental cost of energy, such as for transmission and distribution, or to cover the sunk costs of past investments or power contracts. By setting the CBL and the rate at which that energy is purchased, the utility (or regulatory agency) can set a charge that recovers these fixed or sunk costs without causing the marginal price of energy to deviate from its true cost. Effectively, the CBL builds in a fixed charge for a fixed quantity of energy and that fixed charge can be used to cover costs (or give refunds) without distorting the incremental energy price. In contrast, the BYO baseline cannot be used to cover sunk or fixed costs, because the forward price offered must be very close to the expected real-time price when customers voluntarily choose how much baseline to purchase.

The BYO baseline allows customer to avoid purchasing most of their power at the real-time price. Yet, for incremental consumption decisions, the customer still faces the real-time price as its cost (or opportunity cost, since it can resell power it doesn't use from its BYO baseline), and thus has strong incentives to conserve at peak times. The BYO baseline cannot create a perfect hedge since the customer won't know in advance exactly what quantity it will consume in each hour. To the extent that customers want even more stable electric bills than the BYO baseline would provide, other products, including call options, may develop in a private market. In fact, the BYO baseline itself could be provided by a private market. In reality, however, regulatory uncertainty at the beginning of an RTP program may make private parties reluctant to enter this hedging market, so it would probably make sense for the utility to be the first provider of such risk-hedging products.

2. Time-Varying Prices Versus Average Price Levels

Some customers have expressed concern that under RTP the average retail price they face could skyrocket. Conversely, many utilities have been concerned that RTP will be implemented in a way that leaves them with a revenue shortfall. At the same time, numerous observers have stated that RTP in California is now infeasible because the real-time prices would fail to cover the costs of the long-term contracts to which the state is committed.

While these concerns may seem to be only slightly related, they all reflect similar confusion between setting a desired average level of retail prices and allowing retail price to vary over time. In practice, the *average* retail price can be set at whatever level a regulator chooses while still allowing prices to vary in a way that reflects shortages and surpluses in the market. The key is to recognize that the revenue requirement of the retailer (whether a regulated investor-owned utility, a municipal utility, or a private energy service provider) can be met by imposing a fee or rebate that need not be related to prices in any given hour.

To understand how total costs can be reliably covered while still charging time-varying prices and maintaining stability of customer bills, consider an example of a retailer charging RTP prices to its customers that also hedges by purchasing some power on long-term contract.

Assume that the retailer begins by engaging in no hedging. It charges customers a fixed per-kWh transmission and distribution (T&D) charge plus the spot price of energy in each hour.¹⁰ This satisfies the real-time pricing goal, but does not assure that monthly bills are stable or revenue requirements are met. In fact, the monthly bills, and retailer's revenues, would be as variable as the month-to-month variation in the weighted-average spot energy prices.

To attain the goal of monthly bill stability, the retailer would sign a long-term contract to buy some amount of power at a fixed price.¹¹ To fix ideas and keep the presentation simple, assume that the retailer signs a long-term contract at the same price for each hour. Such a contract is likely to be at about the average spot price of the electricity that the parties anticipate over the life of the contract, but in any given month the contract price could be greater or less than the average spot price. If there are significant shifts in the market, the contract prices could end up being much cheaper or more expensive than the spot wholesale prices.

¹⁰ The spot price here could refer to a day-ahead price or a spot imbalance energy price.

¹¹ In fact, the contract just has to have less variance than the spot price. It could, for instance, have a fuel adjustment clause.

This contract can be considered a financial investment that is completely independent of the retailer's service to final customers. The critical point is that the retailer's return on this financial investment varies directly with the average spot price of energy, and that return can be applied to change the average level of customer bills. When viewed this way, it becomes clear that the long-term contract can affect the average price level without dampening the price variation. The gains (when the average spot price is higher than the contract price) or losses (when the average spot price is lower than the contract price) from the long-term contract could be distributed to customers with lump-sum fees or rebates (perhaps based on the customer's historical usage level) or with a constant (over the month) surcharge or discount on each kWh sold during that month.¹²

If a constant per-kWh surcharge or discount is used, the retailer would then charge the customer the spot price plus or minus the return per-kWh from the long-term contract. Since the profit earned from holding the contract is greater when the spot price is higher, it would be used to offset the high average spot price, thus lowering the volatility of monthly electricity bills. If the retailer hedged nearly all of the load it served, then this offset would be sufficient to nearly eliminate variability in monthly bills. If the retailer hedged, say, 80% of the load, then about 80% of the variability in monthly bills would be eliminated. The actual price that the customer was charged in each hour, however, would still have the same variance as the spot price. The critical point is that the gains or losses in any given hour from the forward contract need not and should not be collected in that particular hour. There is no economic argument for doing so and doing so would greatly reduce the variability of retail prices and, thus, the economic incentive for conservation.

Figure 1-e illustrates the effect that this approach would have had in June of 2000 if the retailer had been lucky enough to sign a long-term contract before prices increased. In this illustration, the retailer is assumed to have signed a contract for 80% of its load at 6¢ per kWh. In addition to energy charges, the retailer is assumed to assess a 4¢ per kWh charge for transmission and distribution. The T&D charge is added to all prices for ease of comparison. The three horizontal lines show the load-weighted average price a customer would pay (assuming it had the same load profile as the system as a whole) if the retailer were fully hedged (lowest line), if it were completely unhedged (highest line), and if it were 80% hedged (middle line).

¹² A CBL, as discussed earlier, can be used to assign proportions of the gains of losses from long-term contracts in a way that doesn't distort customers' marginal incentives at all. If this is done with a surcharge or discount on the energy charge, the surcharge or discount need not be constant. It could, for instance, be implemented as a multiplier of the wholesale price. The important point is that it should not be implemented in a way that substantially dampens retail price fluctuations.

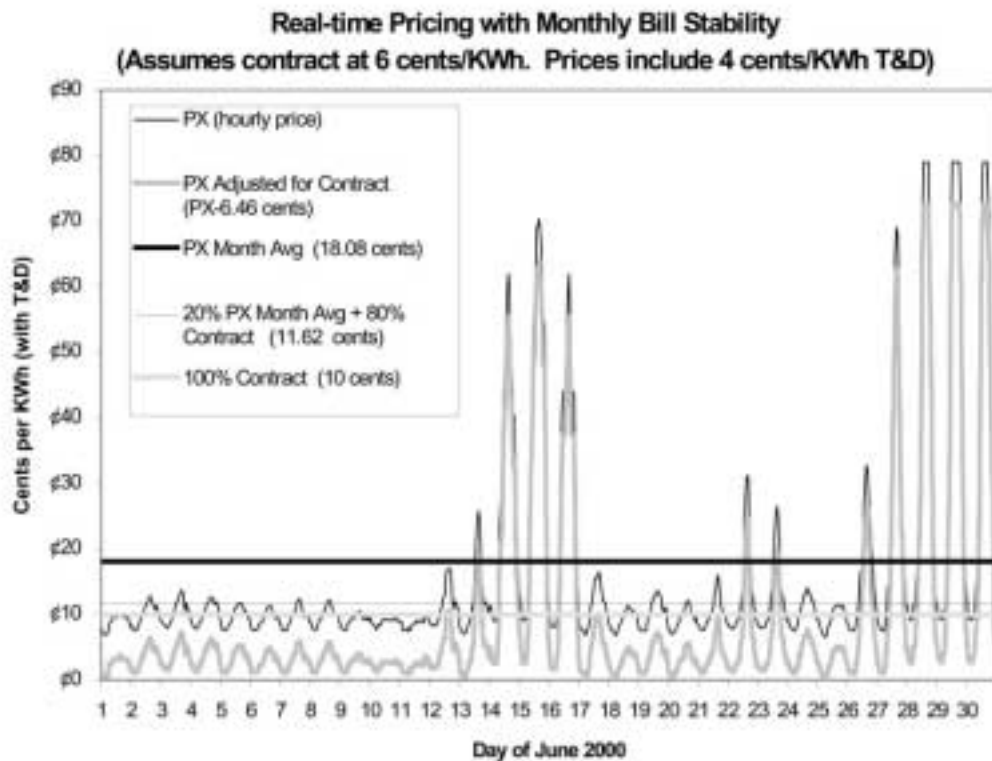


Figure 1-e

Of the two volatile lines, the higher shows the real-time price a customer would pay with no hedging and the lower shows the price the customer would have paid if the retailer had combined real-time pricing with 80% hedging, in this case, purchased through long-term contracts. The load-weighted average of the higher line is 18.08¢, the same as the highest horizontal line. The load-weighted average of the lower line is 11.62¢, the same as the middle horizontal line.¹³ This illustration demonstrates that under real-time pricing with long-term contracts, a customer could face the same volatility in prices as it would under 100% real-time pricing. The only difference would be that the price curve would be shifted down by the “profits” from the long-term contract, which in this example are 6.46¢ per kWh. During the hours of

¹³ This illustration, in which the long-term contract price is below the average spot price, is not meant to suggest that forward prices are systematically cheaper than spot prices. On average, the forward contract price will be about equal to the expected spot price during the life of the contract. Though it does not occur in this illustration, it is possible that this formula could result in negative prices in certain hours. This outcome could be easily avoided, however, with a small modification. A minimum price, say 1¢ per kWh, could be set and any resulting excess revenue could then be redistributed evenly among all other hours.

extremely high spot prices, customers would face prices nearly as extreme, and would have a strong incentive to reduce consumption. Yet, the average monthly prices (and monthly bills) the customer would face would be much less volatile than without hedging.¹⁴

It is important to distinguish between the effect of a price adjustment adder or subtractor in contrast to the retailer hedging discussed here or to the customer hedging described in the previous section. The adder or subtractor that the retailer could institute would be used in order to attain a given revenue requirement, or equivalently, average customer price. One possible use of such a price adjustment would be to change the average retail price so as to cover the costs of a long-term purchase contract that the retailer has signed to hedge energy costs. But, more generally, the price adjustment would be used to true up actual with target revenues while still maintaining time-varying retail prices.

Hedging by the retailer is particularly valuable in a regulated context where customers do not have the choice to hedge price risk themselves by signing private contracts with generators or other market participants. In a competitive retail market, retailers would probably not arbitrarily impose a level of hedging and retail price. Instead, they would offer to pass through the wholesale spot electricity price and would augment that offering with various price protection programs, such as a BYO baseline. The retailer would then hedge its wholesale price risk in a way to match the retail price hedging that its customers have chosen to purchase. In essence, the retailer would serve as a broker of risk hedging services.

3. Distributional Impacts of Adopting RTP

Of great concern in discussions of RTP programs is which participants will be winners and which will be losers from adoption of such a change. A significant effect of RTP is to reduce the total payments to generators in the wholesale electricity market. This occurs because peak demands, when prices are very high (even if the wholesale market is competitive) are reduced. In the long run, this means fewer new power plants need to be built and their costs need not be borne by customers. It is important to note these effects can benefit all customers, those on RTP and those who are not. Furthermore, if the wholesale market is not completely competitive, RTP reduces the ability of sellers to exercise market power, which further reduces wholesale prices and, again, benefits all customers whether on RTP or not. By creating real-time demand elasticity, RTP also lessens the likelihood of system shortages and the potential for customer interruptions or rolling blackouts.

¹⁴ This illustration slightly overstates the monthly bill stability that could be achieved through 80% hedging because it assumes that the hedged quantity is 80% of the actual demand in each hour. The contract (or contracts) would quite likely hedge a larger quantity during periods when demand is anticipated to be high, but the variation would probably not match exactly the actual variation in consumption that occurs. Since price will be highest in periods when the quantity exceeds anticipated levels, the protection from the hedging contract would be slightly less than if it matched the actual consumption pattern exactly.

Among customers on RTP, the benefits vary depending on when a customer consumes power. Customers with a relatively flat consumption profile — whose consumption has less hour-to-hour and day-to-day variance than others on RTP — will see the greatest benefits. Because their consumption does not “peak” as much as the aggregate demand at high-demand times, they will be buying a smaller share of their power at the most expensive times. As a result, their average price per kWh will be lower than for customers with more “peaky” demand.

Customers with more “peaky” demand, who do not respond to the higher prices that will occur when supply is tight, will consume a disproportionate share of their power at the more expensive times. These customers will face a higher average price per kWh than will customers with a flatter demand profile. In California, the peak demands occur on hot summer days and are driven primarily by air conditioning. There are no completely reliable rules, but customers that use power disproportionately for air conditioning generally have more “peaky” demand that is greatest at the time when electricity is more expensive. Customers that use power disproportionately for other uses (lighting, industrial production, machinery) generally have flatter demand profiles.

Customers with “peaky” demands might actually end up paying more than under flat rates, but it is quite possible that they would not. While they would pay high prices at peak times, the overall efficiency of the system would improve and there would be less idle capacity that all customers must pay for. The average price would decline with RTP, but these customers would consume a disproportionate share of their power at higher-price times, so it is hard to know for sure whether their bills would increase or decrease. Certainly, to the extent that they can respond to high prices by conserving or shifting demand, their bills would be more likely to decrease.

Many industrial customers that run 24 hours a day, 7 days a week have expressed concern about RTP because they say that they cannot reduce their demand or shift usage. Customers that run 24x7, however, tend to have flatter demand profiles than the system as a whole. Thus, although they would have to buy power at higher prices during system peaks under RTP, they would buy a smaller share of their power at these times than would other users. Their overall power bills would decline.

The reason for this is that the system is not driven by one customer's ability to conserve, but by the ability of users in aggregate to lower demand at peak times, thereby reducing wholesale electricity prices and reducing the risk of rolling blackouts. If a certain customer cannot conserve at all without suffering major economic losses, then RTP offers enormous benefits, because it can greatly reduce the chance of rolling blackouts, which are especially costly to such customers, and it reduces the wholesale price of electricity at peak time because *other* users reduce their demand.

4. “Mandatory” Versus Voluntary Implementation

A question that arises frequently in discussions of RTP is whether it will be mandatory or voluntary for a given class of customers. Since virtually all consideration of RTP has been only for large customers, the class of customers for whom RTP might be mandatory is those large customers. In practice, all of the programs in the U.S. are voluntary.

It is important to recognize that a mandatory RTP program does not mean that customers need to be exposed to the full risk of the spot electricity market. Hedging by the retailer or by the customer can greatly reduce the price risk associated with RTP. Perhaps a more accurate description would be a “default” RTP program: customers by default pay the real-time price, but they can sign forward contracts that mitigate the volatility in costs they would face if they purchased all of their power at the spot price.

Still, many market participants argue that if any RTP program is instituted it should be done on a voluntary basis. While a voluntary program is attractive in many ways, it also raises difficult equity and efficiency issues that don't arise if RTP is the default.

The customers that would sign up for a voluntary RTP program would be those that have a more attractive load profile — either flatter than most or actually peaking at times when the system demand is low — or *would have* a more attractive profile once they responded to real-time prices. These customers would get lower bills if they paid the wholesale price of the power they used under RTP rather than the average wholesale price of the power that all customers use. In large part, a voluntary program would identify the customers who have been subsidizing other users that consume more at peak times.

This, however, creates a problem for the retailer. In order to avoid a revenue shortfall, either it must charge a higher average price to those that don't sign up for RTP than to those that do or it must place an adder on the RTP price so that the RTP group as a whole faces the same average price as non-participants.¹⁵ A lower average price for RTP participants would be consistent with the cost of serving this group, but it would very likely raise difficult political issues. Rather than being seen as an end to a historical cross-subsidy, it would likely be portrayed as a new subsidy to RTP customers.

On the other hand, an adder to RTP prices that equalizes the average RTP price and the average non-RTP price would undermine the incentives to join the program. If the average per-kWh price for RTP customers is the same as for non-RTP customers, then some — probably about half — of the customers on RTP are paying a higher average per-kWh price on RTP than they would if they switched to the non-RTP rate. Those customers would be better off switching to the flat rate. As they did, this would reduce the

¹⁵ It is quite possible that voluntary RTP would lower the cost of serving both groups, compared to no RTP, by reducing wholesale prices. Nonetheless, given any set of wholesale prices, the non-RTP participants will almost certainly be more costly to serve (on an average cost-per-kWh basis) than the RTP participants.

average per-kWh rate among those remaining on RTP. In order to equalize prices between RTP and non-RTP customers, the retailer would have to raise the RTP adder. Once it did so, a new set of RTP customers would find they were paying a higher average price than they would on a flat rate. They would then be better off switching to the flat rate. This RTP death spiral would continue until only the customer with the most attractive load profile is left on RTP and the adder is set so that this customer is just indifferent between staying on RTP or switching to a flat rate.

An alternative to the RTP death spiral would be to institute RTP on a voluntary basis, but charge each group, RTP and flat-rate, an average price equal to the average cost of serving that group.¹⁶ That is, this would be a no-cross-subsidy implementation of a voluntary RTP program.

When first offered, the RTP plan would primarily attract customers with the most attractive load profiles. But once these customers switched to the RTP plan, the average cost of serving customers that remained in the flat-rate plan would rise. This would make the flat-rate plan less attractive relative to RTP and would cause more customers to switch. Those that would now want to switch would be a selection of customers remaining in the flat-rate plan that have relatively more attractive load profiles. Again, the switching would cause the average cost of serving flat-rate customers to rise, and thus would increase the price charged to them, making the flat-rate plan even less attractive. While this approach might not cause a complete unraveling of the flat rate, it would almost surely attract significant business and result in a higher average price for those that remain on flat rate than for those that move to RTP. Again, it could still lower the price charged to both groups compared to no RTP since the incentive to consume less at peak times would reduce overall peak demand and wholesale prices.

It is worth pointing out that the no-cross-subsidy implementation of a voluntary RTP plan might also be achieved without a regulatory process. Retail choice is likely to have this effect if it is implemented in a way that does not offer a subsidized default utility rate. Customers that are cheaper to serve will abandon the flat-rate utility service in order to get the lower prices associated with their more attractive load profiles. As they do, if the remaining utility customers are not subsidized, their flat-rate price will rise above the average price paid by customers who have moved to a competitive retailer offering RTP.

Implementation of retail choice thus far, however, has generally offered customers remaining with the utility a fixed price independent of the costs of serving these customers. This has set up two types of incentives. First, it has reduced the attraction of moving to a competitive retailer, because as some

¹⁶ We abstract here from other costs, including T&D charges and the adders necessary to cover financial losses from the retailer's long-term contracts or other stranded investments, all of which would be added to the charges of both groups. It is probably best to think of this approach as applying only to large industrial and commercial customers, all of whom could be fitted with real-time meters at relatively low cost.

customers have moved, the price to the remaining customers has not been affected, in contrast to the no-cross-subsidy implementation we've just described.¹⁷ Second, it has created incentives for customers to jump back and forth between competitive suppliers and the fixed-price utility offering. When wholesale prices in California jumped in summer 2000, competitive retailers raised their prices to reflect that increase. The result was that many customers returned to the fixed-price utility rates, which were then being heavily subsidized. When wholesale prices fell in summer 2001, many of the same customers jumped back to competitive retailers.

Successful implementation of RTP does not depend on making it compulsory for any group. It can be implemented on a voluntary basis if it is done with a commitment of no cross-subsidy between RTP and flat-rate customers. In fact, such an approach would be likely to create its own momentum as low-cost customers abandon the flat-rate and increase the wedge between the average prices paid by RTP and flat-rate customers. This would be the result of retail competition if prices to customers that remained on the utility's flat-rate plan were reset to reflect the cost of procuring power for those customers. In practice, however, a voluntary program is usually implemented with price, or subsidy, protection for customers that choose not to switch. This dampens the economic incentive to switch to RTP. The problem is greatly exacerbated if the flat-rate customers are also given a fixed rate that doesn't change when average prices in the wholesale market changes, as occurred in California during the summer of 2000.

E. Conclusion

It is clear that time-varying retail electricity prices can significantly help to reduce system production or procurement costs, as well as to meet operating capacity reserve requirements. Many approaches to implementing this idea are in practice, some more widespread than others. RTP, the most attractive approach from an economic viewpoint, has faced two important impediments. The first, technological, has greatly diminished in the last decade, as discussed in the next section. The second, concern over price volatility, can be addressed with hedging instruments or price protection plans, as has been demonstrated here.

Where RTP cannot be implemented, due to either political or practical constraints, a number of alternatives to flat-rate pricing still exist. Some of the alternatives, particularly critical peak pricing, may accomplish much of what RTP offers, while others, like Time-of-Use pricing, are a much smaller step towards improving the efficiency of electricity systems.

¹⁷ By some, this has been called an attempt to prevent "cherry picking" that would drive up the cost to other customers. By others, this has been called an attempt to preserve the historical cross-subsidy.

