Implementation Experience

The results of the CPP program at Gulf Power and various CPP pilots suggest that CPP programs can provide important benefits without exposing customers to significant risk.

Gulf Power, Florida. Gulf Power, a subsidiary of Southern Company, began marketing its GoodCents Select program to residential customers in March 2000 after experimenting with an earlier version between 1991 and 1994. By the end of 2001, the program had grown to include 2,300 homes, and by 2003 had 6,000 participants. The key features of the program are a monthly participation charge (about $5/month), an absence of incentive payments (incentives are imbedded in the four-part time-of-use), and no penalties for *not* modifying use. GoodCents Select comprises four elements: a TOU rate with a CPP component; a smart meter that receives pricing signals and provides outage detection; customer-programmed automated response technologies (including a smart thermostat governing air conditioning and water heaters, plus heat- and pool-pump timers); and multiple ways to communicate rate changes and critical peak conditions to participants. There are three time-of-use prices for non-critical hours, and a critical-peak price that can be invoked no more than one percent of the hours in a year. Gulf Power's customers have saved more than 1 MW under this program.[133]

Gulf Power believes that both customers and utilities benefit from customer-controlled load management programs when price signals are used in conjunction with technology to automate demand responses. Its customers program the settings on their equipment and have the ability to override price signals; they are willing to participate; and they can save on their bills. Gulf Power said that the utility benefits in several ways: the "program facilitates the promotion of the most economically efficient electric and end-use technologies;" "significant demand reduction can be achieved in real-time (more than 2kW per participant during summer peaks);" demand response is profit-preserving; and, demand response programs to clip peaks should be assessed with the same payback criteria as 30-year combustion turbines (CT) installed to handle peak. Gulf Power reports that the GoodCents program creates initial savings of $35 million, plus annual O&M savings of $2.5 million.[134]

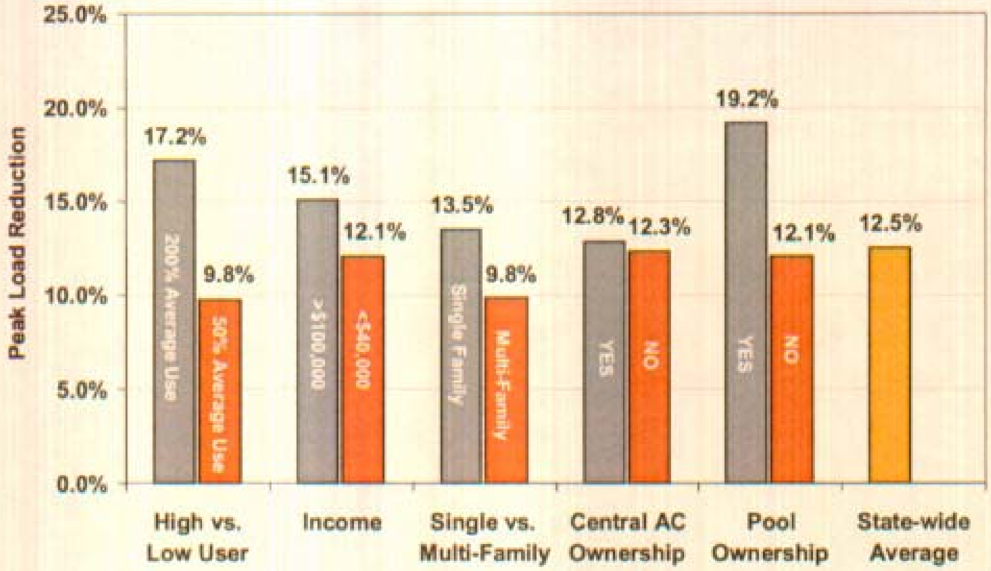
California Statewide Pricing Pilot. California implemented a statewide pilot of CPP, known as the Statewide Pricing Pilot, which included 2,500 customers, involved all three investor-owned utilities (IOUs), and ran from July 2003 to December 2004. Three agencies cooperated in implementing the Statewide Pricing Pilot, including the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), and the California Power Authority (CPA). The pilot tested three rate structures, including a TOU rate in which the peak price was 70 percent higher than the standard rate and twice as high as the off-peak price. It also tested two CPP rates: a statewide TOU rate layered with a CPP that could be dispatched with day-ahead notice up to 15 times annually (CPP-F), and a variable critical-peak rate (CPP-V), targeted at a population that had already participated in a smart thermostat pilot. CPP-V was dispatched with four-hour day-of notification, for two-to-five hours. The CPP-V customers had the option of free enabling technology to facilitate their responses.

Results demonstrated customer responsiveness across all groups and geographies, with and without air conditioning. Figure IV-3 presents the results from the pilot across a number of characteristics. Figure IV-4 displays how customer peak reduction differed by type of rate. Residential customers,

133 Southern Company Services, comments filed in Docket AD06-002, December 19, 2005, 8, noting that participants had saved over 1 MW "thus far" under this program.

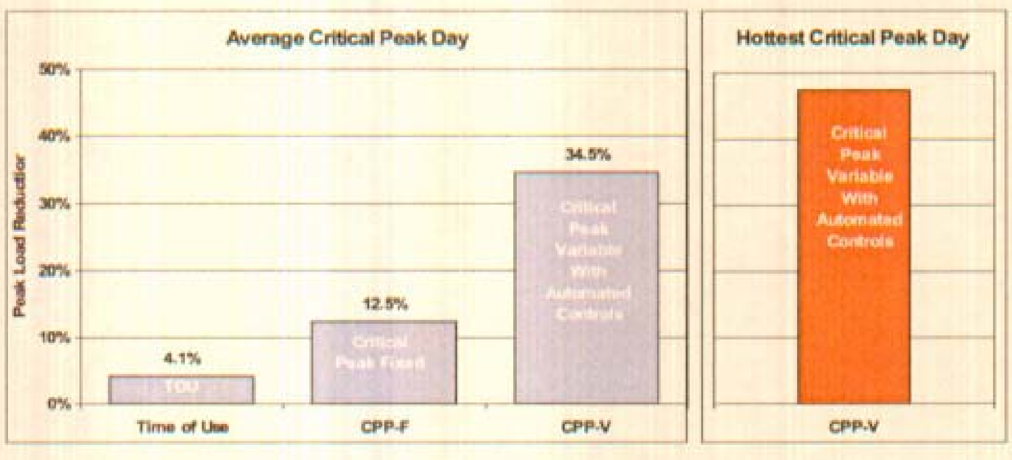
134 Dan Merilatt, GoodCents Solutions, "Demand Response Programs: New Considerations, Choices, and Opportunities," white paper (January 2004), 13-17.

Figure IV-3. California CPP: Residential CPP Response by Attribute



Source: Roger Levy, Joint California Workshop, "Advanced Metering Results and Issues" September 2004.

Figure IV-4. Average Residential Critical Peak Impacts by Rate Treatment



Source: Roger Levy, Joint California Workshop, "Advanced Metering Results and Issues" September 2004.

who had been thought to be less price-responsive than larger customers, achieved 15 percent or more reductions with high price signals on critical days; they achieved five percent reductions with more modest TOU prices. Residential customers were in fact more price responsive as a group than C&I customers, although the absolute effects on energy savings may have been higher with the latter group. The presence of enabling technologies made a dramatic difference in the response rates of customers – up to two-thirds of the reductions in some groups were attributable to smart thermostats (Figure IV-4).[135] Satisfaction among participants was high, with 87 percent of participants responding that the

[135] Faruqui & George, "Quantifying Customer Response to Dynamic Pricing," *The Electricity Journal* (May 2005), 58-59.

program was fair.[136] In fact, a number of the participants remained in the time-of-use program after the pilot was discontinued, even though they then began paying for their own enabling technologies. Post-pilot interviews revealed that, contrary to popular belief, residential customers considered the CPP tariffs easier to understand than their previous inverted tier rates.[137]

Real-Time Pricing

Real-time pricing (RTP) rates vary continuously during the day, directly reflecting the wholesale price of electricity, as opposed to rate designs such as time-of-use or CPP that are largely based on preset prices. RTP links hourly prices to hourly changes in the day-of (real-time) or day-ahead cost of power. The direct connection between wholesale prices and retail rates introduces price-responsiveness into the retail market, and serves to provide important linkages between wholesale and retail markets. There are several RTP variants in place across the United States – day-of versus day-ahead pricing, one-part versus two-part pricing, and mandatory versus voluntary. A two-part RTP rate is the more common form of price-risk sharing;[138] however, the largest customers in Delaware, Maryland, and New Jersey are starting to be placed on day-of mandatory RTP in default-service market designs.

The first RTP programs, in the mid-1980s, were introduced in California as a novel strategy for meeting demand-side management (DSM) objectives and testing critical assumptions about customer acceptance and price response. Utilities such as Niagara Mohawk Power Co. (now part of National Grid) and Georgia Power also were early adopters of real-time pricing tariffs. According to a report on RTP conducted by the Lawrence Berkeley National Laboratory,[139] more than 70 utilities in the United States have offered voluntary RTP tariffs on either a pilot or permanent basis. The motivations of these utilities to implement RTP were varied: either to promote retail market development or to lessen the need to build additional peaking generators.

Day-Ahead Real-Time Pricing (DA-RTP)

DA-RTP customers are given one-day notice of the prices for each of the next day's 24 hours. This gives customers time to plan their responses, such as shifting use (often by shifting load to off-peak hours or by using onsite generation) or to hedge day-ahead prices with other products if they cannot curtail their demand. Niagara Mohawk is an oft-cited example of an early adopter of default DA-RTP for its largest customers. More recently, its experiences with TOU and RTP served as the basis for a New York Public Service Commission (NYPSC) decision to phase-in default RTP for all large customers.

From the early 1980s to November 1998, the default tariff (SC-3A) for Niagara Mohawk's largest customers was a time-of-use rate. In November 1998, Niagara Mohawk implemented default day-ahead RTP for all customers with more than 2 MW of demand, which comprised more than 130 industrial, commercial, and institutional customers. By 2003, 50-55 percent of customers faced real-

[136] Charles River Associates, March 2005, 13.

[137] *Residential Customer Understanding of Electricity Usage and Billing*, Momentum Market Intelligence, WG3 Report, Jan. 29, 2004, viii-ix., cited by Roger Levy, "Advanced metering and dynamic rates: the Issues," September 30, 2004.

[138] Frederick Weston & Wayne Shirley, *Dynamic Pricing: Aligning Retail Prices with Wholesale Market*, June 2005, 5.

[139] Galen Barbose, Charles Goldman, & Bernie Neenan, *A Survey of Utility Experience with Real Time Pricing*, Lawrence Berkeley National Laboratory: LBNL-54238, 2004.

time pricing; in 2004, between 45 percent and 60 percent still had hourly prices.[140] While generally satisfied, customers wished there had been more hedging options available in the earlier years, either through flat-rate supply contracts or financial hedges.[141] In April 2006, NYPSC affirmed an earlier order requiring all utilities to adopt DA-RTP (mandatory hourly pricing) as the default service for their largest customers. Beginning dates vary according to tariff and schedule needs; the phase-in began in May 2006. Each utility has a different threshold to define its largest customers, ranging from 0.5 MW to 1.5 MW.[142]

The Chicago-area Energy Smart Pricing Plan is an example of a popular voluntary residential DA-RTP program. Jointly offered by Community Energy Cooperative and Commonwealth Edison, it first enrolled 750 customers in 2003; 1,100 customers were on the plan in 2006. Participants receive simple interval meters and can check day-ahead prices by calling a toll-free number or visiting a web site. Hedging and risk were built into the program: if the next day's peak price will exceed a specified threshold, customers are notified by phone, fax, or e-mail. The co-op bought a financial hedge to ensure customers never pay more than 50 cents per kilowatt-hour. The co-op's general manager credits the success of this voluntary RTP program to providing members with clear information on how rates work. Its success and popularity across a variety of residential customer types provides an important lesson about smaller customers' willingness and ability to respond to time-based demand response programs. Partially due to the success of this pilot, the Illinois General Assembly voted in April 2006 to require Illinois utilities to allow residential customers to choose RTP in 2007.[143]

Two-Part Real-Time Pricing

An important alternative to DA-RTP is two-part RTP. Two-part RTP designs include a historical baseline for customer usage, layered with hourly prices only for marginal usage above or below the baseline. Customers thus see market prices only at the margin. The baseline design serves as a hedge for customers against real-time pricing volatility, and allows them to achieve savings by curtailing their marginal use at times when prices are higher and by using more during the off-peak tariff times. Figure IV-5 illustrates how two-part RTP tariffs operate.

Georgia Power's RTP program, probably the most successful voluntary real-time pricing program in the United States, uses two-part RTP. It installed meters to record hourly usage for large customers in 1992; the program is available to customers with connected load of 900 kW or more.[144] More than 1,700 commercial and industrial retail customers have signed up for this program or another of Georgia Power's RTP tariffs. According to a Government Accountability Office (GAO) report on demand response, "Georgia Power could count on participants reducing 750 MW of power during

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[140] Charles Goldman, et al., *Does Real-time Pricing Deliver Demand Response? A Case Study of Niagara Mohawk's Large Customer RTP Tariff,* Lawrence Berkeley National Laboratory: LBNL-54974, August 2004, 3; and Goldman & Levy, "Demand Response in the US: Opportunities, Issues, and Challenges," presentation at the National Town Hall Meeting on Demand Response, Washington, D.C., June 21, 2005, 8.

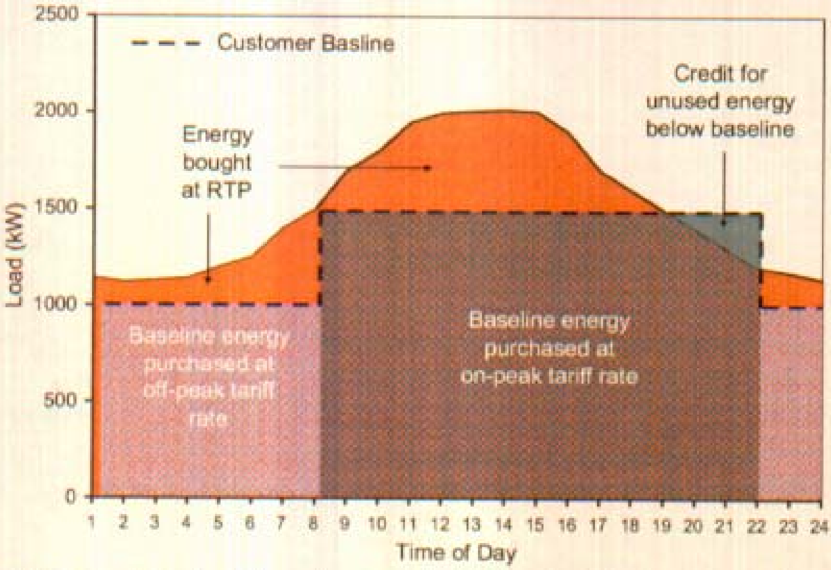
[141] Charles Goldman, et. al., LBNL-54974, 3-6.

[142] The first utilities to phase in default mandatory hourly pricing were Consolidated Edison (ConEd) and Orange and Rockland Utilities, which began in May 2006. NY PSC order on Case 03-E-0641, 16-18.

[143] *Restructuring Today,* April 10, 2006; Lynne Kiesling, www.knowledgeproblem.com, March 2, 2004, and January 14, 2005; and P.A. 094-0977, 94th Gen. Assem., Reg. Sess. (Ill. 2006), effective June 30, 2006.

[144] Southern Company, comments filed in AD05-17-000, November 18, 2005, 40.

Figure IV-5. Two-part Real-Time Pricing Tariff: How it Works



Source: Goldman, et al., *Customer Strategies for Responding to Day-Ahead Market Hourly Electricity Pricing*, August 2005: LBNL-57128.

high-priced hours," with reductions up to "17 percent on critical peak days. These savings reduce the amount of costly peak-generation equipment necessary. This allows the utility to pass along savings to customers."[145]

The secret to success for Georgia Power's program appears to be a combination of corporate commitment to the program, aggressive marketing, customers' ability to hedge through two-part RTP, and rules that allow customers to generate bill savings.[146] Also critical is Georgia Power's belief that customer education is a continuous process, even for a successful program that has been in place for years. The manager of RTP at a customer location may be different this year than last, and companies tend to pay more attention in years with higher or more volatile prices than in relatively lower-priced years.[147]

Use of two-part RTP is also not limited to regulated utilities and is a popular offering of unregulated retailers. Large customers may choose this tariff as an alternative to the default tariff. They may be willing to take on some price risk, but do not want their entire cost of energy exposed to real time prices. Constellation NewEnergy, an unregulated retailer, reports that a large portion of its customers use its two-part RTP structure (known as block index).[148]

Mandatory RTP

Several restructured states have made RTP the standard offer (default) service for the largest customer class, unless they choose an alternative supplier. Delaware, New Jersey, Pennsylvania, Maryland, Ohio, New York, and Illinois have initiatives aimed at implementing default RTP for the largest customers. Default tariffs in New York and Illinois index hourly prices to day-ahead ISO prices,

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[145] GAO, *Electricity Markets: Consumers Could Benefit from Demand Programs, But Challenges Remain* (GAO-04-844, August 2004), 22–23.

[146] Goldman et al., LBNL-54974, 2004 7, 11.

[147] Faruqui & Mauldin, "The Nine Lessons of RTP," *Public Utilities Fortnightly*, July 15, 2002, 32-39.

[148] Constellation NewEnergy, ISO-NE Demand Response Summit, April 27, 2006.

while Delaware, New Jersey, Maryland, and some Pennsylvania utilities index to real-time hourly ISO prices. Through April 2006, default RTP for large C&I customers had been implemented by 11 utilities in four states, and it was proposed or planned for 15 additional utilities.[149]

Demand Response Program Survey Results

The FERC Survey requested information on the use and prevalence of demand response programs across the United States. This section summarizes information on how many programs are offered, and how many customers are currently on these programs.[150]

Incentive-Based Demand Response

Table IV-1 lists the number of entities that offered the various types of incentive-based demand response in the United States in 2005. The FERC Survey indicates that DLC programs and interruptible/curtailable tariffs are the most popular type of incentive-based demand response. The following discussion presents detailed results on the number of incentive-based demand response programs and the number of customers enrolled in these programs by region and by type of company.

Table IV-1. Number of entities offering incentive-based demand response programs in the United States

Type of Program	Number of Entities
Direct Load Control	234
Interruptible/Curtailable	218
Emergency Demand Response Program	27
Capacity Market Program	16
Demand Bidding/Buyback	18
Ancillary Services	1

Source: FERC Survey

Direct Load Control (DLC)

DLC programs are widely available nationally, with 234 entities offering at least one DLC program. DLC programs were targeted primarily to residential customers; however, 33 percent of these entities also offered at least one DLC program for commercial customers. DLC programs are particularly popular among utilities in the MRO region (39 percent of the total number of entities offering DLC programs) followed by SERC and RFC, 17 percent each (see Figure IV-6). Several states in the MRO region (Minnesota and Iowa) have historically either required or encouraged utilities to spend a portion of their revenue on demand-side management programs, including direct load control, and utilities in the upper Midwest have historically had favorable rules that allowed load-management resources to be counted towards meeting reserve requirements. Cooperative utilities and political subdivisions account for the largest (51 percent) portion of entities offering DLC programs followed by municipal entities and IOUs.

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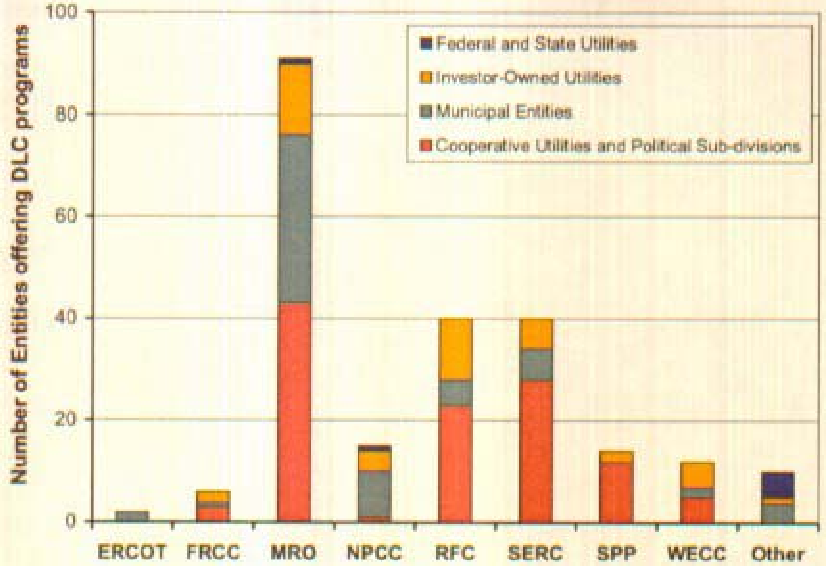
[149] Neenan, "Default RTP Service Links Wholesale and Retail Markets," UtiliPoint *IssueAlert*, October 28, 2005, and Goldman, April 27, 2006, 3-6.

[150] Appendix H lists the entities who offer demand response programs.

Figure IV-6. Direct Load Control programs offered by region and entity type

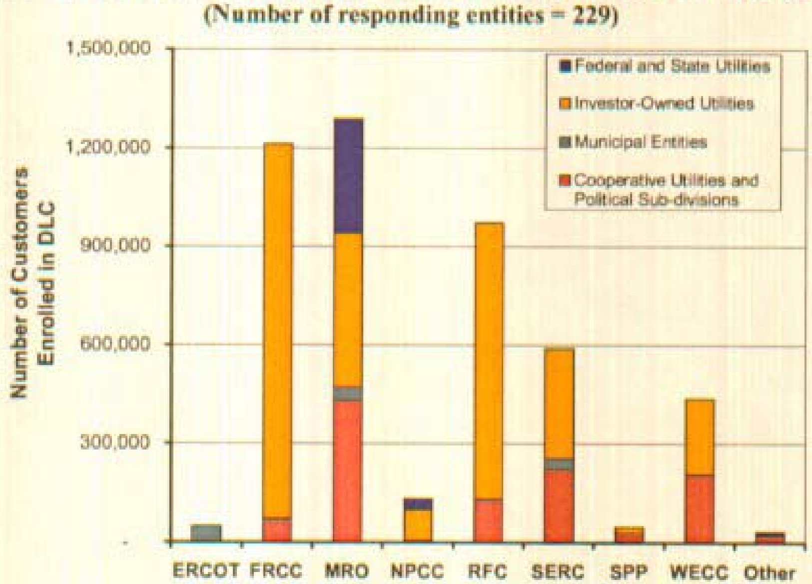


Source: FERC Survey

Figure IV-7 shows the number of customers enrolled in each NERC region as reported by entities that responded to the FERC survey. Approximately 4.8 million customers were enrolled in DLC programs across the nation, with significant participation by customers served by utilities in the FRCC, MRO, RFC, SERC, and WECC regions. The top ten utilities that offered DLC programs are listed in Table IV-2, and these utilities account for 60 percent of all the customers enrolled in DLC programs.

Figure IV-7. Number of customers enrolled in DLC programs

(Number of responding entities = 229)



Source: FERC Survey

Table IV-2. Top 10 entities by customers enrolled in DLC programs

Name of Utility	Number of Customers Enrolled in DLC
Florida Power and Light	740,570
Progress Energy Florida	401,720
Detroit Edison	347,750
Baltimore Gas and Electric	338,568
Northern States Power	283,317
Duke Power	207,794
Southern California Edison	166,318
Public Service Electric & Gas	119,310
Dairyland Power Cooperative	112,656
Sacramento Municipal Utility District	104,079

Source: FERC Survey

Interruptible/Curtailable Rates

Some 218 entities reported that they offer interruptible/curtailable tariffs, primarily to large industrial and commercial customers. This type of demand response program is particularly popular among co-ops; about 95 cooperatives and political subdivisions[151] have customers enrolled on interruptible/curtailable tariffs. Figure IV-8 shows the distribution of these programs by type of utility and region. The greatest number of entities that offer interruptible/curtailable tariffs are located in the MRO, RFC, and SERC regions.

