Rates and Technologies for Mass-Market Demand Response

Karen Herter, Lawrence Berkeley National Laboratory
Roger Levy, Levy Associates
John Wilson, California Energy Commission
Arthur Rosenfeld, California Energy Commission

ABSTRACT

Demand response programs are often quickly and poorly crafted in reaction to an energy crisis and disappear once the crisis subsides, ensuring that the electricity system will be unprepared when the next crisis hits. In this paper, we propose to eliminate the event-driven nature of demand response programs by considering demand responsiveness a component of the utility obligation to serve. As such, demand response can be required as a condition of service, and the offering of demand response rates becomes a requirement of utilities as an element of customer service. Using this foundation, we explore the costs and benefits of a smart thermostat-based demand response system capable of two types of programs: (1) a mandatory, system-operator controlled, contingency program, and (2) a voluntary, customer controlled, bill management program with rate-based incentives. Any demand response program based on this system could consist of either or both of these components. Ideally, these programs would be bundled, providing automatic load management through customer-programmed price response, plus up to 10 GW of emergency load shedding capability in California. Finally, we discuss options for and barriers to implementation of such a program in California.

Introduction

Fuel shortages and reliability concerns in the 1970s prompted utilities to create effective demand response programs. As the emergency passed, however, so did the need and justification for demand response options. Surplus supplies throughout the late 1980s and early 1990s concealed the need for long-range planning, prompting regulators and utilities to reduce funding for demand response research and implementation. Utilities dismantled programs, vendors went out of business, and knowledgeable practitioners moved into other fields.

In 2000 and 2001, California experienced one of the most chaotic electricity shortages in history. High wholesale prices and rotating blackouts threatened public safety and badly damaged the state economy. Unfortunately, very few demand response programs remained in place to mitigate the supply-demand imbalance. Once again, new programs were quickly created in an effort to alleviate the crisis. By the time the new programs were being rolled out, however, the crisis had already begun to subside. In a matter of months, it was determined that the costly new programs were no longer needed, and many were dismantled without ever being used. Today, California demand response programs provide less curtailment than they did a year ago, and due to their negative experiences with the programs of 2000-2001, customers are wary.

Motivation

The motivation for this paper is to provide the framework for the State and utility managers to improve system planning and operations in California. Specifically, we hope that our plan will address the following deficiencies in existing demand response programs:

- The temporary and cyclic nature of demand response programs results in substantial opportunity costs when a crisis does occur.
- Participation rates are low because program costs to customers are high, and value low.
- Strict requirements for participation exclude the vast majority of customers and end-use loads from contributing to system reliability.
- Many demand response programs are not available off peak.
- Fixed payment incentive programs support program-wide economic inefficiencies and inequities, and are not cost-effective in curtailment-free years.
- "Pay-for-performance" payments, based on load drop from an estimated baseline, benefit the inefficient customers more than the efficient customers.
- Customers have little control over their own participation in programs: utilities choose the load to be controlled, the technology to be installed, and the level and duration of control.
- Mandatory demand response today consists solely of rotating outages, a burden unfairly borne by only half of all customers.

Demand Response and the Obligation to Serve

The relationship between demand response and the obligation to serve is often overlooked. Understanding this relationship can substantially impact potential implementation options, program costs, and system-wide capacity and energy impacts. In fact, the solution to many of the problems confronting load management planners today is to stop considering demand response a utility *program* and start considering it a component of the utility *obligation to serve*. Redefined in this way, demand response becomes (1) a candidate for mandatory implementation as a condition of service and (2) an element of customer service.

The obligation to serve is a common law concept that requires regulated utilities to provide adequate, affordable, and reasonably efficient service to all customers without unjust discrimination. Requiring utilities to provide service also includes a companion obligation that requires the customer to pay for the resources that fulfill the service commitment. This basic concept is central to all resource planning processes that seek to balance the utility cost of service with the customer obligation to pay.

The CPUC clarified the need to balance the obligation to serve with outage costs in a ruling that established a "priority system" for the curtailment of electricity during shortages (CPUC 2000). The CPUC rulemaking provides exemptions from rotating outages for those "essential customers" that provide public health, safety, or welfare services. Unfortunately, this ruling focuses on and exempts the entire customer load rather than the specific critical end uses. Even worse, deficient distribution automation capabilities require utilities to exempt entire distribution circuits to protect these essential customers. Today, utilities estimate that about 50% of customer load is exempt from rotating outages due to this ruling.

