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CONFIGURING LOAD AS A RESOURCE FOR COMPETITIVE ELECTRICITY MARKETS – REVIEW OF DEMAND RESPONSE PROGRAMS IN THE U.S. AND AROUND THE WORLD

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Abstract

The restructuring of regional and national electricity markets in the U.S. and around the world has been accompanied by numerous problems, including generation capacity shortages, transmission congestion, wholesale price volatility, and reduced system reliability. These problems have created new opportunities for technologies and business approaches that allow load serving entities and other aggregators to control and manage the load patterns of wholesale and retail end-users they serve.

Demand Response Programs, once called Load Management, have re-emerged as an important element in the fine-tuning of newly restructured electricity markets. During the summers of 1999 and 2001 they played a vital role in stabilizing wholesale markets and providing a hedge against generation shortfalls throughout the U.S.A.

Demand Response Programs include "traditional" capacity reservation and interruptible/curtailable rates programs as well as voluntary demand bidding programs offered by either Load Serving Entities (LSEs) or regional Independent System Operators (ISOs).

The Lawrence Berkeley National Lab (LBNL) has been monitoring the development of new types of Demand Response Programs both in the U.S. and around the world. This paper provides a survey and overview of the technologies and program designs that make up these emerging and important new programs.

Keywords

Demand Response, Load Management, Demand Bidding, Back-up Generation, Price Responsive Load

1. INTRODUCTION

Lawrence Berkeley National Laboratory (LBNL), with funding from the Department of Energy Office of Power Technologies and the Electric Power Research Institute, has been examining the potential role of customer load participation in wholesale and retail electricity markets both in the U.S. and around the world. This study summarizes key findings from two separate research projects. The first project includes case studies of approximately thirty demand response programs in the U.S. offered by twenty one program administrators including investor-owned utilities, ISOs, and a federal power marketing authority (see Table 1).[1] The thirty programs surveyed encompass an array of program types - innovative demand bidding programs as well as more traditional interruptible load management programs.[2] We focus on the market potential of price-responsive load programs and summarize program experience and lessons learned. Case studies were developed based on phone interviews with program managers, review of program information materials, and evaluation studies. The survey covered key program elements such as target markets, market segmentation, and participation results; pricing schemes; dispatch and coordination; measurement, verification, and settlement; enabling technologies; and operational results, where available. The second project includes case studies of another fifteen demand response response programs offered by utilities and power exchanges around the world.[3]

2. U.S. DEMAND RESPONSE PROGRAMS

Demand Response programs in the U.S. have been a growth industry since 1999, when abnormally hot weather combined with generation shortages and transmission congestion resulted in unheard-of wholesale price levels and defaults by some major power brokers. As Table 1 indicates, demand response programs are now offered by a variety of organizations doing business in both regulated retail markets and competitive wholesale markets.

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[1] Earlier work on demand response programs is summarized in Heffner, G. and C Goldman. "Demand Response Programs – An Emerging Resource for Competitive Electricity Markets," 2001 International Energy Program Evaluation Conference, August 21-24, 2001, Salt Lake City, Utah.

[2] A number of programs offered distinct options, where, in one option, participants could be requested to curtail due to system reliability considerations and in the second option, participants could offer to curtail loads in response to wholesale electricity price signals. In our analysis, these options were treated as separate programs in order to draw key distinctions.

[3] This work, funded by EPRI, yielded a proprietary data-base on demand response programs. Contact Dr. W. M. Smith of EPRI at wmsmith@epri.com for more details.

2.1 Demand Response Program Types

Demand Response Programs are grouped into two broad categories: "reliability-based" programs that operate in response to system contingencies and "market-based" programs that are triggered by wholesale market prices. Reliability-based programs are often referred to as "contingency" programs because they are only utilized during emergency conditions, such as generation shortages or when price levels are above allowable caps.

2.2 Summer 2001 Results

Demand Response Programs and other DSM/energy efficiency programs played an important role in mitigating electrical system emergencies in several regions of the country during Summer 2001. The week of August 4, 2001 was a particularly hot period throughout the East Coast. During this period, price-responsive load and other programs reduced system peak demands by 3-6% and helped avert potential system emergencies (see Table 2).

In other regions of the country, however, the summer of 2001 was a relatively low-activity year for demand response load programs.

