3. A Framework for Estimating Large Customer Demand Response Market Potential

In this section, we propose a conceptual framework for estimating demand response market potential among large C&I customers in a given jurisdiction or utility service territory. This framework involves the following five steps (see Figure 3-1):[37]

- *Establishing the study scope*—identifying the target population and types of demand response options to be considered;
- *Customer segmentation*—identifying "customer market segments" (groups of customers with similar characteristics that are expected to respond in similar ways) among the target population;
- *Estimating net program penetration rates*—using available data to estimate customer enrollment in voluntary programs and customer exposure to default pricing programs;
- *Estimating price response*—selecting an appropriate measure of price response given available data and developing elasticity estimates applicable to the identified customer market segments; and
- *Estimating load impacts*—combining the above steps to estimate the level of demand response that can be expected from the target population at a reference price.

Each of these steps is discussed in the sections that follow and illustrated with examples in section 4.

3.1 Establishing the Study Scope

The first step in our framework is to define the study scope at a high level. Specifically, this involves deciding on the target customer population and the types of demand response options to be considered in the market potential study or market assessment.

The target population is typically defined by the type of customer (e.g., commercial, industrial, agricultural), and/or customer size thresholds (e.g., threshold peak demand level). Policy and regulatory considerations often influence the choice of target population.

Different types of demand response options may induce different levels of demand response impacts among customers.[38] For example, everyday hourly pricing tariffs that are linked to wholesale electricity market prices may elicit smaller load reductions on a given day than an emergency program that, depending on program design, may provide a larger curtailment incentive to customers (Goldman et al. 2005, Neenan et al. 2003).

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[37] For demand response options, such as direct load control programs, in which a utility or program operator directly cycles down a participating customer's equipment, engineering approaches may be more appropriate (see section 2).

[38] For a description and classification of various demand response options, see chapter 2 of DOE (2006).

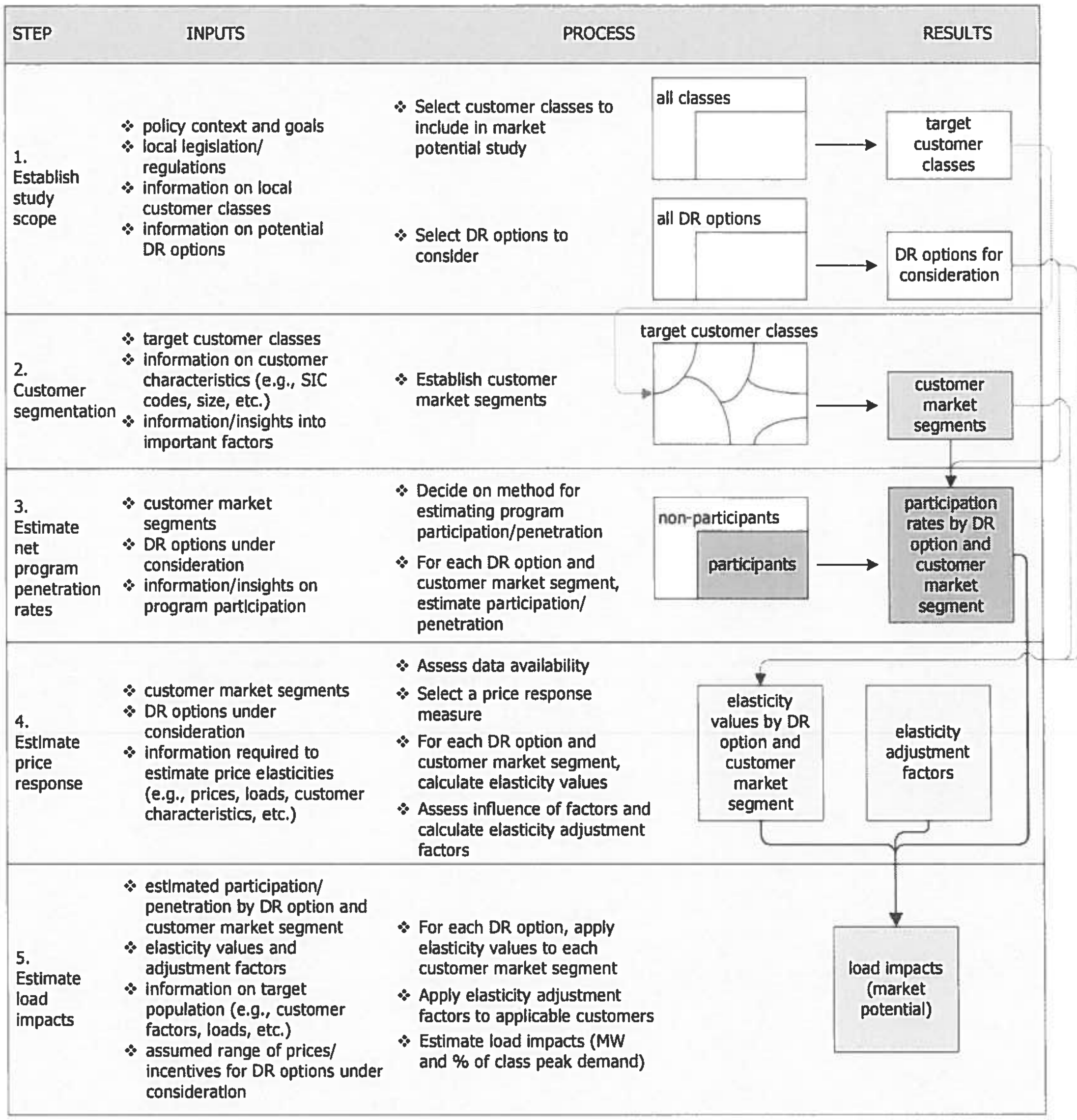

Figure 3-1. Steps for Estimating Demand Response Market Potential

Moreover, certain types of programs or tariffs are more appropriate for certain market structures than others—for example, default-service real-time pricing (RTP) is more likely to be accepted by customers if implemented in the context of retail choice. Market-based, bidding-type programs may also be facilitated by the presence of organized wholesale energy (and/or capacity) markets. Therefore, policymakers will wish to determine up-front which types of demand response options are feasible and appropriate for the target customer population and the incumbent market structure.

The selection of customer groups and specific program offerings can later be refined as more responsive participants are identified in the process of conducting the market potential study.

3.2 Customer Segmentation

With input from policymakers and sponsoring entities (e.g. utilities, ISOs, RTOs), analysts conducting the demand response market potential study should use available information about the target population to identify customer market segments that are expected to respond in similar ways, or that could be approached with specific marketing strategies or program designs. These groups will be analyzed separately in subsequent steps of the market potential analysis so, ideally, they should be refined enough to capture significant trends in customer willingness to participate in and respond to demand response programs or dynamic pricing tariffs.

For large customers, business activity is often strongly correlated with both willingness to participate in demand response programs (or remain on default-service hourly pricing), and willingness and ability to respond to high-price or reliability events by temporarily lowering demand (Goldman et al. 2005, Neenan et al. 2003). Typically, information on large customers' lines of business is available to utilities and policymakers in the form of standard industrial classification (SIC) codes. SIC codes provide quite detailed information about the type of industry a specific customer is engaged in. Analysts usually aggregate these codes into a handful of groupings that provide a reasonable sample size in each, yet distinguish groups of customers with substantially different activities or operating cultures, and similar energy usage characteristics (e.g., load factor and timing of usage). For example, in Goldman et al. (2005), large customers (with peak demand above 2 MW) were divided into five categories: manufacturing, government/education, commercial/retail, healthcare and public works.

3.3 Estimating Net Program Penetration Rates

Next, it is necessary to estimate customer participation rates for the demand response options included in the study.[39] In the context of demand response, participation can imply: (1) customer enrollment in voluntary programs and tariffs, or (2) the retention of customers in programs or tariffs implemented as the default service (i.e., the number of customers who do not switch to an alternative offering).

Demand response participation is often fluid. Customers may enroll in a program for one or more years, and subsequently drop out. They may even subsequently re-enroll in the program, or others may take their place. With some exceptions, the benefits of customer participation are only realized while the customer is enrolled in the program (or exposed to hourly prices).[40]

[39] Practically speaking, no demand response offering will ever experience full participation by all customers to whom it is offered or imposed. In theory it might be possible to impose a mandatory dynamic pricing tariff. However, if alternatives are not offered by the default utility supplier or a competitive retail market is not sufficiently competitive, policymakers are likely to experience strong customer resistance to such a policy.

[40] However, the experience of responding to a particular program may provide benefits beyond that particular program if the customer subsequently exhibits demand response behavior in other programs or dynamic pricing options that were learned in the initial program.

Thus, participation in demand response options can be viewed as *penetration* in a given year "n" (or other applicable timeframe), as follows:

$$\text{Penetration}_n = \text{participants}_{n-1} - \text{dropouts}_n + \text{new enrollees}_n$$

This can be estimated separately for each customer market segment defined in the previous step, and the results added up to determine the overall penetration for the population of eligible customers.

This way of thinking about demand response potential is useful for evaluating an established program over multiple years, particularly in the context of changes to program rules or incentives, or to the level and/or volatility of market prices. From the standpoint of a new, hypothetical program, it may be acceptable to view participation as penetration in a "typical" year of a mature program, with the understanding that a multi-year ramp-up period will be necessary, and that ongoing penetration may be subject to fluctuations due to factors both within and out of the program operator's control.

An important aspect of demand response participation is the interaction of multiple programs and dynamic pricing tariffs. In some situations, program rules may limit customer participation in more than one demand response option. Where such rules are known in advance, the mutual exclusivity of programs should be taken into account when establishing penetration estimates for individual programs. In other cases, customers who are enrolled in multiple demand response options may behave differently than customers participating in a single option. For example, in some jurisdictions, it is allowable for customers that face day-ahead hourly prices for their electricity commodity tariff to participate in emergency or demand bidding programs offered by an ISO or RTO. The potential load response for such customers is probably not as high as the sum of the estimated response for a customer in an hourly pricing program and for a customer in an ISO/RTO program. Such interaction effects, if deemed sizeable, should be accounted for in estimating overall load impacts (see section 3.5).

Analysts have used a number of methods to estimate penetration rates of demand response programs (see Table 3-1). Each of these methods has pros and cons, in part because there is not yet a broad set of information on customer response to various demand response options in a variety of settings. Program penetration rates present the largest uncertainty in this framework, because experience is piecemeal, and because of data limitations. Whatever the chosen method (or methods), we strongly recommend evaluating the impact of a range of participation levels, rather than relying on a single point estimate. In Table 3-1, we describe the approaches used by various analysts to estimate program penetration.

The "Delphi", or "expert judgment", method is a heuristic, or intuitive, method of establishing penetration of demand response programs. SCE (2003) employed this approach, asking several demand response experts to provide estimates of participation in a variety of demand response programs. Another example is Violette et al.'s (2006) analysis of the value of demand response for the International Energy Agency's Demand

Table 3-1. Methods of Estimating Demand Response Penetration Rates

Method	Description	Advantages	Issues/Questions
Delphi (expert judgment)	Solicit estimates from a panel of individuals with experience or insight	Relatively simple method which may provide reasonably accurate estimates	• Results are subjective—what constitutes an expert? • Requires a method of resolving divergent estimates
Translated experience	Use actual participation rates for demand response programs implemented for similar market segments or target populations, and/or in markets with similar supply conditions and market structure	• Uses actual data on realized penetration rates of implemented demand response options • Depending on the data source(s), can provide detailed estimates	Assumes that the customers, market segments, market supply conditions and other characteristics of the population on which estimates are based are identical and directly translatable to the population to which the estimates are applied. Potential sources of bias include: • the method of setting prices/incentives • the level and volatility of prices/incentives • the market structure (e.g., organized market with ISO/RTO vs. vertically integrated utility in region without ISO) • differences in the customer base (e.g., different types of manufacturing facilities in different regions) • differences in customer experience with load management and demand response • climatic differences
Benefit threshold	Set a minimum level of economic benefits required for a customer to participate (e.g. payback time)	Logical theoretical basis for modeling customer participation	• Requires a subjective determination of how high the benefit threshold should be set for different customer market segments and/or individual customers as well as estimates of demand response costs • Assumes that customers act rationally—in reality, not all customers will choose to participate, even if it benefits them
Choice model	Develop a statistical model of the factors that drive customer participation, using data from demand response programs implemented for similar market segments or target populations, and/or in markets with similar supply conditions	• Provides a robust statistical method for estimating participation at a fine level of detail • Uses actual data on customer participation from implemented demand response programs	Assumes that the customers, market segments, market supply conditions and other characteristics of the population on which estimates are based are identical and directly translatable to the population to which the estimates are applied. Potential sources of bias include: • the method of setting prices/incentives • the level and volatility of prices/incentives • the market structure (e.g., organized market with ISO/RTO vs. vertically integrated utility in region without ISO) • differences in the customer base (e.g., different types of manufacturing facilities in different regions) • differences in customer experience with load management and demand response • climatic differences
	Develop a statistical model of the factors that drive customer participation, using survey data on expected choices by the population of interest	• Provides a robust statistical method for estimating participation at a fine level of detail • Uses data obtained from a sample of customers in the target population	• Customers survey responses based on hypothetical options may differ from their actual behavior when faced with real choices • Surveys can be resource-intensive

Response Resources project, in which hypothesized, graduated increases in participation were assumed over a 15-year period, up to a level of 15 percent. The simplicity of the "Delphi" method is appealing, and in the absence of appropriate information sources or resources for a more systematic market penetration study it may be the most feasible approach. However, both the selection of the "experts" and the resulting estimates are highly subjective, and the resultant lack of transparency may be a problem in jurisdictions where demand response implementation may be controversial. Moreover, if the experts' estimates diverge substantially, some (again subjective) method is necessary to resolve them.

Another option is to apply customer participation rates observed in another jurisdiction to the target population (see, for example, Gunn 2005). This has the advantage of using real customer adoption data, and is simple to implement. If customer market segments are well defined and are similar in the two customer populations, this can be an appropriate method. However, it is only as good as the assumption that the source population, market characteristics and demand response options are adequately similar to the population of interest to produce meaningful estimates.

An alternative method is to assume that participation is largely, if not wholly, driven by customers' expectations of benefits. This method can be used to estimate customer participation in a single program, or an array of programs. In the single-program case, customers are assumed to participate if their expected benefit exceeds a threshold level (e.g., a level of nominal dollar savings, or an average per unit electricity cost reduction) over a specified time period. If facing several, mutually exclusive program opportunities, customers are assumed to select the one with the greatest expected benefit (provided it meets a minimum threshold). This approach is appealing in that it does not rely on data from other programs and provides a simple, yet systematic method for estimating participation. However, determining the threshold benefit level entails major assumptions.[41] Customer surveys can provide insights,[42] but if customers do not understand or have much experience with the demand response program or tariff and its associated costs and benefits (e.g., through lack of direct experience), the results may have little resemblance to actual participation when the program is launched. Moreover, surveys can be expensive and time consuming.

Finally, choice models define customer adoption in terms of an "odds ratio"—the probability that a given customer (or average customer in a given customer market segment) will participate, given the choice. They are statistically robust models that can incorporate a variety of drivers for customer choice into a single model, providing greater predictive power than simply assuming participation rates directly. The economic theory behind a choice model is that customers' choices are driven by their (explicit or implicit) calculation of the marginal benefit of each choice.[43] They may be estimated using data on customers' actual choices in the face of real options, or surveys can be designed to collect data on customers' expected choices given proposed hypothetical options. Choice models

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[41] From a purely theoretical standpoint, a customer should be expected to participate in a program if the net benefit is greater than zero. However, uncertainty in a variety of factors that influence the actual level of benefits (e.g., customers' ability to respond on specific days, the level of prices/incentives, etc.), as well as customer and market barriers to participation (e.g., lack of customer awareness of program benefits, institutional barriers within customers' organizations, lack of priority of electricity usage, etc.), necessitate a higher participation benefit threshold. All of these factors should be taken into account when determining the benefit threshold.

[42] See, for example, market research conducted by Momentum (2005) as part of the evaluation of California's Statewide Pricing Pilot.

[43] See Train (1993) for a complete description of the economic foundation for modeling customer choices.

have been estimated to describe large customers' propensity to switch from default-service hourly pricing to the competitive market and their likelihood of participating in ISO-sponsored demand response programs (Goldman et al. 2004, Neenan et al. 2003). These examples demonstrate the use of choice models in a similar context, but do not provide data that can be directly used to estimate demand response program participation. This could be done by evaluating the actual choices of customers in other jurisdictions who have been exposed to demand response options similar to those under consideration. However, the applicability of such models may be limited if the populations and market circumstances differ. Alternatively, a sample of customers in the population of interest could be surveyed about their expected choices, although this approach may be beyond the resources of most analysts charged with estimating market potential.

In summary, while a number of potential methods for estimating the penetration rates of demand response options show promise, limited data and experience confound reliable and statistically sound estimates at present, at least within a reasonable budget for a typical state or utility undertaking a market potential study. There is clearly a need for research to collect detailed data on the drivers for customers' participation in demand response options, and to develop robust models that can be more easily tailored to specific circumstances.

In section 4.2, we develop market penetration rates for five types of demand response programs and tariffs, disaggregated by market segment and customer size. Where possible, the estimates draw upon actual market penetration rates from evaluations of these programs and tariffs (i.e. translated experience), and a Delphi approach was used to fill in gaps. Our objectives are two-fold: (1) to illustrate the sensitivity of market potential estimates to program penetration rates, and (2) to provide some reasonable market penetration rate values for certain types of demand response programs and tariffs that reflect the experience of relatively mature programs (i.e., with 3–4 years of operation).

3.4 Estimating Price Response

The next step in this framework is to define the expected demand response potential of the customers that participate. This is done by assigning a *price elasticity* to each customer market segment, for each type of demand response option, using available information about how similar customers have responded to high prices or program events afforded by similar demand response options. This involves three steps. First, a measure of price response must be chosen, balancing theoretical consistency and data availability constraints. Second, elasticity values are developed for each market segment that will be applied to the target population to develop load response estimates. Finally, factors that affect demand response within the established customer market segments are evaluated and adjustments to the elasticity values are developed to account for their impacts on customer demand response.

3.4.1 Selecting a Measure of Price Response

Studies of consumers' response to changes in electricity prices typically express this response with one of three measures of price elasticity: the *price elasticity of demand*, the *elasticity of substitution*, and the *arc price elasticity of demand*. All are estimated from a sample of customers' observed electricity usage data in the face of changing prices.

From a theoretical standpoint, the price elasticity of demand (also known as the "own-price" elasticity) provides the most consistent characterization of consumer behavior. However, its estimation requires data on customers' production output or the utility they derive from electricity usage that is usually not available, so few analysts have been able to estimate it directly.[44] A number of studies of large customer price response have instead estimated substitution elasticities, which are also grounded in economic theory and can be estimated without output data, but impose assumptions about how customers use electricity.[45] Arc elasticities are much easier to compute (only a limited number of observations of customer loads and prices are necessary) but this comes at the cost of limited explanatory power.

The tradeoffs between theoretical consistency and the amount of data required to estimate these three elasticity measures are summarized in Figure 3-2. As a general rule of thumb, analysts should choose the measure with the greatest theoretical consistency possible given available data.[46]

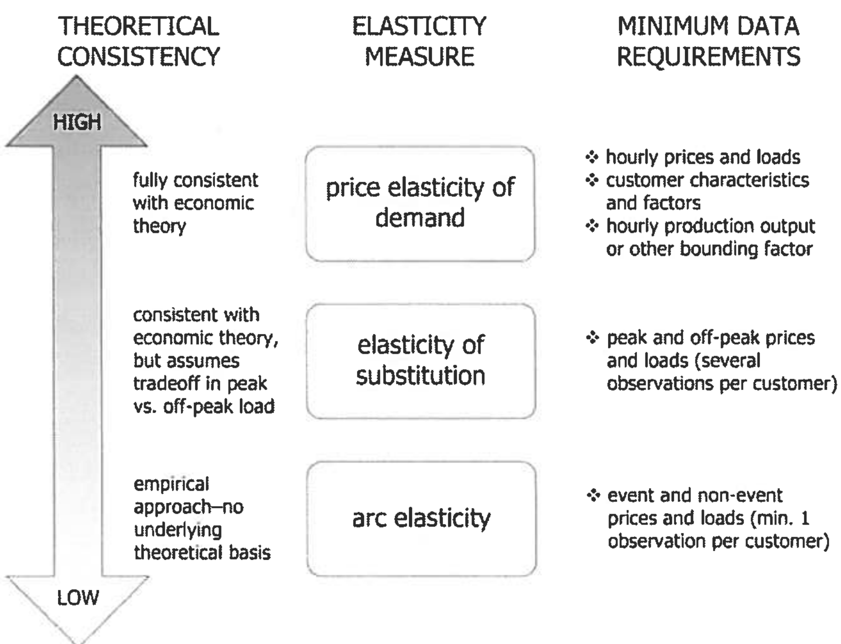

Figure 3-2. Features of Price Elasticity Measures

[44] When this method has been employed, a proxy for firm output or consumer's utility has been derived assuming they follow a cyclical pattern. The extent to which the individual firm or consumer differs from this pattern will determine the degree of inaccuracy in the resulting demand model.
[45] See, for example, Braithwait and O'Sheasy (2001), Boisvert et al. (2004), Caves et al. (1984), Goldman et al. (2005), King and Shatrawka (1994), and Schwarz et al. (2002).
[46] If multiple demand response options are being considered, different elasticity measures may be employed for each, as data requirements dictate. We have taken this approach in the examples provided in section 4.

Price Elasticity of Demand

The demand elasticity is a preferred measure of consumer response to changes in electricity prices from a theoretical standpoint. A behavioral model, grounded in economic theory, is overlaid on observed customer response data to develop a relationship between the quantity of electricity usage and prices. This relationship—the price elasticity of demand—is defined as the observed percentage change in a consumer's electricity usage in response to a one percent change in the price of electricity. Mathematically, it is given by:

(1) $\sigma = \frac{dQ}{dP} * \frac{P}{Q}$, where P is the price of electricity and Q is the quantity of electricity used.

Although the concept is simple, properly estimating the price elasticity of demand requires that certain information be known about how customers use electricity. According to economic theory, the demand elasticity describes how customers decide to alter how much electricity to use, given their value for the amenity it provides, in response to a change in its price. Price elasticity must be evaluated in the context of other factors that may drive energy usage. For example, an industrial customer uses electricity as one of many inputs into a production process. The price of electricity is but one factor driving production—economic factors, availability of other inputs, the pace of customer orders, and other factors may change the customer's demand for electricity by otherwise altering production. Thus, to properly characterize the extent to which electricity prices drive observed changes in usage, information on other factors that may drive electricity usage is needed. For large C&I customers, this could be production output (or an appropriate proxy).

Unfortunately, such information is, at best, burdensome to collect, and often not available at all. For large commercial and industrial customers in particular, production output (or service level) data tends to be regarded as highly confidential.