What the ruling failed to recognize is that available demand response technologies can provide utilities, customers, and system operators with the ability to target and control end uses, or to isolate portions of a facility load in response to reliability conditions. Not only can demand response technologies be used to redress the inability to isolate and protect the essential customers identified in the CPUC ruling, their emergence as proven and widely available technologies can be used to redefine the obligation to serve and to reduce the potential consequence of resource shortages.

Demand Response as a Condition of Service

The objective of demand response is for customers and utilities to respond to critical system conditions by reducing or shutting down their least valuable services. By reducing specific end-uses, customers intentionally create ‘partial outages’ with substantially reduced economic and public welfare impacts in comparison to the alternative of rotating outages. Demand response provides customers with options for targeting the least critical energy applications, reducing overall customer costs and producing precisely the economic balance embodied in the concepts underlying the obligation to serve.

The idea that utilities may require demand response as a condition of service was endorsed by the California Public Utilities Commission (CPUC) and put into practice with the popular OBMC[1] program in the Summer of 2001. Under this demand response program, utilities offered large customers priority status during outages in return for partial load curtailment; i.e. the utility would preferentially serve loads able to respond to contingencies. The popularity of this program highlights the fact that customers prefer a certain partial load curtailment to the possibility of full load curtailment. The participation requirements of the program, however, raise serious questions about equity, since the OBMC, like most other demand response programs, is a service not available to small customers.

Demand Response as an Element of Customer Service

The collective inequities and event-driven origin of existing demand response strategies almost guarantee that conventionally planned programs will be both inefficient and of limited effectiveness. For demand response to be effective, it must be integrated with and considered an integral component of customer service. To do this, it is necessary to rethink the entire concept of demand response, to fully understand existing components of customer service, and how the two can be combined. There are two compelling market factors that create a foundation for beginning this integration process, specifically: (1) energy prices will vary through the day and by season in regulated or competitive markets, and (2) customers should pay for and be held accountable for their cost of service. Collectively, these two market factors combine to produce three different components of customer service that redefine demand response (Table 1).

[1] Optional Binding Mandatory Curtailment

Table 1. Three Components of Customer Service Redefine Demand Response

	① **Basic System Operations**	② **System Protection**	③ **Customer Bill Management**
Attributes of Customer Service	Prices vary independent of competitive or regulated market Customers should pay for the cost of service …so implement time varying rates Install advanced meters	Based on the Obligation to Serve Priorities should be extended to end-uses (not whole circuits) Priority exclusions to protect health/welfare based on the critical nature of the end use application Install mandatory controls	Customers obligated to pay their cost of service …so customers have a right to see and respond to price/cost Dispatchable demand response rates capture wholesale variation Voluntary participation Market technologies to facilitate customer adaptation
Investment Requirement	Meters	Basic end-use control technologies Communications	Controls or automation equipment
Cost Allocation	Cost of Service	Cost of Service	Program/Customer Cost
Benefit Justification	Reduced utility operating cost	Reduced resource cost Controlled load becomes spinning reserve equivalent	Investment offset by bill reduction and improved value of service

Basic system operations. At a fundamental level, the two market factors presented in the preceding paragraph identify a basic requirement to provide customers with time-varying rates and the metering equipment necessary to support such rates. Cost accountability and equipment to support time-varying rates then become a cost of service rather than separable program costs attributable to one or more demand response options. This is an important fundamental change in current utility practice. First, using time-varying rates to hold all customers accountable for system costs creates a common underlying incentive structure that ultimately allows all customers and all loads to govern their energy usage decisions. Second, this approach properly characterizes metering as a cost of service, not a component of demand response.

System protection. Reliability is a key component of customer service. However, no utility system currently provides its customers with measures to mitigate rotating outages when conventional supply-side options are exhausted. Instead, conventional demand response programs focus on obtaining voluntary reductions of peak load to prevent system outages. A failure to obtain sufficient load reduction results in rotating outages that currently curtail *the entire* customer load on only half of the customers. The regulatory rules that currently mandate system protection strategies to minimize the societal costs of full outages should be updated to more selectively focus outages on lower priority end-uses on all customers. Such a system protection strategy:

1. reduces or eliminates the likelihood of future outages
2. redefines control costs as a cost of service, just as distribution automation controls are currently classified as a cost of service
3. distributes the obligation of outages to all customers, not just the half on non-exempt circuits

Customer bill management. A natural extension from the two market factors introduced above is that if customers are to be held accountable for their cost of service, they should also be provided with the opportunity to control their cost of service. A rate-based bill management capability helps redefine demand response initiatives as programs that help customers adapt to their rates. Adding dispatchable components to the underlying rate can be used to reflect variation in wholesale market prices or the availability of system resources. Utilities can also market a variety of control and automation equipment to customers to facilitate response.