Other Incentive-Based Demand Response

To varying degrees, utilities also reported offering other types of demand response programs, including capacity, demand bidding/buyback and emergency programs (see Figure IV-9). Emergency demand response programs were particularly popular in NPCC, where many utilities, retailers, and curtailment-service providers participate in ISO/RTO emergency programs.

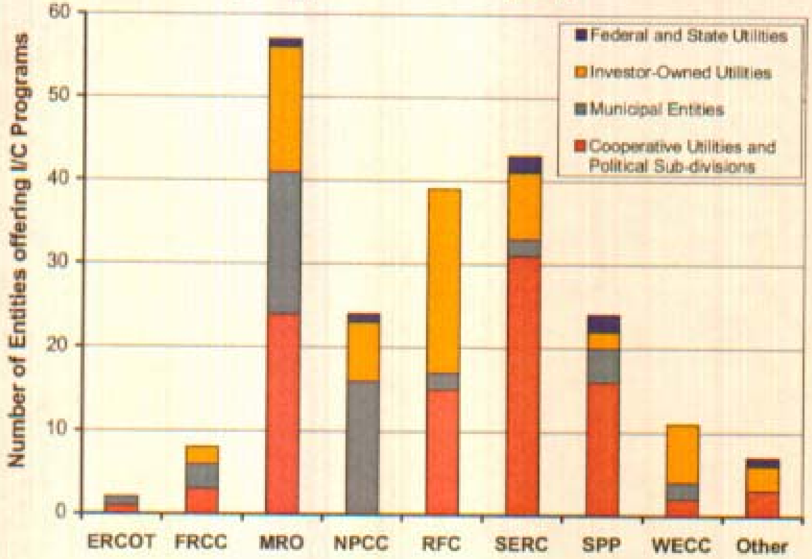
Time-Based Rates

The FERC Survey also requested information on time-based rate programs. Table IV-3 summarizes the number of entities[152] that offered TOU, CPP, or RTP programs in the United States in 2005. As can be seen, only a small number of the 2,620 entities that responded to the survey offered time-based rates, and TOU rates were the most popular rate offering. Comparison of tables IV-1 and IV-3 indicates that TOU rates are the third-most popular rate offering, after DLC programs and interruptible/curtailable tariffs. The following discussion presents more detailed results on the number of time-based programs and the number of customers enrolled in these programs by region and by type of company.

[151] This represents 15.5 percent of the total number of cooperatives and political subdivisions who responded to the survey.

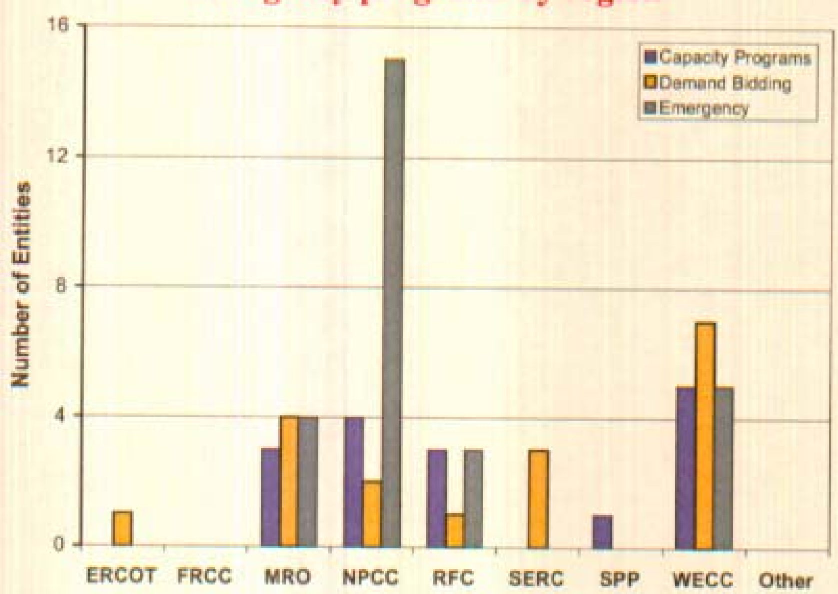
[152] The term "entity" is used herein to refer to the companies that asked to respond to the survey. These entities include investor-owned utilities, municipal utilities, rural electric cooperatives, ISOs/RTOs, and power marketers.

Figure IV-8. Number of entities offering interruptible / curtailable tariffs by region and entity type



Source: FERC Survey

Figure IV-9. Number of entities offering capacity, demand bidding, and emergency programs by region



Source: FERC Survey

Table IV-3: Number of entities offering time-based rates in the United States

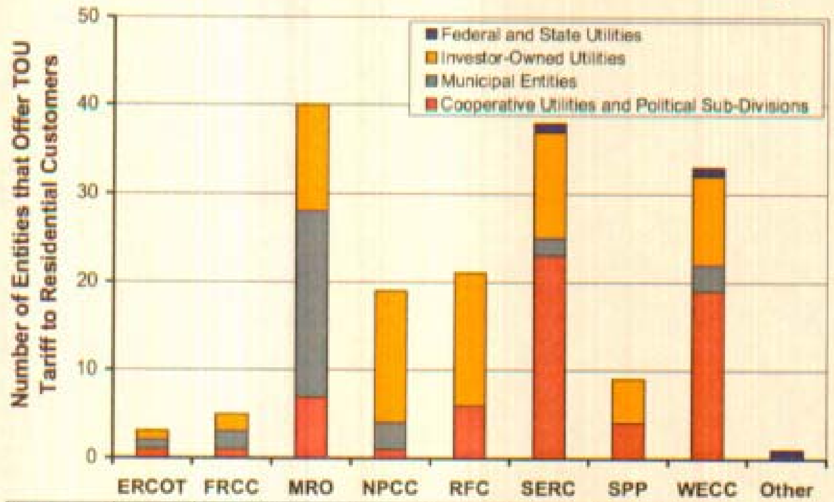
Type of Program	Number of Entities
Time-of-Use Rates	187
Real-time Pricing	47
Critical Peak Pricing	25

Source: FERC Survey

Time-of-Use Rates

Figure IV-10 shows the number of entities that offer time-of-use (TOU) tariffs to their residential customers by NERC region; 148 utilities reported that they offer a time-of-use tariff to their residential customers, while the remaining 39 offer TOU rates to nonresidential customers. Publicly-owned utilities are large users of these programs. Cooperative utilities, political subdivisions, and municipal entities together account for 55 percent of entities offering TOU rates. In order to get a sense of regional differences in TOU tariffs offered to residential customers, the percentage of residential sales of those entities in each region that offer residential TOU tariffs is reported in Figure IV-10. For example, even though only five entities report offering a residential TOU tariff, they account for 78 percent of residential sales in the FRCC region. Residential TOU tariffs appear to be most widely available in the FRCC and SERC regions (78 percent and 72 percent, respectively, of residential sales), followed by WECC (57 percent).

Figure IV-10. TOU tariffs offered to residential customers by entity type[153]



% of Residential Sales	44	78	41	47	39	72	51	57	15

Source: FERC Survey

Electric distribution companies typically offer a TOU tariff as an optional tariff service for residential customers; thus, it is important to track actual customer enrollment on TOU tariffs in order to assess

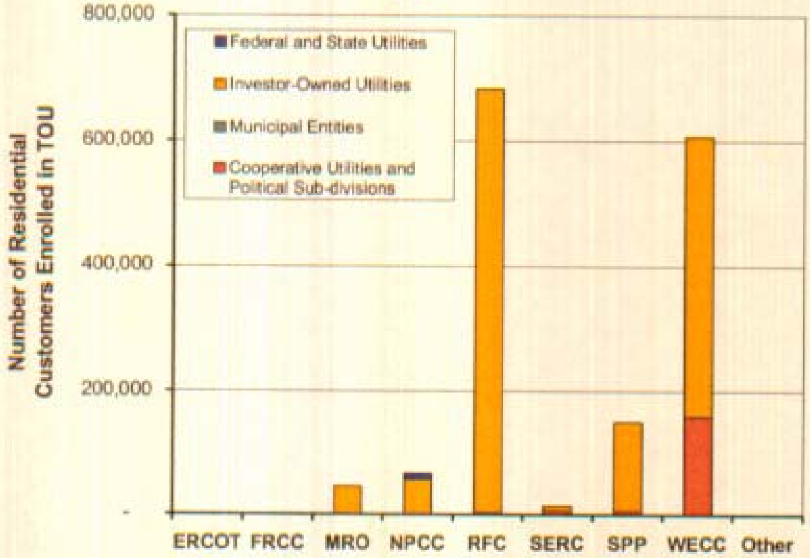
153 Regional definitions used in this figure and subsequent figures are based on NERC regions. Chapter I contains a map and listing of the regions.

customer acceptance and market penetration. About 1.57 million out of 120 million residential customers were signed up for a TOU tariff in the United States, which represents a market penetration of 1.4 percent nationally. Figure IV-11 displays the regional distribution of customer participation in these rates. As can be seen, most of the customers enrolled in TOU rate programs are concentrated in the RFC and WECC regions, and that the vast majority of residential customers on TOU rates are served by investor-owned utilities. Indeed, 10 entities, mainly investor-owned utilities located primarily in the RFC and WECC regions, account for about 85 percent of the residential customers enrolled in TOU tariffs. These 10 entities are listed in Table IV-4.

Critical Peak Pricing

About 25 entities reported offering at least one CPP tariff with an enrollment of about 11,000 customers nationally. Many of the CPP tariffs appeared to be pilot programs (e.g., utilities that participated in the California Statewide Pricing Pilot). About 70 percent of the customers enrolled in CPP rates were served by an IOU, even though 72 percent of the entities offering CPP rates are co-ops and munis.[154] The top five entities by number of customers enrolled in CPP programs are shown in Table IV-5. These five entities account for 96 percent of the total number of customers reported to be on CPP rates.

Figure IV-11. Residential customers on TOU tariffs by region and entity type



Source: FERC Survey

[154] We have concerns regarding the classification by several respondents of their tariff as CPP. For example, one rural cooperative (Cass County Electric Cooperative) with a large number of residential customers enrolled described its CPP tariff as a demand-limiting program involving electric heat backed up by onsite generation for residential customers. Similarly, 12 small cooperatives and municipal utilities reported offering CPP rates for large commercial and industrial customers.

Table IV-4. Top 10 entities by residential customers enrolled in TOU programs

Name of Utility	Number of Residential Customers enrolled in TOU
Public Service Co. of Oklahoma	429,737
Arizona Public Service Company	332,823
Salt River Project	151,000
Southwestern Electric Power Co.	135,816
Pacific Gas and Electric Company	82,055
Baltimore Gas and Electric Company	81,072
Ohio Power Company	38,482
Metropolitan Edison Co	35,640
United Illuminating Company	35,041
Jersey Central Power & Light Co	26,186

Source: FERC Survey

Table IV-5. Top five entities by number of customers enrolled in CPP programs

Name of Utility	Number of Customers enrolled in CPP
Gulf Power Company	6,878
Cass County Electric Cooperative	2,892
Southern California Edison Company	462
San Diego Gas and Electric	230
Pacific Gas and Electric Company	121

Source: FERC Survey

Real-Time Pricing

Forty-seven entities reported offering at least one RTP tariff, with 4,310 customers enrolled nationally (see IV-12). These survey results are consistent with several other recent studies that involved more in-depth analysis of real-time pricing offered as either an optional or default service tariff service by utilities for large industrial and commercial customers.[155] About half of all the entities offering RTP tariffs are located either in RFC or NPCC; several states in these regions (New Jersey, Maryland, New York, and Pennsylvania) have mandated RTP as the default tariff for large customers.

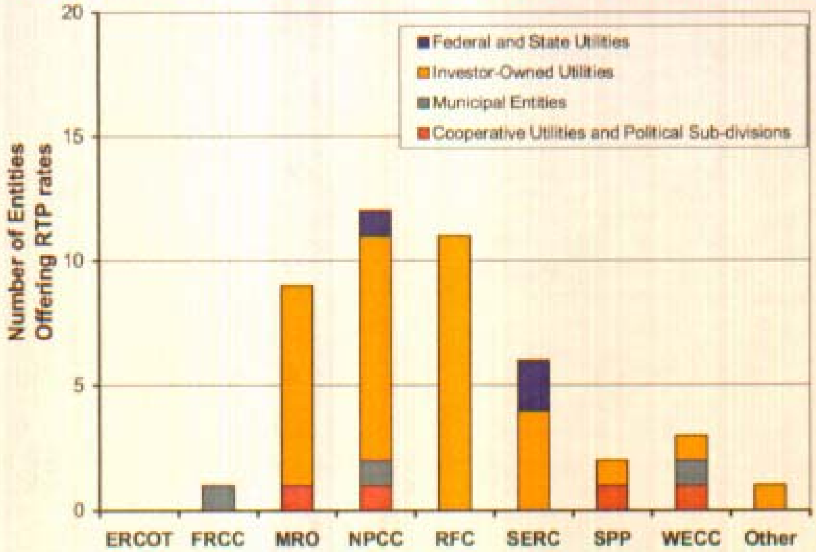
Motivations for the Use of Demand Response and Time-Based Rates

The use and development of demand response programs and time-based rates have been and will be motivated by several factors:

- **EPAct 2005 demand response provisions.** EPAct section 1252(b) directs the states and utilities to consider the costs and benefits of demand response programs and enabling

[155] Galen Barbose & Bernie Neenan, 2004; and Galen Barbose, et al., *Real Time Pricing as a Default or Optional Service for C&I Customers: A Comparative Analysis of Eight Case Studies*, report to the California Energy Commission, Lawrence Berkeley National Laboratory: LBNL-57661, 2005.

Figure IV-12. RTP tariffs offered by region and entity type



Source: FERC Survey

technologies such as advanced meters. While states are not required to implement demand response or advanced metering, this congressional directive should promote reexamination of demand response and advanced metering, and may lead to additional state policies. See Appendix A for the full text of the Smart Metering Section of EPAct 2005.

- **Reliability.** Incentive-based demand response programs enhance system reliability by providing grid operators another tool to use during system emergencies and reserve shortages. Incentive-based programs can provide reliability support for grid operators, whether they are ISOs or vertically-owned utilities.
- **Resource need.** In many instances, incentive-based demand response programs have been implemented to economically meet growing demand or to defer construction or upgrades of generation or distribution. The emergency request for proposals conducted for southwest Connecticut by the ISO-NE in 2004 is an example of such a program.
- **Quick rollout.** In relative terms, incentive-based demand response can be implemented more rapidly than building new generation or transmission. This flexibility allows resource-constrained regions to respond rapidly to meet critical needs (e.g., ISO-NE implemented the winter supplemental program in December 2005 to address concerns about the availability of natural gas supplies during the winter).
- **Regulatory.** Regulatory directives and initiatives have spurred additional growth of demand response. The rapid growth of demand-side management and load management in the 1980s and 1990s was driven by state and federal encouragement and the implementation of integrated resource planning. Recent policies in states like California and New York are leading to renewed growth in demand response as a resource. Federal encouragement of demand response by Congress, DOE, the GAO, and the Commission has provided additional focus on the issue.
- **Rising energy costs.** The rising cost of energy in the intervening years between restructuring and the present means that many states' retail customers now face dramatically higher bills within the next year. The time-lag in customers seeing the real costs of supplying them with power was exacerbated by the dramatic rise in gas prices after hurricanes Katrina and Rita. Armed with knowledge about their power supply, and provided with a portfolio of pricing

plans along with education, training, and enabling technologies, customers can be given the ability and opportunity to change their habits and lower their energy bills.

- **Advances in enabling technologies.** The price for technologies to implement dynamic pricing and automated customer responses has been falling, just as the capabilities of these technologies have been rising. The increasingly advanced functionality of enabling technologies has the potential to provide wider power system and societal benefits beyond those solely within the scope of demand response programs. Automated customer responses is now possible in more situations, allowing both greater customer receptivity and higher utility confidence that customers can and will respond to price-based demand response. These advances have contributed to the rekindling of interest in demand-side policies.
- **Customer interest.** Many customers, particularly large industrial customers, are interested in incentive-based demand response to reduce utility bills and to help maintain system reliability, without exposing them to price risks. Industrial customers have participated in interruptible/ curtailable tariffs for years and have been some of the most active participants in the various utility and ISO incentive-based programs.
- **Lowered utility costs.** LSEs and vertically-integrated utilities are interested in incentive-based demand response when it is cost-effective and can lower their resource acquisition or procurement costs.
- **Risk management.** Customers and LSEs can use demand response to hedge their exposure to high prices and price volatility by operating these resources and programs during these periods.

UtiliPoint International conducted a survey to determine what electric utilities and regulators considered the primary drivers of demand response programs in 2005.[156] Figure IV-13 displays these results. According to the utilities surveyed, regulatory directives and requirements were the primary drivers for their development of programs. UtiliPoint also found that the relative weight given to each driver differs by type of utility. IOUs focus on reliability and reducing utility costs, and have only a modest interest in lowering participant's energy costs. Municipal utilities have a higher interest in lowering participant's energy bills. Co-operative utilities were highly motivated to lower bills for participants and to lower utility costs, and not by increasing reliability.

The UtiliPoint survey also uncovered a difference in perceptions about regulators as drivers of demand response programs. While only 20 percent of regulators reported that regulation was a primary driver for demand response, 68 percent of IOUs that responded cited "regulatory" as the primary driver for developing or expanding demand response.[157]

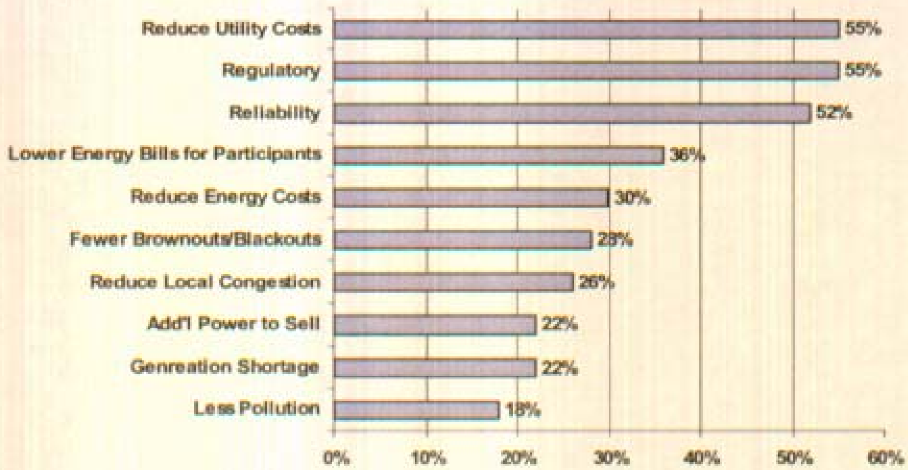
Current issues/challenges

Even with the drivers listed above to motivate increased utilization of incentive-based demand response, the previous discussion suggests that use of incentive-based demand response is not widespread. There are multiple reasons for the lack of greater usage, including:

- **Need for investment in meters and other enabling technology.** Without the ability to measure consumption by time of day (preferably hourly – See Chapter III), it will be difficult to offer and conduct many incentive-based demand response programs, and to measure any reductions. Customers and LSEs also need new automation or control equipment or retrofits

[156] UtiliPoint, *Outlook and Evaluation of Demand Response*, June 10, 2005.
[157] UtiliPoint, *Outlook*, 18, 22-23.

Figure IV-13. Drivers for developing or expanding demand response programs



Source: UtiliPoint, *Outlook*, 18.

to existing equipment and appliances that will allow them to easily adjust consumption. Recent advances in controls, electronics, and communications have dramatically decreased the cost and increased the functionality of these technologies. Greater saturation of advanced meters will support additional demand response, where economic and effective.

- **Lack of incentive for utilities to promote demand response.** The lack of utility incentives has been a long-standing problem with demand resources such as incentive-based demand response and energy efficiency. Since most utility rates are based on a combination of kWh and peak kW demand charges, demand reductions associated with incentive-based demand response negatively impact utility revenues. Even though the reductions may be short-lived, the potential for a reduction in revenues presents a disincentive. The disincentive is greater for utilities in restructured states with active ISO demand response programs. Consequently, as representatives for industrial customers have asserted, electric utilities have been either reluctant to promote these programs or request some form of lost-revenue recovery. This issue has proven to be difficult to address and various solutions have been attempted over the past several decades, with vary levels of success.[158]
- **Negative impact of industry restructuring on delivery of demand response by utilities.** A related challenge is the impact of restructuring on utility incentives. Restructuring has changed the ability of utilities to operate programs and to gain benefits from their operation in two manners. First, the benefits associated with operating incentive-based demand response programs are less for utilities that have divested their generation assets. A primary source of benefits from demand response is through avoiding costs. Consequently, a utility that has divested generation is only able to avoid distribution and transmission costs, not the typically larger benefit from avoiding generation costs or procuring power during peak periods. The benefits associated with operating demand response as a resource are driven more by impacts on local distribution operation and reliability, which is generally a fraction of avoided generation costs. In these states, the utilities cannot internalize the full benefits associated

[158] This issue is the subject of a MADRI-led effort to develop incentives for distributed resources. A good summary of the issue is contained in a white paper prepared for EEI by NERA Economic Consulting, *Distributed Resources: Incentives*, 2006.

with these programs, and additional benefits accrue either to the customer or potentially to a third-party vendor. Second, as was discussed earlier, in some states, such as Texas, distribution companies are not allowed to offer demand response as a service. While these factors reflect key underlying cost and benefit issues, they may represent transitional problems. Ultimately, the proper allocation of costs and benefits should result in competition and innovation among retailers that may include demand response programs and time-based rates.

- **Subsidization.** The form of payment for reductions in incentive-based demand response programs is viewed as a subsidy by many parties, including economists such as Larry Ruff and by industry associations such as EEI. The basic argument raised by these parties is that the correct form of inducing demand response is through pricing and that "any payment to a customer for demand reduction should never exceed the wholesale price minus the retail price that the customers would have otherwise paid to own the power. Any payment above this level would be a subsidy, that is, a nonmarket payment that has to be recovered through a tax or charge on all customers."[159]
- **Measurement of demand reductions.** The measurement of demand reductions associated with incentive-based demand response programs has proven to be a difficult and controversial problem, particularly for demand-bidding, emergency demand response, and capacity programs.[160] The key measurement issue is how to calculate the level of consumption that would have occurred if the participant had not curtailed consumption – i.e., the customer baseline level. Once the customer baseline is determined, the level of reduction is calculated by subtracting the actual demand from the estimated baseline normal demand. However, there are a variety of means to estimate the baseline that are used by utilities and ISOs,[161] typically involving an average of usage over several recent days. A key problem with most estimation methods is the potential for gaming – participants may bid into the market or state that they will curtail when they would already be shut down for the day. The ultimate solution for this measurement problem would be to directly measure usage in real-time or to move toward specific entitlements or to set reduction levels, instead of after-the-fact measurement and estimation.
- **Boom-bust nature of demand response.** A fundamental challenge with incentive-based demand response is the boom-bust nature of electric markets. The use of incentive-based demand response is largely concentrated during periods of tight supplies or reserve shortages. When generation is plentiful, the need for these programs is less, with consequent reduction in payments – either through reduced capacity payments or through infrequent usage. This overcapacity situation exists today in many parts of the country. As a result, customer interest may atrophy and demand response programs are likely to be mothballed or terminated in these regions. However, when supply and demand become tighter, the stock of available demand response resources may not be adequate.
- **Valuation and cost-effectiveness.** One of the key challenges for regulatory approval and review of demand response is the lack of an adopted method or consensus procedure for the evaluation and definition of cost-effectiveness. The cost-effectiveness tests that were developed to assess demand-side management in the 1980s and 1990s[162] focus on avoided

[159] Richard Tempchin (EEI), FERC Technical Conference, transcript, 26-27.

