Demand Response Capability Inventory

3002003317

Demand Response Capability Inventory

3002003317

Technical Update, November 2014

EPRI Project Manager

C. Holmes

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

This is an EPRI Technical Update report. A Technical Update report is intended as an informal report of continuing research, a meeting, or a topical study. It is not a final EPRI technical report.

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

ACKNOWLEDGMENTS

The Electric Power Research Institute (EPRI) prepared this report.

Principal Investigator
C. Holmes

This report describes research sponsored by EPRI.

This publication is a corporate document that should be cited in the literature in the following manner:

Demand Response Capability Inventory. EPRI, Palo Alto, CA: 2014. 3002003317.

ABSTRACT

This report focuses on the following three areas of interest:

- A primer on the need for and valuation of demand response resources
- A summary of recent research on the efficiency of impact evaluation methods for demand response resources
- Recent events that are affecting the market by utilities for creating demand response resources and markets

This report also draws several conclusions, including the following:

- The current demand response availability is 28.3 GW in the United States in 2012, with nearly half coming from PJM.
- The penetration of advanced metering infrastructure meters in the United States is estimated to be 45.8 million in 2013, reflecting a penetration rate of 30.2% of all meters.
- Demand response resources have grown at a compound monthly growth rate of 17.8% between 2007 and 2014.
- Demand response measurement and verification appears to be a more nuanced and less disciplined activity, which has impeded its penetration nationwide.
- The adoption of new demand response technologies and distributed energy resources will create unprecedented opportunities for capacity management. The challenge will be how to fit demand response into the customer value proposition in the era of the integrated grid, which has yet to achieve its potential.

Keywords
Advanced metering infrastructure (AMI)
Baselines
Demand measurement and verification
Demand response
Demand response economics

CONTENTS

LIST OF TABLES

1
ECONOMICS OF DEMAND RESPONSE

Types of Demand Response

Demand response is a reduction in the customer's consumption of electricity from their expected level in response to an increase in the price of electricity or to incentive payments designed to reduce consumption of electricity. Demand response programs come in a variety of types. Some demand response programs are created and run by utilities who work directly with customers to form and execute curtailment plans. Other utility-based demand response programs are delivered in the form of dynamic pricing tariffs that encourage customers to reduce their loads during peak times. There are also demand response programs that are designed by utilities or system operators in which third party aggregators recruit customers and take responsibility over customer curtailment actions.

Demand response often refers to any action taken by a utility customer at the request of the utility that results in a modified pattern of energy use. The instigation of the modified use may be the result of customer initiated efforts. Or, it may be modified as a result of technology that alters the consumption of energy consuming devices. Or, finally it may be triggered by behavioral reaction to utility or government requests.

The main four categories of demand response consist of capacity needed for emergency load relief (extremely short term), capacity needed to maintain system integrity (intermediate term), capacity needed for reserve margins (long term) and finally capacity that can be used for economic (arbitrage) opportunities, i.e. the market price is greater than the contracted price.

The last category represents the basis for valuing demand response resources. That is, all demand response opportunities are valued based on arbitrage—what the utility would have had to pay had the demand response resource not been available. With the exception of emergency load relief the value of demand response resource is based on the difference between what the utility can sell the capacity for and what it paid the customer.

Valuing Demand Response

Capacity Costs

Electric utilities like many industries today are characterized by high capital cost and low operating costs. Electric utilities are a good example of this industry characteristic but many others exist such as cable companies, phone companies and airlines. The pricing strategy is to set prices at operating costs and in competitive markets any additional adder to operating costs can be used to cover fixed costs. The quandary, of course, is to predict the sales accurately so as to adequately recover both operating and fixed costs.

In fact this has been the pricing strategy for most electric utilities for the past seventy years. The difficulty is that the value customers receive from their consumption of electricity drives the costs for it. So when customers enjoy their air conditioning on a hot summer afternoon the capacity available to meet that demand may not be sufficient. This concept of peak pricing and specifically capacity pricing were first investigated by Marcel Boituex.[1]

Marginal costs are defined as the change in costs that occur when output is changed by a small amount. Why are marginal costs important? In the field of economics societal welfare is maximized when several conditions are met. The conditions are known as Pareto optimality. One of these conditions is that when prices equal marginal costs societal welfare is maximized. Prices equal to marginal costs are also one of the outcomes in a perfectly competitive market. In regulated markets such as electric utilities, one of the objectives of regulation is to emulate the desirable outcomes of competition without the negative outcomes normally associated with single suppliers, i.e. restrictions in output to maximize profits.[2]

For utilities there are three main marginal cost components: customer related, energy related and capacity related. Customer related marginal costs reflect the costs to serve one more or one less customer. Energy related marginal costs are the costs to provide one more or one less kWh of energy. This is normally the fuel cost to produce that kWh. Sometimes this value is also known as short run marginal cost (SRMC) as no capital investment is required to generate that additional one kWh.

Marginal capacity costs reflect the cost of adding one kW of additional capacity through a capital investment in generating equipment or demand side resources. The difference between long run and short run is that the long run allows for changes in the capital stock. Which means that long run marginal cost (LRMC) of capacity reflects the "least cost" cost of capacity either from investment in conventional supply-side resources or alternatively in investments in demand-side resources.

If capacity is ample, increases in the demand for capacity produce no additional costs. The marginal cost of capacity is zero. If capacity is short, increases in demand results in higher and higher marginal costs of capacity. Capacity cost changes are normally only seen during conditions of high or dwindling demand or congestion. In the power industry these conditions may occur quickly due to the non-storable nature of electricity.

Utilities routinely conduct marginal cost studies. These studies develop marginal cost components and then apply their results to class load shapes to determine the cost recovery for customers within a class. For the above reasons marginal costs recovery are a good proxy for welfare efficiency and are used as a basis for rate design.

Pricing in Competitive Markets

Competitive markets, sometimes referred to as organized wholesale markets, have established exchanges whereby prices are set in real-time, spot market prices and for future periods. Future or forward markets have defined fungible amounts of power used to facilitate transactions. Normally these transactions take the form of 5X16 which refers to five weekdays for sixteen hours starting at 6 am and ending at 10 pm.