For more than 75 years, electricity planning has been based on meeting a peak demand that has been assumed to be price-invariant. The payoff for greater demand-side price-responsiveness is reduced reliance on generation capacity that is operated only to meet occasional demand peaks. The failure to incorporate demand flexibility has imposed unnecessary generating plants, production costs and environmental harm on society. An electricity system that permits adjustments on both the supply and demand side will improve efficiency, reduce costs, and benefit the environment.

II. PRACTICAL IMPLICATIONS OF DYNAMIC PRICING BY MICHAEL JASKE

Section II of this monograph addresses some important practical implications of RTP and CPP tariffs. Shifts to RTP tariffs imply a host of changes to the customer-supplier relationship, including new price signals, new forms of and interest in usage data, and more active management of the utility-customer relationship. CPP tariffs also require a new signal, and some changes to utility processes, but not necessarily as comprehensive as those implied by full RTP tariffs. Most of what is needed for a CPP tariff is a subset of what is needed for an RTP tariff, if both are being offered, so this section will focus on RTP tariffs with supplemental comments on CPP tariffs as needed.

Section A introduces illustrative RTP and CPP tariffs which are being offered to end-use customers today. These provide an opportunity to understand how the theoretical materials of section I translate into actual tariffs offered to customers. Section B deals with development of a dynamic price signal directly or indirectly linked to market activities, which drives an RTP tariff and could drive a variable CPP tariff. Section C introduces the issues of metering and data communications. Implementing these tariffs requires major changes in collection and processing of usage data, *e.g.*, shifting from a few monthly cumulative measures to many hundreds of interval measurements. Section D describes impacts of the use of interval data on billing and customer service. For example, these data, once validated, must be synchronized with dynamic prices to compute the actual bill for the participants, and these much more complex data must also be made available to the customer. Customers want these data to substantiate their bills as well as to help understand and control their operations. As a result, the opportunities of RTP tariffs create or radically change several utility/customer processes. Section E introduces the issues associated with active utilization of these tariffs by the energy procurement agent. With such tariffs, the purchasing agent must learn how participants will respond to RTP values and may have opportunities to deliberately influence market prices. Finally, section F introduces the topic of the benefits such tariffs appear to bring to the efficiency of a competitive electricity market.

A. Illustrative RTP and CPP Tariffs

Section I introduced the theoretical foundations for RTP and CPP tariffs. Both of these exist in practical forms as tariffs today. Customers under RTP tariffs are a major portion of the load of Georgia Power. Small customers receiving service under a CPP tariff are a growing part of the load served by Gulf Power. These tariffs are described in some detail in the Appendices to this monograph. Faruqui and Mauldin (2002) provide an overview of the participation level in various RTP tariffs around the nation.

1. An RTP Tariff: Georgia Power's Schedule RTP-DA-2

Beginning in the late 1980s, Georgia Power introduced a series of RTP tariffs. By now there are a suite of such tariffs and associated risk management products that Georgia Power offers to customers on a voluntary basis. About 5,000 megawatts (MW) of total customer load participates in this suite of tariffs. For sake of illustration, one of most commonly used tariffs, Schedule RTP-DA-2, is briefly discussed here. Appendix A provides a more in-depth description.

Schedule RTP-DA-2 is available throughout the Georgia Power Service area. It is open to any customer with a load over 250 KW. It operates on the Day Ahead format, meaning that each afternoon customers are provided with a forecast of hourly prices for each hour of the subsequent day. Customer response to these prices, relative to a baseline pattern of electricity usage, has a direct impact on their energy bill.

Schedule RTP-DA-2 is designed so that if the customer baseline load (CBL) accurately reflects average usage patterns, and the customer continues to follow these patterns, then the customer's bill has no marginal impact from RTP prices. If the customer is able to reduce load (relative to the CBL) in periods when RTP prices are high, the customer can receive a significant bill credit. If the customer increases load during these high RTP price periods, then this will result in a substantial increase in the customer's costs. Alternatively, if the customer increases loads (relative to its CBL) in low RTP price periods, the increment to the customer's bill may be quite small.

As discussed in section I, Schedule RTP-DA-2 is a marginal price tariff. It directly subjects the customer to high or low market prices for marginal changes in consumption relative to a pre-determined baseline.

2. A CPP Tariff: Gulf Power's Residential Service, Variable Price Option

Gulf Power's Residential Service, Variable Price Option (RSVP) tariff has been available on a pilot basis since the late 1990s. After two years of evaluation, it is now in full use with several thousand participants. Gulf Power reportedly is shooting for 40,000 participants within a decade. Appendix B provides a complete description of this tariff.

Essentially, RSVP is a standard TOU tariff with a pre-determined fourth period triggered by system conditions at the discretion of the utility. To illustrate the significance of the critical peak price, it is 29¢ per kWh, while the peak period rate is 10.4¢ per kWh. The meter used with this tariff has four registers, and one-way communication signal shifts usage recording into the fourth register. Once a critical period ceases, the meter returns to recording usage in the register appropriate to the pre-scheduled TOU period that would otherwise be in effect. Clearly this means that a non-standard TOU meter is required.

In addition, Gulf Power provides additional opportunities to the customer to actively manage loads when the critical peak period has been triggered. A control panel in the customer's dwelling alerts occupants that the critical peak condition has been invoked. The control panel is also the device for communicating with one or more end-use devices that can be pre-programmed to shed specific end-use loads under CPP conditions. The principal end-uses that are controlled are electric water heating and air conditioning. The end-user can also use the control panel to manually control these same selected end-uses if specific conditions warrant overriding the standard decision rule programmed in by the participant.

It is clear that RSVP involves a special package: (1) a TOU tariff responsive to system conditions as well as standard time of day and day of week parameters, (2) communications from the utility to the participant's

dwelling that both communicates with the control panel and the non-standard TOU meter, and (3) a control panel with programmable, electronic decision logic that directly controls various end-user loads. All of these features work together to ensure that the customer has a satisfactory experience with the RSVP tariff.

B. Developing the RTP and CPP Signals

There are both theoretical and practical considerations for developing the RTP price that drive the tariffs described in section I of this monograph. In two-part tariffs, where the RTP tariff is designed to provide merely the market-based marginal cost to tariff participants, then it clearly should be computed by determining avoidable generation purchases. If the RTP tariff is designed to be used by an energy procurement agent to minimize aggregate expenditures on electricity by inducing RTP participants to reduce load in hopes of driving down market-clearing price, then the RTP price would be computed in a more complex manner. For example, perhaps the RTP price is higher than actual avoided generation purchases by adding a portion of the estimated benefits. In a one-part tariff, the marginal generation purchase costs may be blended with other generation costs to compute the price.

Each tariff design requires a specific approach to developing the RTP price. In addition, there are variations depending upon the degree to which the RTP tariff relies upon actual market information or forecasts of such information. Day Ahead and other *ex ante* variants of RTP tariffs may stimulate greater response due to the longer lead time available to decision-makers once they understand future hourly prices, but there may be risks incurred by the utility in committing itself by using prices based on expectations of costs rather than actual costs.

Compared to RTP tariffs, CPP tariffs require a less complex set of computations using individual customer usage data to compute the bill. However, compared to RTP tariffs which simply pass along the wholesale market price as it is revealed, a CPP tariff requires more complex estimates of the expected pattern of use so that the *ex ante* rate parameters of the basic TOU rate design are computed accurately. Failure to do so may expose the utility to risk in under-recovering actual generation expenses.

1. Computing RTP: Ex Post versus Ex Ante

True RTP prices can only be computed on an *ex post* basis, when all settlement computations have been finalized. Such a tariff can be expected to be unappealing to many customers, who wish to have some degree of certainty about the price they face prior to the event. There are three different *ex ante* forms of RTP tariff now operational: (1) a Day Ahead form, (2) an Hour Ahead form, and (3) a near real-time form

based on ancillary service market operations.¹⁸ Unless a Day Ahead or Hour Ahead market exists to generate actual market prices, the first two of these forms require development of forecasts of RTP prices using expectations of market behavior developed from experience. Such forecasts can, and will be, incorrect; one cannot avoid such errors, but one can aspire that they be unbiased.

Forecasting an *ex ante* RTP value essentially involves developing correlations between historic RTP values and explanatory variables available on the desired *ex ante* time horizon. For example, a Day Ahead version of an RTP tariff intended to reduce avoidable generation purchases might require that RTP values for each hour of the following day be posted at 4:00 p.m. of the previous day. Such a requirement allows participants to schedule shifts or otherwise take action when they know in advance that RTP values will be particularly high (or low). To prepare a set of such values essentially requires that explanatory variables such as load forecasts or both load forecasts and generation availability be correlated with historic hourly prices or average marginal costs in small blocks of hours. Developing statistical relationships, and updating them periodically, would allow development of the *ex ante* RTP signals needed for such a tariff design.

The Federal Energy Regulatory Commission (FERC) imposed or sanctioned market mitigation measures that constrain wholesale prices can introduce distortions into the independent system operator (ISO) real-time market data that render these data insufficient as the foundation for an RTP signal.¹⁹ Under these circumstances, adjustments to actual market data will be needed to prepare an RTP value that can induce desired levels of load reduction/shifting. The term “reliability adder” has emerged as a way of describing an element other than market price in the computation of RTP values. Subsection B.4 addresses this in more detail.

¹⁸ Georgia Power has offered both Day Ahead and Hour Ahead variants of RTP tariffs for several years. The Day Ahead form is much more popular, reflecting a determination by many participants that they value advance knowledge of RTP values so as to be able to schedule activity modifications when prices are expected to be unusually high or low.

¹⁹ On June 19, 2001, FERC imposed Westwide price caps on wholesale market prices. Because some suppliers choose to redirect production out of California, the ISO was forced to make out of market purchases, which were not reflected in formal real-time market data, thus making such data an inaccurate reflection of volumes and costs.

2. Avoidable Generation Purchases

Any marginal cost based RTP forecast should be based on the expected cost of generation purchases which can be avoided by an RTP tariff's expected load reductions. RTP tariffs based on *ex ante* price projections will have to forecast RTP prices based on an incomplete set of market expectations unless a formal market exists to develop such price expectations.²⁰ RTP tariffs could be based on after-the-fact settlements data, but purely retrospective tariffs are unlikely to be appealing to many customers, who generally wish some advance notice in order to make changes in production activity and employee schedules.

Estimating avoidable generation purchases on an *ex ante* basis can be easy or difficult, depending upon the design governing market participant behavior. Under circumstances of deep, liquid spot markets such price signals may be readily available. For example, in the original California market design, a California Power Exchange (CalPX) existed which conducted a second price auction on a Day Ahead basis for each hour of the following day. California Public Utilities Commission (CPUC) directives obligated utility distribution companies (UDC) to “buy from and sell to” this Day Ahead market in serving bundled customers. The result was an hourly unconstrained market clearing price (UMCP), which was modified somewhat from time to time, as California Independent System Operator (CAISO) congestion management practices required. Nonetheless, it was an excellent indicator of market clearing prices in a very deep market. It was available by early in the morning on a Day Ahead basis, and provided an excellent driver for an *ex ante* RTP tariff. No special effort was needed to prepare the estimate; it simply was a feature of the overall market design. Although the CAISO's congestion management process sometimes resulted in different zonal prices, the CalPX UMCP was still the dominant element even of those final prices.

When there are no organized hourly spot markets because most trade takes the form of bilateral contracts, it may be more difficult to develop hourly market prices. For example, once the CalPX went bankrupt in early 2001, the price transparency inherent in the CalPX Day Ahead process vanished. Large volumes of resources were arranged on a bilateral contract basis. Terms and conditions were not disclosed. Public data were limited to the CAISO real-time market, which was thin, chaotic and frequently overshadowed by out-of-market purchases engendered by the dysfunctional situation. Even in the best of times this real-time market did not provide a very clear signal about the avoidable cost of generation purchases. Further, as real-time information, it was not available on a Day Ahead basis, frustrating use as the source

²⁰ In its MD02 proposals, the CAISO has proposed to develop Day Ahead locational energy prices by creating a new integrated, scheduling and congestion management procedure. Market participants would place unbalanced load and generation bids, along with specific load/generation schedules, into the CAISO process on the morning of the Day Ahead of the Trading Day. The CAISO would conduct market clearing and congestion management processes that would result in Hourly Day Ahead energy prices on a locational basis. Such Day Ahead energy prices would be an ideal signal for an *ex ante* Day Ahead RTP tariff. The CAISO submitted its final proposals to FERC on May 1, 2002, most of which FERC has subsequently ordered to be put into effect in early 2003.

for *ex ante* prices. Such *ex ante* RTP values would have to be developed by estimating statistical relationships between historic real-time prices and various indicators available on a forward basis, *e.g.*, load forecast, weather predictions, expected supply/demand balances, etc. Preliminary efforts to develop statistical models using CAISO data during the summer of 2001 were not successful, at least in part due to the strong influence and prevalence of sizeable out-of-market purchases diminishing the volumes of the formal CAISO real-time market and the data available to the public.

FERC has recognized the value of formal markets, and is actively sponsoring efforts leading to their development in various regions. For example, the CAISO was directed to file a proposal for a formal Day Ahead market by May 2002. The CAISO Market Design 2002 (MD02) effort resulted in a May 2002 tariff filing that proposed to integrate Day Ahead scheduling and congestion management into a single process. As proposed, this would restore an hourly estimate of energy prices on a Day Ahead basis, which would provide an ideal basis for *ex ante* RTP values. Even better, these CAISO proposals would produce nodal market clearing prices, which could allow an RTP tariff to be implemented using these local price signals if local regulatory authorities sanctioned such tariff designs.

3. Implications of Avoidable Purchases on Total Power Purchase Costs

In situations where market clearing prices establish the cost for a significant portion of load in a time period, then avoiding marginal generation purchases can reduce market clearing prices and save substantially more aggregate power purchase expenditures than just the cost of the increment of generation avoided. Section I.B of this monograph discussed the theoretical basis.

As an illustration of this point, consider the following example. Assume energy prices are established in a broad spot energy market using a first price auction format to clear the market. At the system peak hour, 10,000 MW of load is expected to be served from these purchases. With demand at the level of 10,000 MW, market price is \$300 per MWh. At a demand level of 9,500 MW, market clearing price is \$225 per MWh. Achieving a load reduction of 500 MW not only saves \$150,000 (500 MW x \$300/MWh) in the peak hour, it actually saves an additional \$712,500 [9,500 MWh x (\$300 per MWh - \$225 per MWh)] due to the reduced price which the remaining loads in the market now have to pay. These effects are not just theoretical. In an earlier stage of redesign of the California market, the CalPX and other stakeholders were actively researching the extent to which demand response could improve market operations.²¹

²¹ Simulations of the CalPX revealed total expenditure reductions that averaged seven times the percentage load reduction. That is, a five percent load reduction in a specific hour of the CalPX Day Ahead market resulted in a 35 percent expenditure reduction for that hour. See Figure 2-c for a visual depiction of the extent to which CalPX UMCP would have been reduced through load reductions of various degrees.

In such a market where there are clear benefits to a large class or group resulting from the actions of those on the RTP tariff, the tariff can be used as a tool to actively shift aggregate expenditures levels. To create additional incentives for RTP tariff participants to respond, many forms of “split the difference” incentive schemes between RTP tariff participants and others served by the same procurement agent can be designed.

4. Correcting Market Imperfections with Reliability Adder

Many disconnections between wholesale and retail markets may prevent market conditions from reaching customers. As an example, take the California situation during 2001 and 2002. Beginning June 19, 2001 and scheduled through September 30, 2002, FERC imposed a Westwide price cap on real time prices to mitigate market power concerns. Such a cap prevents actual hourly market conditions from affecting market price if the cap is continuously constraining market prices. Under such conditions the RTP price might be augmented by a value, known as a reliability adder, that is intended to provide a signal to RTP tariff participants that load reductions are particularly desired in the specific time period.

A reliability adder would be appropriate when operating reserves fall down to, or below, levels needed to comply with Western Systems Coordinating Council (WSCC) Minimum Operating Reserve Criteria (MORC).²² Applying these principles to an RTP tariff with a reliability adder might suggest that as the supply-demand balances for the system become tighter, the higher the RTP signal is “juiced up” through the adder, with the hope that greater will be expected load reductions. This approach could also be used to resolve specific transmission congestion contingencies in a localized area. Essentially this means that RTP tariff participants are providing much of the swing resources to meet reliability, since the market price cap mutes any incentive generators have to respond once the cap is reached.

5. Improving Local Reliability by Reflecting Locational Constraints on the Transmission or Distribution System

RTP tariffs need not be designed to utilize system-wide prices. A nodal market design will provide subsystem price values reflecting long standing local supply-demand conditions or time varying transmission congestion. RTP tariff design that permits such localized prices can elicit load reductions that help to relieve such localized conditions when generalized system load reductions would provide no useful benefit. Such a tariff will be more efficient than one that relies solely on system average RTP values, but the degree of efficiency improvement depends upon the degree of load response that differential prices would elicit. Even without a nodal pricing market design, subsystem RTP prices can be achieved by local modifications to a system-wide price if congestion issues can be efficiently translated into price adjustments for each local region.

²² WSCC (as of 2002, the Western Electricity Coordinating Council) MORC establish guidelines for control area operators to initiate actions when operating reserves fall too low. WSCC guidelines have generally been interpreted as 7% for fossil units, and 5% for hydro units, resulting in a California system average of about 6.8%.

After several years of zonal pricing within its markets, the CAISO proposed to FERC in its Market Design 2002 submissions, to shift to nodal pricing as is already the case in Eastern ISO markets. Implementation of such nodal pricing at the retail level would reverse longstanding CPUC practices of geographic averaging of costs, and might reveal large cost differentials between various subregions within utility service areas.²³ Fears of such differences and the consequences to electricity customers on the high side of the existing congestion zone demarcation have already caused some entities likely to be on high side of transmission cost differentials to express concern.²⁴ Further political and regulatory resistance can be expected despite the economic efficiency gains that might be achieved. Such tariff designs might be more readily accepted on a voluntary basis than a mandatory basis.

6. Determining CPP Signals

CPP tariffs require at least one, and perhaps two pieces of information. As implemented by Gulf Power, a fixed CPP has a fixed set of prices for each of the four tariff conditions.²⁵ The price in the CPP period is set in advance just as it is in each of the three “normal” TOU blocks. Thus, to implement a CPP tariff one must determine when to call a CPP event, and send the appropriate signal through the system to reset the meter and provide customer warning. In a variable CPP tariff, in addition to the event signal, the value of the price to be sent must also be determined. If the package of CPP metering and communication is designed properly, the price level can itself be the signal that resets the meter and it can be displayed to the customer to guide their actions.

For a variable CPP tariff, the CPP value is not necessarily the market value of the power. It can be the higher value that has been determined through participant price elasticity studies that is necessary to obtain the load reduction desired. Thus, the specific design of the CPP tariff, as either a tool to avoid extreme marginal costs or as a system reliability measure, should determine how the CPP value is computed.

²³ Pacific Gas & Electric and Southern California Edison are the two largest electric utilities in the nation, with considerable variation within their service areas in topography, population density and access through transmission systems to electricity resources.

²⁴ As an example, the City of Palo Alto operates a municipal electricity system that schedules power through the CAISO transmission system and purchases from CAISO markets. It is located in a transmission constrained portion of the greater San Francisco Bay Area. During the CAISO’s MD02 design process, Palo Alto expressed concern that its cost of power might rise considerably with no mitigating action that the utility itself could take to alleviate these incremental costs.

²⁵ See Appendix B for a complete description of the Gulf Power CPP tariff.

In all cases, once the CPP tariff is designed and is in place with participating customers, the utility operates these tariffs by monitoring the specific conditions that define the tariff's use of the CPP opportunity. In an economic driven CPP tariff, the market price may be monitored and if near real time forecasts indicate that the level that triggers the tariff will be encountered, then the CPP signal is computed. In a reliability driven tariff, the system operating reserves are monitored, and operating reserves dropping past a threshold define when the signal should be sent.

C. Meters and Communications for Customers

Advanced meters and telecommunication systems are essential elements of a successful RTP or CPP tariff. These systems record usage on a short interval basis, upload the data from the customer site to a central data processing center, and permit customers to access their own usage data. The same communication system may be the source for RTP or CPP values, but this is not necessary. This subsection will discuss the requirements of a metering and telecommunication system to support RTP tariffs, and then review CPP requirements.

The rapid evolution of telecommunication systems is a key factor that makes RTP tariffs more feasible today than in the past. Variable price CPP tariffs can be implemented using slightly less complex hardware and software systems than are required for full RTP tariffs, but the incremental cost of a system capable of RTP does not appear to be much greater than that for these CPP tariffs. A system configured to support fixed price CPP tariffs, such as implemented by Gulf Power, could not subsequently handle RTP tariffs. Therefore, with small incremental cost and considerable upward capability, a full RTP metering system appears to make the most sense.

