AEIC Load Research Committee

Demand Response Measurement & Verification

Applications for Load Research

March 2009

Acknowledgements

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White Paper Focus

The primary focus of this paper is to standardize terminology used in association with Demand Response and Measurement and Verification as it applies to Load Research practices. In addition, this paper will define and contrast the various methodologies used in both the Measurement (impact evaluation) and Verification process of demand response including the development and application of Baselines. This paper deals exclusively with the measurement of demand reduction (kW) achieved by Demand Response programs, and while recognizing that demand response may reduce both demand and energy, makes no attempt to describe/define measurement reductions in energy (kWh) attributed to either Demand Response or Energy Efficiency programs.

The authors highlight and discuss many of the more prominent Demand Response programs currently in use but make no attempt to describe or discuss all existing or potential programs that may reduce peak demand. The programs used throughout this paper are used to help define broad groupings of programs and the Measurement and Verification methods that apply to these groupings.

1 Introduction

1.1 Demand Side Management (DSM)

In the electric industry, the term 'Demand Side Management' (DSM) refers to programs that attempt to influence customer consumption patterns of electricity to match current or projected capabilities of the power supply system (adapted from: AEIC Load Research Manual). DSM consists of two major components: Demand Response (DR) and Energy Efficiency (EE), which is also referred to as conservation.

Figure 1.1 – Components of DSM
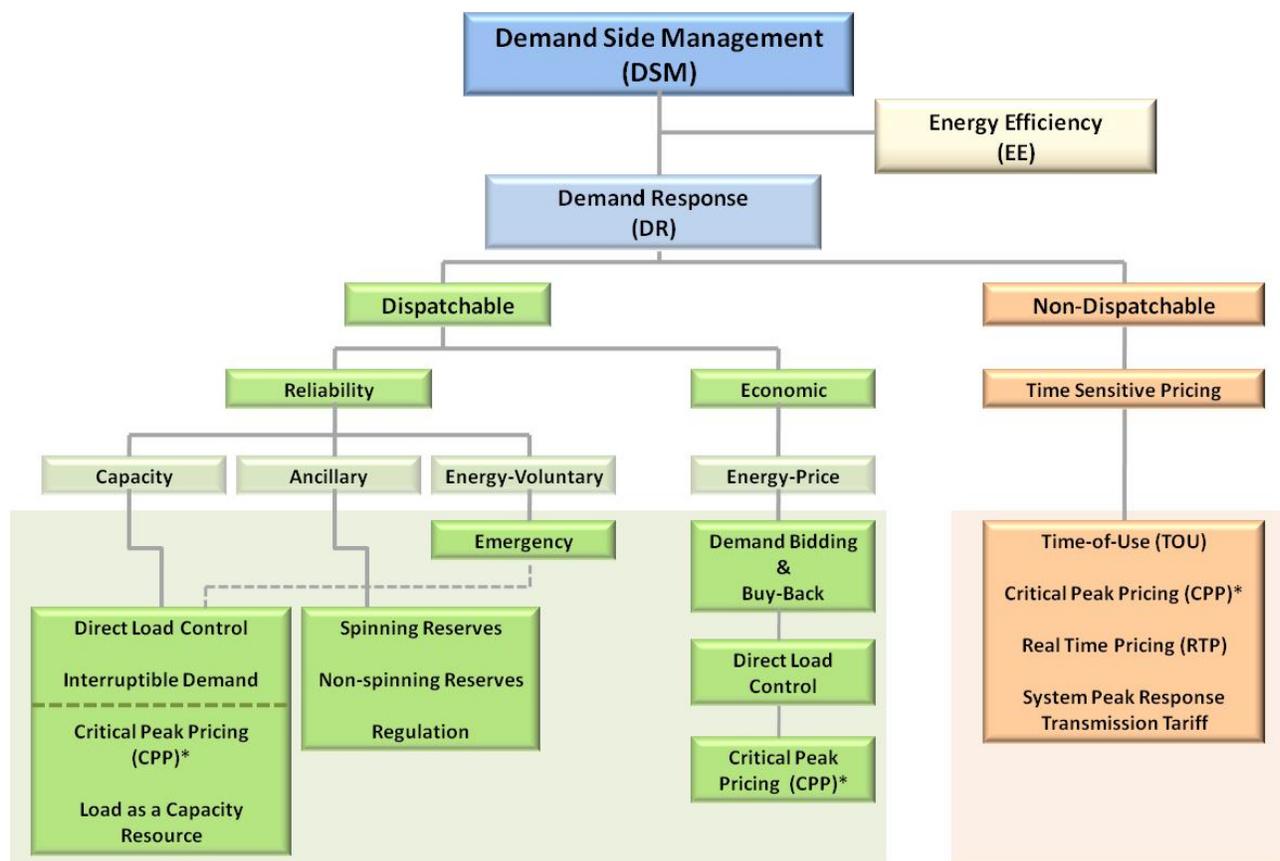
* NOTE: Dependent on the ISO/RTO Critical Peak Pricing (CPP) may be accepted as Dispatchable Load. It is therefore shown as both dispatchable and non-dispatchable on this graphical representation.

Energy Efficiency (EE)

According to the 'National Action Plan for Energy Efficiency' published by U. S. Department of Energy and Environmental Protection Agency (EPA), Energy Efficiency (EE) refers to using less energy to provide the same or improved level of service to the energy consumer in an economically efficient way. The term Energy Efficiency as used here includes using less energy at any time, including at times of peak demand through Demand Response and peak shaving efforts.

Demand Response (DR)

The definition of Demand Response (DR) as used by the U. S. Department of Energy (DOE) in its February 2006 report to Congress and subsequently adopted by the Federal Energy Regulatory Commission (FERC) is stated as:

'Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at time of high wholesale market prices or when system reliability is jeopardized.'

This paper will address and discuss some of the more prominent Demand Response programs currently in use within the United States. The programs discussed do not comprise an exhaustive list of the programs or types of programs currently in use, or being designed, but will serve to help define groupings of programs and applicable measurement and verification methods.

Individual Based Programs

For the purposes of this paper individual based Demand Response programs refers to programs that empower customers to make the ultimate decisions on when, and to what amount, they will curtail usage. Critical Peak Pricing (CPP) and Real Time Pricing (RTP) are examples of individual based Demand Response programs.

Mass Market

Mass market Demand Response programs typically refer to programs that are offered with the same tariff/incentive characteristics to a large set of relatively homogeneous customers such as the residential Class, all Time-of-Use (TOU) commercial customers, or all residential customers with central air conditioning. Examples of mass market Demand Response programs include Interruptible Air Conditioning Direct Load Control programs, Time-of-Use rates and Real Time Pricing (if it is a rate class tariff).

Event Based (Dispatchable)

Demand response programs that have the capability to respond to emergency reliability events and/or peak load reduction events are Event Based programs. Typically, Event Based programs qualify as dispatchable power resources because they are achievable, reliable, verifiable and capable of responding within ISO/RTO (ISO is "Independent System Operator", RTO is "Regional Transmission Organization") time guidelines. Direct Load Control (DLC), callable Demand Response programs and measurable Critical Peak Pricing programs are event based.

Non-Event Based (Non-Dispatchable)

Demand Response programs that are economic based or provide load reductions that are not necessarily available during system peak hours are Non-Event Based programs. These type programs are also considered non-dispatchable because they are not deemed as reliable or verifiable during system peak loading periods. Programs such as Time-of-Use (TOU) and Real Time Pricing (RTP) that are difficult to ascertain hourly customer participation values are examples of Non-Event Based programs.