Of the 30 programs surveyed, only a handful operated more than ten times during 2001. Fourteen of the programs operated just once or not at all. The proximate cause for the generally low level of activity was the limited number of reliability events and relatively low wholesale electricity market prices. However, despite their infrequent operation, several programs played a critical role in mitigating regional system contingency events and provided significant economic and system reliability benefits throughout the year.

2.3 "Contingency" Demand Response Programs

Record setting peaks occurred throughout New England and the Mid-Atlantic regions during the week of August 7. The Contingency programs of NYISO, PJM, ISO-NE, and BG&E were all operated during this period, providing critical relief to the strained grid. The NYISO Emergency Demand Response Program (EDRP) provided an average demand response of 425 MW on four occasions, equivalent to approximately 25% of the total system reserve requirement. An analysis of the program impact estimates that, for *a single hour* during this period, the EDRP likely provided reliability benefits of between $870,000 and $3,484,000. The program is estimated to have resulted in an additional $16.8 million dollars in collateral benefits, associated with reductions in electricity prices and volatility, over the duration of the summer.[4]

The big surprise was California, with only one contingency event throughout the entire summer - despite NERC's predictions of more than 260 hours of rolling blackouts. A major contributing factor was the extensive level of peak demand reduction (on the order of 10%) resulting from a combination of energy efficiency and demand response programs, voluntary initiatives, increases in electricity rates, and widespread media attention. On the single curtailment day 800 MW was curtailed, the majority of which was attributable to the interruptible and direct load control programs of Southern California Edison.

Xcel's Electric Reduction Savings Program also operated quite frequently during summer 2001, with 20 events. However, the program was not generally operated in response to explicit reliability conditions (e.g., generation shortages or transmission constraints), but was, instead, operated so that Xcel could avoid exceeding MAPP authorization levels and paying the associated fines.

2.4 "Market" Demand Response Programs

In the Pacific Northwest, several day-of and day-ahead bidding programs had high activity levels during the winter and spring of 2001, driven by high wholesale electricity prices. However, during the summer there was a dramatic drop-off in demand-response program activity, apparently driven by the Federal Energy Regulatory Commission's (FERC) price mitigation measures. Many programs base the incentive for participants on roughly a 50/50 sharing of the avoided wholesale purchase cost. With the Western soft price cap of approximately $92/MWh, the incentive available for participants dropped down into the $40-50/MWh range, which is well below the level at which most end-users would be willing to bid in load. For example, the day-ahead bidding component to Portland General Electric's (PGE) Demand Buy Back Program (Q), which had been active up until that point, received no bids once the price caps were implemented. However, PGE's program did provide curtailments on an almost daily basis during the summer through "term" events that had been procured prior to the drop in wholesale prices (i.e., demand buy-back initiatives). In California, participants submitted bids for the Demand Bidding Program regularly throughout the summer, but the California Department of Water Resources accepted none because prices remained below the minimum available bid price of $100/MWh.

In the Midwest, program activity was low as a result of the soft wholesale electricity prices throughout the region. Wabash Valley Power Authority's Customer Payback Plan was originally offered with a $200/MWh strike price, but prices remained well below this level, and the strike price was dropped to $50/MWh but there were still no bids offered or accepted.

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[4] Neenan Associates (2002), NYISO PRL Program Evaluation: Executive Summary.

During the August heat wave on the East Coast, real time electricity prices reached $1000/MWh in both ISO-NE and NYISO markets, and more than $900/MWh in PJM's region. All three programs provided load relief during these periods, although the level of load curtailment was generally small. The NYISO's Day Ahead Demand Response Program was available for bidding on a continual basis and operated throughout the summer on 24 occasions.

3. PRELIMINARY FINDINGS – DEMAND RESPONSE PROGRAMS IN THE U.S.

(1) Load relief from "Market" Demand Response programs is typically much lower and often less predictable than load relief from Contingency programs.

The average potential curtailable load for DR Contingency programs and DR Market programs were similar (see Table 3). However, the two program types differed markedly in the load curtailment actually delivered in our sample of DR programs. When system reliability events occurred, actual load curtailments from DR Contingency programs were, on average, about 62% of the potential curtailable load from participating customers. In contrast, the average curtailed load in our sample of DR Market programs was, on average, only about 17% of the potential curtailable load (see Figure 1). There are several possible explanations:

Incentive Mechanisms. The incentive mechanism encompasses both the payment for curtailment and the penalty for non-compliance. Contingency programs are generally "Call-type" programs, in which participants agree ahead of time to provide a specific level of curtailable load upon notification, and in many cases are subject to non-compliance penalties if they fail to meet their commitment. About 50% of the Contingency programs in our sample levied some form of financial penalty.[5] For example, in Kansas City Light and Power's Peak Load Curtailment Program, participants performed at 30% *above* their committed level in aggregate, reportedly in order to avoid non-compliance penalties. Market programs, on the other hand, are generally "Quote-type" programs, where customer participation is "voluntary."[6] Participants are paid solely on the basis of MWh curtailed, and decide on their level of load curtailment on a day-by-day basis, without the risk of being penalized. The decision to curtail is based on a comparison of the curtailment payment to their outage costs, and because both will tend to vary considerably, participation in Quote-type Market programs is highly volatile.