---

[1] Boiteux, Marcel, (1949) 'Peak Load Pricing,' translated in Journal of Business, April 1960, 33: 157-79; reprinted in Nelson, James R. (ed.) Marginal Cost Pricing in Practice, Prentice-Hall Inc., Englewood Cliffs, N. J. 1964.
[2] Henderson and Quandt, *Microeconomic Theory: A Mathematical Approach*, McGraw-Hill Inc., 1971, Chapter Four: Pure Competition and Chapter Seven: Welfare Economics.

Market forces will dictate the price for power in competitive markets. As the purchasers of power bid for supply, the suppliers of resources will decide how much they will provide at each price point. If the quantity demanded exceeds the quantity supplied, the price will rise. This should result in suppliers providing additional supplies at the higher price.

In the short run, continued bidding by purchasers will result in higher and higher prices. In fact, prices may begin to exceed the actual costs to provide by the suppliers. This willingness to pay by purchasers is the mechanism that results in the allocation of the seemingly scarce resources.

This premium over actual short run marginal cost reflects the shortage costs or the capacity premium that results from these market dynamics. It creates a signal to other producers that profits may be made by investing in additional capacity. Over time competitive forces will induce suppliers to increase supply and reduce the incidence of these shortage costs bringing supply and demand into balance where the cost to supply equals the value to the purchasers.

The drivers of supply are driven by the short run marginal cost of energy and capacity. The drivers of demand are driven by the value customers receive from their consumption of electricity or, for most commercial and industrial customers, the costs they incur if they were to lose power—their outage costs. Internet searches may find many studies which attempted to estimate outage costs for different customer groups. The results of these studies have never been fully incorporated by utilities in their rate designs as the estimates are variable across customer types and volatile over time.

The dynamics of markets are such that markets will eventually adjust to the shocks to the systems. If demand increases, suppliers respond by investing in generating equipment to meet the obligation to serve and to keep cost of service in line with the willingness to pay. **Eventually market costs that reflect short run marginal costs of energy and shortage costs will converge to long run energy and capacity costs.**

According to a whitepaper by NERA Associates "In an optimally planned system, prices should be set equal to marginal running costs in any given hour plus the capital cost of meeting 1 extra kW of peak demand. The results will be that revenues so obtained will exactly equal the annual capital cost plus the annual running cost of the system."[3] This affirms the underlying concepts behind peak load pricing and how it provides efficiency and revenue protection to consumers and producers.

In order to promote stability in energy markets, utilities use a measure of reliability as their means to allocate capacity costs. Measures such as loss of load and expected unserved energy are proxies for outage costs and can be used by utilities in rate design to allocate capacity costs over times of expected high demand.

The pricing of a resort room at a vacation destination provides a good example of peak load pricing. The owner of the resort room has to decide how much to charge each visitor. In Florida the demand for rooms is much higher in the winter than in the summer. The costs to clean the room are negligible so the pricing question is primarily about recovering the fixed costs for the resort.

---

[3] Sally Hunt Streiter and Leo T. Mahoney, Jr., "A Simplified Model of Time-of-Day/Seasonal Pricing," NERA Whitepaper, 2001.

If the owner charges the average of the fixed costs throughout the year he will likely be turning customers away in the winter and have empty rooms in the summer. Instead the theory of peak load pricing suggest fixed costs be loaded into the period of highest demand. This is equivalent to each winter vacationer paying for the capacity costs. As long as the value proposition for the vacationers is such that they value staying at the resort more than the opportunity cost of the room rate then the owner will recover all costs and the vacationer is maximizing his welfare.

This may become an iterative process in the short run as his customers have alternatives. They may choose another destination or they may choose to vacation during the summer when it is much cheaper or they may choose to use the money for their child's college fund (opportunity cost). The owner must change his pricing to react to the demands for resort rooms and make further adjustments based on the new patterns.

Peak load pricing is an efficient and flexible form of pricing that helps maximize consumer, producer and societal welfare.

Bridging Short Run Marginal Cost and Long Run Marginal Cost: the Role of Risk Management

Exposure to market conditions produce increased energy volatility and uncertainty—risk. The forces of supply and demand and the need by participants in the market for protection against volatility and uncertainty produce the need for risk management. The demand for risk management services creates markets for both spot and forward transactions. There are four basic risk management activities that occur in competitive commodity markets. Table 1-1 provides a description of basic risk management activities undertaken by market participants.

Table 1-1
Types of Risk Management Activities

Activity	Description
Hedging	A means to offset the losses caused by price level or fluctuations in the price of a commodity
Speculation	Taking a position in the hopes of producing significant returns
Market Maker	An individual or group of individuals who transact in a commodity and quote both the selling price and asking price for a commodity with a spread between the two to cover their expenses
Arbitrage	An action that requires the simultaneous buying and selling of commodities in different market so as to generate a profit based on the difference in prices for the same assets

Risk management provides the bridge between short run and long run marginal costs by creating markets temporally or over time. Given sufficient market players and liquidity between speculators—those desiring to see changes in future market prices for their benefit and hedgers—those who desire to minimize the effect of future market prices on their activities, the prices for future capacity will reflect the expected levels of supply and demand in the future.

In future markets there is no requirement that actual physical assets or output be transacted. In fact the majority of futures transactions do not result in any physical exchange of commodity. Instead it is the existence of market players who are seeking the benefits from that risk management activity that helps to create these markets.

But the confluence of the physical and financial markets does occur when future prices begin to exceed those long run values for capacity and energy. It is at those times that speculators and hedgers discover important market information about the future status of commodity supply and demand and induce the construction or retirement of assets. This all makes a more efficiency and properly functioning market.

The existence of fully functioning forward markets helps facilitate the convergence between short run and long run costs and helps reduce the risks of doing business in the power market for both consumers and producers.

2
SERVICE QUALITY

Demand response programs can be classified in two distinct ways—those that produce a change in the service quality of the customer's end-use energy consumption and those that produce little to no change in the service quality. For instance, an example of a program that may produce a change in the service quality of the customer's end-use energy consumption is air conditioning load cycling programs. These programs reduce the use of air conditioning on typically hot summer afternoons, the period when customers value its use the highest.

An example of a demand response that produces little or no service quality impacts might be the shifting of a defrost cycle in a refrigerator from its normal continual cycle to one where the defrost cycle only occurs at low load times, such as the middle of the night. Most occupants would not notice the impact of the defrost cycle being shifted away from high load periods.