1.2   Demand Response Programs

Demand Response (DR) programs are continuously growing and evolving. Several of the more typical programs have been mentioned above. This section will expand on these examples to give the reader a better understanding of each programs goals and challenges.

Time-of-Use (TOU)

Time-of-Use (TOU) tariffs are DR programs that segment each billing month into smaller hourly windows each with a separate pricing level related to production costs. Participants are provided price signals to reduce load during higher cost hours.   The simplest form of a TOU tariff segments a day into two production cost segments (usually referred to as on-peak and off-peak hours). For example, a Load Serving Entity (LSE) may segment all weekdays as: On-peak hours equal to 1:01 pm through 6:00 pm (inclusive) and all other hours, including weekends, as off-peak. Further segmentation may include seasonal rates.

Direct Load Control (DLC)

Direct Load Control (DLC) programs are designed to reduce load during extreme events (e.g. high production costs, system reliability, etc.). Participants receive substantial credits for decreasing (shedding) load when an event is initiated by the LSE. Some DLC programs provide the LSE with direct control over shedding customer loads (i.e. air conditioning cycling or setback programs). Other programs allow the participant to choose how they will shed load (i.e. interruptible or load curtailment programs). Penalties are usually assessed for nonperformance.

Critical Peak Pricing (CPP)

Critical Peak Pricing (CPP) tariffs are often designed with two standard TOU periods (on-peak hours and off-peak hours) and a third optional critical peak period. Typically, the two standard TOU periods have specific time frames and prices. The third critical peak TOU period is a floating time frame (an event) which may or may not be in effect on any given day. Advance notification by an LSE's intention to call a CPP event is typically given (up to 24 hours).

Figure 1.2 – TOU with Critical Peak Pricing Period
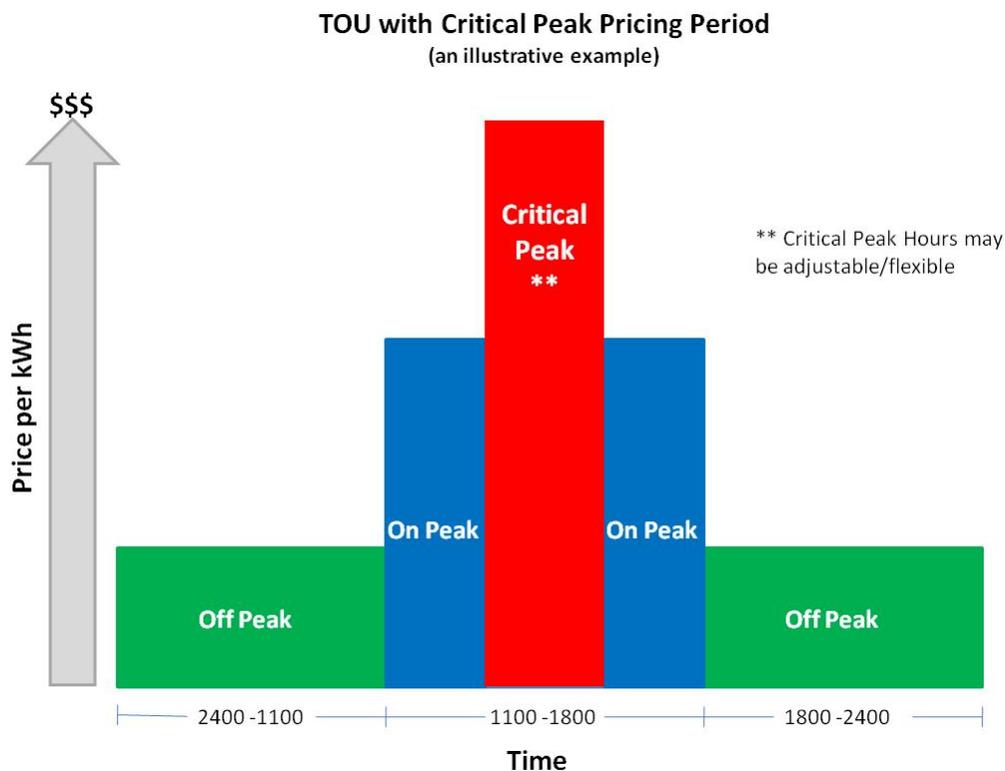
When the LSE initiates a CPP event, customers receive signals indicating the expected energy prices for the next day. Price signals can be as simple as relative price levels (low, medium, high) or specific (tomorrow's CPP price will be $0.435). Customers on CPP tariffs receive discounted on-peak and off-peak pricing as tariff incentives creating the opportunity for customers to reduce their energy costs. However, much of these cost savings disappear if a customer does not reduce consumption during CPP events as stipulated in these tariffs.

Peak Time Rebate (PTR)

Peak Time Rebate (PTR) programs offer rebates to customers who use less electricity during critical peak events. Similar to CPP, if such events are planned, advanced notice can be provided. In addition, some events may occur on an emergency basis, with customer notification given shortly before, or at the initiation of the event. PTR customers may remain on a traditional flat rate or TOU tariff. During a critical event, customer demand must be compared to baseline usage to determine the amount of hourly kW reduction. For example, if a critical peak period is planned on a given weekday between the hours of 2 and 7 p.m., customers may be notified the previous day. The customer's actual hourly demand (kW) during the event would be compared to baseline demand for the same hours. The customer would be paid a rebate based on the amount of demand reduction.   Customers may have the option of obtaining enabling devices, such as smart switches or thermostats or in-home displays, to help them save during critical events.

Real Time Pricing (RTP)

Real Time Pricing (RTP) is typically an hourly market based pricing DR program without specific demand response events called by LSEs. The basic tenet of RTP is that price will determine usage and that the price elasticity within the market will drive customer behavior to reduce load. Prices paid for energy consumed are typically established and made available to customers a day ahead (day ahead pricing) or an hour ahead (hour ahead pricing) permitting customers the opportunity to vary demand and energy use in response to price. Participants are assigned a baseline load shape (sometimes known as a Customer Baseline or CBL). If the customer uses more energy in any hour than their CBL for that hour, then the customer is charged for energy at that hour's market price. The converse is also true. If the customer uses less energy in that hour the LSE will credit the customer for energy not used. It should be noted that some LSEs set every participating customers CBL to zero usage (a one-part RTP program). In this case, no credits are given since there is no CBL. Other market based rates may also be applied.

1.3   Key Drivers to Demand Response (*Dispatchable vs. Non-Dispatchable)*

A key driver for many LSEs is determining if a DR program is considered dispatchable. A dispatchable DR program will have a one-time effect on the LSEs system load shape. An analogy can be made that dispatchable DR programs are like a 'Big Red Button' that LSEs can initiate (an event) to decrease system demand in a relatively short timeframe.   Dispatchable programs are generally regarded as programs that reduce demand with a high degree of certainty. [1] DR programs not designed to alter the short term system load shape are deemed non-dispatchable.

Certain dispatchable DR programs, like Direct Load Control (DLC), can quickly decrease the system load shape. These programs are especially efficient when unexpected reliability or high cost anomalies occur due to forced outages or weather. Their effect is similar to an LSE ramping up spinning reserve or "peaker" generation.

Other dispatchable programs will alter a system load shape but not as quickly. For example, RTP and CPP programs typically provide price signals up to 24 hours in advance of when they are to take effect. The relationship between price and customer loads can be estimated. These estimates are used by generation planners when preparing the next day's dispatch model.

