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Demand Response Evaluation, Measurement, and Verification

A Synthesis of Evolving Protocols and Practices

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PRODUCT DESCRIPTION

As demand response programs become more widespread, there is increased interest in developing evaluation, measurement, and verification (EM&V) protocols to quantify their impact. The success of demand response and pricing plans depends on accurately measuring performance on an event basis. System planners and operators need accurate impact assessments because the load reduction can directly impact system security and reliability, which affects all consumers. This report contributes to the evolution of demand response performance measurement by developing a framework to understand when, how and why various methods are used, and then applying that framework to demand response programs in place today.

Results and Findings

A considerable body of literature has resulted from deliberations by Independent System Operators and Regional Transmission Organizations (ISOs/RTOs), utilities, regulators, policy makers and stakeholders to establish evaluation requirements and comprehensive protocols to implement them. Unfortunately, these materials are widely dispersed and often hard to access and interpret outside their specific circumstances. This report focuses on the quantification question – how utilities measure and verify load impacts from demand response programs in selected ISO/ RTO and utility programs with available data. It also proposes a framework for categorizing EM&V protocols in a way that facilitates understanding their purpose, matches them with demand response program objectives, and compares their performance among programs and pricing plans. A workshop involving ISO/RTO and utility representatives confirmed that the EM&V framework works equally well for wholesale and retail demand response programs. Moreover, the framework will contribute to another EPRI initiative to develop a product-oriented database for demand response programs, which would include categorizing the EM&V method (EPRI Report 1016086).

Challenges and Objectives

The framework presented herein will allow a designer who wants to adapt a wholesale demand response program for a retail application to identify a set of programs to compare performance measures, and select the right one to employ. Likewise, an evaluator who wants to establish expectations for a retail offering's performance will be able to identify a wholesale product to serve as a reference. In addition, the framework facilitates similar comparison among retail and wholesale programs, including analyses of their performance. At present, information about performance measurement is difficult to access and interpret due to a lack of a comprehensive framework and common terminology.

Applications, Values, and Use

The use of the same basic measurement principles for wholesale and retail performance protocols will realize several economies. First, customers will be able to utilize the experience they gain in one market (for example with a retail plan) in order to participate in another (under a wholesale plan). Second, the cost of measurement equipment (meters) and data processing likely will come down due to scale economies if programs adopt similar protocols. Third, the collective body of data available to evaluate how well the measures work will increase more rapidly. Finally, performance measurement standards will promote the development of enabling technologies to assist participants in meeting event curtailment expectations.

EPRI Perspective

EPRI's effort is unique because it proposes a framework for categorizing EM&V protocols that can accommodate both wholesale and retail demand response programs. The research reported herein constitutes a substantial contribution to understanding how demand response can contribute to providing reliable and low-cost electric service to all consumers.

Approach

The goals of the report were to develop a framework for demand response EM&V protocols and test that framework by applying it to selected ISO, RTO and utility demand response programs and retail pricing plans.

Keywords

Demand response
Demand response evaluation
Evaluation, measurement & verification (EM&V)
Dynamic pricing plans

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1 INTRODUCTION

Demand response programs are gaining popularity through a broad range of commercial arrangements organized to induce or impose a reduction in electricity usage. Some rely on the participant to decide whether and how to respond to a change in the price they pay for the electricity they consume, and are sometimes referred to as price response programs. Time-of-use rates and real-time pricing are examples of dynamic pricing plans that link the electricity prices to prevailing supply conditions and costs.

Alternatively, some demand response programs are demand call options. The participant's base service pricing and supply arrangements (typically a conventional uniform rate or time-of-use tariff) can be modified by the program administrator under specified terms and conditions. Critical peak pricing is an example wherein the posted peak time-of-use price is raised by a multiple of four or more to reflect either higher supply costs or the possibility of compromised reliability conditions. Still others involve the utility (or other program administrator) shutting off selected devices under agreed upon circumstances, in many cases with no recourse for the participant to override that instruction.

Demand response programs and pricing plans consist of terms and protocols that indicate how prices are set under all circumstances, when and how price changes can be invoked, and what, if any penalties are imposed for failure to modify usage. They also specify eligibility, set out contract terms and other conditions, and specify the types of metering and enabling technology required for participation.

A companion EPRI initiative is devoted to establishing a framework for classifying demand response programs and pricing plans to facilitate comparing the many programs that have been implemented by utilities, Independent System Operators and Regional Transmission Organizations (ISOs/RTOs), and curtailment service providers (entities that recruit customers to participate in programs sponsored by utilities or ISOs/RTOs). [1] That research revealed that the absence of a framework and common terminology for describing these programs makes it difficult to understand the variety of arrangements that are used and to compare their effectiveness. It is particularly difficult to figure out how load impacts are determined both for the purposes of rewarding participants and for assessing the performance of the demand response resources.

The success of demand response and pricings plans depends critically on performance being measured as accurately as possible on an event basis. Inaccuracies result in over-payments that erode the benefits realized in any event, or under-payments that reduce the level of participation.

[1] *A Proposed Framework for a Demand Response Product Database*. EPRI No. 1016086. Electric Power Research Institute. Palo Alto, CA. December 2008.

Moreover, in some cases the level of load reduction realized is directly related to system security and reliability which affect all consumers.

A considerable body of literature has resulted from deliberations by program designers and evaluators, regulators, policy makers and stakeholders to establish evaluation requirements and then to devise comprehensive protocols to implement them. These are supplemented by a large body of performance simulation data that characterize the strengths and weaknesses of these methods under different circumstances. ISOs/RTOs and some state agencies (for example, the California Energy Commission) have tried to develop comprehensive evaluation, measurement, and verification protocols that apply to specific programs.

Unfortunately, these materials are widely dispersed and often hard to access and interpret outside of the specific circumstances for which they were devised. Sometimes the protocols are highly customized to a specific product or circumstance in ways that are not readily apparent. Equally frustrating is the lack of common terminology which makes it difficult to determine whether common practices are converging or whether demand response performance measurement is still too fraught with uncertainties to support adopting common practices.

This report seeks to contribute to the evolution of demand response performance measurement by developing a framework for understanding when, how and why the various methods are used, and then applying that framework to describe the evaluation practices of the demand response programs that are in place today.

Some Key Terms

Demand response – a change in a consumer's electricity usage level or profile in response to a change in the price it pays for electricity, or another inducement to do so.

Energy efficiency measure – improvements in equipment or systems that produce the same output while using less energy.

Measurement and verification – data collection, monitoring and analysis of electricity consumption for the purposes of establishing program performance.

Demand response event – a specified period of time when curtailments are to be undertaken by program participants or when price changes are to be posted.

Deemed savings – the kW and/or kWh reductions that have been established for specific energy efficiency measures for the purposes of program design and implementation.

Customer baseline load or baseline - the level of consumption the participant presumptively would have consumed but

Evaluation, Measurement and Verification (EM&V) for Energy Efficiency vs. Demand Response

Energy efficiency generally means using less energy to achieve the same level of service. Examples include better insulated homes to reduce the energy used for space conditioning and more efficient appliances, motors, and lighting technologies. Demand response means changes in electricity usage in response to incentives that are designed to discourage consumption when costs are high or reliability is jeopardized, and may encourage consumption when costs are low.

Evaluation, measurement and verification (EM&V) methods have been developed to establish the effects of both energy efficiency and demand response programs. Effective, credible evaluation is critical to ensure that utility sponsored programs are cost effective, produce the desired results, and therefore that the program expenditures were and will be prudent.

There are two types of evaluations that are relevant to energy efficiency and demand response. Impact evaluations are directed at quantifying what the load impacts are. Process evaluations assess why load impacts are what they are, why they might vary from expectations, and how they can be improved. Process evaluations can deal with everything from how programs were communicated and marketed, to assessments of free ridership and persistence, to determinations of installation quality, equipment degradation, or variations in equipment usage. Both types of evaluations are important. However, the focus of this report is on the quantification question – how load impacts from demand response programs are measured and verified in the ISO/RTO and utility programs for which data were available.

Because of the nature of how they influence electricity consumption, there are important differences in energy efficiency and demand response that require different types of evaluation protocols. These differences can be summarized as follows:

- **Basic Character.** Energy efficiency is a measure, which, once installed involves a sustained, virtually irreversible change in the premise's electricity consumption. Demand response is a behavior that is driven by circumstances that requires that participants undertake some action, actively or automatically, every time an event is triggered. As long as the participant makes that decision, the results are subject to several sources of variation.
- **Temporal Character.** Energy efficiency measures produce load impacts that might vary daily or seasonally (due to temperature and humidity, for example), but in predictable ways. Demand response can change unexpectedly or be erratic over a day, month, season, or year, depending upon how much control the participant can exercise over her electricity usage. As a result there are systematic and episodic factors influencing circumstances the participant faces, which influence how she adjusts electricity usage, and hence the level of impact realized.
- **Event-Driven**. An energy-efficiency measure will perform (result in lower load than before it was installed) without any directive action, regardless of whether electricity market prices are high or low. Most demand response products are designed to be operated under specific event-driven circumstances: for example, when the market price reaches a certain threshold or when system reliability is jeopardized.
- **Incentives.** Incentives for energy efficiency programs are usually fixed (i.e., not event-specific) and are the same for all similarly situated participants. There is no need for customer-by-customer performance analysis for settlement purposes. In the case of demand response, performance measures are often used to establish what individual participants will be paid, and whether penalties will be assessed for non-compliance.

Energy efficiency programs are usually designed to promote changing out electric devices or making efficiency improvements to structures. For these types of programs, it is common to "deem" a level of energy savings based on theoretical constructs, laboratory tests, engineering analysis, or field tests of equipment (or a combination thereof), and use those assessments in establishing incentives and other design features.

Impact evaluations are conducted after the program is implemented to determine actual savings. Typically there are efforts to modify the engineering estimates based on the impacts that are realized when the measures are installed in real-world circumstances. Process evaluations might be conducted to determine why savings differ from those expected during program design. For example, the deemed savings for a Compact Fluorescent Lamp (CFL) program might have been based on replacing lamps used several thousand hours a year, but the actual replacements were in fixtures used only a fraction of that time, or the CFLs might have been changed out because their performance was not acceptable to the participant. Alternatively, the methods used to promote adopting the CFLs, for example sending coupons in the mail as opposed to mailing the bulbs directly, may have not been effective.

To the extent that the energy efficiency measure is a permanent change in equipment or structures that results in discernible impacts, there is less need to measure the savings at every home or business that installs CFLs or replaces a conventional air conditioning unit with a more efficient one. Assessing the actual load impacts for a representative sample of customers can provide acceptable levels of accuracy. Metering every home and interviewing every consumer that adopted the measure would be ideal for verifying the impacts, but the issue is cost vs. incremental accuracy. Behavior plays a role in the resource impacts of many energy efficiency measures, but it is much more important in demand response because load impacts are largely (and for some programs, entirely) driven by behavior.

Evaluation of energy efficiency programs is used primarily to refine estimates of deemed values to guide future program designs. Virtually never are the results used to justify taking away incentives already awarded as part of the program design, or to prevent the participant from further program enrollment. In some cases, there may be an imputation against the utility if it received incentives that were based on unrealized performance.

Most demand response programs are driven primarily by participant behavior. Therefore, initial estimates of program benefits would depend upon what each participant nominates or is expected to provide. These load nominations are better described as indicative reductions, which might not be realized in every circumstance where, for example, a curtailment could be called or high prices posted. Measurement and verification protocols are used to determine actual load impacts. In the case of demand response products, measurement and verification activities also affect the settlement process: determining not only whether the participant complied with the rules, but how much each participant should be paid or whether penalties should be assessed for non-performance. Penalties can be several times larger than the benefits that accrued to the participant at enrollment. In other cases the penalty is that further participation is limited or denied.

Performance measurements are undertaken at every participant's premise in most of today's demand response programs. Aggregation is allowed as a convenience, for example, to allow participation by customers smaller than the minimum threshold level set by the program, or to allow for diversified program terms and conditions. Some curtailment service providers reportedly waive the penalty provisions of ISO/RTO programs in return for a large part of the program benefit payments, which in effect places that entity in a speculative position because settlement for the aggregation is conducted at the premise level. This stringent premise-level performance measurement is in part due to concerns about the potential for adverse selection and moral hazard. [2]

The Special Challenge of Establishing a Credible Baseline

A major challenge is that, unlike the case with supply options from which demand response benefits are derived, demand respond results cannot be observed directly. Instead, it involves engaging in counterfactual speculation: what would the load have been, but for the program and its incentives?

The need for a credible baseline is undoubtedly the biggest challenge in evaluating demand response products, and is a major concern in virtually all the demand response programs that are in place today. According to one demand response provider[3] , the ideal baseline should:

- **Be accurate** – providing customers with credit for the load impacts they actually deliver.
- **Have integrity** – calculations for determining the baseline must not encourage or be subject to manipulation.
- **Be simple** – performance calculations must be simple enough for all stakeholders to calculate.
- **Be aligned with program goals.**

Some argue that an additional aspect is required: that the participant be able to determine the baseline before an event commences. [4]

In practice, achieving all these goals is difficult. For example, baseline calculations using regression analysis are generally regarded as being more accurate (where adequate data exist for estimating models) and less subject to

A Case of Opportunistic Bidding

ISO-NE filed to revise one class of its demand response protocols in 2008 to mitigate what appeared to be extensive opportunistic bidding based on adverse selection.

Under the prevailing protocols, event performance was established using the participant's load profile in the ten days prior to an event, excluding days then the participant had been scheduled to curtail. Allegedly, some participants with high summer but low winter loads engaged in an energy market bidding strategy whereby they were able to preserve the appearance of high loads through the fall and early winter months.

They accomplished this by continuously bidding very low amounts at low prices which had the effect of preserving their summer high loads as the basis for measuring performance. (Days on which bids were accepted were excluded from the customer baseline load calculation.) When ISO-NE energy prices rose dramatically in the winter, they offered and were paid for curtailments based on load reductions that never materialized.