A Proposed Statewide Demand Response Program

Based on the discussion in the preceding section, we envision a mass-market demand response program for customers with central heating, ventilation and air-conditioning (HVAC) systems, involving one or both of two major components: (1) a responsive thermostat, and (2) a demand response rate.

We focus on **thermostats** systems for the following reasons:

1. Available load is large – residential and small commercial air conditioning (AC) loads comprise about 20%, or about 10 GW, of the peak summer load in California.
2. Given a choice, residential customers prefer AC curtailment to curtailment of other loads (Levy 2001).
3. Temperature adjustment is more equitable than direct compressor control, which unfairly punishes customers with correctly sized systems more than those with oversized systems.

Demand response rates have been tested in the field and found to be several times more cost-effective than fixed or TOU rates (CRA 2001). Some of the major benefits of rate-based demand response programs over traditional ones include abilities to:

1. allow any size customer to participate with any end-use and demand response technology
2. reward the most efficient customers, not those with the largest curtailable loads
3. eliminate subsidization of customers with peaky load shapes by those with flatter ones
4. allow customers to choose their own method and level of demand response
5. allow customers to determine their own valuation of electricity services
6. allow utilities to focus their efforts on marketing demand response *technologies* instead of demand response *programs*
7. enhance personalized billing and energy information services
8. continue to be cost effective during non-curtailment years
9. encourage innovation in demand response technology markets

These components allow a variety of innovative customer services as well as cost-effective mandatory or voluntary demand response programs. Under a mandatory program, customers with central HVAC systems would receive a controllable thermostat for contingency purposes as a condition of service, reducing or eliminating the threat of blackouts. Under a voluntary program, customers would be placed on a demand response rate and offered a responsive thermostat or other demand response hardware that provides notification or automatic control of equipment. Thus, a single system could be credited with both *system protection* and *economic* benefits, or could be used for only one of these purposes. Below we describe these proposed programs in detail.

Mandatory Curtailment Program

As discussed in a previous section, a CPUC-endorsed precedent has been set for requiring demand responsiveness in return for electricity service. Given this precedent, we propose that the State expand the requirement of demand response capability as a condition of service to the mass market. Under the mandatory demand response program, customers with central HVAC systems would be required to install controllable thermostats as a condition of service. Curtailments would be activated only in contingency situations to avoid rotating outages.

Incentive. No cash incentive or special rate is required. Introduction or continuation of service is the incentive for compliance.

Technology. A mandatory program requires a responsive thermostat for each AC unit plus related communications infrastructure.

Cost. The cost of this program would include the cost of the thermostat hardware and installation plus ongoing communications costs. The cost of a responsive thermostat depends largely on its communications ability. A system protection function requires communication to the unit, but not communications from the unit. Thermostat vendors place the cost of "one-way" communicating thermostats purchased in large volume at less than $100 per unit. New building installations and owner-installed retrofits are done at no cost, while professional retrofit installation currently costs about $100. Network costs also vary by technology. The most commonly used commercial network technology for this application is paging technology, which costs roughly $1 per unit per month.

Impacts. A mandatory AC curtailment program has the potential to offer a maximum of about 10 GW of contingency load response in the summertime, at a cost of less than $100 per kW. Of course, it is unlikely that the full 10 GW would ever be required to stabilize a supply-demand imbalance.

Currently, rotating outages are the only existing mandatory curtailment program. Although a thermostat-based mandatory curtailment program may at first blush seem heavy-handed, the authors wish to stress that this system would be called upon only as the preferred option to blackouts. In this context, impacts from loss of cooling load on public safety, health and the economy are relatively minor in comparison to blackouts, which cause considerably more widespread economic harm and customer discomfort.

