Deregulated Electricity Markets Offer Real-Time Price Signals to Promote Retail Load Management

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ABSTRACT

Deregulation of the electricity market creates new opportunities to develop real-time, price-responsive, load management programs. The deregulated electricity markets represent for the first time the opportunity for a retail load to receive real-time market price signals, reflecting the true value of wholesale energy and ancillary energy services.

Wholesale energy prices in California have repeatedly risen above $150/MWh during high demand periods and have even reached the $750/MWh price cap imposed by the system operator. These price signals, combined with modern communication tools provide an opportunity for end-users to undertake significant amounts of load management by quickly responding to, and taking advantage of values created in the deregulated marketplace.

The California Independent System Operator (ISO) has developed two programs which provide payments to retail customers when the customers implement load reduction during high demand periods. A similar load reduction program is being undertaken by the New England ISO.

This paper examines the load reduction programs of the California ISO and the New England ISO and offers recommendations for improving their effectiveness. The paper also attempts to answer a fundamental question: "Do these load reduction programs provide sufficient revenue to attract and maintain participating load?"

Opportunity for Price-Responsive Load Management

There is a significant value in price-responsive load management within California. This value is created by two main factors: a) a narrowing gap between California's peak demand and the available generation, and the resulting shrinkage of reserve margins, and b) increasing prices and increasing price volatility in wholesale energy and ancillary services markets. The deregulated market structure has provided the opportunity for end-user loads to capture these values by creating true value-based price signals and by unbundling services such as hourly energy and ancillary services. New market makers such as the New York Mercantile Exchange (NYMEX), Automated Power Exchange (APX) and Energy and Environmental Economics (E3) have been setting up separate energy exchanges to cater to the needs of the deregulated electricity markets.

California's peak demand has been growing steadily for the past several years, driven mainly by a very healthy California economy. During this time, however, no significant new power plants have been brought on line. The result is that reserve margins for the California electrical grid have been reduced and may, as described below, reach critical levels during the 2000 – 2002 time frame.

At the same time as reserve margins has been narrowing, wholesale energy prices have been steadily rising since California electric deregulation began in March 1998. The price forecasts for summer 2000 are well above the price levels seen in summer 1997, 1998 and 1999 (NYMEX 2000). The NYMEX electric futures price for delivery at California Oregon Border (COB) is above $85/MWh for this coming summer (July 2000 through September 2000).[1]

Actual prices have shown significant volatility during peak periods. . The hourly prices for wholesale energy in the California Power Exchange (CALPX) rose above $100/MWh on 34 separate days during 1998 and 1999. Figure 1 illustrates a spiking of prices in California on May 23, 2000. On this day a heat wave hit the region when several generation plants were down for scheduled maintenance and unplanned outages. The tight reserve margins resulted in a system emergency and resulting electricity price spikes.