The solution offered (and approved by FERC) was to establish a higher minimum bid price, which all but eliminated this form of opportunistic bidding. However, some argued it was accomplished at the expense of discouraging legitimate bidding behaviors.

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[2] The commercial arrangements between curtailment service providers and their customers are not publicly disclosed. However, several have indicated that a primary aspect of their business is to provide for diversity or participation terms, including penalty exposure.
[3] Breidenbaugh, A. November 2008. "The Demand Response Baseline – A CSP Perspective." Presentation at the EPRI Workshop on Demand Response Evaluation, Measurement & Verification. Dallas, TX.
[4] This was an abiding element of the baseline methods employed today by NYISO, ISO-NE and PJM because curtailment service providers and utilities insisted that consumers would demand that feature.

manipulation. But they are far from simple, requiring specialized expertise and access to data that may not be readily available to all stakeholders.

Moreover, some of those that appear to have attractive features rely on event period data, and therefore can not be pre-determined. [5]

EM&V protocols for most demand response programs use the participant's historic usage profile to establish the baseline. [6] However, because there is no unequivocal way to ascertain either before or after an event what level of demand a participant intended or otherwise would have consumed, using a participant's prior usage profile can lead to opportunistic participation. Two problems have been noted: adverse selection and moral hazard: [7]

Adverse selection. Adverse selection could occur if the performance protocol makes some customers appear to reduce their load when in fact they did not. For example, if event performance is based on the participant's non-coincident peak demand in the previous month, then those customers who have inverted load profiles (higher demand in the evening than in the afternoon hours) would appear to have reduced usage during an afternoon event without changing their consumption. Screening mechanisms could be established to ascertain before registration which consumers have loads that provide them with free-ridership opportunities. However, it is not clear how such prohibitions could be enforced since the consumer can argue that past behavior is not reflective of what it intends under the program. Nor is it apparent how to impose a partial penalty in the case where the advantage does not preclude the consumer from undertaking event-driven changes that are consistent with the program intent.

Moral hazard. A program design could create a moral hazard problem if it encourages participants to behave in ways that they otherwise would not, to the detriment of stakeholders as a whole. If event performance is measured using the participant's usage immediately prior to an event, then the participant has an incentive to anticipate when events are imminent and adjust their usage in a way that makes compliance appear greater than it was. For example, if the four hours prior to an event established the baseline level of usage during an event, participants might find it profitable to increase their usage just prior to events to raise the apparent level of load reduction.

Adverse selection and moral hazard might tend to be coincident biases. A participant that enjoys an advantage just by signing up may be more likely to try to extend that advantage, especially with the aid of a retailer that fully understands the protocols and their nuances.

Opportunistic participation undermines the program's performance, and may result in worse, rather than improved system reliability. It is an unavoidable consequence of using the participant's prior usage as the basis for determining performance. While considerable evaluation effort has been devoted to finding ways to reduce or eliminate this corrupting aspect of demand response performance, no fool-proof method has been devised.

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[5] Janiszewski, J. August 1, 2008. Sloping Averaging Method for Baseline Calculation. DTE Energy. Available from: williamsonm@dteenergy.com.
[6] A convenient summary of methods is: Grimm, C. February 25-27, 2008. Evaluating Baselines for Demand Response Programs. Presented at: 2008 AEIC Load Research Workshop. San Antonio, Texas.
[7] For details see: ISO New England Inc. February 5, 2008. Federal Energy Regulatory Commission, Docket No. ER08-___-000; Filing of Changes to Day-Ahead Load Response Program; Expedited Comment Period and Consideration Requested.

Objectives of This Report

The goal of this report is to provide a synthesis of how demand response performance is being undertaken today, and offer a framework for categorizing EM&V protocols in a way that facilitates understanding their purpose, matching them with demand response program objectives, and comparing their performance among programs and pricing plans. Such a framework will contribute to another EPRI initiative to develop a product-oriented database for demand response programs, which would include categorizing the EM&V method employed. (See EPRI Report No. 1016086.)

The primary focus here is on characterizing how participant event performance is measured today. A related topic, which is addressed herein and will be taken up subsequently in greater detail, is how effective are these programs in producing benefits to participants and society. Methods used for measuring energy efficiency program performance are addressed in a companion report, EPRI Report No. 1016083.

Section 2 summarizes studies that have been conducted to establish the criteria to which baseline methods are designed, and compares the performance of methods currently used. Section 3 describes a categorization scheme to standardize protocols for measuring both wholesale and retail demand response performance. It is based on a framework proposed by ISOs/RTOs, with adjustments to reflect the different role demand response plays in retail relative to wholesale markets. This categorization framework is applied to ISO/RTO programs and to a sample of retail programs to demonstrate its robustness. Some specific program performance evaluation method examples are presented in Appendix A. Section 4 offers suggestions for how durable and widely applicable EM&V protocols can be developed for retail demand response programs.

2
REVIEW OF RELATED STUDIES

As demand response programs are becoming more widespread, and their impact more widely applicable, interest in devising EM&V protocols has grown. The following lists the activities of various organizations sponsoring or actively participating in efforts to improve EM&V protocols for demand response programs:

- Independent System Operators and Regional Transmission Organizations (ISOs/RTOs) have each devised comprehensive protocols, and they are collaborating to develop standards through the standards development process.
- The North American Electric Reliability Council (NERC), Demand Response Data Task Force (DRDTF) is developing data reporting protocols to support systematic and meaningful reporting of ISO/RTO program participation statistics and event performance data.
- North American Energy Standards Board (NAESB), DSM-EE Subcommittee has been chartered by an interest group that includes ISOs/RTOs, utilities, customer representatives, curtailment service providers, regulatory bodies, and others to promulgate standards for both wholesale and retail demand response performance measurement.
- National Association of Regulatory Utility Commissioners (NARUC) is tracking closely the NAESB standards development process and NERC activities.
- Utilities with affiliated demand response programs (i.e., the design fully corresponds with that of an ISO/RTO program) and non-affiliated programs (i.e., the protocols reflect the utility's own system operations) have embedded performance protocols in tariffs.
- Competitive retailers and curtailment service providers are adapting protocols to suit the diversified programs they are implementing.
- The Federal Energy Regulatory Commission (FERC) is encouraging the development of EM&V standards.
- State agencies including the California Public Utilities Commission, California Energy Commission, and the New York State Energy Research and Development Authority are sponsoring research to improve understanding of the underlying principles of good performance measurement and corresponding empirical applications.

Two California initiatives have contributed to the understanding of how alternative performance measurement protocols work, and their comparative advantages and disadvantages:

- In 2003, the California Energy Commission issued a report on the development of protocols for calculating load reductions focusing on short-notice (under 2 to 24 hours) demand response programs. The report analyzes different ways to establish a baseline against which demand reductions can be measured. The methods reviewed range from simple averaging of historic loads over "like" days to regression models to adjust for weather effects on load. The results are displayed graphically and the relative accuracy of the methods is calculated statistically. In general, simple methods are easier to apply and the results are easier to understand and explain. More complex regression analysis can produce more accurate predictions, when adequate data exist to develop them, but they are more difficult to apply and are less transparent. [8]

- In March 2008, the California Public Utilities Commission issued draft guidelines for demand response load impacts to be used in DSM planning and evaluation. [9] The guidelines were developed with input from the California utilities, the California Independent System Operator, large energy consumers, consumer advocacy groups, competitive retailers and curtailment service providers. The recommended protocols were developed to encompass both energy efficiency and demand response programs, and cover topics such as free ridership, persistence effects, and the need to characterize the uncertainty of long-term impacts. The guidelines distinguish between event-based programs and non-event based programs, and review day-matching techniques, regression analysis, demand modeling and engineering analysis. The guidelines are intended to apply to utility evaluation plans, and to be used in preparing load impact estimates for the utilities' 2009-2011 Demand Response Applications. [10]

The above reports are comprehensive in that they address all types of energy efficiency and demand response programs. Complementing these broad reports are more detailed studies of evaluation techniques applied to a single program type. One example is a January 2008 report by Lawrence Berkeley Laboratory which ". . . describes a statistical analysis of the performance of different models used to calculate the baseline electric load for commercial buildings participating in a demand-response (DR) program with emphasis on the importance of weather effects." The authors tested seven baseline models on a sample of 33 buildings in California. The models include averaging methods that use load values from previous days, and explicit weather models. [11] Another example is a detailed analysis of the baseline methods used by four ISOs (New England, New York, California, and PJM), and a construct using a +90^{o} day, based on a single day of load data from Detroit Edison's residential load sample. [12]

For more general audiences, the Leadership group of the National Action Plan for Energy Efficiency (NAPEE) issued guidelines for evaluating the impacts of energy efficiency

[8] Goldberg, M., Agnew, G. February 2003. "Protocol Development for Demand Response Calculation – Findings and Recommendations." Report No. 400-02-017F. California Energy Commission. Sacramento, CA. Available at: www.energy.ca.gov/demandresponse.
[9] California Public Utility Commission. March 2008. "Decision Adopting Protocols for Estimating Demand Response Load Impacts, Proposed Decision of Administrative Law Judge Hecht." Rulemaking 07-01-041. San Francisco, CA. Available at: www.cpuc.ca.gov.
[10] Guidelines for the evaluation of demand response programs in California are available at calmac.org.
[11] Coughlin, K., Piette, M., Goldman, C., Kiliccote, S. January 2008. "Estimating Demand Response Load Impacts: Evaluation of Baseline Load Models for Non-Residential Buildings in California." LBNL-58939. Berkeley, CA. p. 1.
[12] Grimm, C. February 2008. "Evaluating Baselines for Demand Response Programs." Paper presented at the AEIC Load Research Workshop. San Antonio, TX. See also Janiszewski, S. August 2008. "Slope Averaging Methodology for Baseline Calculation." Paper produced form DTE Energy, Load Research Group. Detroit, MI. For more information contact Mark Williamson, Manager, Detroit Edison Load Research, williamsonm@dteenergy.com.

programs.[13] Although ISO/RTO demand response programs are mentioned, the evaluation guidelines proposed by NAPEE apply primarily to energy efficiency and traditional utility-sponsored demand-side management initiatives.

Industry groups are urging standardization of measurement and verification protocols to facilitate the promulgation of demand response pricing plans that apply in all markets and jurisdictions. Curtailment service providers (CSPs), entities that recruit customers to participate in programs sponsored by ISOs/RTOs or utilities, argue that standardized programs would reduce customer acquisition costs, and would allow them to recruit national accounts into programs with the same (or virtually the same) protocols. While the incentive levels are likely to vary across regions and markets, CSPs argue that there is no rationale for large differences in EM&V protocols for pricing plans with the same fundamental purpose and design. They claim that standardized protocols would increase participation because it would provide an incentive for firms with facilities in several markets to participate in programs, which today's widely varying protocols discourage.

A first step toward standardizing EM&V protocols comes from an initiative undertaken by the North American Electric Reliability Council (NERC). It established the Demand Response Data Task Force (DRDTF) to develop a better understanding of the influence of DSM on bulk power system reliability. In December 2007, NERC issued standards for DSM data collection and analysis to ensure that there is appropriate data for assessing and validating demand response efforts, to ensure that demand forecasts adequately reflect the impacts of DSM, and to provide accurate information on the amounts of controllable DSM programs that are available to assist in real-time operations.[14] While this effort stops short of promulgating standards for EM&V, it is a step in that direction as it provides a pool of consistent data that will facilitate protocol design and evaluation efforts, which could then lead to the adoption of more consistent standards and protocols.

A more directive industry initiative is being led by the North American Energy Standards Board (NAESB) to develop standards to ". . . support the measurement and verification characteristics of demand response programs administered for application in the wholesale market . . . (which) may be the subject of individual tariffs filed with and approved by the Federal Energy Regulatory Commission" (FERC). A broad range of groups participated in the NAESB effort, including not only representatives from the ISO/RTO Council (IRC), but also FERC, the Environmental Protection Agency (EPA), the Department of Energy (DOE), Edison Electric Institute (EEI), state regulatory personnel, DSM experts, CSPs, utilities, energy market participants, and EPRI.[15]

[13] National Action Plan for Energy Efficiency Leadership Group, "Model Energy Efficiency Program Impact Evaluation Guide," November 2007. www.epa.gov/cleanenergy/energy-programs/napee/resources/guides.html/#guide5.
[14] North American Electric Reliability Corporation (NERC). December 2007. Data Collection for Demand-Side Management for Quantifying its Influence on Reliability, Results and Recommendations. Princeton, NJ. p. 3. NERC_DSMTF_Report_040308.pdf.
[15] North American Energy Standards Board, DSM-EE Subcommittee, Recommendation to NAESB Executive Committee, Request No.: 2008 AP Item 5(a), Review and Develop Business Practice Standards to Support DR and DSM-EE Programs, p. 6. Available at: www.naesb.org/pdf4/retail_ec110508materials.pdf, pp. 49-80.

The draft NAESB wholesale standards distinguish among four types of demand response programs offered by ISOs/RTOs:

- ***Capacity*** – demand response resources that substitute for or supplement generation resources that are acquired, scheduled and dispatched to assure that forecasted demand for electricity can be met within reliability standards set by NERC.
- ***Energy*** – demand response resources that displace more expensive generation resources to meet the hourly energy requirements of the market or system.
- ***Reserves*** – demand response resources that can respond to curtailment notices quickly (in 30 minutes or less) to meet the system need for contingent resources in the case of the loss of a substantial portion of the generation capability.
- ***Regulation*** – demand response resources that can both curtail and come back on line with very short notice (over intervals as short as a few seconds) to replace the resources needed to equate supply and demand continuously.

The ISO/RTO perspective on demand response categories is shaped by the character of the wholesale markets they operate. Their role is to administer capacity, energy, reserve, and regulation markets to assure that sufficient generation is available to meet retail electricity demands reliably and at least cost. They do so by coordinating the dispatch of generation resources. Accordingly, the ISO/RTO demand response classification scheme and protocols correspond to how generation resources are procured, dispatched, and settled. Demand response is treated as a resource so that it can be fully integrated into wholesale market operations.