Lastly, non-dispatchable programs like TOU are typically designed years in advance and provide historical data that permits the relationship between the TOU prices and customer loads to be estimated. However, these programs rarely affect short term dispatch. These tariffs are more likely to change annual system peak growth rates as customers change their behaviors decreasing their on-peak usage habits.

Regardless of the type of DR program employed (dispatchable vs. non-dispatchable) all require analysis to estimate the demand reduction. The estimate is the difference between what the customer actually used and what that customer would have used had the program not been enacted.   What the customer would have used is referred to as the baseline and is key to effective Measurement and Verification.

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[1]   NERC (North American Electric Reliability Corporation, 'Data Collection for Demand-Side Management,' December 2007

Baseline generation is an evolving process with a limiting factor being data availability. Although many of the current and most widely accepted baseline generation processes are discussed in this white paper, new methods of establishing baselines and measuring their accuracies will continue to grow as Demand Response evolves utilizing the advanced technologies that will be enabled by Advanced Metering Infrastructure (AMI).

1.4   Demand Response Measurement and Verification (M&V)

Measurement and Verification (M&V) refers to the application of appropriate statistical and load research techniques to measure and verify the load reduction impact resulting from the utilization of a Demand Response program. Simply stated, M&V is a process to quantify, with statistical confidence, the value of a Demand Response load reduction throughout the duration of a Demand Response event. Events may last for one or more hours; the measurement typically quantifies the entire event period, and may also quantify the reduction during the peak hour. Measurement can be reported in MW, hourly kW, peak kW, etc. and may further be reported in a variety of intervals including 15, 30, 60 minute and total event duration. Measurement quantifies this load reduction and Verification provides evidence that the reduction is reliable.

Figure 1.3 – M&V Quantifies Load Reduction Value
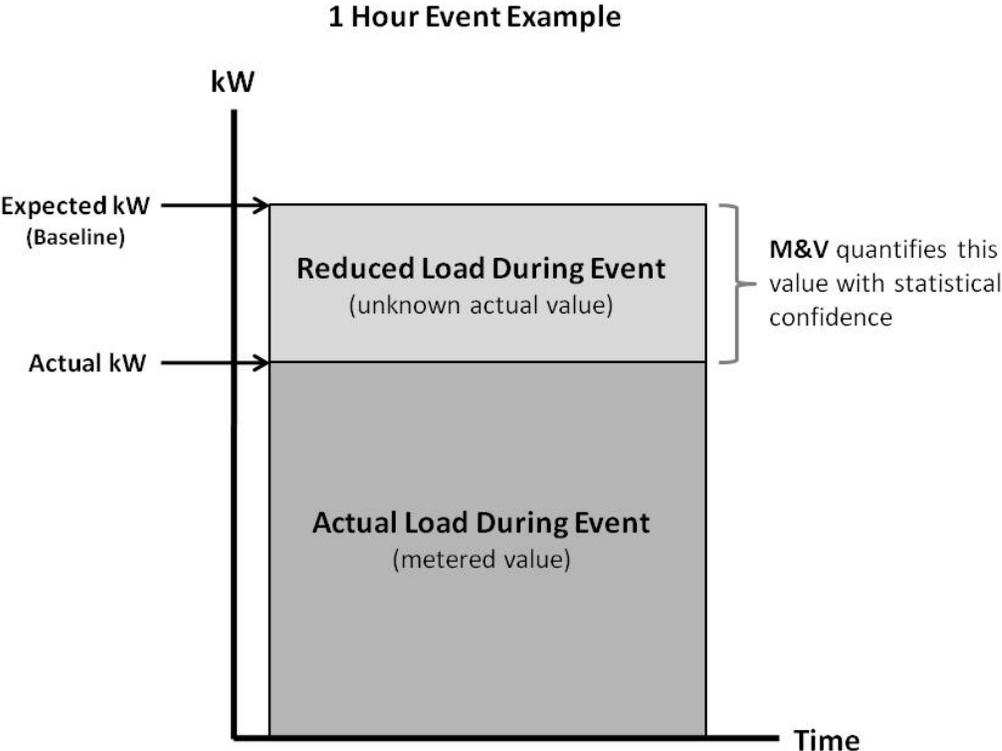
1.5 Identify Stakeholders

Stakeholders are parties who have either a load reduction, or monetary interest, in the measured demand reductions.   Stakeholders include:

- Regulators and policy makers: both state Public Utility Commission (PUC) and federal (FERC and DOE) levels

- Aggregators

- Interveners

- State and local agencies (Attorney General/municipalities)

- System Operators: utility or ISO/RTO

- Utility management

- Program administrators

- Third party program providers, vendors, consultants

- Customers

- Generation, transmission, and distribution planners

2 Individual Measurement (Impact Estimation)

2.1 Introduction to Measurement of Individual Customers

DR programs offer customers the opportunity to reduce demand in response to a price signal or financial incentive. Typically, the request to reduce demand is made for a specific time period on a specific day, which is referred to as a Demand Response event (DR event). A DR event is defined as, "The time periods, deadlines and transitions during which Demand Resources perform."[2]

The figure below depicts the periods of a DR event. It also describes points during the DR event where the customer receives notification of the beginning and end of the event and illustrates the point at which a customer should take action.

Figure 2.1 - Demand Response Event Periods
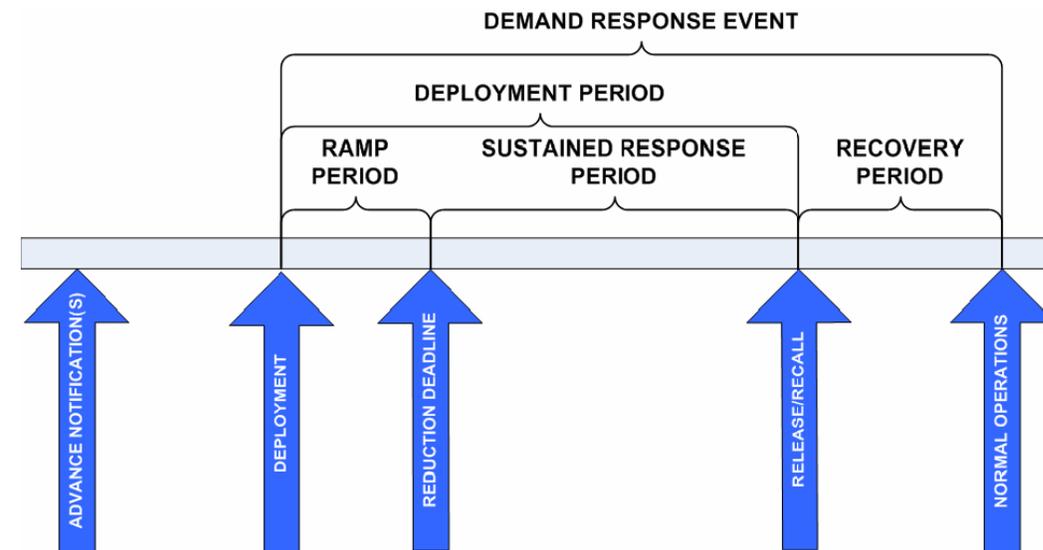
Source: New York Independent System Operator

The process to measure the load reduction when "Demand Resources perform" begins with collecting or calculating the following two key components:

Baseline (CBL) – The amount of energy the customer *would have consumed* absent a signal to reduce. This hourly usage curve (Figure 2.2) is created using methodologies explained later in this section.
Actual Use – The amount of energy the customer *actually consumed* during the DR event period.
Load Reduction - The mathematical difference between the Baseline and the Actual Use.