Elasticity of Substitution

The elasticity of substitution is also grounded in economic theory and can be used to estimate price response. It assumes that customers regard electricity as two distinct commodities—typically "peak" and "off-peak" electricity (defined by their timing during the day)—and that they make decisions about how much peak and off-peak electricity to use based on their relative prices.[47] The elasticity of substitution is somewhat less intuitive than the price elasticity of demand: it is defined as the ratio of the observed change in a customer's peak and off-peak usage to a one percent change in the ratio of peak and off-peak prices.[48] The mathematical formula is:

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[47] The overarching theory is that electricity is one of many inputs into a production process, and that the customer trades off the usage of one input for another (in this case, off-peak for peak electricity) in order to minimize costs.

[48] See Goldman et al. (2005) for a detailed discussion of the elasticity of substitution.

(2) $$\sigma_{po} = \frac{d\left(\frac{Q_p}{Q_o}\right)}{d\left(\frac{P_o}{P_p}\right)} * \frac{\left(\frac{P_o}{P_p}\right)}{\left(\frac{Q_p}{Q_o}\right)}$$, where P and Q are price and quantity, and the subscripts $_p$ and $_o$ refer to peak and off-peak periods.

To estimate a meaningful model, price and usage data in peak and off-peak periods, covering a range of prices, are needed for each customer included in the model. Ideally, customer characteristics and circumstances should also be incorporated into the model to evaluate the extent to which they explain the observed price response.

Arc Price Elasticity of Demand

The arc price elasticity is an empirical measure of price response that is not grounded in economic theory. It can be computed when insufficient data exist to estimate an economically consistent model—the tradeoff is a loss of specificity and explanatory power. Arc elasticities assume that customers change their electricity consumption strictly based on the ratio of a "background" price and an "event" price, without regard for output loss or other economic factors. The mathematical expression is:

(3) $$\sigma_{ARC} = \frac{\left[\frac{(Q - Q_{CBL})}{Q_{CBL}}\right]}{\left[\frac{(P - P_B)}{P_B}\right]},$$

where P_B is the average retail price the customer would normally face (the background rate), Q_{CBL} is the customer's expected normal level of usage at the background rate, P is the commodity price the customer either faces or is paid for curtailing in the event hour, and Q is the customer's observed load during the event hour.

Measuring the Unobservable

It is impossible to directly measure the amount of energy that a customer would have used on a given event day if no event had occurred. How, then, is the quantity Q^{CBL} determined? This is the same dilemma faced by any demand response program that pays customers to curtail.

Program designers and analysts have come up with different methods of developing proxies for customer baseline loads (CBLs). In Appendix B, we describe the approaches of the programs included as data sources in section 4. For more information on the pros and cons of various methods, see Goldberg and Agnew (2003).

The advantage of this approach is that an estimate of price response can be obtained from only customer usage and prices (or incentives paid) during an "event" period, although the expected usage must be estimated somehow (see the adjacent textbox). Moreover, arc elasticities can be computed from a single event hour.[49]

[49] At relatively low prices, arc elasticities have a tendency to pick up more "noise"—changes in usage due to extraneous factors that cannot be measured by the arc elasticity. Alternatively, when prices reach much higher levels, it is assumed that the change in consumption is truly driven by the change in price, thus improving the accuracy of the arc elasticity.

However, this formulation for price elasticity has limited application because it provides a highly localized, event-specific measure of behavior that does not systematically take into account any of the other factors that can influence how a customer responds. The load response at each event can vary considerably. For example, on a very hot day, a customer may be using much more space conditioning energy than usual, but be willing to sacrifice comfort for cash, and reduce this load substantially. The result could be an even greater relative reduction than on a cooler day; in other words, a higher arc elasticity. Another customer might be fulfilling an important commercial obligation that requires it to operate at full capacity, and not curtail at all, regardless of the price. An arc elasticity embodies factors other than price, but provides no way to measure their contribution to the response.[50] We therefore recommend that arc elasticities be used only when the data required to estimate other elasticity measures are not available.

3.4.2 Calculating Elasticity Values

Having chosen an elasticity measure, the next step is to estimate elasticity values for each customer market segment and demand response option included in the study. This requires information on customer response obtained from studies of similar implemented programs or tariffs. Ideally, estimates should draw on as many data sources as possible—where multiple programs or tariffs of a similar type are available, the data can be pooled. Although there are currently few sources of information for certain types of demand response option, over time it should be possible to develop elasticity estimates from a wider base of program experience and data.

3.4.3 Accounting for Factors that Influence Price Response

Studies of customer price response indicate that there is considerable diversity in how customers respond to similar prices and incentives, even among customer market segments (Goldman et al. 2005, Neenan et al. 2003, Schwarz et al. 2002). Table 3-2 summarizes factors that have been observed or theorized in various studies to differentiate when and how customers respond. External factors, such as high-price or program event characteristics and weather, are distinguished from customer-specific characteristics or circumstances, such as customer experience, ownership of onsite generation and other enabling technologies, and electricity intensity.

The impacts of external and customer-specific factors can be quantified and incorporated into market potential studies in three ways:

- they can be included directly in a customer demand model;
- an *ex ante* regression analysis can be used, with the factors as independent variables and estimated elasticities as the dependent variable; and
- simple statistical methods, such as chi-square tests or cross-tabulations, can be used.

[50] These factors are all associated with price, because that is the only variable in the arc elasticity equation used to explain changes in consumption.

Table 3-2. Factors that May Influence Demand Response

Factor	Description	Impact on Response
EXTERNAL FACTORS		
Event duration	• Duration of individual events (e.g., in hours)	• Some customers may not respond unless high hourly prices or incentives are applicable for a block of several hours • Some customers may be unwilling to curtail for long periods (e.g., more than four to six hours)
Event frequency	• Overall frequency of events in a particular season	• If events occur too frequently, customers may be unwilling or unable to continue load curtailments (this is known as "response fatigue") • Conversely, experience gained from multiple events can enable customers to fine-tune their curtailment strategies
Event clustering	• Distribution of events over time (e.g., clustered on consecutive days vs. isolated incidents)	• Clustered events may cause "response fatigue"—reduced willingness or ability of customers to respond
Weather	• Temperature and humidity are strong drivers of HVAC usage • Increased HVAC usage drives overall system demand and prices	• Weather-sensitive loads (e.g. air conditioning) may be somewhat discretionary; some customers may respond more when prices are high or system emergencies are perceived • Conversely, some customers may be unwilling to reduce or curtail air conditioning loads during prolonged or extreme weather events
CUSTOMER-SPECIFIC FACTORS		
Training, awareness and past experience	• Past participation in similar demand response programs or tariffs, or experience managing energy commodity risk (e.g. gas markets) • Attendance at training workshops • Technical audits or information	• May enhance customers' acceptance of demand response options and ability to respond
Onsite generation	• The presence of onsite generation equipment (e.g., backup generators, gas turbines, fuel cell or renewable generation technologies) at customers' facilities	• Subject to environmental regulations, onsite generation allows customers to respond without interrupting electric end uses • Provides customers with more response flexibility
Enabling technologies	• Energy management controls systems (EMCS)—provide customers with the means to program equipment (e.g., HVAC or lighting control systems) usage changes in response to demand response events • Energy Information Systems (EIS)—allow customers to analyze their load usage patterns, establish their baseline energy usage, access information about demand response events or prices, and identify strategies for load curtailment	• EMCS and EIS can help improve the persistence and sustainability of load curtailments, and provide immediate feedback to customers on load curtailment performance
Electricity intensity	• Electricity costs as a share of customers' operating expenses	• Customers whose operations are highly electricity-intensive may be more likely to participate in and respond to demand response options in order to minimize costs • Conversely, high-intensity users may view their electrical end uses as non-discretionary, making them less likely to participate or respond
Business or operational processes	• Features of customers business processes that impact the flexibility of their response (e.g., industrial process equipment, three-shift operations, facilities at multiple geographic locations)	• Certain types of industrial customers that can shift usage by rescheduling industrial processes (e.g., batch processes) or equipment usage (e.g., arc furnaces, aluminum smelters) may be more price responsive

From a statistical standpoint, the first approach is often preferable. However, depending on the demand model used, including variables directly in the model can add substantial complexity, to the point where it becomes impossible to produce a stable representation of demand.[51] The *ex ante* regression approach can provide a feasible alternative. However, to estimate a statistically robust regression, a large number of observations is necessary, and collecting information on customer-specific factors (e.g., through customer surveys) can be challenging. Simple statistical tests are the easiest approach to implement, but cannot account for interactions between multiple correlating factors. They can, nonetheless, provide qualitative insights to enable categorization of responsive and non-responsive customers in each category.

Factors found to influence price response can be used to adjust the elasticity estimates. For example, if customer ownership of a specific enabling technology is found to increase demand response, then separate elasticity estimates can be applied to customers with and without that technology in the target population to achieve a more refined overall market potential estimate. This is demonstrated with an example for onsite generation in section 4.3.2.

While factor-adjusted elasticity estimates can provide more accurate estimates of market potential, their use is only practical if information on the presence of the factors is accessible. Not only must factor-specific information be available among the customers from whose response data elasticity estimates are derived, but also among the target population whose demand response market potential is to be estimated.

3.5 Estimating Load Impacts

The final step in this framework is to pull together all the pieces to estimate load impacts. The estimation of load impacts should be done separately for each demand response option under consideration in the study. As noted in section 3.3, analysts may wish to account for interactive effects arising from program eligibility rules (or customer's operational constraints) that limit participation in multiple programs.

For each customer market segment, program penetration rates estimated in step 3 should be applied to the target population in that segment. Then, elasticity values are applied to the customers in each market segment. These elasticities are then adjusted for individual customers for whom the elasticity adjustment factors developed in the last step are applicable.

Once each customer has been assigned an elasticity value, it remains to translate the results into an estimate of load impacts for a range of expected prices or incentive levels. If the price elasticity of demand was used to characterize customer response, load impacts can be calculated directly for a given price. For substitution and arc elasticities, this task is somewhat more complicated and the methods for doing so are not well established. Here, we describe a method for each type of elasticity.

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[51] This is particularly difficult for non-linear models, such as the Generalized Leontieff model (see Goldman et al. 2005).

3.5.1 Estimating Load Impacts from Arc Elasticities

Given a set of prices, it is fairly simple to derive the percentage change in load from arc elasticity values using the following formula:

$$(4) \qquad \%\Delta L = \sigma_{ARC} \times \left[\frac{(P - P_B)}{P_B} \right],$$

where σ_{ARC} is the elasticity value, P is the program's incentive payment rate (or dynamic pricing tariff's applicable rate during the high-price event), and P_B is the retail price the customer would normally face (the background rate).[52] If an analyst knows something about the expected level of load (i.e. the CBL) during an event, then the percentage change in load can be translated into an estimate of the level of demand response according to the following formula:

$$(5) \qquad DR = (-1) \times Q_{CBL} \times \%\Delta L$$

3.5.2 Estimating Load Impacts from Substitution Elasticities

Because the elasticity of substitution assumes that customers substitute peak for off-peak electricity, it is necessary to establish the proportion of electricity costs that are allocated to both these periods. Customers are also assumed to respond vis-à-vis the average price in each period, both in terms of the nominal changes in the peak and off-peak prices from their average levels, as well as the relative prices in the two periods. As a result, the following separate formulae are used to estimate peak load reductions and off-peak load expansion:[53]

$$(6) \qquad \%\Delta L_p = (\sigma_{po} \times C_o) \times \left[\left(\frac{P_o - \overline{P_o}}{\overline{P_o}} \right) - \left(\frac{P_p - \overline{P_p}}{\overline{P_p}} \right) \right]$$

$$(7) \qquad \%\Delta L_o = (\sigma_{po} \times C_p) \times \left[\left(\frac{P_p - \overline{P_p}}{\overline{P_p}} \right) - \left(\frac{P_o - \overline{P_o}}{\overline{P_o}} \right) \right],$$

where C_o is the off-peak-period cost share as a percentage of the total daily electricity cost (e.g. 50%, 75%, etc.), C_p is the peak-period cost share as a percentage of the total daily electricity cost, P_o is the actual off-peak period price, P_p is the actual peak period price, $\overline{P_o}$ and $\overline{P_p}$ are the average off-peak and peak period prices. Applying equation (5) to equation (6) produces an estimate of the level of demand response (i.e., load reductions during peak periods). Similarly, applying equation (5) to equation (7) provides an estimate of the load impacts in off-peak periods (i.e., increase in load due to load shifting).

Once the load impacts have been established (in MW), they can be expressed as a percentage of the peak demand of the applicable customer class.

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[52] If the customer's otherwise applicable tariff is a time-of-use rate, then P_B should be the period price coincident with the timing of the event.

[53] These formulae assume the use of an Allen-partial elasticity of substitution.

4. Applying the Framework: Large Customer Demand Response Market Potential

We applied the methodology developed in section 3, using available data on large customer participation and response, to estimate the market potential of several types of demand response option at an illustrative urban utility. The purpose of this exercise is threefold:

- to demonstrate the implementation and use of the proposed methodology;
- to gather currently available data on large customer participation and response, which could be used by policymakers and other analysts in market potential studies; and
- to demonstrate, through the use of scenarios, the impacts of various factors on demand response market potential.

The first step in any market potential study is to define its scope (see section 3.1). In this example, we limit our analysis to large, non-residential customers, with peak demand ranging from 350 to 5000 kW or more. This is because we had access to individual customer level data from several large-customer demand response options, which facilitated estimation of participation rates and customer response by market segment and customer size.[54]

We analyze five different types of demand response option in this example (see Table 4-1). These are by no means the only options possible; they simply represent those for which we had data to conduct this exercise.

It is important to recognize that we analyzed these options *independently*. That is, we did not account for possible interactions between different options, should they be offered simultaneously to a given set of customers.[55] Thus, our results likely *overestimate* the combined market potential for these demand response programs and dynamic pricing tariffs should two or more of them be offered to the same customers at once. Program designers that intend to offer a variety of demand response options should ensure that such interactions are accounted for in market potential studies.

The second step in the proposed methodology is to define customer market segments (see section 3.2). Following a recent study of large customer demand response (Goldman et al. 2005), we adopted the following five market segments that are well correlated with differences in large, non-residential customers' willingness to participate in and respond to demand response options:

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[54] We did not have access to this level of data for smaller commercial or residential customers, although the same methods could be applied to smaller customers offered similar demand response options if the required data were available.

[55] If customers are offered more than one type of demand response option, they may face a tradeoff in choosing which programs to participate in, particularly if program rules prohibit multiple program participation. Even where customers are allowed and opt to participate in more than one option (e.g., default hourly pricing combined with a short-notice emergency program), their load response during program events may be enhanced by the dual incentives, yet will almost certainly be less than the sum of their response to each program in isolation.

- manufacturing (SIC 01–39),
- government/education (SIC 81–98),
- commercial/retail (SIC 50–79),
- healthcare (SIC 80), and
- public works (SIC 40–49).

Table 4-1. Demand Response Options Included in Market Potential Simulation

DR Option	Description
Optional hourly pricing	• A dynamic pricing tariff with bundled charges for delivery and commodity • Usually offered by vertically integrated utilities on an optional basis • Typical rate design is a two-part structure, in which a customer baseline load (CBL) is established and billed at an otherwise-applicable tariff rate, with deviations in actual usage billed at hourly prices
Default hourly pricing	• A dynamic pricing tariff in which distribution charges are unbundled from commodity charges • Usually offered by distribution utilities or default service providers in states with retail electric competition • Typical rate design includes demand and/or volumetric distribution charges, with all commodity usage billed at an hourly rate, often indexed to a day-ahead wholesale market
Short-notice emergency program	• A program that offers customers financial incentives for curtailing load when called by a program operator on short notice (i.e., 1-2 hours) in response to system emergencies • Typically, customer response is voluntary (i.e., in some programs, no penalties are levied for not curtailing when called)
Price-response event program	• A program that pays customers for measured load reductions when day-ahead wholesale market prices exceed a floor • Some programs may include bid requirements (i.e., customers are only paid for curtailments that they specify in advance) and/or penalties for failing to respond when committed
Critical-peak pricing	• A dynamic-pricing tariff similar to a time-of-use rate most of the time, with the exception that on declared "critical-peak" days, a pre-specified higher price comes into effect for a specific time period

The remaining three steps in our methodology are described with data and examples in the remainder of this section. First, we introduce the data sources used for each of the five demand response options evaluated. Then, we provide participation estimates for each program and tariff, drawing on the available data. Elasticity values, and adjustments for factors found to influence load response are then derived, again from available data. Finally, these data are combined to estimate demand response market potential using population data from an urban utility in the Northeastern U.S., demonstrating the impacts of various factors on market potential results with the use of scenarios.

4.1 Data Sources

We gathered data from six demand response programs and dynamic pricing tariffs offered by utilities and ISOs/RTOs in recent years (see Table 4-2). They span a range of geographical regions, market structures, and types of demand response option. The data sources all included electricity consumption data (although in some cases confined to declared event periods) and information on customer characteristics (in some cases limited to business classification and peak demand). The specific program and tariff designs are described in Appendix C.

Table 4-2. Data Sources

DR Option	Data Source(s)	Eligible Customers (peak demand)	Available Data Range	Reference
Optional hourly pricing	Central and Southwest (CSW) Utilities' (now American Electric Power) two-part RTP rate	> 1,500 kW	1998–2002 (summers)	Boisvert et al. (2004)
Default hourly pricing	Niagara Mohawk Power Corporation (NMPC), a National Grid Company, SC-3A tariff	> 2000 kW	2000–2004 (summers)	Goldman et al. (2005)
Short-notice emergency program	NYISO Emergency Demand Response Program (EDRP)	> 100 kW	2001, 2002, 2005	Neenan et al. (2003)
	ISO-NE Real-Time Demand Response (RTDR) Program	> 100 kW	2003, 2005	RLW Analytics and Neenan Associates (2003, 2004 and 2005)
Price-response event program	ISO-NE Real-Time Price Response (RTPR) Program	> 100 kW	2003–2005	RLW Analytics and Neenan Associates (2003, 2004 and 2005)
Critical-peak pricing	California Utilities[1] Critical Peak Pricing Program	> 200 kW; > 100 kW for SDG&E	January 2003– September 2004	Quantum Consulting, Inc. and Summit Blue Consulting, LLC (2004 and 2006)

[1] Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) offer a critical-peak pricing tariff to large customers. The tariff design is quite different from that of the California Statewide Pricing Pilot that primarily targeted residential customers (Charles River Associates 2005), and the resulting customer response is correspondingly different.

4.2 Estimating Program Participation from Large Customer Program Experience

In section 3.3 we presented several approaches to estimating customer or load participation in demand response options. In this example, we use a combination of the "translated experience" and "expert judgment" approaches. Where possible, we used actual program participation data from the data sources in Table 4-2. We filled in missing information by surveying program managers of similar types of demand response options, and inferring data from other market segments or programs.[56] Our goal was to estimate participation based on relatively mature programs[57] with 3–4 years of operation.[58]

The resulting participation rates, presented in Table 4-3, were applied directly to the target population in our simulation exercise (see section 4.4). The estimates derived from "expert judgment" are distinguished in Table 4-3 from actual participation rates by italics and red font. In each case, participation is defined as the number of enrolled customers as a percentage of the number of eligible customers.[59] We report the information by customer market segment and peak demand level within a market segment.

The highest participation rates are observed for large customers (>1 MW) in the default hourly pricing tariff. We believe this is largely explained by the default nature of the tariff—participation is defined as *not* selecting an alternative electricity supplier, rather than as the conscious decision to sign up that characterizes the other programs and tariffs.[60]

Another factor that strongly impacts participation rates is the definition and size of the eligible customer population. For the default hourly pricing tariff, only a specific set of large customers, with peak demand above 2 MW were eligible. In contrast, the other programs were open to significantly wider classes of customers. The threshold for the critical-peak pricing program was 100 or 200 kW (depending on the utility). For the ISO programs, eligibility is defined not by customer size class, but by a minimum allowable load reduction (i.e., 100 kW). To develop participation rates, we constructed the pool of

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[56] Complete participation data were available for the default hourly pricing tariff and the critical-peak pricing program. For the two short-notice emergency programs, information on the number of participating customers was available from NYISO and ISO-NE. However, neither agency collects information on the number of customers eligible for their programs. Consequently, we constructed eligible population data from information obtained from multiple sources—evaluation reports for the two programs, data from the Energy Information Administration (EIA 2005), the Commercial Building Energy Consumption Survey database (EIA 2003), and personal communication with ISO and utility staff. The largest information gap was presented by the optional hourly pricing tariff.

[57] As noted in section 3.3, participation rates can fluctuate over time, and it is useful to track participation on an annual basis (i.e., penetration in a given year). However, for an initial market potential study that seeks to estimate the amount of load response that can be expected from a particular program or tariff, it is appropriate to base estimates on participation observed for relatively mature programs.

[58] It is worth noting that Georgia Power's optional hourly pricing tariff experiences extraordinarily high participation rates—in all business categories with peak demand above 1 MW, participation is 50% or more (Kubler 2006). As this program has been in operation for over a decade, and its tariff design provides reasonably certain benefits to participating customers, we believe this represents an upper bound on participation rates in optional RTP tariffs, and we do not adopt these rates for our simulation.

[59] Participation could, alternatively, be defined as the amount of enrolled customer load as a percentage of eligible loads.

[60] The default hourly pricing participation rates do not include those customers that switched to competitive retailers and entered into contracts in which they faced hourly prices indexed to day-ahead or real-time markets for some or all of their load. In Goldman et al. (2005), the authors provide aggregate estimates of the percentage of customers willing to face hourly prices overall, but data limitations (i.e. customer survey non-response) preclude estimates at the market segment level.

eligible customers, assuming that the 100 kW minimum load reduction would be feasible among customers with peak demands of 350 kW and above[61]—thus, a very large number of non-residential customers in New York and the New England states were considered "eligible" for the ISO programs. Consequently, even though the actual number of participants (100–400 customers) is comparable across the programs and tariffs, the denominators range from hundreds to thousands of eligible customers.

Table 4-3. Participation Rates in Demand Response Programs and Dynamic Pricing Tariffs

DR Option	Business Type	Customer Size (peak demand)			
		0.35–0.5 MW	**0.5–1 MW**	**1–2 MW**	**>2 MW**
Optional hourly pricing	Commercial/retail	*0%*	*0%*	*1%*	*2%*
	Government/education	*3%*	*4%*	*6%*	*25%*
	Healthcare	*0%*	*0%*	*1%*	*2%*
	Manufacturing	*3%*	*5%*	*6%*	*25%*
	Public works	*0%*	*0%*	*3%*	*20%*
Default hourly pricing	Commercial/retail	*4.3%*	*11%*	*50%*	43%
	Government/education	*4.2%*	*10%*	30%	42%
	Healthcare	*0.7%*	*1.8%*	50%	7.1%
	Manufacturing	*3.3%*	*8.3%*	29%	33%
	Public works	*3.7%*	*9.2%*	50%	37%
Short-notice emergency program	Commercial/retail	1.2%	23%	5.5%	20%
	Government/education	0.3%	5.3%	2.6%	9%
	Healthcare	0.6%	4.2%	4.3%	22%
	Manufacturing	0.2%	15%	17%	23%
	Public works	1.1%	10%	67%	17%
Price-response event program	Commercial/retail	0.3%	0.8%	1.8%	5.7%
	Government/education	0.3%	2.9%	4.1%	10%
	Healthcare	0.3%	1.6%	8.9%	22%
	Manufacturing	5.7%	10%	9.1%	30%
	Public works	0.1%	0.2%	0.4%	1.1%
Critical-peak pricing	Commercial/retail	0.9%	3.1%	5.2%	4.2%
	Government/education	1.5%	4.1%	2.3%	1.9%
	Healthcare	*0.9%*	*3.1%*	*5.2%*	*4.2%*
	Manufacturing	0.9%	4.5%	7.3%	6.9%
	Public works	1.2%	3.3%	1.3%	2.8%

Note: *Red-italicized* figures are based on expert judgment.