That perspective extends to how the proposed protocols relate to the performance measurement of demand response resources. The NAESB wholesale protocols, as initially constructed by ISO/RTO representatives, define five types of performance evaluation methodologies: [16]

1. Maximum Base Load: applicable where event performance is measured solely on a Demand Resource's ability to reduce to a specified level of electricity demand.
2. Meter Before/Meter After: electricity consumption or demand over a prescribed period of time prior to Deployment is compared to similar readings during the Sustained Response Period. This protocol is particular to demand response providing regulation service to the ISOs/RTOs. Regulation involves following instructions to adjust load using a pre-specified rate of adjustment. For example, a regulation up order of 100 kW requires that the participant reduce its usage by 100 kW over, say, five minutes. Establishing performance in response to these instructions requires that the current level of demand be ascertained so that the performance measure can be established and verified. The convention is that the participant's load is constantly measured so that when a regulation instruction is issued, the final performance level is also established. This could be interpreted as a highly dynamic version of the maximum base load (above) or a highly granular case of the next category.
3. Baseline Type-I: based on a Demand Resource's historical interval meter data that may also include other variables such as weather and calendar data. For ISO/RTO programs, recent days' usage is typically used, for example, the load on the five highest of the past ten eligible days, where the eligibility condition refers to excluding event days.

[16] NAESB 2008, p. 9.

4. Baseline Type-II: based on statistical sampling to estimate the electricity consumption of an Aggregated Demand Resource where interval metering is not available on the whole population. For example, an apartment building may enroll the window air conditioners in selected (or all) apartments for participation, but the inhabitant is responsible for shutting the unit off during events. An interval meter installed on each unit would be cumbersome and unsightly, and so costly as to make participation unattractive under many circumstances. The alternative is to select certain of these units to be metered, and the average performance of those units can then be extrapolated to all participants. ISOs and RTOs have created protocols for determining the type of metering and the metering sampling rate required to accomplish an acceptable, representative measurement level.
5. Metering Generator Output: used for generation assets located behind the participant's meter in which the Demand Reduction Value is based on the output of the generation asset.

The first and last methodology are defined explicitly in terms of metered load only, while performance for all of the others involves establishing a reference or baseline load using the participant's usage prior to the event. However, implicitly a baseline is implied in all the protocols. Under the maximum base load protocol, the participant must be assigned a baseline level of demand so that the level of its curtailment can be determined for payment purposes. For example, a participant indicates that he wants to enroll and be paid for 100 kW of load. To operationalize the maximum base load performance measure, a reference point is needed, for example using the past year's coincident peak. If that coincident peak value was 1,000 kW, then the maximum base load is 900 kW (1,000 kW less 100 kW enrolled for curtailment). As with methods 2-4, a reference, or baseline needs to be established using that participant's historical load or some other benchmark. Also with methods 2-4, the question exists: is that deemed baseline a good measure of what the load otherwise would have been?

Method 5 is used when the participant operates an on-site generation unit, which can be separately metered to measure the output during events. But, metered output indicates only what the unit produced during the event, not the net addition to system generation, which is the corollary to a premise load reduction. Accordingly, there must be some provision to ascertain what the typical output of that unit is under event circumstances, analogous to the baseline, to determine the net event generation, which constitutes performance.

NAESB then mapped the performance methods to the four types of demand response service, as shown in Table 2-1.

Table 2-1
Applicability of NAESB's Demand Response Performance Evaluation Methods for Different Types of Service[17]

Performance Evaluation Type	Valid for Service Type			
	Energy	Capacity	Reserves	Regulation
Maximum Base load	✓	✓		
Meter Before/Meter After	✓	✓	✓	✓
Baseline Type-I (historical interval meter data)	✓	✓	✓	
Baseline Type-II (statistical sampling)	✓	✓	✓	
Metering Generator Output	✓	✓	✓	✓

The NAESB correspondence mapping indicates that ISO/RTO programs use one of several methods to verify event performance. Any of the performance measurement methods is indicated as potentially applicable to capacity and energy programs, and all but one applicable to reserve programs. Demand response providing regulation resources however, are limited to one method each for load curtailments (meter-before/meter-after) and on-site generation (metering generation output).

EPRI's Proposed Framework for Classifying EM&V Protocols for Retail Pricing Plans

EPRI's goal is to develop an EM&V framework that applies to both wholesale and retail programs. Such a framework would allow a designer who wants to adapt a wholesale program design for a retail rate to identify a class of appropriate performance measures to employ. Likewise, an evaluator who wanted to establish expectations for a retail offering's performance would be able to identify a wholesale product to serve as a reference. If wholesale and retail performance protocols utilize the same basic measurement principles, then several economies will be realized, including: customers will be able to move from one to another in a market where both are available, utilizing the experience they gain in one market (for example with a retail plan) in another (under a wholesale plan); the cost of measurement equipment (meters) and data processing likely will come down due to scale economies if programs adopt similar protocols; the collective body of data available to evaluate how well the measures work will increase more rapidly; and performance measurement standards will promote the development of enabling technologies that assist participants in meeting event curtailment expectations.

Such a framework should focus on how the demand response (timing and magnitude of the change in load) is estimated. Conceptually, all methods can be used to compare participant(s)'actual loads to their baseline loads, or to what the load would have been "but for" the program incentives. As observed earlier, one of the biggest challenges in measuring program impacts is the fact that the "but for" load cannot be observed directly. Thus, the EPRI

[17] NAESB 2008, p. 10.

framework presented here differentiates performance measures based on the fundamental character of the demand response pricing plan. Five categories of performance measurement constitute the retail framework, as follows:

1. Firm Power Level (FPL)
2. Pre-specified Customer Baseline Load (CBL)
3. Device-specific Performance Measure
4. Dynamic CBL (CBLD)
5. Net Metered Generator Output

Each category is described below, followed by a comparison of how this framework corresponds to that proposed through NAESB.

Firm Power Level (FPL)

The Firm Power Level has been widely used to administer traditional utility interruptible and curtailable load programs. The FPL is deemed by an agreement between the customer and the utility procuring the demand response resource.

To comply with the program rules, the participant must reduce its load to its FPL (a specified kW). Thus,

- if $FPL^{kW} \geq$ actual kW => event compliance is achieved
- if $FPL^{kW} <$ actual kW => results in a determination of non-compliance

The standard can be: applied to each event hour (or interval, 15-minute, 5-minute, etc.); or it might require that load be reduced to the FPL^{kW} in at least 1 hour (or interval); or compliance is defined by an FPL^{kW} defined as the average of the actual kW readings over the event hours.

Pre-Specified Customer Baseline Load (CBL)

This measure is designed to accommodate hourly pricing that involves the settlement of variances between actual load and the CBL every hour throughout the year based on prevailing prices. For the program year, a kW level is set for each hour in the year in advance. In some programs, CBL values are based on the previous year's hourly consumption levels (kWh), with adjustments to align for weekends and holidays and for events known in advance (such as scheduled maintenance). In other programs, they are negotiated, especially in cases where the participant's facilities are new, or have changed substantially. Sometimes load aggregation across hours is allowed to simplify the participant's tracking actual usage against the CBL (i.e., establishing six four-hour blocks of time for each day). [18]

[18] For a comprehensive review of utility programs including a summary of CBL methods employed, see: Barbose, G., Goldman, C., Neenan, B. December 2004. *A Survey of Utility Experience with Real-Time Priing*. Lawrence Berkeley National Laboratory Report No. LBNL-54238. Available at http://www.lbl.gov/

When an hourly, Pre-specified CBL is used as the baseline, program compliance is determined by comparing the participant's actual load to the CBL in every hour of the year. If the load is at or below the CBL, the participant is compliant, as shown:

- if CBL > actual kW => compliance
- if CBL < actual kW => non-compliance

In most utility RTP programs, the predetermined CBL is used for settlement purposes; deviations of actual load from the CBL result in credits or debits to the base bill priced at the hour's RTP prices. [19]

Device-Specific Performance Measure

Performance is based on a change in the operating status of a specific device (heating and air conditioning unit, water heater, thermostat, pool pump, etc.) instead of using the whole premise load (the metered usage). In its simplest construct, this measure involves an instruction being transmitted by the program administrator (or system dispatcher) to the device that activates a relay and the power to the device is shut off, and remains so until another (reactivation) instruction is issued. More sophisticated systems utilize two-way communication so that the device acknowledges receipt of the instruction, and sometimes even confirms that it was carried out. Compliance is deemed since the device is rendered inoperable. The level of curtailment is based on the assumed power consumption level of the device. Some examples:

- Shutting off a residential central AC unit is typically deemed to reduce load by 0.75 - 1.25 kW per hour.
- Shutting off several devices by closing an isolated premise circuit.
- Dimming lights manually or through a remote control.
- Activating a device that shuts off the flow of power to the facility from the grid automatically, for example an under-frequency relay responding to a local voltage sag.

The event performance measure is pre-determined and specific to each situation. [20] For example, in the case of an AC controlling device, program compliance might be based on one of the following conditions having been met:

- A control signal was sent to a programmable and controllable thermostat,
- A control signal was sent and executed – the temperature setting was raised by a predetermined amount, or

[19] The term RTP is applied to utility programs involving a CBL, which are primarily offered by vertically integrated utilities, and default service programs offered by utilities in customer choice markets where here is no CBL. In the latter case, the hourly posted price is applied to metered consumption in that hour, so no baseline is needed.

[20] For a discussion of measuring device deemed performance see: Violette, D., Erickson, J., Klos, M. New Jersey Central Air Conditioner Cycling Program Assessment. Prepared for Atlantic City Electric, Jersey Central Power & Light, and Public Service Electric & Gas. Summit Blue Consulting, Boulder CO. Available from: dviolette@summitblue.com.

- A control signal was received, and the command was executed and that state was continuously confirmed (it was not overridden by the participant).

The device-specific performance measure does not resolve unambiguously the question of how much load reduction was actually achieved when it was needed, since the amount of load reduction is pre-determined based on engineering analysis or equipment testing. Thus, the device-specific performance measure works best for equipment operating under relatively homogeneous conditions so that determining the load reduction resulting from shutting down a device is predictable and relatively constant.

Dynamic CBL (CBL^D)

This measure was first widely used by ISO/RTO programs to accommodate the character of the restructured electricity markets. The participant purchases electricity service from a retailer, but contracts separately for curtailment service with the ISO/RTO (directly or through an aggregator that might be a utility). Traditional utility baseline methods such as the FPL and Pre-specified CBL were judged not suitable for some programs for several reasons, including:

- Limited data requirements to measure performance. The ISO/RTO does not have access to consumers' retail metering readings, so it has to rely on utilities or competitive retailers for usage data. Baselines that did not rely on extensive historic data (like the Pre-specified CBL) were required.
- Desire to limit opportunities for adverse selection and moral hazard. Program transactions for some programs, like day-ahead energy bidding, create opportunities for opportunistic bidding if the baseline is established well before the event, and therefore are subject to the undesirable consequences of adverse selection and moral hazard.
- Curtailment service providers favored a performance measure based on recent history because they had limited access to the historical data of their customers, and desired to minimize the additional metering cost.
- The programs were envisioned for a wide range of customer circumstances, extending beyond consumers who had an interval meter installed for one or more years prior, a requirement for a Pre-specified CBL, and to consumers whose meters did not include recording maximum demand, a requirement for the FPL method.

While these EM&V protocols are critical for wholesale programs, they have also been adopted by utilities implementing demand response programs that involve appending a curtailment agreement to a base retail program. For example, the Peak Time Rebate programs piloted by the City of Anaheim, the Ontario Energy Board, and Baltimore Gas and Electric utilize a dynamic CBL for the same reasons it was deployed by ISO/RTO programs. [21]

The general concept is the same as for the Pre-specified CBL, in that the dynamic CBL reflects the participant's historic hourly usage. But, in this case the CBL^D is determined by usage in hours corresponding to the event in the days just prior to each event.

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[21] Faruqui, A.; Sergici, S. April 4, 2008. *The Power of Experimentation: New evidence on residential demand response.* The Brattle Group located in San Francisco, California. Available from: ahmad.faruqui@brattle.com.

When the CBL^D is used to represent a firm power level, program compliance is determined by comparing the participant's actual load to the CBL^D in each event hour:

- if $CBL^D \geq$ actual kW => compliance
- if $CBL^D <$ actual kW => non-compliance

A variety of methods have been used to establish the CBL^D. Examples include:

- Hourly kWh load averaged over hours corresponding to the event hours of the previous 5 eligible weekdays. Eligibility refers to limiting the window of comparison to like days (weekdays for a weekday event) and excluding days when an event had been declared for that participant (so as not to penalize the participant for responding to that event).
- Hourly kWh load corresponding to the event hours for highest 5 weekday loads out of the last 10 eligible weekdays.
- The event baseline is sometimes a different load level for each event hour, based on the previous days, and sometimes the recent history is used to establish one load level for all event hours.
- Weather adjustments are allowed in some programs to reflect the coincidence of event and weather conditions that would have resulted in the participant's loads being higher than those of the previous days. Examples include:
  - NYISO allows for an adjustment of the calculated event CBL by the ratio of the temperature in the two hours just prior to the event to the average of the temperatures on the corresponding time period on the days used to calculate the CBL.
  - PJM allows for an adjustment using a temperature-humidity index (THI) approach, which uses a regression to describe the weather-sensitivity of a customer's loads. This is used to calculate a weather-sensitive adjustment, along with an averaged THI for the on-peak hours of the days used in the baseline calculation, and an averaged THI for the on-peak hours of the event day.

NAESB's Meter Before/Meter After standard is a highly granular form of the Dynamic CBL whereby the CBL period is established on very short intervals by reading a meter at the participant's premise to establish the baseline which the participant must achieve to comply with the event obligation. Performance is determined by comparing the actual kW level achieved in the event interval to the baseline.