[160] Measurement issues are less for interruptible/curtailable tariffs because the tariffs generally specify the level of demand reduction or specify the level to which the facility demand must not exceed during an event.

[161] A review of baseline methods can be found in Xenergy, "Protocol Development for Demand Response Calculation," prepared for the California Energy Commission, Contract 400-28-002, August 2002.

[162] The most recent version of tests that were developed in the 1980s is *California Standard Practice Manual: Economic Analysis of Demand-Side Programs And Projects*, State of California, Governor's Office of Planning and

generation costs and are inadequate to capture the additional market and reliability benefits that demand response can bring to retail and wholesale markets. Several ISO/RTOs have attempted to evaluate the cost-effectiveness of demand response in their yearly evaluations, but there is no consistency among them. The Demand Response Resource Center is conducting a comprehensive evaluation and results from this research should be available in late 2006.[163]

- **Delayed payments to demand response providers.** One problem in ISO/RTO markets is the delayed processing and disbursement of payments for demand reductions. ISOs typically wait 60 days or more to finalize settlements. Customers and curtailment service providers object that this delay creates cash flow problems.
- **Customer inertia/desire for simplicity.** Most customers (particularly residential ones) will be resistant to programs if they require effort, such as when the basic design of the program is not simple. Focusing these educational efforts first on the largest customers will allow these customers to adequately assess the rewards and costs associated with participation in demand response programs. Experience in other states such as New York and California (which use some system benefit funds for customer education) has shown that targeted customer education and training increases participation and response rates.
- **Focus on single time-based rate program structures.** Because of their different needs and knowledge levels of *how* to respond, as well as their varying *abilities* to respond, customers need targeted and ongoing training and education to help them understand how to increase their response rates to demand response programs. Customer price-responsiveness varies significantly by market segment among commercial and industrial users. The differences in customers' ability to respond at peak times and the degree to which they are able or willing to respond implies that policy-makers need to create a portfolio of dynamic pricing products from which customers can choose and offer different incentives to different types of customers.
- **Need for simple and fair time-based pricing.** The principles of simplicity and fairness are keys to the success of real-time programs. UtiliPoint found that "as long as customers are convinced that utility-posted prices are fair and reflect actual system circumstances, and are based on competitive markets, they will accept them as the basis for time-varying rates."[164] This seems to be a common refrain from satisfied customers. Customers notified by various means about daily prices and price spikes achieve better responses and are more satisfied with the programs. Both in re-regulated electricity markets and traditional utility territories, multiple notification channels (such as toll-free numbers, pagers, cell phones, and the Internet) increase success rates of RTP programs. Customers' use of programmable communicating thermostats is important for easier response to these rates. [165]
- **Mandatory vs. voluntary participation in price-based programs.** Experience has shown that when participation in price-based programs is voluntary, the level of customer participation and aggregate load reductions have been modest.[166] Voluntary TOU or RTP programs with opt-in can create a self-selection bias problem from the perspective of some LSEs: customers who know they already use less at peak enroll, while those who use more at peak but who may not want to risk shifting or paying higher peak prices do not. Thus, little or

Research, July 2002, http://drrc.lbl.gov/pubs/CA-SPManual-7-02.pdf.

[163] *See* http://drrc.lbl.gov/drrc-ron-7-21-05.html

[164] Bernie Neenan, "Taxonomy of Time-Varying Pricing Designs," UtiliPoint *IssueAlert*, March 29, 2006), 4.

[165] Patti Harper-Slaboszewicz, "Analysis of Time-Based Retail Pricing for Smaller Customers," presentation at "American Utility Week" Conference, Atlanta, GA, April 25, 2006.

[166] Charles Goldman, "Does Real-Time Pricing Deliver Demand Response?," New England Restructuring Roundtable 2005, 7, 11.

no load is shifted from peak, defeating the purpose of the program. In addition, since most voluntary time-based rate programs are designed to be revenue neutral (i.e., on- and off-peak rates designed to collect the same revenue as the non-TOU default tariff from a hypothetical customer), customers with below average on-to-off-peak consumption ratios are free riders who can reduce their bills by taking the TOU rate option without changing their consumption behavior. The revenue shortfall can have undesirable consequences and possibly create revenue losses for LSEs.[167] Customers tend to stay in voluntary programs with clear opt-out options. Customer responses to well-designed, simple programs they perceive as fair are high: they want to stay in the programs, and felt they achieved savings and control. Experience in California suggests that customers especially like dynamic pricing programs that pair automated customer technologies. Customers with access to smarter appliances and systems thought they became more aware of their energy use and costs as well as their routines at home and at work.[168]

- **Varying willingness among utilities to work with third parties.** A 2005 demand response survey found dramatic differences among traditional IOUs, co-ops, and municipal electric utilities (munis) in their preferences in partnering with third parties.[169] Co-ops, which believe they already have a higher interest in using demand response to lower their customers' bills, have a high negative response to using third parties. It is likely that the best fit for third-party involvement may be in organized markets where third parties can aggregate load across IOUs or where aggregators can offer one program design for large companies with multiple locations. Third parties may offer models to bridge that gap for customers served by traditional utilities.

Demand Response Activities at the State, Regional and Federal Level

While the trend in utility investment and activity in demand response over the last decade has been downward, there has been a recent upsurge in interest and activity in demand response nationally and, in particular, regional markets.[170] A recent study stated, "the resurgence of demand response programs stems directly from their rediscovered value as a dual hedge against both reliability risks such as generation shortfalls and transmission congestion, as well as financial risks such as wholesale price spikes."[171] This upsurge has been the result of several factors. First, tight supply conditions in densely populated regions such as California, New York, and the Chicago area created a need for resources that could be quickly deployed. Second, the development of organized markets within ISOs or RTOs created an interest and need for demand response resources. These ISOs/RTOs created programs to coordinate and encourage demand response programs offered by unregulated providers and utilities. These programs have been found to be effective, and have had a far larger impact on market prices

[167] Chi-Keung Woo et al., "Pareto-superior time-of-use rate option for industrial firms," *Economics Letters* (1995), 267-272.

[168] A post-pilot analysis of California's statewide pricing program described 87 percent of pilot customers who perceived program as fair; many stayed on the rate after the pilot was over, although they then paid for the enabling equipment they were given during the pilot. George & Faruqui, CRA (March 2005), 13.

[169] UtiliPoint, *Outlook*, 26-37.

[170] Note that the EIA and NERC data sources may not be capturing this upswing because they do not collect information from unregulated demand-response providers or ISOs/RTOs. The discussion in Chapter V indicates that when ISO programs are included, total resource contribution from demand response stabilized beginning in 2000.

[171] Research Reports International, *Demand Response Programs*, 2005, 6.

than the costs avoided or incurred by the individual participating customer and the ISOs/RTOs.[172] Third, state legislation or regulatory initiatives in many states have provided additional investment or requirements for additional demand response.

Activities at the state and regional level are extremely important to increasing the level of price-responsiveness in markets and promoting demand response. A recent CERA study found a "direct correlation ... between the levels of regulatory support for implementing DSM programs and the level of energy savings achieved by the state's utilities."[173] State activities can include direct investigations into demand-side issues, including demand response, time-of-use rates, and the feasibility of advanced metering. Important activities can also include state regulatory re-examination of utilities' return structure for investment in demand response and advanced meters.

State policies already distinguish a full range of demand-side tools to meet their energy needs beyond demand response defined only as load-curtailment, including energy efficiency, distributed generation, industrial response, and price-based demand response programs.[174] Several states have initiated proceedings in response to EPAct 2005 Section 1252(b) on time-based metering and communications.

Section 1252 (g) (4)(A)-(B) directed states to commence consideration by August 2006, and to complete consideration by a year later.[175] Many states have opened these proceedings; others, by virtue of related proceedings opened within the three years prior to the passage of EPAct 2005, can count those as qualifying.

Other examples of state policies and regional cooperation include:

- The CPUC and the California Energy Commission are promoting demand response and advanced metering through its Statewide Pricing Pilot, Advanced Metering Initiative, and Energy Action Plan II. The Action Plan creates a "loading order" to meet capacity, which places demand response and energy efficiency goals before generation additions; those begin with renewable energy.[176] The CPUC has required investor-owned utilities to meet five percent of their load requirements with demand response.[177] While the CPUC rejected critical peak pricing as the default rate for commercial and industrial customers, it will re-examine it in utility rate cases to focus more on residential customers.[178]
- The Connecticut legislature passed "An Act Concerning Energy Independence" in July 2005, followed by recommendations from the Connecticut Energy Advisory Board. The Connecticut Energy Advisory Board advocated for the state to set goals to reduce its peak demand 10 percent by 2010; promote the increased development of demand response; develop and offer time-of-use rates, interruptible/curtailable tariffs, and advanced meters (beginning

[172] For example, ISO-NE, *Independent Assessment of Demand Response Programs of ISO New England Inc.*, Docket No. ER02-2330-040.

[173] Hope Robertson, Cambridge Energy Research Associates (CERA); *Focusing on the Demand Side of the Power Equation: Implications and Opportunities* (Private Report), Cambridge, MA: CERA, May 2006, 12.

[174] For example Connecticut is offering financial incentives for industrials to use onsite non-grid connected distributed generation, including CHP, under its Energy Independence Bill, July 21, 2005.

[175] EPAct 2005 section 1252(g)(4)(A)-(B).

[176] Sandra Fromm, et al., *Implementing California's Loading Order For Electricity Resources*. California Energy Commission Staff Report, July 2005.

[177] CPUC Decision (D.) 03-06-032, June 2003.

[178] Platts *Megawatt Daily*, May 30, 2006, 8-9 and SNL Energy *Power Daily*, May 26, 2006, 4.

with customers whose demand is more than 350 kW); and offer seasonal rates and aggressive education on energy efficiency, costs, and demand management to all customers.[179]

- New York, Texas, and California are examples of states that worked deliberately to coordinate policy across multiple agencies and stakeholders. In New York, this entails coordination between New York State Energy Research and Development Authority (NYSERDA), the NYISO, the NYPSC, and New York Department of Environmental Resources. While for those states, the ISO, the state, and the retail regulatory agency are nearly geographically the same, lessons about policy coordination across stakeholder agencies and jurisdictions are important for other areas where jurisdictional overlap or confusion impedes policy changes.
- Regional coalitions representing stakeholders from utilities, state public utility commissions, federal regulatory agencies, technology developers, metering companies, and third-party providers have been working together in the Mid-Atlantic (MADRI) and New England (NEDRI, Massachusetts Energy Technology Collaborative) states to find ways to collaborate on promoting demand response and advanced metering.
- State funding of programs, enabling technologies, and education, can advance these initiatives: "two state agencies – NYSERDA in New York and the CEC in California – have been conspicuous leaders in the demonstration of demand response (demand response) programs utilizing enabling technologies."[180]
- State policies on standard offer service or "provider of last resort" (POLR) have increased the number of customers exposed to RTP and time-based rates and pricing. The default tariff rate for the largest customers in New Jersey and Maryland is currently a direct pass-through of the PJM real-time price. Similarly, large customers in National Grid USA's New York territory have been exposed to real-time prices since 1998.[181] The NYPSC recently directed utilities to file draft tariffs that would make real-time hourly pricing mandatory for their largest customer classes already subject to mandatory time-of-use rates.[182] The law further requires that voluntary time-of-use rates be available for New York residential customers.[183]

Another key development is that third-party providers have emerged whose only business is to maximize demand response and use related technologies. They aggregate and deliver load-response to markets, and have skills needed to monitor energy markets and prices. These third parties provide a valuable service to customers, because many large consumers have limited expertise or experience with aggregating or managing demand response, especially in markets. An Lawrence Berkeley National Laboratory survey showed that 70 percent of business managers in Niagara Mohawk's RTP program rarely or never monitored next-day hourly prices; only 17 percent consulted prices routinely; 13 percent only checked day-ahead hourly prices when other signals (such as NYISO events or very hot weather) suggested they would be high.[184] Most businesses monitor their *own* business, not the energy business.

[179] Connecticut, PA 05-1: An Act Concerning Energy Independence.

[180] Charles Goldman, Michael Kintner-Meyer, and Grayson Heffner, *Do "Enabling Technologies" Affect Customer Performance in Price-Responsive Load Programs?* Lawrence Berkeley National Laboratory: LBNL-50328, August 2002, 3.

[181] Galen Barbose et al., LBNL-57661.

[182] Case 03-E-0641, "Proceeding on motion of the Commission regarding expedited implementation of mandatory hourly pricing for commodity service, Order instituting further proceedings and requiring the filing of draft Tariffs," September 23, 2005.

[183] N.Y. Pub. Serv. Law § 66(27).

[184] Charles Goldman, October 28, 2005.

Examples of third-party providers and the services and innovative practices that they conduct include:

- Comverge is a vendor of smart, or programmable, communicating thermostats. These are replacing DLC equipment from utility legacy programs, or being installed fresh. These thermostats can be used to support time-based rate programs such as critical peak pricing.
- EnerNOC is a curtailment-service provider (CSP) or load aggregator for emergency demand response. EnerNOC has aggregated load reductions in the commercial buildings sector, and has sold these reductions into ISO/RTO emergency demand response and capacity programs. It has systems installed in New England, California, and New York. Participating businesses, office buildings, and other medium-sized participants benefit through lower bills or rebate checks.[185]
- Consumer PowerLine (CPLN) is another aggregator that has been innovative in working with urban multiple-family buildings as well as with commercial and industrial customers. It aggregates pools of electricity from clients, creating a virtual power plant that local utilities or ISOs can call on with a half-hour's notice.

The federal government also has been supportive of demand response. DOE has funded multiple projects, which included analyses of the value of demand response, research and development on technologies such as automated controls,[186] and support for regional examinations of demand response and distributed resources (such as MADRI). The Federal Energy Management Program has incorporated advanced metering and demand response directly into policies and procedures that it expects federal facility managers to consider.[187] The GAO examined demand response in two reports in 2004 and 2005.

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[185] CNet news.com., April 29, 2005.

[186] The Pacific Northwest National Laboratory began a pilot called "Gridwise" in January 2006, involving about 300 volunteers and 200 homes. Gridwise supports a regional initiative to test and speed adoption of new smart grid technologies that can make the power grid more resilient and efficient. The homes in the pilot receive real-time price information through a broadband Internet connection and automated equipment that adjusts consumers' energy use based on price. Some customers also have computer chips embedded in their dryers and water heaters that can sense when the power transmission system is under stress and automatically turn off certain functions briefly until the grid can be stabilized by power operators.

[187] *EnergyBizInsider*, "Letters from Readers", Apr. 5, 2006, letter from Kevin Myles, GSA.

Chapter V. Demand Response as a Resource[188]

This chapter addresses the third area, in EPAct section 1252(e)(3), that Congress directed the Commission to consider:

> *(C) the annual resource contribution of demand resources;*

This chapter develops an estimate of the annual resource contribution of demand resources in the United States of about 37,500 MW, and discusses the potential for demand response as a resource for utilities and load serving entities.[189] Information on demand response programs and time-based rates collected in the FERC Demand Response and Advanced Metering (FERC Survey) forms the basis for this estimate.

This chapter is organized into three sections:

- Description of the resource contribution information on demand response programs collected in the FERC Survey
- Demand response resource contribution estimates from the FERC Survey
- Commission staff estimates of resource contribution from existing programs

FERC Survey: Demand Response Program Information

The FERC Survey collected comprehensive information from entities on their demand response programs and time-based rates and tariffs. The survey allowed respondents to provide information on up to eight demand response programs/tariffs for each customer class.[190] When a particular program/tariff was applicable to more than one customer class (e.g. industrial and commercial), respondents were asked to enter the relevant information for each customer class. For wholesale customers, data collected included: enrolled load (in MW) and program design information such as minimum reduction, response time, and others.

For each program and/or tariff, respondents were requested to provide a short description of features, number of customers enrolled, maximum demand (in MW) of enrolled customers, potential peak reductions (in MW), and actual peak reductions (in MW).[191] The FERC Survey defines information on demand response potential for demand response programs or time-based tariffs as:

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[188] Chuck Goldman and Ranjit Bharvirkar of Lawrence Berkeley National Laboratory assisted with the drafting of this chapter.

[189] Chapter VI continues this discussion of the potential for demand resources for regional planning and explores how demand resources can be analyzed and included in regional planning and transmission expansion and operation.

[190] Customers were classified as residential, commercial, industrial, transportation, and other.

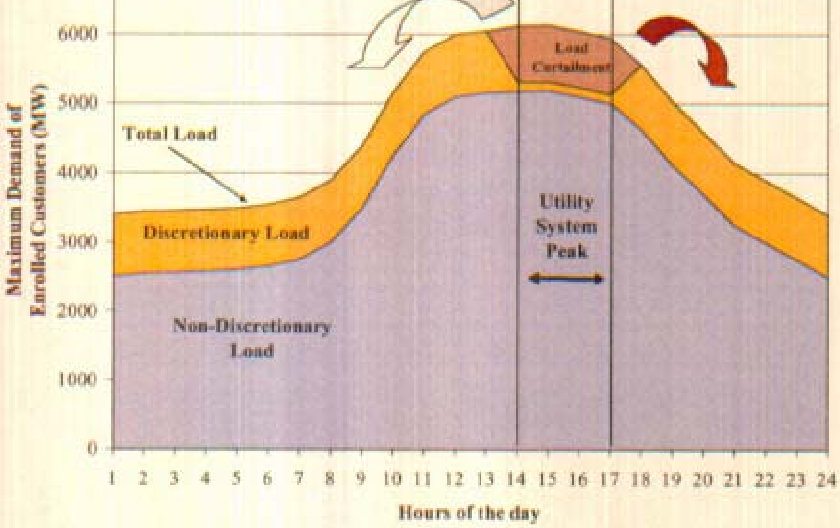
[191] Wholesale entities were not required to report demand response program information by customer class; thus they are treated as a separate category in addition to residential, commercial, industrial, and other customers. From program evaluations conducted by several Independent System Operator/Regional Transmission Organizations (ISOs/RTOs), industrial and commercial customers account for the bulk of enrolled load, although Curtailment Service Providers (CSPs) and Load Serving Entities (LSEs) are allowed to aggregate load reductions from residential customers to participate in ISO/RTO demand response programs. However, it was not possible to develop estimates by customer class for each ISO/RTO.

Potential Peak Reduction (PPR): The potential annual coincident peak load reduction (as measured in MW) that can be deployed from demand response programs, rates and tariffs that coincides with the annual system peak load of the entity (see Figure V-1 which shows a stylized example for a medium-sized utility with a large demand response program).[192] The survey asked respondents to provide PPR as of the end of 2005. This quantity reflects the installed load reduction *capability* and represents the load that can be reduced either by the direct control of the utility system operator or by the customer in response to a utility request to curtail load. PPR forms the basis for the estimates of resource contribution requested by Congress.

Actual Peak Reduction (APR): The coincident reductions to the annual peak load (as measured in MW) in 2005 achieved by customers that participate in a demand response program that coincides with the annual system peak of the utility or Independent System Operator (ISO).

The PPR values provided by entities for the various customer classes and enrolled load information provided by wholesale market entities (e.g., ISOs) serve as the primary basis for estimating the annual resource contribution of demand response resources. Commission staff developed estimates of the annual demand response resource contribution for various United States regions and by type of entity, along with comparisons of actual peak reductions vs. potential peak reduction capability.

Figure V-1. Schematic representation of demand response potential peak reduction for a demand response program



Source: Federal Energy Regulatory Commission

The following sections present estimates for resource contribution. First, the report summarizes the results from the FERC Survey for PPR. Second, it estimates resource contribution by combining data from the FERC Survey with publicly available information on demand response capacity. The FERC

[192] The entity can be an investor-owned utility, a cooperative utility, a political sub-division, a municipal utility, a municipal marketing authority, a federal or state utility, an ISO or an RTO, a power marketer, or a curtailment service provider.

Survey results were supplemented with the additional information because, after reviewing the data provided by survey respondents, it became clear that the FERC Survey results alone should not be utilized to estimate the annual demand response resource contribution because of various data quality issues (e.g., non-response, missing data on demand response potential).

FERC Survey Results: Demand Response Resource Estimates

Potential Peak Load Reduction of Demand Response Programs and Time-Based Rates

The total potential peak reduction for all regions and customer classes is 29,655 MW (see Figure V-2) based on the FERC Survey data. This represents approximately four percent of the total United States projected electricity demand for summer 2006 (743,927 MW).[193] The Reliability First (RFC) region accounts for the largest share of potential peak reduction for existing demand response resources (24 percent) followed by the Midwest Reliability Organization (MRO) and SERC Reliability Corporation (SERC) regions (approximately 16 percent each).[194]

Wholesale demand response programs[195] (primarily operated by ISOs and RTOs) account for about 30 percent of the total demand response resource potential peak reductions nationally and about 50 percent or more of regional resource contribution in three regions: Electricity Reliability Council of Texas (ERCOT) (80 percent); RFC (55 percent); and the Northeast Power Coordinating Council (NPCC) (49 percent). In contrast, wholesale demand response programs account for only about six percent of the potential peak reduction in the MRO and five percent in SERC.

Demand response programs/tariffs targeted to industrial customers provide 32 percent of the total national demand response resource potential. This potential is concentrated in two regions – SERC (73 percent of total regional potential) and MRO (57 percent). Residential customers account for about 20 percent of total demand response resource potential nationally and represent nearly 1,000 MW or more in several regions (Florida Reliability Coordinating Council (FRCC), MRO, RFC, and the Western Electricity Coordinating Council (WECC)). In the FRCC region, residential customers provide 58 percent of the regional demand response resource potential. Commercial customers account for about 16 percent of the demand response resource potential at a national level.

Investor-owned utility-operated demand response programs and time-based tariffs account for 44 percent of total national demand response resource potential (see Figure V-3). The second largest contributors of demand response resource are ISOs and RTOs (24 percent). Cooperative utilities (including political sub-divisions)[196] and federal/state utilities each provide approximately 13 percent of the demand response resource potential. Most of the demand response resource for federal and state utilities is available from industrial customers (66 percent of total potential from companies in this category); in contrast, residential and commercial customers provide about 43 percent of the demand response potential for cooperative utilities and political sub-divisions.

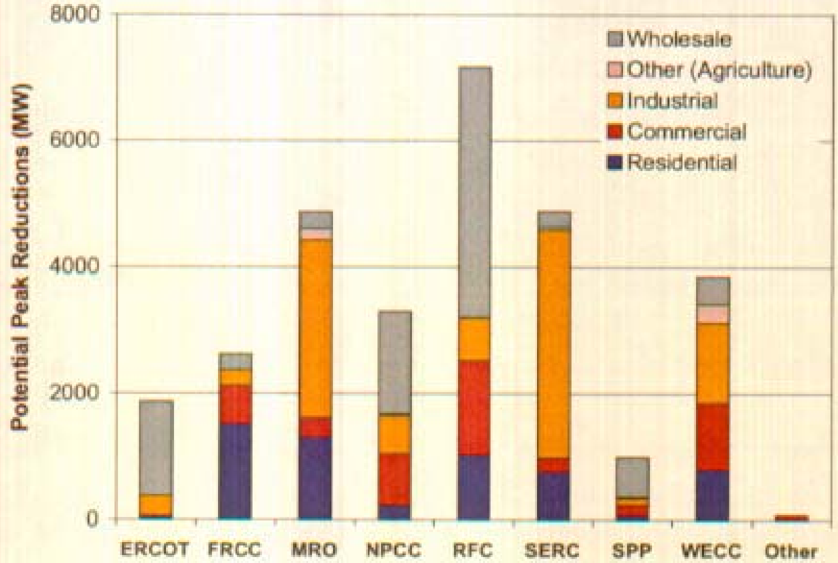
[193] NERC, *2005 Long-term Reliability Assessment*, September 2005.

[194] The report includes a complete listing and map of the NERC regions in Chapter I.

[195] In wholesale demand response programs, retail companies aggregate individual customer load reductions and sell or provide the reductions to the wholesale provider.