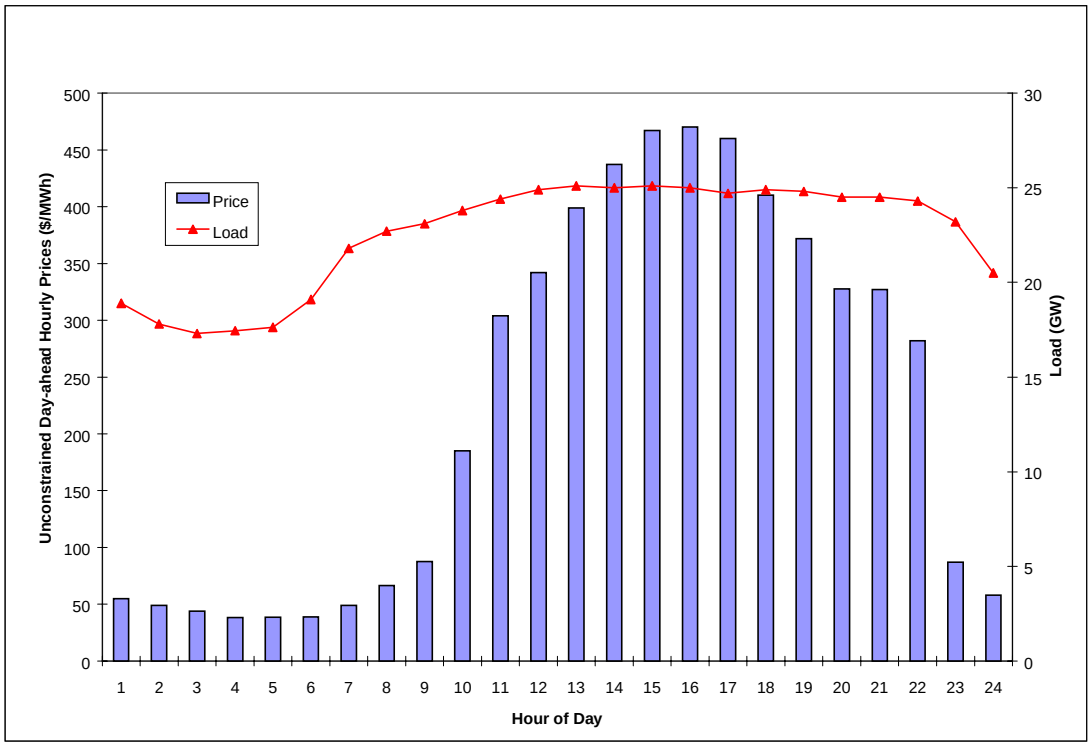

Figure 1. Electricity Prices and Demand in the California Power Exchange 05/23/2000

In addition to the price volatility seen for wholesale energy, the prices in the ancillary services market also have reflected the same price volatility.

The CA ISO believes there will be sufficient electrical supplies for summer 2000 if weather conditions are normal. With about 38,000 MW of internal generation and another 8400 MW of imported power the CA ISO says it can maintain the required seven percent operating reserve margin. In a hot summer scenario, however, the forecasted peak load would outstrip available resources. While internal generation would most likely remain

[1] As of 5/22/00 the NYMEX (New York Mercantile Exchange) forward price at COB is above $85.00 for summer 2000. In comparison, the actual on-peak COB prices were approximately $20.00 during summer 1997, $45.00 for summer 1998 and over $40.00 for summer 1999.

constant during a heat wave, California's neighboring states would typically have less surplus power for export. The combination of high demand and reduced imports could create a shortfall of almost 4000 MW (California ISO, May 10, 2000).

Table 1. Projected California ISO Peak Loads and Resources

Load Condition	Peak Load	In-Area Generation	Net Imports	Excess (+) or Deficiency (-)
Normal	46,250 MW	38,000 MW	8,400 MW	150 MW
Extreme Hot	48,940 MW	38,000 MW	7,000 MW	-3,940 MW

If this extreme heat event occurs (5-10% probability), California utility customers on interruptible tariffs may get interrupted and the situation could even result in rolling blackouts. This situation will likely result in significant price volatility during summer 2000. The predicted low reserve margins and supply shortfalls has prompted the California ISO to undertake the demand reduction programs for the summer of 2000.

Several new merchant power plants are planned for California, but few of these are expected to be operational before summer 2002. There is also the possibility of further delay as several of these proposed plants are meeting significant resistance in siting and regulatory approvals.[2]

High prices for wholesale energy, increasing price volatility, and the shrinking reserve margins create a need for price-responsive load management in California. The combination of true price discovery available through the various power exchanges, the ability of the internet to communicate these price signals, and the increased flexibility of energy load management and control systems create a real opportunity for price-responsive load management in California.

California ISO - Summer 2000 Trial Programs

The California ISO is implementing two trial programs for summer 2000 to increase load management in the California market. These programs are being implemented in order to meet increasing electrical demand, especially during the next two to three years before new generating facilities are constructed.

1) The first program, Summer 2000 Ancillary Services Load Program, allows loads to participate in the Ancillary Services and Real-Time Energy Markets. Under this program three types of services are requested: Non-Spinning Reserve, Replacement Reserves, and Supplemental Energy.

2) The second program is an Emergency Demand Reduction 2000 Program.

[2] For example, Calpine's Metcalf facility (600 MW) planned for South San Jose has met significant local opposition including opposition from the city's largest employer, Intel Corporation. In addition a preliminary assessment (May 15, 2000) from California Energy Commission staff recommends that the Calpine plant not be built at the proposed site due to environmental considerations.