Likewise the inclusion of smart technology into air conditioner thermostats may have a similar effect. Smart thermostats which monitor occupancy may increase air conditioning set points when occupants are away and reduce them to more comfortable levels upon their return. Or the thermostat recognizes a pattern and adjusts set-points in anticipation the occupants return.

Electricity consumption is a derived demand—the demand for electricity is derived from the consumption of something else—an appliance or other end-use. It is the service level that consumers receive from those appliances that determine the value they derive and the potential loss in value they suffer when those appliances do not perform the service desired. Each value is different across customers and generally its loss is difficult to measure.

Value Propositions

For residential customers the loss takes the form of lost customer needs or desires—these include the six "C"s; cost, comfort, convenience, control, certainty and connections. Placing a value on these needs can be difficult but not impossible. The creation of markets for these attributes have become more commonplace. For instance, many airlines now offer extended leg-room seating for a fee. They charge more for exit rows and less for bulkhead seats. They also offer early boarding for a fee. These types of fees were unknown until recently but now are commonplace and presumably determined by the demand for, or the lack of, those attributes.

Commercial and industrial customers, too, have service quality desires. However in their case it is driven more by the value of the lost production they would experience should power be interrupted. These are referred to as customer outage costs. Like many aspects of the utility business the values are driven by averages. So average outage costs for an industrial customer may be hard to estimate, may be different across customer classes and may not be stable. They are definitely expensive to estimate so in many cases markets are established that allow large customers to bid back resources into the market place. Even so the characteristics of consumption may not lend themselves well to the efficient valuation of demand response resources.

Service Design

Service design looks at the characteristics of the consumption of energy and estimates the value of each component. For example industrial customers may have a contract structure known as full requirements. That structure allows the customer to use as much or as little power as they desire. This is a typical structure for residential and commercial customers as well.

On the other hand many industrial customers contract for fixed blocks of power. This structure may be advantageous if they are sure of their load flexibility and are able to sell back into the market when prices are high. Their decision to do so would hinge upon the difference in the opportunity cost of using that power to continue their production process and the price that they could receive in the open market assuming they have access or can use the grid to conduct that transaction.

Service design usually consists of the following dimensions:

- Price—What is the cost per unit? What is the price notice?
- Term—How long is this price structure available?
- Interval—What is the structure of the price, on-peak, flat rate, etc.?
- Quantity—What are the quantity terms, fixed or variable Is it take or pay or is balancing service available? If loads are balanced who receives the proceeds?
- Contractual—How are failures to perform handled? Is security required? Are there liquidated damages?

These service design characteristics are commonly found in natural gas contracts and are becoming more common in the power industry.

Demand Response Service Design

The main service design dimensions for demand response are:

- Notice—How far in advance is the call for interruption made? Is it five minutes or five days?
- Frequency—How many times may a call for interruption be made over the course of the contract term?
- Duration—How long is the interruption once the call is made?
- Contract Term—Is the program available all year long or by season? Can it be renewed automatically?
- Quantity—How is the capacity determined? Can the quantity be resold by the customer? Is the quantity recallable by the supplier? These features are often referred to as the optionality of the commodity and may have a significant pricing effect on the demand response program design.
- Incentives—What is the structure of the incentives? Is the incentive based on a fixed amount? Is the incentive based on performance? Is the incentive paid only when events are called? What is the value of the incentive?

The combination of these service design features each have an expected impact on the cost of the power either in terms of the market price during the event or in terms of the risk that the capacity is available for use by the utility. That is why the capacity savings produced by a voluntary program such as an opt-out feature or a time-of-use based rate have lower value to the utility than one where the impacts are certain and guaranteed.

3
THE DEMAND RESPONSE BASELINE

Introduction

This next section reflects excerpts from an Enernoc report on the accuracy of alternative baseline constructs for evaluating the impacts of demand response resources. This area has been fraught with misconceptions so this reprinting is hoped to add more clarity to the already confusing subject of effective M&V of DR.[4]

The measurement and verification (M&V) generally, and the "baseline" more specifically, of demand response determines the magnitude of the resource and thus plays an important role in determining the value it has to the electric system. M&V also drives customer compensation for participation, and as a consequence, will influence the number and types of customers for whom the demand response program appears attractive. Although there are many methods currently in use, some are much more accurate than others in estimating the fundamental baseline question: what would the customer's load have been in the absence of a demand response event?[5]

In 2009, the Federal Energy Regulatory Commission (FERC) signaled interest in developing standards for demand response measurement and verification when it noted in its report on the National Assessment of Demand Response Potential[6] that "development of standardized practices for quantifying demand reductions would greatly improve the ability of system operators to rely on demand response programs" and "central to the issue of measurement is a determination of the customer baseline." FERC tasked the North American Energy Standards Board (NAESB) to develop M&V standards, and in response, NAESB created a glossary of demand response related terms and defined broad types of demand response programs and performance methods. This paper continues these efforts by providing definitions, discussions, and recommendations concerning the appropriate application of specific baselines for demand response M&V.

Over the course of this report good baseline design is driven by adherence to three fundamental principles: accuracy, simplicity, and integrity. While no baseline is perfect, baselines that balance these principles are better than those that do not.

Fundamentals of Demand Response and Baselines

Demand response programs have different incentive schemes and program objectives. Two of the primary types of incentives are capacity payments and energy payments. Programs provide capacity payments to customers to stand by to be ready to help the grid, either to reduce peak demand or to stabilize the grid during an emergency and prevent blackouts. Energy payments are

---

[4] Excerpted from "The Demand Response Baseline," 2011, EnerNOC, Inc., http://www.enernoc.com/images/whitepapers/pdfs/demandresponsebaseline.pdf

[5] The following chapter reflects a white paper produced by Enernoc titled "The Demand Response Baseline," 2011, http://www.enernoc.com/our-resources/white-papers/the-demand-response-baseline

[6] National Assessment of Demand Response Potential (June 2009), http://www.ferc.gov/legal/staff-reports/06-09-demand-repsonse.pdf

provided based on the actual energy provided (e.g., not consumed) by a customer over a set period of time during a demand response event. Demand response programs use these types of payments to incentivize customers to participate. For customers participating in dynamic pricing programs, the incentives are typically represented by rate discounts during the off-peak periods that more than offset the significantly higher rates during the critical peak periods.