Definition of Potential Curtailable Load. In Contingency programs, participants typically pledge a specific level of curtailable load when they sign up for the program, providing program administrators with a relatively clear measure of the potential curtailable load for the program. In Quote-type Market programs, however, there is no analogous measure of the potential curtailable load of the program. Some program administrators use each participant's peak or average demand as their potential curtailable load, which generally overstates the load reductions that participants are willing to provide, thereby contributing to the apparent low performance of these programs. In this case the difference in performance level may have more to do with unrealistic expectations than with poor performance. Alternatively, some administrators of Market programs work directly with participants to identify specific load curtailment strategies. This approach can provide a more realistic and justifiable measure for realistically estimating the potential curtailable load of a program.

Low Wholesale Electricity Prices. Since the incentive for participation in Market programs is generally tied to wholesale electricity prices, and wholesale prices were generally low in 2001, participation in these programs was limited. Often, only several participants in a program actively bid, with a higher level of participation on days with exceptionally high prices. When prices did spike, it was often in concert with a reliability event, and many customers who simultaneously participated in Contingency programs had their load curtailment resources already committed.

(2) Backup Generators (BUGs) were a favorite demand reduction strategy among customers, but environmental impacts are a concern and must be addressed

Emergency Backup Generators (BUGs) were a particularly popular strategy used by many customers to participate in DR programs. From the customer's perspective, BUGs provide a predictable level of load reduction - their operation can be initiated quickly and with minimal disruption to the end-user's normal operations; and, in many cases, they are already in place, minimizing any additional capital expenses required for participation in a DR program. However, many BUGs are diesel-powered and more polluting than typical central station power plants; thus, their use is typically restricted to a relatively few number of hours per year (e.g., 100-500 hours) by the local air quality control district.

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[5] NYISO's Emergency Demand Response Program (EDRP), which achieved an average load reduction of 450 MW out of a potential curtailable load of 700 MW, did not penalize participants for non-compliance. However, many of the participants in EDRP simultaneously participated as Special Case Resources in NYISO's Installed Capacity Program, which did include non-compliance penalties, and it is unclear at this time to what extent this may have played a role in the relatively high level of performance of the EDRP.

[6] Among our case studies, Cinergy's PowerShare Call Option, Wabash Valley Power Authority's Customer Payback Plan, and Commonwealth Edison's Voluntary Load Reduction Program were the only instances of Call-type Market programs. All of the remaining 17 Market program included in our survey were Quote-type programs.

Among programs in our sample, BUGs represent approximately 17% of the total potential curtailable load.[7] BUGs tended to be more heavily used in Contingency programs, representing 31% of potential load reduction compared to 12% in Market programs (see Figure 2).

Use of BUGs may have been even more pronounced but some states precluded or limited their use in DR programs. For example, BUGs were not allowed in BPA's Demand Exchange Program, PacifiCorp's Energy Exchange Program or Portland General Electric's Demand Buy Back Program. In Dominion Virginia Power's Economic Load Curtailment Program, participation in northern Virginia was reportedly limited due to the more stringent air pollution requirements in that region. Because of the potentially significant reliability benefit that BUGs can provide, states may wish to consider allowing their use for a limited number of hours (e.g., 100-200) per year for DR Contingency programs.

4. DEMAND RESPONSE PROGRAMS AROUND THE WORLD

In mid-2001LBNL conducted a phone and e-mail survey of demand response programs around the world. Our objective was to compare the trends in demand response programs in the U.S. with the activities elsewhere in the world. Summary results are shown in Table 4.

We found that demand response programs around the world are in a transitional state that is not dissimilar to the situation in the .. Many utilities, especially those in Asia, still have strong load management programs that emphasize utility control of end-uses. Other utilities have ongoing efforts in real-time pricing or ice storage, both of which shift loads from on-peak to off-peak periods.