Summer 2000 Ancillary Services Load Program

This program is intended to encourage additional load participation in the ISO's Ancillary Services[3] (AS) and real-time energy markets. Both loads and generators are currently able to participate in the California ISO's markets if they satisfy the ISO Standards for telemetry, metering, and other requirements. However, the tariff and ISO metering and communication protocols were originally designed for generators and many of the metering and telemetry requirements discourage the participation of load. The ISO has attempted to relax these requirements on a trial basis in order to encourage load participation in the ISO's markets for summer 2000.

In March 2000, the California ISO issued a Request for Bids (RFB) seeking participating load to assist in the provision of ancillary services and real-time energy. Under this RFB the ISO was seeking the following participation levels: Non-Spinning Reserve[4] (up to 400 MW), Replacement Reserve[5] (up to 400 MW) and Supplemental Energy[6] (up to 1,000 MW).

The minimum Participating Load was set at 1 MW, however smaller loads may be aggregated together to achieve the 1 MW threshold. Under this program, the ISO would offer the same price to generators and loads for providing these ancillary services. The ISO plans to treat the generators and loads in a very similar manner.

Results from the load reduction bids. The California ISO received six bids, and five were accepted subject to certain conditions. The bid results were the following:

Non-Spinning Reserve:	118.5 MW – 152.5 MW
Replacement Reserve:	289.3 MW – 467.5 MW
Supplemental Energy	289.3 MW – 467.5 MW

For the non-spin and replacement reserves services, the loads will be paid both a capacity payment and an energy payment. The capacity payment will be based on the bid price submitted by each load, and the energy payment is based upon the ISO hourly ex-post energy price that is subject to a $750/MWh price cap. The supplemental energy service only includes energy payments, based upon the ISO hourly ex-post energy price. (California ISO, May 23, 2000)

The ISO faced significant constraints in developing the Ancillary Services demand reduction program because: 1) the ISO operators need real-time data in the control room for each of the ancillary services to be supplied. This ability to "see" the ancillary services requires a certain level of telemetry to get real-time information to the operators. The

[3] Ancillary Services are those energy services required to reliably operate an interconnected electric system. There are a variety of transmission-related and generation-related ancillary services defined by the Federal Energy Regulatory Commission (FERC) and the North American Reliability Council (NERC).

[4] Non-Spinning Reserve is the generation capacity or load which can be brought on-line (or reduce load) within ten-minutes upon demand.

[5] Replacement Reserves is a capacity that can be brought on line, or a load that can be reduced within one hour upon demand.

[6] Supplemental Energy is a real-time hourly energy service that is offered to the ISO. Providers are paid the hourly market-clearing price for each hour that the energy is utilized. There is no capacity payment for this service. Loads could curtail and bid the saved energy into this market.

telemetry requirements (both equipment and procedures) are a significant hurdle to many small loads participating in the AS markets. 2) The ISO is also required to abide by strict WSCC[7] operating standards for its entire operation, including ancillary services. Developing rules that worked for all parties was difficult to accomplish in the short periods of time available to the ISO. (Dozier, 2000)

California ISO – Summer 2000 Demand Relief Program

The second load participation program that the California ISO developed is the Summer 2000 Demand Relief Program. This program does not have the same real-time metering and telemetry requirements as the ISO's Ancillary Services Load Reduction Program as described above. This program uses after-the-fact data collection to determine the amount of load reduction provided by each participating customer.

Through the Summer 2000 Demand Relief Program the ISO was seeking a cumulative demand reduction of approximately 1000 MW during the peak period from June 15 to October 15, 2000 and had the following requirements:

- The loads may be asked to curtail between the hours of 12 noon and 8 pm, Monday through Friday.
- The ISO will provide a 30-minute notice to curtail and each curtailment period will last from 2 to 8 hours. This means that participants are required to be on alert from 11:30 am to 5:30 pm.
- The loads would be called by the ISO as needed after the ISO has issued a Stage 1 alert.[8] There is a maximum of 30 hours of curtailment per month.
- Bid prices were requested on a $/MW-month basis and these demand payments would be made whether the loads are asked to curtail or not.
- There are payment reductions for providing less demand reduction than the contracted demand reduction.

The participating loads must work through a certified Scheduling Coordinator. After a Stage 1 alert has been issued, the ISO will send a mass fax and an e-page to the Scheduling Coordinators signaling the start of the Demand Reduction Program. The Scheduling Coordinator will then contact the participating loads who are required to reduce their metered demand by the contracted amount within a 30-minute period.