Why Baselines Matter

Typical demand response programs rely upon incentivizing energy users based on the extent to which they reduce their energy consumption and therefore require a reliable system to measure energy reduction. For this reason the measurement and verification of demand response is the most critical component of any program. The baseline is the primary tool for measuring curtailment during a demand response event.

A baseline is an estimate of the electricity that would have been consumed by a customer in the absence of a demand response event.

Baselines enable grid operators and utilities to measure performance of demand response resources. A well-designed baseline benefits all stakeholders by aligning the incentives, actions, and interests of end-user participants, aggregators, utilities, grid operators, and ratepayers. Baselines are a challenging aspect of demand response programs because they must represent what the load would have been if a customer had not implemented curtailment measures. In other word, a baseline is a "counterfactual," a theoretical measure of what the customer did not do, but would have done, had there not been a demand response event.

No estimate is perfect, but there are some baselines that are superior to others or best suited to specific programs or customer types. When evaluating a baseline method, a balance between customer and supplier needs can be described by the use of three factors—accuracy, simplicity, and integrity.

Accuracy

Customers should receive credit for no more and no less than the curtailment they actually provide, so a baseline method should use available data to create an accurate estimate of what load would have been in the absence of a demand response event.

Simplicity

The baseline should be simple enough for all stakeholders to understand, calculate, and implement, including end-use customers. In addition, it should be possible to determine the baseline in advance of or during demand response events, so that it can be used to monitor curtailment performance in real time.

Integrity

A baseline method should not include attributes that encourage or allow customers to distort their baseline through irregular consumption nor allow them to game the system.

Balancing these traits is not simple. In some cases, a baseline resistant to manipulation can be so complex as to be unworkable by program stakeholders. On the other hand, the simplest approaches could allow market participants to exploit the baseline in their favor. Therefore, baselines should be evaluated to ensure they provide for all three attributes of accuracy, simplicity, and integrity.

Although there are many types of baselines, thanks to the efforts of NAESB, there is now an "official" FERC-approved (and mandated) basic structure that defines how baselines are created and applied in the measurement and verification of demand response.

There are two types of notifications of demand response events. In some cases, utilities and/or grid operators may provide advance notification to customers or load aggregators when they know that an event will occur or is likely to occur. When it is certain that an event will be called, utilities and/or grid operators notify that the event has been initiated. Aggregators later notify customers of the event at the agreed upon time schedule—this is the deployment of the resources.

According to the NAESB report[7] a demand response event has three phases of curtailment:

- Phase 1—The ramp period, which begins with deployment, is when sites begin to curtail.
- Phase 2—The sustained response period, which is the time period bounded by the reduction deadline and the release/recall, is the time in which the demand response resources are expected to have arrived and to stay at their committed level of curtailment.
- Phase 3—The recovery period, which occurs after customers have been notified that the event has ended, is the period when customers begin to resume normal operations.

A baseline is the electrical usage that would have occurred in the absence of an event. Actual meter data from the period of the event is compared with this baseline to determine the customer's curtailment. When a customer enrolls in a demand response program, engineering specialists working for a utility or aggregator help identify the committed capacity—the capacity that a customer will be expected to provide during an event based on the nature of its operations and its curtailment plan. Once a baseline is generated for a customer, a second line can be created to show the committed capacity, or the usage level that a customer must remain at or below during an event. Suppose that a deployment occurs at 11:00 am and the customer begins to decrease energy usage in preparation for the 12:00 pm reduction deadline.

Primer on Baseline Types

Programs throughout the United States use a variety of baselines. Some baselines are more appropriate than others based on program type, customer type, and/or program season. There is no perfect baseline—they are all estimates. Factors such as the conditions that trigger a demand response event, the frequency of demand response events, timing of notification, and duration of event lead to discrepancies between the optimal baseline characteristics for different program types and customers.

---

[7] NAESB Report: Business Practices for Measurement and Verification of Wholesale Electricity Demand Response, March 2009.

In its publication of demand response standards, NAESB defined five types of baseline methodologies:

- Baseline Type I—Baseline is generated using historical interval meter data and may also use weather and/or historical load data to generate a profile baseline that usually changes hour-by-hour
- Maximum Base Load (also known as Firm Service Level in PJM)—Uses system load and individual meter data from the past demand response season to generate a flat, constant level of electricity demand for the baseline that the customer must remain at or below
- Meter Before—Meter After—Baseline is generated using only actual load data from a time period immediately preceding an event
- Baseline Type II—Statistical sampling generates a baseline for a portfolio of customers in the instances where interval meter for all individual sites is not available
- Generation—Baseline is set as zero and measured against usage readings from behind-the-meter emergency back-up generators. This type of baseline is only applicable for facilities with on-site generation and is not discussed in this paper.

These baseline methodologies differ in regards to baseline shape, type of data used, timeframe of historical data, and program objective and design. In the following sections, each baseline methodology is explained.

Baseline Type I

"A baseline performance evaluation methodology based on a demand resource's historical interval meter data which may also include other variables such as weather and calendar data."

The Baseline Type I method is the most prominent in demand response programs today. Variations of this method include Averaging, Regression, Rolling Average, and Comparable Day.

Characteristics of Baseline Type I methods:

- Baseline shape is an average load profile
- Utilizes meter data from each individual site
- Relies upon historical meter data from days immediately preceding demand response event
- May use weather and calendar data to inform or adjust the baseline

Averaging Methods

The most widely used Baseline Type I methods are the averaging methods, which create baselines by averaging recent historical load data to build estimates of load for specific time intervals. Averaging methods are often called representative day methods or High X of Y methods.

A High X of Y baseline considers the Y most recent days preceding an event and uses the data from the X days with the highest load within those Y days to calculate the baseline.

High X of Y programs are used throughout the United States. For example, a High 4 of 5 baseline is used in PJM, a High 15 of 20 baseline in Ontario and a High 10 of 10 in California.

Baseline methodologies differ in regards to baseline shape, type of data used, timeframe of historical data, and program objective and design.

Selection of the number of days to use for a High X of Y baseline is determined by the following considerations.

Look-Back Window

The look-back window is the range of days prior to the event day that should be considered in identifying the Y days for a High X of Y baseline. In 2007, the Customer Baseline Subcommittee of PJM conducted a study of baselines, and one parameter they examined was the look-back window. The study concluded that 30 days was too restrictive and that a 60 day look-back window was reasonable and should be used. Today, many programs do not have a restriction on the look-back window; however, it is helpful to have a limit in order to avoid using data that is extremely outdated and thus likely not representative. For example, in 2009, ISO New England (ISO-NE) made a change to their economic demand response program because of evidence that the lack of a look-back window resulted in baselines that used out-of-date interval meter data.