Net Metered Generator Output

This performance standard is designed to determine compliance for premises with on-site generation. Event compliance is achieved by operating an on-site generation unit during an event, but output must be incremental to the output the unit would otherwise have produced absent the event, or a CBLG. The participant elects the level of output (program obligation) it will provide during program events. The event level for CBL^G can be determined using any of the CBL methods where the reference load is defined as the metered output of the generation unit.

- if (Generation Output - CBLG) > obligation => compliance
- if (Generation Output - CBLG) < obligation => non-compliance

Comparison of the NAESB and EPRI Demand Response EM&V Categories

NAESB has issued draft protocols for measuring demand response performance for wholesale demand response programs administered by ISOs/RTOs. They are intended to promote harmonization of ISO/RTO program business rules. However, they are not highly specific and are therefore indicative rather than all-encompassing. The actual protocols used for any specific program are defined in an ISO/RTO tariff and accompanying business rules, which take precedence over any NAESB-issued standards. [22]

EPRI devised demand response EM&V performance protocols as part of an overall framework to support the design, implementation and evaluation of retail demand response and dynamic pricing plans. The EPRI framework is intended to be comprehensive and all-inclusive. It is comprehensive in that it considers all aspects of design, implementation, and evaluation so that important relationships between the design and implementation of a plan and its evaluation are taken into account. The overall framework is all-inclusive in that it seeks to reconcile wholesale and retail demand response plans.

Table 2-2 compares the NAESB and EPRI frameworks for EM&V. Overall, the correspondence is very high. The differences for the most part reflect design differences between the wholesale and retail perspectives.

Table 2-2
Comparison of NAESB and EPRI Demand Response M&V Categories

	EPRI Evaluation Framework Categories				
Proposed NAESB Performance Evaluation Categories	**Firm Power Level**	**Pre-Specified CBL**	**Device-Specific**	**Dynamic CBL**	**Net Metered Generator Output**
Maximum Base Load	Identical				
Meter Before/After				Special Case	
Baseline Type I				Identical	
Baseline Type II	NAESB's sampling techniques can be applied to any circumstances where individual premise or device metering is not practical or cost effective				
Generator Output					Identical

Table 2-2 compares the NAESB performance evaluation categories with those being proposed here. The similarities and differences are as follows:

- NAESB's Maximum Base Load category is identical to EPRI's Firm Power Level category.

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[22] ISO/RTO tariffs are complex and subject to constant revision. Consequently, a universal standard is impractical. However, the NAESB standards if adopted and used by all ISO/RTOs will likely lead to greater harmonization of the key aspects of demand response performance measurement.

- NAESB's Generator Output category is identical to EPRI's Net Metered Generator Output category.
- NAESB's Meter Before/After is intended to apply specifically to regulation. In the EPRI framework, this type of measurement is a special (highly granular) case of the Dynamic CBL.
- NAESB's Baseline Type I corresponds to EPRI's Dynamic CBL.
- NAESB's Baseline Type II applies to aggregations of customers using sampling methods to extrapolate to the performance of the population of all participants. In EPRI's framework, sampling can be applied to any product baseline (except for regulation) in cases where interval metering is not practical or cost effective.
- Finally, the EPRI framework recognizes the need for a Pre-specified CBL to support the bundled two-part rates (like RTP and Variable Peak Pricing VPP) that are feasible at the retail level.

The applicability of EPRI's proposed performance measures to the different types of demand response resources is shown in Table 2-3. The overall applicability of the performance measures is similar to what NAESB recommends, with two minor differences:

- NAESB does not designate emergency as a separate product while EPRI does. [23]
- NAESB does not specifically recognize a Device-specific CBL, but its Baseline Type II could accommodate aggregation programs involving devices.

Table 2-3
Applicability of EPRI Performance Measures to Types of Resources

Performance Measures	Energy	Capacity	Ancillary Services		Emergency
			Reserves	Regulation	
Firm Power Level	✓	✓			
Pre-specified CBL	✓	✓			✓
Device-specific CBL	✓	✓	✓	✓	✓
Dynamic CBL	✓	✓	✓	✓	✓
Net Generator Output	✓	✓	✓	✓	✓

[23] Emergency programs refer to programs like those launched by PJM and NYISO in 2000-2001 to establish a new source of supplemental resources comprised solely of load curtailments and supplemental on-site generation that are dispatched to resolve operating reserve shortfalls, and compensates participants based on the amount of energy (load curtailment or net generation) they provide during events. See EPRI Report No. 1016086, p. 2-5.

Summary

The classification scheme proposed by NAESB for measuring the performance of ISO/RTO demand response programs can be readily adapted for application to retail programs implemented by utilities, and in states that have implemented retail competition, competitive retailers.

3
MAPPING SELECTED ISO/RTO AND UTILITY PROGRAMS INTO THE EPRI EM&V FRAMEWORK

Introduction

This section describes the results of applying the EM&V framework described in Section 2 to programs currently available from ISOs/RTOs and selected utility demand response programs to demonstrate its applicability in both sectors of the market. First, ISO/RTO programs were mapped into the EM&V categories EPRI established to verify the consistency with what has been proposed through NAESB. Then, demand response pricing plans and programs available from utilities that are participants in EPRI's Program 170 (Energy Efficiency in a Carbon Constrained World) were mapped into the categorization framework to verify its applicability to retail circumstances.

Mapping EM&V Practices

The mapping was accomplished by reviewing each tariff and related program material available from each entity, interpreting its performance measurement provisions, and then assigning a category from the EPRI EM&V framework. In some cases, the program provider was contacted to resolve uncertainties about the methods it employed. The performance evaluation methods used for selected ISO and utility demand response programs are summarized in Appendix A. Detailed descriptions of each are available from each program's provider (references and web links are provided in the appendix.)

Most of the energy programs (ISO/RTO) and pricing plans (utility) utilize the Dynamic CBL to measure event performance (Table 3-1). Some allow Device-specific measures and have provisions for Net Metered Generator Output measurement. The notable exception to the use of the Dynamic CBL is Georgia Power, which uses the Pre-specified CBL for its two-part RTP program that requires settlements based on the variance of metered usage from historic usage in every hour of the year. Several ISO/RTO programs allow for Device-specific measurement, primarily to accommodate appliance control programs that were implemented in their markets. Some ISOs/RTOs allow behind-the-fence generation units to participate in energy markets, which require using the Net Metered generation Output protocol to determine the realized net increase in energy attributable to event performance.

Table 3-1
Performance Methods Used to Evaluate Energy Programs

Entity	Product	FPL	Pre-specified CBL	Device-specific	Dynamic CBL	Net Metered Generator Output
ISOs/RTOs						
CAISO	Participating Load Program - Supplemental Energy				X	
ISO-NE	Day-ahead Load Response Program				X	
ISO-NE	Real-time Demand Response Program - Energy				X	
ISO-NE	Real-time Price Response				X	
MISO	Emergency Demand Response Program	X		X	X	X
MISO	Demand Response Resource Type I				X	
MISO	Demand Response Resource Type II				X	
NYISO	Day Ahead Demand Response				X	
NYISO	ICAP Special Case Resource Program - Energy			X	X	X
PJM	Economic Load Response - Energy			X	X	X
PJM	Emergency Load Response - Energy - Mandatory			X	X	
NBSO	Bid-Based Demand Response				X	
AESO	Voluntary Load Curtailment Program	X				
IESO	Emergency Load Reduction Program			X	X	X
IESO	Emergency Demand Response Program				X	
IESO	Dispatchable Load				X	
Utilities						
Con Ed	Day Ahead Demand Reduction Program (Rider W)				X	
Con Ed	Day Ahead Hourly Pricing Rider (Rider M)				X	
Georgia Power	Critical Peak Pricing - Residential Rider Schedule Pilot (CPP-R-1)		X			
Georgia Power	Real Time PrIcing Day Ahead Schedule (RTP-DA-2)		X			
Georgia Power	Real Time PrIcing Hour Ahead Schedule (RTP-HA-2)		X			
PG&E	PeakChoice				X	
PG&E	Capacity Bidding Program (E-CBP)				X	
PG&E	Scheduled Load Reduction				X	

The capacity programs listed in Table 3-2 exhibit a wide range of methods are used for measuring event performance. Several ISO/RTO programs also use the FPL method that has been the conventional protocol for utility interruptible and curtailable programs, and which is used by several of the utility programs examined herein. However, several ISO/RTO programs and several utility pricing plans have adopted the Dynamic CBL method, probably because these programs are offered to consumers for which historic demand readings are not available (a requirement for the FPL) and perhaps in the growing belief that using recent usage is applicable to a wide range of customer circumstances and is easier to administer. Many programs allow for Device-specific measurement, reflecting in part the increased focus on device control to provide a higher (at least perceived) degree of reliability. Device-specific measurements is also consistent with services that are partially discretionary (AC and lighting over a few hours) or can be rescheduled (pool pump operation, recharging electric carts and tow-motors) that are acceptable to many consumers that otherwise might not participate.

Table 3-2
Performance Methods Used to Evaluate Capacity Services

Entity	Product	FPL	Pre-specified CBL	Device-specific	Dynamic CBL	Net Metered Generator Output
ISOs/RTOs						
ERCOT	Emergency Interruptible Load Service	X		X	X	
ISO-NE	Real-time Demand Response - Capacity				X	
ISO-NE	FCM			X	X	X
ISO-NE	Real-time Profiled Response			X	X	X
ISO-NE	Real-time emergency generation resource				X	X
MISO	Load Modifying Resource	X		X	X	X
NYISO	ICAP Special Case Resource Program – Capacity	X		X		X
PJM	Emergency Load Response - Capacity	X		X	X	X
NBSO	Interruptible Load	X		X		
Utilities						
Kansas City Power & Light Co.	Mpower	X				
Kansas City Power & Light Co.	Energy Optimizer			X		
Kansas City Power & Light Co.	Air Conditioner Load Control			X		
Kansas City Power & Light Co.	Voluntary Load Reduction Rider	X				
Con Edison	Residential AC Program			X		

Entity	Product	FPL	Pre-specified CBL	Device-specific	Dynamic CBL	Net Metered Generator Output
Utilities (Continued)						
Con Edison	ICAP -Special Case Resources (Rider P)	X				
Con Edison	Emergency Demand Response Program (Rider V)				X	
Georgia Power	Demand PlusEnergy Credit Rider (DPEC-1)	X				
Georgia Power	Real TimePricing -Day Ahead Schedule (RTP-DA-2)		X			
Georgia Power	Real TimePricing -Hour Ahead Schedule (RTP-HA-2)		X			`
Pacific Gas & Electric	PeakChoice				X	
Pacific Gas & Electric	Base Interruptible Program (E-BIP)-Option A	X				
Pacific Gas & Electric	Base Interruptible Program (E-BIP)-Option B				X	
Pacific Gas & Electric	Business Energy Coalition				X	
Pacific Gas & Electric	Capacity Bidding Program (E-CBP)				X	
Pacific Gas & Electric	Optional Binding Mandatory Curtailment Plan (E-OBMC)				X	
Pacific Gas & Electric	SmartAC Program			X		

Ancillary services programs included in Table 3-3 are exclusive to ISOs/RTOs, and use some variation of the Dynamic CBL method as the basis for determining program performance. These are cases where demand response provides operating reserves (30-minute or 10-minute spinning or non-spinning reserves). They use previous days' load history, or a period just prior to the event, to establish a baseline.

Table 3-3
Performance Methods Used to Evaluate Ancillary Services

Entity	Product	FPL	Pre-specified CBL	Device-specific	Dynamic CBL	Net Metered Generator Output
ISOs/RTOs						
CAISO	Participating Load Program (non-spinning)				X	
ERCOT	Loads Acting as a Resource providing Responsive Reserve Service - Under Frequency Relay Type			X		
ERCOT	Loads Acting as a Resource providing Responsive Reserve Service - Controllable Load Resource Type				X	
ERCOT	Loads Acting as a Resource providing Non-Spinning Reserve Service				X	
ERCOT	Load acting as resource (controllable) (Regulation)				X	
ISO-NE	Demand Response Reserves Pilot (NS Reserve)				X	X
MISO	Demand Response Resource Type I				X	
MISO	Demand Response Resource Type II				X	
MISO	Demand Response Resource Type II				X	
NYISO	Demand Side Ancillary Services Program (spin & non-spinning)				X	
NYISO	Demand Side Ancillary Services Program				X	
PJM	Economic Load Response - reserve				X	
PJM	Economic Load Response - regulation				X	
NBSO	30 Minute Non-Spinning Reserves	Detailed performance evaluation methodologies have not been defined				
NBSO	10 Minute Non-Spinning Reserves					
NBSO	10 Minute Spinning Reserve					
NBSO	Load Following					
NBSO	Regulation					
AESO	Supplemental Operating Reserves (Non-spin)				X	
AESO	Frequency Load Shed Service			X		
IESO	Dispatchable Load (Spinning Component)				X	
IESO	Dispatchable Load (Non-Spinning Component)				X	

The last product category is emergency services offered by NYISO, PJM and Consolidated Edison (Table 3 4). The dynamic CBL is used for all five programs. These EM&V protocols were designed specifically by the two ISOs/RTOs to provide a source of supplemental reserves that could be called upon to avert potentially devastating shortfalls. The Dynamic CBL was devised specifically for that purpose by PJM and NYISO and first introduced for programs they implemented in 2000-2001. The Con Ed pricing plan mimics the design of the NYISO so that its participants can enroll in the NYISO program. NYISO and PJM also offer a Device-specific CBL, and NYISO has a Net Metered Generator Output measure for participants with on-site generation.