The amount of actual load reduction for each participating load is based on the difference between the metered load during a curtailment period and the average demand for that load during the previous week. This method for calculating the actual amount of demand reduction is not perfect, but does appear to be relatively simple and eliminates the need for expensive metering and telemetry equipment. The only device required is an hourly interval meter that records hourly energy usage.

As an example of the potential revenue, a 10 MW load that bid $12,000 per MW-month would receive a $480,000 capacity payment over the four-month period. The load would also receive (via an ISO credit to the scheduling coordinator serving that load) an energy payment based on the hourly energy prices for each hour the load actually curtailed. (California ISO, March 11, 2000)

[7] WSCC – Western System Coordinating Council

[8] ISO State 1 alert is issued when the reserve margin falls below 7%.

Response to ISO summer 2000 demand relief program request for bid. A total of 1000 MWs of demand reduction was requested. Bids were received from 10 respondents. Of these, 5 bidders were deemed responsive. The bids ranged from a minimum capacity of 1 MW to a maximum of 50 MW, with an average bid of 4.4 MW. One bidder submitted several sub-portfolios. A summary of the responsive bids received appears below:

Total Capacity Offered	180.25 MW
Total Capacity Cost	$26,111,329
Weighted Average Capacity Price	$36,215/MW-Month
Smallest Bid Price Requested	$500/MW-Month
Largest Bid Price Requested	$120,000/MW-Month
Average Bid Price Requested	$37,739/MW-Month

The California ISO initially felt that the bid results reflect too little participation at too high a price. However given the limited choices available to the California ISO, the responsive bids were accepted. (California ISO, April 17 2000) The Demand Relief bids received by the California ISO appear reasonable when compared to the prices that the ISO may have to pay in the Ancillary Services market.

- The existing Ancillary Services capacity price of $750/MWh for the 160 hours per month that Loads are available for the Demand Relief program is equivalent to $120,000/MW-Month.
- The Average bid of $36,215/MW-Month is equivalent to an Ancillary Services bid of $226/MWh for the 160 hours per month that the Loads are available to the Demand relief program. This price of $226/MWh is only 30% of the $750/MWh price cap for ancillary services. (California ISO, April 17, 2000)

The revenue obtained from participating in the ISO Demand Relief Program can be compared to the revenues that load would receive from participating in an interruptible tariff program. In order to make this comparison, the total yearly discount from an interruptible tariff should be applied to the four summer months when load is most likely subject to dispatch. Under one California utility program, the discount is $84 per kW-year, which at an 85% peak load factor, equals about $70,000 per MW-year. Allocated over the four months when the load is subject to dispatch results in a monthly revenue of $17,500 per MW-month. (California ISO, April 17, 2000). This comparison shows that the average bid price requested of $37,739/MW-Month is a significantly larger incentive than the revenue available from the interruptible tariffs.

Load Reduction at California Utility Companies

While neither of the California ISO demand reduction programs were limited to direct-access customers, most of the participants were direct-access customers with very few participants from the incumbent Utility Distribution Companies (UDCs).[9] Several reasons

[9] The three main Utility Distribution Companies (UDCs) in California are Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric.

may account for this low participation, 1) the UDCs do not have a financial incentive to encourage customer participation in the ISO load reduction programs, 2) customers already on interruptible tariffs were not allowed to participate, and 3) the UDC rules and the rules of the California PX are cumbersome and may need to be adapted to encourage customer participation in the ISO load management programs

The California UDCs have developed their own demand reduction programs. A recently approved demand-responsiveness program allows a target group of customers to curtail energy usage in exchange for payment when the day-ahead CALPX price is expected to be at or above $250/MWh.

City of Palo Alto Utilities. In response to the expected demand shortfalls for summer 2000 in California, the City of Palo Alto Utilities (CPAU) planned to develop a program to pay customers to reduce demand and/or turn on standby generators during periods of ISO alerts in the summer. After analyzing the requirements for implementing such a system, the CPAU has instead chosen a voluntary program that includes public name recognition for large customers who reduce reliance on the grid during high demand periods. The CPAU decided not to develop a demand reduction program with financial incentives for summer 2000 for the following reasons:

a) Many of the CPAU large customers are sensitive high-tech manufacturing processes and/or large office buildings which are not very flexible loads.
b) The financial payments offered by the market were fairly small compared to the very high curtailment costs for these large customers, and
c) There was insufficient time before summer 2000 for Palo Alto to adequately design, advertise, test and implement a load management program that included contracts and financial payments to customers.