A number of other factors may also influence rates of customer participation in demand response programs and tariffs. Most obviously, program design features—such as the structure and level of incentive payments, penalties for non-performance, and the

[61] Though allowed in the program rules, load aggregators were not that active in these short-notice emergency demand response programs (although they were active in the NYISO ICAP/SCR program). With aggregation, the pool of "eligible" customers would be even less well-defined.

duration, frequency and advance notice of events—may affect customer decisions to enroll. Other program-specific factors may include customer familiarity with and/or the reputation of the entity administering the program, the effectiveness of marketing and/or customer education efforts, and the availability of technical or financial assistance. Given the small size of our sample (six programs) it is difficult to draw conclusions about which program designs encourage or discourage participation. Nonetheless, evaluations of some of these programs did examine drivers for participation, with statistically robust results (see Appendix D for a summary of these findings).

4.3 Developing Elasticity Values and Adjustment Factors from Large Customer Response Data

For each of the demand response programs and tariffs, we calculated elasticity values for each market segment using individual customer load and price data obtained from the data sources outlined in section 4.1. For the two hourly pricing tariffs, we estimated demand models to calculate substitution elasticities.[62] For the other programs, data was only available during declared event hours, providing insufficient observations to estimate a fully specified demand model, so we calculated arc elasticities.[63] For the short-notice event program estimates, we pooled the observations from the New York Independent System Operator (NYISO) and ISO-New England (ISO-NE) emergency programs. Estimates for all other demand response options were derived from a single data source (see section 4.1). For each type of program and tariff, we calculated four sets of elasticity values (described below) to support the scenarios in section 4.4, which simulate market potential under a variety of assumptions.

4.3.1 Average Elasticity Values

For each program, we computed average elasticities for the customers in each market segment (see Table 4-4)[64].

4.3.2 Elasticities Adjusted for Onsite Generation

Ideally, a demand response market potential study should evaluate the impact of a variety of external and customer-specific factors on individual customer price experience. Unfortunately, very little information was available among our data sources on the factors identified as potential drivers in section 3.4.3 (see Table 4-5).

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[62] This was done as part of case studies conducted on the individual tariffs. For more details, see Goldman et al. (2005) and Boisvert et al. (2004).

[63] See section 3.4.1 for a discussion of tradeoffs in selecting elasticity measures. Substitution and arc elasticity values are not directly comparable, although the market potential impacts derived from them are.

[64] For the price response event program, a number of program events occurred when prices were quite low ($100–150/MWh). Including observations from these low-price events resulted in extremely high average elasticities, because there was considerable variation in loads, but relatively small differentials between the event prices and the otherwise applicable (baseline) tariff rate. To remove this "noise" from the elasticity estimates, we restricted our analysis to observations in which the price was $150/MWh or higher.

Table 4-4. Average Elasticity Values

Customer Market Segment	Demand Response Option				
	Optional Hourly Pricing	Default Hourly Pricing	Short-notice Emergency Program	Price Response Event Program	Critical-peak Pricing
Commercial/retail	0.01	0.06	-0.03	-0.09	-0.10
Government/education	0.01	0.10	-0.02	-0.16	-0.06
Healthcare	0.01	0.04	-0.04	-0.05	-0.01
Manufacturing	0.26	0.16	-0.04	-0.16	-0.05
Public works	0.07	0.02	-0.08	-0.22	-0.08

Note: Elasticity of substitution values are shown for optional and default hourly pricing and are typically positive; arc elasticity values are shown for all other demand response options and are typically negative.

Table 4-5. Availability of Data on External and Customer-Specific Factors

Factor	Demand Response Option				
	Optional Hourly Pricing	Default Hourly Pricing	Short-notice Emergency Program	Price Response Event Program	Critical-peak Pricing
EXTERNAL FACTORS					
Event duration, frequency & clustering			•	•	
Weather	•	•	•	•	
CUSTOMER-SPECIFIC FACTORS					
Business activity (market segment)	•	•	•	•	•
Customer size (peak demand)	•	•	•	•	•
Training, awareness & past experience		•	§		
Onsite generation		§	•		•
Enabling technologies		§	§		•
Electricity intensity		§	§		
Business or operational processes		§	§		•

§ Available for subset of customers
• Available for all customers

The most detailed and consistent information was available for the default hourly pricing tariff, which was the subject of an in-depth case study involving customer surveys designed to collect information on various factors (Goldman et al. 2005). However, the study found very few factors, aside from weather and customer business activity, with a statistically significant impact on price response. This may be, at least partly, due to sampling issues—customer-specific factors were only available for the subset of customers that answered the survey.

Both short-notice emergency programs, however, provided consistent and revealing information on the relationship between customer ownership of onsite generation and demand response. Customers in these programs with onsite generators had, on average, arc elasticities about 40% higher than customers that did not. From this information, we developed elasticity adjustment factors for the short-notice emergency program. For customers without onsite generation, the elasticities decline by 14% relative to the average elasticities for each market segment. For those with this technology, the elasticity values are 52% higher than the average (see Table 4-6). Applying these revised elasticity estimates to simulate market potential can result in either higher or lower estimates than are given by the average elasticities in Table 4-4, depending on the distribution of onsite generators among the target population relative to that from which the elasticities were estimated (see section 4.4.3).

Table 4-6. Elasticity Values Adjusted for Onsite Generation

Customer Market Segment	Short-notice Emergency Program	
	without DG	with DG
Commercial/retail	-0.03	-0.05
Government/education	-0.02	-0.03
Healthcare	-0.03	-0.05
Manufacturing	-0.04	-0.07
Public works	-0.07	-0.12

We did not apply this adjustment to the elasticity estimates for other demand response programs because it is only consistent with the usage of onsite generation for emergency demand response programs. For economic programs, customers' decisions to use onsite generation can be very different, often driven by economic rather than reliability criteria. There is anecdotal and empirical evidence that customers with onsite generation can be very responsive to optional hourly pricing tariffs (see, for example, Schwarz et al. 2002), but there is little information on the impact of onsite generation on response to other demand response options.

4.3.3 Elasticities Refined to Reflect Response at High Prices

In our market potential simulations in section 4.4, we estimate market potential assuming an "event" (or high hourly) price of $500/MWh. This places the results on an equal footing for each of the programs. However, the customer load response data used to estimate the elasticities differed for each program and for some the customers faced a wide range of prices. Applying average elasticities derived from a range of price levels to estimate response to a specific price may be misleading if customers respond differently at different price thresholds.[65] To test for this effect, we refined the elasticity estimates, computing them using only data at price thresholds comparable to the $500/MWh price.

For the default hourly pricing option, substitution elasticities were developed using a flexible model that allowed for statistical evaluation of response at different price thresholds (see Goldman et al. 2005). We applied adjustment factors derived from this model to each market segment to develop elasticities tailored to response at high prices.[66]

For the arc-elasticity values calculated from the demand response programs, we simply eliminated observations for which the event price was below $450/MWh, and recomputed average elasticities for each sector and program from this smaller set of observations.

The resulting elasticity values are presented in Table 4-7. For the default hourly pricing tariff, commercial/retail and government/education customers increase their response at high prices. For manufacturing customers, there is no change in elasticity, and for the other sectors a slight decline in response is observed.

Table 4-7. Elasticities Based on Customer Response to High Prices ($500/MWh)

Customer Market Segment	Demand Response Option			
	Default Hourly Pricing	Short-notice Emergency Program	Price Response Event Program	Critical-peak Pricing
Commercial/retail	0.10	-0.03	-0.02	-0.04
Government/education	0.16	-0.02	-0.02	-0.04
Healthcare	0.03	-0.04	-0.01	-0.00
Manufacturing	0.16	-0.04	-0.03	-0.03
Public works	0.01	-0.08	-0.02	-0.05

Note: Elasticity of substitution values are shown for optional and default hourly pricing; arc elasticity values are shown for all other demand response options.

Since very few of the observations for the two short-notice emergency programs involved event prices lower than $450/MWh, the revised elasticity estimates are essentially unchanged.[67]

[65] Statistically significant differences in customer price response at different prices were found by Goldman et al. (2005).
[66] The analysis of the optional hourly pricing tariff did not examine the effect of prices on response in detail, so we were unable to conduct this sensitivity analysis for this tariff.
[67] The program design of the NYISO EDRP program sets a floor price of $500/MWh, so none of these observations were removed. ISO-NE's emergency program offers two floor-price options—$500/MWh and $250/MWh—depending on the amount of notice customers receive of impending events. Thus, only a few observations, corresponding to the lower floor-price option, were removed from the sample.

For the price response event program and critical-peak pricing, the elasticities decrease compared to the averages in Table 4-4 in all market segments. This occurs because these customers' load response was fairly consistent across the range of prices. Although this may seem counterintuitive, we believe that this result is consistent with our underlying conceptual framework of customer response which is based on the notion that many large business and institutional customers are only willing to curtail or forego load which they consider "discretionary," irrespective of price level. This means that arc elasticities computed when prices were high (with comparable load response but lower price differentials) result in lower elasticities than those computed at lower prices. Restricting the dataset to events with higher prices therefore results in lower average elasticities. This effect is relatively minor for the critical-peak pricing example, but is quite pronounced for the price response event program.

4.3.4 Elasticities Refined for Within-Sector Variation in Price Response

We also defined and estimated elasticities that account for differences in customer response *within* market segments.[68] For each market segment and program, we computed "low", "medium" and "high" elasticity values that reflect the observed distribution of customer response among our data sources. Each value represents the load-weighted average elasticity of a subset of customers within a given market segment, for a given program. For low values, all customers with elasticities less than 0.01 (absolute value) were included. The high values reflect the most responsive tenth percentile of customers in a particular market segment. The medium values are computed from the remaining customers.

In this way, we derived the low, medium and high elasticity estimates in Table 4-8. In some cases, there were too few customers to compute all three values (e.g., certain market segments are underrepresented in the optional hourly pricing tariff). In other cases, low values are not reported as there were no customers with elasticities below the 0.01 threshold (e.g., some market segments in the critical-peak pricing and price response event programs).

[68] Goldman et al. (2005) found a wide range in customer response within all large customer market segments.

Table 4-8. Low, Medium and High Elasticity Seed Values

Customer Market Segment	Demand Response Option								
	Optional Hourly Pricing			Default Hourly Pricing			Short-notice Emergency Program		
	low	medium	High	low	medium	high	low	medium	high
Commercial/retail	—	0.01	—	0.00	0.03	0.35	-0.00	-0.03	-0.16
Government/education	—	0.01	—	0.00	0.06	0.96	-0.00	-0.02	-0.17
Healthcare	—	0.01	—	0.00	0.04	0.05	-0.00	-0.03	-0.14
Manufacturing	0.00	0.29	0.99	0.00	0.06	0.56	-0.00	-0.05	-0.24
Public works	0.00	0.18	1.04	0.00	0.02	0.08	-0.00	-0.08	-0.31

Customer Market Segment	Demand Response Option					
	Price Response Event Program			Critical-peak Pricing		
	low	medium	High	low	medium	high
Commercial/retail	-0.00	-0.07	-0.66	-0.01	-0.07	-0.39
Government/education	-0.00	-0.13	-0.73	—	-0.04	-0.22
Healthcare	—	-0.03	-0.35	-0.00	-0.02	-0.03
Manufacturing	—	-0.14	-0.73	-0.01	-0.03	-0.28
Public works	—	-0.21	-0.70	—	-0.06	-0.18

Note: Elasticity of substitution values are shown for optional and default hourly pricing; arc elasticity values are shown for all other demand response options.

4.4 Putting it All Together: Market Potential Simulation Results

The final step in this simulation exercise was to apply the elasticity values to information on the customer population of an urban utility in the Northeastern U.S. (see the adjacent textbox) to develop market potential estimates. For the two hourly pricing options, we used formulas (5) and (6) in section 3.5 to calculate load impacts by market segment and customer size from the substitution elasticity values. For the other options, for which arc elasticity values were available, we used formulas (4) and (5) (also in section 3.5).

To estimate load impacts from substitution and arc elasticities, information or assumptions about expected loads (i.e., CBLs), and event and non-event prices are needed. For expected loads, we used

Overview of our Sample Utility

We selected an urban utility in the Northeastern U.S., for which we had access to large customer characteristics and usage data, to demonstrate market potential simulations.

The selected utility is relatively small; the peak demand of its large, non-residential customers is only ~1,700 MW. These customers represent about 40% of the utility's peak demand, and consist largely of commercial/retail, government/education and healthcare facilities. Manufacturing customers are less prevalent than for utilities that serve suburban or rural communities.

business-class specific load profiles derived from NMPC SC-3A customer data.

We also adopted a common and consistent set of assumptions for underlying retail rates and "event" prices in scenarios in order to evaluate demand response options and cases on an equal footing. We developed peak and off-peak tariff rates by customer size classification for a hypothetical utility (see Table 4-9).[69] We assumed the same "event" price of $500/MWh (or 50¢/kWh) for all customers and programs. This is fairly typical of both the high prices observed in hourly pricing programs in recent years, and incentive floor prices offered by ISO emergency programs. Off-peak rates on event days (necessary to calculate load impacts from substitution elasticity values)[70] were scaled up from the off-peak tariff rates to reflect typically higher off-peak prices that accompany high on-peak prices in wholesale markets. The assumed peak period is from noon to 6:00 p.m.

Table 4-9. Prices Used in Market Potential Simulations

Customer Size (MW)	Tariff Rate (¢/kWh)		Event Day Prices (¢/kWh)	
	Peak[1]	Off-peak	Peak[1]	Off-peak
0.35–0.5	15.0		50.0	16.7
0.5–1	14.0		50.0	15.6
1–2	13.0		50.0	14.5
2–5	14.4	11.2	50.0	13.4
> 5	13.2	10.2	50.0	12.3

[1] The peak period is defined as 12:00 a.m.–6:00 p.m. All other hours are considered off-peak.

We developed five scenarios to demonstrate the effects of various factors on demand response market potentials and to evaluate the robustness of the substitution and arc elasticities to changes in the simulation inputs. The scenarios are as follows:

- *Base case*—uses average elasticity values by market segment and customer size, and participation rates developed in section 4.2, to estimate market potential;
- *Program participation*—demonstrates the impact of customer participation rates on market potential;
- *Onsite generation*—accounts for differences in elasticity for customers with and without onsite generation;
- *Response at High Prices*—uses elasticities that reflect customer response at high prices (above $450/MWh); and

[69] We deliberately scaled the tariff rates to reflect typical differences in distribution rates among size classes, as well as the prevalence of single-block rates for smaller customers in the U.S.

[70] For the arc elasticity examples, only two price inputs are needed to calculate load impacts: an event price (peak-period event price in Table 4-9) and an otherwise applicable rate (peak-period tariff rate in Table 4-9). Estimating impacts from substitution elasticity values requires off-peak as well as peak prices for event and other days. See section 3.5 for more information.

- *Within-Sector Variation in Customer Response*—evaluates the impact of modeling a distribution of price responsiveness among the target customer population.

4.4.1 Base Case

We express demand response market potential estimates both in terms of direct MW savings and as a proportion of the non-coincident peak demand of the target population of large customers.[71] The overall base-case results range from 0% to 3% of the peak demand for the target population of customers larger than 350 kW (see Table 4-10). The load reductions for the largest customers (>1 MW) enrolled in the default hourly pricing and price response event programs represent 5-6% of their aggregate peak demand. The highest market potential (3% of peak demand) corresponds to the default hourly pricing tariff. This is largely due to the relatively high customer acceptance rates for this tariff (see Table 4-3).

Table 4-10. Market Potential Results: Base Case

Customer Size (MW)	Optional Hourly Pricing		Default Hourly Pricing		Short-notice Emergency Program		Price Response Event Program		Critical-peak Pricing	
	MW	% of class peak demand[1]	MW	% of class peak demand[1]	MW	% of class peak demand[1]	MW	% of class peak demand[1]	MW	% of class peak demand[1]
0.35–0.5	1.0	0%	2.8	0%	0.4	0%	1.6	0%	1.3	0%
0.5–1	1.1	0%	3.9	1%	4.3	1%	3.0	1%	1.7	1%
1–2	1.9	1%	14.4	6%	3.8	2%	3.9	2%	1.9	1%
> 2	21.6	4%	34.8	6%	11.5	2%	29.1	5%	2.4	0%
Total	**25.6**	**2%**	**55.9**	**3%**	**19.9**	**1%**	**37.6**	**2%**	**7.3**	**0%**

[1] Peak demand is non-coincident.

Note: Each demand response option was evaluated separately—the results are not additive.

4.4.2 Impact of Participation Rates

Market assessments often examine the impact of differing rates of participation on program potential. In Figure 4-1, we illustrate the impact of aggressively marketing programs to customers so as to achieve two and three times the base-case participation rates (which reflect the experience of the demand response programs used as data sources). Considering that participation rates of double or triple the current experience are indeed aggressive, the results, in the order of 3–6 percent of non-residential peak demand, can be viewed as an approximate upper bound on market potential for each type of demand response option among large C&I customers. For default hourly pricing,

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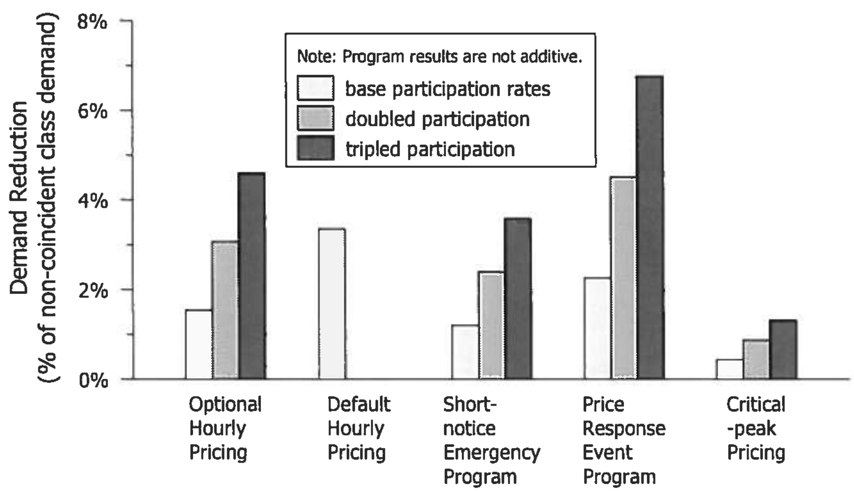
[71] We did not have class-level peak demand for the Northeastern utility, only customer-level peak demand. To approximate class peak demand, we added the individual customer peak demands. Because not all customers' peak demand occurs at the same time, this overestimates the actual class peak (and therefore under-estimates the load impacts).

which by definition would not be marketed to customers, we do not show enhanced participation, although the base case results are included in the figure for comparison.

The results in Figure 4-1 were calculated using the same elasticities and other inputs as the base case—only the participation rates vary. The embodied assumption is that the additional enrolled customers are just as responsive to price signals or emergencies as the relatively "early adopters" observed among our data sources. In reality, it may be that the most responsive customers are also the first to sign up, leading to declining average elasticities as more customers are enrolled. On the other hand, strategies that combine program marketing with technical assistance to develop fully automated demand response could enhance both participation rates and response to prices or emergencies. An automated demand response pilot in California with a sample of ~30 medium and large commercial, institutional, and high-tech buildings demonstrated this potential, achieving consistent average load curtailments of ~10% with high customer satisfaction (Piette et al. 2005; CPUC 2006a). However, there is currently no large-scale program experience to confirm or refute these possibilities.



Note: The level of demand response (elasticity) is assumed to be the same for all scenarios—this assumption has yet to be evaluated with actual program experience.

Figure 4-1. Impact of Program Participation Rates on Demand Response Market Potentials

4.4.3 Accounting for Onsite Generation

We examined the impact of refining and disaggregating the elasticity estimates for the short-notice emergency program to account for differences in response by customers with and without onsite generation technology.[72] On average, customers in this program with onsite generation had arc elasticities about 40% higher than those customers that did not. Interestingly, this resulted in slightly lower market potential estimates than the base case

[72] We limited this case to the short-notice emergency program due to data limitations. For other demand response options, little information is currently available on the impact of onsite generation on customer response.

(i.e., 17.6 versus 19.9 MW) (see Table 4-11). This is due to differences in our assumptions about the distribution of onsite generators among the customer population at the representative urban utility compared to the observed distribution among the customers from whom the elasticity estimates were estimated.[73] For a utility with a higher relative penetration of onsite generation technologies, this refinement would yield higher market potential results than the average elasticities provide.

Table 4-11. Market Potential Results: Onsite Generation

Customer Size (MW)	Short-notice Emergency Program	
	MW	% of class peak dmd[1]
0.35–0.5	0.3	0%
0.5–1	3.7	1%
1–2	3.4	1%
> 2	10.2	2%
Total	**17.6**	**1%**

[1] Peak demand is non-coincident.

Although the overall market potential estimates are comparable in our example, understanding differences in the underlying elasticities among customers with and without enabling technologies can help policymakers target programs to customers that are likely to be the most responsive (e.g. those with on-site generation equipment). Furthermore, research suggests that onsite generation can improve the consistency, as well as the degree, of customer response.[74]

4.4.4 Accounting for Response at High Prices

In this scenario, we refined the elasticity estimates of four of the program types to better reflect customer response at the $500/MWh event price assumed for these simulations. Comparing the results in Table 4-12 with the base case (Table 4-10) reveals that for the default hourly pricing program, accounting for differences in response at higher prices results in higher market potential (i.e., 74 versus 55 MW). This result is driven by the fact that customers in certain market segments (government/education and commercial/retail) were more price-responsive at higher prices and our illustrative utility had a high proportion of these types of customers.

[73] Detailed information on the distribution of onsite generators among the Northeast utility's customers was not available. To perform the simulation, we developed onsite generation penetration rates using data from EIA's Commercial Building Energy Consumption Survey (EIA 2003) and Manufacturing Energy Consumption Survey (EIA 2002).
[74] NYISO EDRP customers with onsite generation provided actual load reductions that were closer to their subscribed load than those without (Neenan et al. 2003).

Table 4-12. Market Potential Results: Response at High Prices

Customer Size (MW)	Default Hourly Pricing		Short-notice Emergency Program		Price Response Event Program		Critical-peak Pricing	
	MW	% of class peak demand[1]	MW	% of class peak demand[1]	MW	% of class peak demand[1]	MW	% of class peak demand[1]
0.35–0.5	4.1	1%	0.4	0%	0.3	0%	0.7	0%
0.5–1	5.7	2%	4.2	1%	0.5	0%	1.0	0%
1–2	19.2	8%	3.7	2%	0.7	0%	1.0	0%
> 2	45.3	8%	11.1	2%	5.1	1%	1.3	0%
Total	**74.2**	**4%**	**19.4**	**1%**	**6.6**	**0%**	**4.1**	**0%**

[1] Peak demand is non-coincident.