Voluntary Price Response Program

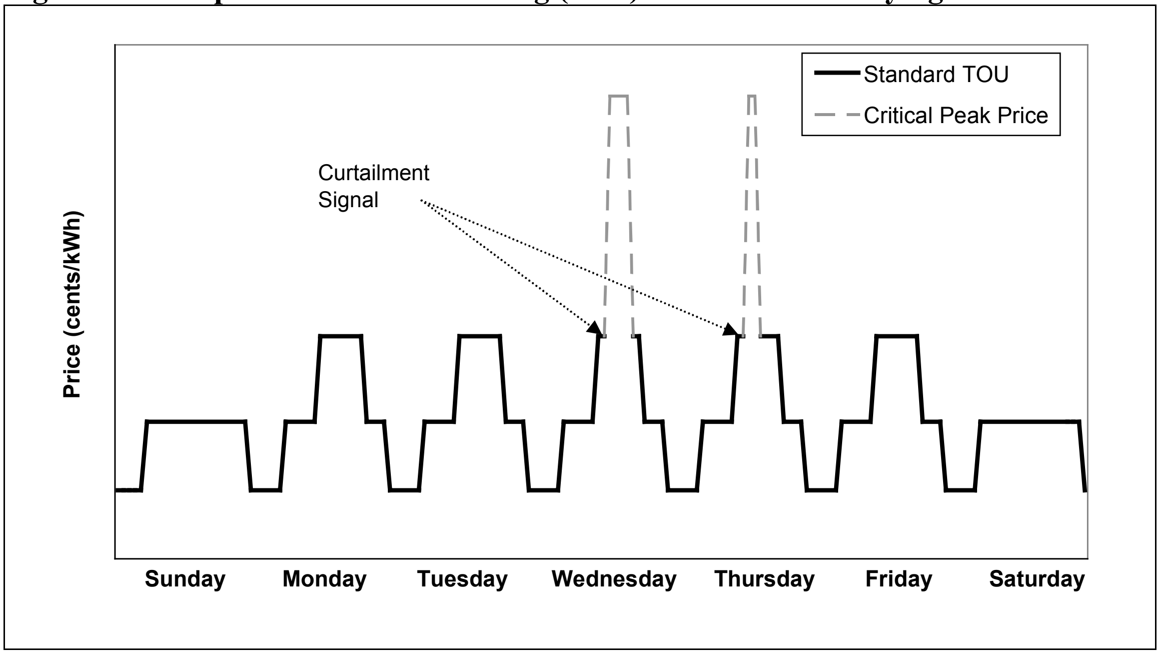
As discussed in the preceding section, one or more demand response rates should be offered as an element of customer service. Bundled with hardware information or offerings, this rate can be considered a voluntary demand response program. Under the proposed voluntary program, any customer – not just those with central HVAC systems – could request to be placed on a demand response rate. Responsive thermostats and/or other demand response technologies should be offered to help these customers respond to price signals, thereby lowering their bills. The details of this system are described below.

Incentives. Incentives for program participation include (1) lower rates during non-emergency periods, (2) ability to reduce bills by responding to contingency or price signals, (3) an advanced meter with accompanying services (where absent), and possibly (4) free, low-cost or amortized demand response equipment, such as responsive thermostats or water heater controls.

The incentive to conserve load during emergencies is avoidance of high prices as determined by the demand response rate. One promising demand response rate with experience in the field is critical peak pricing (CPP), which consists of a standard flat or time-of-use (TOU) rate plus "critical peak" price tiers (Figure 1).

While the critical peak *price level* (indicated along the y-axis) can be predetermined just like other flat or TOU price levels, the critical peak *periods* (indicated along the x-axis) are not predetermined. Instead, they are triggered by emergency events, low supplies, or high wholesale electricity prices. Critical peak prices could occur at any time for any length of time. Notification of expected critical-peak periods hours or even a day ahead would allow participating customers to prepare in advance, for example through automated pre-cooling if desired.

Figure 1. Example Critical Peak Pricing (CPP) Rate with Underlying TOU Rate



Predetermination of price levels and of the annual number of hours of curtailment allows demand response rates like CPP to be constructed such that the average customer's monthly bill would not change if they do not change their usage pattern. Of course, customers that consistently use more electricity during peak periods will pay more, while those with a flatter load shape will pay less – as is appropriate. Thus, such a rate reduces subsidies paid by flat-load customers (often those without AC) to benefit peaky customers (those having AC).