1. Metering Systems Required for RTP Tariffs

RTP tariffs, and most load curtailment programs making up overall demand-response, require advanced metering and data communication systems. Generally there are several components: (1) an interval meter measuring energy consumption and perhaps other billing determinants on at least an hourly interval basis, (2) an automated communication system for uploading these usage values to a central data processing center, (3) customer access to their own hourly usage data as the basis for understanding onsite loads, and (4) notification of RTP prices and system emergency alerts that trigger load reduction behaviors.

There are numerous hardware and software configurations that meet these basic conditions. One element that may vary a great deal from system to system, or even from customer to customer within a specific system, is the degree of contemporaneous knowledge of facility loads. At the low end, a customer may be able to access yesterday's hourly interval usage values in the morning today. At the high end, a customer may be able to obtain nearly instantaneous reading of facility loads with little or no lag. There are at least two alternative approaches to achieve this goal. First, very rapid access to usage may be obtained by

direct feeds from the meter, such as through kyz pulse contacts, with these kyz pulses converted to digital data using a PC-based software package on the customer’s premise. Also feasible, though perhaps less rapid access to site usage data may be obtained through the normal data upload channel and back down through an internet-based information system. Many systems are built to enable occasional “on demand” reads, but unless the system has been designed to accommodate the bandwidth to communicate in this fashion for extended periods, it is unlikely to be sustainable for long or for many customers.

As an illustration of the type of effort needed to quickly deploy the hardware required for RTP tariffs, consider California’s response to the California energy crisis of late 2000 and early 2001. The California legislature allocated \$35 million of general fund tax dollars for the installation of RTP metering systems for all customers over 200 kW.²⁶ Originally it was hoped that these RTP metering systems could be deployed quickly enough to have an effect during the summer of 2001, but this proved too optimistic. A slower deployment path proved to be necessary. Utilities initially identified over 20,000 customers whose loads met the criteria. Ultimately, about 22,300 meter points covering approximately 30 percent of peak load in the state were determined to be eligible.²⁷ Over 200 kW implies that these customers are medium-sized, or larger, commercial buildings and industrial customers. Assuming that approximately 15% of peak load of these customers could be reduced, then approximately five percent of total system peak load might be reduced under high market

²⁶ In the spring of 2001, California Assembly bill AB1x-29 provided \$35 million for these purposes as part of an allocation of several hundred million dollars for energy efficiency programs and peak load reduction programs.

²⁷ Table 2-a provides initial estimates of the customer counts and significance of these large users.

Table 2-a
Investor Owned Utilities - Customers with Demands Over 200 KW

Customer Type	Customers	Cust. Load (MW)	% of System Peak
Customers > 500KW	7,600	7,826	20.8%
Customers 200 to 500 KW	14,435	3,687	9.8%
All Customers >200KW	22,035	11,513	30.5%

price conditions.²⁸ This is within the range of loads that Hirst (2002) has been reported as successfully moderating market outcomes and preventing high market prices. Interestingly, some benefits have been achieved from these metering and information display systems, despite the absence of an RTP tariff, because when the conversion was made each customer was placed on a special TOU rate.²⁹ Not only did a shift from a demand charge to a TOU rate incent new behavior, the customers with RTP metering systems were able to see their usage profiles as never before and take action to respond to the time differentiated rates.

There are a substantial number of issues associated with the advanced metering and telecommunication systems required for RTP tariffs. Most of these concern whether the costs of such systems exceed the benefits. Unfortunately, the benefits described for these systems rarely seem to include the system efficiencies they can induce in a competitive market setting. Efforts to resolve these concerns have delayed installation of RTP-capable metering systems in most parts of the country. A few advanced metering systems have been installed in various utility service areas, but only in the Puget Sound Electric system does the advanced metering system seem to be used to support modern market-based tariffs.

²⁸ Georgia Power reports peak load reductions in this range for its RTP tariffs. See Section III and Appendix A for more details.

²⁹ As of the date of this monograph, the installation is nearly complete for some utilities, while others have encountered various delays. Larger utilities have found it necessary to use multiple telecommunication pathways, since no single pathway covers their entire population of customers over 200 kW. Typically these multi-pathway systems involve hard telephone lines, two-way pager networks, and radio signal networks. Investor-owned utility recipients of these systems, under the jurisdiction of the California Public Utilities Commission, have been placed on a TOU rate, if they were not already on one before the meter was installed. In practice, this means that only customers on the 200-500 kW range were shifted to a TOU rate if they were not already on one, because in California over 500 kW customers have been on such rates for many years.

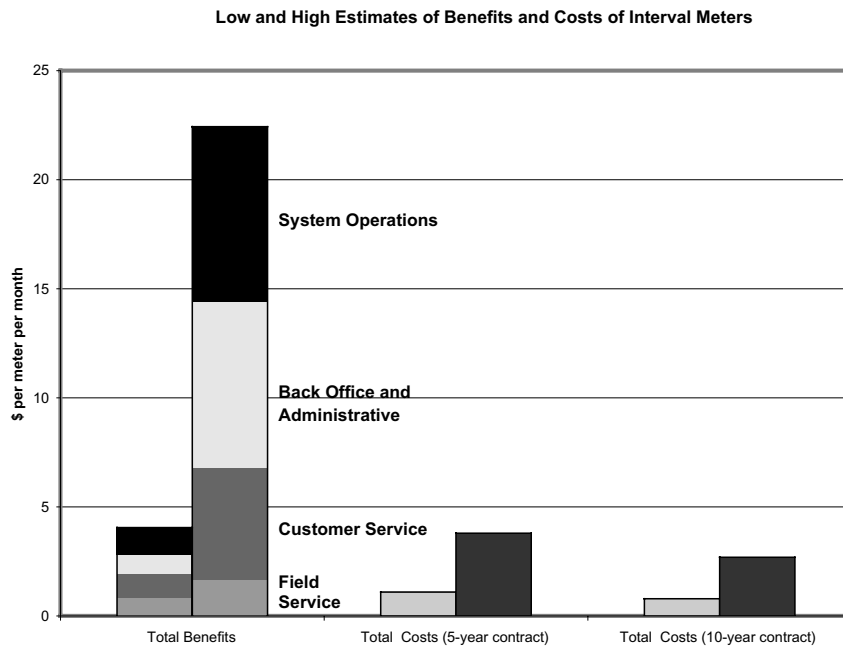


Figure 2-a. Comparison of Estimated Range of Benefits and Costs of Advanced Metering Systems

Figure 2-a summarizes a view of RTP metering system costs versus benefits prepared for the California Energy Commission (CEC) as part of its Public Interest Research program.³⁰ This figure indicates that for a considerable range of expected costs and benefits, that in a large majority of the cases, benefits exceed the costs. Only for the combination of very low benefits and high costs would there be any doubt that benefits exceed costs. If one adds in the benefits of making markets work more efficiently to those depicted in Figure 2-a, then there are yet fewer combinations of costs and benefits for which these advanced metering systems are not cost-effective.

2. Customer Access to RTP Signal

Clearly RTP tariffs cannot be effective unless customers receive the RTP signal to trigger their response. Use of the Internet facilitates distribution of RTP signals on a “broadcast” basis to all customers. This is a departure from previous practice in many demand response programs, which generally relied upon telephone calls and pager signals to communicate that an event was being triggered. Since virtually all customers participating in an RTP tariff will want to have access to usage data for their facility, this means that a personal computer with communication capabilities is already virtually required, thus communicating the RTP signal through the internet appears to be efficient.

³⁰ Levy Associates, *Meter Scoping Study*, 2002.

The CAISO has pioneered access to system usage data and exchange of data through modern telecommunication systems. The numerous market participants and other entities interested in CAISO data have encouraged the CAISO to develop extremely extensive databases with a great deal of this information available to the public through the internet, not just to market participants themselves.

There are likely to be at least two specific forms of RTP signal: (1) service-area wide forms in which everyone on the tariff obtains the same RTP signal, and (2) tailored RTP signals to geographic groups of participants or even specific customers. The first form is that traditionally conceived for RTP tariffs in which the overall supply-demand balance for the service area or the control area is the basis for the signal. The latter is emerging as an alternative because RTP tariffs, and other load response programs, are now being seen as potential transmission contingency tools that may be deployed in very specific areas.³¹

Finally, there are also two means by which the customer obtains whatever type of RTP signal is appropriate for their tariff. First, data are posted on an Internet website and the customer is responsible to obtain the proper data. Second, a “push” technology in which the proper RTP values are distributed directly to the participant, perhaps as email or as instant messages that trigger action directly.³² These seem likely to supplant older, broadcast forms such as radio signals that do not allow individual or small customer groups to be distinguished and triggered separately without extensive retrofit.

³¹ The CAISO has proposed in its MD02 process that several market design changes be instituted which would result in nodal, rather than zonal, prices on a Day Ahead basis. Such prices would be an ideal driver for the CEC’s proposed Day Ahead RTP tariff, but there could be 20-50 nodes or hubs with their own price patterns. RTP tariff participants would have to use the proper price based on their location. In its July 17, 2002 MD02 Order, FERC has approved these design elements, but the date of implementation has not yet been finalized.

³² There are several pilot projects evaluating various configurations for IP addressable control devices that would respond to price signals. See Section III of this monograph for more details.

3. Customer Access to Self-Usage Data

As noted previously, participants in an RTP tariff must gain access to their own usage data in order to develop an understanding of how the facility responds to one or more load reduction actions. Since few customers have knowledge of the load shape patterns of their cumulative monthly usage, deciding to participate in an RTP tariff should be preceded by a period of time in which the customer's usage data are available through the metering and telecommunication system. This allows the prospective participant to gain an understanding of their facility's response to specific actions. Common sense suggests that RTP response will be maximized when participants are educated about the potential response of their own facility to various control actions, and then "experiment" to learn what actually happens under various conditions. Clearly gaining this knowledge requires one or more of the RTP metering systems described above.

In addition to the raw (or perhaps processed) interval usage data, a customer most likely will require some software package in which to assess the information and to make sense of it. In the RTP metering systems deployed for large customers in California, customers access their usage data through password-protected, internet-based software systems provided by the UDC from among several available from commercial vendors. These software systems allow customers to download their own usage data, but also visualize it directly on the website to allow comparisons in one or more ways, archive it for future reference, and perhaps trigger "exception" reports to attract attention to particular time intervals.

4. Metering Systems for CPP Tariffs Without Variable Pricing

The metering and communication system required to support a CPP tariff without variable pricing resembles that for TOU tariffs, but with communications from the utility to the meter. In addition to the normal three registers defined solely by time of day, day of week, and season; a fourth register accumulates energy consumed during the CPP events. Since these events are triggered by various events not strictly determined by time, the meter must have a communication link to the utility to receive the reset signal. The minimum required is a radio signal to the entire class of CPP meters or perhaps several subclasses if the utility desires to segment response in different portions of a service area. No customer-specific message is required when implementing a CPP tariff in contrast to more recent interruptible programs that may require telephone, pager or internet messages to warn individual participants that load shed conditions are being triggered.

When periodic meter reading is performed, a CPP-capable meter is read like most other TOU meters, except consumption data are extracted from four registers rather than three. In many meter reading intervals this fourth register will record zero consumption, since no CPP event was triggered during the month. Data collected through a manual or drive-by meter reading system are uploaded to the utility data processing system much like that for any other TOU customer.

5. Metering Systems for CPP Tariffs with Variable Pricing

The metering and telecommunication system required to support a CPP tariff with variable pricing becomes more complex than for a simple CPP tariff. A CPP tariff with variable pricing does not simply have four conditions, but can have as many conditions as there are CPP events with different price levels. While one could conceive of augmented TOU meters with 10 or 20 registers, which probably would accommodate as many CPP events likely to occur during any one billing period, no such meters are produced today. Each of the registers above three would have to be defined by the time and price for a CPP event that had been triggered. Since all customers do not have meters read on the same day, this means that some customers have a particular CPP event near the end of their meter reading interval and some during the beginning. For those customers about to have their meter read, a particular CPP event may be the fourth or specific linkage of CPP events to specific registers in each customer's meter would change from month to month.

The easiest solution to this problem is to install an hourly interval metering system comparable to that needed for an RTP tariff. Rather than accumulating consumption without regard to chronology within the meter, the hourly interval data series would be uploaded to the utility and processed using software to determine consumption for the standard TOU periods and any CPP events triggered during the monthly meter-reading period. Associating the proper CPP price to any consumption during a CPP event is a simple association task readily accomplished using standard software that can be operated each month. Only the values in an hourly CPP price data file need to be updated to accomplish the bill computation task.

Finally, using a full interval metering system allows the participating customers to receive data about their usage patterns before, during and after CPP events. Customers may be better able to understand their non-CPP usage patterns and able to accommodate themselves to additional reductions during CPP events once they become familiar with these data.

D. Billing and Customer Service

RTP and CPP tariffs require major changes to billing processes, since the time-interval nature of the data lead to far more extensive data handling and bill computations. Some limited experience suggests that they may also impose greater burdens on customer service personnel at call centers, at least until customers develop a familiarity with the usage data and the likely consequences of RTP fluctuations and CPP events.³³ Anecdotal accounts of utilities with interval metering systems also report that customer bill complaints are more readily resolved when a specific pattern or recorded usage can be offered to the customer, which triggers recollections of unusual events that explain higher consumption levels.

³³ Personal communication, Penny Gulleckson, Puget Sound Electric, December 2001.

1. Modifications to Billing Processes to Use Interval Data

The billing process that utilizes interval data is substantially different than that which merely uses cumulative usage or TOU data. Four traditional processes must be substantially modified: (1) data access and validation, (2) bill preparation, (3) bill presentment, and (4) usage data and billing determinant archival.

Data access and validation for interval data are obviously different than the comparable processes for cumulative usage data. Meter reading inherently requires a more automated process when there are 720 or more hourly values for the month, or 2880 or more 15-minute values for the month, as opposed to a single cumulative reading used to compute the monthly usage value. These several order of magnitude increases in data volume must also be validated in quite different ways. Although some utilities have used mobile vans to collect these time series on a monthly basis, most utilities with RTP metering systems collect the data each day for 24 hourly or 96 15-minute usage intervals by uploading the data through a telecommunication system. These data are validated and then added to a previous string in storage for that customer from previous days; they may also be posted to an Internet site from which customers may retrieve their own data.

Data validation consists of the development and application of validation, editing and estimation (VEE) protocols to ensure that settlement quality data are acquired and available on a timely basis. VEE protocols have been developed in California as an adjunct to the direct access/energy service provider (ESP)/non-UDC collection and processing of load data. UDCs would presumably use these same VEE protocols for bundled service RTP tariff participants rather than create new ones.

Bill preparation using interval data requires matching a chronological time series of usage data with a similar chronological price series appropriate to that customer. There may be a library of price series resulting from the CAISO's nodal pricing proposal, as well as Day Ahead, Hour Ahead, and actual "real-time" versions for each geographic locale. A convolution of usage values and prices synchronized by time determine the value of the energy consumed by each individual customer in the billing period. In some cases, involving the departure of loads from a customer baseline, the baseline itself must be retrieved and used to compute such departures for each billing interval. Thus, in some forms of RTP tariff, such as the Georgia Power two-part RTP tariff and its variants, more complex computations of differences in load from a baseline time differences in prices are used to determine the energy portion of the monthly bill.

Most utility billing systems have the ability to import values into the final bill from supplemental sources, thus permitting utilities to perform these interval-data based billing computations in specialized software systems and import the result into the final billing process. This seems the likely course of action until RTP tariff participation justifies modifications to mainstream billing algorithms.

Bill presentment for the RTP interval data tariff participant also involves communicating to the customer about these 744 or 2976 data intervals. Some customers will have accessed these data, or part of them, during periods in which high RTP prices justified exceptional attention. The bill, however, needs to provide, or in some manner encourage access to, all of the data for the billing period.

Usage data archival and perhaps archival of other billing determinants is regulated in California by CPUC rules obliging utilities to store customer-specific billing determinants for several years to facilitate resolution of billing disputes. Several orders of magnitude increase in raw consumption data volume imply that the archival process will be more complex. In addition, the much more complex computations to render a bill using time-varying prices also suggest storage of some intermediate computations, which will further increase data volume and re-billing complexities. While, in principal straightforward, these increases in data volume may create transition issues as utilities plan for and implement new archival processes.

2. Complexities of Managing Metering and Billing Processes

The description of the billing process described above may sound straightforward, but the complexities of accomplishing this routinely for thousands of participants are formidable. Large commercial and industrial customers have supported for years several consulting and service firms whose business is bill checking. The volume of high cost mistakes and ultimate corrections in favor of the customer suggest that the process of computing and rendering a bill is not easily accomplished. At least for a transition period, the switch to RTP interval data will likely mean additional mistakes.³⁴

³⁴ During 1998 and 1999, California experienced many of these transitional headaches as the energy service provider to a direct access customer was allowed to contract with qualified meter service providers and meter data management agents to install and process hourly interval data for customers greater than 50 KW peak demand. Whether these entities providing meter service provider and meter data management agent services were new start-up companies or units within utilities, there were numerous foul-ups concerning hourly usage data.

As an illustration of these issues, consider the following hypothetical concern:

An RTP tariff customer has an accounts payable department that handles utility bills. The accountant in this unit cannot match summary information on the bill and its supplemental data files with publicly available information. A utility call center employee receives a telephone call from this accountant. The customer's representative questions whether market prices were really as high as portrayed in the bill summary sheet, which shows a monthly average hourly value. The customer service rep needs to access the customer's hourly usage values and the proper RTP values for that customer. It turns out that the customer's representative does not understand that the nodal price option was selected by the customer's plant engineer, and there is a systematically high nodal price for that location compared to the system average data published on the ISO website. Once the discrepancy is explained, the customer's accountant is satisfied. In resolving this complaint, the customer service rep must have access to highly sophisticated data, and be knowledgeable about one of the most complex tariffs available from a utility.

It is highly likely that these issues will increase burdens on utility call centers, at least initially.

3. Processing CPP Tariff Data

A fixed price CPP tariff so closely resembles a TOU tariff that very few differences exist. Rather than three "buckets" there are four "buckets" of consumption data. In many periods of the year, the consumption in the CPP "bucket" will be zero. Thus the result of the computations will be driven by the rates for energy consumption in the three "normal buckets".

A variable price CPP tariff will most readily be supported by an hourly interval metering system. Participants in such a tariff will have 744 values (in many intervals) with chronological distinctions which must be matched up to anywhere from a few to a hundred TOU/ CPP values. The first step is to populate a file with those hours in which CPP events were triggered and insert the price defined for each such event. The remainder of this chronology is appropriately priced using the standard TOU rates for the hour of day, day of week, and season of year determination of the normal TOU "buckets." Software programming decisions will govern whether to achieve this most efficiently by accumulating the consumption in non-CPP periods into TOU period "buckets" and applying the standard TOU price to the accumulated consumption, or whether the TOU prices are used to populated the non-CPP time spots in the 744 intervals. The product of the hourly consumption and the hourly prices summed across the entire period becomes the energy charge for that billing period.

E. Reliance Upon RTP and CPP Response

Unlike other forms of demand response (such as load curtailment programs and demand bidding systems), RTP and CPP tariffs permit much greater discretion to participants to react in response to a simple price incentive. Participants will do so in various ways not necessarily known to energy procurement agents, system planners or system operators. To maximize the benefits of such tariffs, the utility and others in the industry must become aware of aggregate RTP and CPP tariff participant behavior, and modify their own actions in response to this new pattern of behavior for some loads. This implies changes in both short-term power-purchase and long-term resource planning activities.

1. Expected Response to Various RTP Tariffs

Estimating response to RTP tariffs is essential for two purposes: (1) accurate load and resource scheduling, and (2) minimizing total procurement costs. At the same time, this will be a quite difficult endeavor as RTP tariffs are first introduced, but then become less uncertain as experience is gained.

Accurate estimates of aggregate response are important to an energy procurement agent submitting bids into short-term or real-time markets or in directly scheduling generation into an ISO. Accurate schedules may be increasingly important as the CAISO and/or FERC seek to minimize differences between forward schedules and actual operations. Further, and perhaps more important, competing for resources increases costs, if the load forecast driving these purchases is inaccurate, then expenditures will not be minimized. Too much high priced power may be acquired through forward purchases compared to lower peak demand actually experienced as RTP tariff participants respond with load reductions. Complimentarily, an over-forecast of the impacts of an RTP tariff building load in low-priced, off-peak hours could be more expensive than necessary if these increased loads are not foreseen and load is covered by short term or real-time market purchases when forward purchases could have been much less expensive.