The CPAU is establishing a customer notification program to alert customer when there is a system-wide electricity shortage. Customers will then voluntarily reduce demand and/or turn on standby generators during severe shortages during summer 2000. The CPAU is planning to implement a load management program with financial incentives for the summer of 2001.

The true results of the California ISO's two demand reduction programs will depend on how the loads respond during system emergencies. The results of the summer 2000 experience will prove valuable to the ISO staff in developing the summer 2001 demand relief programs. Suggestions for improving the summer 2000 program are included in the Recommendations section at the end of this paper.

The Emergency Load Reduction Program of the New England ISO

The New England ISO has initiated a Load Response Program for Summer 2000. This program is intended to reduce system load by several hundred MWs during peak load periods. A similar incentive program at $8/kW per event implemented by the New England ISO in the summer of 1999 and by NEPOOL in the 1996 and 1997 summer periods attracted 400 to 500 MW of participation. The program will begin on June 1, 2000 and end on September 30, 2000.

The incentive payments for the Summer 2000 Load Response Program specifies 200 MW blocks priced at $500, $750, and $1,000 per MWh interrupted. The New England ISO would call upon an interruptible block (in price order) based upon the Energy Clearing Price for the New England market and the level of ISO action being implemented.[10]

Payments will be based upon the actual load reduction achieved when the interruption is requested. Load Reduction in response to an ISO request is completely voluntary. There are no penalties for failure to reduce load.

Following each requested interruption, the distribution companies serving the interrupted customer will calculate an estimate of the load reduction actually achieved in each hour of request. This estimate should be based on hourly meter readings adjusted to account for normal load shapes and temperature differences. The load reduction estimates will then be reported to New England ISO. The Load Reduction Program also includes a mechanism whereby customers on interruptible tariffs are provided an incentive to participate with further load reductions. (New England ISO. 2000).

For illustration, assume a large customer ("New England Widgets") has agreed to participate in the Load Response Program at the $750/MWh block. During a four-hour load reduction request, the load reduction achieved by New England Widgets is 1 MW during the first hour, 1 MW during the second hour, 2 MW during the third hour and 4 MW during the fourth hour. The payment to New England Widgets is $750 * (1+1+2+4) = $6,000. This is a significant amount of revenue and appears attractive because the customer's response was entirely voluntary and there are no significant metering or telemetry requirements.

Suggestions for Increasing the Participation and Effectiveness of Load Management Programs

Based on the evaluation of the California and New England load reduction programs there are a number of recommendations to be made. These recommendations may be helpful to others involved in the design and development of demand reduction programs.

Make the Demand Reduction Program as Simple and Clear as Possible

Portions of the California ISO demand reduction programs are complex. For example, in order to participate in the ancillary services market, the California ISO is requiring a similar type of communication protocols, metering and telemetry equipment for a 200 MW power plant as for a 1 MW load. These requirements are particularly strict for the non-spin category, where loads will be required to have a 10-minute dispatch time and have sophisticated telemetry.[11]

There is considerable concern in the marketplace that the communication and telemetry requirements will restrict the participants to only the largest loads. The participants

[10] The New England ISO has sixteen steps in its Operating Procedure #4 (OP4) that describe the actions to be taken during a capacity deficiency.

[11] The ISO is requiring 4-second scan and 1-minute polling for the non-spin category. The ISO also requires the load to be "seen" by the ISO. The communication systems to support these requirements are expensive.

are further concerned that even the large loads will not participate due to the exclusion of customers on interruptible rate tariffs.

One market participant with a much simpler system is the Automated Power Exchange (APX). APX has developed a computerized electricity marketplace that is a simpler and less costly than the California Power Exchange. In its Ohio market, APX has established a Retail Buyback Program that provides end users with a real-time feed that shows the current spot and forward prices. If the price is high, the end-user can choose to curtail energy consumption and get paid for the amount of reduction (Elliot). The APX Ohio program may provide some insight into the design of other load management programs.

The New England ISO Program appears to be fairly simple. The New England ISO has the advantage of building upon it experience from the 1999 Emergency Demand Reduction Program.