Note: Each demand response option was evaluated separately—the results are not additive.

In contrast, for the price response event program and critical-peak pricing, restricting observations to only high-price events resulted in lower average arc elasticities in all market segments (see Table 4-7). The arc elasticity values are lower for these options because participating customers provided roughly the same amount of load reduction at low prices (~$200/MWh) as they did at $>450/MWh (i.e., the percentage change in load remains the same during the high price event hours, while the percentage change in price increases). As a result, the market potential estimates are lower for these two programs than the base case that used average elasticities across all observed prices.[75] Because the short-notice emergency program elasticities were virtually unchanged (see section 4.3.3), the difference in market potential relative to the base case is negligible.

This scenario demonstrates the limitations of arc elasticities in accounting for influences other than price on customer load changes. Because only prices and load at a single event are captured in estimating arc elasticities, there is no way to account or correct for noise in the estimates (i.e. other factors that drive changes in customer usage). At higher prices, we believe that changes in load are more likely a result of prices rather than other factors. When arc elasticities are used, it is therefore important to be cognizant of these limitations and ensure that observations are drawn from conditions similar to those under simulation.

4.4.5 Accounting for Within-Sector Variations in Customer Response

Our final scenario examines the impact of accounting for differences in customer response within market segments. By assigning low, medium and high elasticities to proportions of the customers in each market segment defined by observed elasticity distributions among customers, we developed the results in Table 4-13.

[75] Even in the base case, however, we restricted observations for the price response event program to prices greater than $150/MWh, as estimates at lower prices resulted in inordinately high elasticities due to large changes in load relative to the small price differential.

Overall, this contributes to lower market potential estimates for all programs compared to the base case (see Table 4-10). With very few exceptions, this is true for customer size classes within programs as well. Several studies of large customer price response have found that most of the observed aggregate load response is attributable to a small number of very price-responsive customers, with other customers contributing more modest curtailments or none at all.[76] Accounting for this distribution, rather than assuming average elasticities across the board, more accurately depicts actual load impacts.

Table 4-13. Market Potential Results: Response Distribution Effects

Customer Size (MW)	Optional Hourly Pricing		Default Hourly Pricing		Short-notice Emergency Program		Price Response Event Program		Critical-peak Pricing	
	MW	% of class peak demand[1]	MW	% of class peak demand[1]	MW	% of class peak demand[1]	MW	% of class peak demand[1]	MW	% of class peak demand[1]
0.35–0.5	0.8	0%	3.0	1%	0.5	0%	1.6	0%	1.2	0%
0.5–1	0.9	0%	4.1	1%	5.7	2%	2.9	1%	1.8	1%
1–2	1.8	1%	13.6	6%	3.6	2%	3.5	1%	2.4	1%
> 2	14.3	3%	26.4	5%	14.2	3%	24.2	5%	0.9	0%
Total	**17.8**	**1%**	**47.1**	**3%**	**23.9**	**1%**	**32.3**	**2%**	**6.4**	**0%**

[1] Peak demand is non-coincident.

Note: Each demand response option was evaluated separately—the results are not additive.

4.5 Summary: Discussion

The results of our simulations illustrate possible ranges of demand response market potential for large commercial and industrial customers at an urban Northeast utility, as well as several key methodological and data issues. These stylized results are specifically tied to and reflect the characteristics of this urban utility's large customer base as well as the specific assumptions we made about prices and other factors in this simulation. As such, they should not be taken as definitive estimates of market potential in general and should certainly not be translated directly to other utilities or jurisdictions. Nonetheless, we draw the following insights and conclusions from our scoping study of demand response market potential.

First, we believe that the results provide an indication of a reasonable range of the demand response market potential of non-residential customers if offered similar demand response options by other similar utilities. The aggregate load reductions for our urban, Northeast utility ranged from 7 to 55 MW for each demand response option, representing about <1 to 3% of the peak demand of the target population of large customers. In interpreting the relatively small aggregate load reductions obtained from large customers in specific programs, we note that it may not be necessary for demand response resource

[76] See, for example, Braithwait and Armstrong (2004), Goldman et al. (2005), and Schwarz et al. (2002).

options to achieve their full technical potential or very high participation rates in order to provide optimal value to a power system.

Second, the simulations illustrate the relative impact of certain factors, particularly customer participation rates, on aggregate load reduction that could be achieved among the target population of large customers. It is worth noting that participation rates currently represent the largest data uncertainty for analysts undertaking market potential studies. Clearly, there is a need for systematic collection and reporting of information on the eligible target population (by market segment) as well as a better understanding of the drivers for participation in various demand response programs and customer acceptance of dynamic pricing tariffs.

Third, the scenarios also demonstrate the importance of refining and disaggregating elasticity estimates for different groups of customers rather than simply applying average values. In several cases, this resulted in *lower* market potential estimates in our simulations. Policymakers considering establishing demand response goals need to be cautious; as goals extrapolated from pilot programs or demand response potential study estimates based only on small samples of very responsive customers may not be achievable.

Fourth, the simulation results demonstrate that arc elasticities, though in some cases necessary due to data limitations, are more sensitive to changes in assumptions than substitution elasticities. The additional resources necessary to derive elasticities from theoretically based demand models are well worth the added confidence they afford to market potential studies and market assessments on which important policy decisions may be based.

Finally, we emphasize that all demand response market potential studies should examine a range of scenarios—not limited to those demonstrated here—in estimating the potential of demand response options to deliver load reductions when needed. Each jurisdiction should evaluate factors that may drive local market potential and, to the extent possible, represent them in market potential studies.

5. Advancing the State of the Art: A Market Assessment Research Agenda

In this study, we have described and demonstrated a methodology that is well suited to modeling the market potential of large-customer demand response options that rely on customer-initiated actions in response to dynamic prices or financial incentives. We have also provided program participation rate and elasticity values that can be used as a starting point for demand response market assessments.

However, this information is based on a limited set of programs, and a number of key methodological and data constraints limit their usefulness for demand response market potential studies and assessments. Moreover, no individual state or utility will have the resources or the access to information to fill in all the gaps.

In this section, we present a market assessment research agenda that highlights specific gaps in the current state of knowledge about customer participation in and response to demand response options as well as areas where methodologies are not well developed. Addressing these gaps will involve evaluating the experience of existing programs and tariffs and compiling results in a consistent and publicly available format so that they are available to a broad audience.

With this in mind, we recommend that state and federal policymakers and regulators encourage utilities, other load serving entities, ISOs/RTOs, program evaluators and analysts to conduct the following activities:

1. **Link Program Evaluation to Market Potential Studies:** *Evaluations of demand response programs should systematically collect data on the characteristics of participating customers; hourly customer loads, prices, and response; other factors found to be relevant drivers of customer participation and response; and information on the size and characteristics of the target or eligible population.*

   For this report, we had access to customer-level information for several established demand response programs offered to large non-residential customers. To develop a broader base of information on customer participation rates and demand response, there is a need for continued data collection from existing as well as new demand response programs.

   To support future analyses of program participation, **utilities (and possibly ISOs/RTOs)** should provide information on both customer enrollment and the eligible customer population (numbers of customers and amount of load), so that accurate participation rates can be calculated.[77]

[77] Several of the data sources used in this study did not have information on the eligible customer population, making it difficult to develop realistic program participation rate estimates (see section 4.2).

In terms of customer characteristics, **demand response program administrators and evaluators** should collect, at a minimum, information on customer size (i.e. peak demand for large customers) and market segment.[78]

To support estimation of price elasticities, customer loads and prices are needed, preferably on an hourly basis. In addition, customer characteristics—at a minimum, data on customer market segments and availability of enabling technologies such as onsite generation—are needed, along with other factors found to be relevant drivers of customer participation and demand response.

Regulators and policymakers responsible for authorizing new demand response programs and tariffs should ensure that adequate data collection practices are included in program administration and evaluation.

2. **Program Participation:** *Develop predictive methods for estimating participation rates in demand response programs and dynamic pricing tariffs that incorporate customer characteristics and other factors that drive participation. Where applicable, include interactive effects of multiple program offerings in estimating market penetration rates.*

   Of all the steps involved in estimating demand response market potential, methodologies (and data) for estimating program participation are the least well established. However, program participation is perhaps the most important variable determining the aggregate market potential of demand response programs and tariffs. Existing studies (this one included) have either assumed penetration rates based on "expert judgment" or have directly applied observed participation rates without adjustment for factors that might drive them. There is also a need to better understand customers' participation decisions when faced with multiple demand response options, whether offered on an "either-or" or complementary basis.

   To address this, **program evaluators and analysts** should develop predictive models from observed customer participation rates that account for customer- and market-specific factors that drive response, including interactions between multiple program offerings. The development of better methods, along with the addition of more data sources, will enable more defensible estimates of market potential under a range of circumstances.

3. **Price Response:** *Estimate price elasticity values for different market segments, accounting for the relative impact of driving factors, and report methods and results transparently. Where possible, estimate demand or substitution elasticities, using fully specified demand models, rather than arc elasticities. Where applicable, account for the effects of customer enrollment and participation in multiple demand response offerings.*

[78] Market segment information may consist of SIC codes or other information on business activity for large customers.

As more data on pilot and full-scale demand response programs and tariffs become available, elasticity estimates should be refined to reflect both a larger body of experience and improved understanding of the drivers of price response. Where feasible, **program evaluators** should estimate the price response of customers using fully specified demand models that can account for interactions among factors driving response.[79] Understanding the diversity of customer circumstances and behavior, across markets and over time can be key to realizing the full benefits of demand response. Information from customers that simultaneously participate in multiple demand response options (e.g., customers on default hourly pricing that participate in emergency programs) should be used to improve the understanding of program interactions on customer demand response, allowing market potential studies to model interactive effects.

4. **Assess the impacts of demand response enabling technologies:** *For large customers, there is a need to document the impacts of specific demand response enabling technologies on customer participation and load response, given limited evidence and mixed results from existing evaluations.*

The current understanding of the impacts of enabling technologies on demand response is somewhat rudimentary, partly because past evaluations have collected limited information on the presence of these technologies, and partly because many of them are at an early stage of market penetration and customer awareness of their demand response applications is low.[80]

Demand response program administrators should consider gathering information on the availability and use of *demand-response enabling technologies* among customers, through some combination of utility or third-party surveys, and deployment statistics from technology incentive and/or technical assistance programs. We also recommend that **program evaluators** obtain information on customers' load curtailment strategies that involve onsite generation,[81] peak load controls, energy management control systems, energy information systems, and other demand response enabling technologies disseminated as part of technical assistance programs.

5. **Publicize Results:** *Explore ways to pool customer-level data, while protecting customer confidentiality, so that information to support demand response market assessments is available in a standardized format.*

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[79] Depending on the program design, call-type programs offered to customers on flat rate electricity tariffs may not expose customers to a wide enough range of prices to support estimation of a demand model. In such cases, arc elasticities may be estimated, but analysts should exercise caution in interpreting the results (see section 4.4.4).

[80] For example, Goldman et al. (2005) had to collect information on enabling technologies through customer surveys, and the response rates limited the number of customers for whom enabling technology impacts could be measured. The same study found that many customers that owned technologies with the potential to assist with price response in fact used them for other purposes.

[81] Information on diesel-fired emergency back-up generators should be tracked separately from cogeneration, combined heat and power, and other distributed energy technologies.

Currently, information on customer participation in and response to demand response programs and dynamic pricing tariffs is spread across a variety of program evaluation and case study reports. The results and methods are not standardized, nor are they, in many cases, transparent. This report has attempted to address this problem by compiling individual customer data from a number of demand response program evaluations targeted at large customers.

Going forward, **ISOs, RTOs, utilities** and **state and federal policymakers** should explore ways to pool the results of various demand response program evaluations in a standardized format, so that customer-specific information, appropriately masked, can be aggregated to develop improved program participation and elasticity estimates. The results of such efforts should be made available to assist with market assessment activities.

If implemented, these recommended activities will produce more detailed and robust price response and participation rate values that can be used by utilities and states undertaking demand response market assessment activities in their service territories or regions. However, in order to make best use of this information, utilities, ISOs, and states will need disaggregated information on the characteristics of their target population of customers (e.g., customer loads by size range, market segments, enabling technology deployment) in order to apply these values to their local area. In some cases, this information is not typically collected by utilities on their customers. Therefore, we recommend that **states, utilities and their consultants** conducting demand response market assessments first assess the current availability of information on customer characteristics and usage in their jurisdictions and include plans to collect or estimate any necessary incremental information in their study plans and budgets.

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Appendix A. Review of Methods for Estimating Demand Response Potential

A number of studies and tools have attempted to estimate demand response potential in recent years. In this Appendix, we summarize seven recent examples that have targeted large C&I customers. The methodologies used in these studies and tools can be broadly classified into four categories: customer-survey-based methods, benchmarking methods, engineering approaches, and elasticity approaches. These approaches are defined in section 2.2.

Customer Surveys

Among the reviewed studies, only an evaluation of California's large customer demand response programs adopted a customer-survey-based approach (Quantum and Summit Blue 2004). In this study, Quantum Consulting Inc. (now Itron) and Summit Blue Consulting LLC conducted a quantitative telephone survey of 500 non-participants. The ensuing market potential estimates were not independently confirmed with on-site engineering analyses. Nineteen percent of the respondents indicated some likelihood that they would participate in one of the programs, and another ten percent said they were "highly" likely to participate. The survey results suggest a total market potential of 1,200 to 1,800 MW with an average technical potential of 16 percent of coincident peak demand. Further, most customers said they would be willing to consider taking specific demand response actions on a limited number of hot summer afternoons. The survey responses also suggested significant demand response potential across all eligible size groups, including the smallest customers (100-200 kW range).

Benchmarking

One of the reviewed studies adopted a benchmarking approach. As part of the International Energy Agency Demand Response Resources project, Gunn (2005) conducted a survey of 40 North American utilities' experience with demand response programs that included questions about the types of demand response programs offered, participation in demand response programs, and the amount of load curtailed. Based on this survey, benchmarks for demand response potential were developed. These benchmarks were based on best-in-class demand response programs as identified through the survey of 40 North American utilities. The benchmarks developed for programs targeted to C&I customers are as follows:

- Interruptible/Curtailable:
    - Benchmark: 10% peak-load reduction
    - 17% of utilities report peak reductions greater than 15%—mainly from steel plants
    - 11% report reductions of 10–14%
    - ~50% report reductions of less than 4%
    - On average, the surveyed I/C programs had been in operation for 24 years
    - Larger reductions were reported by vertically integrated utilities than for utilities in areas with organized wholesale markets and ISOs/RTOs

- The highest reported participation rate was ~2% of C&I customers—most attributed low participation to restrictive eligibility criteria

- Demand Bidding:
  - Benchmark: 8-9% of utilities' C&I peak demand
  - Achieved in the past when prices were more volatile and higher
  - 67% of the utilities reported demand reduction impacts of 3% of their C&I peak demand or less
  - 20% of the utilities reported program impacts of 4%-7% of their C&I peak demand

The survey did not yield sufficient data to develop benchmarks for other demand response options such as critical-peak pricing, time-of-use rates, and real-time pricing.

Using these benchmarks, the project developed an online demand response potential calculator that provides a basic estimate of the available market potential in a given marketplace. For large C&I customers, demand response potential is estimated only for interruptible rates and demand bidding programs. The calculator uses demand response product benchmark performance information gathered from the International Energy Agency's Demand-Side Management Program Task XIII as a proxy for demand response market penetration (Gunn 2005). It then translates this proxy to the local (or target) market based on some simple user inputs:

- Number of C&I customers
- By program type:
  - System Peak Demand (MW)
  - C&I Sector % of system peak demand
  - Percent of C&I customers eligible for program
  - Average load reduction per participant customer (MW)
  - Current demand response product (MW)

Two estimation methods are presented. The first simply applies the 10% of C&I peak demand benchmark developed from North American interruptible rate and demand bidding programs. The second allows the user to input the following program parameters:

- the total number of C&I customers in their area
- the percentage of customers eligible for the demand response programs, and
- the average impact per customer.

The calculator estimates demand response potential assuming long-term program participation rates of 10% for demand bidding and 25% for interruptible rate programs.

Engineering Approaches

A number of analysts have adopted engineering approaches to estimate demand response potential. We found four such examples, which are described below. None of these models is currently available in the public domain, and detailed documentation on the precise methods used is similarly unavailable.

The work described below represents the most recent engineering-based approaches adopted to study demand response market potential in the U.S. Studies conducted in Australia (Charles River Associates and Gallaugher & Associates 2001, Energetics 2000 and 2005), Spain (Instituto Ingenieria Energetica 2004), and Europe (EFFLOCOM 2004) provide additional examples of engineering approaches for estimating demand response market potential.

DRPro™ Model

Quantec, LLC's DRPro™ model is a proprietary MS Excel-based model for estimating technical and market (achievable) demand response potentials (Haeri and Gage 2006). It is based on a hybrid top-down/bottom-up approach. For each demand response program type, the model begins by disaggregating loads into appropriate customer classes, market segments and end uses. Technical potential is then estimated at a gross level, assuming that all customer load sectors are potentially available for curtailment, except for those that clearly do not lend themselves to interruption. Market potential is then determined as the fraction of the technical potential that may be expected to be available for curtailment subject to customers' response to the program (program participation rates) and curtailment events (event participation rates).[82] Program and event participation rates are assumed to be dependent on program type, customer characteristics, incentive levels (for load response), and price elasticities (for price response).

Data requirements of DRPro™ include demand response program information (options and strategies, applicable customer classes, eligibility requirements), utility data (hourly system load profile, customer class load shapes, sales by customer class, end-use load profiles, customer count by class and load size, costing periods), and market data (market or avoided utility capacity and energy costs, expected program and event participation rates). The methodology consists of the following steps:

1. **Define customer sectors, market segments, and applicable end uses**. The first step involves defining appropriate sectors, market segments, and end uses within each segment.
2. **Screen customer segments and end uses for eligibility**. This step involves screening of market segments and end uses for applicability of specific demand response strategies. For example, the hospital segment and certain commercial end uses, such as cooking loads in the restaurant segment, may be excluded.
3. **Compile utility-specific sector/end-use loads**. Load profiles are developed for each end use within various market segments of each utility. Contributions to system peak for each end use are then estimated based on end-use shares derived from end-use load shapes.

[82] Event participation rates vary by program type and may approach 100% for DLC.

4. **Estimate technical potential**. Technical potential for each demand response program is assumed to be a function of customer eligibility in each class, affected end uses in that class, and the expected impact of the strategy on the targeted end uses. Analytically, technical potential (*TP*) for a demand-response program *s* is calculated as the sum of impacts at the end-use level (*e*), generated in customer class (*c*), by the program, according to the formulae:

$$TP_s = \sum TP_{sce}$$

and

$$TP_{sce} = LE_{cs} \times EUS_{cs} \times LI_{se}$$

where LE_{cs} (load eligibility) represents the percent of customer class loads that are eligible for strategy *s*, EUS_{cse} represents the share of end use *e* in customer class *c* eligible for demand-response strategy *s*, and LI_{se} (load impact) is the percent reduction in end-use load *e* resulting from program *s*. Load eligibility thresholds are calculated in terms of the percent of the load by customer class and market segment that meets minimum (or maximum) load criterion for each program based on program filings.

5. **Estimate Achievable Potential.** Achievable potentials for each program s are derived primarily by adjusting technical potentials by two factors: expected rates of program and event participation. Achievable potential (AP) is thus calculated as the product of technical potential (TP), program participation rates (PP), and expected event participation (EP) rates:

$$AP_s = \sum TP_{sce} \times PP_s \times EP_s$$

The resulting estimates of achievable potentials are then adjusted for load reductions achieved already by various programs, and applicable resource interactions to avoid double counting.

Estimates of program and event participation rates are generally derived based on benchmarking, past experience or expert opinion through a "Delphi" method. For price response programs, event participation rates are determined using price elasticities for various programs.

DRPro™ also offers the capability to simulate program and event participation rates under alternative scenarios using a Monte Carlo simulation technique. The model has been used in assessing demand response potentials for Puget Sound Energy, PacifiCorp, Portland General Electric, Aquila Networks, and Duke Energy.

Bass Diffusion Curve Model

XENERGY (now KEMA) used an "expert elicitation" approach to develop model parameters for its Bass Diffusion Curve Model (Gunn 2005). The modeling team used the professional judgment of a panel of experts to reach a consensus on key inputs to the supply curve model based on their experience in designing, managing, and evaluating demand response programs. This model was used to estimate the demand response potential for a time-of-use type program in Southern California Edison (SCE)'s service territory.

Demand response potential was estimated using a series of demand response supply curves that varied by program type and market segment. A Bass Diffusion Curve, populated with electricity usage data by market segment and time period, was used to forecast the amount of load that would voluntarily sign up for a time-of-use rate over time.[83] This produces forecasts of market penetration for a given point in time based on three parameters (number of people who will eventually participate, likelihood of a non-participant deciding to participate due to the influence of a participant, and likelihood of a non-participant deciding to participate due to the influence of factors other than participants) and on the total market penetration prior to the time period being forecasted. The Bass diffusion curve assumes that only a subset of the eligible customers initially participate and curtail load (referred to as "early adopters") and that "word of mouth" recommendations from these early adopters have an influence on subsequent participation rates.

XENERGY applied the Bass curve to electric accounts in seven market segments (five residential and two non-residential representative accounts were used). Information on the number of accounts in each segment and on the average electric demand during the "peak" summer period was provided by Southern California Edison, the local utility. Three parameters of the Bass curves for each segment were estimated by the expert panel.

The output of the Bass model is an estimate of the number of accounts and the amount of load that would choose to be on a time-of-use rate each year. To forecast the load impacts of the time-of-use rate, the expert panel assumed the ratio of the peak to off-peak price would likely be about 3 to 1. That ratio resulted in the shifting of about 10%-15% of peak-period electricity usage to the off-peak period. The panel responses suggested that residential customers would be able to shift a higher percentage of their peak load than non-residential customers.

Neenan Associates HECO study

For a Western IOU, Neenan Associates (a Utilipoint company) developed estimates of the economic potential for demand and price response in light of the utility's need for resources to manage peak loads for a 3-5 year period. Demand response potential estimates were calculated for each market segment based on three customer characteristics: size (average maximum demand)[84], business type (SIC code), and rate class. This was accomplished by calculating a "peak performance index" (PPI), defined as the ratio of curtailed load to a customer's peak demand, for each market segment of customers in the ISO-NE and NYISO programs. The PPI estimates were then applied to

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[83] The Bass Curve is commonly used to forecast the market acceptance of new concepts or existing concepts with very low market awareness.