Baseline – Actual Use = Load Reduction

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[2] "Business Practices for a Framework for Measurement and Verification of Wholesale Electricity Demand Response", Proposed Standards approved by the NAESB DSM-EE Subcommittee for Quadrant WEQ, December 2, 2008

Figure 2.2 - Baseline Example
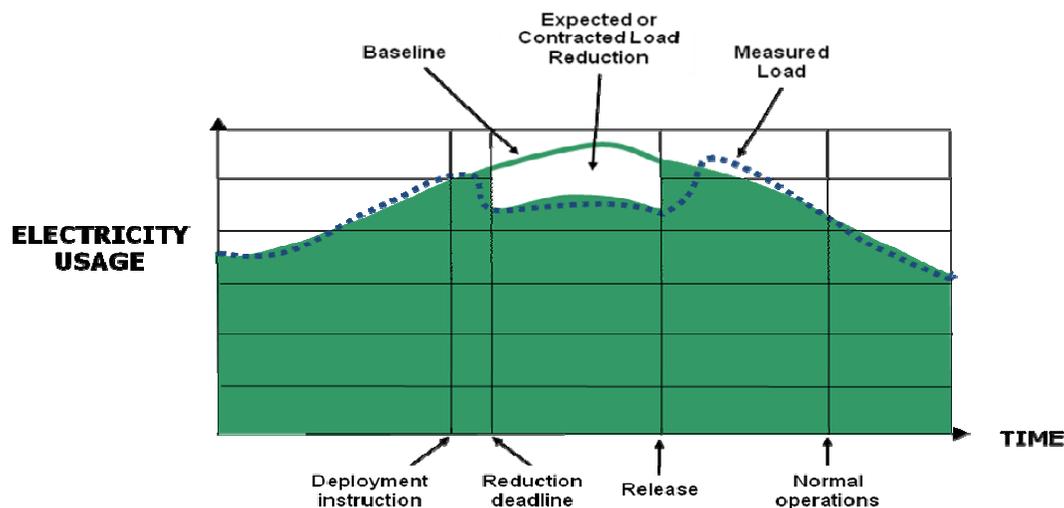
Source: New York Independent System Operator

Many DR programs base incentives on whether a customer curtailed during the DR event and if so, how much they curtailed. The calculation of the baseline is a critical piece of these particular programs.   If the baseline for a customer is calculated too high, the electric utility will pay incentives in excess of the customer response. If the baseline is too low, less or no load reduction will be recorded which can lead to customer non-participation in future DR events. It may also eliminate incentives to participate, resulting in a customer requesting to be removed from the Demand Response program. Therefore, it is in the best interest of both the utilities and the customers to have as accurate a baseline estimation as possible.

2.2   Baseline Methodologies
Two common techniques for calculating baselines are day matching and regression analysis. Day matching attempts to select a baseline day that most accurately matches the DR event day. Regression analysis simply involves using statistical regression methods to create a model.

Day Matching
Day matching consists of taking a short historical time period (which can be anywhere from one week to sixty days in length) and attempting to match what the usage for an event day would have been based on the usage during the historical period chosen. This usually involves choosing a subset of days from the historical period and averaging them, often with an adjustment for the current day's conditions applied to the calculated baseline. For example, if the DR event day occurs on a weekday, hourly data from weekdays are used in the calculation of the baseline.   The following approaches are examples of specific uses of day matching.

Previous Days Approach[3,4]

This approach calculates a baseline for a DR event day by averaging hourly load data using a subset of days from a historical period[5].   The small subset of days and the historical days are the same type of day as the DR event day such as a weekday or weekend. This results in a baseline load curve of average hourly values calculated from a customer's previous actual use.   In Figure 2.3 below, three equivalent days prior to the DR event day are selected to be averaged together to create a baseline.

Figure 2.3 - Previous Day Approach Example

Hour	Days Averaged to Create Baseline			Hourly Baseline
	Day 1	Day 2	Day 3	
1	1.81	1.20	1.14	**1.38**
2	1.64	1.08	0.98	**1.23**
3	1.49	0.97	0.92	**1.13**
4	1.41	0.91	0.88	**1.07**
5	1.34	0.93	0.83	**1.03**
6	1.30	0.96	0.83	**1.03**
7	1.29	1.02	0.89	**1.07**
8	1.45	1.05	1.04	**1.18**
9	1.53	1.10	0.99	**1.21**
10	1.59	1.31	1.09	**1.33**
11	1.75	1.52	1.10	**1.46**
12	1.86	1.58	1.14	**1.52**
13	2.06	1.83	1.23	**1.71**
14	2.11	1.98	1.39	**1.83**
15	2.21	2.16	1.47	**1.95**
16	2.29	2.22	1.62	**2.04**
17	2.30	2.25	1.76	**2.11**
18	2.41	2.37	1.75	**2.17**
19	2.41	2.43	1.89	**2.24**
20	2.29	2.24	1.75	**2.09**
21	2.26	2.24	1.71	**2.07**
22	2.37	2.34	1.71	**2.14**
23	2.27	2.24	1.65	**2.05**
24	1.99	1.88	1.45	**1.77**

Hourly baseline = Average of Day 1, Day 2, Day 3

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[3] CAISO Demand Response Resource User Guide, Guide to Participation in MRTU Release 1, November 29, 2007, Version 3.0

[4] ISO New England Manual for Measurement and Verification of Demand Reduction Value from Demand resource, M-MVDR, Revision: 0, February 28, 2007

[5] ISO New England (ISO NE) uses five equivalent days prior to a DR event day in their baseline calculation while California ISO (CAISO) uses three equivalent days prior to a DR event day. The number of days used by both ISO NE and CAISO are specific to their service territories and not necessarily translatable to other service territories. An analysis specific to a particular service area should be completed to determine the optimum number of days needed in a baseline methodology.

Average Daily Energy Usage Approach[6,7]

This approach uses daily energy (the sum of the 24 hourly energy values for a day) to choose which days are included in the baseline calculation. Suitable days are selected based on their daily energy being comparable (75% or greater) to the daily energy of a *selected day,* prior to the DR event day. The *selected day* is chosen because; a), it is the most recent non DR event day and, b) it is the same type of day as the DR event day.   Additionally, a daily energy ratio is calculated by comparing the daily energy of the suitable days to the daily energy of the selected day prior to the DR event. In the following example (Figures 2.4 and 2.5), the baseline is created, similar to PJM and NYISO methods, by averaging the five highest ratio daily energy days.

Figure 2.4 - Average Daily Energy Usage Approach Example

Date	Day Of Week	Daily Energy	Ratio	Acceptable Day
7/31/2006	Monday	39.792	1.307	Yes
7/28/2006	Friday	31.226	1.026	Yes
7/27/2006	Thursday	30.511	1.002	Yes
7/26/2006	Wednesday	30.647	1.007	Yes
7/25/2006	Tuesday	29.899	0.982	Yes
7/21/2006	Friday	28.995	0.952	Yes
7/20/2006	Thursday	29.373	0.965	Yes
7/19/2006	Wednesday	28.798	0.946	Yes
7/18/2006	Tuesday	32.707	1.074	Yes
7/17/2006	Monday	40.264	1.323	Yes
	Average	**32.221**		
	Selected Day	**30.445**		

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[6] NYISO Day-Ahead Demand Response Program Manual, July 2003
[7] Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.