Allow Sufficient Time to Develop the Demand Reduction Program

The development of the California ISO programs was complicated by the need to develop the programs in an extremely short period of time. The ISO had only three months to complete the initial program design, develop the program rules, pricing and technical requirements, educate staff and potential market participants, develop the pro-forma contracts, send out the request for bids (RFB), and receive and evaluate the bids. This timeframe, driven by the need to have a program operational by June 15, 2000, was way too short.

California ISO staff stated that just about every single aspect of the two ISO programs was subject to debate. In order to get the program operational for summer 2000 significant decisions regarding program design had to be made quickly with little experiential data to draw upon. The results of the summer 2000 trial programs will be incorporated into the design of programs for summer 2001. (Dozier, 2000)

The rushed nature of the program development kept many participants from bidding. ISO staff felt that there were more loads available that could have been participating if there had been more time for bidders to respond and more clarity regarding the program rules and pricing structures. (Hoffman, 2000)

The New England ISO also appears to have had a short time to develop its Summer 2000 program. Work began in early March 2000 for a program implementation on June 1, 2000. Allowing less than 90 days for the development of a demand relief program will limit customer awareness, understanding, and participation. (New England ISO, 2000)

Allow Sufficient Time for Customers to Evaluate a Load Reduction Program

All parties associated with the California ISO's Demand Reduction Programs felt that additional load would participate if there had been more time for loads to evaluate and understand the ISO's program and the potential impact on their business. One of the key observations from California ISO staff and market participants is that additional time is required for market participants to evaluate a proposed demand reduction program.

Allow for Customer Flexibility

Allowing customers the choice of whether or not to participate in a particular call for load reduction appears to be an important element for increasing customer participation. While there are some customers who can participate in load reduction any day of the week from 2-8 hours (see the California ISO program) many customer cannot participate at all times. ABC Widget Company may be able to endure a four-hour curtailment on most summer days. But ABC Widget Company does not participate in the California ISO program because the rules require a reduction of up to 8 hours. Other examples are customers who can participate in load reduction on most days, but need the flexibility to decide whether to participate on any given day. The New England ISO appears to have a high level of customer flexibility in its program.

There is a tradeoff between providing capacity payments and purchasing customer commitment, and providing only energy payments and leaving customers with more flexibility. An ideal load reduction program may have several types of incentives to capture different customers needs and flexibility.

Encourage Partnerships and Load Aggregation

One of the keys to a successful load management program is developing significant economies-of-scale. These economies can be achieved through partnerships and load aggregation. The New England ISO program appears to encourage aggregation by providing flexibility for distribution utilities to solicit customers in their territory. The California ISO program encouraged aggregation, and one successful bidder aggregated a large number of water utilities to participate in an aggregated bid. (Viner 2000).

E-Source Report

E-Source has recently published an excellent report titled *The Dawning of Market Based Load Management.* This report provides a good overview of the requirements for effective demand reduction programs, and suggestions for developing effective load management programs. Some of the conclusions from this report are the following:

- The opportunities for market-based load management are growing steadily, but it will take some time to effectively link wholesale prices to retail markets;
- Becoming a "negawatt" marketer is a complex business involving skills of power marketing, retail sales, and energy management;
- Customers are unlikely to put themselves at risk of price volatility in exchange for a price break. Programs need to be designed to the risk level of customers and effectively marketed (Capage, Davis & LeBlanc 1999).

Readers are encouraged to read this E-Source document to get additional information on implementing load management programs.[12]

[12] This information was provided courtesy of E SOURCE, an information services company providing organizations with unbiased, independent analysis of retail energy markets, services and technologies. E SOURCE, Inc., 4755 Walnut Street, Boulder, Colorado 80301, USA (303) 440-8500.

Summary

The California ISO and New England ISO have implemented very different types of load reduction programs. These programs offer an opportunity for end use customers to implement load management and help to meet a larger system-wide need of electrical reliability. The market participants and staff will learn a great deal from the experiences of summer 2000. The observations and recommendations in this paper could help improve the load reduction programs for summer 2001 and beyond.

This paper has also attempted to answer a fundamental question: "Do these load reduction programs provide sufficient revenue to attract and maintain participating load?" While the Load Reduction Programs of the New England ISO and California ISO have attracted a significant amount of initial participation, the full answer to the question will only be answered after summer 2000 when the actual participation levels are known.

Many utilities, marketers and large customers are watching these ISO load reduction programs. The success or failure of these programs will have a large impact on the future direction of load management programs.

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