[84] Information on the HECO customers' average maximum demands was not available. To address this, sales (kWh) data were used along with load factors (derived from calculations and expert judgment) to estimate the maximum demand (kW) of each customer.

similar market segments in the Western utility's service territory to calculate the demand response potential for each market segment. Sensitivity analyses were performed to estimate the impact of varying penetration rates on market potential. An expansion of residential device control program was recommended, along with its extension to small businesses. Time-of-use and real-time-pricing (RTP)-type rates were recommended for larger customers to build sustainable economic price response behaviors.

EPRI Study

The Electric Power Research Institute (EPRI), on behalf of the California Energy Commission (CEC), conducted an analysis to better understand customer participation in demand response tariffs and programs, and to identify and develop any "unique, non-duplicative" software tools that could facilitate the study of demand response potential (EPRI Solutions 2005).

Parts of the study involved identifying groups of customers with common characteristics (e.g. size, enabling technology, etc.) that make them good candidates for participating in demand response programs. One of the activities under this task was to estimate the amount of load reduction achievable from the customer groups. Data from in-depth interviews with energy managers of selected industrial and agricultural groups was used for this purpose. This was done by first estimating the coincident peak demand for each group, and then estimating an "upper limit" on load reduction potential from customer survey responses.[85] This estimate was then successively scaled down. First, an adjustment was made to account for the percentage of peak demand deemed to be "realistically curtailable". This was accomplished with scaling factors estimated from survey responses and experience from other demand response programs. Next, the estimates were reduced to reflect the percentage of committed load actually shed. This factor was assigned a value of 80%. Finally, the estimates were further reduced to account for expected program participation rates. The survey also collected information about customer awareness of demand response programs, decision-making process on whether to participate in demand response programs, and type and characteristics of tools that can assist energy managers in their decision-making process.

Elasticity Approach

We found only one example of a study that adopted an elasticity approach to estimating demand response market potential. Christensen Associates estimated the potential demand response effects of RTP in California using elasticities estimated from the experience of Georgia Power Company's RTP program, on which 1,600 of its large C&I customers take service (Braithwait and Armstrong, 2004).

Christensen Associates calculated elasticity estimates from the usage data of Georgia Power's RTP customers of various business types and applied them to data on similar groups of customers in California. The results were appropriately scaled to reflect the

[85] Customers were asked to apportion their load among various end uses, and then to rate each end use with respect to its curtailability. Load corresponding to the end uses that were definitely not curtailable was subtracted from the customer's peak demand.

relative size of those business types in California. It was estimated that 5,000 MW of C&I customer load could be eligible for RTP. Assuming full participation in a two-part RTP structure, aggregate load reductions of 800 MW were estimated for high hourly prices in the range of $0.50/kWh. Customer participation was addressed in sensitivity analyses (for example, at 50% market acceptance, load response would be about 400 MW).

Appendix B. Methods for Establishing Customer Baseline Loads

This Appendix discusses methods and issues that arise in establishing a customer's baseline electricity usage. A customer baseline load (CBL) refers to the amount of electricity a customer would have consumed in the absence of a demand response event.[86] In estimating demand response market potential, CBLs are used in two contexts: (1) to estimate arc elasticities (see section 3.4.1)[87] and (2) to estimate load reductions from elasticity values (see section 3.5). CBLs are also a design feature of many demand response programs—they provide an estimate of customers' otherwise-applicable level of electricity usage against which load reductions can be measured. This provides a means to determine the level of incentives (or penalties) due to individual customers in incentive-based programs. Two-part RTP tariffs also use a CBL to determine a level of usage that is priced at a flat (or time-of-use) rate, with deviations from the CBL exposed to hourly-varying prices.

CBL definitions used by demand response programs typically rely on customers' actual load shapes on days leading up to a demand-response event day. The underlying premise is that the days just before the demand response events are most likely to characterize the level and profile of energy that customers would otherwise have used on the event day, capturing seasonal and economic forces, other than prices that drive demand. To account for weather impacts (e.g., loads may naturally be higher on event days due to high temperatures), some programs allow the customer to add an adjustment factor that accounts for the event day's temperature compared to previous days. Relying on historical data allows customers and program administrators to agree on an amount of load reduction occurring during a demand response event that can be used for settlement purposes. This can be critical for demand response programs that require customers to reduce load by a specified amount, as opposed to a specified level, and impose penalties for non-compliance. The CBL calculation procedures used in demand response programs for which we estimated elasticity values are summarized below.

<u>NYISO Emergency Demand Response Program (EDRP) and California Critical Peak Pricing tariff</u>

In the NYISO EDRP program, a customer's CBL is calculated based on the average daily event period usage (during similar hours as the event) for each of the most recent ten weekdays, starting two days prior to the event and excluding holidays and other EDRP event days. Low usage days, where average daily event period usage was less than 25% of the average event period usage, are also excluded. From these ten days, the five with the highest electricity usage are selected. For each hour of the event, the average usage in that hour over the five selected days is the CBL.

The CBL method used for the California Critical Peak Pricing program is almost identical to the NYISO method. The only difference is that the three highest-usage days are used in the CBL calculation, rather than five.

[86] Note that methods used to establish a CBL are premised constructions, because the level of load that would have been consumed by the customer in the absence of a demand response event is unknowable.
[87] A CBL is not necessary to estimate substitution elasticities (see section 3.4.1).

ISO-New England CBL Method

The ISO-New England CBL method uses rolling averages. Each day, a customer's CBL is updated, with the new CBL calculated by averaging the previous day's metered load (10% weight) and the previous day's CBL (90% weight). The previous day's CBL too is an average of the load and CBL from the day prior, and so on and so forth. Thus, the CBL is derived from the customer's historical load on each non-event weekday day since joining the program.

Appendix C. Programs and Tariffs Used as Data Sources

This Appendix provides a short description of each of the demand response programs and dynamic pricing tariffs included as data sources in this report, as well as references to other studies that provide more information on them.

Central and South West Two-Part RTP Tariff

We developed elasticity values for optional day-ahead hourly pricing from an evaluation of Central and South West (CSW) Utilities' (now American Electric Power) two-part RTP tariff (Boisvert et al. 2004). The CSW RTP tariff prices variations from a pre-established CBL at hourly-varying prices. The CBL is established individually for each customer, and is an hour-by-hour representation of expected consumption on the otherwise-applicable standard tariff. As CBL usage is charged at the otherwise-applicable tariff rate, it represents a hedge to the customer. Hourly prices are communicated to customers on a day-ahead basis, and any deviations in usage from the CBL are either credited or debited from the CBL usage at the hourly rate.

CSW also offered an optional program in which a customer could nominate some of the CBL for additional short-term hourly price exposure in return for a corresponding reduction in the tariff demand charge. For these participants, day-ahead prices were provisional. CSW could, within specified limits, adjust their hourly prices upward by $0.38/kWh with only a single hour's notice, and simultaneously reduce their CBL by the amount of nominated load. Since these customers faced greater price volatility, they were expected to be more price-responsive.

Niagara Mohawk Power Company SC-3A Tariff

We developed elasticity values and market penetration rates for default-service day-ahead hourly pricing, drawing upon a case study of Niagara Mohawk Power Corporation (NMPC), now a National Grid Company. NMPC has offered hourly unbundled pricing as the default tariff for its largest customers, with peak demand greater than 2 MW, since 1998. In contrast to the CSW tariff, there is no CBL. Instead, distribution charges are unbundled from commodity to facilitate retail competition for commodity supply. All commodity usage is billed at a rate indexed to the New York Independent System Operator (NYISO)'s day-ahead wholesale market. Delivery charges are collected through a demand charges. Some customers also elected to face hourly prices in supply contracts arranged with competitive retail suppliers. See Goldman et al. (2005) for more details on the tariff design, context, and customer response to hourly pricing.

New York Independent System Operator Emergency Demand Response Program

We developed elasticity values and market penetration estimates for a short-notice, emergency demand response program, drawing from evaluations of the New York Independent System Operator (NYISO) Emergency Demand Response Program (EDRP). The EDRP provides customers an opportunity to earn the greater of $500/MWh or the prevailing location-based marginal price (LBMP) for curtailments when NYISO calls them during system-wide or locational operating reserve shortages. This program is voluntary; there are no consequences for enrolled participants that fail to curtail within the two hours of the request. For more information on the program and customer response, see Neenan et al. (2003).

ISO-New England Real-time Demand Response Program

Our market penetration estimates for a short-notice, emergency demand response program also draw upon results from the ISO-NE Real Time Demand Response Program. ISO-NE offers financial incentives to customers for curtailments when operating reserves are forecasted to run short. However, ISO-NE's Real-Time Demand Response (RTDR) program offers customers two advance-notice options: 30 minutes or two hours. Participants electing the 30-minute notice period, who reduce their consumption during the event, are paid the greater of the Real-Time Locational Marginal Price (LMP) applicable to their load zone or $500/MWh. For those electing the longer notice period, a lower floor payment is set: $350/MWh. Participants in this program are also eligible to earn installed capacity (ICAP) credits. The quantity (in MW) of a participant's ICAP credit is based on their enrolled (committed) reduction or actual performance in a reliability event. Failure to reduce load during an event results in the forfeiture of ICAP credit earned for the month the event occurred. In addition, the participant's ICAP credit in the months following the reliability event is de-rated accordingly. For more information on this demand response program and customer response to it, see RLW Analytics and Neenan Associates (2003, 2004 and 2005).

ISO-New England Real-time Price Response Program

We developed elasticity values and market penetration estimates for an ISO price response event program, drawing upon evaluations of the ISO-NE Real-Time Price Response (RTPR) program. The RTPR provides financial incentives to participating retail customers for voluntary load reductions when the Real-Time LMP is expected to be greater than or equal to $100/MWh during the hours of 7:00 a.m. to 6:00 p.m. on non-holiday weekdays.[88] Once the price event is declared, ISO-NE is authorized to make payments for any load that is curtailed during the entire 11-hour period. Participating customers are paid the greater of $100/MWh or the Real-Time LMP in their Load Zone for voluntary load reductions during price events. For more information, see RLW Analytics and Neenan Associates (2003, 2004, and 2005).

California Utilities' Critical Peak Pricing Program

We developed elasticity values and market penetration estimates for a critical-peak pricing tariff targeted at commercial and industrial customers, drawing upon evaluation results of a critical-peak pricing tariff implemented by California's three investor-owned utilities (see Quantum Consulting and Summit Blue Consulting 2006 for more details). The tariff is offered to C&I customers with peak demands of 200 kW and above for Pacific Gas & Electric and Southern California Edison and 100 kW and above for San Diego Gas & Electric. Critical-peak events can be declared for a number of reasons (e.g.

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[88] ISO-NE opens the eligibility period in a Load Zone when actual Day-Ahead Locational Marginal Prices (LMP) or Real-Time LMP as forecasted by a Resource Adequacy Analysis for that Load Zone equals or exceeds $100/MWh during the eligible hours (7:00 a.m. to 6:00 p.m.).

temperature, system constraints, utility discretion, etc.). The events are pre-specified to apply for the hours of 12 noon to 6:00 p.m. Usage in the first three hours is priced at roughly three times the otherwise applicable tariff (OAT) rate, and the subsequent three hours are priced between five and ten times the OAT. Customers receive day-ahead notice of impending events. For more details see Quantum Consulting and Summit Blue Consulting (2004 and 2006).

Appendix D. Factors Found to Influence Demand Response Program Participation

In this Appendix, we summarize the findings of research into drivers for customer participation in the demand response programs used as data sources in this study.

Customer-specific Factors that Influence Participation Rates

Three evaluation studies examined customer-specific factors that may influence participation rates in the following demand response options: Niagara Mohawk Power Company (NMPC)'s default hourly-pricing tariff, the California utilities' critical-peak pricing tariffs, and the New York Independent System Operator (NYISO) Emergency Demand Response Program (EDRP). In these evaluations, information about customer-specific characteristics was collected through in-depth customer surveys and interviews of a sample of eligible customers. The findings discussed here are statistically robust.

Based on a logistic model developed for customer participation in NMPC's default hourly pricing tariff, Goldman et al. (2004) found that:

- customers located in the Capital region (where prices were higher than in other regions) were four times more likely to stay on default-service hourly pricing than customers in other regions;
- industrial customers were four times, and government/education customers were three times, more likely to remain on the default rate than commercial/retail and healthcare customers; and
- customers with summer-peaking electricity usage were 4.5 times more likely to opt out of the default hourly-pricing tariff than winter-peaking customers.

Quantum Consulting Inc. and Summit Blue Consulting LLC's (2004 and 2005) evaluations of California's critical-peak pricing program also used logistic models to identify important customer-specific characteristics that drive participation rates. Compared to non-participants, participants in the California demand response programs were found to:

- be more likely to have participated in other demand response programs;
- closely monitor electricity markets and prices;
- report that their energy costs comprise over 10% of their total annual operating costs; and
- hold an optimistic view of the adequacy of California's power supply.

Non-participants reported an inability to reduce peak demand more often than participants. They were also less likely than participants to engage in batch processing.

Two evaluations of NYISO's demand response programs have yielded insights into customer decisions to participate in demand response programs (Neenan et al. 2002 and 2003). Based on logistic analyses, these studies reported that:

- customers that have prior experience with load management programs were more likely to participate in demand response programs;

- educating customers on how to reduce load was likely to increase participation by a factor of two;
- customers with access to real-time load information were twelve times more likely to participate than customers without this information; and
- the provision of technical and financial assistance (e.g., through NYSERDA programs) also increased the odds of customer participation in EDRP.

The NYISO evaluations also found that several customer characteristics were important predictors of customer participation:

- the odds of manufacturing customers participating in an emergency program were about six times higher than for other customers;
- customers whose peak electricity usage occurs during the afternoon were 3.6 times as likely to participate in NYISO's EDRP than other customers;
- customers with multiple production shifts (i.e., more flexible operating practices) were twice as likely to participate than customers with just one shift; and
- the odds of customers with on-site generation participating in an emergency program were over three times higher than other customers.

Year-to-Year Participation Trends

As discussed in section 3.3, participation in demand response programs can change each year as some customers drop out and others enroll. Most demand response programs require a one-year commitment, and customers must re-enroll on an annual basis. Table D-1 illustrates how participation can change over time. Enrollment statistics are shown for two representative years, along with "churn rates"—the percentage of customers dropping out, signing up, and switching to or from alternative programs—for ISO-NE and NYISO demand response programs.

Table D-1. Churn Rates for ISO-NE and NYISO Demand Response Programs

Program	Reference-year[1] enrollment[2]	Changes in Enrollment (churn rates)				New enrollment[2]
		dropouts	new enrollees	switched to other programs	switched from other programs	
ISO-NE Emergency DR Programs	91	31%	56%	9%	9%	114
ISO-NE Price Response Program	332	14%	24%	0.6%	0.6%	367
NYISO EDRP and ICAP-SCR	1761	33%	20%	N/A	2%	1536

[1] Reference year is 2003 for the ISO-NE programs, and 2002 for the NYISO programs.
[2] Enrollment is in terms of number of customer accounts.

For both of the ISO-NE programs, total enrollment increased from 2003 to 2004, and for the NYISO programs, overall participation declined between 2002 and 2003. However, the overall statistics hide underlying churn rates. ISO-NE's emergency program experienced much higher volumes of customers leaving and entering the program than the price response program. For the NYISO emergency programs, although a significant number of new customers enrolled in the program, an even higher dropout rate was responsible for the overall decline in enrollment.

Unfortunately, insufficient data were available to assess churn rates over a longer period. Moreover, a number of changes to the program designs may have impacted the observed rates. Therefore, it is difficult to draw any conclusions from these results.

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A Methodology for Estimating Large-Customer Demand Response Market Potential

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A Methodology for Estimating Large-Customer Demand Response Market Potential

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ABSTRACT

Demand response (DR) is increasingly recognized as an essential ingredient to well-functioning electricity markets. DR market potential studies can answer questions about the amount of DR available in a given area and from which market segments. Several recent DR market potential studies have been conducted, most adapting techniques used to estimate energy-efficiency (EE) potential. In this scoping study, we: reviewed and categorized seven recent DR market potential studies; recommended a methodology for estimating DR market potential for large, non-residential utility customers that uses price elasticities to account for behavior and prices; compiled participation rates and elasticity values from six DR options offered to large customers in recent years, and demonstrated our recommended methodology with large customer market potential scenarios at an illustrative Northeastern utility. We observe that EE and DR have several important differences that argue for an elasticity approach for large-customer DR options that rely on customer-initiated response to prices, rather than the engineering approaches typical of EE potential studies. Base-case estimates suggest that offering DR options to large, non-residential customers results in 1-3% reductions in their class peak demand in response to prices or incentive payments of $500/MWh. Participation rates (i.e., enrollment in voluntary DR programs or acceptance of default hourly pricing) have the greatest influence on DR impacts of all factors studied, yet are the least well understood. Elasticity refinements to reflect the impact of enabling technologies and response at high prices provide more accurate market potential estimates, particularly when arc elasticities (rather than substitution elasticities) are estimated.

Introduction

Demand response (DR) is increasingly recognized as an essential ingredient to well functioning electricity markets. This growing consensus was formalized in the Energy Policy Act of 2005 (EPACT), which established DR as an official policy of the U.S. government, and directed states (and their electric utilities) to consider implementing DR, with a particular focus on "price-based" mechanisms. The resulting deliberations, along with a variety of state and regional DR initiatives, are raising important policy questions: for example, *How much DR is enough? How much is available? From what sources? At what cost?*

In this paper, we examine analytical techniques and data sources to support DR market assessments that can, in turn, answer the second and third of these questions. We focus on DR for large (> 350 kW), commercial and industrial (C&I) customers, although many of the concepts could equally be applied to similar programs and tariffs for small commercial and residential customers.[1] We define DR market potential as *the amount of DR—measured as short-term load reductions in response to high prices or incentive payment offerings—that policymakers can expect to achieve by offering a particular set of*

[1] Our proposed approach may not be appropriate for direct load control programs, which involves cycling or shedding of equipment (e.g. air conditioners, water heaters) of residential and small commercial customers.

DR options to groups of similar customers (e.g. market segments) under expected market or operating conditions.[2]

In this scoping study, we review analytical methods and data that can support market assessments (e.g., for dynamic pricing tariffs) or market potential studies (e.g., for programmatic DR) for DR options offered to large commercial, industrial and institutional utility customers. We comment on differences between energy efficiency (EE) and DR that make translation of methods for EE potential studies problematic, present a conceptual framework for estimating market potential for large customer DR, compile participation rates and elasticity values from six large customer dynamic pricing and DR programs and apply them to estimate DR market potential in an illustrative utility service territory. Finally, we present a research agenda that identifies additional information and improved methods that would support more reliable DR market assessments.

Approaches Used to Study DR Market Potential

A number of utilities and regional groups have performed DR market potential studies in recent years, primarily to develop the demand-side section of utility resource plans, or to assist with planning or screening of potential DR programs.[3] A few states and regions have begun to set DR goals; market assessment studies could serve as a foundation to ensure that such goals are achievable, and help identify market segments and strategies to meet them. Studies of DR market potential necessarily involve estimating two separate elements: *participation*, the number of customers enrolling in programs or taking service on a dynamic pricing tariff; and *response*, quantities of load reductions at times of high prices or when curtailment incentives are offered. Among seven reviewed DR market potential studies, four distinct approaches were used:[4]

- *Customer surveys*—Participation rates and expected load curtailments are obtained from surveys of utility customers about their expected actions if offered hypothetical DR options and used to estimate market potential. This approach uses information obtained locally, but the responses are subjective—customers may not know what they would actually do (particularly if they have no prior DR experience), or may respond strategically. We found only one example of this approach.
- *Benchmarking*—Participation rates and load reductions observed among customers in other jurisdictions are applied to the population of interest. An advantage of this approach is that it relies on actual customer experience and actions. However, it assumes that any differences in the customers and market context have an insignificant impact on participation and load response. Only one of the reviewed studies adopted this approach.
- *Engineering approach*—Four of the seven reviewed studies used bottom-up engineering techniques, similar to those used to estimate EE market potential. They are variations on the approach of applying assumed participation and response rates to data on local customers, loads or equipment stock. These rates are typically assumed to be constant, regardless of price or incentive levels.
- *Elasticity approach*—This approach, adopted by one of the reviewed studies, involves estimating price elasticities from the usage data of customers exposed to DR programs and/or dynamic

[2] DR market potential can be expressed as a percentage reduction in market demand that can be expected at, for example, a price (or offered curtailment incentive) of $500/MWh.

[3] See Haeri and Gage (2006), Quantum Consulting and Summit Blue Consulting (2004), SCE (2003), and EPRI Solutions (2005).

[4] See Appendix A of Goldman et al. (2007) for a summary of the reviewed studies and their methods.

pricing tariffs. After determining an expected participation level, price elasticities are applied to the population of interest to estimate load impacts under an expected range of prices or level of financial incentives to curtail load. Like the benchmarking approach, elasticities are based on actual customer response. They also quantify the relationship between customer behavior (i.e., load reductions) and price. When demand models are used to estimate elasticities, variables can be introduced to account for customer- or market-specific factors that influence price response, enabling the translation of results to other jurisdictions that may vary in these factors.

What Makes DR Different from EE?

While EE and DR both involve modifying large customers' use of and demand for electricity, they differ in several important ways that may affect market potential: *The nature of participation*—For DR options, participation involves two steps: enrolling in a program or tariff, usually on an annual (or other periodic) basis; and providing load reductions during specific events (e.g., system emergencies or periods of high prices). For EE, "participation" consists of a one-time decision to invest in EE measures or equipment.

- *The drivers of benefits*—DR benefits often hinge on customer behavior (i.e., ability and willingness to curtail) in response to hourly prices, financial incentives, and/or system emergencies. EE-related savings are largely a function of the technical characteristics and performance of the installed equipment or measures.
- *The time horizon and valuation of benefits*—From a customer perspective, DR benefits—which depend on rare events that occur in near-real time (system emergencies or energy price fluctuations)—may be highly variable and are often short-term. In contrast, investments in EE measures typically produce a fairly certain stream of savings over a multi-year period (i.e. the economic lifetime of the measure) which the customer can value at expected retail energy rates.

Given these differences, we make the following observations and recommendations on methods for estimating DR market potential:

- For residential and small commercial direct load control programs, customer load impact estimates can be derived from bottom-up engineering approaches or statistical evaluations of samples of participating customers with appropriate metering.
- For large customer DR options that rely on customer-initiated response to prices (e.g., hourly or critical-peak pricing) or curtailment incentives (e.g., short notice emergency or price response event programs), we recommend an elasticity approach.[5]
- Participation should be thought of in terms of market *penetration* in a given year. Unfortunately, participation is the most difficult aspect of DR options to estimate, due to a limited experience base. With time and experience, this should improve.
- Because of the limited experience base for many DR options, approaches that rely on customer survey response to hypothetical DR options, or benchmarking, are probably not all that meaningful. The "best practices" approach, which has been used in some EE market potential studies, makes most sense when there is a larger experience base (i.e., mature programs offered by many utilities or ISOs over a lengthy period).

[5] We note, however, that DR programs involving reserve or capacity payments and/or penalties for non-response (e.g., interruptible rates, capacity programs) present difficulties in estimating elasticities, because customer incentives are less clearly tied to individual events.