Figure 2.5 - Average Daily Energy Usage Approach Example

Hour	Days Averaged to Create Baseline					Hourly Baseline
	07/17/06	07/31/06	07/18/06	07/28/06	07/26/06	
1	1.49	1.20	1.34	1.14	1.12	**1.26**
2	1.46	1.08	1.18	0.98	1.01	**1.14**
3	1.29	0.97	1.07	0.92	0.95	**1.04**
4	1.21	0.91	1.00	0.88	0.87	**0.97**
5	1.11	0.93	0.97	0.83	0.86	**0.94**
6	1.08	0.96	0.97	0.83	0.88	**0.95**
7	1.10	1.02	1.02	0.89	0.90	**0.99**
8	1.18	1.05	1.06	1.04	1.03	**1.07**
9	1.29	1.10	0.99	0.99	1.15	**1.10**
10	1.46	1.31	1.12	1.09	1.26	**1.25**
11	1.61	1.52	1.22	1.10	1.24	**1.34**
12	1.65	1.58	1.23	1.14	1.33	**1.39**
13	1.68	1.83	1.39	1.23	1.40	**1.51**
14	1.94	1.98	1.63	1.39	1.50	**1.69**
15	2.00	2.16	1.62	1.47	1.50	**1.75**
16	2.01	2.22	1.74	1.62	1.50	**1.82**
17	2.02	2.25	1.80	1.76	1.63	**1.89**
18	2.23	2.37	1.80	1.75	1.66	**1.96**
19	2.22	2.43	1.87	1.89	1.68	**2.02**
20	2.29	2.24	1.82	1.75	1.56	**1.93**
21	2.03	2.24	1.60	1.71	1.42	**1.80**
22	2.18	2.34	1.59	1.71	1.55	**1.87**
23	2.07	2.24	1.46	1.65	1.45	**1.77**
24	1.64	1.88	1.22	1.45	1.23	**1.48**

Hourly baseline = Average of Day 1, Day 2, Day 3, Day 4, Day 5

Proxy Day Approach

The proxy day approach selects the hourly loads of a single day to represent a customer's hourly loads on a DR event day. A proxy day is one that has the same characteristics as a DR event day. Characteristics typically used to select a proxy day include maximum temperature, day-of-week, weekday vs. weekend, etc. Most methods currently in use limit the time period that may be considered when selecting the proxy day.

2.3   Baseline Adjustment

An adjustment to the calculated baseline might be needed to factor in the weather effects on a customer's load on the DR event day. This adjustment consists of determining the difference between the calculated baseline and the actual customer load during the ramp period of the DR event day (Figure 2.6). The adjustment value is mathematically determined and applied to the calculated baseline during the hours of the deployment period of the DR event.

Figure 2.6 - Baseline Adjustment Example

Example of a Weather Sensitive Customer Modeled Better with a Temperature Adjustment
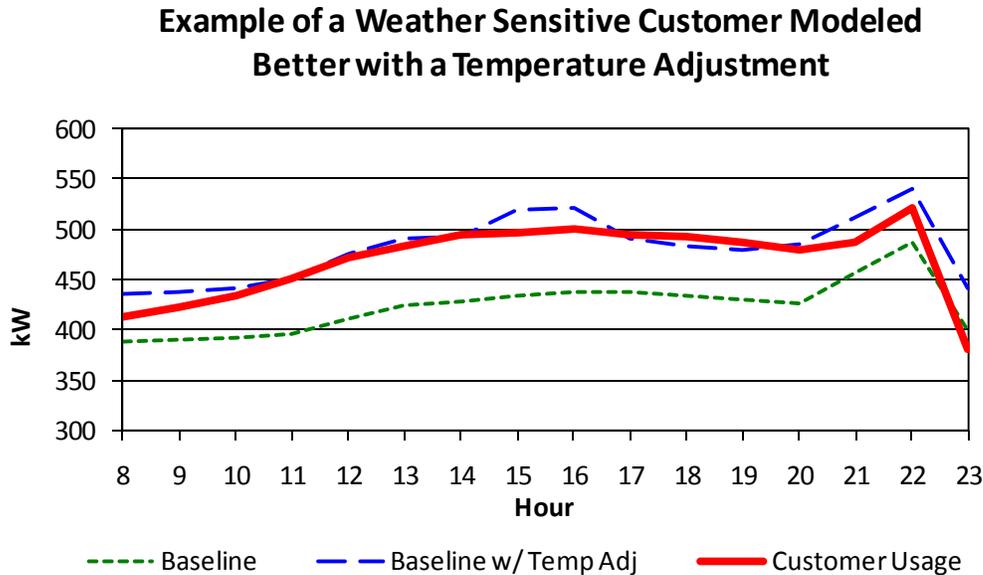
2.4   Regression Methods

Another methodology is to use regression methods[8] to create a model to represent the customer's load shape on an event day. The development of the baseline could be accomplished in two ways. The first is to include only non-event day data for an individual customer, and the other is to use a pooled data series that distinguishes between event and non-event days.

Individual Customer Regression Baseline

Peak period energy model: If interval metering is unavailable, a model can be specified that uses peak period energy as a function of cooling degrees. Hourly kW is derived by applying an average hot day load shape to the resultant. The specified energy model may be of the form:

$$kWh = \beta_0 + \beta_1 * \text{Cooling Degree Days};$$

Hourly demand model: When interval metering is available, a demand model can be specified. One form of the model uses hourly demand as a function of cooling degree hours.

$$kW = \beta_0 + \beta_1 * \text{Cooling Degree Hours}$$

To then estimate the energy or demand baseline, the weather conditions of the event day would be multiplied by the resulting parameters.

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[8] See AEIC Load Research Manual, Second Edition, page 7-12 for more information on this topic.

Pooled Baseline Regression Analysis

For mass market programs, interval data may not be available for most customers. To develop a baseline for this type of situation, a random sample of program participants must be recruited, metering installed, and the data for the sample is used to represent the population. A model is then specified that includes metering data for each metered customer and data for event and non-event days.

An example of such a situation could be defined as follows:

$$(1) \quad kW_{it} = \alpha_0 + \sum_{i=1}^{n-1} \alpha_i \, Cust_i + \beta_1 \, Wthi_t + \beta_2 \, Cycle_{it} + \sum_{i=1}^{n-1} \delta_i \, Cust_i * Cycle_{it} + \beta_3 \, Wthi_t * Cycle_{it} + \varepsilon_{it}$$

Where: kW_{it} = the value of the dependent variable for customer i at hour t;
$Cust_i$ = Indicator variables for each of the participants and, 1 for customer i, 0 otherwise;
$Wthi_t$ = The weighted temperature humidity index calculated hourly[9];
$Cycle_{it}$ = Indicator variable that is 1 if half-hour is being cycled, 0 otherwise; and,
ε_{it} = a random error term for customer i at hour t.

The dependent variable in this analysis consists of integrated demand recorded during each of the half-hours. The parameters from Equation (1) are used to estimate reductions in hourly demand. Reductions are defined as the estimated usage on non-event days minus estimated usage on event days. Based on Equation (1), the average baseline day can be expressed either as:

$$(2) \quad Baseline_t = \left(\alpha_0 + \left(\sum_{i=1}^{n-1} \alpha_i \div n\right) + \beta_1 \, Wthi_t \right).$$

And the average per customer reduction in hourly demand can be expressed as:

$$(2) \quad Reduction_{it} = -\left(\beta_2 + \left(\sum_{i=1}^{n-1} \delta_i \div n\right) + \beta_3 \, Wthi_t \right).$$

To then estimate the demand baseline or demand reduction, the weather conditions of the day of interest would be multiplied by the resulting parameters.