However, we also found several programs – notably the Stattnet load reservation program and the TEPCO and Tai Power Company industrial interruptible programs – that are quite similar to counter part demand response programs in the U.S.

Only Stattnet, however, offered a program where the offeror was a regional transmission organization (RTO) or independent system operator (ISO) such as that found with increasing frequency to be operating demand response programs in the U.S. We suspect that this will change as regional power pools are introduced around the world.

Table 4: Results of Overseas Demand Response Program Survey

Region	Utility or Offeror	Program Name	Description
Europe	Stattnet	Load Reservation for Power Regulation	Industrial load shedding as an ancillary service offering
Europe	EDF	TEMPO	Real-time pricing
South America	Eletrobras	Demand Controller	Domestic water heater load control
Africa	ESKOM	HW Cylinder Load Control	Domestic water heater load control for distributors
Asia	KEPCO	AC Load Control	LV AC Load Control
Asia	KEPCO	Ice Storage Cooling	Commercial Buildings Thermal Storage
Asia	Kyushu Electric	AC Load Control	Domestic AC load control
Asia	Tai Power Company	Package AC Load Control	Cycling of commercial air conditioners (20 hp minimum)
Asia	Tai Power Company	Interruptible rates for HV customers	Several levels of curtailment or interruption offered for 500 kW + customers
Asia	Tai Power Company	Large Commercial AC Load Cycling	For 100 hp + AC loads, paging system for load control
Asia	TEPCO	Large Customer Interruptible Program	Large customers interrupt 500 kW or more of load w/ 3 hours notice
Asia	TEPCO	ECO-Ice Program	Incentive payments to popularize ice storage for small commercial & domestic users

[7] Several programs in our sample did not provide an estimate for the percent contribution from BUGs, although they did indicate that a significant portion of their potential curtailable load was associated with BUGs. Since these programs were not included in the calculation, it is likely that the overall contribution of BUGs among our sample was in the 20-25% range.

Table 1: Case Study Programs and Program Administrators

Administrator(s)	Organization Type	Programs	Reference Code*
AES NewEnergy	Retail Electricity Service Provider	Incremental Incentive Curtailment Program	A
Ameren	Investor-Owned Utility	Customer Energy Exchange	B
Baltimore Gas and Electric	Investor-Owned Utility	Load Response Program Option 1 Load Response Program Option 2 Rider 14 Emergency Generation and Rider 16 Curtailable Service	C2 C3 C4
Bonneville Power Authority	Federal Power Marketing Authority	Demand Exchange Pilot Program	D
Cal ISO	Independent System Operator	Demand Relief Program, Discretionary Load Curtailment Program	E1 E2
Cinergy	Investor-Owned Utility	Power Share Program	F
Commonwealth Edison	Investor-Owned Utility	Voluntary Load Reduction Program	G
Dominion Virginia Power	Investor-Owned Utility	Economic Load Curtailment Program	H
ISO-NE	Independent System Operator	Load Response Program – Class 1 Load Response Program – Class 2	I1 I2
Kansas City Power and Light	Investor-Owned Utility	Peak Load Curtailment Credit, Voluntary Load Reduction Program	J1 J2
Nevada Power, Sierra Pacific Power	Investor-Owned Utility	Optional Curtailment Program for Large Customers	K
NYISO	Independent System Operator	Day Ahead Demand Response Program, Emergency Demand Response Program	L1 L2
Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric	Investor-Owned Utility	Demand Bidding Program, Interruptible Programs, Optional Binding Mandatory Curtailment Program	N1 N2 N3
PacifiCorp	Investor-Owned Utility	Energy Exchange Program,	O1
PJM ISO	Independent System Operator	Load Response Pilot Program – Economic Load Response Pilot Program – Emergency	P1 P2
Portland General	Investor-Owned Utility	Demand Buy Back Program	Q
San Diego Gas and Electric	Investor-Owned Utility	Regional Blackout Reduction Program	R
Southern California Edison	Investor-Owned Utility	Direct Load Control Programs	S
Wabash Valley Power Association	Electricity Cooperative	Customer Payback Plan	T
Xcel Energy	Investor-Owned Utility	Electric Reduction Savings Program, Peak Day Partner Program	U1 U2

Table 2: Summer 2001 Contributions of Price-Responsive Load and Other DSM Programs.[8]

ISO	System Peak (MW)	Interruptible Load	Curtailable Load	Other DSM	Total DSM	DSM as % of Peak
PJM	52,977	2,000	70	-	2,070	3.9%
NY ISO	29,983	-	500	365	865	2.9%
ISO NE	25,675	-	65	1,522	1,587	6.2%

Table 3: Average Performance Characteristics of Contingency and Market Programs with Curtailment Events in 2001.