A Framework for Estimating Large Customer DR Market Potential

We propose a framework for estimating large customer DR market potential in a given jurisdiction or utility service territory that involves five steps:

- *Establishing the study scope*—identifying the target population and types of DR options to be considered;
- *Customer segmentation*—identifying "customer market segments" among the target population;
- *Estimating net program penetration rates*—using available data to estimate customer enrollment in voluntary programs and customer exposure to default pricing programs;
- *Estimating price response*—selecting an appropriate measure of price response (price elasticity of demand, substitution elasticity or arc elasticity) given available data, and developing elasticity estimates for various DR options, customer market segments, and factors found to influence price response from the observed load response of customers exposed to DR options; and
- *Estimating load impacts*—combining the above steps to estimate the expected DR that can be expected from the target population at a reference price.

We applied this methodology, using available data on large customer participation and response, to estimate the market potential for several DR options at an illustrative urban utility in the Northeastern U.S.

Establishing the Study Scope

We limited our analysis to large, non-residential customers with peak demand greater than 350 kW and examined the five different types of DR options described in **Table 1**.

We analyzed these options *independently* and did not account for possible interactions between different options should they be offered simultaneously to a given set of customers. Thus, our results likely *overestimate* the combined market potential for these DR programs and dynamic pricing tariffs should two or more of them be offered to the same customers at once.

Our data sources for participation rates and price elasticities for each of these DR options are provided in **Table 2**.

Customer Segmentation

Analysts conducting DR market potential studies should use available information about the target population to identify customer market segments that are expected to respond in similar ways, or that could be approached with specific marketing strategies or program designs.

For this study, we adopted five market segments based on SIC codes—manufacturing, government/education, commercial/retail, healthcare, and public works—that Goldman et al. (2005) found to be well correlated with differences in large, non-residential customers' willingness to participate in and respond to DR options.

Table 1. DR Options Included in Market Potential Simulation

DR Option	Description

DR Option	Description
Optional hourly pricing	• A dynamic pricing tariff with bundled charges for delivery and commodity offered on an optional basis • Typical rate design is a two-part structure, in which a customer baseline load (CBL) is established and billed at an otherwise-applicable tariff rate (either TOU or flat rate), with deviations in actual usage above and below the CBL billed at hourly prices
Default hourly pricing	• A dynamic pricing tariff, in which commodity costs are unbundled from other rate components (e.g. distribution and transmission charges), offered as default service in states with retail competition • Commodity usage is billed at an hourly rate, typically indexed to an organized wholesale energy market (e.g. day-ahead or real-time energy market)
Short-notice emergency program	• A program that offers customers financial incentives for curtailing load when called by a program operator on short notice (i.e., 1-2 hours) in response to system emergencies • Typically, customer response is voluntary (i.e., in some programs, no penalties are levied for not curtailing when called)
Price-response event program	• A program that pays customers for measured load reductions when day-ahead wholesale market prices exceed a floor • Some programs may include bid requirements (i.e., customers are only paid for curtailments that they specify in advance) and/or penalties for failing to respond when committed
Critical-peak pricing	• A dynamic-pricing tariff similar to a time-of-use rate most of the time, with the exception that on declared "critical-peak" days, a pre-specified higher price comes into effect for a specific time period

Table 2. Data Sources

DR Option	Data Source(s)	Eligible Customers (peak demand)	Reference
Optional hourly pricing	Central and Southwest (CSW) Utilities' (now American Electric Power) two-part RTP rate	> 1,500 kW	Boisvert et al. (2004)
Default hourly pricing	Niagara Mohawk Power Corporation (NMPC), a National Grid Company, SC-3A tariff	> 2000 kW	Goldman et al. (2005)
Short-notice emergency program	NYISO Emergency DR Program (EDRP)	> 100 kW	Neenan et al. (2003)
	ISO-NE Real-Time DR (RTDR) Program	> 100 kW	RLW Analytics and Neenan Associates (2003, 2004 and 2005)
Price-response event program	ISO-NE Real-Time Price Response (RTPR) Program	> 100 kW	RLW Analytics and Neenan Associates (2003, 2004 and 2005)
Critical-peak pricing	California Utilities[1] Critical Peak Pricing Program	> 200 kW; > 100 kW for SDG&E	Quantum Consulting, Inc. and Summit Blue Consulting, LLC (2004 and 2006)

[1] Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) offer a critical-peak pricing tariff to large customers. The tariff design is quite different from that of the California Statewide Pricing Pilot that primarily targeted residential customers (Charles River Associates 2005).

Estimating Net Program Penetration Rates

The next step is to estimate customer participation rates for DR options included in the study. Participation can imply: (1) customer enrollment in voluntary DR programs and tariffs, or (2) the retention of customers in tariffs implemented as the default service (i.e., the number of customers who do not switch to an alternative offering).

DR participation is often fluid. Customers may enroll in a program for one or more years, and subsequently drop out. They may subsequently re-enroll in the program, or others may take their place. The benefits of customer participation are generally only realized while the customer is enrolled in the program (or exposed to hourly prices).[6] Thus, participation in DR options can be viewed as *penetration* in a given year "n" (or other applicable timeframe), as follows:

$$\text{Penetration}_n = \text{participants}_{n-1} - \text{dropouts}_n + \text{new enrollees}_n$$

This can be estimated separately for each customer market segment defined in the previous step, and the results added up to determine the overall penetration for the population of eligible customers.

This way of thinking about DR potential is useful for evaluating an established program over multiple years, particularly in the context of changes to program rules or incentives, or to the level and/or volatility of market prices. From the standpoint of a new, hypothetical program, it may be acceptable to view participation as penetration in a "typical" year of a mature program, with the understanding that a multi-year ramp-up period will be necessary, and that ongoing penetration may be subject to fluctuations due to factors both within and out of the program operator's control.

Analysts have used a number of methods to estimate penetration rates of DR programs (see Goldman et al. (2007) for discussion of various approaches). Each has pros and cons, in part because there is not yet a broad set of information on customer response to various DR options in a variety of settings. Program penetration rates present the largest uncertainty in this framework, because experience is piecemeal, and because of data limitations. We strongly recommend evaluating the impact of a range of participation levels, rather than relying on a single point estimate.

We compiled participation rates by market segment and customer size for each DR option in our simulation (see **Table 3**). Our goal was to gather data on program participation based on relatively mature programs with 3–4 years of operation. Where possible, we used actual program participation data from the data sources in **Table 2**. We filled in gaps by surveying program managers of similar programs and tariffs, and inferring data from other market segments or programs; these data are indicated in red italic font in **Table 3**.[7]

The highest participation rates are observed for large customers (>1 MW) in the default hourly pricing tariff. We believe this is largely explained by the default, "opt out" nature of the tariff, which tends to increase participation rates because some customers decide not to decide. In a default hourly pricing tariff, participation is defined as *not* selecting an alternative electricity supplier, rather than as the conscious decision to sign up that characterizes the other programs and tariffs.[8]

Table 3. Participation Rates in DR Programs and Dynamic Pricing Tariffs

DR Option	Business Type	Customer Size (peak demand)			
		0.35–0.5 MW	0.5–1 MW	1–2 MW	>2 MW
Optional	Commercial/retail	*0%*	*0%*	*1%*	*2%*

[6] However, the experience of responding to a particular program may provide benefits beyond that particular program if the customer subsequently exhibits DR behavior in other programs or dynamic pricing options that were learned in the initial program.

[7] For the two short-notice emergency programs, information on the number of participating customers was available from NYISO and ISO-NE. However, neither agency collects information on the number of customers eligible for their programs. We constructed eligible population data from information obtained from third party sources (see Goldman et al. 2007).

[8] The default hourly pricing participation rates do not include those customers that switched to competitive retailers and entered into contracts in which they faced hourly prices indexed to day-ahead or real-time markets for some or all of their load.

DR Option	Business Type	Customer Size (peak demand)			
		0.35–0.5 MW	0.5–1 MW	1–2 MW	>2 MW
hourly pricing	Government/education	*3%*	*4%*	*6%*	*25%*
	Healthcare	*0%*	*0%*	*1%*	*2%*
	Manufacturing	*3%*	*5%*	*6%*	*25%*
	Public works	*0%*	*0%*	*3%*	*20%*
Default hourly pricing	Commercial/retail	*4.3%*	*11%*	*50%*	43%
	Government/education	*4.2%*	*10%*	30%	42%
	Healthcare	*0.7%*	*1.8%*	50%	7.1%
	Manufacturing	*3.3%*	*8.3%*	29%	33%
	Public works	*3.7%*	*9.2%*	50%	37%
Short-notice emergency program	Commercial/retail	1.2%	23%	5.5%	20%
	Government/education	0.3%	5.3%	2.6%	9%
	Healthcare	0.6%	4.2%	4.3%	22%
	Manufacturing	0.2%	15%	17%	23%
	Public works	1.1%	10%	67%	17%
Price-response event program	Commercial/retail	0.3%	0.8%	1.8%	5.7%
	Government/education	0.3%	2.9%	4.1%	10%
	Healthcare	0.3%	1.6%	8.9%	22%
	Manufacturing	5.7%	10%	9.1%	30%
	Public works	0.1%	0.2%	0.4%	1.1%
Critical-peak pricing	Commercial/retail	0.9%	3.1%	5.2%	4.2%
	Government/education	1.5%	4.1%	2.3%	1.9%
	Healthcare	*0.9%*	*3.1%*	*5.2%*	*4.2%*
	Manufacturing	0.9%	4.5%	7.3%	6.9%
	Public works	1.2%	3.3%	1.3%	2.8%

Note: *Red-italicized* figures are based on expert judgment.

Another factor that strongly impacts participation rates is the definition and size of the eligible customer population. For the default hourly pricing tariff, only a specific set of large customers, with peak demand above 2 MW were eligible. In contrast, the other DR programs were open to significantly wider classes of customers. The threshold for the critical-peak pricing program was 100 or 200 kW (depending on the utility). For the ISO programs, eligibility is defined not by customer size class, but by a minimum allowable load reduction (i.e., 100 kW). To develop participation rates, we constructed the pool of eligible customers, assuming that the 100 kW minimum load reduction would be feasible among customers with peak demands of 350 kW and above[9]—thus, a very large number of non-residential customers in New York and the New England states were considered "eligible" for the ISO programs. Consequently, even though the actual number of participants (100–400 customers) is comparable across the programs and tariffs, the denominators range from hundreds to thousands of eligible customers.

A number of additional factors may influence rates of customer participation in DR programs and tariffs, including: program design features such as the structure and level of incentive payments, penalties for non-performance, and the duration, frequency and advance notice of events; customer familiarity with

[9] Though allowed in the program rules, load aggregators were not that active in these short-notice emergency DR programs (although they were active in the NYISO ICAP/SCR program). With aggregation, the pool of "eligible" customers would be even less well-defined.

or reputation of the entity administering the program; the effectiveness of marketing and/or customer education efforts; and the availability of technical or financial assistance.

Estimating Price Response

The next step in this framework is to assign *price elasticities* to each customer market segment, for each type of DR option, using available information on how similar customers have responded to high prices or program events afforded by similar DR options.

Analysts typically measure consumer response to changes in electricity prices with one of three measures of price elasticity: the *price elasticity of demand*, the *elasticity of substitution*, and the *arc price elasticity of demand*. All are estimated from a sample of observed customer electricity usage data in the face of changing prices.

From a theoretical standpoint, the price elasticity of demand (also known as the "own-price" elasticity) provides the most consistent characterization of consumer behavior. However, its estimation requires data on customers' production output, or the utility they derive from electricity usage, that is usually not available.[10] A number of studies of large customer price response have instead estimated substitution elasticities, which are also grounded in economic theory and can be estimated without output data, but impose assumptions about how customers use electricity. Arc elasticities are much easier to compute (only a limited number of observations of customer loads and prices are necessary) but this comes at the cost of limited explanatory power.

The tradeoffs between theoretical consistency and the amount of data required to estimate these three elasticity measures are summarized in **Figure 1**. As a general rule of thumb, analysts should choose the measure with the greatest theoretical consistency possible given available data.

For each DR option included in our simulation, we calculated elasticity values, disaggregated by market segment, using individual customer load and price data. For the two hourly pricing tariffs, we estimated demand models to calculate *substitution elasticities*.[11] For the other programs, insufficient numbers of observations covering too small a range of prices were available to estimate a fully specified demand model, so we calculated *arc elasticities*.[12] The resulting average elasticity values estimated for each program and market segment are presented in **Table 4**.[13]

Studies of customer price response indicate that there is considerable diversity in how customers respond to similar prices and incentives, even among customer market segments. External factors—such as high-price or program event characteristics and weather—and customer-specific characteristics or circumstances—such as customer experience, ownership of onsite generation and other enabling technologies, and electricity intensity—may influence price response. Unfortunately, insufficient information was available among our data sources to evaluate the impacts of most such factors (see Goldman et al. 2007).

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[10] Those analysts that have estimated own-price elasticities derived a proxy for firm output or customer utility that assumes a cyclical pattern.

[11] For more details, see Goldman et al. (2005) and Boisvert et al. (2004).

[12] Substitution and arc elasticity values are not directly comparable, although the market potential impacts derived from them are.

[13] For the price response event program, a number of program events occurred when prices were quite low ($100–150/MWh). Including observations from these low-price events resulted in extremely high average elasticities, because there was considerable variation in loads, but relatively small price differentials. To remove this "noise" from the elasticity estimates, we restricted our analysis to observations where the price was $150/MWh or higher.

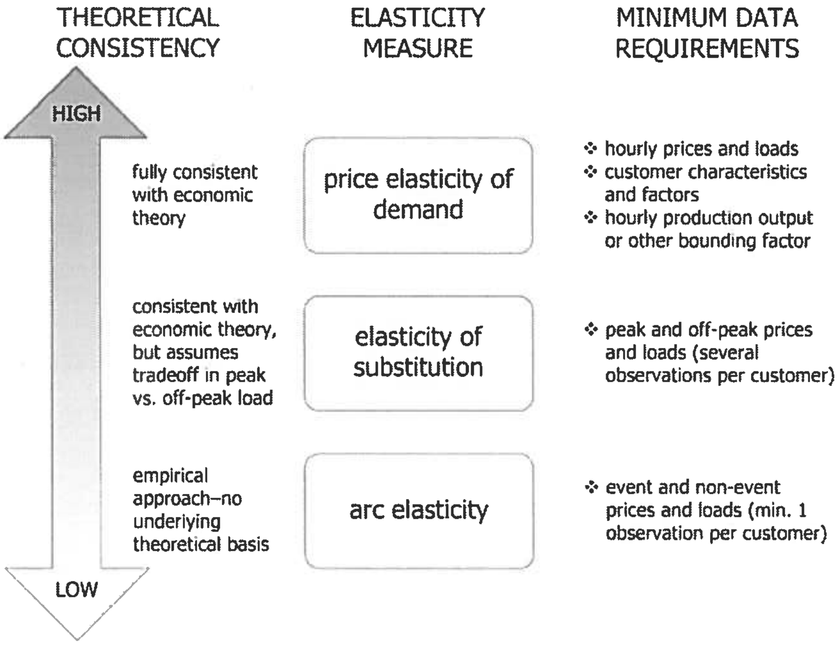

Figure 1. Features of Price Elasticity Measures

Table 4. Average Elasticity Values

Customer Market Segment	DR Option				
	Optional Hourly Pricing	**Default Hourly Pricing**	**Short-notice Emergency Program**	**Price Response Event Program**	**Critical-peak Pricing**
Commercial/retail	0.01	0.06	-0.03	-0.09	-0.10
Government/education	0.01	0.10	-0.02	-0.16	-0.06
Healthcare	0.01	0.04	-0.04	-0.05	-0.01
Manufacturing	0.26	0.16	-0.04	-0.16	-0.05
Public works	0.07	0.02	-0.08	-0.22	-0.08

Note: Elasticity of substitution values are shown for optional and default hourly pricing; arc elasticity values are shown for all other DR options.

However, for one of the short-notice emergency programs (NYISO EDRP), enough information was available to differentiate response among customers owning onsite generation from those without this technology. On average, customers in this DR program with onsite generators had arc elasticities about 40% higher than customers that did not. This translates to elasticity values for customers without onsite generation that are 14% lower than the average elasticities for each market segment (see **Table 5**). For those with onsite generation, the elasticity values are 52% higher than the average.

We also refined the elasticity estimates to reflect customer response at high prices (> \$450/MWh). The base case elasticity estimates were evaluated over a range of prices, and this refinement tests the sensitivity of the estimates to this assumption.[14] Our market potential simulations assume an "event" (or high hourly) price of \$500/MWh, so this refinement brings the elasticity estimates in closer alignment

[14] Applying average elasticities derived from a range of price levels to estimate response to a specific price may be misleading if customers respond differently at different price thresholds. Goldman et al. (2005) found statistically significant differences in customer price response at different prices.

with the simulated conditions.

Table 5. Arc Elasticity Values Adjusted for Onsite Generation

Customer Market Segment	Short-notice Emergency Program	
	without DG	with DG
Commercial/retail	-0.03	-0.05
Government/education	-0.02	-0.03
Healthcare	-0.03	-0.05
Manufacturing	-0.04	-0.07
Public works	-0.07	-0.12

For the default hourly pricing option, high-price substitution elasticities were developed using a flexible model that allowed for statistical evaluation of response at different price thresholds (see Goldman et al. 2005). We applied adjustment factors derived from this model to each market segment to develop elasticities tailored to response at high prices.

For the arc-elasticity values calculated from the DR programs, we simply eliminated observations for which the event price was below $450/MWh, and recomputed average elasticities for each sector and program from this smaller set of observations.

The resulting elasticity values of customer response to high prices are presented in **Table 6**. For the default hourly pricing tariff, commercial/retail and government/education customers *increase* their response at high prices while there is no change in manufacturing customers' response.

Table 6. Elasticities Based on Customer Response to High Prices ($500/MWh)

Customer Market Segment	DR Option			
	Default Hourly Pricing	Short-notice Emergency Program	Price Response Event Program	Critical-peak Pricing
Commercial/retail	0.10	-0.03	-0.02	-0.04
Government/education	0.16	-0.02	-0.02	-0.04
Healthcare	0.03	-0.04	-0.01	-0.00
Manufacturing	0.16	-0.04	-0.03	-0.03
Public works	0.01	-0.08	-0.02	-0.05

Note: Elasticity of substitution values are shown for optional and default hourly pricing; arc elasticity values are shown for all other DR options.

Very few of the observations for the two short-notice emergency programs involved event prices lower than $450/MWh, so the revised elasticity estimates are essentially unchanged.[15]

For the price response event program and critical-peak pricing, the elasticities shown in Table 6 decrease compared to the averages in **Table 4** in all market segments. This occurs because these customers' load response (the numerator in the arc elasticity) was fairly consistent across the range of prices, while the price differential (the denominator) increases with higher event prices. We believe that

[15] The program design of the NYISO EDRP program sets a floor price of $500/MWh, so none of these observations were removed. ISO-NE's emergency program offers two floor-price options—$500/MWh and $250/MWh—depending on the amount of notice customers receive of impending events.

this result may be partly attributable to the program design and is also consistent with the notion that many large business and institutional customers are only willing to curtail or forego load which they consider "discretionary." Restricting the dataset to events with higher prices therefore results in lower average elasticities. This effect is relatively minor for the critical-peak pricing example, but is quite pronounced for the price response event program (compare elasticity values in Table 4 vs. Table 6).

Estimating Load Impacts

The final step is to pull together all the pieces to estimate aggregate load impacts, which should be done separately for each DR option under consideration.[16]

For each customer market segment, program penetration rates should be applied to the target population in that segment. Then, elasticity values are applied to the customers in each market segment, allocating any factor-specific elasticity estimates (such as those developed for customers with and without onsite generation in the previous section) to those customers to whom they apply.

Once each customer has been assigned an elasticity value, it remains to translate the results into an estimate of aggregate load impacts for a range of expected prices or incentive levels. The methods for doing this depend on the type of elasticity estimated (e.g., substitution or arc elasticity). Goldman et al. (2007) discusses these methods in detail. Once the load impacts have been established (in MW), they can be expressed as a percentage of the peak demand of the applicable customer class.

To demonstrate the application of our methodology, we applied our compiled participation rate and elasticity values to information on the customer population of an urban utility in the Northeastern U.S. to develop market potential estimates. The selected utility is relatively small; the peak demand of its large, non-residential customers is ~1,700 MW. These customers represent about 40% of the utility's peak demand, and consist largely of commercial/retail, government/education and healthcare facilities. Manufacturing customers are less prevalent than is typical among utilities that serve suburban or rural communities.

To estimate load impacts, we used business-class-specific load profiles derived from NMPC SC-3A customer data to establish "expected" customer loads absent DR (i.e., customer baseline loads). We also assumed an "event" (or high hourly) price of $500/MWh for all DR options. This is fairly typical of the high prices observed in hourly pricing programs, as well as incentive floor prices offered by ISO emergency programs, in recent years.

We developed five scenarios to demonstrate the effects of various factors on DR market potentials and to evaluate the robustness of the substitution and arc elasticities to changes in the simulation inputs;we highlight results from several of the scenarios (see Goldman et al (2007) for complete results).

Base Case. The base-case scenario uses average elasticity values by market segment (**Table 4**), and the participation rates in **Table 3** to estimate market potential for each DR option. The results range from <1% to 3% of the peak demand of the target population of customers larger than 350 kW (see **Table 7**).[17] The load reductions for the largest customers (>1 MW) enrolled in the default hourly pricing and price response event programs represent 5-6% of their aggregate peak demand. The highest market potential (3% of peak demand) corresponds to the default hourly pricing tariff—this is largely due to relatively high customer acceptance rates for this tariff.

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[16] Analysts may wish to account for interactive effects arising from program eligibility rules that limit participation in multiple programs.

[17] We did not have access to class-level peak demand for the Northeastern utility. To approximate class-peak demand, we summed individual customers' peak demands. Because they are not simultaneous, this overestimates the actual class peak (and therefore under-estimates the proportional load impacts).

Table 7. Market Potential Results: Base Case

Customer Size (MW)	Optional Hourly Pricing		Default Hourly Pricing		Short-notice Emergency Program		Price Response Event Program		Critical-peak Pricing	
	MW	% of class peak demand[1]	MW	% of class peak demand[1]	MW	% of class peak demand[1]	MW	% of class peak demand[1]	MW	% of class peak demand[1]
0.35–0.5	1.0	0%	2.8	0%	0.4	0%	1.6	0%	1.3	0%
0.5–1	1.1	0%	3.9	1%	4.3	1%	3.0	1%	1.7	1%
1–2	1.9	1%	14.4	6%	3.8	2%	3.9	2%	1.9	1%
> 2	21.6	4%	34.8	6%	11.5	2%	29.1	5%	2.4	0%
Total	**25.6**	**2%**	**55.9**	**3%**	**19.9**	**1%**	**37.6**	**2%**	**7.3**	**<1%**

[1] Peak demand is non-coincident.

Note: Each DR option was evaluated separately—the results are not additive.