Exclusion Rules

When calculating a High X of Y baseline, certain days prior to the event day are excluded from the Y eligible days, generally because the load on those days is characteristically different from load on regular business days when events occur. It is generally accepted that previous demand response event days, holidays, and weekends should be excluded. Many programs have adopted the standard that holidays are those days that the North American Electric Reliability Corporation (NERC) identifies as “Off-peak days.”

In addition to the basic exclusions, thresholds and scheduled shutdowns have also been considered. An analysis by PJM in 2011 examined the use of thresholds to aid in selection of the Y days.[8] A threshold of 10% means that a day prior to the event day is excluded from the Y eligible days if the average load during a specified window on that day is less than 10% of the average load of all Y days under consideration over that same time frame. The PJM results showed that a High 5 of 7 day baseline could be improved when a threshold of 25% was used rather than 10%. A study by Lawrence Berkeley National Labs (LBNL) recommended that scheduling information related to shutdowns and large swings in energy be included to help inform baseline predictions. In particular, LBNL recommended that there be a way to capture when facilities are closed on Mondays or during the summer and to use that information when calculating baselines. The exclusion of demand response event days, holidays and weekends is necessary, but further exclusions such as load thresholds or scheduled shutdowns can greatly increase the complexity of baseline calculations.

Relationship between X and Y

Once a group of prior days is identified as the Y days, that group of days is narrowed down to a subset of X days in order to obtain a better representative group of days. This subset of days should be formed based on the nature of the program. For example, a demand response event within a summer emergency demand response program is often called on a day when load is

[8] “PJM Empirical Analysis of Demand Response Baseline Methods,” Markets Implementation Committee, April 2011.

expected to be high, usually driven by extreme weather conditions. Not all of the eligible Y days, however, will have been days with high load. Thus, an unadjusted baseline that uses data from all Y days will include a number of non-event-like days and the baseline will consistently understate the participant's true baseline, reducing the incentive to participate while challenging the accuracy of the program. To avoid this baseline understatement, many programs remove the days with the lowest load levels. Alternatively, operators of peak shaving programs that operate year round may have observed that events do not always overlap with high load days. Thus, those programs may choose to use a Middle X of Y baseline rather than a High X of Y baseline, in order to capture a more appropriate middle level of load during the fall and spring seasons. Another approach that has merit for other reasons is the use of an adjustment to the High X of Y, or Middle X of Y baselines.

Time Intervals

Most programs capture frequent intervals of data. This captures greater detail around the load behavior of customers. In most analyses of baselines, hourly load data was used, simply because processing 5-minute interval data for hundreds of customers and lots of baselines was an unnecessary logistical strain.

Baseline Adjustments

The subset of X days is designed to consist of days similar to the event day. The conditions on the event day, however, are often different from prior day conditions, especially for customers with weather-sensitive loads that increase during extremely hot and/or extremely cold conditions. Programs that are triggered by peak demand conditions or emergencies caused by generation outages often coincide with days of extreme weather temperatures. For this reason, High X of Y baselines are often adjusted. A baseline adjustment is sometimes called a "day of adjustment" because the adjustment is made based on data from the day of the event. Even for programs that are not likely to be called on days of abnormally high loads, adjustments help in situations where load is lower or higher than it has historically been, and the baseline doesn't accurately capture the load behavior immediately prior to the event on the event day.

An adjustment is defined by the time frame that is used to make the adjustment and by the choices to use adjustments that are scalar or additive, capped or uncapped, and symmetric or asymmetric.

Timing and Duration

Most baseline adjustments use a timeframe of 2-4 hours prior to the event. More than 1 hour is needed to be representative of the difference and 4 or more hours may consider conditions too far away from the event to be representative. Actual load over this time period is compared to the load estimated by the baseline over the same time period and is used to calculate the appropriate adjustment. It is optimal for the adjustment to use load values from time intervals preceding deployment. For example, if load is used during the ramp period, then the adjustment could penalize a customer for early curtailment or allow a customer to game the system by increasing load temporarily. Both these issues compromise the integrity and accuracy of adjustments, but can be avoided by using a timeframe for the adjustment that precedes notice of the event start. For example, if an event starts at 12:00 pm and customers will be notified at 11:00 am, then the load from 8 am–11 am could be used to calculate an adjustment.

In order to limit the magnitude of any adjustment, some programs use a cap. However, capped adjustments can penalize customers on days of extraordinarily high load.

Scalar Versus Additive

Adjustments can be calculated using a scalar or an additive factor. The scalar technique is based on a percentage comparison. If load on an event day prior to notification is 30% above the calculated baseline, then each time interval of the baseline would be 130% of the calculated baseline. The additive approach instead calculates the actual demand difference in kW. If load during the calculation period is 50 kW above the calculated baseline, then 50 kW is added to each interval in the actual event baseline.

Capped Versus Uncapped

In order to limit the magnitude of any adjustment, some programs use a cap. For example, a customer with 100 kW baseline exhibits demand of 130 kW prior to event notification. Using an additive adjustment, the customer baseline throughout that day's event would be increased by 30 kW. If the program uses a 20% cap, however, then the additive adjustment would be limited to 6 kW.

Symmetric Versus Asymmetric

It is important to consider whether adjustments reflect demand conditions symmetrically (baseline adjusted up and down) or asymmetrically (baseline only adjusted up). The symmetric approach considers that day-of conditions can have a real impact on customer demand in both directions and therefore symmetric adjustments can maximize the accuracy of a baseline calculation. However, a symmetric adjustment can permit downward adjustments that could have damaging unintended consequences.

For example, a customer may decide to shut down a product line after a batch is complete, because the customer knows the reduction deadline is approaching. If the baseline uses meter data from after the production line has been shut off in order to compute the adjustment, then the baseline of that customer could drop and misrepresent the expected load conditions in the absence of an event. For this reason, program designers must take careful consideration to avoid any overlap of the timeframe used to calculate the adjustment and the ramp period.