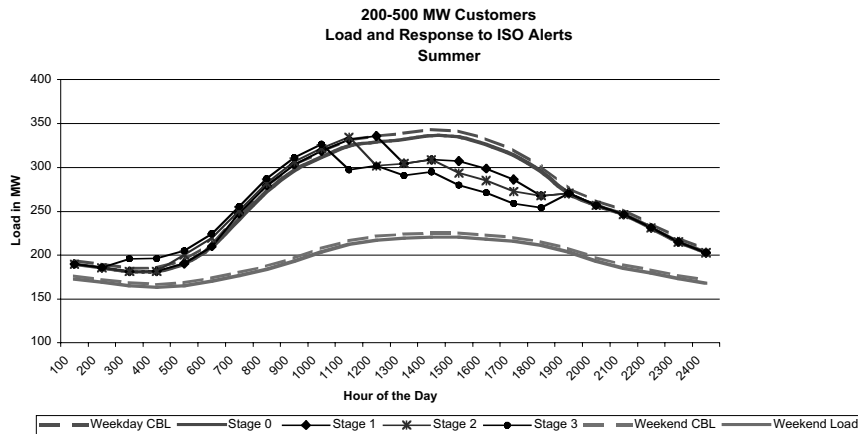


Figure 2-b. Illustration of Aggregate Response of Commercial Building Participants to an RTP Tariff using a Reliability Adder.

Figure 2-b illustrates how the aggregate load for the RTP tariff participants within the class of commercial building customers might react to different levels of RTP price, which includes both “avoided cost” and “reliability-added” components. For sake of illustration, this figure shows both weekday and weekend typical summer days, reflecting weekday occupancy generally consistent with office buildings. The CBL reflects a Georgia Power Day Ahead RTP tariff design in which a historic baseline provides a reference from which departures have costs or benefits. Stage 0 reflects a modest RTP level and minimal impact. Stage 1, 2, and 3 refer to CAISO operating reserve warning conditions in which a “reliability adder” is added onto the base RTP forecast. Successively high degrees of emergency means successively high reliability adder, higher overall RTP prices, and therefore a presumption of greater response from the group of RTP tariff participants. Reflecting a commercial building behavior, some of the response is to shift load to early morning hours as the building heating, ventilating and air conditioning (HVAC) system pre-cools the building and then shuts off for a while allowing the internal temperatures in the building to gradually rise toward the higher set point for HVAC operation. Section III of this monograph examines individual customer response in more detail.

Developing an initial understanding of the likely responses and modifying it through time as actual interval usage data are acquired and assessed is intrinsic to this effort of integrating RTP response into utility load forecasting and energy procurement activities. How to accomplish this requires close coordination between specialized units within utilities — load research personnel and system load forecasting personnel — who normally do not interact on a day-to-day basis.

2. Adapting Expectations Through Experience

Absent experience with an RTP participant pool, the energy procurement agent for such customers will have to guess initial patterns of response and quickly adapt these guesses on the basis of actual response. In the case of a new tariff, with naive participants and naive energy procurement agent, a doubly-complex set of adaptations to RTP prices will take place. Participants will be learning and changing their behavior for a given RTP value at the very same time that the energy procurement agent is trying to improve guesses about their behavior under given RTP values. Of course, system and market conditions will be generating a different pattern of RTP values each day!

One might speculate that samples of the various classes of customers with different usage patterns or different combinations of base usage pattern and likely response to RTP would be assessed frequently, perhaps updated daily. Typical response curves to various RTP price levels for each hour are developed for each customer group. Tracking numbers of customers participating in an RTP tariff would provide the scaling factors that weight the response patterns for each group into the aggregate behavior of the entire RTP tariff population.

Clearly this activity must involve judgment based on the size and rate of growth of participation in an RTP tariff. One could imagine a large California utility rapidly developing a level of participation of 1-2,000 MW, which would suggest very great need to pay attention to the details because of the energy procurement costs that might be minimized by careful use of such a resource.

3. Using Expected Response to Avoid Generation Purchases

The energy procurement agent for RTP participants will want to gauge how response to RTP values leads to changes in final dispatch patterns. This is the basis for forecasting RTP values in a Day Ahead tariff format linked to actual market costs. Depending upon the nature of the customers participating in RTP tariffs, these relationships could be different at different hours of the day, days of the week, and seasons of the year.

A monopsonistic purchaser might deliberately inject higher values into RTP price signals to generate a response that minimizes aggregate energy expenditures for his entire purchasing pool. Such a purchaser with the ability to influence the market clearing price needs to understand the effect of incremental load on market clearing prices. Obviously this means very careful examination of market clearing prices and the various explanatory factors other than load that help to explain market behavior.

4. Response to CPP Tariffs

Much of the same reasoning described above for RTP tariffs also applies to participants in CPP tariffs. Starting with “guesstimates” of likely response, developing experience with actual response to CPP events, and marshalling some analysis of explanatory factors can lead to reliable estimates of CPP response.

Since most CP tariffs restrict operation to a fixed number of events or a total number of hours during a year, the operator of a CPP tariff also needs to monitor cumulative usage of the CPP feature and factor remaining opportunities into the dispatch decision for any particular CPP event.³⁵ As a general rule, a capped CPP tariff will be used more freely early in the period after the usage count has been reset to zero and less often under identical circumstances as the usage count grows toward the annual cap. Program operators will be “saving” the remaining opportunities to trigger the program for when it is “really needed.”

5. Relying upon Expected Response to Avoid Committing Resources

With sufficient experience in the behavior of RTP and CPP tariff participants under various price patterns, the energy procurement agent for these customers may develop confidence in this behavior such that commitments to resources can be modified. At peak, this may mean that forecast peak demand may be permanently adjusted downward, thus reducing peak load resource commitments, whether from bilateral contracts or bids into real-time or spot markets. At off-peak periods, this may mean adjusting loads upward to “count upon” the higher loads that low off-peak prices of an RTP tariff will induce.

With a decade’s experience with RTP tariffs, Georgia Power reports that in its resource planning process that 500 MW of peak demand reduction is counted on from RTP tariff participants. This means that Georgia Power foregoes acquiring combustion turbines or multi-year contractual purchases of peaking resources that it might otherwise have acquired.³⁶ Gulf Power’s reliance upon its CPP tariff is less clear, and the level of participation may not yet justify avoiding resource commitments.³⁷

³⁵ This is much like the decision process for an air conditioner cycling program with a similar restriction on the number of curtailments or annual hours of curtailment allowed within a program design.

³⁶ Personal communication from Jeff Burleson (Georgia Power) and Michael T. O’Sheasy (Christensen and Associates).

³⁷ Gulf Power reports approximately 2,300 customers on CPP tariffs as of December 2001.

F. Market Performance with RTP/DR vs. Without RTP/DR

It is now becoming commonplace to assert that electricity markets cannot be competitive unless a sufficient amount of demand response is available. The FERC Standard Market Design Notice of Proposed Rulemaking frequently mentions the need for further development of demand responsiveness in order to assure efficient market performance.³⁸ FERC commissioners are cited in press releases and trade journal reports as emphasizing the need for more price-responsive demand. As discussed in section I.D, there are theoretical bases for such assertions as well as some empirical evidence of the size of this effect.

The theoretical formulation of benefits from introduction demand responsiveness has been confirmed by experiments conducted by the now-defunct CalPX. The CalPX operated a Day Ahead energy market from April 1998 to January 2001 with very large daily volumes. Its market clearing price was determined through a second-price auction in which supply and demand curves were formed through daily bidding, and the market clearing price solved for through mathematical operations.

As a result of high prices under some market conditions in 1999, the CalPX began examining what would happen with slightly lower demand curves in certain high priced days. The CalPX actually re-simulated the formal market clearing price algorithm with lower, hypothetical demand bids reflecting reasonable estimates of load reductions from price responsive demand programs.³⁹ The results of the CalPX experiment were dramatic reductions in market clearing prices when the original price was high.

Figure 2-c illustrates typical results for a specific day in the summer of 1999. The top curve reports the actual UMCP for each of five hours in the peak portion of the day. The lower lines show the result of resimulating the market clearing price with hypothetical lower bids of 5, 10, and 15 percent, respectively. As the load reductions increase, the market clearing price decreases. Clearly, major reductions in overall market clearing price were achieved with relatively small reductions in load.

³⁸ FERC, *Notice of Proposed Rulemaking, Standard Market Design*, Docket No. RM01-12-000, July 31, 2002.

³⁹ Personal communication, John Flory, California Power Exchange, February 2000.

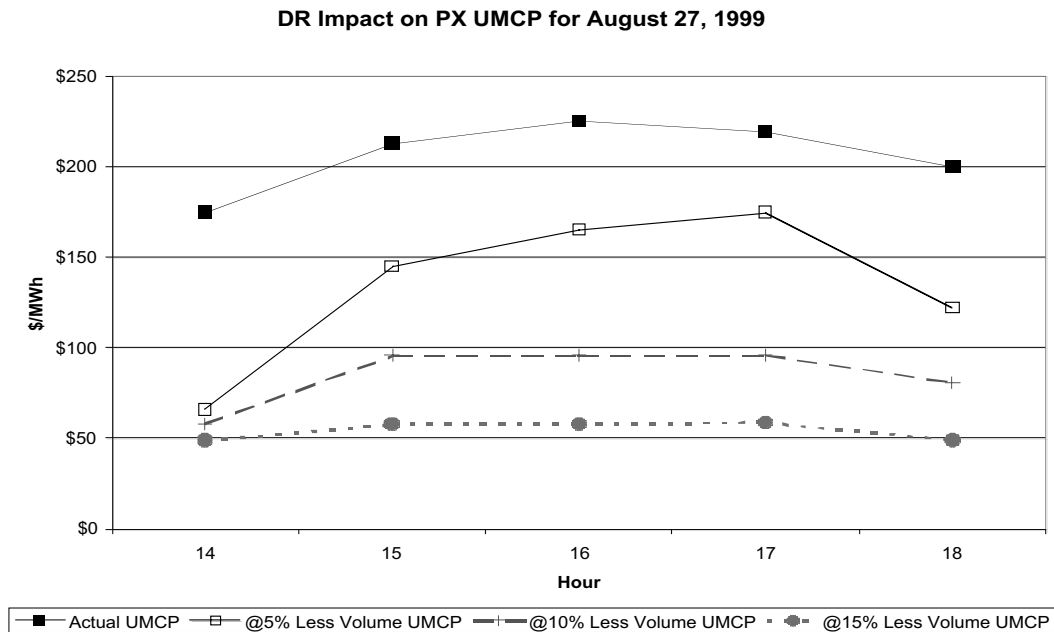


Figure 2-c. Illustration of the Reduction in CalPX Day Ahead UMCP from Hypothetical Load Reductions

What is important about Figure 2-c is its basis in fact. The results reported are what the CalPX market price really would have been with these lower levels of loads replacing the actual load bids. Because the CalPX Day Ahead market clearing was determined by a specific algorithmic process, it is capable of experimentally determining market prices by adjusting the scale and pattern of bids. At the time, CalPX staff were supportive of greater efforts to achieve price responsiveness in their market, so they conducted these experiments in a manner that closely matched what would have happened to market prices had actual market bids been lower as hypothesized. In the shallower, less transparent bilateral contract markets prevalent today one could not expect as dramatic a response as was revealed for the CalPX market.

G. Conclusion

It should be clear that RTP and CPP tariffs are feasible, but involve substantial changes in metering equipment, access to and processing of meter data, and the use of these data by both the participant and the procurement agent. These changes involve both costs and benefits. Over time, the balance between them has been shifting toward net benefits as costs for equipment and telecommunication services decrease

through time. New categories of benefits have emerged when these tariffs are implemented in competitive electricity markets. While there are utilities with extensive RTP tariff experience, utilities with fully deployed advanced meter reading systems, and utilities with fully deployed advanced meter reading systems with extensive TOU rate participation; there are as yet no utilities that have fully implemented dynamic tariffs and advanced metering systems for all customers. Section 4 of this monograph addresses that “vision.”

III. CUSTOMER RESPONSE TO DYNAMIC PRICING

BY ARTHUR ROSENFELD

Measured performance from around the country and from limited experiments in California confirms that customers can reduce demand in response to various dynamic stimuli. While much of the response nationally has come from larger industrial customers, there are good reasons to believe that California buildings can and should play an increasingly important role in the future. Evidence for this claim comes from both the magnitude of certain "shedtable" loads, such as building air conditioning (A/C) and lighting, in the California electricity system, and from the growing availability of various enabling building communication and control technologies/schemes to facilitate these responses.

In this section, we discuss how customers, and in particular buildings, can respond to dynamic tariffs. We show that meters and control systems enable customers to respond to price signals and reduce their levels of consumption. We provide data from simulations and actual experience of how such response could and does occur. Finally, we provide suggestions on how California could move forward with demand response and dynamic tariffs.

A. Buildings' Contribution to Summer Peak Demand

Figure 3-a shows loads served by CAISO for the 52 weeks of 2000.

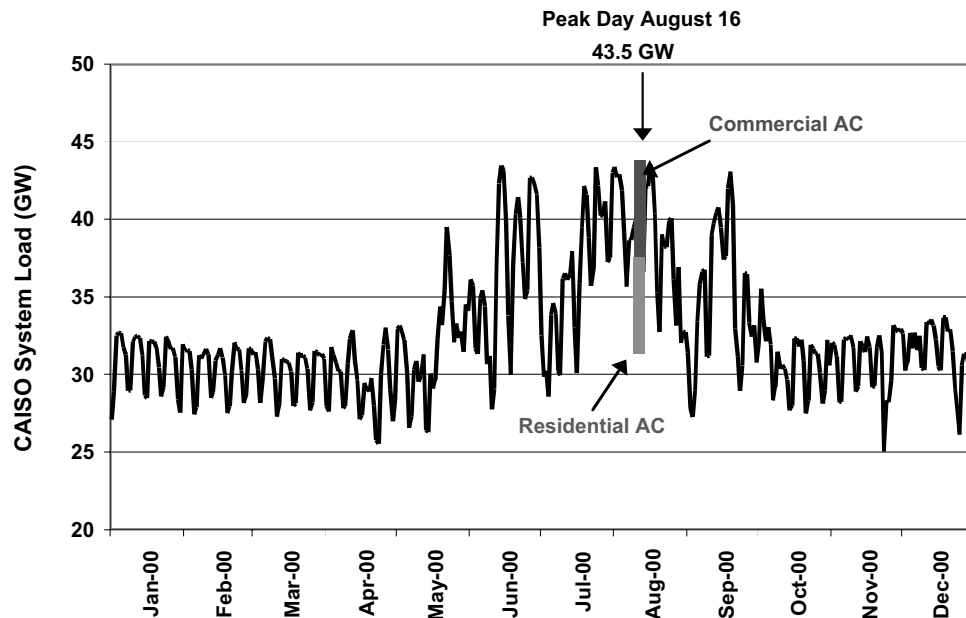


Figure 3-a. Daily peak loads in the CAISO for the year 2000. Each tooth is a week; each gap is a weekend. The CAISO load was about 85% of total California load in 2000.

Source: Pat McAuliffe, CEC staff.

Note the steady 33 gigawatts (GW) from January to mid-May and from October to November and the 30% rise to 43 GW during the summer. This rise of 10 GW is entirely air conditioning: some 5 GW residential plus about 5 GW of additional air conditioning in commercial buildings, on top of year-round air conditioning demand to cool the cores of commercial buildings.

Figure 3-b shows the CEC disaggregation of load on a hot day. We focus our attention on commercial and residential air conditioning and commercial lighting (the 1st, 2nd, and 4th highest bars) because air conditioning and lighting can be modified slightly *without* disturbing productivity, while still getting a large reduction if demand response is widely implemented. Commercial and residential air conditioning are 15% and 14%, respectively. Commercial lighting is 11%. Note that in summer, the heat from each 3 kW of lighting adds about 1 kW to air conditioning.

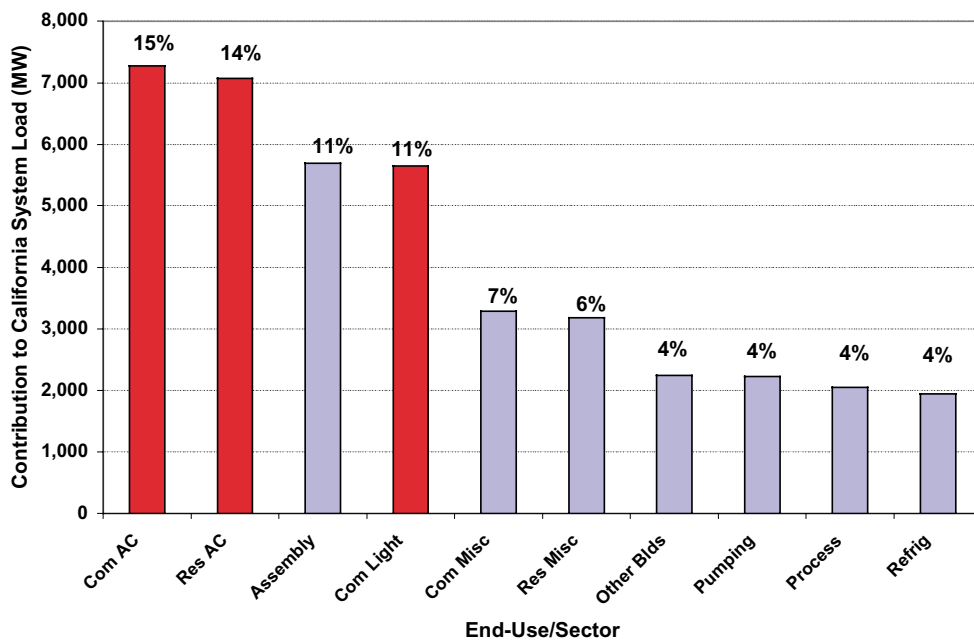


Figure 3-b. For a total California peak load of 50,000 MW, this figure shows the top ten end uses. Note that air conditioning accounts for almost 30%, or 15,000 MW of the peak load. Lighting in commercial buildings accounts for another 11%.

Source: CEC Demand Analysis Office.

We shall show that there is an opportunity during times of high prices to reduce the peak associated with commercial air conditioning and lights. Homes have almost no on-peak lighting load, but we can target 25-35% of residential air conditioning.

We first address commercial lighting, which directly contributes 11% of peak load plus 4% more indirectly through air conditioning. Beginning in 1982, California’s Title 24 new building standards required each commercial space to install at least two light switches. To date, this standard has created approximately 300 MW of commercial building lighting available for manual load reduction.⁴⁰

During the summer of 2000, the Sacramento Municipal Utility District (SMUD) and the Los Angeles Department of Water and Power (LADWP) experimented with load reduction in their own buildings. When lights were dimmed slowly by one-third and as the temperature drifted up 4° F over four hours, only a few complaints were received. We note that during that summer people were fearful of outages, and we were asking them to curtail for only a few hot afternoons, so it is not clear how these results can be extrapolated to typical conditions.

Figure 3-c shows Pacific Gas and Electric’s (PG&E) estimated hourly load for a very hot day, 9 July 2002, broken down into residential and non-residential.

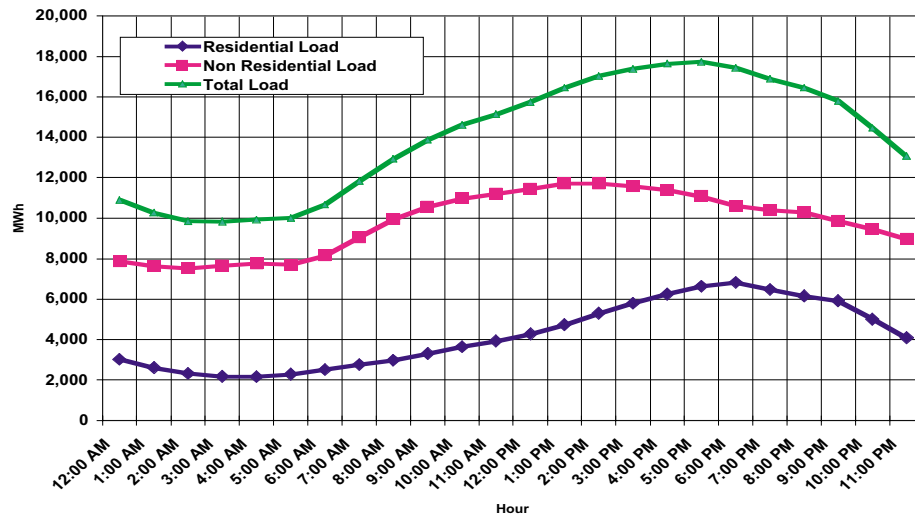


Figure 3-c. PG&E estimated system load for a hot day in July 2002, peaking between 5 and 6 p.m. Residential load peaks between 6 and 7 p.m. Non-residential peaks between 2 and 3 p.m.

Source: Pat McAuliffe, CEC

⁴⁰ Assumes one-third reduction of lighting in commercial spaces built after 1982. Source: personal communication with Jeff Johnson, New Buildings Institute, White Salmon, WA. August, 2002.