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[9] Hourly wet bulb and dry bulb temperature readings were obtained from the National Weather Service. These data are used to produce a half-hourly weighted temperature and humidity index (WTHI). This measure of weather takes account of both the dry bulb temperature and the humidity conditions contemporaneous with the hourly period under examination, and also takes account of the dry bulb temperatures and humidity conditions during the previous two days. The formula used for THI is:

$$THI_t = 17.5 + .55*DryBulb_t + .2*WetBulb_t$$

For WTHI, the current day's THI gets a weight of 10, the previous day's THI gets a weight of 3, and the weight for two days ago is 1. These data are a main driver in explaining electric usage.

Table 2.1 - Pros and Cons of Baseline Methodologies

Baseline Methodology	Pro	Con
Previous Day	• Most likely the same usage pattern as the event day • Easy method for customer to understand	• Does not take into account the effects of weather on load • The need for a baseline adjustment
Average Daily Usage	• Easy method for customer to understand • Averaging takes out the variability in load for the days used to create the average day	• An average load shape created from multiple day load shapes will not totally capture the usage pattern for an event day • The need for a baseline adjustment
Proxy Day	• Matches a day based on defined variables uniform with event day	• Finding a day based on the defined variables • The need for a baseline adjustment • There might not be a day to use as the proxy day
Regression Model	• Concept of variable relationship is easy to understand	• Customer understanding of the process used • Selecting the correct variables to use in the model

2.5   Engineering Algorithms

Engineering algorithms are mathematical processes created to measure load requirements of electrical equipment, such as electric motors. Algorithms can be as simple as analyzing the data from recording usage patterns of electrical equipment to building complex models to determine equipment load requirements. These measurements of load can then be used by the customer during a DR event to base how much load is being reduced or eliminated by shutting down equipment. For instance, Figure 2.7 represents the hourly usage pattern of an electric motor calculated by using an engineering algorithm. With this information a customer can reduce or power off this motor to meet a load reduction during a called DR event.

Figure 2.7 - Engineering Algorithm Example

Hour	1	2	3	4	5	6	7	8	9	10	11	12
Use in kW	40	42	43	46	49	51	60	85	92	94	95	97
Hour	13	14	15	16	17	18	19	20	21	22	23	24
Use in kW	97	97	97	97	97	93	85	73	61	55	47	40

3   Mass Market Measurement (Impact Estimation)

Mass market measurement refers to impact estimation of DR programs where individual measurement of customer impact is too expensive or time consuming. Impact estimation is achieved by aggregating all participating customers and comparing the resultant load shapes against similar non-participating customers. To generate these load shapes a well defined target market for the DR program is required. Target markets are segments of larger customer classes defined by specific characteristics. A target market may intersect more than one utility customer class. Customers in the target market that accept the program offer are classified as program participants, while customers declining the program offer are classified as non-participants. This section will focus on measuring the impact of a program offered to a target market.

Figure 3.1 – Target Market Flow

Impact estimation of a mass market DR program is similar to the process for measuring individual customer impacts. A profile representing the CBL is developed and compared to a profile that has been developed to represent all participating market customers (the "Actual Use"). The difference between the CBL and Actual Use profiles represents the impact of the DR program offer.

3.1   Development of CBL Profiles

Mass market CBLs are typically developed using one of two options. Option one uses a control group to develop a load shape for non-participating customers in the target market. Option two develops a CBL via estimations based on the participant market's response to DR events. Figure 3.2 illustrates which option is generally selected based on DR program type.

Figure: 3.2 – Baseline Development Selection Guide

	TOU Time-of-Use	RTP Real Time Pricing	CPP Critical Peak Pricing	DLC Direct Load Control	PTR Peak Time Rebate
Control Group	√	√	$\sqrt{}^1$	$\sqrt{}^2$	$\sqrt{}^1$
Estimation based on Participants' Response			√	√	√

[1] Option depends on the number of days in which the program may be initiated.
[2] Program may see control groups utilized if Samples are deployed.

Using a Control Group to Develop a CBL

Control groups work very well for developing a CBL when the program has a large number of repetitive DR events. This is because many of the non-CBL estimation techniques require the availability of similar days (temperature, day-of-week, etc.) where no event has occurred. For example, a TOU program which defines several time periods and is available on a seasonal basis will require a control group to facilitate impact estimation. [10] This is because every day can be considered an event day and no non-event days will be available to generate the CBL. A control group is comprised of non-participating customers within the target market. Utilities often leverage existing load research samples to generate a control group to minimize additional costs. If no pre-existing sample is available, a specific control group sample can be designed to measure non-participating customer use. [11] The CBL is the non-participants' (from control group sample) load shape for the same timeframe as the participants' load shape.

Leveraging Existing Load Research Samples

To leverage an existing load research sample, participant sites must be removed from the original sample to eliminate bias. For example, a utility offers a new TOU program to all customers in its Residential customer class (the Target Market). Further, the utility has an existing Residential sample that estimates the customer class (before the new TOU was offered). When expanded from the sample level to the class level, the results will include both those customers participating in the new TOU program and those that do not. Therefore, the goal is to develop a CBL that omits the new residential TOU participants. This is achieved by subtracting Participant Market use from the Target Market to get the Baseline Load Shape for each hour by using this simple formula:

Target Market – Participant Market = Baseline Load Shape

For example:
T = Target Market (existing LR sample which includes <u>all</u> residential customers)
P = Participant Market (those customers that are participants in a DR program) and
B = the Baseline Load Shape
h = Hour ending

For Hour ending 17:00 T_h – P_h = B_h or,

(800 MW) – (300 MW) = 500 MW

This simple formula is applied on an hourly basis to develop the CBL.

It is important to note that this process should only be used at the expanded class level. Attempts to use it at the average customer use level may yield unexpected results.

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[10] Time-of-use programs may reflect marginal cost and / or price elasticity which needs much more evaluation. Analyst should refer to program design criteria set by their pricing organization.
[11] Several chapters in the AEIC Load Research Manual are dedicated to the development, implementation and analysis of samples.
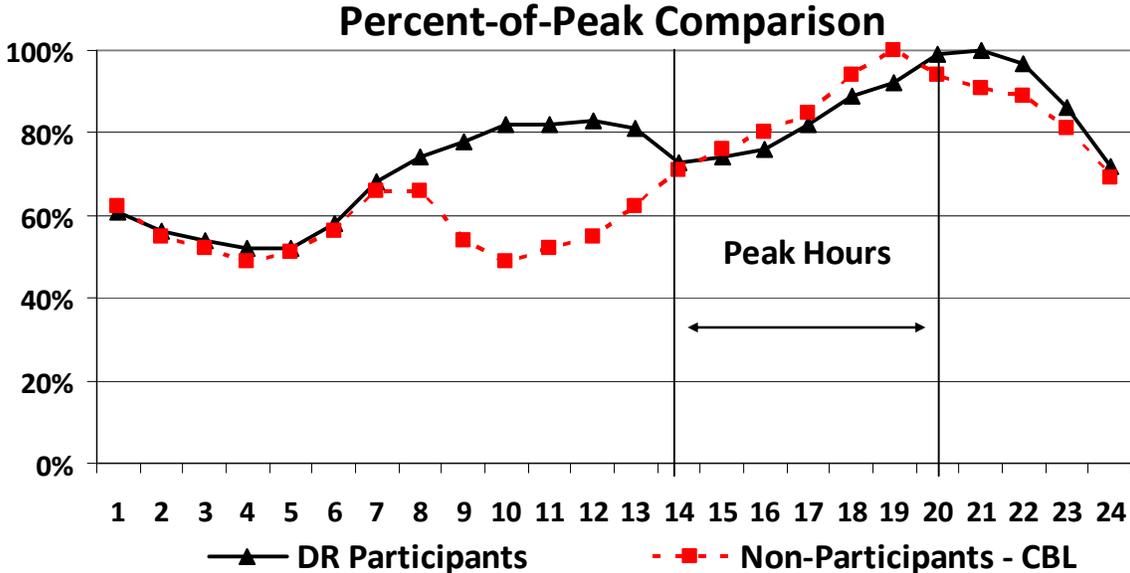
Comparison Techniques