Program Type	Number of Programs	Average Potential Curtailable Load (MW)	Actual Average Curtailed Load (MW)	Actual/Potential
Contingency	8	158	84	62%
Market	10	204	21	17%

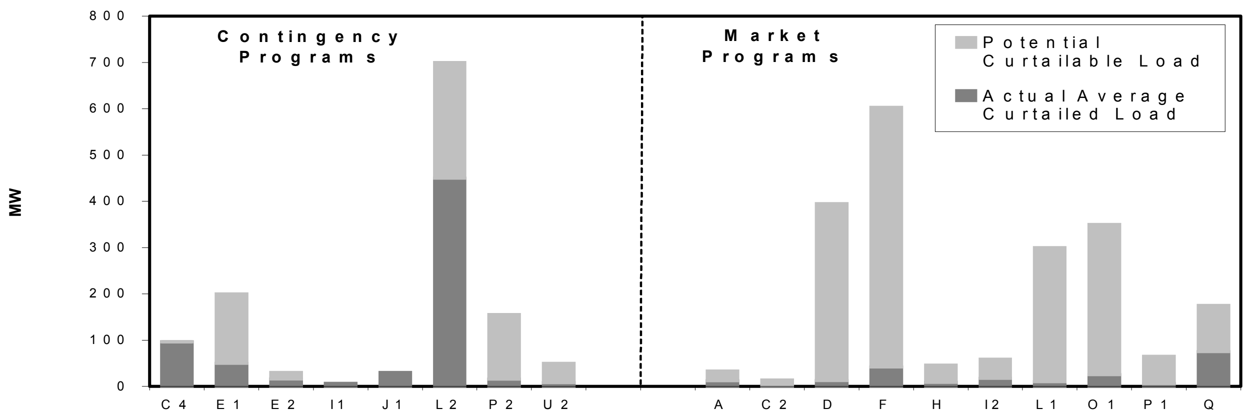

Figure 1: Comparison: Potential vs. Actual Curtailable Load in Contingency and Market Programs

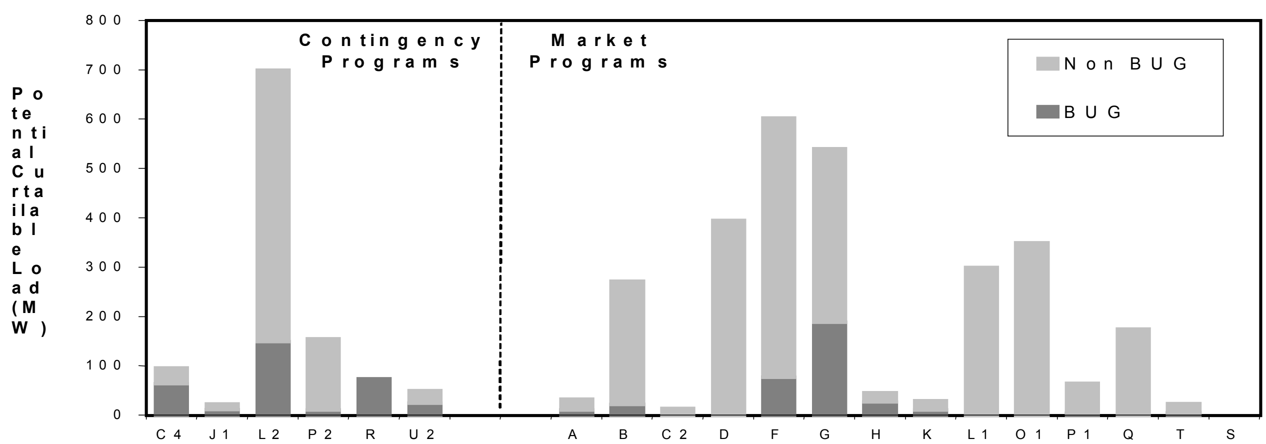

Figure 2: The role of backup generation (BUG) in demand response programs

[8] Based on Xenergy/KEMA Consulting. "Demand Response During Market Transition: Lessons of Summer 2001," Presentation to USDOE Office of Power Technology, Francis Cummings, Nov. 8, 2001.