Table 3-4
Performance Methods Used to Evaluate Emergency Services

Entity	Product	FPL	Pre-specified CBL	Device-specific	Dynamic CBL	Net Metered Generator Output
ISOs						
NYISO	Emergency Demand Response			X	X	X
PJM	Emergency Load Response - Energy – Voluntary			X	X	
Utilities						
Con Edison	Curtailable Electric Service (Rider O)				X	
Con Edison	Distribution Load Relief Program - (Rider U)				X	
Con Edison	Emergency Demand Response Program (Rider V)				X	

Summary of the EM&V Practices Mapping

The mapping exercise outlined above confirms that the EM&V framework devised by EPRI can be used to categorize both wholesale and retail demand response programs in a meaningful way. This will facilitate developing a comprehensive database on demand response programs that will help designers and evaluators compare and contrast programs on the basis of common design features. Such an initiative is being undertaken by EPRI under Program 170, interim results of which are reported in EPRI report No. 1016086. Further, this framework can serve as the starting point for the development of more robust and comprehensive standards as part of industry collaborations such as that being undertaken by NAESB.

EM&V Workshop Findings

EPRI conducted a workshop on November 13-14, 2008 to review the proposed EM&V framework with ISO/RTO and utility representatives. Representatives from sixteen utilities, three ISOs/RTOs, and one curtailment service provider participated, along with EPRI project staff. One ISO/RTO representative presented the wholesale EM&V standards they had proposed through NAESB, are under review at NAESB. EPRI presented its retail equivalent framework, and several utilities reported on their efforts to devise methods for evaluating demand response performance.

A survey administered at the start of the workshop provides an indication of how standards for EM&V were perceived:

- 86% indicated that they think that current EM&V protocols result in adverse selection (free ridership) that exceeds 5%, and 36% said it exceeds 20% of demand response participation.
- 65% said that protocols result in moral hazard (gaming) in excess of 11%.
- Two-thirds said that these factors are more likely to be associated with residential participants; the remaining responses were spread evenly over commercial and industrial sectors.
- For ISO/RTO programs, 38% said that these factors are most likely associated with capacity programs, 31% indicated energy bidding, 25% ancillary services and 5% emergency programs.
- Regarding retail demand response pricing plans, 44% indicated that interruptible programs were most susceptible to moral hazard adverse selection, 25% indicated direct load control, 6% real-time pricing, and 25% peak time rebate (the retail equivalent to the ISO/RTO emergency program). Regarding the last result, workshop participants are more wary of veracity of the peak time rebate program at the retail level than they are at the wholesale level.
- 83% indicated that standards are needed for ISO/RTO demand response EM&V protocols, while slightly less (75%) see the need for standards for retail programs.
- 63% of workshop participants indicated that they did not believe that smart metering would resolve today's EM&V shortcomings.

The ISO/RTO and utility representatives indicated that the proposed EPRI framework provides a foundation for the development of protocols and standards that serve both wholesale and retail demand response performance measurement. After considerable discussion, the utility participants were polled again to summarize their positions on how to address EM&V development for retail demand response programs:

- All agreed that another workshop focused on more fundamental aspects of EM&V is needed.
- They concur on the proposition that development of EM&V standards is best achieved through collective efforts to take advantage of the existing research and development work and utilize the experience that many are assuming.
- 85% indicated that more analytical (evaluation and verification) research needs to be undertaken.
- All indicated that EPRI should become involved in the NAESB initiative to devise retail EM&V standards for demand response.
- •54% indicated that they should be involved with the NAESB initiative as members, and the rest indicated that their participation would involve following the progress of the NAESB process.

The workshop results confirm that utilities are concerned that the protocols used today are insufficient, and that there would be considerable gain from working together, and cooperatively with ISOs/RTOs to devise standards that foster more effective and widespread participation in demand response programs and pricing plans.

4
CONCLUDING REMARKS AND RECOMMENDATIONS

Demand response evaluation activities are undertaken to address two sets of issues. The first is program design, including rules for compliance and settlement determination. For new programs, a performance measure must be chosen, either from similar programs implemented elsewhere, or by designing a new protocol. For ongoing programs, results achieved in past years with the program can be assessed and process evaluations can be conducted to determine why actual results may have differed from initial expectations, or from the results obtained in other programs. Such comparisons are difficult to make today because it is difficult to identify comparable programs, and detailed performance data are sparse. Related to program compliance and settlement, key design issues include: how should the extent of compliance with program rules be determined, and how should load impacts be established for purposes of settlement?

The second set of issues relates to the need to estimate (verify) the load impacts that the program actually produced. For supply options, the term "estimated actuals" is an oxymoron, because energy produced is metered directly. For demand resources, the term is appropriate because the relevant baseline is what the load otherwise would have been, absent the program event, which can never be observed directly. Settlement protocols are ways to deem the load impact for settlement purposes, and necessarily involve counterfactual speculation. After the fact performance assessment is also needed to determine the extent to which program rules including those for settlement, are actually working, identify potential design improvements, and provide critical inputs to evaluating the benefits and costs of such programs. Moreover, performance estimation is an essential element of system planning and operations. The value these resources provide depends on the extent to which reductions can be forecasted by system planners and operators.

There is a growing body of research addressing demand response performance issues. There are also several efforts underway to categorize demand response evaluation protocols by program type and to establish EM&V standards, including efforts by NERC, NAESB and this effort by EPRI. EPRI's contribution, as reported herein, has been to build on the work by NERC and NAESB to categorize wholesale demand response programs and to develop a framework that could apply to both wholesale and retail demand response programs and pricing plans. That framework was then applied to ISO/RTO and selected utility programs to assess, for different product types, what evaluation protocols are being used and why.

The results are encouraging in that the framework was demonstrated to be useful and vetted with ISO and utility staff, who confirmed that comprehensive information on program evaluation protocols would be very helpful and is badly needed. Although much progress has been made, there is still more work that could be done to make the fundamentals of underlying design and performance measurement more transparent to all stakeholders. Participants in an EPRI workshop indicate that there is considerable work to be done yet, and that EPRI can play an important role, beginning with taking an active role in the ongoing NAESB retail standards development process and by helping to coordinate utility initiatives.

A

EM&V EXAMPLES FOR SELECTED PROGRAMS

This Appendix contains an overview of the performance evaluation methods for selected ISO/RTO and utility demand response programs, as referenced in Section 3. The examples provide summary information only, and those interested in the full details should refer to the program sponsor's tariffs or program documentation for specific details.

ISO/RTO Programs

ISO/RTO: PJM
Program: Emergency Load Response (Capacity) [24]
Deployment Type: Reliability
Compliance Type: Mandatory
DR Service Type: Capacity

Program Description

Demand response offers can be made to supply load reduction as a capacity resource that can be bid into the forward Reliability Pricing Model (RPM) auctions. Once the auction is completed, demand response resources selected are obligated to supply the offered capacity during the delivery year. [25] The Emergency Load Response – Capacity Only (as well as Emergency Load Response – Full Option) program allows for capacity to be provided through three types of load management resources:

- Direct Load Control (DLC): a communication signal is used to cycle a customer's equipment through the load serving entity's market operations center
- Firm Service Level (FSL): customer reduces its load to a pre-determined kW level upon notification
- Guaranteed Load Drop (GLD): customer reduces its load by pre-determined amounts upon notification[26]

[24] The Emergency Load Response Program has "Capacity Only", "Energy Only", and "Full" options, the latter including both capacity and energy payments.
[25] http://www.pjm.com/markets/demand-response/capacity-market.html
[26] PJM Demand Side Response Presentation. September 2008. http://www.pjm.com/services/training/downloads/20080930-pjm-demand-side-response-4.pdf

Performance Evaluation Type(s)

- Firm Power Level
- Device-specific Performance
- Dynamic CBL
- Net Metered Generator Output

Performance Evaluation Description

The specific performance evaluation description depends on the type of load management resource:

1. Direct Load Control (DLC)

The load reduction during each hour of the event is based on the following formula:

> DLC Load Drop = No. Active Customers * Per Participant Impact (MW) * Loss Factor * Transmission Signal Ratio
>
> Where:
>
>> No. Active Customers = the number of participants involved on the day of the interruption;
>>
>> Per Participant Impact = the PJM-approved impact from a load research study;
>>
>> Loss Factor = the applicable factor to equate the meter-level impact to a generator-level impact;
>>
>> Transmission Signal Ratio = the percentage of the hour that the signal was operated (100% = 1.0)” [27]

DLC capacity pertains to device-level control (e.g. A/C cycling programs), and load research studies are performed to estimated impact over a sample, which can be deemed to a larger population.

Using the EPRI terminology, this performance evaluation is categorized as Device-specific CBL.

1. Firm Service Level (FSL) and
2. Guaranteed Load Drop (GLD)

[27] PJM Manual 19: Load Forecasting and Analysis, Revision: 13. June 2008. http://www.pjm.com/contributions/pjm-manuals/pdf/m19.pdf, Appendix A, p. 21

There are several options available to estimate the firm service level or guaranteed load drop for each customer[28] :

- Comparable days (i.e. similar non-event days, with the option of factoring in weather differences, or an average of customers' actual hourly peak loads). This is defined as either a Firm Power Level using EPRI terminology
- Same days (i.e. baseline is calculated based on load on the same day a certain period before the event). This is defined as Dynamic CBL using EPRI terminology
- Load Profile (i.e. the baseline is calculated based on "unrestricted" load profile). This is also defined as a Dynamic CBL using EPRI terminology
- Customer Baseline (i.e. a method by which the five most recent non-event days, with other restrictions and adjustments, are used to calculate the baseline[29]). This is also defined as Dynamic CBL using EPRI terminology
- Regression Analysis (i.e. past load and weather data is used to calculate a baseline). This is also defined as Dynamic CBL using EPRI terminology

Furthermore, both FSL and GLD can be achieved through onsite behind the meter generation, thus another CBL category is Metering Generator Output using EPRI terminology.

[28] PJM Manual 19: Load Forecasting and Analysis, Revision: 13. June 2008. http://www.pjm.com/contributions/pjm-manuals/pdf/m19.pdf

[29] PJM Demand Side Response Presentation. September 2008. http://www.pjm.com/services/training/downloads/20080930-pjm-demand-side-response-4.pdf, slide 83-91

ISO/RTO: PJM
Program: Economic Load Response
Deployment Type: Economic
Compliance Type: Mandatory
DR Service Type: Ancillary Services – Reserves

Program Description

Demand response can provide synchronized reserves to the PJM market, although such resources are limited to 25% of the Synchronized Reserve requirement for each reserve zone in order to gain experience with this type of reserve resource. Resources are required to deliver demand reduction within 10 minutes of notification of an event. The market is cleared hourly, and resources are paid the clearing price for providing the hourly service. [30] In order for demand response resources to participate in the reserve market, they must be able to receive the appropriate "All-call" messages, they must have PJM-approved controls in place to automatically drop the required load, they must have appropriate metering and telemetry infrastructure in place such that the data scan rate is no less than 1 minute, and no more than one level of operating intervention between PJM and the load-reducing customer. [31]

Performance Evaluation Type(s)

Dynamic CBL

Performance Evaluation Description

Metered data, in 1-minute intervals, is obtained at the start and end of a Synchronized Reserve Event. Performance is determined by comparing these values with the customer's load reduction obligation (the accepted bid kW level). It is recommended that ten minutes' worth of data at the start and the end of the event call is collected. [32] This is classified as a form of Dynamic CBL, because the baseline is taken to be the metered load when the event is called.

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[30] PJM. 2008. Synchronized Reserve Market. http://www.pjm.com/markets/demand-response/synchronized-reserve-market.html
[31] PJM. April 2006. Load Response in the Ancillary Service Markets (presentation). http://www.pjm.com/services/training/downloads/load-response-in-ancillary-service.pdf, slide 64
[32] PJM. April 2006. Load Response in the Ancillary Service Markets (presentation). http://www.pjm.com/services/training/downloads/load-response-in-ancillary-service.pdf, slide 102

ISO/RTO: NYISO
Program Name: NYISO Installed Capacity/Special Case Resource Program (ICAP/SCR)
Deployment Type: Reliability
Compliance Type: Mandatory
DR Service Type: Capacity

Program Description

ICAP/SCR allows customer load curtailments to meet the installed capacity obligation of load-serving entities. SCRs are loads that can be reduced upon two-hour notice, as well as customer-owned generators. The resource must be 100 kW or greater, although customer aggregation is allowed by Responsible Interface Parties.

Performance Evaluation Type(s)

- Firm Power Level
- Device-specific CBL
- Net Metered Generation Output

Performance Evaluation Description

In the case of Firm Power Level, the Installed Capacity Equivalent (ICE) of the resource that provides capacity through load reduction (wholly or partially) is calculated for the month as follows:

> "$ICE_{gm} = APMD_{gm} – CMD_{gm}$
>
> Where:
>
> ICE_{gm} is the Installed Capacity Equivalent of the amount of Unforced Capacity[33] that Resource g supplies in month m…
>
> $APMD_{gm}$ is the Average of Peak Monthly Demands for Resource g applicable to month m; and …
>
> CMD_{gm} is the Committed Maximum Demand for Resource g applicable to month m. [34]"
>
> Also, aggregated load can be qualified as an SCR through, for example, a multi-customer direct load control program. Such programs are generally considered on a case by case basis, but this would be an example of the use of a Device-specific CBL.

[33] Unforced Capacity: "The measure by which Installed Capacity Suppliers will be rated, in accordance with formulae set forth in the NYISO Procedures, to quantify the extent of their contribution to satisfy the NYCA Minimum Installed Capacity Requirement, and which will be used to measure the portion of that NYCA Minimum Installed Capacity Requirement for which each LSE is responsible." NYISO. July 2007. NYISO Installed Capacity Manual. http://www.nyiso.com/public/webdocs/documents/manuals/operations/icap_manual.pdf, p1-1.
[34] NYISO. November 2008. Installed Capacity Manual Attachments, Attachment J. http://www.nyiso.com/public/webdocs/products/icap/icap_manual/app_a_attach_icapmnl.pdf, p. J-11

In the case of Net Metered Generation Output, the Installed Capacity Equivalent (ICE) of the resource is calculated as follows:

> "$ICE_{gm} = CGO_{gm}$
>
> Where:
>
> ICE_{gm} is the Installed Capacity Equivalent of the amount of Unforced Capacity that Resource g supplies in month m; and
>
> CGO_{gm} is the Contracted Generator Output for the generator(s) located at Resource g applicable for month m…"[35]

Performance in terms of the ICAP/SCR obligation requires that the customer reduce its load to the specified ICE (FPL) in at least one hour of each event, or during a test conducted during the six-month capability period.