Techniques to quantify DR impacts may vary based upon the measure required. In most cases the measure is defined by the jurisdiction, or ISO/RTO, establishing the Measurement and Verification requirements. Some of the more common measures include: how much energy shifting occurred during the peak period; the demand reduction during the peak hours; or the decrease in demand during a pre-established period (i.e. coincident with the system peak or class peak). Dependent upon the granularity and magnitude of data gathered for the Measurement and Verification process, scaling or unitizing the data may be required to accurately compare the participant load shape to the non-participant load shape as described in the following discussions. It is fully recognized that several options exist to scale load shapes and the discussions below are used to illustrate some of the more common options.

Percent Shift from Peak Period (Average Demand)

One comparison technique is the determination of the average demand decrease. This technique estimates the total energy shifted from peak hours to off-peak hours by calculating the difference in on-peak energy usage between the CBL and the participants' load shape. For example, assuming a TOU class uses 1,000 MWh in a month, with 60% of the energy used in the on-peak hours and 40% in the off-peak hours. If the CBL load shape uses 65% of its energy in the on-peak hours, the difference is 5% (65% - 60% = 5%). Therefore, TOU customers shifted 5% of their usage to the off-peak hours. This equates to 50 MWh (5% times 1,000 MWh). Average demand shifted is calculated based on this energy shift calculation, divided by total hours for the evaluation period. In this example, average demand shift from the peak period is 417 kW (50 MWh / (6 hours * 20 days) * 1000), (Figure 3.3).

**Figure 3.3 – Average Demand Shift**

Average Hourly Variation Evaluation (Demand Estimation)

Another comparison technique is the determination of the total demand savings at the time of a particular hour of interest like the hour of system peak. This comparison technique works well when the average customer use for both the participant and non-participant classes are similar.

The total demand savings is determined by expanding the daily hourly reduction coincident with the system peak by the number of participants. For example, if the Utility's system typically peaks at 5 pm (17:00 hours) and there are 1,500 participants, then the total demand savings is 615 kW [0.41 kW * 1,500 customers = 615 kW] (Figure 3.4).

Figure 3.4 - Average Hourly Variation Evaluation
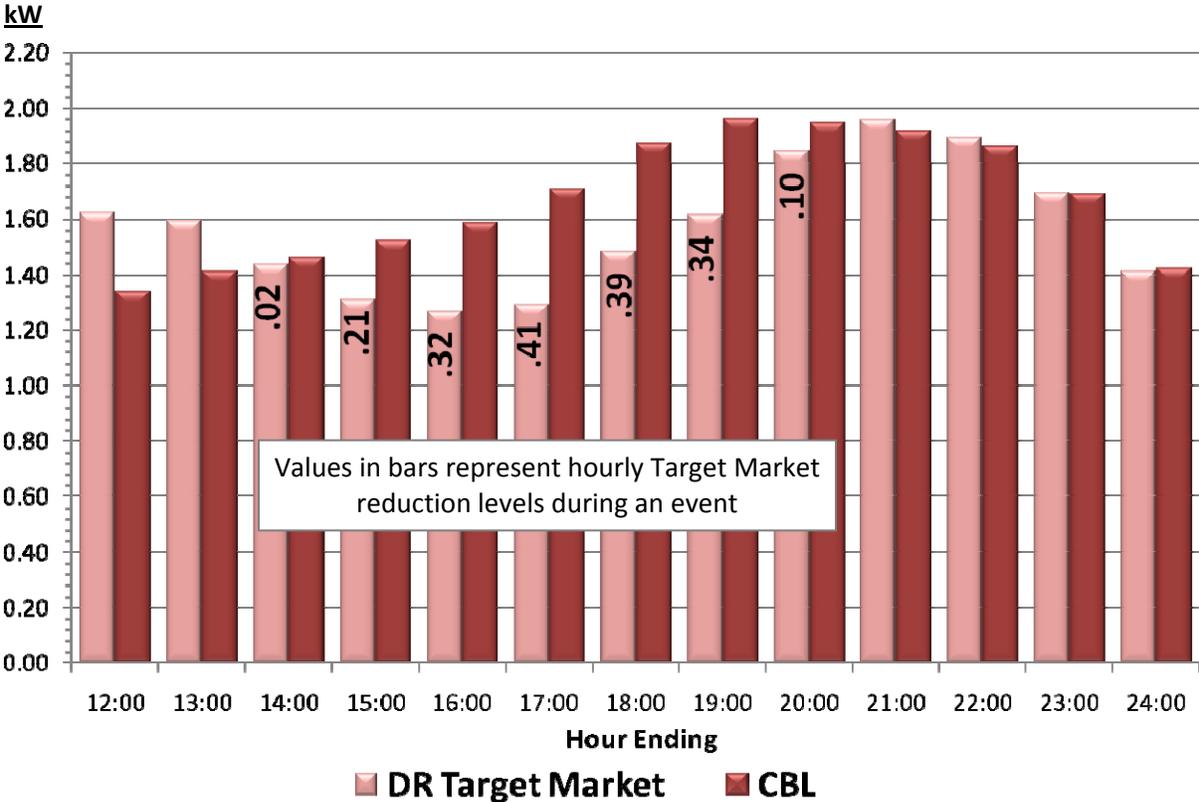
Developing CBLs from Estimation of Participants' Response

The second option is to develop a CBL from estimation based on participants' response. This process is most useful when relatively few DR events are initiated. In this method, the CBL is developed using the participants' load shape and any of the processes presented in Section 2 (Individual Measurement).

Some mass market DR programs have discreet, non-repetitive events (e.g. Direct Load Control residential air conditioning, or Critical Peak Pricing). Often, these programs have a limited number of callable hours during a season. In addition to the previously discussed mass market process, many of the evaluation techniques like those examples discussed in the earlier 'Individual Measurement' section can be used in developing the CBL. The key is the ability to develop an effective participant load shape.

Using both Control Group and Customer Time-Series Data

Another option for estimating Demand Response impact uses a control group as well as participant data during event and non-event periods. As an example, the average demand for both the participant (P) and control (C) groups may be measured during a pre-treatment period, prior to the activation of the program. During program activation, the average demand for the participant and control groups can again be measured. The impacts are estimated using this 'difference of differences' approach:

$$\text{Imp\_kW} = (P\_kW_t - C\_kW_t) - (P\_kW_{t-1} - C\_kW_{t-1})$$

Imp_kW refers to the estimated kW impact
P_kW_t refers to the average kW for the participant group at time t
C_kW_t refers to the average kW for the control group at time t
t refers to a point in time during activation
t – 1 refers to an earlier point in time prior to activation

3.2 Discussion on the Effects of Individual Customers on Mass Market Results

Mass market programs are constantly evolving as customers frequently enter and exit programs. Knowing who is in your program becomes important when developing both CBL and participant customer load shapes. The following are key issues that should be frequently reviewed regarding the status of Measurement and Verification programs.