Technology. Customers may be offered or provided with a responsive thermostat that can be programmed by the customer (or by the thermostat installer at the customer's request) to respond to curtailment signals consistent with their own value of service. Customers can reduce their electricity bill by pre-programming the thermostat to adjust the set point temperature by a few degrees, or to shut the system off entirely during high-priced curtailment periods. At any time during curtailment periods, the customer may override the pre-programmed control strategy and choose to pay the curtailment price. Other notification or responsive technologies may be offered to customers without central HVAC.

Cost. The cost of this program would include the cost of the thermostat hardware and installation, ongoing communications costs, and the cost of a new rate. If the thermostats are required under the mandatory program described previously, the cost of a voluntary program is limited to the cost of designing and implementing the new rate. If the voluntary program is implemented independent of the mandatory program, the full, partial or amortized cost of the thermostats and networking must be included.

Impacts. Existing research on the load impacts of voluntary temperature adjustment in response to price variations in residential and small commercial buildings is not sufficient to accurately estimate impacts of a statewide voluntary program. In addition, the ability and inclination of customers to respond with non-AC loads is not well established. Assuming a program size of one million and a sustained load drop of 0.5 kW per participant, this program could offer 500 MW of voluntary AC peak load response. Further research is needed to assess the potential impacts resulting from space and water heating, lighting, and other non-AC loads.

Because the customers set the control strategies, all comfort impacts, override actions and resulting savings are directly tied to each customer's individual preferences and actions. This makes the program equitable, economically efficient, and customer-driven. There are no free riders – customers only get compensated for actual participation relative to their measured contribution. If the customer reduces load, their incentive will be reflected as a reduction in energy charges they otherwise would have incurred without control. If a customer chooses not to respond to a request for curtailment, they will pay the respective energy charges. There are no separate rate-plus-incentive tariffs and no recurring program costs even when no curtailments are called. With this program design, technology is on call and 'always available' to address unexpected supply shortages and pricing problems.

Synergistic Effects of Combining the Proposed Mandatory and Voluntary Programs

The same equipment can be used to support both aforementioned demand response programs. Under this scenario, customers with central HVAC systems would be required to install responsive thermostats to respond to system emergencies. These same customers could volunteer to participate in a an optional rate-based demand response program as described above, maximizing program and customer benefits by using the same equipment for more than one program. In addition to these clear cost benefits, the use of a voluntary price responsive program would reduce or eliminate the need to dispatch mandatory curtailments, maximizing societal benefits and economic efficiency.

Discussion

Implementation Options for California

Demand response rates and technologies may be categorized as responsibilities of either utilities or customers. At the utility end, back office systems and access to a dedicated or commercial communications network must be in place to send out curtailment or price signals. At the customer end, technologies are needed to receive signals and respond with notification and/or automated load control. This distinction has implications for implementation authority.

The key strategies defined in this paper require (1) customer-end demand response technologies as a condition of service, and (2) utility-end demand response rates and technologies as elements of customer service. State entities with complete or partial authority to order the implementation of these strategies include the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), and the California Legislature.

CPUC. The CPUC can require customer-end demand response technologies through utility rules as a condition of service, and can also mandate that the utilities acquire the necessary back office and networking systems to support demand response rates and programs. In May 2002, the CPUC issued a draft Order Instituting Rulemaking (OIR) to address "policies and practices for advanced metering, demand response, and dynamic pricing" (CPUC 2002).

CEC. The CEC load management standards authority extended by the Warren-Alquist Act can address customer- and utility-end technologies and rates. The Act stipulates, however, that "Compliance with such changes in rate structure shall be subject to the approval of the Public Utilities Commission in a proceeding to change rates or service" (State of California 2002). CEC authority under Titles 20 and 24 of the California Code of Regulations allows requirements for customer-end technologies only.

Legislature. The legislature can directly or indirectly mandate rates and technologies, independently, or through directing the CPUC or CEC to act. The California Legislature has passed legislation on demand response rates and technologies on several occasions.[2] None have resulted in serious change. Currently, the legislature is considering a bill that would "require the commission (CPUC) to order each electrical corporation to establish a mandatory AC load control program for all residential customers of the corporation that have a central AC system" (Bowen 2002).