Regression

Another variant of the Baseline Type I is a regression baseline. This baseline is built using a customer-specific regression analysis to estimate load based on prior load behavior, weather conditions, calendar data, system demand, and time of day. Regression analysis may be the most accurate of baseline methodologies because it takes into consideration more variables that influence load. Over the last ten years, numerous groups have compared the merits of regression baselines to High X of Y methods. A study by LBNL[9] found that High X of Y methods work better than regression methods for high load variability customers. A previous study for California Energy Commission (CEC) in 2003 discovered that High X of Y methods perform close to weather regression models. Later in 2009, however, an analysis by the Association of

---

[9] Estimating Demand Response Load Impacts: Evaluation of Baseline Load Models for Non-Residential Buildings in California," Environmental and Energy Technology Division, LBNL, January 2008.

Edison Illuminating Companies (AEIC)[10] showed that regression methods outperform High X of Y methods. Quantum Consulting recognized that regression may be a more accurate method, but not practical for real-time use during events. Typical explanatory variables used in regression models tested in these studies include Average kW, Cooling and/or Heating Degree Days, Day Type Indicators, and Day of Average kW.

Regression baselines are complex to calculate and as mentioned they require load, weather, and day-type data. They may rely on interval meter data from an entire summer to estimate load during event days of that summer. In this case, it is not possible to calculate a baseline in real time during an event, since the regression equation can only be created at the end of the summer. For customers and aggregators, it is important to present the baselines during an event, because it shows a customer whether it is meeting curtailment expectations. Furthermore, regression analysis can also delay post-event performance evaluation and hurt customer satisfaction when results cannot be delivered in a timely fashion. Regression baselines sacrifice too much simplicity for accuracy; therefore, they are not a preferred M&V method for any demand response programs.

Other Baseline Type I Methods

Two other Baseline Type I methods are Comparable Day and Rolling Average. The Comparable Day method allows an aggregator to find a day that is similar to the event day and use the load of that similar day as the baseline for the actual event day. This method still uses historical meter data, but unlike the Averaging methods, it uses only data from one day, rather than from multiple days. Two challenges with Comparable Day are 1) it is not possible to know the baseline during the event which could impede meeting curtailment goals, and 2) there are no objective criteria for selection of the day which makes it difficult to assess the appropriateness of a comparable day.

The Rolling Average baseline uses historical meter data from many days, but gives greater weight to the most recent days. The baseline relies on a greater number of data points, which could improve accuracy for a customer who has similar load patterns and levels throughout the year. For customers whose energy usage fluctuates between seasons, however, the rolling average may not be the best method.

For example, suppose a customer is a ski area with ski lifts that are closed down for most of the summer. In the winter, the ski lift operates for 10 hours each day. If an event was called at the beginning of the ski season, a Rolling Average baseline would reflect the summertime usage and might be too low for the customer to receive any credit for curtailment.

Maximum Base Load

"A Maximum Base Load is a performance evaluation methodology based solely upon a Demand Resource's ability to reduce to a specified level of electricity demand."

Maximum Base Load (MBL) methods identify the maximum energy usage expected of each customer and then set a specific level of electricity usage that is equal to the maximum level

---

[10] Association of Edison Illuminating Companies (AEIC), Demand Response Measurement & Verification, Applications for Load Research, Revised May 2013.

minus the committed capacity of the customer. MBL methods are sometimes referred to as "drop to" methods because a customer must drop to a specific level of usage during an event. In comparison, most Baseline Type I methods are referred to as "drop by" because the customer knows the amount of committed capacity that they must drop, but the level of usage is not necessarily a constant level. The MBL is an example of a static baseline, because it remains at one level, as compared to a Baseline Type I method that generates a dynamic, changing profile of the load throughout the hours of the day. Note that with an MBL baseline, it is entirely possible for a customer to "perform" by doing nothing all, so long as its load is already at or below the "drop to" level.

Characteristics of Maximum Base Load methods:

- Baseline shape is static
- Utilizes meter data from each individual site and from the system
- Relies upon historical meter data from previous year
- Coincident vs. non-coincident

An MBL baseline can be either coincident or non-coincident. A coincident baseline uses peak hours of the summer that are chosen based on system load peaks.

A non-coincident baseline also uses peak hours, but they are determined by individual load behavior and not by the system load. This means that the hours that contribute to the non-coincident baseline vary among customers.

Meter Before/Meter After

"A performance evaluation methodology where electricity consumption or demand over a prescribed period of time prior to Deployment is compared to similar readings during the response period."

In an ancillary services event, the minimal notice and reduced event durations create a set of circumstances that require a unique baseline calculation. Generally, an ancillary services event is intended to reduce load on the grid at that moment, for a short period of time, rather than to reduce a dynamic load profile likely to fluctuate over time.

Characteristics of Meter Before/Meter After methods:

- Baseline shape is static
- Utilizes meter data from each individual site
- Relies on small day-of time interval of historical meter data

The demand response baselines and programs discussed thus far have been focused on emergency and energy services where customers participate for 4–8 hours at a time. In ancillary services, however, the duration is much shorter, usually 10 minutes to two hours. For this reason ancillary programs typically use meter before-meter after baselines.

Baseline Type II

"A performance evaluation methodology that uses statistical sampling to estimate the electricity consumption of an Aggregated Demand Resource where interval metering is not available on the entire population."

Most baselines are created using historical meter data from the individual site of the customer. There are instances, however, where data from individual sites is not available, but instead data from a meter that aggregates or is representative of several sites is available. In these cases, the meter data can be used to create a baseline for a group of sites and then a method used to allocate load to specific sites. For example, consider a group of sites that are homogenous with similar load behavior. A Baseline Type II method could meter a few of the sites in order to develop an average load estimate per site and then use that to allocate load from the aggregated baseline.

In demand response programs with commercial and industrial customers, Baseline Type II methods are not common, because most sites either have or can be cost-effectively equipped with interval meters. The Baseline Type II method is more often used in residential demand response programs, where it has been cost-prohibitive to install interval meters at every house. As deployment of residential interval meters increases, however, the need for Baseline Type II methods will likely decrease.

Choosing the Optimal Baseline

Baseline Type I Methods exhibit higher accuracy and lower variability compared to MBL methods. The Baseline Type I methods (High 4 of 5 and High 4 of 5 Adjusted) both have lower median percent errors than the MBL baselines. Indeed, the Baseline Type I methods have errors that were close to or at zero. Furthermore, the variability in median percent errors of the Baseline Type I was significantly smaller than the variability in the MBL baselines as shown by the smaller width of the bars.