Ensure the meters analyzed belong to the population being estimated

As participants enter and exit a program, they can inadvertently be assigned to the wrong analysis group. For example, assume the analyst has generated a valid control group sample to estimate the baseline for non-participants of a CPP program. Subsequently, if one of the sample points is allowed to enter the CPP program and yet remains in the baseline sample, then a bias has been generated in the development of the baseline load shape. This bias can grow if more sample points convert to CPP participants.

Know which customers choose not to participate in an event

Some programs have opt-out, buy-through or over-ride provisions. Participants choosing to opt-out may affect the participants' load shape. The M&V plan should define what is to be measured and the process to be used to determine results. If the metric is to provide the average impact for all customers enrolled in the program, then opt-out customers' loads are included in the participants' load shape analysis. However, if the metric is to provide a load shape for all customers who said they would perform during the event, only those customers who have chosen to opt-in are included.

Ensure all available information is used

Mass market demand programs tend to be dynamic in nature with customers entering and exiting often. Participants choosing to opt-out can be included in non-participant CBL load shape analysis. These opt-out customers meet the target market criteria and will tend to improve the quality of the CBL load shape. It is recommended that developing appropriate processes is necessary to ensure each customer is correctly segregated by their opt-out, opt-in characteristics for each DR event.

3.3 Operability Studies

Mass market DLC programs may tend to degrade in performance over time due to mechanical failures of switches and/or signal receptors. Estimated load reductions from mass market load control programs must be adjusted according to the percentage of units that remain operable, in order not to over state demand reductions.

Plans for mass market programs should include periodic operability studies to estimate and determine the magnitude of any operability problems and potentially shed light on the underlying causes. From the operability study, a failure rate can be computed from the number of working devices divided by the total number tested. The resulting net-to-gross ratio is applied to lower the load reduction estimate. For example, one ISO required that either an operability study be conducted every five years, or the utility could instead elect to use an operability ratio of 50%. This illustrates that the careful DR measurement impacts described in this paper can be drastically reduced by operability study results, or the lack thereof.

Stakeholders should agree at the outset of the program on a sampling, testing and reporting protocol, acceptable ratios, or remediation pending improvement. For example a simple random sample of 250 participant homes will give an initial estimate with an error bound of ±5% at the 90% level of confidence.   Once a net-to-gross ratio of 90% (or better) is demonstrated, a simple random sample of 100 program participants would achieve the same error bound. [12]

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[12] p. 37, Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in PJM Region, March 2007, Prepared for the PJM Load Analysis Subcommittee & Charles Goldman, Lawrence Berkeley National Laboratory, by RLW Analytics
http://www.pjm.com/committees/working-groups/lrwg/downloads/20070301-pjm-deemed-savings-report.pdf

4 Conclusion

The Measurement and Verification of a Demand Response event results is, and will continue to be, a subject that requires more than a single methodology that can be applied to the wide range of Demand Response programs currently in place. It is, however, well established that baseline load curves of customer use can provide the proxy shape for 'what a customer's load would have been' absent a demand response event. The AEIC Load Research Committee, and the expert practitioners who authored this paper, have developed this paper to present the various baseline and M&V methodologies currently developed and briefly discuss how each is performed in actual practice. The intent is to promote clarity and proper application of these methodologies while providing a single source document of definitions and discussion by actual practitioners. It is not the intent of the AEIC Load Research Committee to promote any given method.

The AEIC Load Research Committee has consistently developed documentation and training programs to promote the advancement of highly reliable analysis and techniques by Load Research professionals and industry experts focused on the study of electrical use characteristics.   As Measurement and Verification techniques mature, and additional measurements required by AMI and Smart Grid technologies are identified, the Committee will continue this practice.   The most recent studies and papers can be viewed at www.AEIC.org/load .research.

Please contact the AEIC Load Research Committee Secretary for additional information or to discuss the content of this white paper. Contact information can be found at www.AEIC.org/load_research.

5   Glossary

Actual Use – The amount of energy the customer _actually consumed_ during the DR event period.

Advanced Metering or Advanced Metering Infrastructure (AMI) [13] - A system including measurement devices and a communication network, public and/or private, that records customer consumption, and possibly other parameters, hourly or more frequently and that provides for daily or more frequent transmittal of measurements to a central collection point

Conservation - Conservation includes consumer actions or decisions to use less energy, reconsidering priorities and eliminating some energy use. Conservation and energy efficiency (see separate definition) are often used as though they are synonymous, because both reduce kilowatt-hours (kWh) used by consumers.

Critical Peak Pricing (CPP)[13]- CPP rates typically charge a much higher price during a few hours per day on critical peak days. The number of critical peak days is usually capped for a calendar year and are linked to conditions such as system reliability concerns or very high supply prices.

Customer Baseline (CBL) - The amount of energy the customer _would have consumed_ absent a signal to reduce.

Demand Response (DR) [13] - Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Demand Response Event[13] - A period of time identified by the demand response program sponsor when it is seeking reduced energy consumption and/or load from customers participating in the program. Depending on the type of program and event (economic or emergency), customers are expected to respond or decide whether to respond to the call for reduced load and energy usage. The program sponsor generally will notify the customer of the demand response event before the event begins, and when the event ends. Generally each event is a certain number of hours, and the program sponsors are limited to a maximum number of events per year.

Demand Resources - The set of demand response and energy efficiency resources and programs that can be used to reduce demand or reduce electricity demand growth.

Direct Load Control (DLC) [13] - A demand response activity by which the program sponsor remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, water heater) on short notice. Direct load control programs are primarily offered to residential or small commercial customers

Energy Efficiency (EE) [13] - Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatt-hours), often, but not always, without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technologically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include energy saving appliances and lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.

Peak Time Rebate (PTR) - Programs that offer rebates to customers who use less electricity during critical peak events.

Real Time Pricing (RTP) [13] - A retail rate in which the price for electricity typically fluctuates hourly reflecting changes in the wholesale price of electricity. Real time pricing prices are typically known to customers on a day-ahead or hour-ahead basis.

Regional Transmission Organization (RTO) [13] - An organization with a role similar to that of an independent system operator but covering a larger geographical scale and involving both the operation and planning of a transmission system. RTOs often run organized markets for spot electricity.

Target Market - Segments of large customer classes defined by specific characteristics.

Time-of-Use (TOU) Rate [13] - A rate where usage unit prices vary by more than one time period within a 24 hour day. TOU rates reflect the average cost of generating and delivering power during those time periods. Daily pricing blocks might include an on-peak, partial-peak, and off-peak price for non-holiday weekdays, with the on-peak price as the highest price, and the off-peak price as the lowest price.

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[13] 2008 Assessment of Demand Response and Advanced Metering Staff Report, Federal Energy Regulatory Commission, December 2008, Appendix C: Glossary for the Report

6   Acronyms

AMI	Advanced Metering Infrastructure
CBL	Customer Base Line
CPP	Critical Peak Pricing
DLC	Direct Load Control
DOE	Department of Energy
DR	Demand Response
DSM	Demand Side Management
EE	Energy Efficiency
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
LSE	Load Serving Entity
M&V	Measurement and Verification
NERC	North American Electric Reliability Corporation
PUC	Public Utility Commission
RTO	Regional Transmission Organization
RTP	Real Time Pricing
PTR	Peak Time Rebate
TOU	Time-of-Use