Commercial buildings and industry are dropping load by 4 p.m., just as many workers are returning home and turning on their air conditioning or down their thermostats. Figure 3-c suggests a strategy of targeting commercial air conditioning from about 1 to 5 p.m. and then addressing residential load from about 4 to 8 p.m.

B. How Commercial Buildings Can Respond to Price Signals

Figure 3-d shows conceptually the response of a building to a 4° F, 4-hour thermostat set-up, and dimming lights by one-third.

Figure 3-d, while *conceptual*, is roughly based on computer simulation.

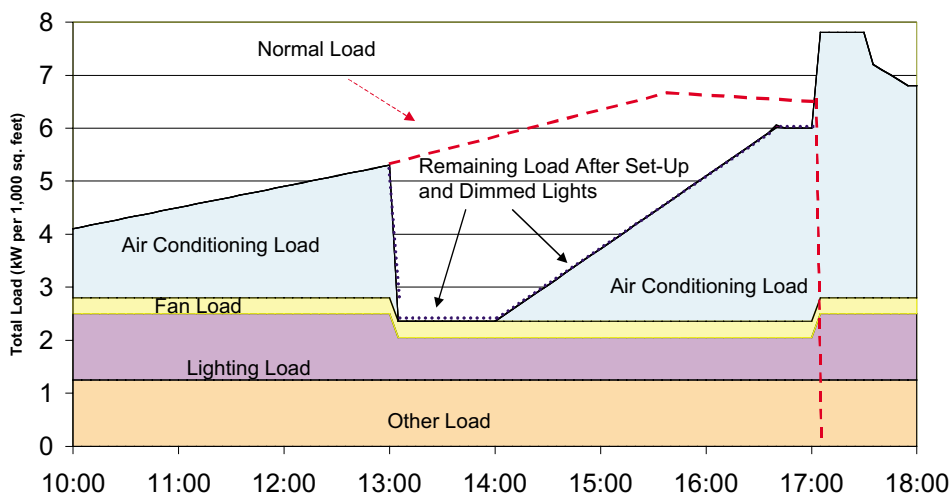


Figure 3-d is a conceptual illustration of the response of a building to CPP on a hot afternoon. The example assumes CPP is invoked from 13:00 to 17:00. The figure shows two different usage patterns in a single sketch. Pattern 1 (Normal Load) is a typical office, where loads drop at about 5 p.m. For Pattern 2, the air conditioning demand actually increases after 5 p.m. because the thermostat has been set back down to 72° F.

Source: Pat McAuliffe, CEC

The top line, “Normal Load,” shows building demand on a typical day, peaking at 3 to 4 p.m. To get the line “Remaining Load after Set-Up and Dimmed Lights” we assume that at 1 p.m. a price signal triggered an energy management control system (EMCS) or a pre-programmed communicating thermostat to raise its setpoint temperature by 4° F. The lights are dimmed by one-third. The air conditioning then shuts down, saving 90% of its demand, but continues to draw 10% for fans to provide normal ventilation. When the building temperature reaches the higher setpoint value, the compressor will cycle on briefly, but the average cooling demand during the second hour will be low because the cool thermal mass is still

absorbing heat from the conditioned space. Even in the fourth hour, demand is still down about 10% because the air conditioning unit is more efficient at extracting heat from a space that is 4° F closer to outdoor temperature.

Figure 3-d assumes not only the 4° F set-up, but also a one-third dimming of the lights. Specifically, the lighting density of 1.2 W/ft² of floor drops to 0.8 W/ ft². The air conditioning load is reduced by about 0.1 W/ft², for a total savings of about 0.5 W/ ft².

1. Simulated Response of Commercial Buildings

Figure 3-e (from Hamzawi 2000) shows the air conditioning response simulated with the DOE-2 energy analysis program. The model was run with *hourly* time steps, so the load drop resulting from the thermostat set up at 1 p.m., is plotted at 2 p.m. Hence, the true vertical drop that occurred at 1 p.m. shows only as a slope over one hour.

Figure 3-e applies to a hypothetical prototype medium size (75,000 ft²) 3-story office building with packaged HVAC systems in Sacramento, where the lights were also dimmed by one-third. Averaged over the 4-hour curtailment, it predicts an air conditioning reduction of 1.5 kW/1000 ft² (31% of the baseline load for those 4 hours).

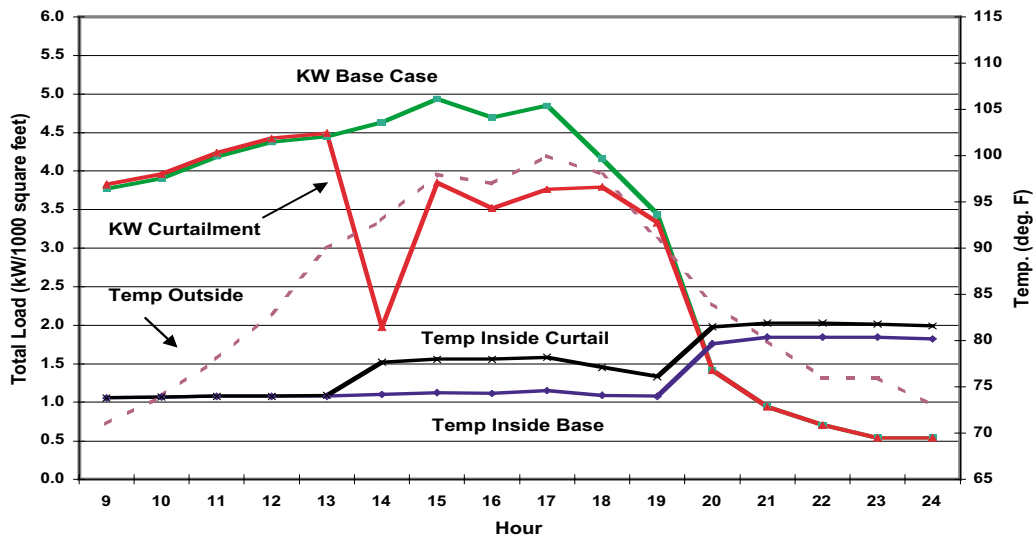


Figure 3-e. DOE-2 Simulation of a hypothetical medium-sized office on a hot day (max. 100° F) in Sacramento. The curtailment case assumed a 4° F thermostat set-up and one-third lighting reduction. Curtailment was initiated at 1 p.m. and concluded at 5 p.m. Impacts per 1,000 ft² were: Average Hourly Savings: 1.5 kW (1-5 p.m.); First Hour Savings (1 p.m.) = 2.7 kW; Total Savings Daily 6.1 kWh.

Source: Ed Hamzawi, SMUD

2. Measured Response of Commercial Buildings

Figure 3-f shows the *measured* results of the 4° F experiment in the office area of a 2-story office/warehouse building on the SMUD campus. Figure 3-f shows the actual response of a building on the SMUD campus in Sacramento. The SMUD building was a small separate office/warehouse facility on the SMUD campus of about 4,000 ft² with packaged HVAC units.

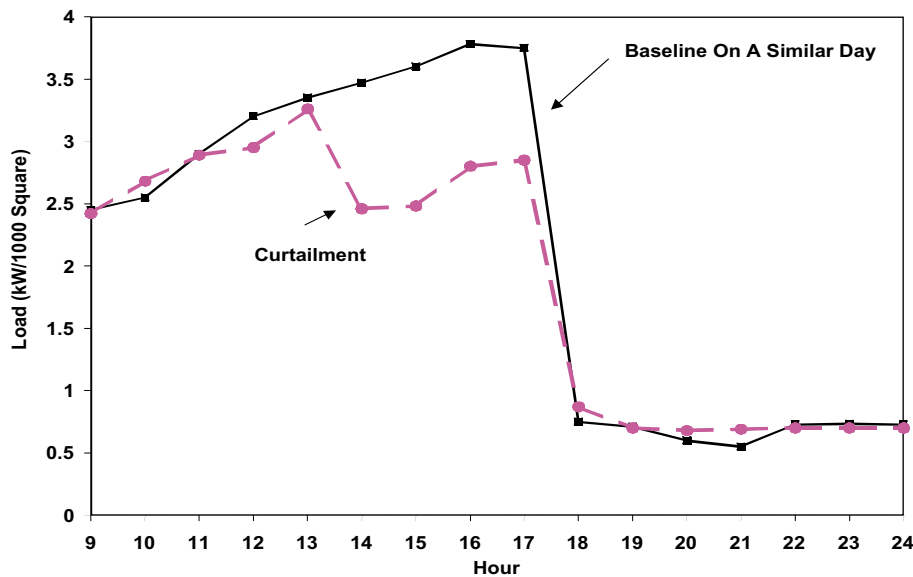


Figure 3-f. Actual measured air conditioning load in SMUD office building. Curtailment involved a thermostat set-up of 4° F from 1 p.m. to 5 p.m. Lights were dimmed. The load after hour 18 is from fans which run continuously and cool the building overnight.

Source: Hamzawi, SMUD (2000).

The graph nicely agrees with the DOE-2 run, giving a 4-hour average curtailment of 1 kW/1000 ft² compared to a baseline of 3.5 kW.

A summer 2000 experiment found results consistent with SMUD results in part of LADWP's high-rise headquarters. [Mirseyedi and Cunningham, 2000].

3. Cost of Metering and Control Systems for Commercial Buildings

In 2001, while the CEC was supervising the installation of 23,000 real-time meters, the legislature gave the CEC nearly \$50 million for a large peak load reduction program. As of September 2002 nearly half of the work is complete. This half represents 1800 contracts or grants where the curtailment potential has been measured by a third party. The result is shown in Part B of Table 3-a. The 1800 projects cover a range of commercial buildings, from refrigerated warehouses through offices and hotels.

Table 3-a. CEC contracts for peak load reduction in summer 2001. Since we expected outages and urgently needed curtailed load, contractors controlled some lights and thermostats by hand and then completed the automation installation after the summer.

	Building Type	Curtailed Load	A. Peak Load	B. Project Cost	C. 4-hr Avg. Curtailment	D. Cost per kW Drop	E. % Load Drop
			<i>(MW)</i>	<i>(\$)</i>	<i>(ΔMW)</i>	<i>(\$/ΔkW)</i>	<i>(ΔMW/MW)</i>
Part A — Case Histories							
1. Staples	Retail Chain	HVAC, Lighting	12.8	\$ 320,000	2.8	\$ 114	22%
2. Foothill-DeAnza	College Campus	HVAC, Lighting	10.9	\$ 275,000	1.5	\$ 183	14%
3. Hewlett-Packard	Office Campus	HVAC, Lighting	6.8	\$ 280,000	1.4	\$ 200	21%
4. Alameda County	Government Facilities	HVAC	4.4	\$ 283,000	1.7	\$ 167	39%
5. Doubletree Hotel	Hotel	HVAC	1.4	\$ 74,000	0.2	\$ 370	14%
6. Macanan	Office Building	HVAC, Lighting	0.65	\$ 72,000	0.065	\$1,102	10%
Total or Average			37.0	\$ 1,300,000	7.7	\$ 170	21%*
Part B — All 1800 Non-residential Contracts and Grants, as verified by Nexant Inc.							
7. All 1800 Projects	Non-residential	HVAC, Lighting, & Process	1150	\$21 million	200	\$100	18%*

*Roughly speaking, 20% curtailable *building* load corresponds to about 30% curtailable *A/C and lighting* load.

Part A Source: CEC 2002, <http://www.ConsumerEnergyCenter.org/enhancedautomation>.

Part B Source: M. Messenger, CEC, personal contact 8/13/02.

Summaries of six of these projects are posted on the CEC web site. These six are displayed in Table 3-a Part A. Four of the projects both set up the thermostat and dimmed lighting; two merely set up the thermostat. The fractional savings (Column E) ranged from 10% to 39%, and averaged 21%. As explained below the table, roughly 20% of building load corresponds to a saving of about 30% of the curtailable load of air conditioning and lighting.

Column D shows that system installation costs \$170 for each kW of load drop enabled. Approximately 60% of this cost is due to hardware and software. The remaining 40%, which should drop if demand response is adopted as a standard for the whole state, represents the cost of administration, marketing, testing, etc. At a cost of \$170 per kW, this is significantly less than the \$500/kW cost of a new peaking plant or the cost of rotating outages.

Table 3-a Part B gives the results from all 1800 completed projects. Compared to Part A, the cost per curtailed kW (\$100) is significantly lower, and the fractional load drop (18%) is slightly lower. It may be interesting to compare this 18% with the 16%-20% savings of Georgia Power real time pricing customers on a high-price day. Georgia Power is discussed in more detail below.

Part B of Table 3-a shows that the average cost of control systems for buildings is \$100 per kW curtailed. Of course, they would not be used without an incentive such as a dynamic rate, which requires a real-time meter, which adds only about \$20-\$30 per kW curtailed.

The arithmetic is as follows. In section 2 we explained that the CEC has already managed the installation of 23,000 interval meters at a cost of \$1500 each.⁴¹ First we consider a large building (about 100,000 ft²) with 500 kW of load, which drops 15% (75 kW) in response to a critical price. Our cost, then is \$1500/75 kW, so \$20/kW curtailed. For a, 100 kW building curtailing 15 kW with a \$500 meter, the cost rises slightly, but only to \$30/kW curtailed.

This range, \$20-\$30/kW curtailed is lost in the uncertainty of the control system cost, but we end this section with the crude estimate that the cost of the control system, *with the meter*, is probably in the range of \$100 - \$200/kW curtailed as a retrofit measure, and could well turn out to be just \$100/kW for a new building. Since it appears meters are cost-effective to the utility (see Figure 2-a), we could reduce our cost estimate accordingly.⁴²

⁴¹ To put this cost into perspective, we note that the cost of an advanced meter is significantly less than the average monthly electricity bill.

⁴² In this discussion we have ignored the monthly communication cost. Many of the current 23,000 CEC meters (over 200kW) have been installed with dedicated phone lines charged at commercial rates of up to \$400/month. But this was done as an emergency solution. Under normal conditions, communications costs (radio, pager, internet, etc.) should drop to a few dollars/month per meter.

C. How Homes Can Respond to Price Signals

1. Simulated Response of Homes

Figure 3-g shows the DOE-2 run for an 1,800 ft² single family house on a hot Sacramento day. The thermostat was set up 4° F, for 4 hours, starting at 2 p.m. The model assumes no residential lighting and a slab foundation. DOE-2 predicts that the air conditioning savings last for the full four hours of thermostat set-up. Averaged over the 4-hour curtailment, it calculates savings of 1.6 kW (28%) or 0.9 kW/1000 ft². For homes not built on slabs, we would expect less savings.

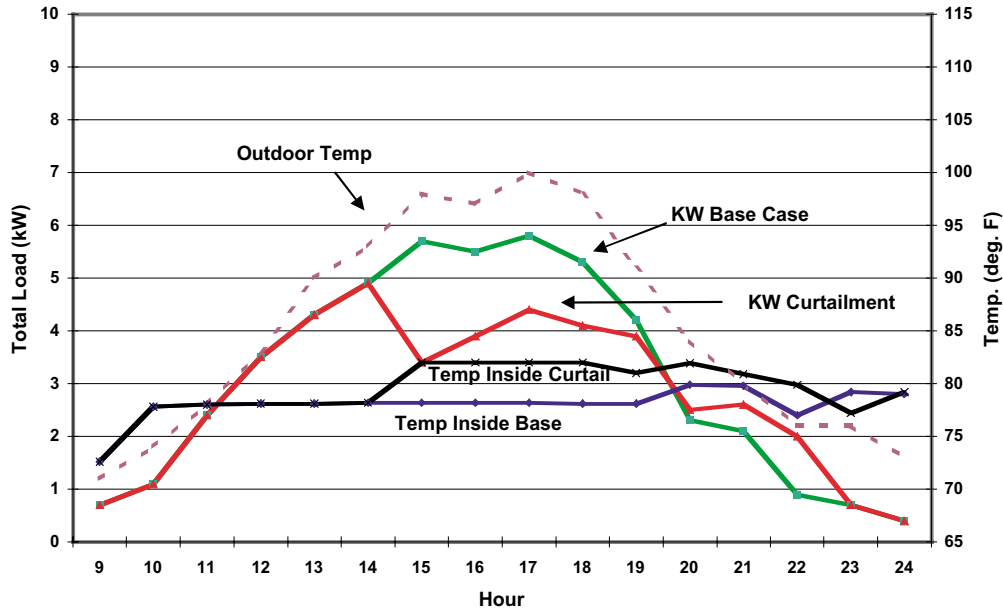


Figure 3-g. Simulation (DOE-2) of a hypothetical Single-Family Residence Hot Day (Max. 100°F) in Sacramento. Curtailment case is a thermostat offset of 4° F from 2 p.m. to 6 p.m. Curtailment savings of: Avg. kW (2-6 p.m.) = 1.6; First Hour kW (2 p.m.) = 2.3; Total from 2 p.m. to 6 p.m. = 6.4 kWh however, daily savings equals = 5.0 kWh due to rebound effect.

Source: Ed Hamzawi, SMUD

2. Measured Response of Homes

Figure 3-g, calculated by DOE-2, predicted a 4-hour average curtailment of 1.6 kW for a 4° F set-up in a home in Sacramento. In California we have load response data from air conditioning *cycling* programs but none yet from thermostat set-up.⁴³ In Pensacola, Florida, customers in Gulf Power’s GoodCents Select program dropped 1-2 kW during curtailments (Figures 3-h and 3-i).

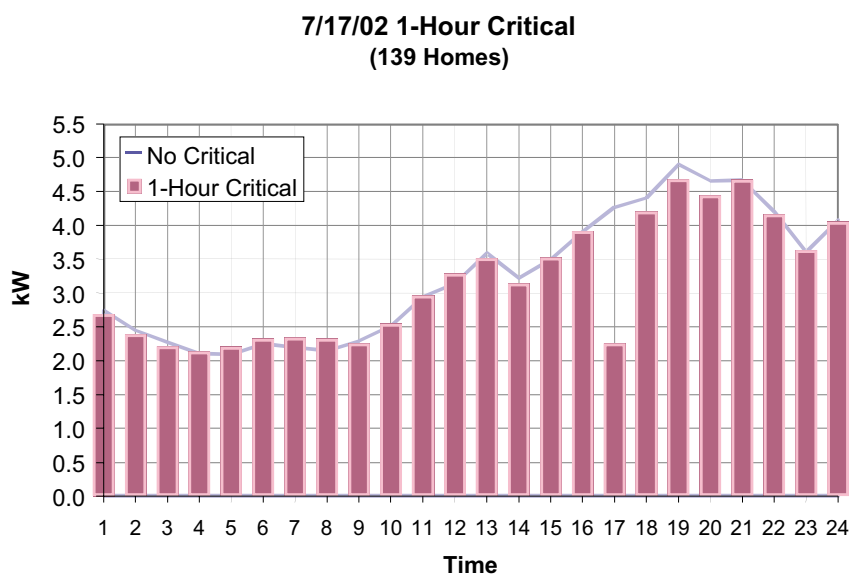


Figure 3-h. Average Load and Load Reduction in Gulf Power CPP program. The TOU rate (11 a.m. to 8 p.m.) was 9.3 ¢/kWh. The 1- and 2-hour CPP was 29 ¢/kWh, an extra 20 ¢/kWh. The 1-hour CPP dispatch was at hour 17.

Source: Brian White, Gulf Power

⁴³ Unfortunately most US experience with air conditioning control dates back to shortly after the 1973 OPEC oil embargo. At that time the CEC required utilities to offer air conditioning “cycling” accomplished through direct radio control by the utility of the air conditioning compressor. Cycling has served us well for 25 years during emergencies, but we think that it has now been superceded by the communicating thermostats, which allow more precise comfort control.

**7/18/02 2-Hour Critical
(139 Homes)**

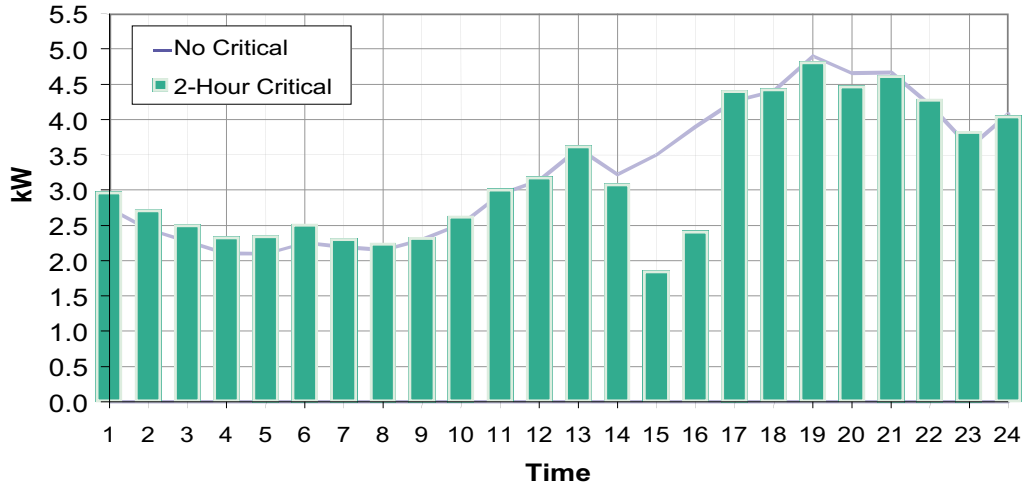


Figure 3-i. Average Load and Load Reduction in Gulf Power CPP program. The TOU rate (11 a.m. to 8 p.m.) was 9.3 ¢/kWh. The 1- and 2-hour CPP was 29¢/kWh, an extra 20¢/kWh. The 2-hour CPP dispatch was at hours 15 and 16.