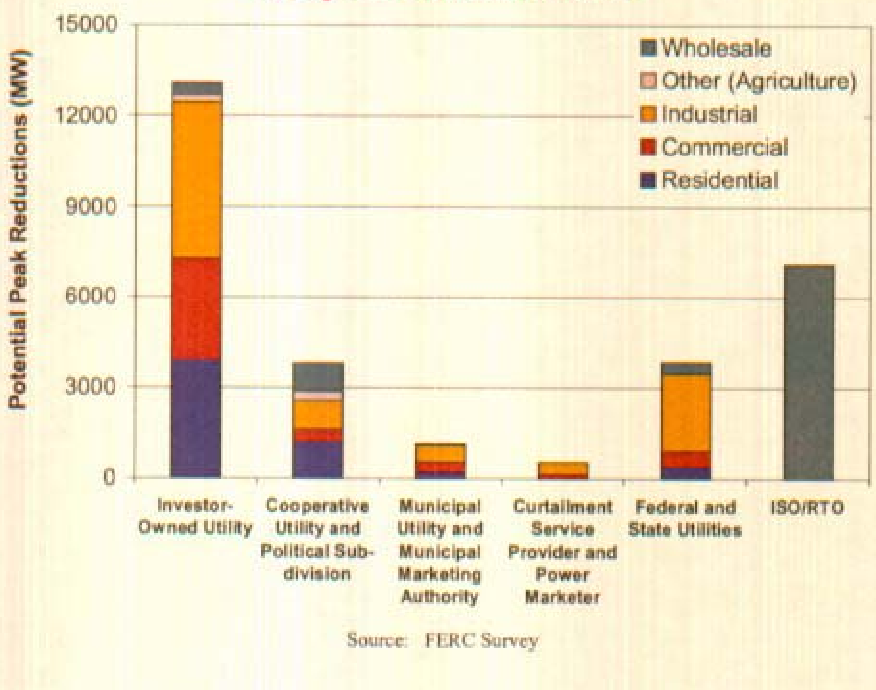
[196] While Commission staff tracked responses from electric cooperatives and political subdivisions in the FERC Survey, this report combines results due to their similarity.

Figure V-2. Demand response potential peak reduction by region and customer class



Source: FERC Survey
Notes: Other reliability region includes Alaska and Hawaii

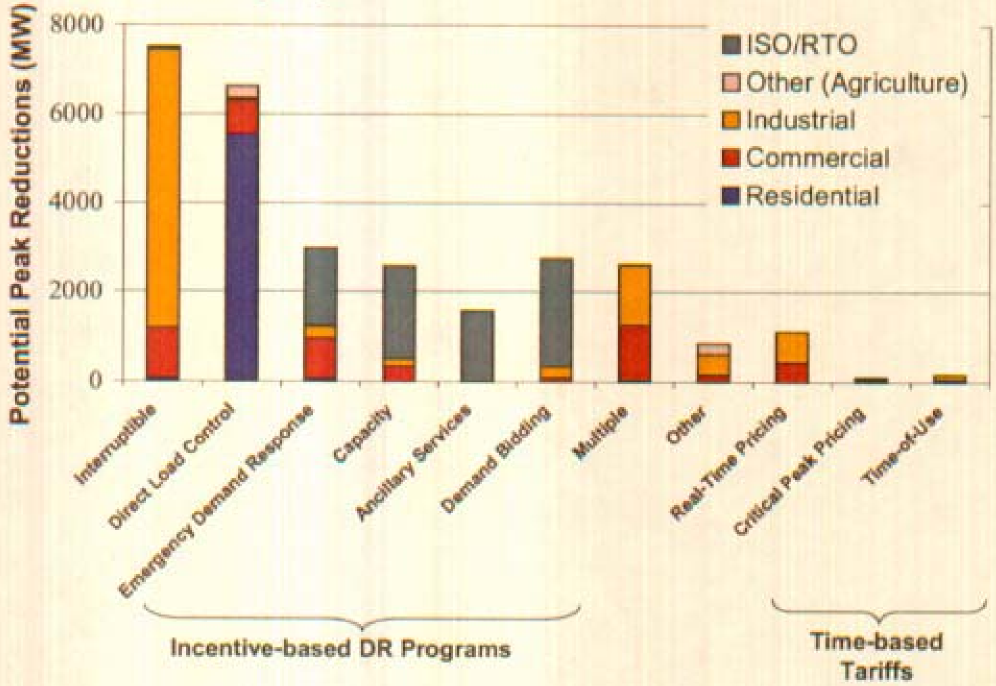
Figure V-3. Demand response potential peak load reduction by type of entity and customer class



Source: FERC Survey

Electric industry participants were also asked to provide information in the FERC Survey on the type of demand response programs or time-based tariffs offered to customers.[197] The results are displayed in Figure V-4. Interruptible/curtailable tariffs account for about 7,504 MW of demand response resource potential (27 percent of the total national potential), followed closely by direct load control (DLC) (24 percent). Most of the potential peak reduction associated with interruptible/curtailable tariffs is available from industrial customers (84 percent of total interruptible/curtailable potential), while most of the DLC resource is available from residential customers (84 percent of the total direct load potential). In contrast, a significant share of the demand response resource potential in ancillary services, capacity market programs, demand bidding, and emergency demand response programs are provided by wholesale customers of ISOs and RTOs. Respondents indicated that a number of demand response programs/tariffs, primarily targeted to industrial and commercial customers, had more than one type of program feature; these entries were classified in the "Multiple" category after review of data quality.

Figure V-4. Resource potential of various types of demand response programs and time-based tariffs



Source: FERC Survey

Based on responses to the FERC Survey, time-varying pricing tariffs (includes time-of-use, real-time pricing, and critical peak pricing) comprise only five percent of the total demand response resource potential. However, it is likely that the reported PPR values for time-based tariffs, particularly time-of-use rates, are too low for several reasons. First, 67 percent of the survey respondents that stated that they offered time-of-use type programs only provided data on the number of customers signed up for the tariff, and were unable to provide a demand response resource potential value. Second, it is more difficult for respondents to accurately estimate the demand response potential for customers on

[197] See Chapter IV for a detailed discussion of the various demand response program and time-based rate types.

time-varying tariffs because estimates of customer demand elasticities are typically required.[198] It is unclear what methods respondents used to estimate demand response potential for customers on time-varying tariffs. However, it is clear that demand response resource potential reported by respondents for time-of-use tariffs significantly underestimates this quantity because of missing data for PPR values.

Actual vs. Potential Peak Reductions of Demand Response Programs and Time-Based Rates

Potential versus actual peak load reductions for demand response programs for each reliability region in Figure V-5. In interpreting information on actual peak reductions of demand response programs or time-based tariffs, it is important to recognize that: (1) certain types of demand response programs (interruptible/curtailable tariffs, emergency demand response programs, and DLC) are often only called on during system emergencies, which are infrequent and do not occur each year because they are dependent on weather and system conditions; (2) activity levels in "economic" demand response programs (e.g., demand bidding) are influenced by the volatility and level of electricity commodity prices; (3) demand response program design features influence customer response (e.g. penalties for non-performance); and (4) most utilities do not routinely track or estimate actual peak reductions for customers on time-based rates as measurement and evaluation studies are required – consequently, survey non-response is an issue for time-based rates. On a national basis, respondents to the FERC Survey reported about 8,716 MW of actual peak reductions in 2005. Although the RFC region has the largest existing demand response resource potential (see Figure V-2), respondents reported that demand response programs and price-based tariffs in the MRO, WECC and SERC regions accounted for the largest number of MWs actually deployed in 2005 (see Figure V-5). The ratio of actual to potential peak load reductions for demand response programs was between 40-50 percent in three regions (FRCC, MRO, and WECC).

It is important to note that ISO/RTOs did not report actual peak load reductions in the FERC Survey, which potentially leads to underestimates of actual peak reduction for those regions with significant wholesale demand response programs.[199]

In Table V-1, the median value of the ratio of actual to potential peak reductions is presented for various types of demand response programs. Among the sample of DLC programs, the actual peak load reduction in 2005 is 56 percent of the potential peak reduction for the typical (i.e., median) program.[200] For interruptible/curtailable tariffs, the actual peak load reduction is lower: median value of 39 percent of the potential peak reduction.[201] These results suggest that a DLC program (because the utility has some control over the customer's end use equipment) may offer a more predictable

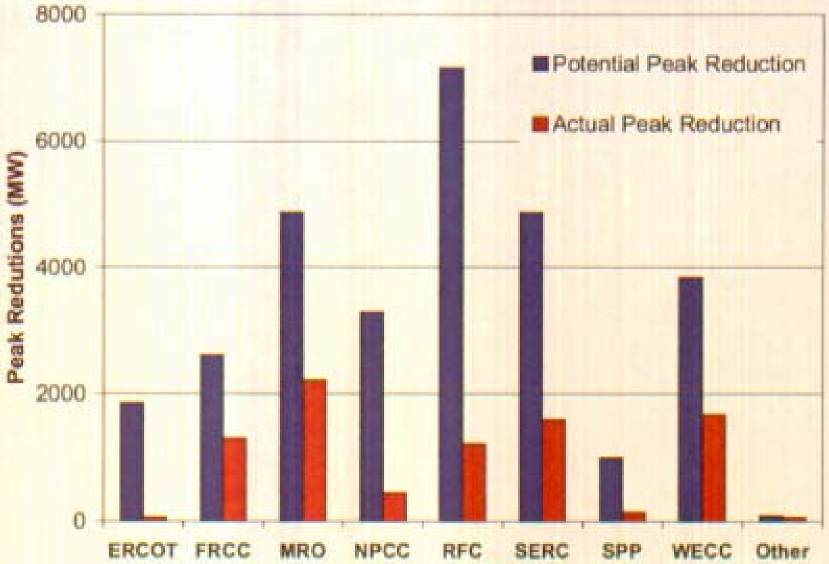
[198] Customer demand models require hourly interval usage data, retail prices, and information on customer characteristics.

[199] PJM reported a maximum hourly reduction of 205 MW out of 1,619 MW of emergency demand response resource and 226 MW out of 2,210 MW of economic resources. ISO-NE reported a total energy reduction of 66,251 MWh from 472 MW of demand response resources enrolled in various programs. (Reference: State of the Market Reports for PJM and ISO-NE. ERCOT reports that Load Acting as a Resource (LAAR) provided 4,637 GWh in 2005 and received $71.1M in payments (S. Krein, "Load Participation in ERCOT Ancillary Services Markets," April 18, 2006, AESP Brown Bag Seminar).

[200] Another interpretation is that the median value of 0.75 (or 75 percent) indicates that exactly half of the demand response programs targeted to residential customers have the ratio of APR to PPR greater than 0.75 in 2005.

[201] Customers on I/C tariffs typically initiate and control load curtailments when events are called by the utility (in contrast to residential customers in DLC programs); most I/C tariffs include penalties for non-performance.

Figure V-5. Demand response resource potential versus actual deployed demand response resources by region



Source: FERC Survey
Notes: Other reliability region includes Alaska and Hawaii

Table V-1. Ratio of actual deployed demand response resource to demand response resource potential by program type

Program Feature	Sample Size	Median Value
Direct Load Control	440	.56
Interruptible/Curtailable	195	.39
Emergency Demand Response	25	.01
Capacity Programs	10	.14
Demand Bidding	12	.10

Source: FERC Survey

demand response resource than other demand response programs that rely on customers to respond to events or calls. The actual vs. potential peak load reduction is significantly lower (less than 15 percent) for other demand response programs such as emergency demand response programs, capacity market, and demand bidding; these results should be interpreted with caution as sample sizes are small (25 or fewer entities reporting).

Table V-2 shows median values for the ratio of actual to potential peak load reductions for different types of entities that responded to the FERC Survey. The ratio of actual to potential peak load reductions was somewhat higher among customers enrolled in demand response programs offered by the typical cooperative and municipal utility (0.66 and 0.65) compared to an investor-owned utility (0.40). This result suggests that municipal utilities and cooperatives, as a group, tended to call or rely on their demand response programs in 2005 more than investor-owned utilities and/or that actual performance during events was closer to customers' subscribed load reductions.

Table V-2. Ratio of actual demand response peak reduction versus potential peak load reduction

Type of Entity	Sample Size	Median Value
Investor-owned Utility	74	0.40
Co-operative Utility or Political Sub-division	209	0.66
Municipal Utility or Municipal Marketing Authority	91	0.65
Curtailment Service Provider or Power Marketer	9	0.37

Source: FERC Survey

Existing Demand Response Resource Contribution

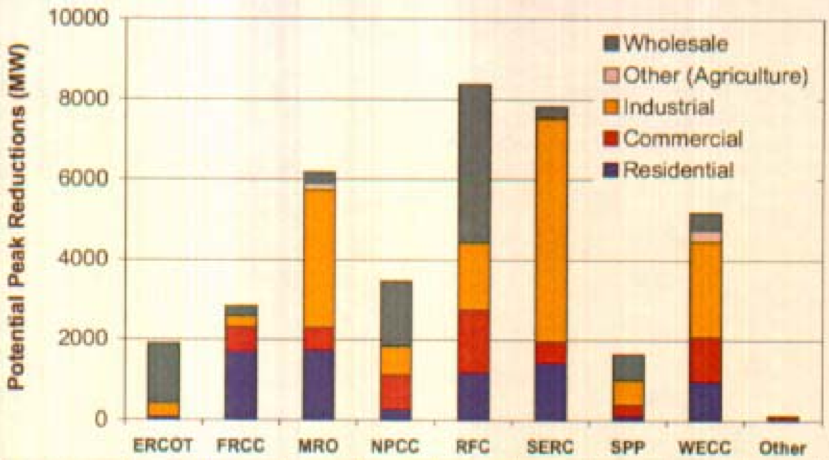
In this section, estimates of the existing demand response resource contribution for the United States drawing upon an analysis of FERC Survey responses and other sources (e.g., EIA Form 861, ISO/RTO demand response program evaluations) are presented.[202] Nationally, existing demand response resource contribution of 37,552 MW is estimated. This represents approximately five percent of the total United States projected electricity demand for summer 2006.[203] A breakdown of resource contribution by reliability regions is shown in Figure V-6. The three regions with the largest demand response resource contribution to the national total are RFC (22 percent of the total national potential) followed by SERC (21 percent) and MRO (16 percent). The demand response potential reported by entities in the RFC, SERC, and MRO reliability regions ranges from about 6,000 to over 8,000 MW in each region.

Given that peak loads vary significantly among reliability regions, it is also useful to characterize the existing demand response potential capability relative to each region's summer peak demand. Demand response resource potential ranges from three to seven percent in most NERC reliability regions, with the notable exception of the MRO region. The demand response resource potential reported by utilities in the MRO region as a share of the region's summer peak demand is significantly higher (20 percent) compared to other reliability regions. Since the MRO value is significantly higher than the other regions, an exploratory analysis was conducted in an attempt to understand and offer possible explanations for this somewhat surprising result. First, several states (Minnesota and Iowa) in the MRO region currently have or previously had laws that required utilities to invest a certain percentage of revenues in demand side management programs (1.5-2 percent), which contributed to demand response resource development. Utilities in this region have made significant investments in residential DLC programs, including both air conditioning and water heating programs. Second, utilities in the upper Midwest have historically had favorable rules that allowed load management resources to be counted towards meeting reserve requirements. Third, the characteristics of the customer base in the region, particularly among industrial customers, may be relatively more favorable

[202] Commission staff chose to draw upon additional sources for the resource contribution estimate because of data quality issues associated with the potential peak reduction estimates in the FERC Survey. These issues included: non-response to the survey, missing or partial responses to the potential peak reduction questions, and possible double-counting. These issues and how the various data quality checks and corrections that the Commission staff utilized are discussed at greater length in Appendix F.

[203] NERC, 2005.

Figure V-6. FERC staff estimate of existing demand response resource contribution



	ERCOT	FRCC	MRO	NPCC	RFC	SERC	SPP	WECC	Other
As Percent of Projected Summer 2006 Peak Demand	3%	7%	20%	6%	4%	5%	4%	4%	N/A

Source: FERC Survey
Notes: Other reliability region includes Alaska and Hawaii

to demand response resource development (e.g. steel plants and processes that can be interrupted). Utilities in the MRO region report that interruptible/curtailable tariffs are particularly popular among their large industrial customers.

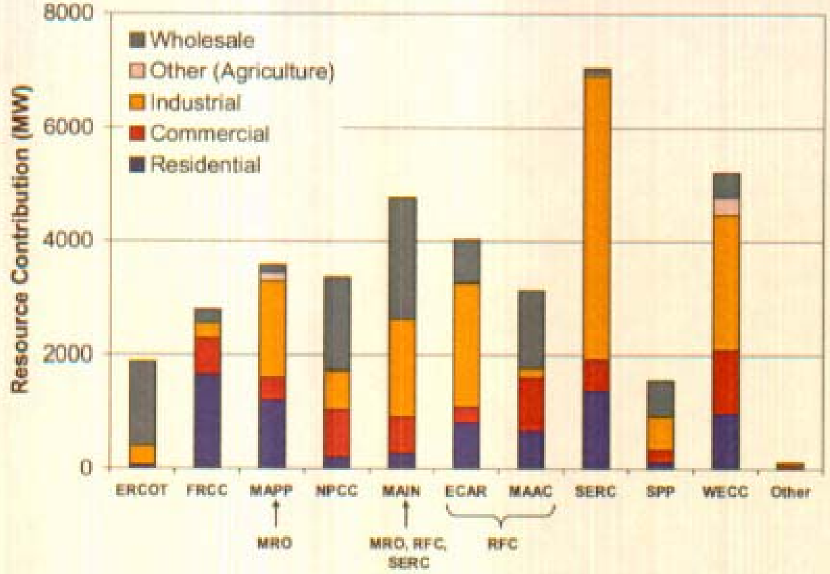
In Figure V-7, the demand response potential reported by electric industry participants are presented using the previous boundaries for NERC Reliability Regions, prior to recent consolidations. This may facilitate comparison between previous industry (NERC) and government (EIA) studies that have assessed demand response capability.

Investor-owned utilities account for about 47 percent of the total demand response resource contribution on a national basis, followed by ISO/RTO demand response programs, which account for about 19 percent of the national demand response resource contribution (see Figure V-8).

Results from the FERC Survey supplemented with data from other sources indicate that almost 530 entities operate at least one demand response program/tariff. These programs vary substantially in their design and features and also by their sheer size. The top 25 retail entities with the largest demand response programs account for about 56 percent of the national total demand response resource contribution, while the top 50 retail entities account for about 73 percent of the demand response resource contribution (see Table V-3). This means that less than 10 percent of all retail entities with demand response programs/tariffs provide almost three-fourth of the total demand response resource.[204]

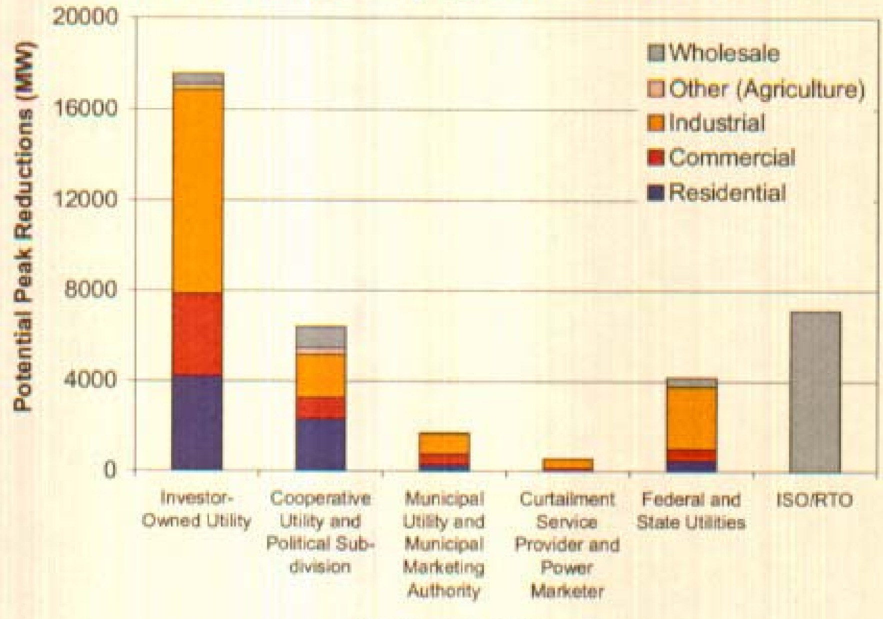
[204] ISO and RTOs, as wholesale entities, are excluded from this analysis; PJM, NYISO, and ISO-NE, together provide approximately 8,500 MW of demand response resource potential.

Figure V-7. FERC estimate of existing demand response resource contribution using old NERC region definitions



Source: FERC Survey
Notes: Other reliability region includes Alaska and Hawaii

Figure V-8. FERC staff estimate of existing demand response resource contribution by entity type and customer class



Source: FERC Survey

Table V-3. Demand response resource contribution of the largest retail entities.

Retail Entities	Potential Peak Reductions (MW)	Percent of Total Potential Peak Reductions
Top 25	15,172	56
Top 40	18,344	69
Top 50	19,947	73

Source: FERC Survey

Note: These figures do not include demand response programs operated by ISOs and RTOs.

Chapter VI. Role of Demand Response in Regional Planning and Operations[205]

This chapter addresses the fourth and fifth area Congress directed the Commission to consider in EPAct section 1252(e)(3):

(D) *the potential for demand response as a quantifiable, reliable resource for regional planning purposes; and*

(E) *steps taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment as a quantifiable, reliable resource relative to the resource obligations of any load-serving entity, transmission provider, or transmitting party.*

Demand response is an important, reliability resource for the power system in the United States. As was reported in Chapter V, there is approximately 37,500 MW of existing demand response potential in the United States, which represents roughly five percent of the peak load; large enough to be "real" but still relatively small. These resources are factored into regional resource planning and transmission enhancement planning either explicitly or implicitly as modifiers to the load forecast in most regions. Demand response resources currently supply ancillary services and efforts are underway to allow them to supply more. However, sole and explicit use of demand response as an alternative to transmission expansion is extremely rare.

The primary focus of this chapter is on the integration of demand response resources into regional planning, with a significant focus on the role of these resources in regional transmission planning and operation.

This chapter is organized into six sections:

- Potential for demand response for regional planning
- Transmission planning process and demand response
- Regional treatment of demand response
- Examples of projects that incorporate demand response into regional transmission planning
- Concerns and obstacles
- Steps that could be taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment

Potential for Demand Response for Regional Planning

Demand response can play a role in regional planning. This role is examined in the following discussion on regional planning in general and in the more detailed discussion on regional transmission expansion planning and operations in the remainder of this chapter. The goals of regional planning include, but are not limited to: ensuring that all customers have access to service, maintaining a reliable electricity supply, maximizing economic benefits, and/or minimizing costs. The

[205] Brendan Kirby of Oak Ridge National Laboratory assisted in the drafting of this chapter.

application of these goals varies depending on specific regional load requirements, available generation mix, customer interest, and state and regional policies.

Historically, most regions of the United States satisfied their load requirements through generation and transmission planning activities conducted by individual utilities. Beginning in the 1980s, many states such as California, Hawaii, Nevada, New York, Ohio, and others adopted integrated resource planning procedures and requirements to formalize these planning efforts, to ensure full examination of a variety of resources, and to allow regulator and public input into resource planning. These utility-integrated resource plans were typically prepared by individual utilities, but various states, such as California, engaged in statewide resource planning exercises. The use of resource planning at a larger, multi-state regional scale is limited,[206] but in recent years its use has expanded with the development of Independent System Operators/Regional Transmission Organizations (ISOs/RTOs) and other entities pursuing broad planning.[207] However, such planning is not universal or uniform which presents challenges for realization of a truly effective regional plan.

In the past, traditional resource planning concentrated on supply-side and transmission resources. With the advent of integrated resource planning, demand-side options (including various forms of demand response such as direct load control) were directly examined and integrated into the planning process. The two primary means used to incorporate demand-side measures in an integrated resource plan: (a) as an adjustment to the long-term demand forecast; or (b) as an explicit resource.