[35] NYISO. November 2008. Installed Capacity Manual Attachments, Attachment J. http://www.nyiso.com/public/webdocs/products/icap/icap_manual/app_a_attach_icapmnl.pdf, p. J-11

ISO/RTO: NYISO
Program: Demand-Side Ancillary Service Program (DSASP), Demand Resource for 10 minute spinning reserve
Deployment Type: Economic
Compliance Type: Mandatory
DR Service Type: Ancillary Services – Reserves

Program Description

Specific Operating Reserves, which are required when the NYISO experiences a power system contingency requiring emergency action, can be provided by demand response. These include 10-minute synchronized and non-synchronized reserves, as well as 30-minute synchronized and non-synchronized reserves.

Performance Evaluation Type(s)

Dynamic CBL

Performance Evaluation Description

- Response = Base Load MW – Metered Load MW during reserve schedule[36]
- Base Load MW = Interval before dispatch instruction
- Metered Load MW = Actual metered load of each interval during reserve schedule

This is classified as a form of Dynamic CBL as the baseline is the metered load when the event is called. The performance is then measured by comparing the baseline load to the metered load during the event.

[36] NYISO. May 2008. Demand Side Ancillary Services Program Participation – Part 1. Price Response Load Working Group (presentation). http://www.nyiso.com/public/webdocs/committees/bic_prlwg/meeting_materials/2008-05-19/DSASP_Participation_overview.pdf

ISO/RTO: Midwest ISO (MISO)
Program Name: Emergency Demand Response
Deployment Type: Reliability
Compliance Type: Voluntary
DR Service Type: Energy

Program Description

This program encourages market participants to establish the capability to dispatch various demand resources (e.g. interruptible load) or behind-the-meter generation during NERC Energy Emergency Alert 2 or 3 events (EEA2 and EEA3). Program participants are currently limited to facilities operators with available demand response resources, or load serving entities that have contractual agreements with such facilities. Emergency Demand Response offers consist of the load reduction offer and the associated curtailment price. When an event is about to be called, dispatch instructions are developed based on the resource bid information submitted for that day. When the event is called, instructions are sent to the required resources, which are then responsible to for reducing by the level they bid. [37]

Performance Evaluation Type(s)

- Firm Power Level
- Device-specific CBL
- Dynamic CBL
- Net Generation Output

Performance Evaluation Description

For resources that use a Firm Power Level:

> "The EDR Offer shall specify: (i) the minimum and maximum amount of the offered demand reduction (in minimum increments of 0.1 MWh) or; specify the firm service level to which the EDR Participant will curtail demand and specify the EDR Participant's peak Load" [38]

For resources that use a Dynamic CBL:

> "Unless an alternate approach is agreed upon by the Transmission Provider and an EDR Participant and such alternate approach is documented in the Business Practices Manuals, measurement and verification for hourly interval metered EDR Participants will be based

[37] Midwest ISO, September 2008. DRAFT Business Practices Manual – Emergency Demand Response, Version 1.0. http://www.midwestmarket.org/publish/Document/25f0a7_11c1022c619_-7f3a0a48324a/EDR_BPM%2009-04-08%20v1.pdf?action=download&_property=Attachment
[38] Midwest ISO, FERC Electric Tariff, Third Revised Vol. 1, SCHEDULE 1 – Scheduling, System Control and Dispatch Service, p. 1050Z.44

> upon actual hourly usage in the Hour immediately preceding notification to the EDR Participant of the EDR Dispatch Instruction by the Transmission Provider." [39]

For resources that use Net Generation Output

> "When on-site generation is deployed exclusively to support the demand reduction, the EDR Participant may provide qualified meter data from the on-site generation for each hour of the … event day… Provision of hourly meter data from the on-site generation will be deemed a certification by the EDR Participant that the on-site generation was not used for any purpose other than to support the demand reduction during the … event day." [40]

[39] Midwest ISO, *FERC Electric Tariff,* Third Revised Vol. 1, SCHEDULE 1 – Scheduling, System Control and Dispatch Service, p. 1050Z.51

[40] Midwest ISO, *FERC Electric Tariff*, Third Revised Vol. 1, SCHEDULE 1 – Scheduling, System Control and Dispatch Service, p. 1050Z.51

ISO/RTO: ISO-NE
Program: Day-Ahead Load Response Program (DALRP)
Deployment Type: Economic
Compliance Type: Mandatory
DR Service Type: Energy

Program Description

The Day-Ahead program is an option for participants enrolled in other Real-Time Load Response Programs. Participants must be able to provide a minimum of 100 kW of energy reduction, but aggregation by Load Zone to at least 100 kW is permitted. Load Response Event days can occur on weekdays (or non-demand response holidays) between 7:00am and 6:00pm.

Participants bid curtailment offers into the day-ahead market, and if the bid is included as part of the next day's schedule, they are obligated to curtail in the corresponding hours the following day, and are paid the Day-Ahead price. Actual (real-time) load reduction during the event is then compared against the cleared value, and settlements are made at the appropriate Real-Time Zonal Price. [41]

Performance Evaluation Type(s)

Dynamic CBL

Performance Evaluation Description

For New Assets, with no previously calculated CBL, the initial CBL is the simple average for each hour from the five program days following asset qualification. Program days include weekdays and non-demand response holidays. During this five-day period, the resource cannot be interrupted, so Load Response Event days can be used in the initial CBL calculation. Missing data during this time are assigned values of zero, and are included in the calculation.

Once the first CBL is calculated (i.e. on day six, using the first/previous five days of data), the asset is considered an Existing Asset, and is ready to respond. The daily CBL is then based on the previous day's CBL in some manner, depending on whether it is a Load Response Event program day:

For each non-Load Response Event program day, the CBL is calculated using the weighted average of 0.9 applied to the previous day's CBL and 0.1 applied to the meter data for the present program day. Non-event CBLs are calculated to provide a baseline for event days.

For each Load Response Event program day, the CBL for the present day is equal to the CBL of the previous day. In the case of consecutive event days, the initial day's CBL will continue to be used for each subsequent Load Response Event program days.

[41] ISO-NE. October 2007. Manual for Measurement and Verification of Demand Response Reduction Value from Demand Resources (Manual M-MVDR). http://www.iso-ne.com/rules_proceds/isone_mnls/m_mvdr_measurement_and_verification_demand_reduction_revision_1_10_01_07.doc

Specific details can be found in the ISO New England Manual for Measurement and Verification of Demand Reduction Value from Demand Resources, Manual M-MVDR. [42]

As this evaluation methodology is an average of historic data prior to the event, it is classified as a Dynamic CBL under the EPRI framework.

[42] ISO-NE. October 2007. *ISO New England Load Response Program Manual*. http://www.iso-ne.com/rules_proceds/isone_mnls/m_lrp_load_response_program_revision_12_10_01_07.doc

ISO/RTO: ERCOT
Program: Load Acting as a Resource – Under Frequency Relay
Deployment Type: Reliability
Compliance Type: Mandatory
DR Service Type: Ancillary – Reserves

Program Description

Part of the Load Acting as a Resource (LAAR), this program allows load curtailments to provide responsive reserves. The customer is required to install an Under Frequency Relay (UFR) which not only serves as a means for imposing curtailment during declared events, but also exposes the customer to curtailments that result from a drop in voltage on the circuit that serves the customer premise. Upon detection of a drop in frequency, the UFR automatically opens interrupting the load. As with other LAAR programs, participants that are scheduled receive capacity payments, regardless of whether or not an event is declared. [43]

Performance Evaluation Type

Device-specific Measure

Performance Evaluation Description

Telemetry is required to indicate the load on each breaker (MW), the breaker status, the response telemetry (which is non-zero when providing load response service), high set UFR status, and that the response is within the schedule control error of the Qualified Scheduled Entity. Load must go through a qualification testing procedure[44] , and is subject to annual evaluation. [45]

This is classified as a form of Device-specific measure given that the relay is used to shut off power to the grid.

However, it can be argued that it is also a form of Dynamic CBL as well, as the baseline is taken to be the metered load just prior to an event being called. The performance is then measured by comparing the baseline load to the metered load during the event. From ERCOT Protocols, Section 6: Ancillary Services[46] :

> "ERCOT shall measure and record the MW data beginning one (1) minute prior to the start of the frequency excursion event or Manual/Dispatch Instruction until ten (10) minutes after the start of the frequency excursion event or Manual/Dispatch Instruction.

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[43] ERCOT. ERCOT Demand Side Working Group. http://www.puc.state.tx.us/electric/projects/32853/091506/Mary_Anne_Brelinsky.pdf
[44] ERCOT. LAA Responsive Reserve Qualification. October 2003. http://www.ercot.com/content/services/programs/load/laar/prsqualification.doc
[45] ERCOT. ERCOT Protocols. Section 6 : Ancillary Services October 2008. http://www.ercot.com/content/mktrules/protocols/current/06-100108.doc#_Toc210448229
[46] ERCOT. ERCOT Protocols. Section 6 : Ancillary Services October 2008. http://www.ercot.com/content/mktrules/protocols/current/06-100108.doc#_Toc210448229

Satisfactory performance is measured by comparing the actual response to the frequency response capability required in the Operating Guides.” (p. 6-170)

ISO/RTO: Alberta Electric System Operator (AESO)
Program: Supplemental Operating Reserves
Deployment Type: Reliability
Compliance Type: Mandatory
DR Service Type: Ancillary Services – Reserves

Program Description

As part of the AESO's Ancillary Services, load can be provided as a resource to satisfy Supplemental (non-spinning) Reserves (load cannot be used as a resource for AESO's other Operating Reserves). The minimum provision of Supplemental Reserve Resource(s) within a utility is 5 MW. Specific requirements exist for data refresh rates, meters and breakers, telemetry accuracy and availability, staffing levels, and voice communications. [47]

Performance Evaluation Type(s)

Dynamic CBL

Performance Evaluation Description

The provider must ready its resource for reduction within 15 minutes of the receipt of an Ancillary Services dispatch from the System Controller. The System Controller then issues a Directive to the resource, upon which time the resource has 10 minutes to achieve the requisite real power change or "AS Directive Volume". At a minimum it must reach 100% of this volume, but at a maximum level of 110%. Once reached (within 10 minutes), the resource must be capable of maintaining 95% or within 1 MW of the Directive Volume for up to a maximum of 60 minutes.

The performance evaluation is classified as a form of Dynamic CBL, as the baseline is the metered load before the load reduction occurs. The performance is then measured by comparing the baseline load to the metered load during the event.

[47] AESO. December 2004. AESO Operating Reserves Technical Requirements – *Technical Requirements for Provision of Supplemental Reserves by Loads*. Version 2.0. http://www.aeso.ca/downloads/Tech-req-supp-res-loads-vs_2.0_final.pdf

Utility Examples

Utility: Kansas City Power and Light (KCP&L)
Program: MPOWER Rider (Schedule MP) – Commercial and Industrial[48]
Deployment Type: Reliability
Compliance Type: Mandatory
DR Service Type: Capacity

Program Description

The Rider is designed to enlist C& I load support in shaving peak demand through curtailment and shifting production to off-peak times. The program is available to Commercial and Industrial customers who choose to opt for this rider. Once enrolled, the program is mandatory by contract with one, three or five year terms. Participating customers must be able to curtail at least 25 kW of load when called.

The maximum number of peak load curtailment events shall not exceed 10 separate occurrences (events) per year with the additional provision that events shall be declared on no more than three consecutive days per calendar week and the cumulative annual curtailment hours not exceed 80 hours in any calendar year. Customers receive a curtailment notification, a minimum of four hours prior to the start time of a curtailment.

Performance Evaluation Type

Firm Power Level

Performance Evaluation Description

Hourly kW is measured using interval metering. An “estimated peak demand” is established by calculating the average of the customer's monthly maximum demand for Monday through Friday between 12:00 p.m. and 10:00 p.m. from June-September of the previous year. A Firm Power Level is set for the months of June-September which is equal to the “Estimated peak demand” minus the maximum curtailment possible (25 kW or more). Performance is determined by comparing the event actual kW to the estimated peak demand.

If the customer's estimated peak demand is less than 25 kW, the customer is not eligible for participation, because this would imply that there is no curtailable load of 25 kW or greater. However, there is an exception to this rule. If a customer's estimated peak demand is less than 25 kW and they have a generator with a capacity greater than 25 kW along with paralleling gear that allows supplying energy to the grid during an event, they could potentially participate.

There are no payments for over performance during any event hour and no payment at all for any level of under-performance.

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[48] Program descriptions have been excerpted from: Kansas City Power & Light Company, *MPower Rider Tariff Schedule Document* http://www.kcpl.com/about/KSRates/Sched76.pdf

Utility: Kansas City Power and Light (KCP&L)
Program: Air Conditioner Load Control Rider (Schedule ACLC) [49]
Deployment Type: Reliability
Compliance Type: Mandatory
DR Service Type: Capacity

Program Description

The Rider is available to single-family residential customers that have installed a central air conditioner or heat pump with an electrically-driven compressor rated at 2 kVA or more, which is in good operating condition. For customers requesting service under this rider, KCP& L installs a temperature-activated cycling device (load controller) on the customer's central air conditioner or heat pump. The controller is installed and maintained by KCP&L at no direct cost to the customer.

KCP&L is permitted without notice or restraint to commence interruption of electric service to the cooling unit compressor during periods when the ambient temperature is 95° F and above. The load control device will interrupt electric service to the cooling unit compressor for approximately seven and one-half (7½) minutes for each 30 minute period until the ambient temperature falls to 88° F.