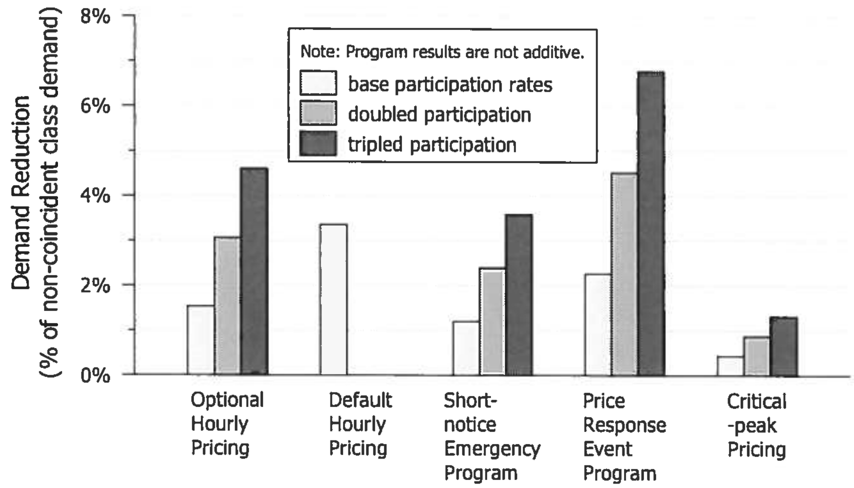
Impact of Program Participation Rates. Market assessments often examine the impact of differing rates of participation on program potential. **Figure 2** illustrates the impact of aggressively marketing programs or promoting optional tariffs to achieve two and three times the base-case participation rates, which reflect current DR experience. The results, on the order of 3–6% of non-residential peak demand, can be viewed as an approximate upper bound on DR potentials.[18] For default hourly pricing, which by definition would not be marketed to customers, we do not show enhanced participation, although the base-case results are included in the figure for comparison.

Accounting for Onsite Generation. We examined the impact of refining the short-notice emergency program elasticity estimates to account for the influence of onsite generation technology on customer response (see **Table 8**). This resulted in slightly lower market potential estimates than the base case for this DR option (i.e., 17.6 versus 19.9 MW). This is due to our assumptions about the distribution of onsite generators among the customer population at the illustrative urban utility compared to the observed distribution among the customers from whom the elasticity estimates were estimated.[19]

Although the overall market potential estimates are comparable in this example, understanding differences in the underlying elasticities among customers with and without enabling technologies can help policymakers target programs to customers that are likely to be the most responsive (e.g. those with on-site generation equipment).

[18] These results assume that the additional enrolled customers are just as responsive to price signals or emergencies as the relatively "early adopters" observed among our data sources. In reality, it may be that the most responsive customers are also the first to sign up, leading to declining average elasticities as more customers enroll. On the other hand, strategies that combine program marketing with technical assistance to develop fully automated DR could enhance both participation rates and response to prices or emergencies.

[19] Detailed information on the distribution of onsite generators among the Northeast utility's customers was not available. To perform the simulation, we developed onsite generation penetration rates from building survey data (see Goldman et al. 2007).



Note: Elasticities are assumed constant over all participation scenarios—this assumption has yet to be evaluated with actual program experience.

Figure 2. Impact of Program Participation on DR Market Potential

Table 8. Market Potential Results: Onsite Generation

Customer Size (MW)	**Short-notice Emergency Program**	
	MW	% of class peak dmd[1]
0.35–0.5	0.3	0%
0.5–1	3.7	1%
1–2	3.4	1%
> 2	10.2	2%
Total	**17.6**	**1%**

[1] Peak demand is non-coincident.

Accounting for Response at High Prices. In this scenario, we refined the elasticity estimates of four of the program types to better reflect customer response at the $500/MWh event price assumed for these simulations. Comparing the results in Table 9 with the base case (Table 7) reveals that for the default hourly pricing program, accounting for differences in response at higher prices results in higher market potential (i.e., 74 versus 55 MW). This result is driven by the fact that customers in certain market segments (government/education and commercial/retail) were more price-responsive at higher prices and our illustrative utility had a high proportion of these types of customers.

Table 9. Market Potential Results: Response at High Prices

Customer Size (MW)	**Default Hourly Pricing**		**Short-notice Emergency Program**		**Price Response Event Program**		**Critical-peak Pricing**	
	MW	% of class peak demand[1]	MW	% of class peak demand[1]	MW	% of class peak demand[1]	MW	% of class peak demand[1]
0.35–0.5	4.1	1%	0.4	0%	0.3	0%	0.7	0%
0.5–1	5.7	2%	4.2	1%	0.5	0%	1.0	0%
1–2	19.2	8%	3.7	2%	0.7	0%	1.0	0%
> 2	45.3	8%	11.1	2%	5.1	1%	1.3	0%

	Default Hourly Pricing		Short-notice Emergency Program		Price Response Event Program		Critical-peak Pricing	
Total	74.2	4%	19.4	1%	6.6	0%	4.1	0%

[1] Peak demand is non-coincident.
Note: Each DR option was evaluated separately—the results are not additive.

In contrast, for the price response event program and critical-peak pricing, restricting observations to only high-price events resulted in lower average arc elasticities in all market segments. The arc elasticity values are lower for these options because participating customers provided similar load reductions at low prices (~$200/MWh) as they did above $450/MWh (i.e., the percentage change in load remains the same during the high price event hours, while the percentage change in price increases). As a result, the market potential estimates are lower for these two programs than the base case that used average elasticities across all observed prices. Because the short-notice emergency program elasticities were virtually unchanged (see **Table 6**), the difference in market potential relative to the base case is negligible.

This scenario demonstrates the limitations of arc elasticities in accounting for influences other than price on customer load changes. Because only prices and load at a single event are captured, there is no way to account or correct for noise in the estimates (i.e. other factors that drive changes in customer usage). At higher prices, we believe that changes in load are more likely a result of prices rather than other factors. When arc elasticities are used, it is therefore important to be cognizant of these limitations and ensure that observations are drawn from conditions similar to those being simulated.

Conclusions

The above simulations illustrate possible ranges of DR market potential for large commercial and industrial customers at an urban Northeast utility, as well as several methodological and data issues. The results are tied to the characteristics of this urban utility's large customer base as well as the specific assumptions we made about prices and other factors in the various scenarios. Nonetheless, we draw the following insights and conclusions from our scoping study of DR market potential:

- We believe that the results provide a **reasonable first approximation of the range of DR market potential among non-residential customers** if offered similar DR options by similar utilities. While the observed load reductions—1% to 3% of the peak demand of the target population of large customers—are modest, a number of studies suggest that a little DR can often go a long way towards ameliorating system emergencies or high prices. If policymakers or regulators establish higher DR goals, then our results suggest that the DR market potential of all customer classes should be considered—not just large commercial and industrial customers. Pilot program results suggest that enabling technologies and automated DR can also increase both the number of customers willing to participate in DR options as well as the predictability and consistency of their load response.
- The simulations illustrate the **relative impact of certain factors, particularly customer participation rates, on potential aggregate load reductions** of large customers. Participation rates currently represent the largest data uncertainty for analysts undertaking market potential studies. Yet achieving higher participation rates among eligible large customers is critical for obtaining a significant amount of price-responsive load. Assessment of DR potential should attempt to account for the level of program resources (e.g. education, training, technical assistance) that will be devoted to program implementation and which may influence participation rates.

- The scenarios also demonstrate **the importance of refining elasticity estimates rather than applying average values**. In several cases, this resulted in *lower* market potential estimates in our simulations. Policymakers considering establishing DR goals should be aware that goals extrapolated from pilot programs or DR potential study estimates based only on small samples of very responsive customers may not be achievable.
- Finally, we emphasize that **all DR market potential studies should examine a range of scenarios**—not limited to those demonstrated here—in estimating DR market potential.

Recommendations

To advance the state of knowledge about customer response to DR programs and dynamic pricing tariffs and facilitate DR market assessments, we recommend that state and federal policymakers and regulators encourage utilities, retailers and Independent System Operators/Regional Transmission Organizations and their program evaluators conduct the following activities:

1. ***Link Program Evaluation to Market Potential Studies***: Evaluations of DR programs should systematically collect data on the characteristics of participating customers; hourly customer loads and prices; other factors found to be relevant drivers of customer participation and response; and information on the size and characteristics of the target or eligible population.
2. ***Program Participation***: Develop predictive methods for estimating participation rates in DR programs and dynamic pricing tariffs that incorporate customer characteristics and other factors that drive participation. Where applicable, studies should include interactive effects of multiple program offerings in estimating market penetration rates.
3. ***Price Response:*** Estimate price elasticity values for different market segments, accounting for the relative impact of driving factors, and report methods and results transparently. Where possible, we recommend that provisions be made to estimate demand or substitution elasticities, using fully specified demand models, rather than arc elasticities.
4. ***Assess the Impacts of DR-Enabling Technologies***: For large customers, there is still a need to document the impacts of specific DR enabling technologies on customer participation and load response, given limited evidence and mixed results from existing evaluations. At a minimum, program evaluators should gather information on customer's load curtailment strategies that involve onsite generation,[20] peak load controls, energy management control systems, energy information systems, and any other technologies disseminated as part of technical assistance programs.
5. ***Publicize Results***: Explore ways to pool customer-level data, while protecting customer confidentiality, so that information to support DR market assessments is available in a standardized format.

These activities would provide more detailed and robust price response and participation rate values that can support DR market assessment activities. However, in order to make best use of this information, utilities, ISOs/RTOs, and states will need disaggregated information on the characteristics of their target population of customers (e.g., customer loads by size range, market segments, enabling technology deployment). Some of this information is not typically collected by utilities on their customers. Therefore, we recommend that **states, utilities and their consultants** conducting DR market

[20] Information on diesel-fired emergency back-up generators should be tracked separately from cogeneration, combined heat and power, and other distributed energy technologies.

assessments first assess the availability of information on customer characteristics and usage in their jurisdictions and include plans to collect or estimate any necessary incremental information in their study plans and budgets.

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

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

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Abstract

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

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

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

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

Keywords

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

1. INTRODUCTION

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

2. U.S. DEMAND RESPONSE PROGRAMS

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

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

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

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

2.1 Demand Response Program Types

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

2.2 Summer 2001 Results

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

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

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

2.3 "Contingency" Demand Response Programs

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

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

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

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

2.4 "Market" Demand Response Programs

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4. DEMAND RESPONSE PROGRAMS AROUND THE WORLD

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

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

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

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

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

Table 4: Results of Overseas Demand Response Program Survey

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

Table 1: Case Study Programs and Program Administrators

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

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

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

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

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

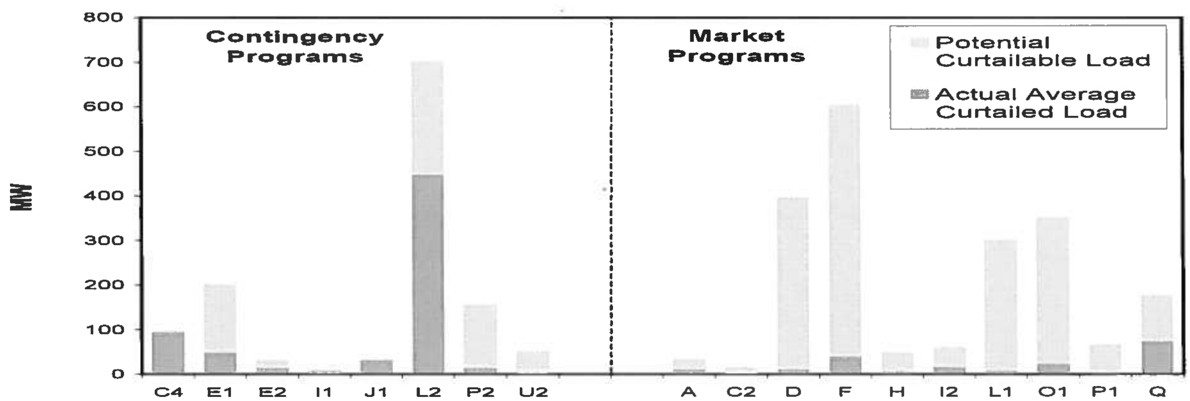

Figure 1: Comparison: Potential vs. Actual Curtailable Load in Contingency and Market Programs

0100200300400500600700800C4J1L2P2RU2ABC2DFGHKL1O1P1QTSPotentialCurtailableLoad(MW)Non BU

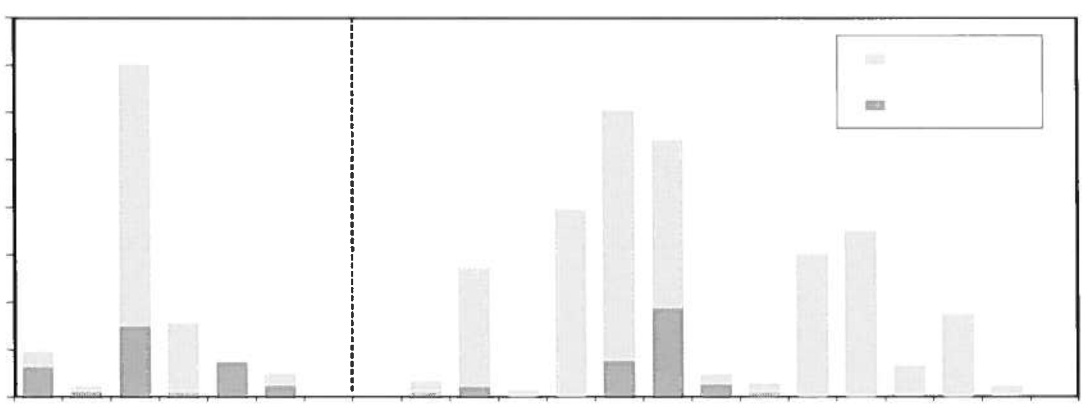

Figure 2: The role of backup generation (BUG) in demand response programs

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

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Demand Response in U.S. Electricity Markets: Empirical Evidence

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Demand Response in U.S. Electricity Markets: Empirical Evidence

Prepared for the
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U.S. Department of Energy

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Abstract

Empirical evidence concerning demand response (DR) resources is needed in order to establish baseline conditions, develop standardized methods to assess DR availability and performance, and to build confidence among policymakers, utilities, system operators, and stakeholders that DR resources do offer a viable, cost-effective alternative to supply-side investments. This paper summarizes the existing contribution of DR resources in U.S. electric power markets. In 2008, customers enrolled in existing wholesale and retail DR programs were capable of providing ~38,000 MW of potential peak load reductions in the United States. Participants in organized wholesale market DR programs, though, have historically overestimated their likely performance during declared curtailments events, but appear to be getting better as they and their agents gain experience. In places with less developed organized wholesale market DR programs, utilities are learning how to create more flexible DR resources by adapting legacy load management programs to fit into existing wholesale market constructs. Overall, the development of open and organized wholesale markets coupled with direct policy support by the Federal Energy Regulatory Commission has facilitated new entry by curtailment service providers, which has likely expanded the demand response industry and led to product and service innovation.

1. Introduction

Demand response (DR) can be defined 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 times of high wholesale market prices or when system reliability is jeopardized." [1, 2][1] This concept of demand response can be traced to the beginnings of the U.S. electric power industry (circa early- to mid-1890s), where system engineers and utility executives debated the optimal pricing regime for this new found service: Hopkinson's demand charge or time-of-day differentiated rates [6]. The universe of time-based retail rates has expanded significantly from these early days of the industry to now include real-time pricing (RTP), critical peak pricing (CPP) and variations thereof [2, 3, 7, 8].

As our definition suggests, U.S. utilities have also utilized incentive-based programs, often based on reliability differentiation, to elicit demand response from customers [3]. Utilities implemented load management (e.g. direct load control) programs and interruptible/curtailable tariffs in the early 1970s, both of which were in essence call options in which the customer sold the right but not the obligation for the utility to curtail or shed some of the customer's load in exchange for an upfront payment (in $/kW-month or a bill credit for participation) or a per kWh discount for the non-firm electricity consumption [2]. The initial interest in load management was driven in part by the increasing penetration of air conditioning which resulted in needle peaks and reduced load factors. With the advent of integrated resource planning in the late 1970s and 1980s, utilities increasingly recognized the system cost impacts of meeting peak loads and began to view load management as a reliability resource.

In the mid-1990s, with the advent of electricity restructuring, policymakers and utilities interested in facilitating the development of regional, competitive wholesale (and, in some states, retail) electricity markets initially focused primarily on market design and structure, albeit with a supply-side focus (e.g., open access to transmission services, vertical de-integration, establishing independent system operators). However, the problems in many restructured electricity markets (e.g. electricity crisis in Western state power markets in 2000-2001, price volatility and spikes, perceived market power, reliability concerns during system peak demand conditions, and failure to produce expected benefits to consumers) led policymakers to conclude that demand response, in all of its different forms, is essential to the efficient functioning of wholesale electric markets [9]. The Energy Policy Act of 2005 (EPACT) codified that a key objective of U.S. national energy policy was to eliminate unnecessary barriers to wholesale market demand response participation in energy, capacity, and ancillary services markets by customers and load aggregators, at either the retail or wholesale level.

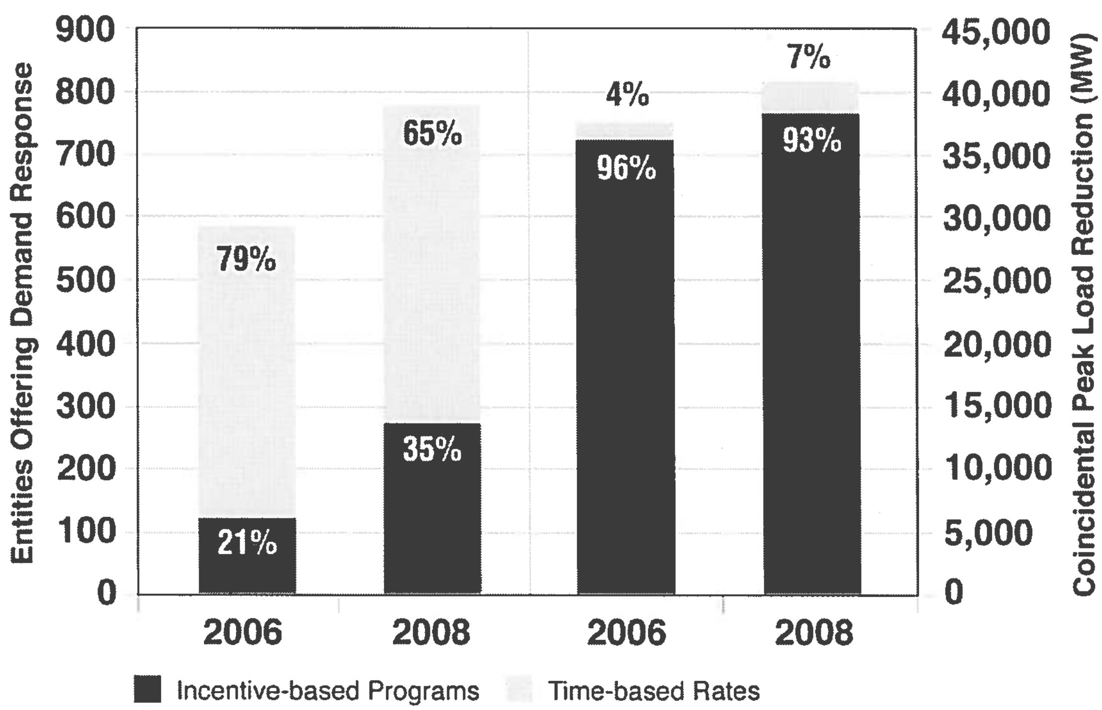
[1] Other studies have developed alternative typologies to characterize demand response resources [3, 4] which are linked to program objective (e.g., system reliability or price response) or resource planning (e.g. firm vs non-firm resources) Given our subsequent focus on the two Federal Energy Regulatory Commission reports on demand response, we have chosen to use the typology found therein [2, 5].

It is therefore critical to assess existing capabilities of DR resources among load serving entities and customers to provide load reductions in response to system emergencies and/or high market prices, and assess the actual performance of DR resources during recent periods. Empirical evidence of DR resources is needed in order to establish baseline conditions, develop standardized methods to assess DR availability and performance and to build confidence among policymakers, utilities, system operators, and stakeholders that DR resources do offer a viable, cost-effective alternative to supply-side resources. In this study, we summarize the existing contribution of DR resources in U.S. electric power markets (i.e., retail and wholesale), with a primary focus on enrollment and performance of incentive-based DR programs in organized markets (rather than time-based retail rates). Both types of DR resources are critical to the development of competitive electricity markets [10 - 12].

This paper proceeds as follows. First, it provides an overview of the types and magnitude of existing DR resources in the United States and then focuses on the evolution and maturation of incentive-based DR programs in organized markets in terms of enrollment and performance. Next, it discusses the evolution of legacy, existing load management programs and interruptible/curtailable tariffs offered by utilities within the new framework of organized wholesale markets, drawing on results of recent studies of the Midwestern Independent System Operator (MISO) and Southwest Power Pool (SPP) conducted by the authors. Finally, it explores the role that third party DR program providers (i.e. curtailment service providers) have played in expanding the scope of the DR industry, again drawing on the empirical evidence of recent activity.

2. Current Size and Scope of DR in the United States

As part of the Energy Policy Act of 2005, the U.S. Congress directed the Federal Energy Regulatory Commission (FERC) to develop a comprehensive national assessment of the size and scope of electricity DR resources and advanced metering as part of a national energy policy [2]. To accomplish this task, the FERC prepared and administered a comprehensive survey, first in 2006 [2] and then again in 2008 [5], to ~3300 organizations representing all aspects of the electric delivery industry (e.g., investor-owned utilities, municipal utilities, rural electric cooperatives, power marketers, state and federal agencies, and unregulated DR providers) from all 50 states. About 55% of these organizations (~1850 responses) completed the DR section of the survey.



Source: [2] and [5].

Figure 1. Estimated size of DR resources in the United States.

Among survey respondents, there has been a significant increase (117%) in the number of entities offering DR programs: 126 in 2006 vs. 274 in 2008 (Fig. 1) and about a 10% increase in the number of entities offering dynamic pricing tariffs to retail customers. Nationally, the potential size of peak load reductions from existing DR resources, relative to national peak demand, was about 5.0% in 2006 [2] and grew to 5.8% in 2008 [5].[2]

Many more entities offer some type of time-based retail rate as compared to incentive-based DR programs. However survey respondents indicated that these time-based retail

[2] In estimating existing DR Resource contribution, FERC staff drew upon FERC survey responses and other sources (e.g. Energy Information Administration Form 861, Independent System Operator (ISO) or Regional Transmission Operator (RTO) DR program data).

rates account for a small part of the total existing DR resource base. In 2008, customers enrolled in existing incentive-based DR programs were capable of providing ~38,000 MW of potential peak load reductions, while time-based retail rates were expected to produce another 2,700 MW (Fig. 1). In percentage terms, about 93% of the peak load reduction from existing DR resources in the U.S. is provided by various types of incentive-based programs (Fig. 1).

Given that peak loads vary significantly by region, it is also useful to characterize existing DR resources compared to a region's summer peak demand (see Fig. 2). Demand response resource potential ranges from 3 to 9% of a region's summer peak demand in most regions, with the notable exception of the Midwest Reliability Organization (MRO) region where DR resources represent a much higher percentage of summer peak demand.