Several states require each utility to include demand-side measures as a part of their particular demand forecast but not necessarily as an energy resource. Massachusetts includes demand-side measures only to the extent that they impact load on infrastructure during peak or critical times.[208] Another state, Hawaii, includes demand-side management in both the forecasting and resource procurement processes. Energy efficiency options play a more important role in Hawaii's demand-side management than options such as load management.[209]

Other state legislatures and regulators require utilities to include demand-side measures more directly. In California, the California Public Utility Commission (CPUC) introduced a requirement that forced each utility to meet three percent of annual system peak demand for 2005 through demand response programs. The requirement increases one percent each year until 2007.[210] California also includes demand-side measures as a resource after utility energy contracts expire. Once the long-term contracts that were signed by the California Power Authority during the California crisis expire, each utility must employ all possible energy efficiency, demand response, and distributed resources before issuing offer requests for supply-side resources. The utility must exhaust all available energy efficiency, demand response, and distributed generation resources and prove to the CPUC that the use of fossil fuels over renewable resources has justification.[211]

[206] One notable exception is the regional planning activities of the Northwest Power and Conservation Council over the years in the Pacific Northwest.

[207] The role of regional planning is discussed in the Open Access Transmission Tariff (OATT) Reform NOPR Docket Nos. RM05-25-000 and RM05-17-000. See *Preventing Undue Discrimination and Preference in Transmission Service*, 71 Fed. Reg. 32,686 (June 6, 2006), FERC Stats. & Regs. ¶ 32,603 (2006).

[208] Regulatory Assistance Project, *Regulatory Assistance Project Electric Resource Long-range Planning Survey: Massachusetts*, July 2003.

[209] Liz Baldwin, *Regulatory Assistance Project Electric Resource Long-range Planning Survey: Hawaii*, June 2005.

[210] CPUC Decision (D.) 03-06-032, June 2003.

[211] Regulatory Assistance Project, *Regulatory Assistance Project Electric Resource Long-range Planning Survey: California*, August 2005.

Many other states do not incorporate demand-side measures or demand response in any way. In more than 20 percent of the states examined in a survey conducted by the Regulatory Assistance Project, demand-side measures were either not required by the state or no incentive existed to include demand-side measures in the integrated resource plan.[212] The rationale for not requiring the inclusion of demand responses varies. Arizona's rationale is that since it is a net exporter of power, utilities have not developed demand response strategies such as real-time pricing, and no incentive exists to motivate creation of these measures.[213] Maine has not required integrated resource planning, energy efficiency, or demand-side projects since it restructured its electric industry. Maine utilities used to have demand-side targets, but that ended with restructuring; ISO New England is now the primary entity that coordinates regional planning.[214] Energy efficiency and load management also are not included in integrated resource plans in Kansas, conceivably because supply options often appear to make more economic sense to utilities that have demand options. Kansas utilities can sell excess power on the wholesale market, and the resulting wholesale revenues can be used to keep regulated rates lower. Consequently, demand options are not always considered by the utilities.[215]

A principal challenge to including demand response measures in an integrated resource plan is how to directly model and value these measures. A recent case study conducted by Dan Violette and Rachel Freeman for the International Energy Agency provides a comprehensive assessment of the potential of demand response resources for regional planning.[216] According to Violette and Freeman, for demand response resources to be valued correctly within an integrated resource planning framework, resource plans must have a sufficiently long time horizon. Demand response can reduce the costs of low-probability, high-consequence events, but these events may only occur once a decade. The modeling and resulting integrated resource plan must also address various uncertainties, such as fuel prices, weather, and system factors. By explicitly including the risk factors, demand response can be assessed as a risk management tool.

The Violette and Freeman case study involved creating a model that would allow tradeoffs between both supply and demand-side resources. They examined changes in system costs with and without the inclusion of demand response resources for a 19-year time horizon. The case study provided an estimate of the valuation of demand response resources for the electric system, and included results on uncertainty measurements, hourly costs, capacity charges, demand response capacity usage, and loss of load, among other things.

In particular, substantial differences for plans with demand response resources and those without existed with regards to hourly costs, capacity charges, and capacity usage. In a simulated case comprised of a peak demand day with additional system stresses, the addition of demand response reduced the maximum hourly costs by more than 50 percent. Figure VI-1shows a total cost savings of $24.5 million.

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[212] These states include: Wyoming, Arizona, Ohio, Kansas, Michigan, Delaware, Pennsylvania, and Maine.

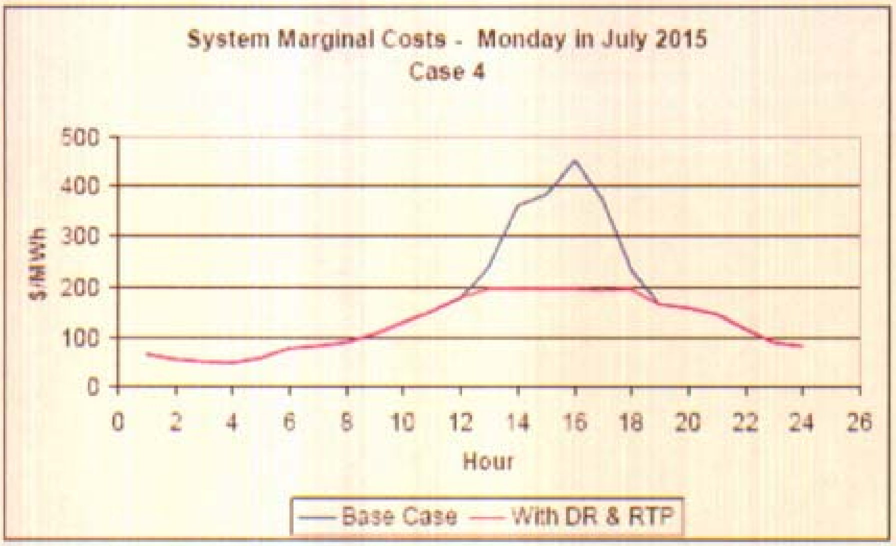
[213] Regulatory Assistance Project, Regulatory Assistance Project Electric Resource Long-range Planning Survey: Arizona, July 2003.

[214] Catherine Murray, Regulatory Assistance Project Electric Resource Long-range Planning Survey: Maine, July 2003.

[215] Liz Baldwin, Regulatory Assistance Project Electric Resource Long-range Planning Survey: Kansas, September 2005.

[216] Daniel M. Violette and Rachel Freeman, "Demand Response Resources (DRR) Valuation And Market Analysis: Assessing DRR Benefits And Costs," Summit Blue Consulting, http://www.summitblue.com/publications/DRR%20Valuation%20and%20Market%20Analysis.pdf, 2006.

Figure VI-1. Marginal costs savings from demand response resource programs



Source: Daniel M. Violette and Rachel Freeman, "Demand Response Resources (DRR) Valuation And Market Analysis: Assessing DRR Benefits And Costs," Summit Blue Consulting, 2006

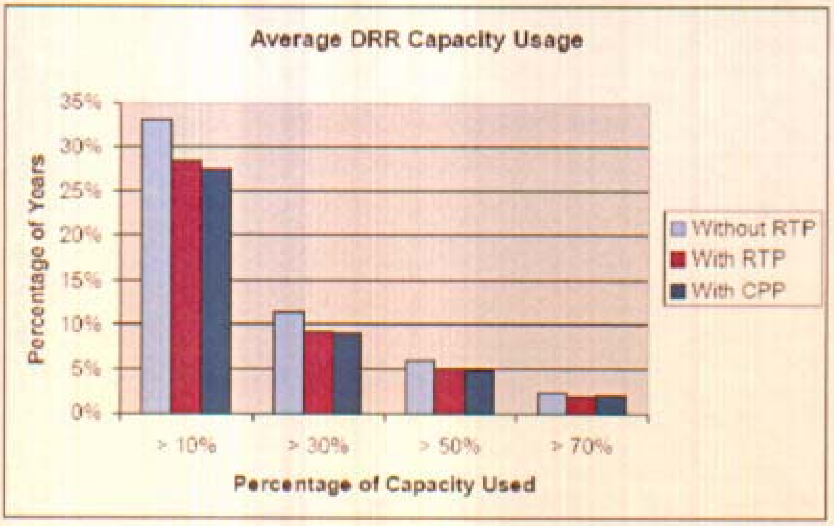
A substantial percentage of new capacity charges was deferred due to the availability of demand response. The savings amounted to $892 million (2004 dollars) over the 20-year horizon. Capacity charge savings were affected by the amount of demand response resources dispatched per year. The model reflected a significant deployment of demand response resources once every four years. A small amount of demand response resources was used frequently, while use of all available demand response resources happened infrequently. Figure VI-2 shows the percent of demand response resources used under three different program scenarios: without real-time pricing, with real-time pricing, and with critical peak pricing.

The net present value of the total system cost showed a reduction with the inclusion of demand response. The savings in incremental costs were 10 percent for the peak-pricing scenario and 23 percent for the real-time pricing scenario.

Violette and Freeman concluded that "overall, this case study shows that a Monte Carlo approach, coupled with a resource planning model, can address the value of DRR given uncertainties in future outcomes for key variables, and can also assess the impact DRR has on reducing the costs associated with low-probability, high-consequence events. In this case study, the addition of DRR to the resource plan reduced the costs associated with extreme events, and it reduced the net present value of total system costs over the planning horizon."[217] The importance of the results achieved by Violette and Freeman in their case study is that demand response resources can be directly incorporated into integrated resource planning methods.

[217] Daniel M. Violette and Rachel Freeman, 2006; DRR refers to demand response resources.

Figure VI-2. Percent of capacity from demand response resources used for different percents of time horizon



Source: Violette and Freeman, 2006

Violette and Freeman also recommended that, in future modeling efforts, care should be taken to indicate the specific costs and capabilities of individual demand response and pricing products. Greater specificity could have a significant impact on model results and could reduce the costs of implementing demand response products without affecting system benefits. In addition, the model limited competition of demand response resources to only combustion turbines. Upon inspection of the model results, this limitation forced older generation with higher costs to remain online later in the planning horizon, thus increasing the energy production costs which could otherwise have been offset by demand response programs. Reoptimization with the correct costs could lower overall average system costs, leading to greater savings. A third recommendation for future models is to develop more realistic system stress cases. The stresses in the model could be considered too extreme or not extreme enough, depending on the real-world application.

Transmission Planning and Operations and Demand Response

In this section, Commission staff focuses on the role of demand response in transmission planning and operations. After reviewing the transmission planning process, the discussion focuses on how demand response resources can be integrated into planning and operations.

Transmission Planning Process

Transmission planning is conducted to identify system upgrade and expansion needs for reliability and economic benefits. Details of the planning process vary from entity to entity but the basic process is the same. The power system is modeled under expected future conditions. When inadequacies in the transmission system are identified, there are specific processes that are utilized to find solutions. Typically system planners use load flow, transient stability, and voltage collapse analysis to assess system adequacy. This analysis is an elaborate, well orchestrated, inclusive, effective process which typically provides years of warning with regards to the need to upgrade the power system in order to meet the expected needs. The process often distinguishes between system upgrades that are needed to maintain reliability and those that are only needed to facilitate commerce or increase efficiency.

ISOs/RTOs, regional reliability councils, and regional planning organizations do not typically have the obligation or authority to directly design or construct transmission enhancement solutions. Once they identify transmission system inadequacies, they publicize the needs and expect transmission, generation, and demand-side investors to propose projects to solve the problems. The planners evaluate the proposed solutions to see if they meet the technical and economic requirements of the system. The best projects are endorsed and put into the regional transmission expansion plan. The projects must then be approved by state and federal regulators as appropriate.

The ISO/RTO Planning Committee is an organization composed of the Alberta Electric System Operator (AESO), the California Independent System Operator (CAISO), the Electric Reliability Council of Texas, Inc. (ERCOT), the Independent Electricity System Operator (IESO) in Ontario, the ISO New England (ISO-NE), the Midwest ISO, the New York ISO (NYISO), the PJM Interconnection (PJM), and the Southwest Power Pool (SPP). The committee provides a concise description of the evolving state of regional transmission planning:

> Regional electric system planning is evolving. In the early days of an ISO/RTO planning effort, transmission expansion plans often represented a compilation of the member utilities' local transmission plans. As the planning organization and stakeholder relationships grow stronger, the plans grow in scope and complexity, starting with work to conduct reliability planning on an intraregional basis and then moving to interregional reliability and economic or environmental improvement projects. Often, the next step is to strengthen the plan to address a particular system need or policy issue that exceeds reliability alone. After the RTO's planners and transmission owners become comfortable with regionally integrated reliability planning, the next step is to look at intraregional and interregional economic opportunities, where new transmission investment can significantly increase interregional flows and reduce costs.[218]

The generation and transmission solutions offered to the regional planner are typically developed by well established competitive generation companies and regulated transmission providers. A few developers of merchant transmission also occasionally develop projects. Transmission planners explore a host of possible solutions including upgrading existing lines, building new lines, adding control devices, etc. Separate departments exist to perform the electrical analysis, acquire right-of-way, design civil engineering solutions, procure equipment, and interface with the affected communities, construction. Getting new transmission lines built is difficult, but there is a large, elaborate, and detailed process that exhaustively examines all possible transmission solutions and actively seeks the most desirable. Generation planning is also well established. No such similar process exists for examining demand response solutions. Instead, Commission staff has determined that demand response is typically treated as a solution that may be examined if it is offered by others and if the offering meets criteria that were established based upon traditional transmission and generation technical solutions.

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[218] ISO/RTO Planning Committee, *ISO/RTO Electric System Planning, Current Practices, Expansion Plans, and Planning Issues*, February 10, 2006.

Demand Response in Transmission Planning

All of the various types of demand response resources discussed earlier in this report (particularly in Chapter IV) can impact transmission adequacy, and several of these options can be used as direct substitutes for transmission enhancement. For example, time-based rates and direct load control can target specific hours when response is desired. The former facilitates voluntary market response to price signals while the latter utilizes direct control commands. Both types can be used to address capacity inadequacy caused by a lack of generation or a lack of transmission. In addition, while not the subject of this report, energy efficiency reduces consumption during all hours and typically reduces the need for transmission. It is not focused on hours when transmission is congested and may not provide as cost effective a response to a specific transmission problem as more directed alternatives.

Demand response is not treated in transmission planning uniformly across the United States. As is discussed later in this chapter, many organizations state that their responsibility is limited to identifying transmission concerns and evaluating the viability of proposed solutions. Specific projects are to be proposed by generation, transmission, and demand response companies. Conversely, some institutions specifically state that they always evaluate demand response alternatives for transmission enhancements but demand response solutions do not show up in their transmission expansion plans. The 2006 ISO/RTO Planning Committee report states that its nine organizations have approved 1,121 transmission projects worth $15.6 billion including 5,070 miles of new transmission lines and 133,062 MW of approved new generation. In contrast, only 4,000 MW of new and existing demand response projects are mentioned and only for New York and California. An additional 500 MW of demand response are mentioned by ISO-NE.

In one sense, demand response *is* included in almost all transmission planning. Known existing or expected demand response is incorporated into the reliability assessment, either as a modification to the expected load or as a responsive resource. Load that is responsive to real-time or time-of-use prices, for example, is accounted for by modifying the forecast peak and off-peak load. Load that responds to system operator calls is used as a responsive resource, similar to generation, to mitigate problems found in the transmission analysis. Energy efficiency measures simply reduce energy requirements and are incorporated into future load forecasts, often without explicit consideration by transmission planners.

Commission staff has concluded that system planners do not typically include new demand response as a potential solution to transmission adequacy problems. Demand response is not considered equally when a system planner lays out options for dealing with the discovered transmission inadequacies. The Bonneville Power Administration (BPA) and MISO have policies calling for demand response considerations but these policies have not resulted in actual projects.

Provision of Ancillary Services by Demand Response

Demand response resources can also assist in the operation of transmission systems in the form of ancillary services such as operating reserves.[219] Customers participating in these programs are

[219] Reliability rules currently prohibit the use of responsive load to provide some ancillary services (spinning reserve for example) in some regions but technically the generation/load balance can always be restored by changing either side of the equation. See B. Kirby, *Spinning Reserve From Responsive Loads*, Oak Ridge National Laboratory: ORNL/TM-2003/19, March 2003.

continuously poised to respond, but only has to reduce consumption when a reliability event actually occurs. The response duration depends on the nature of the event and the type of reserve being supplied (see Figure VI-3) but is typically provided in seconds to minutes rather than the hours required when peak shaving or responding to price signals. Fast communications are often required to notify the load when response is needed. While customer load loads providing reliability reserves do not reduce transmission loading itself under normal conditions, they can reduce the amount of transmission capacity that must be held in reserve to respond to contingencies. This both reduces the need for new transmission and increases the utilization of existing transmission to provide energy from low cost generation.

Some demand response resources are technically superior to generation when supplying spinning reserve; the ancillary service requiring the fastest response. Many systems can curtail consumption faster than generation can increase production. The only time delay is for the control signal to get from the system operator to the load. This is typically 90 seconds or less (much less with dedicated radio response), much faster than the 10 minutes allowed for generation to fully respond. When responding to system frequency deviations, the curtailment can be essentially instantaneous. Communications delays are not encountered because frequency is monitored at the load itself.

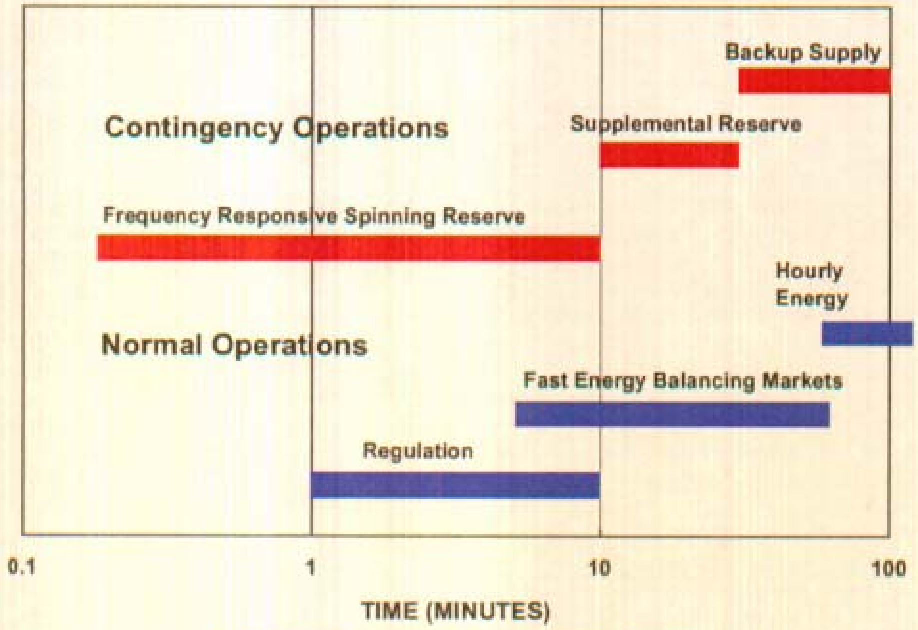
An example where demand response provides superior spinning reserve when compared with generation can be seen in Figure VI-4.[220] In this Figure, WECC's interconnection frequency response is shown for the sudden loss of the Palo Verde unit 1 generator. The lower curve shows system frequency response, with generators providing all of the spinning reserve. The upper curve shows that system frequency when 300 MW of spinning reserves were provided by a large pumping load instead of from generation. As can be seen, system frequency does not dip as low and recovers more quickly.

Markets for ancillary services typically develop shortly after markets for energy are established. The interdependence between the supply of energy and ancillary services makes this natural. Table VI-1 shows the current state of ancillary service markets, and whether demand response is allowed to participate.

Demand response has typically allowed provided supplemental (non-spinning) and slower reserves. Restrictions on allowing demand response to provide spinning reserve have eased recently in some areas. ERCOT allows demand response as a supplier of spinning reserve. PJM permits demand response to supply spinning reserves and regulation. NYISO expects to allow demand response to supply spinning reserves in the third quarter of 2007. MISO is in the midst of ancillary service market design and the supply rules are not yet clear.

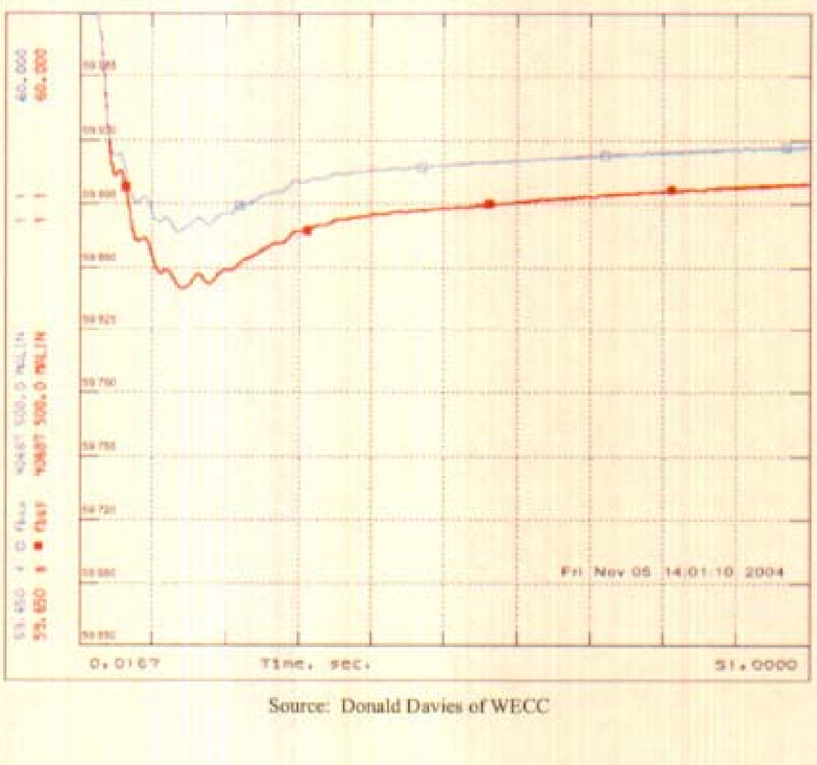
[220] John Kueck and Brendan Kirby, Presentation to the WECC CMOPS, January 7, 2005. Stability runs performed by Donald Davies of the Western Electricity Coordinating Council (WECC).

Figure VI-3. Response time and duration that characterize ancillary services



Source: Brendan Kirby of Oak Ridge National Laboratory

Figure VI-4. Impact of demand response on WECC system stability



Source: Donald Davies of WECC

Table VI-1 Current and pending ancillary service markets[221]

	Regulation	Spinning	Non-spinning Supplemental (10 min)	Long Term Supplemental (30 min)	Replacement (60 min)	Co-optimization exemption
ISO-NE	☑	☑	☑ D	☑ D		No
NYISO	☑	☑ D	☑ D	☑ D		No
PJM	☑ D	☑&C D	☑&C D			Yes
MISO	C	C	C			Not yet set
ERCOT	☑	☑ D		☑ D	☑ D	Yes
CAISO	☑	☑	☑ D			Yes

Notes:

☑ – Market based
C – Cost based
F – Fixed monthly MVAR payment
D – Demand response is allowed to participate (or will be shortly)
New England has forward reserves for obtaining supplemental and regulation

Co-optimization of ancillary services and energy markets presents a unique problem for demand response. Co-optimization (and in California, the Rational Buyer) is based on the idea that the various services can be ranked in order of "quality." Quality is judged by required speed of response, with regulation being the highest quality service followed by spinning, non-spinning, supplemental, long-term supplemental, replacement reserves, and energy supply. The reasoning is that higher quality services can and should always be substituted for lower quality services if the higher quality services are available at a lower price. If not enough replacement reserves are offered into the market but there is an excess of spinning reserves, for example, the system operator is able to purchase spinning reserves and use them as replacement reserves. The reserve supplier is supposed to be indifferent since it is being paid the spinning reserves price and being asked to provide the slower and therefore easier to provide replacement reserves service. This rationale is often extended to allow the system operator to use excess reserves as an energy supply when energy prices are high. This works well for most generators since they are indifferent as to how long they run (they may have minimum run times but generally do not have maximum run times).