Both MBL baselines overstate meter load and have high variation in errors. Results show a 5% over-bias with the Coincident MBL and a 30% over-bias with the Non-Coincident MBL. While the 5% over-bias is a low overstatement, both MBLs also have a high variability in the median percent errors.

Adjustments should not be capped. The analysis above shows small differences between capped and uncapped baselines among all customers. Caps can have severe consequences for individual customers. For example an event in California in summer 2010 used a symmetric baseline adjustment with a 20% cap. In this example, the customer had abnormally high load the morning of an event, but because the adjustment was capped, the baseline could not be adjusted properly to reflect day-of load conditions. Due to this technicality, the customer had trouble reducing to the expected level, despite managing to drop 4 MW. Given that the analysis does show slightly higher accuracy for uncapped adjustments and to avoid glitches adjustments should not be capped.

Research shows that regression approaches found that High X of Y approaches provide a good balance between accuracy and simplicity. The PJM study also concluded that the High X of Y and regression methods it evaluated offered similar accuracy across all segments, and thus regression approaches were not recommended given their greater complexity and thus higher administrative costs than High X of Y methods.

While historical meter data can create a reasonable baseline, incorporating load information from directly before an event will improve the accuracy of the baseline.

Conclusions

Baselines matter. They are a critically important foundation for good demand response resource design, and as programs continue to expand, the necessity for clear, reliable measurement and verification standards becomes an even bigger contributor to grid reliability.

Previous studies have already helped inform demand response programs and they will continue to do so. Additionally, other novel designs already in practice are worth further study. The rolling average baseline, for example, has been used by ISO-NE for many years, and it would be useful to compare that method to High X of Y baselines.

Customers with volatile loads continue to be a challenge, and further analysis to develop and identify baselines that better manage these customers is needed. Given what we currently know about baselines, as well as our experience with a wide range of demand response programs regarding what baselines are more or less appropriate than others. We conclude that—for most peak load management applications—High X of Y baselines with day-of adjustments represent the best balance of accuracy, simplicity, and integrity. While M&V will almost always require some nuanced considerations around system needs and customer engagement, these three pillars of good baseline design should be the starting point when drafting program rules.

4
DEMAND RESPONSE INVENTORY

Demand Response Resources in 2012

In March 2013 North American Electric Reliability Council (NERC) published the early stage of its Demand Response Availability Data System (DADS) for two time periods: the 2011 summer and the 2011–2012 winter. For the U.S. and Canadian entities providing information about demand response programs that are deployed for reliability purpose NERC reports there were 527 demand response events during the summer of 2011 and the average combined capacity of these resources was 50.9 GW. The average sustained response was 3 hours and 6 minutes. The average combined capacity for the winter was 48.7GW and the average sustained response was 1 hour and 43 minutes.[11]

Significant decreases in demand response potential were realized in the PJM markets. According to the market monitor's report for 2012/2013 delivery year, a marked decrease in clearing prices in PJM's forward capacity auction caused the number of credits for demand response to fall sharply in 2012.

These reports are reflective of both the U.S. and Canada. Canadian utilities are very active in the demand response area and it is likely that a significant amount of demand response is included in these totals. Table 4-1 provides an estimate of the demand response totals for the U.S. only.

[11] National Assessment of Demand Response Potential (December 2012), http://www.ferc.gov/legal/staff-reports/12-12-demand-repsonse.pdf

Table 4-1
Demand Response Load Potential in the United States

RTO/ISO	Demand Response Resource Potential at U.S. ISOs and RTOs			
	2011		2012	
	Demand Response (MW)	Percent of Peak Demand	Demand Response (MW)	Percent of Peak Demand [9]
California ISO (CAISO)	2,270 [1]	5.0%	2,430 [1]	5.2%
Electric Reliability Council of Texas (ERCOT)	1,570 [2]	2.3%	1,750 [3]	2.6%
ISO New England, Inc. (ISO-NE)	1,231 [2]	4.4%	2,769 [4]	10.7%
Midcontinent System Operator (MISO)	9,529 [2]	9.2%	7,197 [5]	7.3%
New York Independent System Operator (NYISO)	2,247 [2]	6.6%	1,888 [6]	5.8%
PJM Interconnection, LLC (PJM)	14,127 [2]	8.9%	10,825 [7]	7.0%
Southwest Power Pool (SPP)	1,514 [2]	3.2%	1,444 [8]	3.1%
Total	32,488	6.7%	28,303	6.0%

Sources:

1 California ISO 2012 Annual Report on Market Issues and Performance

2 2012 Assessment of Demand Response and Advanced Metering, FERC Staff Report California ISO 2012 Annual Report on Market Issues and Performance

3 ERCOT Quick Facts (May 2013)

4 2012 Assessment of the ISO New England Electric Markets, Potomac Economics

5 2012 State of Market Report for the MISO Electric Market, Potomac Economics

6 2012 State of the Market Report for the New York ISO Markets, Potomac Economics

7 PJM Load Response Activity report, July 2012, “Delivery Year 21012-2013 Active Participants in PJM Load Response Program”

8 SPP Fast Facts (March 1, 2013)

9 Estimates based on peak demand data from the following: California ISO 2012 Annual Report on Market Issues and Performance, ERCOT 2011 & 2012 State of the Market Reports; 2011 Assessment of ISO New England Electricity Markets; ISO-NE Net Energy and Peak Load Report (April 2013); 2011 & 2012 State of the Market Reports for the MISO Electricity Markets; 2011 & 2012 State of the Market Reports for the New York ISO Markets; 2012&2012 PJM State of the Markets Reports, Vol.2; SPP 2011&2012 State of the Market Reports

Note: This table is publically available and reproduced here.