Source: Brian White, Gulf Power

The one-hour dip was 2 kW; the two-hour dip averaged 1.6 kW. We are surprised to see no overshoots when the thermostat is returned to normal, and suspect that the air conditioning units were sized so as to be running continuously on a hot day, and simply could not draw more power, so that the houses re-cooled quite slowly at the end of the critical price period.

3. Cost of Metering and Control Systems in Homes

A number of possibilities exist for how residents might respond to a dynamic price. For example, residents may choose to install controls that automatically respond to price signals. Alternatively, they may prefer a simple notification system and then manually reduce load when prices are high.

For an air conditioned home, Figure 3-j considers six combinations of one-way and two-way communications for meters and thermostats, most of which are the subject of current experiments or programs.

A promising configuration is illustrated in panel 1b, which consists of a one-way signal from the utility to the thermostat, and communication nightly from the meter to the utility. Compared with programmable thermostats already required in California, a one-way communicating thermostat might cost \$50 to \$100

more for the extra cost of communications, the ability of the owner to pre-program response to price, an override button, and an improved display. We estimate that the real-time meter might cost an extra \$100, for a total system cost premium of \$150 to \$200. While these estimates are very rough at this time, they appear to be less expensive than many other peaking options. If we assume two-hour sustained reductions of between 1 and 2 kW, and a cost of about \$200 per home, then we can achieve four-hour sustained reductions for a capital cost of about \$200 - \$400 per kW.

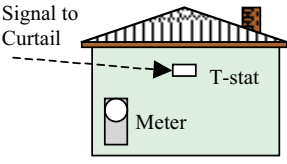
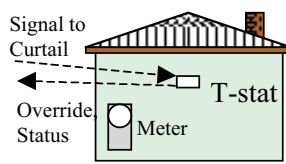
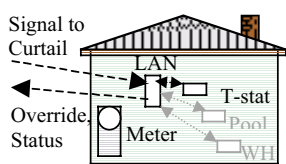
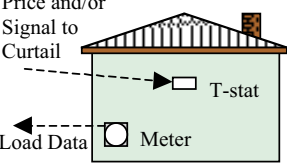
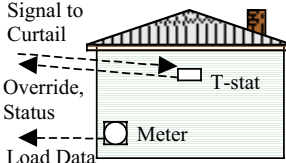
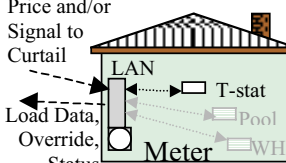
Base Case Meter: \$20 T-Stat: \$30 Total: \$50	1. One-way Thermostat (~\$100) Utility cannot directly verify customer receipt of signal or monitor overrides.	2. Two-way Thermostat (~\$300) Allows utility to verify customer receipt of signal and monitor overrides.	3. Gateway System (~\$800) Allows communication to, from, and between devices on local area network (LAN). Utility can verify signal reception and monitor overrides.
a. Standard Meter (~\$20) <ul style="list-style-type: none"> • Load impacts and incentives must be estimated based on average customer. • Incentive to conserve cannot be integrated into the rate. 	<p style="text-align: center;">1a</p>  <p style="text-align: center;">System Cost: \$100-\$200 Programs: Austin, SMUD</p>	<p style="text-align: center;">2a</p>  <p style="text-align: center;">System Cost: \$300-\$400 Programs: LIPA, SCE, SDG&E</p>	<p style="text-align: center;">3a*</p>  <p style="text-align: center;">System Cost: \$800-\$1000 Programs: None</p>
b. Advanced Meter (~\$100) <ul style="list-style-type: none"> • One-to-one correlation between measured load impacts and incentives. • Incentive to conserve can be integrated into the rate. 	<p style="text-align: center;">1b</p>  <p style="text-align: center;">System Cost: \$200-\$300 Programs: None</p>	<p style="text-align: center;">2b*</p>  <p style="text-align: center;">System Cost: \$400-\$500 Programs: None</p>	<p style="text-align: center;">3b</p>  <p style="text-align: center;">System Cost: \$900-\$1100 Programs: SMUD, Gulf Power</p>

Figure 3-j. Communicating thermostat hardware configurations options and cost estimates.

Source: Herter 2002

Note that configuration 3b is the Gulf Power “GoodCents Select” critical peak pricing program mentioned in the previous section and summarized in Appendix B.

D. What Price Signal “Works”? The Experience of the Georgia Power Company

So far we have seen in Table 3-a that *in a test* a commercial customer (over 200 kW) can drop load 18% to 21%. Except for the Gulf Power residential program (Figure 3-h), we have presented little information on how big a price incentive (RTP or CPP) is needed to get customers’ attention.⁴⁴ Christensen Associates have sent us data from Georgia Power’s RTP programs. We can address this crucial price issue, and see that demand response varies greatly from class to class. We start with the most responsive class of customers.

Figure 3-k shows hourly data for the most motivated customers, those who elected the Hour-Ahead RTP tariff option. These are large industrial customers willing to pay attention to hourly prices and vary loads accordingly in order to minimize their electricity cost. For example, they may alter their schedules for crushing rock or liquefying air at pre-defined prices. They may also rely on on-site generating units to supply portions of their power needs.

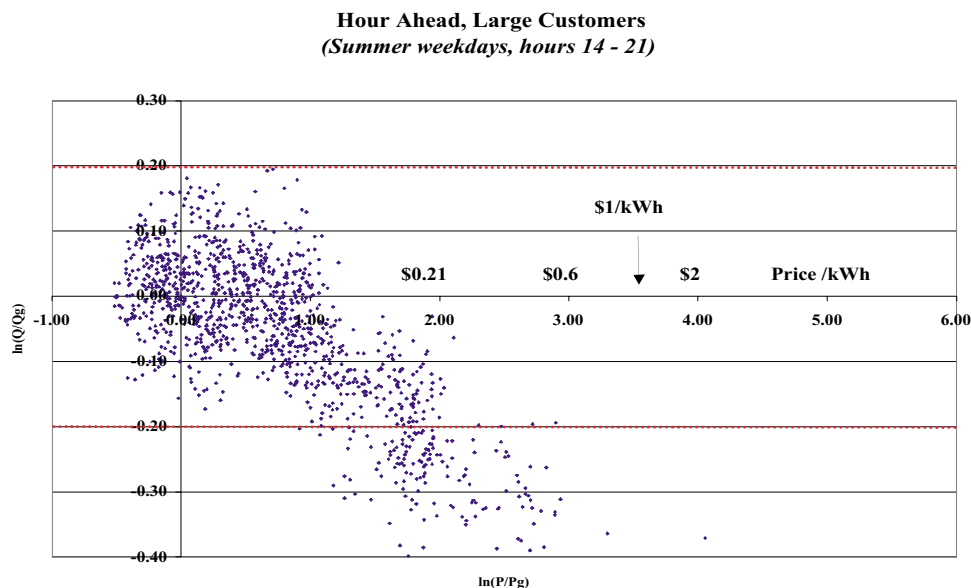


Figure 3-k. Demand response of large industrial Hour-Ahead customers in Georgia Power’s RTP program. Scales are logarithmic. We have added on the x-axis a few price levels in \$ per kWh.

Source: Braithwait, Christensen and Associates

⁴⁴ Details on the two-part Georgia tariff can be found in Appendix A.

Each dot in Figure 3-k represents an observation, for the Hour-Ahead group as a whole, of hourly load Q and hourly price P , each defined relative to a baseline average value on a typical low-price day. Given the wide range of prices, the scales on the two axes are logarithmic. That is, the values on the vertical axis represent $\ln Q/Q_g$, and on the horizontal axis represent $\ln P/P_g$, where Q_g and P_g refer to baseline quantity and price. The relatively small changes in load shown on the vertical axis can be considered to represent percentage changes relative to the baseline (*e.g.*, -0.20 represents a 20% load reduction). As an aid to the reader, we have indicated various price levels that correspond to the natural log scale on the horizontal axis.

The Hour-Ahead class is indeed price-responsive; in hours of 20¢ per kWh prices, customers cut demand by 20%, while prices of 50¢ per kWh lead to load reductions of 30%!

In Figure 3-l, we show load changes for a group of industrial customers who have signed up for the Day-Ahead tariff. Customers in this group had previously been on a voluntary curtailable service contract and had no on-site generation. For this customer group, an RTP price of 20¢ per kWh produces a smaller but significant 10% load reduction.

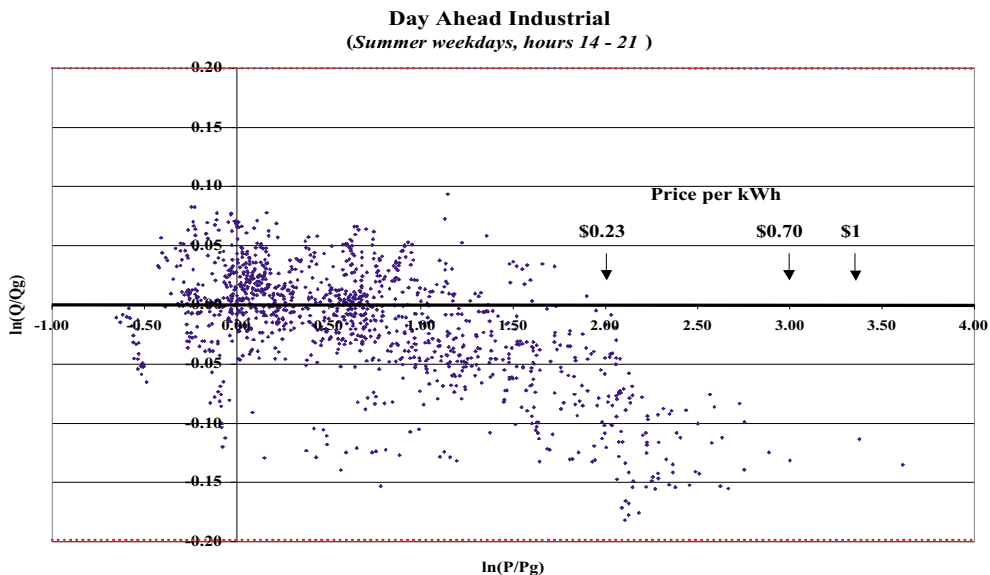


Figure 3-l. Demand response of industrial Day-Ahead customers in Georgia Power’s RTP program. Customers have loads greater than 5 MW; 25% of the customers have on-site generation.

Source: Braithwait, Christensen and Associates

Finally, Figure 3-m shows load response for commercial accounts who again switched from curtailable service to Day-Ahead RTP. In this case, we see that at prices below approximately 10¢ per kWh, loads tend to increase as price goes up. This result is due not to price response, but to the typically positive correlation between temperature (here causing greater air conditioning loads) and price.

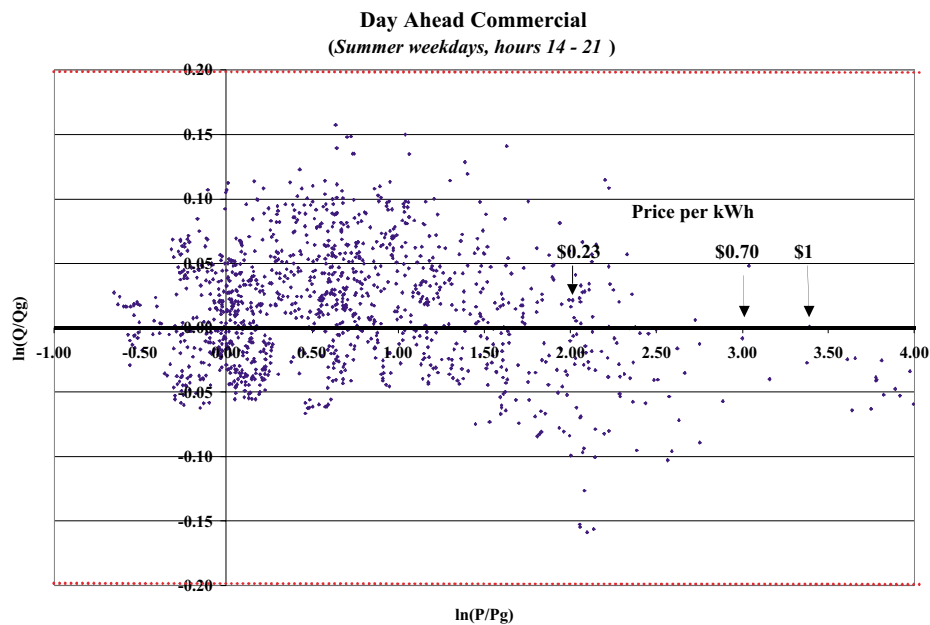


Figure 3-m. Demand response of commercial Day-Ahead customers in Georgia Power’s RTP program.

Source: Braithwait, Christensen and Associates

However, by approximately 23¢ per kWh there is enough response to overcome the temperature effect (which otherwise might have increased load by 15%), and by 50¢ per kWh, demand has decreased by 5-10%. However, data are rather limited in this range.

The importance of such data for California cannot be over emphasized. Such data developed for California’s mix of commerce and industry would enable demand response to be directly incorporated into resource planning, FERC’s proposed reserve margin requirement, and tariff design.

E. Estimating Response to Dynamics Tariffs in California: Three Opportunities

The results reported from both Georgia Power and Gulf Power are encouraging. At Georgia Power, larger customers respond to higher real-time prices by reducing loads on the order of 20% to 30% when faced with prices in the 25¢ to 50¢ per kWh range. Commercial customers when faced with a price of 50¢ per kWh drop load by 10%. At Gulf Power, residential customers respond to critical peak prices of 30¢ per kWh by reducing loads by 1.5 to 2 kW for one or two hours. These data are specific to the types of tariffs and customer composition in these utilities, as well as the local weather. Only limited data are available in California. A recent CEC staff report (CEC, 2002) provides an overview and discussion of the existing demand response projects in California. Many of these are just beginning and “were not designed to assess short-term dynamic price response.”

Additional research regarding how customers would respond to dynamic pricing is warranted. Results of this research will be valuable in better understanding what role demand response can play in meeting California’s future electricity needs. A number of approaches to better understand the implications of dynamic pricing on customer response should be pursued simultaneously. **First**, the pilot studies currently underway should be modified. The CEC (2002) has provided a detailed listing of possible modifications. In general, the suggested modifications would involve the introduction of additional dynamic pricing tariffs into some of these pilots. **Second**, the installation of 23,000 interval meters with communication systems for customers of 200 kW or greater will be completed by the Fall of 2002. A voluntary critical peak pricing tariff should be introduced for a portion of these customers. Since metering and communications already are installed, the incremental cost of such a tariff should be very low. **Third**, as new buildings and homes are constructed, electricity meters and thermostats will need to be installed. Such installations offer the opportunity to deploy interval meters and thermostats with advanced programming and communications capability at little additional cost. We suggest that at least a portion of new homes and buildings be offered the option of a critical peak pricing tariff.

IV. A VISION FOR DYNAMIC PRICING

BY SEVERIN BORENSTEIN, MICHAEL JASKE, AND ARTHUR ROSENFELD

The previous three sections have outlined the theoretical elements of dynamic pricing tariffs; the practical implications of these tariffs for metering, communication and other hardware systems; and the customer implications and impacts of such tariffs. To achieve price-responsive demand, much would change in the way that customers behave and the ways in which customers and these providers interact. Deciding whether to move down the path to an effective level of price-responsive demand, whether for selected customer groups or for the mass of utility customers, requires an assessment of the benefits versus the costs, and a judgment that expected benefits exceed expected costs. We believe they do.

A. An Evolving Context

The context in which advanced metering systems and dynamic pricing are assessed is now rapidly evolving. The traditional approach was an integrated utility implementing an AMR system to reduce costs, and perhaps achieve a few incremental benefits. In the past few years, the context has been shifting to that of a restructured electricity industry in which price-responsive demand is a desired characteristic that can only be achieved by installing advanced metering systems and incentives for customers to reduce loads under some conditions.

1. Integrated Utility Without Competition

The standard context for conducting an assessment of the benefits and costs of advanced metering systems would focus on an individual utility reducing costs for traditional activities such as meter reading and gaining benefits compared to manual meter reading, such as reduced theft and improved distribution system planning.⁴⁵ Various utility-specific questions further define this context. For example, is the utility a single fuel utility in which electricity is the only commodity distributed to customers? Or is the utility also a distributor of natural gas? Are the services areas reasonably coterminous or are they quite different?

Even if the utility is not exposed to competitive wholesale market prices, it presumably still has a range of generating costs which increase as more costly facilities are dispatched under the conditions causing system loads to grow. A dynamic pricing tariff can still provide “avoided cost” benefits by reducing usage of these more costly facilities. In reality, nearly all utilities trade power with neighboring areas on the margin and therefore face market prices as the cost (or opportunity cost) of the power they supply. Priced at the

⁴⁵ Of the major AMR system deployments implemented to date, only one took place in a service areas directly involved in a restructured electricity industry. In that service area, very little emphasis on retail pricing has yet taken place. A second system deployment took place in a region indirectly impacted by wholesale market restructuring. This utility first extended its original system architecture to provide consumption pattern data information back to customers, and later implemented TOU rates for all small customers.

margin, some customers will be unwilling to pay as much as the cost of providing power, thus properly reducing their usage and reducing overall generating costs. Further, marginal cost-based pricing should also induce participating customers to increase loads in periods when prices are very low.⁴⁶

2. *Utilities in Restructured Electricity Markets*

In recent years the question has evolved into whether to develop some limited amount of price-responsive demand, supported by advanced metering systems, in the setting of a restructured market for electricity. Some utilities in various portions of the country have determined that a restructured electricity industry requires at least some degree of price-responsive demand in order for the promise of competitive electricity markets to be realized. There is still no clear consensus on whether to develop demand bidding programs, to introduce dynamic tariffs, or both.

If the utility obtains substantial amounts of electricity from a wholesale market, then the utility or its customers, or both, may be exposed to substantial price risk. The California Crisis of June 2000 through June 2001 harmed many utilities obtaining substantial portions of power in various Western Interconnection markets, not just the three investor-owned utilities operating in California under the regulatory authority of the California Public Utilities Commission. Dynamic pricing for a substantial portion of these customers may be a means to change the dynamics of setting market clearing prices in a restructured market. If this is feasible, and if it can be successful, then this may create benefits that can be attributed to dynamic pricing, and thus offset some or all of the costs of establishing these tariffs and their associated hardware.

Further strengthening the call for greater price-responsive demand are calls from the FERC that demand response is a necessary element of standard market design,⁴⁷ and also its absence was a key element of the California market's failure.⁴⁸ FERC rhetoric focuses on demand bidding, which they see as an essential element to play demand resources "on par" with generation resources. Demand bidding initiatives have become widespread in areas of the country with competitive market structures.⁴⁹ Relatively less attention

⁴⁶ The RTP tariffs introduced by Georgia Power in the late 1980s reflect a commitment to marginal cost-based tariffs for larger customers, which made sense when Georgia Power supplied all of its own power as well as in recent years when Georgia Power must purchase some supplies in a competitive market.

⁴⁷ FERC. *Standard Market Design Notice of Proposed Rule*; July 31, 2002: p. 271.

⁴⁸ FERC. *Order on CAISO Market Design 2002 Proposals*, Docket EL02-1656; July 17, 2002: p. 57.

⁴⁹ Examples include the New England ISO Demand Response Collaborative, a NYSEERDA effort in New York, and an emerging dynamic pricing initiative in the PJM region.

has been paid to more “passive” customer involvement in price-responsive demand through reaction to dynamic tariffs.⁵⁰

3. *The Infrastructure Dilemma*

Any recommendation concerning dynamic pricing tariffs must necessarily address the suite of support hardware and software required to implement such tariffs. Further, to the extent that one anticipates a progression through time toward more use of dynamic pricing tariffs in various customer classes, then hardware/software support issues become more complex. Levy (2002) reviews these issues in more depth.