Unfortunately, co-optimization can unintentionally block many demand response resources from participating in reserves markets. An air-conditioning load, which can respond rapidly and provide excellent spinning reserve at low price, for example, may be unwilling to provide the multi-hour response required for replacement reserves or energy.[222] The chance that it will be forced to do so by the co-optimizer may block demand resources from making themselves available to enhance system reliability. Very recently this problem has been recognized and addressed in several (but not all) markets. The CAISO, for example, allows demand response resources to declare themselves as unavailable for providing anything except the reserve market it has bid into. Energy is traded through bilateral contracts in ERCOT so it is separate from the ancillary service markets and the problem does not arise. PJM allows resources to submit different capacities in the ancillary service and energy markets so a demand response resource can state that it has zero energy capacity. These markets are noted in Table VI-1 under the "Co-optimization exemption" column.

[221] This table was adapted from the Ancillary Services Round Table, Midwest Independent System Operator, Carmel Indiana, April 26-27, 2006.

[222] Energy limited hydro generators and emissions-limited thermal generators have a similar constraint and cannot afford to risk being called on for extended operations.

Regional Treatment of Demand Response

Transmission system planning responsibilities are spread among a number of groups. The North American Electric Reliability Council (NERC) is the industry organization which addresses power system reliability. Regional councils provide added specificity as it relates to the particular needs of their region. ISOs, RTOs, and balancing authority (control area) operators have very specific concerns with the transmission systems they operate. Concerns about the impact demand response can have on transmission planning span a broad range. While it was not possible to conduct an exhaustive survey of the demand response activities of all the organizations with transmission planning responsibility in North America for this report various organizations were selected for inclusion in order to span the geographic scope as well as the range of organizational structures. Prior to examining how each region addresses demand response, the following discussion presents its treatment at the NERC level. The information provided in this section draws upon information obtained directly from the NERC regions and ISO/RTOs.[223]

North American Electric Reliability Council

NERC was formed in 1968 as the utility industry organization which develops voluntary reliability rules to coordinate how the bulk electric system is planned and operated. The voluntary structure is being replaced with a structure that requires mandatory compliance with reliability standards pursuant to the provisions of the Energy Policy Act of 2005 (EPAct 2005). Under the new system, the Federal Energy Regulatory Commission has the authority to review reliability standards proposed by the Electric Reliability Organization (ERO) that when approved, provide reliability of the nation's bulk-power system. The rule concerning the certification of the ERO has been issued by the Commission and the selection of an ERO is expected shortly. NERC filed the initial standards for formal review on April 4, 2006. On May 11, 2006, Commission staff issued a preliminary assessment containing a thorough review of the 102 NERC standards and on July 5, 2006, it held a technical conference with the industry to discuss the standards. A notice of proposed rulemaking concerning which standards might be accepted or remanded is expected to be issued in the fall.

NERC Reliability Standards address the types of assessments and the applicable criteria to be used in evaluating the reliability of the bulk electric system. They do not directly address the use of demand response or any other solutions to achieve compliance with the applicable criteria. In general, there are three classes of options; generation solutions, transmission solutions, and demand response solutions. The choice of one or more classes of options is usually based on their relative cost and effectiveness.[224]

Of the 102 standards and the Glossary of Terms Used in Reliability Standards presented by NERC for approval as mandatory standards, eight standards directly or indirectly deal with demand-side issues and demand response. They are:[225]

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[223] The following individuals provided information during discussions concerning regional demand response: Adam Keech and Jeff Bladen of PJM; Keith Tynes of SPP; Tom Abrams of Santee Cooper and SERC; Brian Silverstein of BPA; Robert Burke and Mario DePillis of ISO-NE; Dave Lawrence of NYISO; Charles Tyson, Dale Osborn, and Jeff Webb of MISO; Art Nordlinger of Tampa Electric and FRCC; Alan Isemonger of CAISO; Stephen Pertusiello of Consolidated Edison; and Donald Davies, Dick Simons, and Jay Loock of WECC.

[224] Note that demand response is unique in that it is essentially the only solution that is directly discussed in the standards.

[225] NERC, *Reliability Standards for the Bulk Electric Systems of North America*, North American Electric Reliability Council, Princeton, NJ, February 7, Downloaded from www.nerc.com on March 20, 2006.

- Standard BAL-002 — Disturbance Control Performance
  - The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserves.
- Standard BAL-005 — Automatic Generation Control
  - The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.
- Standard TOP-002 —Normal Operations Planning
  - Identifies performance to be achieved using all tools available to the operators.
- Standard MOD-016-0 — Actual and Forecast Demands, Net Energy for Load, Controllable DSM (demand side management)
  - Planning Authority and Regional Reliability Organizations must document actual and forecast demand data, net energy for load data, and controllable DSM data.
- Standard MOD 019-0 — Forecasts of Interruptible Demands and DCLM Data
  - Load Serving Entities must provide forecasts of summer and winter peak interruptible demands and Direct Control Load Management (DCLM) response capabilities for the next five to ten years.
- Standard MOD-020-0 — Providing Interruptible Demands and DCLM Data
  - Load Serving Entities must report their interruptible demands and direct load control management capabilities to Balancing Authorities, Transmission Operators, and Reliability Coordinators on request.
- Standard MOD-021-0 — Accounting Methodology for Effects of Controllable DSM in Forecasts
  - Load-Serving Entities, Transmission Planners, and Resource Planners must document how conservation, time-of-use rates, interruptible demands, and Direct Control Load Management are addressed in peak demand and net energy forecasts.
- Standard TPL-006-0 — Assessment Data from Regional Reliability Organizations
  - Regional Reliability Organizations are required to provide data concerning actual and projected demands and net energy for load, forecast methodologies, forecast assumptions and uncertainties, and treatment of Demand-Side Management including program ratings, effects on annual system loads and load shapes, contractual arrangements, and program durations.

Seven additional MOD standards contain guidance concerning collecting and reporting forecast demand and (if interpreted broadly) demand side management program performance data. NERC states that the purpose of these standards includes: "Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. *In addition to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed*"[226] (emphasis added). Forecasted load, with demand response included, drives the need for generation expansion and transmission to deliver the generation to the load.

The following NERC MOD standards try to assure that accurate demand and demand side response data is collected by requiring the Regional Reliability Organizations (RROs) "to establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the Interconnected Transmission Systems:"

[226] NERC, 2006

- Standard MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures
- Standard MOD-012-0 — Dynamics Data for Transmission System Modeling and Simulation.
- Standard MOD-013-0 — RRO Dynamics Data Requirements and Reporting Procedures
- Standard MOD-014-0 — Development of Interconnection-Specific Steady State System Models
- Standard MOD-015-0 — Development of Interconnection-Specific Dynamics System Models
- Standard MOD-017-0 — Aggregated Actual and Forecast Demands and Net Energy for Load
- Standard MOD-018-0 — Reports of Actual and Forecast Demand Data

NERC submitted its "Glossary of Terms Used in Reliability Standards" to the Commission with the 102 reliability standards for approval as mandatory reliability standards. There is a discrepancy between the definition of "Spinning Reserve"[227] and "Operating Reserves – Spinning."[228] The latter permits demand response to be considered as part of the spinning reserve requirement while the former does not. Furthermore as pointed out in the "FERC Staff Preliminary Assessment of NERC Reliability Standards"[229] under BAL-002-0 "the minimum percentage of spinning reserve required as part of the contingency reserve is not defined in the standard but is at the discretion of the RRO. Various regions have different definitions as to which resources are eligible to be counted as spinning reserves. For example in some regions large irrigation pumping and pumped hydro resources are permitted to be used as spinning reserves, and in other regions they are not. These deficiencies need to be addressed. Under BAL-005, the reliability goal of balancing generation and load requires the ability of the Balancing Authority to have control over adequate amounts and types of generation reserves and controllable load management resources."[230]

Texas Interconnection and the Electric Reliability Council of Texas

Electric Reliability Council of Texas (ERCOT) is both a NERC Region and an interconnection which lies completely within the borders of the state of Texas. In 2001, ERCOT consolidated the operation of 10 control areas into a single control area with bilateral energy transactions and ancillary service markets serving 20 million people with a peak load of 60,000 MW, 24,000 miles of transmission, and a $20 billion electricity market. Energy is arranged through bilateral agreements. ERCOT obtains ancillary services and balancing energy (15 minutes) through markets. While ERCOT does simultaneous selection of ancillary service resources it does not force ancillary service providers into the energy market.

ERCOT coordinates transmission planning with the various transmission and distribution service providers in Texas. Modeling expected future conditions identifies transmission limitations and helps in the comparison of alternative solutions. ERCOT also determines the transmission enhancements necessary to accommodate generation interconnection. ERCOT distinguishes between transmission enhancements that are required to maintain reliability regardless of the generation dispatch and those for which generation redispatch can be substituted. Demand response alternatives are considered

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[227] Unloaded *generation* that is synchronized and ready to serve additional demand (emphasis added).

[228] The portion of Operating Reserve consisting of: Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or Load fully removable from the system within the Disturbance Recovery Period following the contingency event

[229] Federal Energy Regulatory Commission, *Staff Preliminary Assessment of the North American Electric Reliability Council's Proposed Mandatory Reliability Standards* ("FERC Staff Preliminary Assessment of NERC Mandatory Reliability Standards"), Docket RM06-16, May 11, 2006, 30.

[230] FERC Staff Preliminary Assessment of NERC Reliability Standards, 32.

where possible. The ERCOT board approves all major transmission projects. ERCOT determines which transmission provider will build the transmission enhancement and notifies the Public Utility Commission (PUC). The transmission provider applies for and obtains PUC approval to build the transmission enhancement; ERCOT supports the PUC approval process.

ERCOT makes extensive use of demand response. Load is allowed to provide responsive reserves (spinning reserve), non-spinning reserves (30 minute response), replacement reserve, and balancing energy. Over 1,100 MW of load is qualified to provide spinning reserves and over 1,200 MW of loads is qualified to provide non-spinning reserve. Over 500 MW of response was observed during recent frequency excursions. Demand response is currently limited to providing half of the reserves needed until system operator experience is gained.[231] Interestingly, not a single load has offered to provide balancing energy while demand response is providing as much responsive reserve as allowed. This may indicate that demand response duration is more limiting than response speed.

On April 17, 2006, ERCOT was forced to use 1,000 MW of involuntary demand response and 1,200 MW of voluntary demand response to successfully prevent a system-wide blackout. Unusually high and unexpected load due to unanticipated hot weather, coupled with 14,500 MW of generation that was unavailable due to planned spring maintenance, resulted in insufficient capacity to meet load. System frequency dropped to 59.73 Hz at one point. Rolling blackouts were required for about two hours, with individual customers curtailed between 10 and 45 minutes at a time. All of the load called upon to respond did so successfully (voluntary and involuntary), though there was a 15 minute delay with one block of involuntary load curtailment.

Western Interconnection and the Western Electric Coordinating Council

WECC is the NERC regional reliability council responsible for the Western Interconnection, encompassing all or parts of fourteen states, two Canadian provinces, and a portion of Mexico. Peak load is about 146,000 MW. There are a number of transmission planning groups within WECC that are responsible for portions of the interconnection: Southwest Transmission Expansion Plan group (STEP), Northwest Transmission Assessment Committee (NTAC), Southwest Area Transmission (SWAT), Rocky Mountain Area Transmission Study (RMATS), and Colorado Coordinated Planning Group (CCPG).

WECC does not encourage or discourage demand response; it is neutral concerning technology choices for reliability solutions. WECC does not conduct transmission system planning; instead each WECC member to plan its portion of the transmission system. WECC compiles the system-wide base cases used by others to plan the transmission system and evaluate the need for new transmission. These base cases incorporate the input from each of the members, both for existing conditions and for conditions expected in the future. WECC notes that it is not specifically aware of what demand response is included in the information supplied by the members. Expected peak loads may be reduced by the amount of expected demand response. WECC indicated that it is not aware of any obstacles to greater use of demand response.

[231] Joel Mickey, *Competitive Ancillary Services Market in ERCOT*, MISO Ancillary Services Round Table, April 26, 2006.

Alhough it does not perform transmission planning,[232] WECC does report on the amount of interruptible demand and demand side management capacity that is available. The breakdown by subregion is shown in Table VI-2.[233]

Table VI-2. Interruptible demand and demand-side management in WECC

	Interruptible Demand (MW)*	Demand Side Management (MW)
WECC Total	1950	514
California-Mexico	1352	458
Arizona-New Mexico S. Nevada	285	1
Rocky Mountain	161	0
Northwest Power Pool	160	55

Source: WECC, *2005 Summer Assessment*, Salt Lake City, UT, May 2005
* Note: Total is not the sum of the parts because they are not simultaneous

The WECC 2005 Summer Assessment discusses transmission congestion concerns in each of the subregions. It explicitly discusses recent transmission upgrades that help to alleviate congestion. It does not discuss demand response as helping to reduce transmission congestion. The closest it gets to connecting demand response with congestion relief is:

> The CAISO control area has 1,610 MW of reliability-related interruptible load programs that may be activated should adverse operating conditions occur. However, only about 1,290 MW of the total is in the more constrained southern portion of the control area. In addition to these reliability-related interruptible load programs, up to 915 MW of additional total-area demand relief may be available, but some of that demand relief is limited by restrictions such as day-ahead notification.[234]

Similarly, the WECC 2005 Summer Assessment on the Pacific Direct Current Intertie states that the capacity of the Intertie is impacted by the amount of available demand response:

> The Pacific Direct Current Intertie (PDCI) will have a 3,100 MW north to south (export) limit. The PDCI south to north (import) limit will be 2,200 MW due to lack of direct service industry load tripping remedial action. ... The Northwest Direct Service Industry, which is composed mostly of aluminum smelters, experienced an electricity consumption decrease from just above 2,500 average megawatts in 2000 to less than 500 average megawatts in 2002.[235]

Even though the transfer capacity on the intertie has been reduced because of a reduction in available demand response, there is no further discussion of either the value of or methods to increase demand response.

[232] The purpose of the WECC Planning Coordination Committee is to (in part): (a) recommend criteria for adequacy of power supply and reliable system design; (b) accumulate necessary data and perform regional reliability studies; (c) evaluate proposed additions or alterations in facilities for reliability; and (d) identify the types and investigate the impact of delay on the timing and availability of power generation and transmission facilities. WECC, Downloaded from www.wecc.biz on February 12, 2006.

[233] WECC, *2005 Summer Assessment*, Salt Lake City, UT, May 2005.

[234] WECC, 2005

[235] WECC, 2005

WECC has adopted a uniform underfrequency load shedding plan and requires members to have 37 percent of the load shed in various steps for underfrequency conditions.[236]

The following discussion explores the role of demand response in two WECC subregions: BPA and CAISO. While not an exhaustive examination of the full WECC, examination of these subregions provides useful information on how the role of demand response is evolving in the region.

Bonneville Power Administration

BPA owns and operates 15,000 miles of transmission, about 75 percent of the high voltage grid in the Pacific Northwest. It does not own generation; it markets wholesale electrical power from federal and non-federal generators. About 40 percent of the electric power used in the Northwest comes from BPA.[237] At peak use, the system transports about 30,000 MW of electricity to customers.[238]

BPA has a highly visible effort aimed at identifying non-wires alternatives to transmission enhancement. Load in the Pacific Northwest has continued to grow but BPA has not build any substantial transmission enhancements between 1987 and 2003. BPA is concerned that congestion is increasing and reliability may suffer. BPA believes non-wires solutions may be a more cost effective solution while deferring the need to build new transmission facilities.[239] Non-wires solutions are attractive because transmission constraints often occur 40 hours or less per year. New transmission to meet these peak conditions would sit idle most of the time. Alternatively, customers could respond without much disruption to their normal operations. BPA cites two past successful demand response projects that justify its current efforts at finding additional non-wires solutions. Traditional conservation measures lowered peak loads on Orcas Island for several years while an underwater cable was replaced. The Puget Reinforcement Project used conservation programs to helped avoid voltage collapse in the Puget Sound area and delayed construction of additional transmission lines crossing the Cascade mountains for ten years. Technological advances in load control and distributed generation lead BPA to conclude that additional opportunities now exist. BPA has committed to study non-wires solutions before deciding to build any transmission enhancements.[240]

BPA is now targeting the Olympic Peninsula with a pilot project that started in 2004. The transmission system on the Olympic Peninsula (and in other areas) does not meet NERC's reliability criteria. BPA's focus is on deferring transmissions enhancement temporarily, rather than looking at demand response as a permanent resource. BPA evaluates each project based upon the savings associated with transmission project deferral. A demand response project might be viewed as a three-year deferral of a $60 million transmission project, for example. In that case, the value of the demand response project would be $11 million based on a 7 percent interest rate. Unlike the ultimate transmission project that demand response is delaying, the economic viability of demand response would not be examined over the 30-year life of a typical transmission line.

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[236] WECC, *Western Electricity Coordinating Council Relay Work Group Underfrequency Load Shedding Relay Application Guide - Revised*, August 3 2004.

[237] BPA, Downloaded from www.bpa.gov on April 14, 2006.

[238] BPA, *Transmission Planning Through a Wide-Angle Lens, A Two-Year report on BPA's Non-Wires Solutions Initiative*, Bonneville Power Administration, ("BPA Non-Wires Solutions Initiative"), September 2004.

[239] BPA, *Non-Wires Solutions, Questions & Answers , Exploring Cost-Effective Non-Construction Transmission Alternatives*, Bonneville Power Administration, www.transmission.bpa.gov/planproj/non-wires_round_table/ ("Non-Wires Solutions Q&A"), 2004.

[240] BPA Non-Wires Solutions Initiative, 2004.

BPA identified 20 transmission problem areas in 2001, and nine were designated as high priority. A study was commissioned to examine both the overall BPA transmission planning process and the specific transmission needs. The resulting report recommended process changes in BPA's transmission planning to consider non-wires alternatives early enough that they can make a difference. The report also identified specific projects that might be amenable to non-wires solutions.

BPA formed a Non-Wires Solutions Round Table to obtain opinions from a diverse set of stakeholders within the region. Members included environmental groups, regulators, large energy consumers, Indian tribes, renewables advocates, and independent power producers. They addressed four issues: screening criteria, detailed studies for particular problem areas, non-wires technology, and institutional barriers.[241]

Specific projects that were identified as candidates for non-wires solutions were:

- Puget Sound Area – the required non-wires load reduction was too large and the wires solution also reduced transmission losses so the Kagley-Echo Lake transmission line solution was selected.
- Olympic Peninsula – this was selected as a pilot project to test non-wires technologies including aggregated distributed generation and demand reduction.
- Lower Valley, Wyoming.

Institutional barriers identified by the Round Table include:

- Lost utility revenue – utilities are reluctant to pursue demand response when it may reduce sales and revenue.
- Lack of incentive for accurate forecasting – high load forecasts can justify additional transmission; thereby making it more difficult for demand response solutions to be adopted.
- Lack of transparency in transmission planning.
- Load shielded from actual wholesale electricity price volatility – additional demand response would make economic sense if loads could see the true value of that response.
- Reliability of non-wires solutions – this can be both an actual and a perceptual problem.
- Funding and implementation – multiple parties can benefit from demand side solutions (generation, transmission, and distribution) but it can be difficult to determine who should pay and who should implement the programs. Partnerships are often necessary but difficult to arrange.

Currently BPA demand response efforts are still in the pilot program stage. Through pilots, BPA will test the dependability of demand response solutions. The first full initiative to actually defer a transmission project may happen late in 2006.

California ISO

The State of California has a very active demand response program supported by the California Energy Commission, the California Public Utility Commission, and the California Consumer Power and Conservation Financing Authority. Demand response resources range in size from residential air conditioners to California Department of Water Resources 80,000 horsepower pumps. As was

[241] BPA Non-Wires Solutions Initiative, 2004.

discussed in Chapter IV, California expects to have demand response equal to five percent of the system peak available by 2007. California has established a "preferred loading order" to guide energy decisions. The loading order consists of decreasing electricity demand by increasing energy efficiency and demand response, and meeting new generation needs, first with renewable and distributed generation resources, and second with clean fossil-fueled generation.[242] Quantitative goals are not included for the use of distributed generation or demand response as an alternative to transmission enhancement and coordination with transmission planning is a recognized problem in California.

CAISO was created by the state to operate the transmission system for most of the state including 25,000 miles of transmission lines and a peak load of over 47,000 MW. The CAISO transmission planning process reviews the transmission expansion plans submitted by the participating transmission owners to assure that they solve identified problems, are the best alternatives, and are the most economical from a system point of view. The CAISO performs a comprehensive review to assure that nothing is missing. Management approves projects costing less than $20 million and refers larger projects to the CAISO board for approval. Studies are performed to establish Reliability Must Run generation requirements. CAISO has approved 337 transmission enhancement projects costing over $3 billion. Both the CAISO and the California Public Utility Commission have authority to require transmission enhancements to meet regulatory obligations.

The CAISO is currently proposing a new planning process. The CAISO will produce a five-year project-specific plan and a ten-year conceptual plan will be produced to address reliability and economic needs. It will submit identified projects to the transmission owners. Participating transmission owners are then expected to submit transmission plans that incorporate the CAISO plan. The transmission plan is designed to eliminate congestion and reliability must run requirements as well as to provide economic signals for generation siting.[243] The 2005 CAISO transmission initiatives encompassed seven projects, which included substation and line work. No demand response projects were included.

The CAISO has a great deal of experience obtaining ancillary services from competitive markets. It operated the first ancillary service markets and currently has a proposal before the Commission to redesign those markets. The CAISO proposes to implement its redesign by November 2007. Demand response resources are currently not allowed to supply regulation or spinning reserves. While the CAISO has used a "Rational Buyer" mechanism and proposes in the future to use co-optimization to substitute "higher quality" ancillary services for "lower quality" services and energy supply, demand response resources and energy-limited hydro generators can flag their capability as being available for contingency response only.[244]

Eastern Interconnection

The Eastern Interconnection is the largest of the three interconnections in North America but it has no organization with overall reliability responsibility. Instead, it is composed of six regional reliability councils that coordinate activities to assure that the interconnection remains reliable. Since there are multiple ISOs within the Eastern Interconnection, the Inter-RTO/ISO Council is also developing an inter-RTO/ISO expansion plan process. Steps are being taken to facilitate coordinated joint planning

[242] S. Fromm, K. Kennedy, V. Hall, B.B. Blevins, *Implementing California's Loading Order For Electricity Resources*, California Energy Commission Staff Report, July 2005.

[243] A. J. Perez (CAISO), *New ISO Transmission Planning Process*, August 1, 2006.

[244] Alan Isemonger, *CAISO Ancillary Service (AS) Procurement Under MRTU*, MISO Ancillary Services Round Table, April 26, 2006.

over a vast region but this process does not appear to include much in the way of demand response. The following discussion presents the transmission planning activities of the various Eastern Interconnection RTO/ISO and regional reliability councils.

Midwest ISO

The Midwest ISO (MISO) manages the transmission system and operates electricity markets for a region that covers all or part of fifteen states and one Canadian province. Peak load is approximately 132,000 MW; 16 percent of the total US/Canadian load and 21 percent of the Eastern Interconnection load. The Midwest ISO Transmission Expansion Plan 2005 (MTEP 05)[245] describes the currently recommended transmission needs for the MISO system. The plan identifies 615 facility additions requiring $2.9 billion in investment by 2010. MISO develops the regional plan based upon a roll-up and integration of the individual transmission owners' plans. The results are discussed with the Organization of Midwestern States and approved by the MISO board.