Possible Barriers

Reluctance of utilities to upgrade existing infrastructure. While many utility distribution and billing systems are outdated, utilities are reluctant to abandon legacy systems and invest in unfamiliar technology. This reluctance is heavily influenced by the uncertainties associated with cost recovery approval and the future role of the utilities.

Cost-effectiveness models. Demand response cost-effectiveness models typically include advanced metering systems in the cost analysis, but do not include the system-wide benefits of advanced metering outside the energy consequences of the particular demand response program under investigation. Cost effectiveness models revised to take into account system-wide benefits of advanced metering show that advanced metering systems are independently cost-effective (Levy 2001). What is more, the method of justifying the costs of any multiple-function equipment through the benefits provided by just one of its possible uses is shortsighted at best.[3]

Resistance to mandatory measures. Mandatory demand response measures are politically risky. The alternative, however, is to charge customers higher rates and incur outages. Both of these are also mandatory measures, but they are mandatory measures that already exist, and so while costly, are perhaps more palatable to customers and policy-makers alike. Voluntary measures, such as rate offerings, clearly do not have customer resistance issues.

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[2] See Public Utilities Code §353.3(b), §393, and §739.11, and SB1976, currently under consideration.
[3] Using this method, a tent will always be more cost-effective for sleeping than a house.

Resistance to demand response rates. The CPUC and others have resisted demand response rates as being (1) driven by a broken electricity market and (2) too burdensome on customers. To address the first issue, we note that rates, whether they vary by hour or by decade are driven by the market, broken or not. The real issue is how closely tied to the market these rates are, and we believe that demand response rates can be designed to be as loosely (CPP) or closely (RTP) tied to the market as the times warrant. As for the burden on customers of unpredictable rates, technologies available today are capable of completely automating response to contingency or price signals, relegating customer decision making to the one-time effort of programming these technologies to respond as desired.

Next Steps

Learn from past/existing programs in CA and other states and conduct additional research where needed. Several California utilities are currently experimenting with demand response programs involving controllable thermostats. We expect that the information and experience resulting from these programs will contribute significantly to this effort. In addition, we hope to work with some of these utilities to make minor modifications to existing pilots, enabling features such as time-varying rate structures and measured load response.

Revisit the obligation to serve. The key argument of this paper has been that demand response should be an element of the utilities' obligation to serve – not just a series of utility programs that sprout and wither with the times. To effect this suggestion, the existing text of the utilities' obligation to serve needs to be revisited, and steps taken to include a discussion of demand response that is consistent with its importance as a explicit component of system reliability on par with spinning reserves.

Conclusions

In this paper, we propose to eliminate the event-driven nature of demand response programs by considering demand responsiveness a component of the utility obligation to serve. As such, demand response can be required as a condition of service, and the offering of demand response rates becomes a requirement of utilities as an element of customer service. Using this foundation, we explore the possibility of a smart thermostat-based demand response system capable of two types of programs: (1) a mandatory, system-operator controlled, contingency program, and (2) a voluntary, customer controlled, bill management program with rate-based incentives. Any demand response program based on this system could consist of either or both of these components. Ideally, these programs would be bundled, providing automatic load management through customer-programmed price response, plus up to 10 GW of emergency load shedding capability in California. Realization of these ideas and implementation of corresponding demand response programs is largely the responsibility of the CPUC, which is gearing up for an investigation of the issue. Should the CPUC fail to act promptly or sincerely, both the CEC and legislature have shown continuing interest in demand responsiveness. It is likely that at least one of these State entities will use their authority to improve demand response capabilities in California before the next crisis appears.

Definitions

Load management. A portfolio of strategies that give the utility or system operator the ability to manipulate load to maintain the supply-demand balance.

Demand response. Short-term load management in response to price or system needs.

Rate. The retail price of electricity. The most common rates in use today are fixed and time-of-use (TOU) rates.

Demand response rate. A rate that allows automatic or dispatchable price variations to signify system conditions or wholesale electricity costs. Also called dynamic rates. The most common demand response rates in use today are critical peak pricing (CPP) and real time pricing (RTP).

Demand responsive load. Loads that have (1) a communication pathway and (2) controls that allow response to a request/command from the system or system operator.

Tariff. A contract between the electricity provider and consumers, consisting of a rate plus any other contractual obligations.

Demand response tariff. A tariff that includes load response requirements and incentives, typically fixed or per kW payments.

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