Performance Evaluation Type

Device-specific CBL

Performance Evaluation Description

A Device-specific CBL is used to establish performance.

[49] Program descriptions have been excerpted from: Kansas City Power & Light Company, *Air Conditioner Load Control Rider/Tariff Schedule* http://www.kcpl.com/about/KSRates/Sched4.pdf

Utility: Consolidated Edison Company of New York (Con Edison)
Program: Distribution Load Relief Program (Rider U) [50]
Deployment Type: Reliability
Compliance Type: Voluntary
DR Service Type: Emergency

Program Description

Through Con Edison's Distribution Load Relief Program (DLRP), customers agree to reduce their electricity usage during critical times to help maintain reliable service on the company's power delivery system. Customers who can guarantee load reductions can participate in mandatory DLRP and will receive monthly payments for their commitment. Two options for participation are available:

- Customers who participate through the DLRP voluntary option will receive payments for the reductions made on an event-specific basis. DLRP voluntary events can be activated during two time periods each year — the winter capability period (November 1 to April 30) and the summer capability period (May 1 to October 31).
- The mandatory option is available only for the summer for a period of not less than four hours as designated by Con Edison, based on forecast system reliability conditions. Con Edison may designate specific networks, feeders or geographical areas in which load relief will be requested. Con Edison will notify customers or aggregators, no less than 30 minutes in advance of the commencement of a Load relief period.

Con Edison customers who can reduce their electricity consumption and/or supply delivery by at least 50 kilowatts (kW) are eligible. Customers who cannot meet the 50 kW minimum can still participate through a load aggregator registered with the NYISO. All participants must have an operating revenue-grade interval meter(s) with associated telephone line(s).

Performance Evaluation Type

Firm Power Level; Dynamic CBL[51]

Performance Evaluation Description

For the 2008 capability period this program is offered with two options: DLRP-mandatory and DLRP-Voluntary. By design, the DRLP-mandatory option is similar to NYISO's Installed capacity/special case resources (ICAP/SCR) program and the DLRP-Voluntary option is similar to NYISO's Emergency Demand Response Program (EDRP), though there are differences in rules, implementation and when they are called.

[50] Program descriptions excerpted from: Consolidated Edison Company of New York Inc., *Distribution Load Relief Program (Rider U) Tariff Schedule* http://www.coned.com/documents/elec/158q-158r5.pdf
[51] Wellington, A. November 2008. "Distribution Load Relief Program (DLRP)." Presentation at the EPRI Workshop on Demand Response Evaluation, Measurement and Verification. Dallas, TX.

The mandatory option pays for electricity not used during an event and a monthly incentive for a guaranteed reduction commitment. There are no penalties but there is a de-rating for non-compliance. The program is open for eligible customers including those who are already enrolled in NYISO's ICAP/SCR and/or EDRP programs. The Voluntary option pays only for electricity not used during the event. There is no penalty for non-compliance.

For capacity payments, an Average Peak Monthly Demand (APMD) is established for each participating customer. The APMD (similar to the methodology described in NYISO's Installed Capacity Program manual[52] averages the customers' peak monthly demand in June, July, August and September from previous years' capability period. The customer pledges the amount of load reduction. The AMPD minus the pledged reduction provides the Firm Service Level (FSL). During the event duration, the customer must be below the FSL to receive full capacity payments.

For Energy payments, a Customer Baseline Load (CBL) is established for each participating customer. The CBL (similar to the methodology described in NYISO's Emergency Demand Response Program manual[53] calculates an average usage curve on a window of 30 previous days. Out of these 30 days, 5 similar days are selected to calculate the average energy usage for each hour of the event/test day.

[52] NYISO Installed Capacity Manual, October 2008. http://www.nyiso.com/public/webdocs/products/demand_response/special_case_resources_icap_program/icap_mnl.pdf.

[53] NYISO Emergency Demand Response Manual, July 2008 http://www.nyiso.com/public/webdocs/products/demand_response/emergency_demand_response/edrp_mnl.pdf.

Utility: Consolidated Edison Company of New York (Con Edison)
Program: Day-Ahead Demand Reduction Program (Rider W) [54]
Deployment Type: Economic
Compliance Type: Mandatory
DR Service Type: Energy

Program Description

The Day-Ahead Demand Reduction Program (DADRP) is a NYISO Program. Customers can participate in this program in accordance with the NYISO's program rules; Con Ed helps interested customers enroll as a service. Customers agree to reduce load when wholesale electric market prices exceed a pre-determined "strike" price. Any full-service Con Edison customer who has an interval meter and who is capable of reducing load by at least 100 kW per account through load curtailment can participate. Con Edison aggregates the load reduction nominations from customers and submits them to the New York Independent System Operator (NYISO) for evaluation. Bids that are scheduled by the NYISO are paid the corresponding day-ahead LMP and obligated to curtail the next day. Penalties are enforced for non-compliance in which case, customers must buy back any shortfall in load reduction at either the day-ahead or the real-time hourly price, whichever is greater.

Con Ed notifies the customer if the bid has been accepted by the NYISO. Customers choosing this option must agree to stay on the rate for a minimum of one year. Customers are paid at least the market-clearing price of electricity which will not be less than $0.05 for each kilowatt-hour curtailed.

Performance Evaluation Type

Dynamic CBL

Performance Evaluation Description

A Customer Baseline Load is established, which is the average hourly energy consumption, rounded to the nearest kWh, for each of the 24 hours in a day calculated in accordance with the NYISO methodology as selected by the customer, which is a Dynamic CBL. The Calculated Load Reduction (CLR) is evaluated which is the difference between the Customer Baseline Load and the customer's actual metered load on an hourly basis.

When the CLR is less than the customer's bid, Con Edison will charge the customer a penalty.

[54] Program descriptions excerpted from: Consolidated Edison Company of New York Inc., *Day Ahead Demand Reduction Program (Rider O)* http://www.coned.com/documents/elec/158U-158W.pdf

Utility: Consolidated Edison Company of New York (Con Edison)
Program: Emergency Demand Response Program (Rider V) [55]
Deployment Type: Reliability
Compliance Type: Voluntary
DR Service Type: Emergency

Program Description

The Emergency Demand Response Program (EDRP) may be activated by the New York Independent System Operator (NYISO) as a response to power shortages or other emergencies. Con Ed's customers can participate in this program according to the NYISO's program rules. Consequently performance measurement is defined by the NYISO protocols for (EDRP). Customers will receive the greater of $0.45 for each kilowatt-hour curtailed, or 90% of the price of energy in the real-time wholesale market, the real-time zonal Locational-Based Marginal Price.

Performance Evaluation Type

Dynamic CBL, Device-specific CBL, or Net Metered Generator Output.

[55] Program description excerpted from: Consolidated Edison Company of New York Inc., *Emergency Demand Response Program, Rider V* http://www.coned.com/documents/elec/158s-158t1.pdf

Utility: Georgia Power
Program: Demand Plus Energy Credit Rider Schedule (DPEC-1) [56]
Deployment Type: Reliability
Compliance Type: Voluntary
DR Service Type: Capacity

Program Description

This rider is applicable to any customer who provides, upon request, at least 200 kW of demand reduction. Georgia Power determines when to declare events that provide DPEC-1 payment opportunities in the four summer billing months of June through September. Customers will receive bill credits in exchange for reducing electric demand during periods in which Georgia Power is experiencing extreme supply and demand conditions. There will be a minimum notice of 30 minutes for demand reductions. After due verification, a monthly energy credit is paid to the customer in each billing month which includes a reduction period. The demand credit rate and the energy credit rate vary by the maximum hours of curtailment per year. Georgia Power pre-defines a DPEC peak period during the summer months of June through September, from 12:00 noon to 8:00 p.m. on non-holiday weekdays. Not more than eight (8) hours of demand reduction is permitted per day.

The contract term is one year and will be automatically renewed for an additional year, unless terminated with 30 days' written notice to Georgia Power. The customer may terminate his DPEC contract at any time by informing the company and honoring the remaining portion of his contract.

Performance Evaluation Type

Firm Power Level

Performance Evaluation Description

The customer and Georgia Power agree on the customer's Firm Demand Level (FDL) in kilowatts. The customer must reduce demand to the FDL or lower during all reduction periods to qualify for payment. A "Normal Electric Demand" (NED) is established for each of the summer billing months of June through September and for each of the winter billing months of October through May. The monthly NED is the customer's actual metered, average demand during non-holiday weekdays, excluding days in which there was a demand reduction, from 12:00 noon to 8:00 p.m.

Performance is evaluated by metering the actual demand (kW) reduction and the actual energy (kWhs) during the reduction period. At the end of each billing month which includes a reduction period, the company calculates a monthly energy credit which is equal to the product of the energy credit rate and the metered monthly actual energy (kWh) reduced below the Normal Electric Demand (NED), excluding energy reduced below the FDL. At the end of each summer billing month, Georgia Power calculates a monthly demand credit which is equal to the product

[56] Program descriptions excerpted from: Georgia Power, *Demand Plus Energy Credit Rider Schedule, DPEC-1 Electric Service Tariff* http://www.georgiapower.com/pricing/pdf/14.00_DPEC-1.pdf

of the demand credit rate and the actual demand reduction. The actual demand reduction is the difference in the Normal Electric Demand (NED) and the FDL during the DPEC Peak Period.

Utility: Georgia Power
Program: Real Time Pricing – Day Ahead Schedule (RTP-DA-2) [57]
Deployment Type: Reliability/Economic
Compliance Type: Voluntary
DR Service Type: Capacity/Energy

Program Description

The Rate Schedule is available for Georgia Power's Commercial and Industrial customers that maintain a peak 30-minute demand of at least 250 kW each month. Georgia Power Company provides hourly energy prices termed as "RTP-DA" prices to customers by 4:00 p.m. for the following day, via a pre-specified method. These hourly prices apply to corresponding variances in the customer's hourly actual load from the level specified in it CBL. The customer must sign a contract for five (5) years with Georgia Power for use of the RTP-DA schedule A. Customer baseline load (CBL) is developed which is the basis for achieving revenue neutrality with the appropriate non-RTP-DA firm load tariff on a customer-specific basis. Mutual agreement on the CBL is a precondition for use of RTP-DA.

Performance Evaluation Type

Pre-specified CBL

Performance Evaluation Description

The CBL is developed using one complete calendar year of either customer-specific hourly firm load data or monthly billing determinant data that represents the electricity consumption pattern and level agreed to by the customer and Georgia Power. For customers with existing load, the CBL will initially be developed from either actual historical metered half-hourly (1/2) interval data for a customer's specific location or from a template scaled to the actual historical monthly energy and monthly peak demands. For customers with new load, the CBL will initially be based on 100% of a Commercial customer's total projected load or 60% or greater of an Industrial customer's total projected load.

[57] Program description excerpted from: Georgia Power, *Real Time Pricing – Day Ahead Schedule, RTP-DA-2, Electric Service Tariff* http://www.georgiapower.com/pricing/pdf/6.20_RTP-DA-2.pdf

Utility: Pacific Gas and Electric Company (PG&E)
Program: PeakChoice (Electric Schedule E- PeakChoice) [58]
Deployment Type: Reliability/Economic
Compliance Type: Voluntary
DR Service Type: Capacity/Energy

Program Description

PeakChoice is a demand response program available to PG&E's bundled service customers billed on a commercial, industrial, or agricultural demand-based time-of-use electric rate schedule. Participants must have an interval meter capable of recording 15-minute interval usage and be read remotely. Each participating customer must reduce a minimum of ten (10) kW. For customers that have a demand greater than 200 kW or greater for three consecutive months in the past 12 billing months, PG&E installs the interval meter and the communication equipment (if required) at no cost for customers that commit at least one full year of participation. Customers must also have, at their expense: (1) access to the Internet and an e-mail address to receive event notifications and (2) an alphanumeric pager that is capable of receiving a text message sent via the Internet. All participating customers must choose specific program features[59] such as to customize the program to meet their operational needs.

Customers can participate on a "Committed Load" basis and/or on a "Best Effort" basis. "Committed Load" customers are required to curtail their load by the Committed Load amount relative to a baseline when notified of an event. In return, "committed load" customers receive a monthly capacity payment, and an energy payment, but are subject to penalties for non-compliance. "Best Effort" customers receive an energy payment for the energy reduced during an event, and are not subject to penalties for non-compliance.

Performance Evaluation Type

Dynamic CBL

Performance Evaluation Description

A Customer Baseline (CB) is established if there are at least ten (10) similar weekdays of interval data available on PG&E's PeakChoice website. The CB on any given day during the program is the hourly average based on the three (3) highest energy usage days of the immediate past ten (10) similar weekdays when a customer is notified of an event. The three (3) highest energy usage days are those days with the highest total kWh usage during the event window elected. The load during each hour of these selected three days will be averaged to calculate an hourly baseline for each event hour. The past ten (10) similar days will include Monday through Friday, excluding PG&E holidays, and will additionally exclude days when the customer was

[58] Program descriptions excerpted from: Pacific Gas and Electric Company, PeakChoice , Electric Schedule E-PeakChoice tariff http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-PEAKCHOICE.pdf

[59] Program features include minimum event notification time, event duration, maximum number of events per summer season, maximum consecutive event days, event window and the level of load reduction commitment (up to 85% of peak load).

paid to reduce load on this or another interruptible or other curtailment program, or days when a rotating outage that affected the customer is called.

Energy payments are paid if at least 50% of the committed load is reduced in any specific hour, up to a maximum of 150% of committed load reduction in one hour during the event. The hourly delivered load is equal to the hourly CB minus the metered average demand during the event hour. The hourly delivered load cannot be less than 10 kW.

"Committed Load" customers receive a Committed Load Payment (CLP) which is determined on an hour by hour basis and is dependent on the calculated Committed Rate (CR), the Committed Load, and any hourly adjustments.