There is essentially no attention paid to demand response in the MTEP 05. No demand response projects have been identified within the $2.9 billion in reliability investment. Generation redispatch and transmission system expansion are recognized as methods to address inadequate reliability, but demand response is not mentioned. Line conversion is specifically addressed as an alternative to new construction, but demand response is not. The description of the process for determining system adequacy, needed additions, and generation redispatch does not include a discussion of demand response. However, the plan does recognize that controlled involuntary load shedding is an effective tool that the system operator can rely upon to contain rare events and prevent uncontrolled outage cascading. MTEP 05 only mentions "Demand-side options" once, when it states that their evaluation is required: "The MTEP process is to consider all market perspectives, including demand-side options, generation location, and transmission expansion alternatives." Commission staff cannot determine whether demand-side options actually are considered in the process.[246]

There is a brief section on "Load Technologies," which discusses the possible future use of controlled floor heating to help shape wind output to more closely follow other loads. Alternatively, "the load could be used as a dynamic brake for generator stability considerations following a fault on the transmission system."[247] There is no mention of the adequacy or inadequacy of current load control technologies to address current system needs.

MISO is currently engaged in an active ancillary service market design process that, while not explicitly using demand response to address transmission adequacy, is considering how demand response can participate in supporting system reliability.[248] The MISO stakeholder process is examining how ancillary service markets operate in other regions, including how they accommodate demand response. That process should result in a filing with the Commission in 2006.[249]

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245 MISO, *Midwest ISO Transmission Expansion Plan 2005 – MTEP 05*, June 2005.

246 There is one further sentence in the report that states "In rare situations the 'redispatch' can manifest itself as dropping load and backing down generation rather than simply shifting generation among sources."

247 MISO, June 2005.

248 MISO, Ancillary Services Round Table, Midwest Independent System Operator, Carmel, Indiana, April 26-27, 2006.

249 See June 6, 2006 resource adequacy report in Docket No. ER06-1112 at 7. In addition, MISO will be including effectively implementing enhanced DSM programs in its Phase II filing expected in 2007.

PJM Interconnection

At this time, the PJM Interconnection (PJM) serves 51 million people in all or parts of 13 states and the District of Columbia. It has a peak demand of approximately 135,000 MW; roughly 16 percent of the total US/Canadian load and 22 percent of the Eastern Interconnection load. PJM began in 1927 and developed as a tight power pool. In 1997, it became fully independent and started its first bid-based energy market, and it became an RTO in 2001.[250]

Transmission planning in the PJM region is accomplished through the Regional Transmission Expansion Planning Protocol which annually generates a Regional Transmission Expansion Plan (RTEP) covering the next 10 years. RTEP determines the best way to integrate transmission with generation and demand response projects to meet load-serving obligations.[251] Over $1.8 billion in transmission enhancement projects have been identified through the RTEP process. Although supply or demand side solutions may be found to be a more efficient or effective replacement for transmission enhancements, PJM is not authorized to implement them directly.[252] Instead, PJM identifies transmission solutions to problems and, subject to cost/benefit analysis, recommends their implementation through the RTEP if no solution has been proposed by a market participant within a one-year window. PJM's approach is to give market forces an opportunity to determine whether transmission investment beyond that needed to ensure reliability is warranted. While PJM planners work with transmission owners to assess the impact of a proposed project on the PJM system, the upgrades are the sole right of each transmission owner to construct.

Each RTEP includes: 1) a set of recommended "direct connection" transmission enhancements; 2) a set of "network" transmission enhancements; 3) a set of market-proposed generation or merchant transmission projects; 4) a set of baseline upgrades; and 5) the cost responsibility of each party involved. Most demand response is implicitly included in PJM regional transmission planning as a modifier to forecast load. PJM typically assumes that the current level of demand response will continue into the future when evaluating any specific transmission area.

PJM has recently made changes to its market structure to allow demand response resources to participate in ancillary services markets. As of May 1, 2006, demand response resources may provide spinning reserves and regulation. PJM is the first RTO to allow demand response to participate in each of the ancillary services markets.[253] Demand response in the regulation and synchronized reserve markets is initially limited to 25 percent of total requirements until system operator experience is gained. Loads are compensated for their capacity contributions as well. PJM has stated that "Demand response should be encouraged so long as it is the right economic answer. However, it is not an end in itself."[254]

PJM has identified a number of obstacles to incorporating demand response into PJM transmission planning and operations: lack of widespread use of hourly and sub-hourly metering, which is required

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[250] PJM, downloaded from www.pjm.com on April 3, 2006

[251] PJM, *Amended And Restated Operating Agreement Of PJM Interconnection, L.L.C., Schedule 6 Regional Transmission Expansion Planning Protocol*, PJM Interconnection, April 26, 2006, and PJM, *PJM Regional Transmission Expansion Plan*, 2006, and PJM Interconnection, www.pjm.com, February 22, 2006. Note that the planning horizon is expanding to 15 years with the next RTEP.

[252] PJM Interconnection L.L.C, comments filed in Docket AD06-2, December 19, 2005.

[253] A. Keech, *PJM Ancillary Services Markets*, MISO Ancillary Services Round Table, April 26, 2006. Load can not supply black start or reactive power.

[254] PJM Comments, December 19, 2005.

to accurately measure demand response, and the lack of good long-term demand response forecasting.[255]

Southwest Power Pool

Southwest Power Pool (SPP) is a NERC regional reliability council and a FERC-approved RTO for all or parts of Arkansas, Kansas, Louisiana, Mississippi, Oklahoma, New Mexico, and Texas. SPP serves 4 million customers with about a 39,000 MW peak load with 33,000 miles of transmission lines.

SPP identifies the region's transmission expansion needs through an open stakeholder process. Coordinating with the region's 45 electric utilities, SPP identifies the best overall regional transmission expansion plan. SPP then directs or arranges for the necessary transmission expansions, additions, and upgrades including coordination with state and federal regulators.

SPP does not itself explicitly include demand response in transmission planning studies, although it does consider generation as an alternative to transmission enhancement. Individual LSEs incorporate any current or expected demand response that is within their boundaries in their load forecasts. Individual transmission owners could investigate demand response solutions as alternatives to transmission expansion projects but they are not required to do so by the region. SPP does require 30 percent of the load to be interruptible on under frequency load shedding relays in three blocks of 10 percent each.

Florida Reliability Coordinating Council

Florida Reliability Coordinating Council (FRCC) is the regional reliability council for the state of Florida. Transmission system planning for the approximately 43,000 MW peak load region is dominated by its peninsular geography, with all connections to the Eastern Interconnection made at the northern border. FRCC coordinates the transmission planning efforts of the members for the region and assesses resource adequacy for the 10 year future period.

Although the amount of demand response in FRCC is sizable (seven percent of peak demand, see Chapter V), the Florida PUC has been reevaluating the cost effectiveness of demand-side management and has been reducing the rebates offered to consumers. Consequently, the amount of available demand-side management capability has been decreasing. Transmission planners do not consider demand response, and the demand forecast is not reduced by the amount of expected demand response. Planners feel that there is not sufficient demand response in any one location to eliminate the need for transmission enhancement. Demand response could delay the need for a project by a year, at most.

Still, there is a lot of demand response capability in Florida. Progress Energy Florida (formerly Florida Power Corporation), for example, has operated a very successful demand response program that it began in the 1980's and includes 800,000 out of 4.4 million customers. 1000 MW of peak load reduction and 2000 MW of emergency response ares available within two seconds to one minute. However, FRCC does not qualify this resource as spinning reserve.[256]

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[255] Jeff Bladen (PJM), FERC Technical Conference, January 25, 2006, transcript, 251-256.
[256] Ed Malemezian, Interview with Brendan Kirby, ORNL, 2005.

New York ISO

NYISO was formed in 1998 as part of the restructuring of New York State's electric power industry. The NYISO is an outgrowth of the New York Power Pool which was formed following the Northeast Blackout of 1965. The power pool coordinated the statewide interconnected transmission system and economically dispatched the generation fleet. Its mission is to ensure the reliable, safe, and efficient operation of the state's 10,775 miles of major transmission system and to administer an open, competitive and nondiscriminatory wholesale market for electricity in New York State. Peak summer load is about 32,000 MW. The NYISO's market exceeded $10 billion in 2005.[257]

NYISO recently initiated a Comprehensive Reliability Planning Process which identifies reliability concerns and transmission needs. This process involves extensive modeling, considering expected loads, generation resources, transmission limitations, and demand response resources including the Emergency Demand Response Program and Special Case Resource programs, discussed later. The process identifies reliability based needs rather than solutions. Generation, transmission, and demand response-based projects can be proposed. NYISO selects acceptable solutions based on their technical capability to address the identified problem and the economic viability. Only in rare cases when no acceptable solutions are proposed will the ISO discuss compelling a transmission owner to construct a transmission-based solution (backstop solution). As was the case with PJM, the NYISO intends this process to promote market based solutions to reliability problems.

Transfer limits into southeastern New York are limited by voltage rather than thermal constraints with a significant need arising by 2008. 1,750 MW of resources from generation or demand response will be needed by 2010 in order to free up voltage-support capability. As a partial response to this problem, the New York Public Service Commission (NYPSC) is requiring 300 MW of demand reduction in New York City. Consolidated Edison is to obtain half of that response (150 MW). The other half will come from other suppliers. The NYPSC has also set time lines and metering requirements to help accelerate acceptance. Demand response solutions may receive funding from New York State Energy Research and Development Authority.

NYISO may allow demand response to supply spinning reserves. This will likely occur in the third quarter of 2007. Currently, demand response can only supply non-spinning reserve.

Ancillary service bids are co-optimized with energy requirements by the NYISO, allowing the system operator to use ancillary service resources to supply energy if needed. This may be limiting the amount of demand response offered to the system, since some loads may be unwilling to expose themselves to the risk of being required to curtail operations for an extended period.

ISO New England

ISO New England (ISO-NE) evolved out of the NEPOOL tight power pool which, prior to 1999, provided joint economic dispatch across Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. The ISO-NE has over 8,000 miles of transmission lines to serve about a 27,000 MW peak load.

ISO-NE stated that it works with stakeholders to develop fair and efficient wholesale electricity markets, to plan a reliable bulk power system, and to protect the short-term reliability of the control

[257] NYISO, downloaded from www.nyiso.com, April 3, 2006.

area. ISO-NE annually develops a 10-year Regional System Plan which accounts for the addition of generation units, demand response, load growth, and generation retirements. System economics and air emissions are considered, along with reliability, in planning the transmission system. In addition to specifying what transmission enhancements are required, the Regional System Plan also helps attract market solutions (generation and demand response) to mitigate the need for the transmission enhancements. The current Regional System Plan includes 272 transmission projects that are expected to cost between $2 and $4 billion.

Demand response is not the same as transmission enhancement in ISO-NE's eyes. Demand response can provide a temporary solution until a permanent transmission enhancement is in place. When the power system in Southwest Connecticut was recognized as being inadequate, it was also acknowledged that neither transmission nor generation solutions could be implemented in time to restore reliability. Demand response solutions of 250 MW were sought to quickly fill the reliability gap. Transmission solutions are still being pursued to permanently resolve the problem.

ISO-NE believes it has authority from FERC to order transmission construction if needed to maintain reliability. Conditions have never warranted that action. Instead the ISO has preferred to identify needs and allow the market to propose generation, transmission, or demand response solutions. The ISO views its role as selecting the best from what is proposed rather than identifying the best solution on its own. Selected projects then move through the state and federal regulatory process to enter the rate base or transmission tariff if they are transmission based. Generation and demand response projects move through their own regulatory and commercial processes.

The existing form of ISO-NE's capacity markets makes it difficult for demand response resources to fully participate in the ancillary service markets. Forward capacity markets mean that reserve costs are mostly sunk in real-time and rational real-time offers are expected to clear at $0. Further, ISO-NE utilizes forward reserve auctions, two to five months in advance, to procure 10-minute non-spinning reserve and 30 minute operating reserves. These are difficult commitments for demand response resources to make. These markets are designed to satisfy 95 percent of the reserve requirements and include penalties for failure to respond in real time. Any resource can participate, but it must look like a low-capacity generator with a high energy price and capable of providing reserves 98 percent of the time.[258]

Demand response resources can also register as a Dispatchable Asset Related Demand, and essentially will be treated as generators. The resources cannot restrict its response to contingency events; energy and ancillary services are co-optimized based upon the bid response price. Submitting a $999/MWh only partially mitigates the energy deployment risk and also undesirably reduces contingency event deployments.[259]

Southeastern Electric Reliability Council

Southeastern Electric Reliability Council (SERC) encompasses all or parts of 16 states in the southeastern and central United States. Prior to the recent consolidation of the 10 regions into eight, SERC was the largest with a peak load of about 165,000 MW. It has 5,057 MW of interruptible load and demand response and 50,000 MW of load shedding capability. SERC does not have a regional policy concerning the use of demand response related to transmission enhancement. Transmission

[258] Mario DePillis, *The New Ancillary Services Markets of New England*, MISO Ancillary Services Round Table, April 26, 2006.

[259] Mario DePillis, 2006.

planning and the role of demand response is left to the individual transmission owners.

International Examples

In many parts of the world, as in many parts of the United States, demand response impacts transmission planning indirectly by impacting expected demand. In the Nordic countries, for example, Nordel (the regional transmission operator) regards demand response as critical to supporting reliability but it does not implement demand response programs itself as this is done by the individual countries. Demand response appears to be more aimed at providing balancing capability than at deferring transmission and distribution investment.[260] Australia provides a counterpoint.

Australia's National Electricity Market operates the longest interconnected power system in the world – more than 4,000 kilometers from Queensland to South Australia. Peak demand is 31,000 MW. Energy prices are typically under A$40/MWh but can go as high as A$10,000/MWh during system emergencies.[261] Such a geographically large power system is necessarily dependant on transmission and transmission constraints are not uncommon. A major method for demand response to participate in markets is in support of the deferral of capital expenditure for load-growth related network expansion.

New South Wales enacted a "D Factor" which allows Distribution Network Service Providers to retain capital expenditures avoided through targeting of demand management. The New South Wales DM Code of Practice also requires Distribution Network Service Providers to exhaust demand-side management as an alternative before undertaking load-driven network expansion.

Example Demand Response Projects

The following examples illustrate the steps that have been taken to consider and use demand response as an alternative to transmission at various utilities and regions.

LIPA Edge

The LIPA Edge project is a good example of how a demand reduction project that controls residential and small commercial air conditioners using modem technology has the potential of serving as a resource for ancillary services. The installed technology has the technical ability to provide spinning reserves, as well as peak load reduction.

Remotely controllable Carrier Comfort Choice thermostats, coupled with two-way communication provided by Silicone Energy and Skytel two-way pagers allow the Long Island Power Authority (LIPA) to monitor capability and response, as well as to control, load reductions. It also enables customers to control their individual thermostats via the Internet, a benefit that motivates participation.[262] The project currently controls 25,000 residential units and 5,000 small commercial

[260] Grayson Heffner, *Demand Response Providing Regulation and Reserve Services in Nordic Electricity Markets – DRAFT*, Consortium for Electric Reliability Technical Solutions, March 2006.

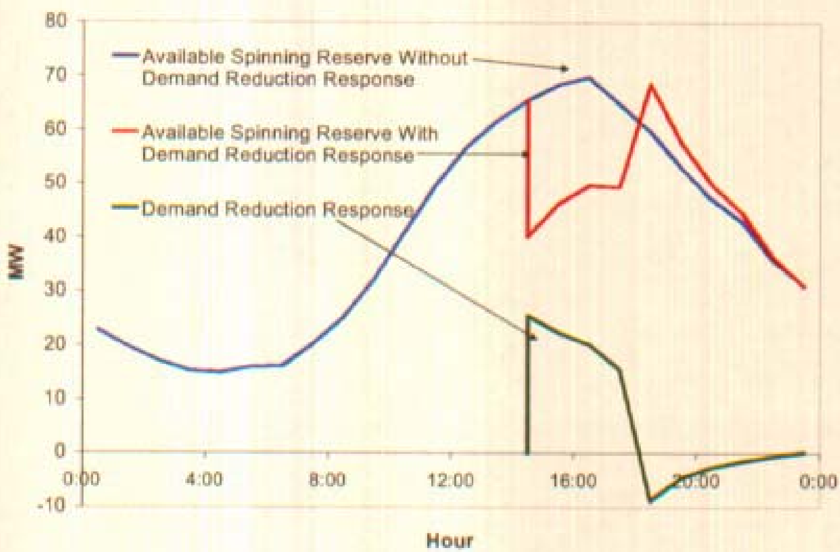
[261] Grayson Heffner, *Demand Response Provision of Ancillary Services in Australia's National Electricity Market - DRAFT*, Consortium for Electric Reliability Technical Solutions, March 2006.

[262] LIPA, *LIPA Edge*, presentation to the New York Independent System Operator Price-Responsive Load Working Group, 21 November 21, 2002.

units provide 36 MW of peak load reduction.[263]

Detailed discussions with Carrier in 2002 revealed that the technology is fast enough to provide spinning reserves and provides ample monitoring capability. Further analysis of test data revealed that the program can typically deliver 75 MW of 10-minute spinning reserves[264] at little or no additional cost at times of heavy system loading. This could provide a significant benefit for capacity-constrained Long Island. Significant spinning reserve capability remains even if the system is being used for peak reduction as shown in Figure VI-5.[265] Spinning reserves capacity is now likely over 100 MW.

Figure VI-5. LIPA Edge spinning reserve capability during August 14, 2002 curtailment



Source: Brendan Kirby of Oak Ridge National Laboratory

Southern California Edison Feeder Relief

Southern California Edison (SCE), with California Energy Commission support, is conducting a Demand Response Dispatch Verification Research and Demonstration Project in the summer of 2006 to demonstrate the impacts of distributed resources both as a means to provide specific load relief at the substation and distribution feeder level, and as a spinning reserves resource. The system uses the Internet, the SCE-wide area network, and various wireless technologies to provide two-way control and monitoring of the devices that control electric loads at approximately 450 sites in Southern California. Two specific objectives are to demonstrate that, when load is curtailed by a dispatch signal, the available MW demand response of a specific circuit can be predicted with a 90 percent statistical confidence and demonstrate that the load can be curtailed reliably and quickly on the issuance of a dispatch signal. The load shed is expected to start within 10 seconds of the signal and be fully implemented within two minutes.

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[263] Michael Marks, E-mail discussion with Michael Marks of the Applied Energy Group, April 15, 2006.

[264] This test was conducted when the peak reduction program only had 25 MW of capacity.

[265] Kirby, 2003.

SCE is implementing a special contract for the test with 400 to 500 residential customers and 50 to 100 commercial customers. Various curtailment intervals are to be tested. The selected circuit has a peak load of 9 MW. SCE expects to curtail 2 to 3 MW depending on time of day, temperature, and day of week. A rigorous statistical analysis has been performed in planning the number of customers under the test, the number of tests, and the data acquisition system to ensure the results provide a relative precision of 15 percent at the 90 percent level of confidence. SCE expects the test to provide a benchmark for repeatable, precise, rapid demand response used as a reliability service.[266]

BPA Olympic Peninsula

BPA is conducting several pilot projects aimed at deferring the need for transmission enhancements. Several technologies are being utilized including:

- Direct load control – 20 MW from electric water heating, pool pumps, heat pumps, forced air furnaces, and baseboard heating. One-way radio pagers and power line communications within the residence are being used.
- Demand response – 16 MW from electric water heaters, cloths dryers, pool pumps, heat pumps, and forced air furnaces. Fiber optic and cable internet connections are being used to communicate with Grid-Friendly™ appliances. Customers can set prices for response. Grid-Friendly™ appliances will also respond to system frequency disturbances.
- Voluntary load curtailment – 22 MW through the Demand Exchange internet-based auction where loads can offer to reduce consumption in response to reliability or market volatility events.
- Distributed generation – 4 MW from industrial and commercial backup generators.
- Energy efficiency – 15 MW.

Consolidated Edison

Consolidated Edison provides an example where demand-side resources are being explicitly sought as an alternative to transmission and distribution expansion. Consolidated Edison issued a request for proposals in April 2006 seeking at least 123 MW of demand side management in targeted areas of New York City and Westchester County in order to defer transmission and distribution capital investment. Multiple proposals will be considered; each proposal must be for at least 500 kW of aggregated peak summer load reduction. Consolidated Edison provided detailed information and maps for each geographic area to help project developers. Materials include:

- Numbers and types of customers (residential, commercial, small commercial, types of business, types of residential, numbers of central air conditioners, numbers of room air conditioners, etc.)
- Sizes of individual customer loads (10-300+KW)
- Total required load reduction (2-25 MW)
- Need date (2008-2011)
- Minimum project duration (two to four years)

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[266] SCE, *California Independent System Operator and California Energy Commission, CERTS Demand Response Project, Plan For Summer 2006 Demand Response Test on Southern California Edison Distribution Circuit*, March 23, 2005

Clean distributed generation may be proposed, as well as energy efficiency measures. Distributed generators can reduce customer load but they may not export to the grid to be considered for this program. Energy efficiency measures are allowed (compact florescent lights, energy efficient motors, efficient air conditioning, and steam chillers, for example).

Consolidated Edison has chosen not to include direct load control and measures that "temporarily curtail or interrupt loads" in this request for proposals. These will also not consider operating and maintenance improvements and improved new construction measures.[267]

Mad River Valley Project

In 1989, Green Mountain Power (GMP) needed to enhance the distribution system feeding Sugarbush Resort in the Mad River Valley in central Vermont. Load was expected to grow and a $5 million parallel 34.5 kV line was needed. Instead, Sugarbush installed an energy management system to enable it to monitor and control its load and keep the total feeder load below 30 MW. Snowmaking was the major controlled load. GMP also engaged in an energy efficiency program for other customers on the feeder. Note that GMP largely abandoned the follow-on demand side management work once the network problems were resolved.[268]

The Energy Coalition

The Energy Coalition was formed in 1981 by end users to aggregate demand response to help alleviate generation and network capacity shortages in southern California. The Business Energy Coalition of the Energy Coalition is a specific project in the San Francisco area that specializes in short-term network relief. A 10 MW pilot project is based on the area's 200 largest customers with day-ahead and same-day response. Response is limited to five hours/event, one event/day, five events/month, and one hundred hours/year. Response can be called upon for CAISO Stage 2 emergencies, spinning reserve shortfalls, forecasted San Francisco temperatures above 78 degrees, local emergencies, and total CAISO load forecast to exceed 43,000 MW.

Concerns And Obstacles

There are a number of obstacles to the greater use of demand response as an element in transmission planning and operations. Specific concerns and obstacles that have been identified by Commission staff are discussed below.

Lack of Uniform Treatment of Demand Response.

There are many examples of features of reliability rules that accommodate generator limitations that do not increase system reliability. They are necessary to enable generators to provide the desired reliability response but they are not themselves directly related to that desired reliability response. A partial list includes:

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[267] Consolidated Edison, *Request For Proposals To Provide Demand Side Management To Provide Transmission And Distribution System Load Relief And Reduce Generation Capacity Requirements To Consolidated Edison Company Of New York, Inc.*, www.coned.com, April 14, 2006.

[268] Richard Cowart, *Distributed Resources and Electric System Reliability*, The Regulatory Assistance Project, 2001.

- Minimum run times
- Minimum off times
- Minimum load
- Ramp time for spinning reserve
- Accommodation of inaccurate response
- Limiting regulation range within operating range to accommodate coal pulverizer configuration

These rules are necessary to elicit the reliability response the power system requires. Similar accommodations could be afforded to other technologies, such as demand response, based on their limitations. A partial list might include:

- Maximum run time
- Value of capacity that is coincident with system load
- Value of response speed
- Value of response accuracy
- Match metering requirements to resource characteristics

Perceived Temporary Nature of Demand Response

When demand response is considered as an alternative to transmission expansion, it is typically considered as deferral rather than as an alternative. This has important implications for demand response financing as well as performance. The economic viability of demand response is determined by comparing the cost of the demand response project with the present value of the savings obtained by delaying construction of the transmission investment for a few years. The transmission alternative, however, is evaluated over a 20 to 30-year facility life. Since transmission additions are large projects, transmission additions typically reduce or eliminate the need for targeted demand response resources. The basic reasoning is that load growth will eventually make the transmission investment necessary so demand response can only delay the inevitable. Operating practice often follows the same temporary logic. Demand response programs may be discontinued once the transmission project they have been delaying is finally installed. The excess capacity that is typically initially made available by transmission expansion (discussed below) makes demand response, at least temporarily unnecessary. A transmission investment is not considered in the same way. If additional transmission is needed later, it is additional transmission, not replacement. Note that demand response can also be long-lived – Progress Energy Florida's demand response program has been operating for over 20 years.