The core issue is that the metering and meter reading equipment needed to support dynamic pricing tariffs as complex as variable critical peak pricing and other forms of dynamic pricing can be expensive to purchase and install, particularly for smaller customers. There are some incremental costs beyond “standard” AMR systems that simply replace manual meter reading systems. It is very costly to make an upgrade to specialized CPP meters and then decide later to upgrade those same customers to permit them to select variable CPP or RTP tariffs, because a second set of new equipment would have to be purchased and installed replacing the specialized CPP meter, probably before its economic life had been depreciated. However, we also believe there are substantial benefits that result from the ability of these systems to improve traditional utility business activities and to support dynamic tariffs. Contemplation of a progression of mandatory tariffs toward some form of dynamic pricing tariff brings with it the issue of overbuilding for short term needs to serve long term needs.

As an example, suppose that one wishes to shift small commercial customers to TOU rates for now, to allow a CPP rate as an option, and to nominally decide to introduce mandatory CPP with variable CPP as an option in the future. Assuming aside all of the customer education issues associated with this sort of change, mandatory TOU would require a meter upgrade from simple cumulative kilowatt-hour (kWh) meters, and CPP would require a specialized TOU meter with a fourth register and communications capability to shift to the critical period at the discretion of the utility. A further evolution to variable CPP in the future would require an interval metering system, and perhaps communications uplink to upload the usage data to the utility, but not a download link to reset a register-oriented TOU meter.

⁵⁰ On June 10, 2002, the CPUC issued *Order Instituting Rulemaking on Policies and Practices for Advanced Metering, Demand Response, and Dynamic Pricing*, R.02-06-001. On July 17, 2002, the CEC issued an *Order Instituting an Investigational and Rulemaking Proceeding to Assess and Implement Rates, Equipment, and Protocols to Foster a More Price-responsive Electricity Market*, Docket No. 02-DR-01. The CPUC, CEC and California Power Authority are closely coordinating their activities in these companion proceedings to achieve increased price-responsive demand.

What hardware should be installed to permit both the base tariff change, the optional tariff allowed, and the future tariffs contemplated? One option is to universally install TOU meters and to replace them with specialized TOU meters whenever a customer wanted to elect CPP. Another option is to install full RTP metering systems (interval meter, communication channels for the usage data that can support daily or real-time uploading, and internet display of usage data). A third option would be to install interval metering, but only read the usage data and post them to the utility customer master file on a monthly basis, and install/activate higher frequency communications as customers elect voluntarily or are shifted to a more dynamic tariff that justifies the communication system costs. Each of these has different patterns of costs through time and different abilities to support shifts to more dynamic tariffs for system deployment schedules different than those committed to at the initial decision. It is nearly impossible to say which is “least cost” or most cost-effective without engaging in an assessment of various market pricing scenarios.

B. Our Long Term Vision

We believe that sufficient evidence has been accumulated to support the view that dynamic pricing is a critical feature of modern electricity systems. Price-responsive demand (PRD) will ultimately prove to be more important to ensuring system adequacy than emergency load curtailment programs. Within price-responsive demand we believe that dynamic pricing will prove to be more important than demand bidding, because it offers greater choice to the participant and has lower overhead costs. We have a vision of widespread dynamic pricing, but like all visions, it is unclear what precise steps will most efficiently achieve the vision.

1. A Policy to Guide Development of Dynamic Pricing

We propose a policy to guide dynamic pricing and advanced metering system deployment to achieve price-responsive demand:

All customer classes should be exposed to time-based prices associated with *ex ante* estimates of generation procurement costs in combination with specific consideration of system operating conditions around system peak or other stressed conditions.

How does one translate this policy statement into actual tariff proposals? First, it suggests that at least TOU rates are necessary for all customer classes. The days of annual averaging of generation costs and the inherent cross-subsidies this creates across or within customer classes are over. Second, especially in those utilities with considerable exposure to wholesale market prices, even *ex ante* TOU rates cannot predict the timing and extent of market-based generation prices. Thus a CPP-like tariff is needed to ensure that system reliability can be maintained at the lowest cost. Using a CPP-like signal ensures that customers really want to use electricity at the times it is most costly and the system is most stressed in delivering it.

Third, larger customers should be expected to take on a more complex tariff than smaller customers because they have greater ability to afford the overhead costs of dealing with the myriad of options that exist when electricity is priced on an hourly RTP basis. Finally, it does not seem reasonable to expose utilities to procurement risks that they cannot control. In the old integrated utility era, the utility could be held accountable for powerplant construction costs and performance once constructed. This is less tenable in an era of restructured markets.⁵¹

Thus, for smaller customers the preferred package seems to be to require CPP, with a more costly hedge option to obtain ordinary TOU, and a lower cost option to select variable CPP. For larger customers, RTP should be the default with the customer allowed to hedge up to just variable CPP. We believe it is appropriate that large customers remaining fully exposed to at least limited forms of market-based prices so as to contribute to system reliability.

Larger customers can protect themselves from the volatility of RTP prices or CPP prices by purchasing various financial instruments, such as the Georgia Power price protection products discussed in section II.A and appendix A. While offering price protection products is outside the mainstream of most utilities in the country, they make explicit risk allocations that have all too often been opaque. The price protection products offered by Georgia Power are regulated products authorized by the Georgia Public Service Commission, with financial consequences to ratepayers as well as to tariff participants. In a competitive market paradigm an explicit treatment of risk allocation is needed to ensure that everyone involved fully understands the liabilities to which they may be exposed.

To permit the upgradability of the tariffs, all customers should have an interval metering system, although the data uploading capability of the communication system should vary depending upon the needs of the tariff under which the customer receives service. The customer would make this choice. Customers on straight TOU probably do not require daily access to hourly data, so a monthly or biweekly upload could be sufficient. A wide range of telecommunication systems can achieve such upgradability. In some instances to achieve an upgrade may require a new communication link to the customer. In others, requiring this upgrade might suggest no customer-specific equipment change, but would require upgrades in the bandwidth of the overall communication system as greater numbers of customers use data uploads more frequently.

⁵¹ California Assembly Bill 57 (Statutes of 2002, Chapter 835) would require that utilities either not face reasonableness reviews for power procurement activities approved in advance or be subject to balanced risk/reward systems.

2. A Specific Tariff, Infrastructure, and Data Display Proposal

We can summarize our vision for dynamic pricing and associated infrastructure by providing a tabular display of the key elements for each of several customer classes. Table 4-a provides a proposed implementation of this policy statement including both specific tariff recommendations and the associated metering and other infrastructure requirements. For each of five customer groupings, we describe our vision for the tariff options, the metering and telecommunication system, and the customer information display that we believe appropriate to each group. In concert with our proposed policy, we foresee all customers exposed to at least some time-differentiated rate. We allow customers to opt to hedged or optional rates depending upon the risk preferences. For most customers an interval metering system is needed to record usage, but the telecommunication system that retrieves these data may operate at different levels consistent with the customer's need to access usage data to make decisions in response to tariff prices. Similarly, customers should be able to access their own usage data in a way that displays usage profiles, but at a frequency consistent with the data retrieval required by the tariff.

We urge a total shift toward time-based pricing for all customers, not just as an option. We believe that dynamic, market cost-based tariffs should be the default. Customers ought to be able to hedge such tariffs to obtain a fixed price, but they should expect to pay for this certainty and risk transfer. Utilities should no longer be asked to shoulder this risk. As discussed above, a comprehensive advanced metering infrastructure is required to support such tariffs. It should be adaptable enough to permit differential rates of data uploading and display commensurate with the tariff for the customer. To the extent that ongoing operating costs can be reduced by matching the frequency of data uploads to the incentives of the tariff, then this seems sensible.

**Table 4-a
Our Vision for Customer Class Tariff and Metering Systems**

Class	Tariff	Metering System	Data Display
Residential and small commercial	Default = CPP Hedge = TOU Option = var. CPP	Interval metering system with monthly data recording capability and electronic retrieval with variable frequency	Internet-based, password-protected, access to usage data, displaying lagged monthly upgradable to lagged daily
Large commercial	Default = var. CPP Hedge = TOU Option = RTP	Full RTP metering and data retrieval communications	Internet-based, password-protected, access to usage data, displaying lagged daily upgradable to near real-time
Industrial	Default = RTP Hedge = var. CPP	Same as Large Comm.	Same as Large Comm.
Ag and other	Default = CPP Hedge = TOU Option = var. CPP	Interval metering system with monthly data recording capability and electronic retrieval with variable frequency	Internet-based, password-protected, access to usage data, displaying lagged monthly upgradable to lagged daily
Non-discretionary Accounts (street-lights, traffic signals, etc.)	TOU	Sample-based engineering calculation of loads	On-demand access to sample usage data by owner

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APPENDIX A. REAL TIME PRICING AT GEORGIA POWER COMPANY

BY MIKE O'SHEASY, CHRISTENSEN AND ASSOCIATES

There are a number of RTP programs throughout the United States with clearly the largest and most successful existing at Georgia Power Company (GPC). GPC points to several factors that contribute to their remarkable success, but two of the most powerful success enablers are (1) tariff design, and (2) a family of complementary RTP products.

The most popular of the suite of RTP products is RTP-DA-2. It is a two-part tariff with a customer baseline (CBL) load shape which is based upon the customer's historical load prior to going on RTP. It is priced at standard embedded tariffs and comprises the first part of the tariff. The second part of the tariff is hourly load deviations from the CBL priced at hourly RTP prices. These hourly RTP prices are based upon GPC's hourly forecasted marginal cost plus a risk adder. In the case of RTP-DA-2, these marginal costs are computed a day ahead (DA), and 24 hourly prices are transmitted to DA customers around 4 a.m. the prior day. Deviations below the CBL are credited to the customer at the hourly RTP price. This feature, which is common to all products in the RTP family, enables GPC to enjoy remarkable demand response to high prices. For the family, it can reach as high as 800-1,000 MW, or 5% of GPC's system peak. Commercial and industrial customers with a minimum peak demand of 250 KW are eligible for RTP-DA-2. The two-part technique enables customers to maintain their traditional bills by holding their loads to the traditional loadshape (CBL), and enables the utility to recover its embedded revenue requirements through the CBL/standard bill portion of the bill (revenue neutrality). The second portion of the bill which is impacted by RTP prices enables customers to purchase additional kWh or forgo kWh at the utility's marginal costs, enabling efficient purchasing decisions for both the customer and the utility.

There is an administrative fee of \$155/month for customers over 1,000 KW and \$175/month for customers under 1,000 KW to cover billing, administrative, and communication costs of RTP-DA-2. An Internet website is provided for customer retrieval of prices.

RTP-HA-2 is very similar to RTP-DA-2, except RTP prices are transmitted hourly. At approximately 10 minutes before each hour of the day, an RTP-HA price is provided for the subsequent hour beginning in approximately 70 minutes. Prices are retrieved by the customer from a dedicated server by using phone lines and a modem. The minimum peak load eligibility for RTP-HA-2 is 5,000 KW. As a result of this eligibility requirement and the mere "hour ahead" price notification, this tariff is utilized by a limited number of very large customers while RTP-DA-2 is popular with a large number of customers who run the gamut from small to large in size. The administrative fee for RTP-HA-2 is \$850 per month to cover the relatively higher billing, administrative, and communication costs. In general, RTP-HA-2 customers are the most price-responsive.

RTP-DAA-2 is an RTP tariff that enables DA customers to *adjust* their CBLs on an *annual* basis (higher or lower) based upon GPC's expected DA prices for the forthcoming year. By raising their CBL, an RTP customer is insuring himself against the possibility of higher than expected DA prices. By lowering his CBL, the RTP customer can enjoy the benefits of lower than expected RTP prices if that should actually occur. The administrative fee for RTP-DAA-2 is \$175 per month for customers greater than 1,000 KW

and \$195 per month for customers less than 1,000 KW to cover billing, administrative, and communications costs associated with RTP-DAA-2. Because of the two-part nature of the tariff, the economic incentive to price respond remains regardless of the annual CBL level of RTP-DAA-2.

RTP-HAA-2 is similar to RTP-DAA-2 except it permits HA customers to *adjust* their CBL's up or down on an annual basis using forecasted HA prices for that contract year. The administrative fee is \$870 per month. Once again, the two-part nature of this tariff incents RTP-HAA-2 customers to continue to price respond regardless of the annual CBL level agreed to under this tariff.

Price Protection Products under tariff PPP-1 are financial contracts that enable any RTP customer to manage his price exposure to RTP. The customer must first be on an RTP tariff (DA-2, HA-2, DAA-2, or HAA-2). He can then protect RTP load above his CBL up to the total incremental RTP kWh's that he purchased the prior year.

These financial contracts involve a specific timeframe, a specific quantity, and a specific price. They clear at the end of the billing period based upon the difference in the PPP contract price and the actual average RTP price over the contract period. For instance, a typical PPP contract might be for 1,000 KW over all hours of July at a contract price of 4.5 ¢/kWh. If the actual underlying RTP price were 4.2 ¢/kWh, the customer would be charged in addition to his *metered* RTP bill for July of:

$$1,000 \text{ KW} \times 31 \text{ days} \times 24 \text{ hours/day} \times (.045 - .042) = \$2,232$$

There are different types of Price Protection Products:

A Price Cap is a ceiling guarantee on the average RTP price over a specific time period. Customers are protected against the average RTP price going above the Cap Price. Customers pay an up-front premium for the guarantee.

A Contract for Differences (CfD) is a fixed price guarantee for the average RTP price over a specific time period. Customers are able to lock in a fixed price and know for certain what the average price will be. No up-front premium is required.

A Collar is a Cap and Floor on the average RTP price over a specific time period. Customers are protected against the average RTP price going above the Cap Price. No up-front premium is required. Each Cap Price has Floor price associated with it.

An Index Swap is a financial agreement that ties an RTP swap price to a commodity price index. If the commodity price decreases, the Swap price decreases. If the commodity price increases, the Swap price increases.

An Index Cap is a financial agreement that ties an RTP cap price to a commodity price index. If the commodity price decreases, the Cap price decreases. If the commodity price increases, the Cap price increases.

Because these PPP's are financial instruments with fixed quantity components not directly related to the actual metered load during the billing period, the RTP customer's economic incentive to price respond remains intact regardless of the amount of load contracted under PPP-1.⁵²

Price-Responsiveness

Over the years, GPC has analyzed its RTP customers' price-responsiveness for purposes of developing forecasting tools in order to predict the amount of load response it can expect at different RTP price levels. The analysis has looked at the price-responsiveness of both individual customers and groups of customers with similar characteristics. The individual results have typically shown a wide range of price elasticities across customers in a particular business type (*e.g.*, textile or chemical plant, office building, grocery store). Typically, a relatively small fraction of customers are extremely price-responsive, with price elasticities in the range of -0.1 to -0.25 . Finally, a relatively large portion of customers (on the order of a third to half) appears to be only modestly responsive or not responsive at all.

Aggregating these results across customers, and examining price-responsiveness at different price levels, GPC has found that customers' price-responsiveness differs by customer type, and typically increases at higher price levels. GPC's largest RTP customers, who face hour-ahead prices, exhibit price elasticities ranging from approximately -0.2 at moderate prices, to -0.28 at prices of $\$1/\text{kWh}$ or more. Among the customers facing day-ahead prices, those previously possessing flexibility prior to going on RTP have price elasticities ranging from -0.04 at moderate prices to -0.13 at high prices. Finally, the remaining majority of the RTP load shows price elasticities of about -0.02 at moderate prices, but rising to -0.06 at high prices. See Figures 3-k, 3-l, and 3-m in the main section of this report.

As of June 2002, GPC benefited from a total of 1,639 customers under their RTP tariffs. Of these, there are currently 184 PPP contracts in place, which is considerably fewer PPP contracts than prior years, largely due to the lower RTP price volatility expected for 2002.

⁵² "Real-Time Pricing: Supplemental Price-Risk Derivatives", *Public Utilities Fortnightly*, March 1, 1997.

APPENDIX B. GULF POWER'S RESIDENTIAL SERVICE VARIABLE PRICE OPTION

Source: Levy Associates, Principal Investigator, R. Levy and Plexus Research, Inc, Project Investigators, R. Abbott and S. Hadden. *New Principles for Demand Response Planning*, Electric Power Research Institute (EPRI). EP-P6035/C3047; March 2002.

We thank EPRI and the authors for their permission to reproduce below part of Appendix B from the *New Principles* report.

Gulf Power Company, an operating division of Southern Company, serves approximately 376,000 retail customers in the western “panhandle” of Florida. In early 1991, Gulf initiated a field trial of an innovative demand response program that employed a unique combination of customer service, prices and technology. As a result of that field trial, approximately two years ago Gulf Power implemented a unique demand response program that combines a conventional time-of-use (TOU) price structure, a real-time dispatchable super-peak price, advanced metering and appliance control.

The Residential Service Variable Price (RSVP) price option offered by Gulf Power uses the combined TOU and dispatchable price to encourage and compensate residential customers to shift loads in direct proportion to energy company needs. Unlike other residential demand response programs anywhere else in the country, the RSVP option combines incentives and technology into a true ‘distributed control’ program. The energy company controls the price signal. Customers use the integrated pricing/technology package to determine how, when and to what extent they will modify their usage patterns on any given day. The RSVP option is also unique among demand-response programs because it actually charges customers a monthly participation fee. Gulf Power markets the RSVP option under a program called GoodCents SelectSM (Select).

Background

The Select program is a direct successor to the TranstexT Advanced Energy Management field trial conducted at Gulf Power between 1991 and 1994. TranstexT concepts were developed in the early 1980's by Integrated Control Systems (ICS), a joint venture by Southern Company and Southern Bell. ICS brought together an innovative development team convinced that ‘homeostatic’ pricing research, the forerunner of real-time pricing that originated at MIT, was relevant and in the long-run, essential to improved energy company operations. The ICS development team engaged numerous metering, appliance and other industry participants to develop a practical system for implementing their version of real-time pricing. The result was a program design that incorporated:

- An innovative four-part TOU price structure.
- A dispatchable thermostat that could be programmed with conventional set points as well as customer price-activated load management options.

- A gateway that could read the revenue meter.
- Power line control devices the customer could use to control loads in response to energy company price signals.

The gateway communicated with the energy company by telephone and with the residential loads by a commercial power line technique (X-10 and CEBus). Customers programmed their thermostats and loads to respond to the conventional three-part TOU price structure and to the fourth “critical” price dispatched by the energy company.

The first version of the TranstexT system included home shopping, banking and information services. It was tested at Georgia Power in the early 1980s. This and several other field trials resulted in a series of conceptual and technical improvements that eventually led to the final trials by Gulf Power and American Electric Power Company in the early 1990’s. Table B-1 summarizes the results from Gulf Power and three American Electric Power operating companies. All four field trials produced convincingly positive energy and customer results. Customers expressed enthusiasm for the system’s many information and control features.

	AEP Appalachian Power	AEP Columbus Southern	AEP Indiana & Michigan	Gulf Power
Test Group	160	149	124	242
Control Group	60	60	50	195
Prices (\$/kWh)				
Low Price	\$.004	\$.007 (winter)	\$.020	\$.035
Medium Price	\$.034	\$.033 (winter)	\$.061	\$.046
High Price	\$.102	\$.107 (winter)	\$.162	\$.087
Critical Price	\$.152	\$.160 (winter)	\$.244	\$.288
Avg. Impacts				
Winter Peak	3.5 KW	6.2 KW	6.6 KW	2.9 KW
Winter Energy	Insignificant	5%	Insignificant	< 1%
Summer Peak	1.5-2.0 KW	1.5-2.0 KW	1.5-2.0 KW	1.8-2.2 KW
Bill Reduction	11.6%	10.4%	14.9%	13.6%

Table B-1. TranstexT AEM Residential Dwelling Impacts ⁵³

⁵³ TranstexT Advanced Energy Management System, Project Review, Levy Associates, July 1994.

At the conclusion of the TranstexT field trial, Gulf Power evaluated the economic, technical and customer results. Gulf Power concluded that the TranstexT program was cost effective and compatible with its operating objectives. As a result, a formal application was filed with the Florida Public Service Commission to approve a formal program.

Although the Florida PSC approved the Gulf Power request, TranstexT went out of business before an expanded program could be implemented.

The TranstexT AEM was not a commercial success for a variety of business reasons. Ten years of field trials and research without any full-scale programs took a major financial toll. However, the concepts were effective and well received by consumers. In the mid 1990's Scientific Atlanta introduced a residential gateway called MainGate that performed most of the same functions [provided by the TranstexT AEM]. Early tests of the Scientific Atlanta system re-confirmed the TranstexT results, producing high consumer acceptance and demand reductions that approached 50% of residential load during the energy company's peak period.

The Gulf Power Select Program

Scientific Atlanta transferred its load control switch and MainGate business lines to Comverge in 1999. Gulf Power's sustained interest in the product came to fruition when the Florida Public Service Commission approved its application for the Residential Select Variable Pricing (RSVP) program. The company started marketing the program to customers in March 2000. Gulf Power residential customers can now choose from among three different service options:

- The standard residential service RS price structure.
- A conventional TOU program under the RST price structure. (Gulf Power does not actively promote the RST price structure.)
- The Select RSVP price structure, which employs the Comverge MainGate control system.