Utility: Pacific Gas and Electric Company (PG&E)
Program: Optional Binding Mandatory Curtailment (Electric Schedule E- OBMC) [60]
Deployment Type: Reliability
Compliance Type: Mandatory
DR Service Type: Capacity

Program Description

Under the program, eligible customers can be exempted from any potential "block progression" rotating outages that are based on supply constraints, but not from a rotating outage that may be caused by daily, localized emergency circuit switching. In return, customers agree to reduce the load on the entire electric circuit that serves their facility, when requested by PG&E. There are no financial incentives for participating in the program. An OBMC Agreement has an initial term of one (1) year but may be extended from year to year.

All bundled service and direct access service customer in PG&E service territory, who can reduce electric load on a PG&E circuit or dedicated substation to a specified level within 15 minutes of notification are eligible. Customers must be able to demonstrate 15% load reduction from the established Maximum Load Level (MLL) and file annually an OBMC plan that shows how the 15% reduction below the prior year's average monthly peak circuit demand will be accomplished. Upon notification from PG&E of an OBMC curtailment, OBMC customers must immediately commence implementation of the load curtailment measures contained in their load reduction plan.

The MLLs correspond to a reduction in a circuit's loading of between five (5) and fifteen (15) percent in five (5) percent increments. The CAISO may call for load reductions on a required MW level, but PG&E will require the OBMC customers to reduce their load to the next highest five (5) percent increment. For each operation, PG&E will notify the customer of the required percent reduction, along with the start and end times for the OBMC operation. PG&E may extend the end time or increase the percentage reduction of any ongoing OBMC operation as necessary to correspond with CAISO directives.

Failure to meet the load relief criteria established by an OBMC plan shall result in a non-compliance penalty for the OBMC customers equal to $6.00 per kWh times the average total load on the applicable circuit less the required MLL, as measured during each half-hour of the rotating outage. Failure to pay these penalties may result in termination of electric service.

Performance Evaluation Type

Dynamic CBL

[60] Program descriptions excerpted from: Pacific Gas and Electric Company, *Optional Binding Mandatory Curtailment Plan, Electric Schedule E- OBMC Tariff* http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-OBMC.pdf

Performance Evaluation Description

Maximum Load Levels (MLLs) are established by PG&E for the circuit or dedicated substation, which correspond to each of the 5, 10, and 15 percent load reduction levels.

MLL calculation methodology is specified based on the applicable customer's curtailment obligation. For example customers participating in a capacity interruptible program where the customer has not met their monthly or annual curtailment obligation and the customer's FSL under that program is less than the customer's baseline, the MLL for the 5 percent load reduction is equal to the product of the FSL times 0.95. The MLL for the 10 percent load reduction is equal to the product of the FSL times 0.90. The MLL for the 15 percent load reduction is equal to the product of the FSL times 0.85.

The baseline for determining MLLs is equal to the average recorded hourly usage amount (if available) for the same hours as the OBMC operation hours on the immediate past 10 similar days, excluding days when the customer was paid to reduce load under PG&E's Demand Bidding Program and days when the OBMC program operated. For establishing similar days, if the OBMC event is called on a business day, then 10 prior business days are used; if the OBMC event is called on a weekend or holiday, then 10 prior weekend and holidays are used.

Utility: Pacific Gas and Electric Company (PG&E)
Program: Capacity Bidding Program (Electric Schedule E-CBP) [61]
Deployment Type: Reliability/Economic
Compliance Type: Mandatory
DR Service Type: Capacity/Energy

Program Description

Schedule E-CBP is a voluntary demand response program that offers customers incentives for reducing energy consumption when requested by PG&E. Customers receiving bundled service, aggregation service, or direct access service and being billed on a PG&E commercial, industrial, or agricultural electric rate schedule, are eligible for participation. Participating customers must have an approved interval meter capable of recording usage in 15-minute intervals and being read remotely by PG&E. The initial term is 12 months, after which a directly-enrolled customer or Aggregator may request to terminate participation in the program.

The program days are Monday through Friday during the program season (May 1 through October 31), excluding PG&E holidays. The program hours are 11:00 a.m. to 7:00 p.m. on program days. PG&E may trigger a Day-Ahead/Day-of CBP event when PG&E's procurement stack is expected to require the dispatch of electric generation facilities with heat rates of 15,000 Btu/kWh or greater for the day-ahead/day-of market, or when PG&E, in its sole opinion, forecasts that resources may not be adequate. PG&E will notify directly-enrolled customers and aggregators by 3:00 p.m. on a day-ahead basis of a CBP Event for the following business day. To participate in this program, a customer, including aggregated customers, must have a valid customer specific energy baseline (CSEB) at least 5 calendar days prior to the first day of the operating month.

Performance Evaluation Type

Dynamic CBL

Performance Evaluation Description

For directly-enrolled customers, the CSEB on any given day during the program is the hourly average based on the three (3) highest energy usage days of the immediate past ten (10) similar days. A day-ahead or day-of event is based on the immediate past ten (10) similar days. The three (3) highest energy usage days are those days with the highest total kilowatt hour usages during the program hours. The past ten (10) similar days will include Monday through Friday, excluding PG&E holidays and will additionally exclude days when the customer was paid to reduce load on an interruptible or other curtailment program or days when rotating outages were called.

Capacity nominations must be submitted under available program options (such as Day Ahead and Day-of), by directly-enrolled customers and aggregators no later than 5 calendar days prior to the operating month. Payments under this rate schedule are determined by capacity price,

[61] Program descriptions excerpted from: Pacific Gas and Electric Company, *Capacity Bidding Program, Electric Schedule E- CBP Tariff* http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-CBP.pdf

capacity payment and capacity penalty and energy payments. If one or more CBP Events were called during the operating month, then the Capacity Payment for the operating month is the sum of the Adjusted Hourly Capacity Payments/Penalties for the operating month, which are determined by calculating the hourly delivered capacity for the event hour. Such capacity is equal to the CSEB for the event hour minus the average demand during the event hour. The average demand is defined as the energy consumed during the event hour converted to demand measured in kilowatts. T he Hourly Delivered Capacity cannot be greater than the Nominated Capacity or less than zero (0).

B
GLOSSARY

AESO – Alberta Electricity System Operator

Ancillary Services (Demand Response Service Type) – Ancillary services market programs allow customers to bid on load curtailment in the spot market as operating reserve or regulation. When bids are accepted, participants are paid the spot market price for committing to be on a standby and are paid the spot market energy price if load curtailment is required.

Baseline – A baseline, often referred to as the customer baseline load (CBL) is the level of usage that the participant otherwise would have consumed during an event. The difference between the baseline and the actual metered event usage therefore is the performance, or load impact.

Baseline Type-I – NAESB terminology for a baseline that is based on a Demand Resource's historical interval meter data which may also include other variables such as weather and calendar data. For ISO/RTO programs, recent days' (e.g. last five or ten) usage is typically used.

Baseline Type-II – NAESB terminology for a baseline based on statistical sampling to estimate the electricity consumption of an Aggregated Demand Resource where interval metering is not available on the whole population.

CAISO – California Independent System Operator

Capacity Service (Demand Response Service Type) – Assuring that sufficient capacity is available to meet anticipated loads reliably.

Critical-Peak Pricing (CPP) – A type of pricing mechanism whereby normal flat rates or time-of-use (TOU) rates are in effect except for certain peak days, when pre-specified higher electricity usage rate is superimposed on the normal flat rate or TOU rate. CPP prices are used during contingencies or during high wholesale electricity prices for a limited number of days or hours per year.

Customer Class – Customer type classification that includes residential, industrial and commercial customers.

Deemed Savings – The kW and/or kWh reductions that have been established for a specific energy efficiency measure for the purposes of program design and implementation.

Demand Bidding/Buyback – Demand Bidding (also called Buyback) programs are programs in which consumers bid on specific load reductions in the electricity wholesale market. A bid is accepted if it is less than the market price. When a bid is accepted, the customer must curtail his load by the amount specified in the bid or face penalties.

Demand Response – A change in a consumer's electricity usage level or profile in response to a change in the price it pays for electricity, or another inducement to do so.

Device-Specific Performance Measure – Performance is based on a change in the operating status of a specific device (air conditioning unit, thermostat, direct load control device, etc.) instead of using the whole premise load (the metered usage). In its simplest construct, this involves an instruction being transmitted by the program administrator (or system dispatcher) to the device that activates a relay and the power to the device is shut off, and remains so until another reinstruction is issued. More sophisticated systems utilize two-way communication so that the device acknowledges receipt of the instruction, and sometimes even confirms that it was carried out. The event performance measure is pre-determined and specific to each situation. Device-specific Performance Measure is one of EPRI's five categories of Demand Response performance measurement.

Direct Load Control (DLC) – In DLC programs, utilities have the ability to remotely shut down participant equipment on a short notice. In return, participating customers receive upfront incentive payments or rate discounts.

Dynamic Pricing – A pricing mechanism whereby electricity is priced in a way that reflects the time-variation in electricity supply costs.

Dynamic Customer Baseline Load (CBLD) – The baseline is determined based on usage in the days just prior to each event. The event CBLD may be determined by load during corresponding periods on days prior to the event, and in some cases during other periods. It might also be adjusted for weather conditions. Dynamic CBL is one of EPRI's five categories of Demand Response performance measurement. It also includes the sub-category of Rolling CBL, which is analogous to NAESB's Meter Before/Meter After performance evaluation methodology.

Economic (Deployment Type) – The Demand Resource is dispatched based on its attributed economic value in the dispatch system, minimizing the cost to serve scheduled or anticipated energy requirements.

EM&V – Evaluation, Measurement, and Verification

Emergency Demand Response – The Emergency Demand Response Program (EDRP) is a short-notice program that provides payments to electric customers who reduce load during specific times during emergency conditions (when electric reliability is jeopardized). During these events, participants are expected (typically not obligated) to either reduce energy consumption or transfer load to an alternate off-grid source.

Emergency Service (Demand Response Service Type) – Provision for supplemental energy resources to cover extreme circumstances.

Enabling Technology – Hardware, software and communication technology that is mandatory for implementing dynamic pricing-based programs. Examples of enabling technologies include energy meters/interval meters, thermostat/controls, and communications/network.

Energy Service (Demand Response Service Type) – demand resources bid to curtail load for scheduling or dispatch, displacing generation needed to serve load.

Energy Efficiency Measure – Improvements in equipment or systems in order to produce the same output while using less energy.

ERCOT – Electric Reliability Council of Texas

Event – A specified period of time when curtailments are to be undertaken by program participants or when price changes are to be posted.

Firm Power Level (FPL) – FPL is deemed by agreement between the customer and the utility procuring the demand response resource. To comply with the program rules, the participant must reduce its load to its FPL. FPL is one of EPRI's five categories of Demand Response performance measurement.

IESO – Independent System Operator of Ontario

Impact Evaluation – Evaluation to determine the actual load impacts of demand response programs.

Installed Capacity (ICAP) – ICAP market programs are offered to customers who can commit to providing pre-specified load reductions when system contingencies arise. Participants usually receive a day-ahead notice of events and are penalized if they do not respond to calls for load reduction.

Interruptible/Curtailable (I/C) – These programs allow participating customers to receive upfront incentive payments or rate discounts, if they shed their load to a pre-defined level during a specific time. Participants who do not respond can face penalties, depending on the program terms and conditions.

ISO – Independent System Operator

ISO-NE – Independent System Operator of New England

Mandatory (Compliance Type) – The Demand Resource faces penalties if it does not comply.

Maximum Base Load – NAESB terminology for a baseline applicable where event performance is measured solely on a Demand Resource's ability to reduce to a specified level of electricity demand, regardless of its electricity consumption or demand at Deployment. Analogous to firm power level.

Measurement and Verification (M&V) – Electricity consumption data collection, monitoring, and analysis for the purposes of establishing program performance.

Meter Before/Meter After – NAESB terminology for the measurement of demand over a prescribed period of time prior to Deployment and then comparing it similar readings during the Sustained Response Period. This protocol is particular to demand response providing regulation service to the ISO/RTO.

Metering Generator Output – NAESB terminology for generation assets located behind the participant's meter in which the Demand Reduction Value is based on the output of the generation asset. Identical to EPRI's Net Metered Generator Output classification of performance measurement.

MISO – Midwest Independent System Operator

NAESB – North American Energy Standards Board

NAPEE – National Action Plan for Energy Efficiency

NBSO – New Brunswick System Operator

Net Metered Generator Output – This performance standard is designed to determine compliance for premises with on-site generation. Event compliance is achieved by operating an on-site generation unit during an event, but output must be incremental to the output the unit would otherwise have produced absent the event. Net Metered Generator Output is one of EPRI's five categories of Demand Response performance measurement.

NYISO – New York Independent System Operator

PJM – PJM Interconnection, LLC. The regional transmission organization (RTO) for all or part of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

Pre-specified Customer Baseline Load (CBL) – This measure is designed to accommodate hourly pricing and settlement of variances between actual load and the CBL. For the program year, a kW level is set for each hour in the year in advance. In some programs, CBL values are based on the previous year's hourly consumption levels (kWh), with adjustments to align for weekends and holidays and for events known in advance (such as scheduled maintenance). In other programs, they are negotiated, especially in cases where the participant's facilities are new, or have changed substantially. The Pre-specified CBL is one of EPRI's five categories of Demand Response performance measurement.

Process Evaluation – Refers to the overall demand response program implementation procedure or plan including all administrative, marketing and management processes that were followed.

Real-time Pricing (RTP) – RTP is a pricing mechanism whereby electricity prices may change as often as hourly to reflect the cost of supply. A price signal is provided to the user on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level.

Reliability (Deployment Type) – The Demand Resource is dispatched to preserve system reliability at acceptable levels.

RTO – Regional Transmission Organization

Time-of-Use (TOU) – Electricity prices are set for a specific time period on an advance or forward basis. The electricity prices differ in different blocks of time. Prices paid for energy consumption during different time blocks are pre-established and known to consumers in advance, allowing them to vary their usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall.

Voluntary (Compliance Type) – The Demand Resource is not penalized if it does not comply.

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