While this argument that demand response is a temporary solution is logical, it is different from how other transmission investments are evaluated. A subtransmission line might be installed or upgraded, delaying the need for a new transmission line for a few years. The subtransmission line would not be taken out of service or out of the rate base, however, once the larger line was in place. It would instead be considered a permanent part of the power system.

How transmission costs are incurred and paid for is also important. Transmission is a long-lived, capital intensive, low maintenance investment with almost no cost related to use. Once installed, in one sense, use of transmission is free; there appears to be no marginal cost. Conversely, demand response typically has costs (or user inconvenience) associated with each use; there is a marginal cost. Consequently, once transmission is available it is used instead of demand response, furthering the idea that demand response is a short lived, high operating cost solution when compared with transmission.

While transmission projects have few costs associated with use they do have significant annual maintenance costs. Transmission assets deteriorate rapidly with no maintenance (tree trimming, relay and breaker maintenance, etc.). It is difficult to tie specific costs to specific users but the marginal costs are there.

Regulatory Treatment of Transmission and Demand Response Costs

Transmission is almost always a regulated asset. Once it is in the rate base, its costs are fully covered. Demand response is not usually treated as a regulated capital resource placed in a rate base. Demand response may be cheaper overall but once transmission is available transmission always appears to be lower cost. Transmission cost recovery is essentially guaranteed once a project is built. A 230 kV high voltage transmission line would not be taken out of the rate base when an extra high voltage 765 kV line was overlaid on the transmission system, regardless of how line loadings changed.

Reliability regions and ISOs are typically barred from actively developing demand side resources as alternatives to transmission enhancement. Their role is limited to facilitating competitive markets where generators and loads can economically optimize their production and use of energy. Their transmission planning activities identify constraints that are or will be impacting reliability or commerce. Regulated transmission providers and competitive generation and demand entities are expected to offer solutions, which the ISO and region assess.

BPA seems to have considered this rational as well. A 2001 BPA consultant report stated: "In many respects these nonwires activities have been outside of TBL's (Transmission Business Line – BPA's transmission side of the business) purview and TBL has had to be passive with respect to them. If they happen, TBL can account for them, but it cannot make them happen."[269] BPA changed its approach to transmission planning and now formally considers non-wires alternatives for all transmission enhancement projects costing $2 million or more.

Reliability of Statistical Demand Response

An often expressed concern is that demand response is not as reliable or as certain as generation response. While there is no absolute guarantee that any physical resource will be able to provide a specific response at any specific time, large generators have dedicated staff, extensive monitoring and control, and strong economic incentives to actually provide the response they are contracted to provide. Loads, especially small loads, do not have the same staffing or equipment resources. Response is voluntary in some cases. Nevertheless, there is good reason to believe that the inherent reliability of the response from aggregations of small loads is actually better than the reliability of response from large generators.

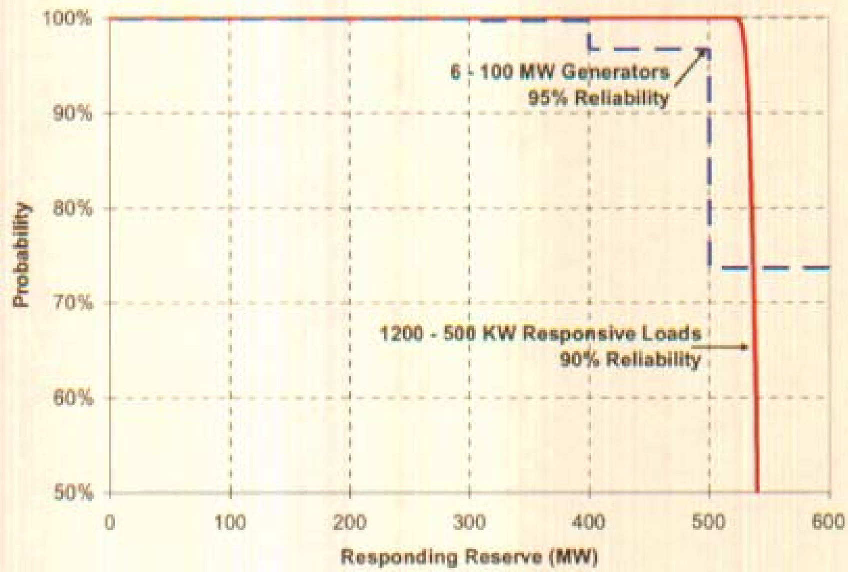
Fundamentally, curtailments based on customer actions are a statistical resource, while generation is a deterministic resource. Some load reductions are large and deterministic while some generators are small and statistical; but as a general rule, individual load reductions are small, are important in aggregate, and behave statistically; individual generators are large, are important individually, and

[269] R. Orans, S. Price, D. Lloyd, T. Foley, and E. Hirst, *Expansion of BPA Transmission Planning Capabilities*, Bonneville Power Administration, November 2001.

behave deterministically. There are advantages to both types of resources and both should be used. The important thing to note is that there are differences.[270]

Aggregations of small demand response resources can provide greater reliability than fewer numbers of large generators, as illustrated in Figure VI-6. In this simple example, operating reserves are being supplied by six generators that can each provide 100 MW of response with 95 percent reliability. There is a 74 percent chance that all six generators will respond to a contingency event and a 97 percent probability that at least five will respond, which implies a nontrivial chance that fewer than five will respond. This can be contrasted to the performance from an aggregation of 1,200 demand response resources of 500 kW each with only 90 percent reliability each. This aggregation typically delivers 540 MW (as opposed to 600 MW) but never delivers less than 520 MW. As this example illustrates, the aggregate demand response is much more predictable and the response that the system operator can "count on" is actually greater.

Figure VI-6 Comparison of probability of response between aggregated demand response and fewer large generators



Source: Brendan Kirby of Oak Ridge National Laboratory

Operating reserves have historically been provided by large generators that are equipped with supervisory control and data acquisition monitoring equipment that telemeters generator output and various other parameters to the system operator every few seconds. Operating reserve resources are closely monitored for three reasons: (1) to inform the system operator of the availability of reserves before they are needed; (2) to monitor deployment events in real time so that the system operator can take corrective action in case of a reserve failure; and (3) to monitor individual performance so that compensation motivates future performance. Because the same monitoring system provides all three functions, we often fail to distinguish between these functions. For small loads, it may be better to look at each function separately.

[270] Kirby, 2003.

The statistical nature of aggregated demand response lends itself to useful forecasting in place of real-time monitoring. Forecasting errors for load-supplied reserves can be more easily accommodated than forecast errors for the total load. A 10 percent error in the load forecast for a 30,000 MW balancing authority can result in a 3,000 MW supply shortfall. A 10 percent error in 600 MW of expected reserve response from demand response can be handled by derating the resource and calling for 10 percent more response than is needed. This derating can be refined as experience is gained.

Demand response forecasting errors for large aggregations of small responding loads are fortunately correlated with overall load forecasting errors. If total load is higher than the forecast, so are the available reserves from demand response.

Metering requirements could be based on the reliability requirements of the system, recognizing that large deterministic resources present a different monitoring requirement than aggregations of small statistical resources in order to achieve the same system reliability.

Manual Override and Voluntary Response

Demand response programs often find that they must accommodate voluntary response in order to increase participation. This is not surprising. While the cost of electricity is important to most consumers, it is only one of many costs. Loads often find it impossible to make firm, long-term curtailment commitments because there is some chance that external events (external to the power system) will prevent them from reducing power consumption when requested. Even if a customer is able to respond 99 percent of the time, the other one percent of the time may be perceived to be of such high importance that the load is unwilling to participate in a curtailment program. This reaction is surprisingly universal; it can be true for residential as well as commercial and industrial customers.[271] Day-ahead and hour-ahead hourly markets reduce or eliminate this problem for many large loads and generators. But the transaction burden of constantly interacting with energy and ancillary service markets is likely too great for many small loads. Many will prefer to establish a standing offer for response that they are able to honor the vast majority of the time.

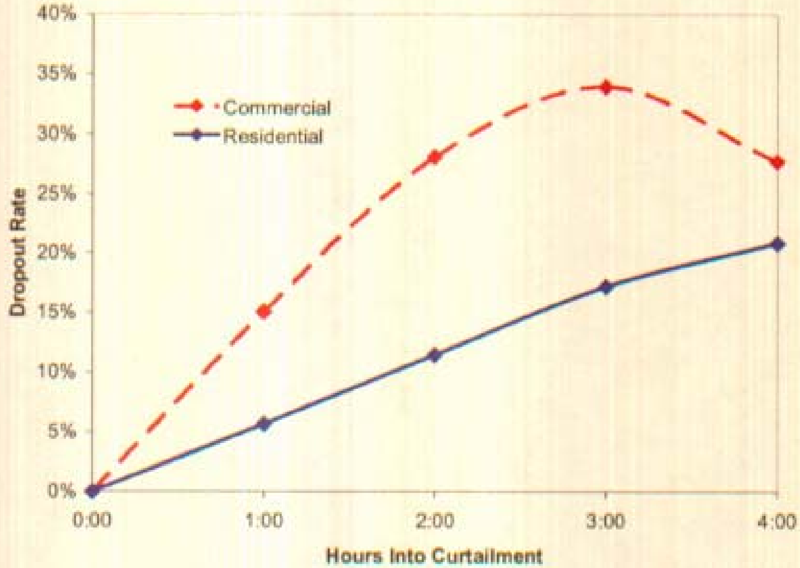
Manual override provides an alternative with benefits for both the power system and the customer. With a manual override feature, the load curtailment occurs, but the individual customer has the option of overriding the curtailment. The advantage to the power system is that this option increases the load participation and likely reduces the required compensation. The advantage to the customer is that it can opt out of a particular curtailment if the inconvenience or cost for the specific event is unusually high. Many peak reduction programs now include this feature, and it appears to be successful. Most important, the increase in participation outweighs the number of customers overriding the curtailment. How the opt-out is configured can be important.

The natural fear from the power system side is that many customers will always opt out, but the size of this problem may not be large. Opting out requires the customer to notice that the curtailment is happening and decide that the inconvenience is too great. The customer must take specific action for

[271] An industrial load may have an unexpected order and consequent production goal. A residential customer may have a sick child at home and be unwilling to allow air conditioning curtailment. Neither event could be predicted in advance and neither event is tied to power system conditions.

each event. Customers that chronically opt out could also be dropped from the program. Figure VI-7 shows the override experience for the LIPA Edge program during peak reduction testing on the afternoon of August 14, 2002.[272] By three hours into the curtailment, a significant number of customers were overriding and this must be considered when valuing the program.

Figure VI-7 Statistics from the LIPA Edge program manual override experience



Source: Brendan Kirby of Oak Ridge National Laboratory

Manual override is less of a problem when spinning reserve and contingency response is being supplied than when the peak load is being reduced for two reasons: (1) contingency event duration is shorter, and (2) natural human inertia and the slow temperature rise prevents customer response within the typical spinning reserve deployment event. But there is a technical solution as well. For example, there are types of smart thermostats that offer the power system operator the additional option of distinguishing between events that the customer can override and events that the customer cannot. This provides the customer with the ability to opt out of longer demand reduction events while blocking the override during shorter contingency events.

Capacity Credit

Demand response programs are sometimes economically disadvantaged in areas with formal capacity markets. For example, some markets impose an artificial requirement that response must be available 24 hours a day, all season long. This is reasonable when the only source of response is generation whose availability is typically not time variant. Some load is not available to respond in rectangular strips, however. But it is always available when the power system is most heavily loaded and most stressed; at the time of the daily load peak. The ancillary services of regulation, spinning, and non-spinning reserves are needed just as much as capacity that is delivering real-power to serve load.

[272] Kirby, 2003.

Co-Optimization – Response Cost Vs Duration

Many demand response resources differ from most generators in that the cost of response rises with response duration. An air conditioning load, for example, incurs almost no cost when it provides a 10-minute interruption but incurs unacceptable costs when it provides a six hour interruption. Conversely a generator typically incurs startup and shutdown costs, even for short responses but only has ongoing fuel costs associated with its response duration. In fact, many generators have minimum run times and minimum shutdown times. This low-cost-for-short-duration-response (coupled with fast response speed) makes some demand response resources ideal for providing spinning reserve but less well suited for providing energy response or peak reduction.

This policy works well for most generators but causes severe problems for loads that need to limit the duration or frequency of their response to occasional contingency conditions.[273] Loads can submit very high energy bids in an attempt to be the last resource called but this is still no guarantee that they will not be used as a multi-hour energy resource. Submitting a high cost energy bid also means that the load will be used less frequently for contingency response than is economically optimal. Price caps on energy bids further limit the ability of the loads to control how long they are deployed for.

California had this problem with its Rational Buyer approach, but it has since changed its market rules. It now allows resources to flag themselves as available for contingency response only. PJM allows resources to establish different prices for each service and energy providing a partial solution. ERCOT does not have this problem because energy is supplied through bilateral arrangements. Energy and ancillary service markets are separate. Possibly as a consequence, half of ERCOT's contingency response comes from demand response.

Steps that could be taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment

Section 1252(e)(3) of EPAct 2005 requires that the Commission identify steps that could be taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment. Based on comments and Commission staff review of regional transmission planning and operations, Commission staff has identified several actions and steps that could be taken to obtain increased access for demand resources. The merits of taking the following steps should be considered by appropriate transmission planners and state and federal regulators:

- Assure that regions that schedule resources and reserve needs properly recognize the capabilities and characteristics of demand resources, particularly when energy and ancillary services are co-optimized.
- Assure that requirements are specified in terms of functional needs rather than in terms of the technology that is expected to fill the need. This applies to ancillary services as well as to transmission enhancement.
    - Value response speed and accuracy.
    - Value statistical response.

[273] Co-optimization often does not work for energy or emissions-limited generators either.

- Accommodate the inherent characteristics of demand response resources (just as generation resource characteristics are accommodated).
    - Recognize that some demand response resources have maximum run times.
    - Recognize the statistical nature of demand response from aggregations of numerous small loads.
    - Recognize that the monitoring and communications requirements to maintain system reliability are fundamentally different for aggregations of large numbers of small resources than they are for fewer large resources.
    - Recognize the coincidence of demand response capability and total system load. Allocate appropriate capacity credit to demand response.
    - Accommodate voluntary response and perform the research required to establish the level of reliable response capability.
- Allow appropriately designed demand response resources to provide all ancillary services including spinning reserve, regulation, and any new frequency responsive reserves.
- Allow for the consideration of demand response alternatives for all transmission enhancement proposals at both the state and ISO/RTO level.
    - At the minimum, transmission expansion planning procedures would allow demand response resources to be proposed and considered as solutions to congested interfaces or load pockets along with local generation or transmission enhancements.
    - Require demand response evaluations early enough in the process so that demand response solutions can actually be developed.
    - Require reporting of alternatives considered and reasons for decisions.
- When appropriate, treat demand response as a permanent solution, similar to transmission enhancements.

Chapter VII. Regulatory Barriers

This chapter addresses the sixth area, in EPAct 2005 section 1252(e)(3), that Congress directed the Commission to consider:

> *(F) regulatory barriers to improved customer participation in demand response, peak reduction and critical period pricing programs.*

The regulatory barriers discussed in this chapter are based on input received in written comments, comments filed and discussion heard at the FERC Demand Response Technical Conference (FERC Technical Conference), a review of demand-response program experience, and through a comprehensive literature review.[274]

Regulatory Barriers

Disconnect Between Retail Pricing and Wholesale Markets

The most frequently mentioned regulatory barrier in the literature and in the comments reviewed by Commission staff is the disconnect between fixed retail rates and fluctuating wholesale prices. By placing even a small percentage of customers on tariffs based on time-based rates, resources can be allocated more efficiently. Time-based rates offer customers incentives to shift their consumption to periods with lower rates and allow them to save on their energy bills. This is true with or without retail choice. And because the cost of delivering energy during peak periods is higher than averaged flat rates, average pricing results in an income transfer from customers who use a lower proportion of their energy during peak periods to those who use a high fraction of their electricity on peak.[275]

Because most customers do not face time-varying prices (see Chapter IV discussion), they are charged prices associated with the average cost to produce electricity calculated over extended period of months or years. Large customers in a few states have direct exposure to hourly pricing, but this is the exception, not the rule.[276] The Government Accountability Office (GAO), in its 2004 report on demand response, highlighted this disconnect: "Most of today's electricity system is a hybrid – competition setting wholesale prices and regulation largely setting retail prices. In addition, local public power entities (munis) and rural electric coops (co-ops) account for about 25 percent of the wholesale market and are self-regulated."[277]

Even though the benefits of placing at least some customers on time-based rates is well documented, and while major industry organizations and regulatory agencies are in favor of greater implementation

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[274] Earlier chapters discussed barriers associated with non-regulatory areas such as implementation and customer perception.

[275] California Energy Commission, *Feasibility of Implementing Dynamic Pricing in California*, report to the legislature to satisfy the legislative requirement of SB 1976, October 2003, http://energy.ca.gov/reports/2003-10-31_400-03-020F.PDF.

[276] Only a few states such as California, Connecticut, Illinois, and New York have taken actions to introduce greater amounts of time-based rates into their jurisdictions.

[277] GAO, *Electricity Markets: Consumers Could Benefit from Demand Programs, But Challenges Remain*, GAO-04-844, August 2004, 9.

of time-based rates,[278] the structure of retail rates is largely based on fixed rates. Only a few states such as California, Connecticut, Illinois, and New York have taken actions to introduce greater amounts of time-based rates into their jurisdictions. The basic structure of retail rates has not changed significantly for decades, and even the default (standard offer service or Provider of Last Resort (POLR)) rates offered in restructured states usually maintain the historic non-varying rates and rate structures or use pre-specified fixed prices. The disconnect between retail rates and wholesale markets has grown larger as opportunities to integrate demand response into wholesale markets have increased, but retail offerings have stagnated.

ISO-NE's CEO, Gordon van Welie, posited that the continuation of flat retail pricing is "paternalistic and outdated," stating his belief that "some form of dynamic pricing should be the basis for default service pricing for large customers."[279] However, others argue against implementation of time-based rates based on concerns about whether consumers can reasonably be expected to adjust their demand for essential uses. For example, the Pennsylvania Office of Consumer Advocate argues that time-based rates "are not appropriate when the usage relates to essential home heating or air conditioning and necessary appliance usage."[280]

Although there have been many experimental and pilot programs, it is not clear why these have not moved into full implementation. As a panelist at the FERC Technical Conference expressed it, "we are suffering the death by a thousand pilots."[281]

The examination of smart metering and time-based rates in the state deliberations required by EPAct 2005 should shed some light on this barrier, and may lead to greater deployment of advanced metering and time-based rates. In addition, advances in technology and cost declines associated with metering and controls, in combination with the greater system benefits they now offer, should also help ameliorate concerns about cost-effectiveness.

Utility Disincentives Associated with Offering Demand Response

A long-standing barrier to electric utility investment in and promotion of customer demand-side programs is that historically, utilities make money from the sale of electricity. Otherwise stated, traditional rate-making models have been based on formulas of:

PROFIT = REVENUE – COSTS and REVENUE = PRICE * QUANTITY [282]

Any actions taken by customers to reduce their overall consumption through energy efficiency, adjustment of their consumption in response to prices or load reductions during peak periods or reserve shortages, will likely reduce short-term utility revenues if they result in a reduction in kWh consumption or reduced customer peak demand. In particular, utilities cannot be assured that if customers shift their peak load reductions to off-peak usage, the utility will remain revenue neutral. As NERA stated, "while utilities have long championed conservation for a variety of long-term business reasons, it is possible that demand response would decrease earnings in the short-term and

[278] For example, the Edison Electric Institute and New York Public Service Commission.

[279] Gordon van Welie, speech to 2006 ISO-NE Demand Response Summit, April 27, 2006.

[280] Pennsylvania Office of Consumer Advocate, comments filed in Docket AD05-17, November 18, 2005.

[281] Alison Silverstein, FERC Technical Conference, transcript, 42:9.

[282] Frederick Weston and Wayne Shirley, "Scoping Paper on Dynamic Pricing: Aligning Retail Prices with Wholesale Markets," prepared for MADRI Regulatory Subgroup, June 2005, 1, 12-15.

that this would serve as a disincentive for the utility to play an active role in promoting demand response."[283]

The restructuring of the electric industry has added additional disincentives for distribution utilities. In some states, utility divestiture of generation and load-management assets [284] and the transfer of the POLR obligation to serve have removed significant drivers for utility investment. If a distribution utility does not have a direct load responsibility, then the long-term benefits associated with operating demand response as a resource are driven more by impacts on local distribution operation and reliability, and these are usually a small fraction of avoided generation costs.

Policies to address utility disincentives to demand-side activities and management have been suggested and implemented for many years.[285] Policy changes fall into three categories:

- **Remove Disincentives.** Policies that remove retail rate structures and rate designs that have discouraged implementation of demand response by decoupling profits from sales volumes.
- **Recover Costs.** Policies that give utilities a reasonable opportunity to recover the costs of implementing demand-response programs.
- **Reward Performance.** Sometimes referred to as performance-based ratemaking, retail rates and regulatory policies can include incentives for implementing high-performance demand-response programs. Incentives are usually higher returns on investment if the programs demonstrate success, through reduction of peak demand or peak period energy use, or payments based on increased customer enrollment. Shared-savings mechanisms (where utilities share the savings and/or profits associated with the demand-response programs with customers or third-party aggregators) can also be employed as another performance incentive.

Productive discussions on the best means to address utility disincentives continue. Decoupling policies are being actively examined in state proceedings, and have been implemented in California and Oregon. Other states such as New York[286] and Connecticut[287] rejected rate decoupling, noting the negative impact that large revenue accruals can have on rate stability. A recently approved rate plan for Consolidated Edison provides an additional example of policies that are directed at removing disincentives. Under the rate plan, Consolidated Edison will recover demand-response implementation costs (spread over three to five years) through monthly adjustment charges for all electric customers who benefit. Their incentive to perform is based on a process Consolidated Edison and the NYPSC agreed on in order to monetize the costs of demand response and "make the distribution company whole" by doing demand response.[288] Consolidated Edison is entitled to recover the lost revenues from demand management that are incremental to what are already contained in its

[283] NERA Economic Consulting (NERA), *Distributed Resources: Incentives*, prepared for EEI, April 20, 2006, 10.

[284] More than 3,500 MW of capacity from interruptible contracts no longer exists. Steven Braithwait, B. Kelly Eakin, Laurence D. Kirsch, *Encouraging Demand Participation In Texas's Power Markets*, Laurits R. Christensen Associates, Inc., prepared for the Market Oversight Division of the Public Utility Commission of Texas, August 2002.

[285] A good summary of these policies in included in Hope Robertson, *Focusing on the Demand Side of the Power Equation: Implications and Opportunities*, Cambridge Energy Research Associates, May 2006, 15-16.

[286] State of New York Public Service Commission, Case No. 03-E-0640, Staff Report, July 9, 2004, 7-8.

[287] Connecticut Department of Public Utility Control, *Investigation into Decoupling Energy Distribution Company Earnings from Sales*, Final Decision, Docket No. 05-09-09, January 18, 2006.

[288] MADRI business case subgroup meeting and conference call, May 15, 2006; for ConEd's demand-side agreement; and NYPSC Order on Demand Action Plan, Case 04-E-0572, March 15, 2006, see http://www.energetics.com/MADRI/#may06