Gulf Power expects approximately 10% to 12% of its residential customers to eventually sign up for the RSVP price structure. They expect it will take up to eight years to connect the 40,000 to 50,000 anticipated participants. At the end of 2001, Gulf Power reported approximately 2,300 homes are served by the RSVP price structure with more new installations every month.

Gulf Power eventually expects to build additional services on the gateway concept. Security and Internet-based home control and information services have been mentioned as possible options. Other expected program features include capability that will allow customers to view their energy use profiles

over the Web and to remotely manage their thermostat settings. Figure B-1 and Figure B-2 compare the *scheduled* prices for summer and winter weekdays for the three available residential tariffs. The RSVP tariff reflected in the Tables depicts the three-part standard time-of-use periods and the \$0.29 per kWh ‘critical peak’ pricing. The critical peak price can be dispatched by Gulf Power at any time on a need basis. The approved tariff allows Gulf Power to invoke the critical price at any time with 30 minutes advance notice for no more than 1% or 88 hours each year. The standard residential price structure (RS) is a conventional all energy tariff with no time period differentiation. RST is a standard two-part peak/off-peak time-of-use tariff.

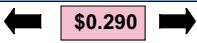

Summer - Weekday									
Rate Option	Monthly Charge	AM				PM			
		3:00	6:00	9:00	Noon	3:00	6:00	9:00	
RS	\$ 8.07	\$0.057							
RST	\$11.10	\$0.027				\$0.104			\$0.027
RSVP	\$12.60	\$0.035		\$0.046		\$0.093		\$0.046	
									

Figure B-1. Weekday Scheduled Energy Charges - Summer

Winter - Weekday								
Rate Option	Monthly Charge	AM				PM		
		3:00	6:00	9:00	Noon	3:00	6:00	9:00
RS	\$ 8.07	\$0.057						
RST	\$11.10	\$0.027	\$0.104	\$0.027		\$0.104		
RSVP	\$12.60	\$0.035	\$0.093		\$0.046			
								

Low / Off-Peak
 Medium / Shoulder
 High / On-Peak
 Critical Rate

Notes:

1. All figures in \$/kWh.
2. Rates shown include estimated fuel and other charges of \$0.023 /kWh.
3. RSVP includes a 'critical rate' of \$0.29 /kWh applied for up to 88 hours per year.

Figure B-2. Weekday Scheduled Energy Charges - Winter

Comparing the RST and RSVP tariffs raises questions concerning perceived incentives. Although each appears to offer some pricing advantage, Gulf Power reports only 12 participants on the RST price structure. According to Gulf Power, customers place a much higher value on RSVP because of the convenience, financial and automation benefits.

From Gulf Power's perspective, the dispatchable component of RSVP provides the energy company with significant benefits, described below.

Customer Participation Requirements and Benefits

While there are no minimum usage levels to qualify for participation, customers must meet the following conditions to receive the RSVP price structure:

- Service of 200 amps or less
- Touch tone phone service
- Central heating and air conditioning equipment compatible with the Select thermostat (a modified Honeywell product suitable for most residential applications)
- Satisfactory paging signal reception, and
- Physical clearance around the meter for the MainGate hardware.

Incentive Payments

The RSVP program has many unique features that distinguish it from all other residential demand response programs in the US. Two in particular stand out from all the rest.

First, unlike other residential demand response programs, the RSVP does not provide participants with incentive payments. Instead, all incentives for participating are embedded in the underlying four-part dispatchable TOU price structure. Customers accrue financial benefits only to the extent that they modify their usage patterns in response to the incentives. There are no requirements to shift or modify usage patterns, nor are there penalties for not modifying usage patterns. Customers that choose not to modify their usage patterns simply pay the tariff price.

Second, unlike other residential demand response programs, the RSVP actually requires the customer to pay a \$4.53 monthly participation fee. Gulf Power justified monthly participation fees as a means for offsetting program equipment and operating expenses. To date, customers have not considered the fee a barrier to participation. In fact, they regard the automation and energy management benefits they receive as being well worth the monthly fee.

Other Program Benefits

The equipment package installed as part of the RSVP program provides participants with several additional benefits apart from the tariff.

The MainGate communication gateway interfaces with the billing meter. Features inherent to its design allow Gulf Power to give participants three additional service benefits, including:

- The MainGate unit continuously monitors participant electric service and automatically notifies Gulf Power if the service is interrupted. Gulf Power assures customers this ‘outage notification service’ will result in prompt dispatch of a service truck, even if no one is home to report the outage.
- The MainGate unit also accumulates customer usage information necessary to compute the time-of-use bill. As an added benefit, Gulf Power provides this information to customers with the bill, showing them how much energy the home used in each time interval, including critical periods.
- Finally, the MainGate includes a meter-socket whole-house surge protector.

The programmable thermostat used in conjunction with the MainGate unit gives the customer capability to take advantage of the RSVP tariff by programming and automatically controlling home heating and cooling systems, water heaters and pool pumps.

Gulf Power’s customer surveys show that, considered as a “bundle”, the RSVP program provides a pool of benefits that customers feel justifies the \$4.53 monthly participation premium.

System Description

The principal operating components of the hardware to support the Select program and its RSVP price structure are shown in Figure B-3. The homeowner programs the thermostat to control the space temperature setting to his or her preferences. The homeowner also programs the controllable loads in the house to be either “off” or “enabled to run” for each time interval of the RSVP price structure and for the critical price, which may occur at any time. Most of the time the residence operates in response to the

RSVP time-of-use schedule. The temperature settings and the controllable loads are managed according to the homeowner's time-based program. If a critical price occurs, the thermostat applies the homeowner's control preferences for critical price, regardless of the time of day.

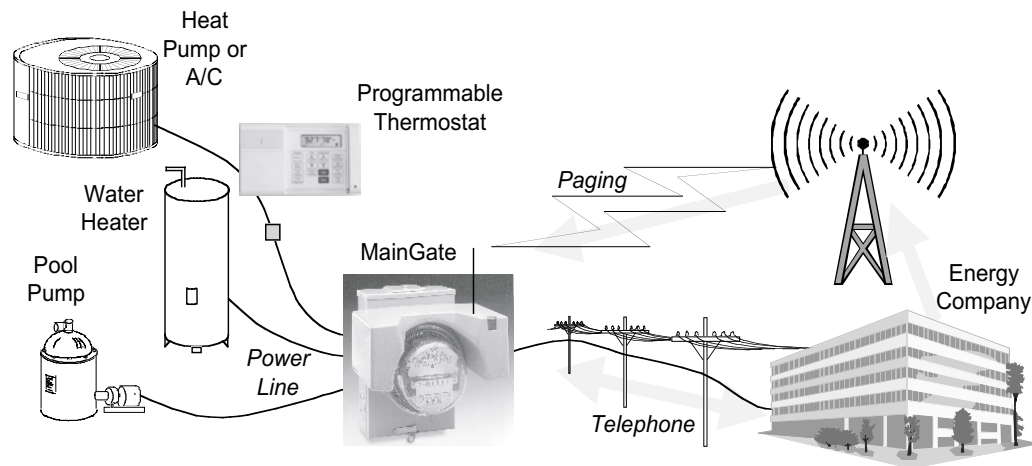


Figure B-3. MainGate System Overview

The energy company uses commercial paging to send a critical price signal or other spontaneous contact to the customer. A paging receiver in the MainGate receives the signal and communicates it to the thermostat via the power line using the CEBus protocol. The energy company may also use paging to command the MainGate to call the energy company on the customer's phone line. In this way the energy company can initiate an exchange with the MainGate to reprogram the system, read the meter, or recover load profile data.

Controllable loads in the Select program include:

- Heat pump or air conditioner
- Swimming pool pump or spa
- Electric water heater

Control devices for the pool/spa and water heater are provided and installed with other Select components by the energy company at no cost to the customer.

Program Results & Economics

Casual inspection shows that the RST and RSVP price structures—both of which are optional—are broadly similar with important differences. The RST off-peak price is lower than the lowest RSVP price, and lasts longer. Arguably, a consumer could do better on the RST price structure than on the RSVP price structure, if that consumer acquired the control equipment needed to manage loads. This would include a programmable thermostat, and time switches or other programmable automation for the pool/spa and water heater. Only twelve residences are served under the RST price structure, indicating convincingly that consumers are disinclined to acquire their own control equipment. Gulf Power reports that consumers like the “bundle” of the RSVP price structure, including a fully debugged control system and free installation.

According to customer service staff, during the first summer of 2000 the energy company invoked the critical price “a few” times. No critical periods were declared during the summer of 2001. Gulf Power cites the following results.

- Base coincident peak demand = 6.1 KW/household
- Average demand reduction = 2.1 KW/household during the high price period
- Demand reduction = 2.75 KW/ household during critical periods (triggered during heat storms, distribution outages, and lightning storms)
- Average energy reduction = 22% during high price period
- Average energy reduction = 41% during critical period
- Customer satisfaction = 96%, highest ever for Gulf Power program

Originally, Gulf Power sought to have customer’s pay a monthly service charge that would recover the full cost all MainGate, associated hardware and related installation fees. As the program moved through the regulatory process, however, Gulf Power and the Public Service Commission agreed that participating customers should pay only part of the cost. This approach was justified on the basis that all ratepayers would ultimately benefit from the reduced demands and corresponding reduced costs of power that participants would contribute. To the extent that RSVP participants respond to the tariff incentives, they improve the overall utilization of system generating resources and reduce Gulf Power’s cost for peak power. Gulf Power states that the \$4.53 monthly participation premium pays about 60% of program costs.

APPENDIX C. DEMAND RESPONSE SUPPLIERS

Source: Levy Associates, Principal Investigator, R. Levy and Plexus Research, Inc, Project Investigators, R. Abbott and S. Hadden. *New Principles for Demand Response Planning*, Electric Power Research Institute (EPRI). EP-P6035/C3047; March 2002.

There are currently four major vendors of demand response systems, which have been profiled by Roger Levy et al. in the EPRI report cited above. We thank EPRI and the authors for their permission to reproduce below part of their section 4.

**Table 4-2 of Levy et al.
Demand Response Supplier Profiles**

Supplier Profile
<p>Cannon Technologies</p> <p>Cannon had been a value-added reseller of ABB load management systems. It was the major provider of head-end systems software to ABB. Several years ago Cannon acquired from ABB the rights to the following load management technologies that had previously existed as Westinghouse or ABB products: VHF radio, Broadcast FM-SCA, Ripple and the EMETCON® power line carrier. Cannon has since augmented these products with newer, internally developed products that constitute most of its current sales, described later.</p>
<p>Comverge Technologies</p> <p>Comverge is a lineal descendant from AT&T Broadband Systems and Lucent Technologies. In 1996, AT&T developed a broadband-based gateway metering and control product line as part of a multi-level agreement with Public Service Electric and Gas Company (PSEG). Approximately one year into the project, the utility division was spun off into the Lucent subsidiary. PSEG placed a 500,000 point order, however Lucent decided to exit the utility business. The Lucent utility research group spun itself off into Comverge. Comverge subsequently acquired the former Scientific Atlanta load management product line, including the industry-dominant VHF radio switch business with various proprietary protocols, the more complex MainGate® metering and control “gateway” and the Honeywell SmartStat® communicating thermostat.</p>
<p>DCSI</p> <p>DCSI has provided a two-way load control and automatic meter reading (AMR) system called TWACS® since the late 1970’s. Its two-way direct load control system at Florida Power and Light is the largest of its kind in the US, encompassing more than 800,000 residential points. Most load control installations in the US are one-way, with outbound communications from the utility to the control device. Two-way load control provides a means of locating failed or tampered load control switches, and otherwise costly and complex undertaking with one-way communications. Still, most new load control applications are still served with one-way signaling.</p> <p>The DCSI product line had been increasingly recognized as a competent automatic metering system that was capable of supporting complex price structures, with less interest shown in its load control capabilities, but DCSI management has responded to the recently renewed interest in load management with additions to the load control product options to include a smart thermostat offering.</p> <p>DCSI evolved from technology originally obtained by Emerson Electric under license from the New England Electric System (now National Grid). Emerson Electric later spun out a number of its system-oriented businesses into a new NYSE corporation called ESCO. DCSI is strongly profitable, and is currently a unit of ESCO.</p>
<p>Other Load Management Companies □</p> <p>Many other small companies populate the load management technology marketplace, each with much smaller market shares than the companies mentioned above. These include companies that are more generally viewed as AMR companies and those with special purpose offerings for selected niches of the market such as, for example, C&I applications, irrigation pumping controls or hybrid communications technology mixes such as paging outbound with telephone backpath for metering and verification. Examples include companies such as Innovatec, Peregrine Control Technologies (the former PageTap Corporation) and Regency. Each company has its own ideas about what the industry needs and how to serve that need. Some of the smaller suppliers have directly opposing points of view on how demand-response should be obtained, but all are unanimous in their passionate view that load management is an under-appreciated and under-utilized resource with much greater potential. For purposes of this report we shall concentrate on the offerings and trends perceived by the larger players.</p>

Technologies and Products

There are three distinct product lines that dominate the current demand response market:

1. Load Control Switches – Load control switches are remotely controlled electronic devices that typically include a communications module and relay. They are wired into the control circuitry of an existing air conditioner, water heater or space heater. The communications modules are used to receive an activation signal from the host energy company, which causes the relay to disconnect power to the controlled appliance. The amount of time the unit remains off is usually controlled by a pre-programmed timer function built into the unit. Functionally, control switches being sold today provide the same capability as those sold over 20 years ago.
2. Controllable Thermostats – Controllable thermostats combine a communications module with a conventional setback thermostat. They replace an existing thermostat for package-type air conditioners and space heaters. Using the communications module, the host energy provider can raise or lower the thermostat to impact device operations. Most models also provide the host energy company with capabilities identical to those provided by load control switches.
3. Multi-function, Gateway Systems. Of the three, gateways make up an insignificant part of the total shipments. Gateways usually provide a local area network within the customer facility to support control over lights, pumps and other loads beside the air conditioner, space heater or water heater. The requirements for a network, additional control switches and more complex installation make these devices only marginally cost effective.

Cannon Technology - Technology and Products

Most of Cannon's load management products are now based upon paging technology for addressable signaling to the load control device at the consumer's premises. This is supported by Motorola's FLEX® paging national or regional services. Although Cannon acquired the designs and technologies for the VHF-FM and the Broadcast FM-SCA load control devices developed by ABB, the company is not currently manufacturing them. But what about utilities with existing VHF-FM or Broadcast FM-SCA systems? Why not manufacture compatible load control devices for those systems? Cannon's answer is that it is better and less costly to leave the existing units in place, cover the new locations with paging-based units, and replace the master station software with their YUKON® software package that will manage communications with both the older "legacy" load control devices and the new paging-based devices. For completely new systems Cannon argues that the paging-based approach is demonstrably less costly and affords a freedom from energy-company-owned communications infrastructure that was unknown in the 1980's.

The paging-based Cannon load management product line takes shape in three forms. First, there is the classical radio controlled switch with paging communications. This is a radio-controlled relay with certain supporting logic and a restoration times to return the load to service without the need for a second command. The paging addressing protocol for all load management devices includes a hierarchical structure having energy company address, “GEO” address, zip address, substation address, feeder address and an individual address. This allows load management actions to be taken with surgically selected groups of customer locations. Unique communications with a single device in the field is supported for reprogramming of that device and for exempting a particular customer from control actions. The capability of exempting a single device can also be part of the energy company’s offering to the consumer. The consumer can get on to the energy company web site, enter his password, and choose to “override” energy company control. The number of permissible overrides can be selected by the energy company as part of demand response program design.

Cannon’s ExpressStat™ RF Programmable Thermostat uses the addressing structure above to support rather extensive and flexible communications and programming of the Honeywell-based thermostat. Control options start with classical direct load control but extend to options involving consumer choice and intervention. These supported options include:

- Automation of pre-cooling or pre-heating of the consumer’s premises
- Energy company control of absolute temperature set point, regardless of customer setting
- Set a temperature offset or bias of the consumer’s setting (example: add +2°F)
- Remotely adjust or bias the natural duty cycle of the appliance prior to control.

Cannon observes that the automatic setback and other features of the thermostat are sufficiently attractive to many consumers that they will accept the device and some level of load control without any explicit monthly incentive. Several suppliers observed that utilities express a desire to avoid being locked into fixed monthly incentive payments.

A third product in the Cannon load control line-up is the ExpressStat™ Window Air Thermostat. Cannon observed that window or through-the-wall air conditioning is prevalent in many parts of the country, especially in homes that were built with hot water heat and have no forced air ductwork. These air conditioners are plug-in appliances, a perennially difficult application for direct load control. Cannon has teamed with Enernet of Syracuse, NY to develop a product that combines two attributes. Enernet designed a product for window air conditioning units, which have notoriously imprecise thermostats, and no setback capabilities. The Enernet product simply “remotes” the thermostat function to a high quality electronic setback thermostat that can be conveniently located on any wall. The thermostat, in turn, communicates with the window air conditioner with LONWORKS™ wireless communications. Cannon has

added a paging load control receiver to the product, affording the same control options as mentioned above for conventional split A/C systems. Utilities can provide this improved thermostat to consumers in exchange for the ability to exert control when program needs dictate. The benefits to the consumer of having the thermostat may obviate the need for any financial incentive payment.

Comverge - Technologies and Products

Comverge also offers paging-based load control products, but continues to manufacture VHF load control switches. These are called Digital Control Units (DCUs). Comverge is able to sell the VHF switches for up to 20% less than the paging based switch, which makes them attractive for expansion of existing systems. For new systems the price premium for paging may be more than offset by the elimination of any need for installing and maintaining VHF radio infrastructure.

Comverge offers a version of its DCU with an adaptive algorithm that observes and records the air conditioner's duty cycle using a small current sensor. This duty cycle may then be adjusted equally for all remotely controlled units. This is designed to eliminate the "free-rider" problem of customers with oversized air conditioners, and has similarities to products having similar aspirations in the 1980's. Comverge-sponsored research indicates that this device is capable of producing 20% to 30% greater load reduction than simple direct load control.

Comverge has a "smart thermostat" based upon the Honeywell unit that has many of the capabilities of the Cannon Technologies thermostat described above, including hierarchical addressing and a variety of strategies for energy company intervention.

The MainGate® product line was acquired from Scientific Atlanta with the load control product line. The most prominent current installation is 12,000 points currently installed with Gulf Power in partial fulfillment of an order for 40,000 units obtained by S/A. This communicating gateway product is tied to metering and to three controllable loads. These loads typically are water heat, HVAC and pool pumps. There are two season price structures, each having a three part time-of-use price structure (Example: 4¢, 8¢, 12¢) with a dynamically controlled "super-peak" price (Example: 29¢). Using the controllable thermostat that is part of the package provided to the consumer, that consumer could make selections to have loads controlled in accordance with price. For example if the price is in the peak or dynamic "superpeak" price period, control pool pump OFF and raise space temperature set point by 4° F). Comverge reports that the customer pays for the product with a \$4.50 monthly charge, but can readily save \$20 or more each month. The MainGate equipment and its installation, including the load control components, currently cost approximately \$1000. Comverge reports that the Sacramento Municipal Utility District (SMUD) will be implementing a 200-point MainGate trial installation.

Comverge has prepared a commercial offering under which it will actually *sell* KW load reduction. It will arrange the program, own and install the control apparatus, and agree to provide a known amount of

demand reduction when the energy company “presses the button.” The energy company will pay an up-front charge for this capability and an amount that is related to the amount of load reduction provided and how often. At least four utilities are known to be considering this option. None have so far committed. This innovative business approach has similarities to the “outsourcing” business model in AMR that was originated by CellNet Data Systems and is now being offered by Schlumberger using the same technology.

DCSI - Technologies and Products

The DCSI product line blends AMR, distribution automation and load control products and capabilities, all based upon communication over the energy company’s power lines. The basic communications technology was developed in the 1970’s but has been extensively cost-reduced and refined in the intervening years. In the 1980’s the company was entirely focused on large investor-owned utilities. In more recent years the company has very successfully penetrated the rural electric cooperative, municipal and government energy markets. Some of these installations are primarily automatic meter reading (AMR). Others are primarily direct load control. By virtue of their two-way communications the load control system is capable detecting failures or deliberate tampering. A “flag” in a return message from the consumer’s premises to the energy company can pinpoint a problem. In the more severe case of a unit that has been destroyed or that has simply failed, the lack of a communications response will itself identify a problem. The economics of detecting and replacing failed load control devices on a timely basis can be very persuasive.

DCSI is currently augmenting its load control product line with devices that provide more interactivity with customer premises.