Advanced Metering Infrastructure Deployment Status

Table 4-2 provides AMI deployment status

Table 4-2
Advanced Metering Infrastructure Meter Deployment in the United States

Source of Number of Advanced Meters	Estimates of Advanced Meter Penetration			
	Date	Number of Advanced Meters	Total Number of Meters	Advanced Meter Penetration Rates (%)
2008 FERC Survey	Dec-07	6.7 [1]	144.4 [1]	4.6%
2010 FERC Survey	Dec-09	12.8 [2]	147.8 [2]	8.7%
2012 FERC Survey	Dec-11	38.1 [3]	166.5 [3]	22.9%
EIA-861 Annual Survey	Dec-11	37.3 [4]	151.7 [4]	24.6%
Institute for Electric Efficiency	May-12	35.7 [5]	151.7 [4]	23.5%
Innovation Electricity Efficiency	Jul-13	45.8 [6]	151.7 [4]	30.2%

Sources:

1 FERC, Assessment of Demand Response and Advanced Metering Staff Report (December 2008)

2 FERC, Assessment of Demand Response and Advanced Metering Staff report (February 2011)

3 FERC, Assessment of Demand Response and Advanced Metering Staff Report (December 2012)

4 Energy Information Administration, Form EIA-861 Data File 2 and Data File 8 for 2011

5 Institute for Electric Efficiency, Utility-Scale Smart Meter Deployments, Plans & Proposals (May 2012).

6 Innovation Electricity Efficiency, Utility-Scale Smart Meter Deployments: A Foundation for Expanded Grid Benefits (August 2013).

Note: This table is publically available and reproduced here.

According to the same FERC report[12] "The wealth of information produced by advanced meters has spurred the increased development of customer services and products such as home energy reports, home energy management software, and mobile software applications (e.g. Notifications, outage/restoration mapping, usage profiles, billing and service requests). This trend will likely continue. The compound annual growth rate for AMI meter deployments has been a 17.3% compound monthly growth rate between December 2007 and July 2013 with 45.8 million AMI meters in place. The penetration rate is estimated at 30.2% of all meters in the United States.

[12] National Assessment of Demand Response Potential (December 2012), http://www.ferc.gov/legal/staff-reports/12-12-demand-repsonse.pdf

Four demand response program types made up 80 percent of the total reported potential peak reduction in 2012. These programs are:

- Load as a capacity resource: 29 percent of all reported demand response potential peak reduction
- Interruptible load: 24 percent of all reported demand response potential peak reduction
- Direct load control: 15 percent of all reported demand response potential peak reduction
- Time-of-use: 12 percent of all reported demand response potential peak reduction

The dominant program type in 2012 is load as a capacity resource (20,000 MW), a departure from the results of previous surveys. In 2010, the predominant program type was emergency demand response (13,000 MW); load as a capacity resource made up less than 9,000 MW of the total reported potential peak reduction. This change for load as a capacity resource and emergency demand response reflects the changes in wholesale market program offerings, along with changes in how PJM chose to categorize its Emergency Load Response—Full Option program.

According to this same FERC report, the residential percent of total demand response was 28.7 percent of the total in 2012 with a 24 percent penetration of AMI meters for the residential class. The implication is that a three-fold increase in residential AMI meters could provide an enabling of demand response of three-fold as well.

The successful implementation of AMI into the residential class could produce 18.0 percent peak demand reduction nationwide. This would represent an additional 60 GW of peak demand reduction enough to forestall generating plant construction and reduce wholesale power prices for years.

5
FEDERAL ENERGY REGULATORY COMMISSION ORDER 745 RESCISSION

Status of Federal Energy Regulatory Commission Order 745

In March of 2011, the Commission issued order No. 745 relating to demand response compensation in organized wholesale energy markets. The directive brought wholesale demand response regulation and pricing under FERC's jurisdiction. Under the terms of the order demand response was considered on par with pother wholesale power supply resources such as power plants.

Because demand response has the same market value as power plants, consumers that provided demand response were to be paid according to the Locational Marginal Price (LMP). This according to FERC "helps to ensure the competitiveness of organized wholesale energy markets and remove barriers to the participation of demand response resources, thus ensuring just and reasonable wholesale rates."

On May 23, 2014 the U.S. Court of Appeals vacated FERC order 745. By rescinding Order 745, the court has devalued demand response in wholesale energy markets and reduced the incentive for demand response providers to offer this service.

According to the latest report from Greentech Media Research, U.S. Demand Response Markets Outlook 2014, a recent ruling by the U.S. Court of Appeals could cost the American demand response market $4.4 billion in unrealized revenue opportunity over the next ten years. The market is large and will continue to grow, but not at its full potential.

Without Order 745, the market will still grow at an annual rate of 4.9 percent on average, reaching $2.2 billion in 2023. If the order is reinstated, this same report forecasts the market to grow at nearly 8 percent per year, reaching $2.9 billion in 2023. The cumulative difference between these two outcomes is $4.4 billion in unrealized revenue

The report cites technology innovation as a key way for vendors to stay relevant in the rapidly evolving market. "The way we think about demand response is fundamentally shifting," said report co-author Mei Shibata. "The adoption of new demand response technologies and distributed energy resources is creating unprecedented opportunities—as well as uncertainties—around demand optimization."

The report predicts that the next decade of the U.S. demand response marketplace will be more "dynamic than the previous 30 years" combined.

It is expected that FERC will appeal the ruling to the Supreme Court but should it refuse to hear the appeal the ruling will stand. This will likely result in a reduction in demand response inventory on a national basis.

Export Control Restrictions

Access to and use of EPRI Intellectual Property is granted with the specific understanding and requirement that responsibility for ensuring full compliance with all applicable U.S. and foreign export laws and regulations is being undertaken by you and your company. This includes an obligation to ensure that any individual receiving access hereunder who is not a U.S. citizen or permanent U.S. resident is permitted access under applicable U.S. and foreign export laws and regulations. In the event you are uncertain whether you or your company may lawfully obtain access to this EPRI Intellectual Property, you acknowledge that it is your obligation to consult with your company's legal counsel to determine whether this access is lawful. Although EPRI may make available on a case-by-case basis an informal assessment of the applicable U.S. export classification for specific EPRI Intellectual Property, you and your company acknowledge that this assessment is solely for informational purposes and not for reliance purposes. You and your company acknowledge that it is still the obligation of you and your company to make your own assessment of the applicable U.S. export classification and ensure compliance accordingly. You and your company understand and acknowledge your obligations to make a prompt report to EPRI and the appropriate authorities regarding any access to or use of EPRI Intellectual Property hereunder that may be in violation of applicable U.S. or foreign export laws or regulations.

The Electric Power Research Institute, Inc. (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, affordability, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI's members represent approximately 90 percent of the electricity generated and delivered in the United States, and international participation extends to more than 30 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

Together…Shaping the Future of Electricity

3002003317

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com