Several factors may help to explain this result: (1) several states (Minnesota and Iowa) require utilities to invest a percentage of revenues from retail sales (1.5-2%) in demand-side management (DSM) programs, (2) utilities in the upper Midwest have historically had favorable resource adequacy rules that allow load management to be counted towards meeting reserve requirements, and (3) the customer base includes a significant fraction of industrial load that is amenable to interruption (e.g. steel plants) [5]. Among the existing DR resource base, residential customers account for ~6,000 MW while industrial customers account for ~14,800 MW. In the Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), and Reliability First (RF) regions, a significant portion of DR resources is attributable to programs offered by ISOs and RTOs (e.g., classified as wholesale). Elsewhere in the U.S., the majority of existing DR resource potential comes from more traditional DR programs: interruptible/curtailable rates for industrial customers and direct load control for residential and small commercial customers.

3. DR Resources in Eastern U.S. ISOs

3.1 Participation

Most of the growth in incentive-based DR resources has occurred in organized wholesale markets administered by ISOs/RTOs. Since 2001, FERC has required ISO/RTOs to file annual program evaluations or include a detailed discussion of their DR program enrollment and performance in annual state of the market reports. To illustrate trends in the development of DR resources in some organized markets, we focus on three ISOs located in eastern U.S. electricity markets: New York Independent System Operator (NYISO), ISO New England (ISO-NE), and PJM Interconnection (PJM).

The New York ISO has historically offered three different incentive-based DR programs: Emergency Demand Response Program (EDRP), Special Case Resource (SCR) program, and the Day-Ahead Demand Response Program (DADRP). EDRP is a voluntary program that pays strictly for energy; while SCR provides an up-front payment for capacity, a payment for load reductions when dispatched, but includes the threat of penalties for non-compliance with capacity obligations during declared program events.[3] The DADRP is an economic DR program that allows participants to submit load curtailment (i.e., supply) offers into the NYISO's Day-Ahead Market, where they compete side-by-side with generators. If a DADRP participant's offer is accepted, that participant is obligated to curtail the committed amount the following day, or else covers any open position it has at the higher of the real-time or day-ahead location-based marginal price (LBMP).

ISO-NE also offers three incentive-based DR programs: its Real-Time Demand (RT-Demand), Real-Time Price (RT-Price) and Day-Ahead Load Response (DALRP) program. There are three options for customers wishing to participate in ISO-NE's emergency (RT-Demand) DR program: the first two require participants to send near real-time meter data every 5-minutes to the ISO, but differ in terms of the length of notification prior to an event they require (i.e., RT-30 Minute or RT-2 Hour) and consequently the floor energy price paid for curtailments ($500/MWh and $350/MWh, respectively); the third option (RT-Profiled) requires neither communications devices nor interval meters to be installed in order to participate. In all the cases, enrolling participants are subject to non-performance penalties. The RT-Price program provides customers the opportunity to reduce load in real-time when a specific price point is exceeded, while the DALRP offers customers the opportunity to participate indirectly in the ISO-NE's Day-Ahead energy market.[4]

PJM provides its customers with three incentive-based DR programs: Emergency, Active Load Management (ALM), and Economic load response programs. The Emergency and ALM programs are dispatched under system emergencies, but differ in terms of the requirements for participation. As a result of the introduction of a forward capacity

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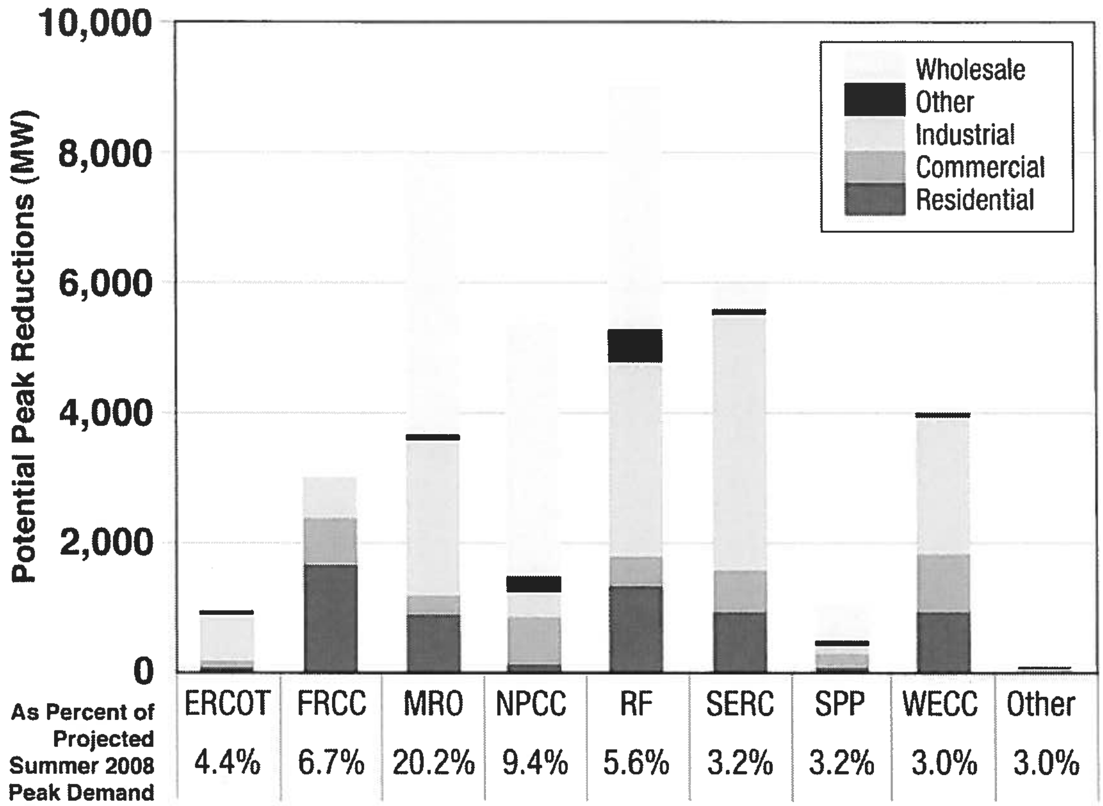
[3] Prior to 2003, end-use customers had to enroll in both EDRP and SCR to receive both an up-front capacity payment and any energy payment that would be provided during program events.

[4] The methodology for triggering an RT-Price event has evolved over the past several years. At the program's inception, customers were able to curtail anytime between 7 a.m. and 6 p.m. if the day-ahead locational marginal price (LMP) or forecasts of real-time LMP exceeded $100/MWh. Starting in 2005, the event start time was scaled back to include only afternoon hours. More recently, the ISO has altered the trigger price to better track economic conditions in the wholesale market.

market in 2007, the design of the Emergency and ALM programs was altered to accommodate these respective resources in the Reliability Pricing Model (RPM).[5] The Economic program has given customers the opportunity to participate in the Real-Time energy market, either through direct or indirect scheduling.

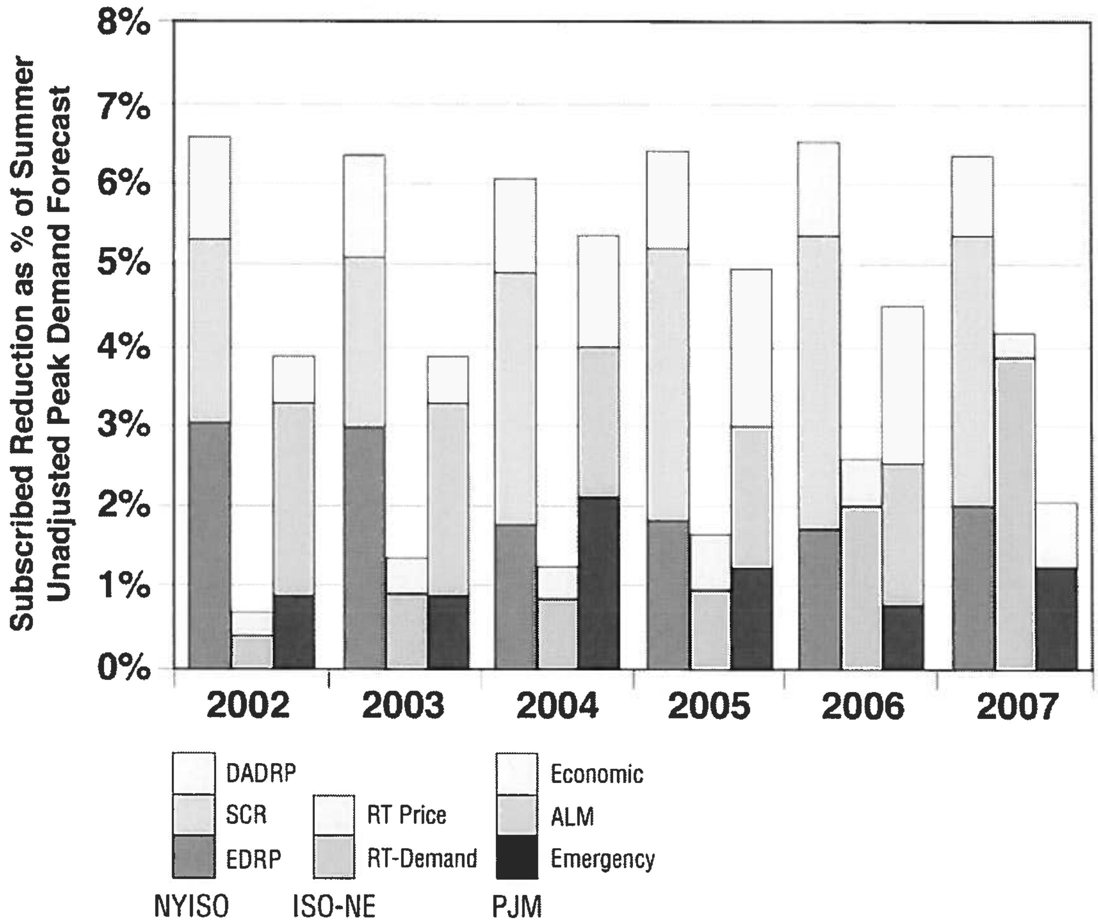
In addition, these three ISO/RTOs have recently developed opportunities for DR resources to participate in ancillary service markets. Both the NYISO and PJM allow DR resources to participate in regulation, 10-minute and 30-minute operating reserves markets. ISO-NE is offering a pilot program for customers to participate in providing operating reserves.



Source: [5].

Figure 2. Estimated size of DR resources by NERC region and customer sector

[5] The participation figures in 2007 for the Emergency program represent the enrollment in the "Energy Only" option, which is consistent with the voluntary nature of the Emergency program prior to that year. For reporting purposes, we have chosen to include all participants in the "Full" and "Capacity Only" options of the current Emergency program under the ALM category. This characterization is consistent with the historic ALM program, which included mandatory performance with the possibility for penalties and offered some form of a capacity payment.



Source: FERC filings, annual State of the Market reports, working group presentations.

Figure 3. Comparison of Northeastern ISO incentive-based DR program enrollment

Fig. 3 illustrates how DR program enrollment has evolved in these three ISO/RTOs from 2002 through 2007. In New York, the total size of the DR resource portfolio has not changed dramatically over the past six years, although there have been significant changes in the mix of individual programs.[6] Since 2003, when joint participation in EDRP and SCR was no longer allowed, there has been a clear migration away from EDRP towards the more lucrative but demanding SCR program.[7] The up-front reservation payment provided in the SCR program provides an ongoing revenue stream that is crucial to the financial viability of load aggregators and attractive to customers.

In interpreting results for PJM, it is important to recognize that PJM significantly expanded its footprint (and summer peak demand) since 2005 and 2007 as new utilities from the Midwest joined PJM. Enrollment in PJM's DR programs has grown significantly from 2002 to 2007 from ~2100 MW to 4600 MW, although in percentage

[6] Enrollment in the NYISO DR program increased dramatically from 775 MW in 2001 (not shown in Fig. 2) to 2,025 MW in 2002.

[7] The subscribed load reductions prior to 2003 associated with participants jointly in EDRP and SCR were assigned to SCR, as that program has the threat of penalty for non-compliance.

terms it is lower because PJM's footprint has expanded. PJM has also seen a major shift in its pool of program participants over time.

Significant changes in the designs of the Emergency and ALM programs were undertaken as part of Reliability Pricing Model (RPM), development process, in order to allow as many resources as possible to participate in that forward capacity market. Such alterations in the programs' designs appear to have elicited an exodus from the purely voluntary Emergency program option (i.e., Energy-Only) towards the capacity-based (Full and Capacity-Only) options, the latter labeled as ALM in Fig. 2.

During this period, participants enrolled in PJM's economic DR programs increased their subscribed peak load reductions from 335 MW in 2002 to ~2500 MW in 2007. Customers in two zones, Commonwealth Edison (ComEd) and Baltimore Gas & Electric (BGE), account for nearly 65% of this increase in the economic program's capabilities. Since joining PJM, ComEd has enrolled and transitioned its existing DR assets into PJM's economic DR programs and also expanded its offering of DR programs (i.e., Early Advantage, Rider 32 and Voluntary Load Reduction Programs) [13]. Enrollment in economic DR programs in the BG&E zone almost tripled in 2007 compared to 2006 (140 to 393 MW), which may have been a response to very large rate increases in Maryland and aggressive marketing by curtailment service providers (CSPs).

In ISO-NE, the RT-Demand response program increased in size from 0.4% of forecasted system peak demand in 2002 to 3.9% in 2007, nearly an 800% increase in just 5 years. Since 2007, the introduction of the Forward Capacity Market (FCM) in New England has also contributed to the continued growth in DR resources, as estimated peak load reductions associated with the RT-Demand response program increased by 51% between 2007 and 2008.

Enrollment in DR programs provides system operators with an indication of the size of the customer resource base that is willing to curtail or shift load in response to system contingencies or high market prices. However, because participation is voluntary in some of these DR programs and because the utility often does not have physical control of the customer's load response (as in a direct load control program), information on the actual performance of DR resources during system emergencies or in response to high prices is crucial to assessing the long-term viability of DR resources. In order for these resources to be treated comparably to "iron-in-the-ground" generation assets, system operators must be confident that DR resources will perform in a consistent and predictable fashion. Performance metrics offer all market participants, and especially system operators, the opportunity to tangibly recognize the value of DR.

3.2 Performance

Two different performance metrics have been proposed by evaluators of the NYISO DR programs: Subscribed Performance Index (SPI) and Peak Performance Index (PPI) [14]. SPI compares the actual load reduction to what was initially subscribed to a DR program, while PPI estimates the customer's actual DR load curtailment compared to their peak demand. Given the infrequent reporting of the PPI by ISOs and the difficulty of producing the PPI independently, we focus on the SPI. For consistency of reporting, we focus on the portfolio level metric, whose definition was taken from [14]:

$$SPI_p = (E_d / E_s) \cdot 100\% \,, \quad (1)$$

where

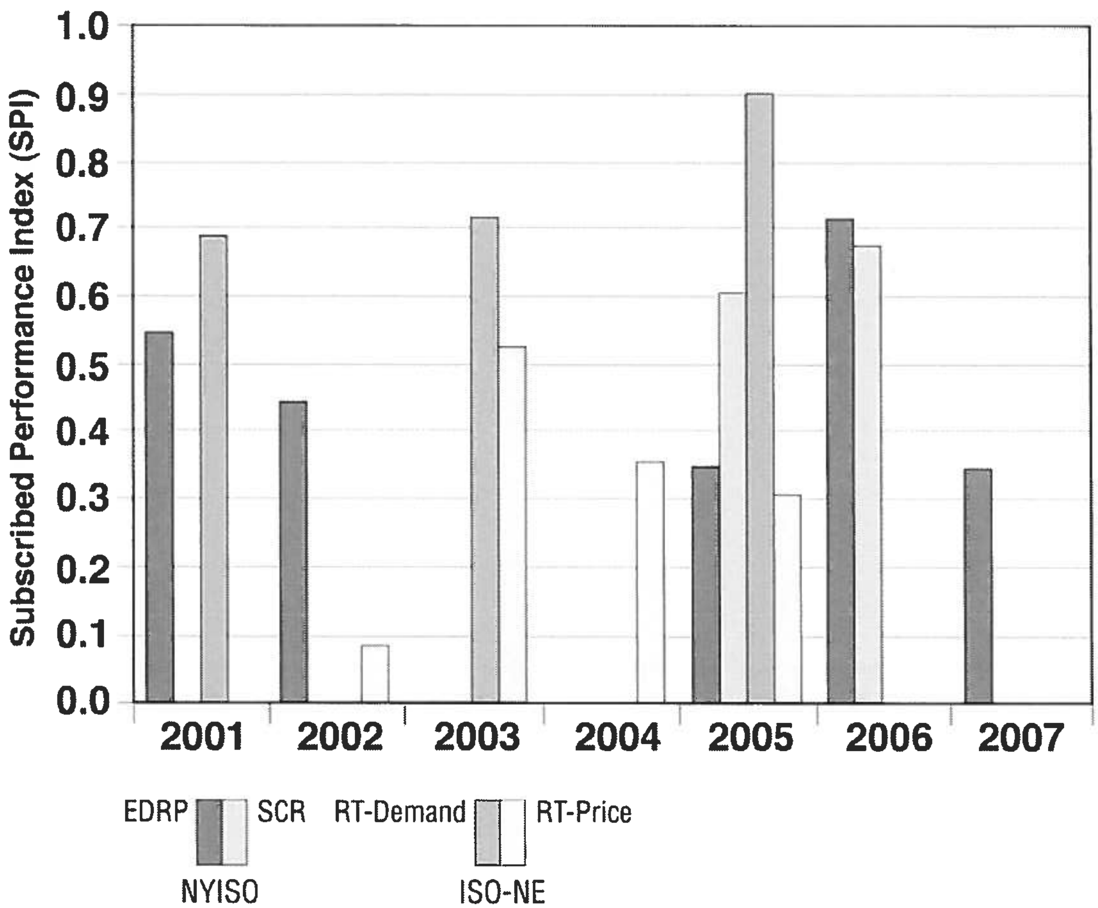
$$E_d = \sum_{i=1}^{M} \left(\sum_{t=1}^{N} (CBL_{i,t} - E_{i,t}) \right), \quad (2)$$

$$E_d = \sum_{i=1}^{M} \left(\sum_{t=1}^{N} (CBL_{i,t} - E_{i,t}) \right), \quad (3)$$

and

E_d = the total electric energy curtailment <u>delivered</u> by all customers in a program,
E_s = the total electric energy curtailment <u>subscribed</u> by all customers in a program,
CBL_t = the customer baseline of customer i in hour t (MWh),
$E_{i,t}$ = the electric energy of customer i in hour t (MWh),
M = the total number of customers in a program,
N = the number of hours per curtailment event, and
$E_{sub,i}$ = the subscribed load curtailment of customer i (MWh).

We were able to derive SPI values in Fig. 4 from ISO-NE and NYISO DR programs for several years based on the evaluation results or reported program performance. In some cases, the lack of a reported metric in certain years is either because no events were declared (e.g., 2004) or conditions surrounding a declared event would not produce an accurate assessment of performance relative to subscription (e.g., 2003 Northeast Blackout).



Source: FERC filings, annual State of the Market reports, working group presentations.

Figure 4. Comparison of Northeastern ISO program performance

The average SPI for ISO-NE's Economic program is 0.32 for four years with program data, which suggests that program participants' load curtailments were only about 32% of their subscribed load commitment during high price events. The SPI varied considerably from one year to the next – ranging between a low of 9% (2002) and a high of 53% (2003), illustrating how highly variable performance is of these enrolling participants.

The relatively low and highly variable SPI for the ISO-NE Economic DR program is not too surprising, given the fact that this program was new to participants (who may have been unsure about how much load curtailment to "subscribe"), there were no penalties for non-performance, and participants had complete discretion concerning when and how much of a load reduction to undertake based on an economic analysis of the opportunity cost of consuming load. In our view, this type of performance metric can provide useful information over time (as customers obtain more experience with measurement and verification protocols used to estimate curtailed load during events) and if training and technical assistance are provided to customers to help them quantify the amount of discretionary load that they can and are willing to curtail or shed during events.

The two DR capacity market programs (NYISO SCR and ISO-NE RT-Demand) provided 64% (SPI=0.64) and 77% (SPI=0.77) of their expected curtailments, respectively. The voluntary emergency DR program (NYISO EDRP) produced an overall average SPI of 0.52. These results suggest that the actual performance of DR programs with non-compliance penalties will be closer to their committed load curtailment compared to economic or voluntary emergency DR programs (that do not have penalty provisions). In terms of consistency, the NYISO SCR and the ISO-NE RT-Demand programs' performance index also varies considerably less than the SPI for EDRP. The variability in SPI over time is also very important to system operators who have the responsibility for maintaining grid reliability.

If DR is to play an increasing role in wholesale markets as an economic or reliability resource, system operators and resource planners must be able to accurately predict what DR resources can provide during system events in order to maximize their contribution to market efficiency and system stability while minimizing overall system costs. Recent efforts by system operators to manage and integrate intermittent generation resources provide an instructive example. Intermittent generation resources, like DR, are playing an increasing role in the bulk power system. As wind generation has grown over the past several years, ISO/RTOs have been forced to not just rely on these resources' accepted offers in forward markets to predict real-time performance but have also developed internal forecasts of their output in order to ensure sufficient reserves are in place to maintain reliability. For example, in September 2008, the NYISO brought on-line a new state-of-the art wind forecasting system that feeds wind-power forecasts based on meteorological data and historical operating characteristics directly into NYISO operational systems to better maintain the requisite balance of load and generation and predict wind power output on an hourly basis [15].

4. Integration of Existing Utility DR Programs in Wholesale Markets

As part of the transition to competitive, organized wholesale markets, it is necessary for the wholesale market rules and requirements to accommodate and facilitate a transition of existing DR resources into these new markets. Initially, the design of organized wholesale markets focused primarily on developing market rules that worked for supply-side assets. The FERC and state regulators in a number of states have placed increasing emphasis on ensuring that market rules provide an opportunity for existing DR assets enrolled in legacy incentive-based programs to participate in organized wholesale markets.

Working with the Lawrence Berkeley National Laboratory, the Organization of Midwest's Demand Response Initiative (MWDRI)[8] and the Southwest Power Pool each commissioned a detailed survey of the design features, operational triggers used to call events (e.g., system emergencies, market conditions, local emergencies), DR resource availability (e.g. seasonal, annual), participant incentive structures, and historic performance of existing DR programs and dynamic pricing tariffs offered by load serving entities in each ISO/RTO [16 - 17]. Although the timing of the surveys differed by roughly a year, they shared common goals:

- To inventory the existing set of retail incentive-based DR programs and dynamic pricing rates;
- To assess differences and similarities among existing retail incentive-based DR programs and dynamic pricing rates; and
- To help inform the debate at MISO and SPP concerning how to best make use of existing retail DR assets at the wholesale level.

The survey for SPP was fielded to 52 different cooperatives, municipal utilities, investor-owned utilities (IOU), state agencies, independent power producers (IPP), power marketers and transmission companies. Thirty entities, all municipal utilities and IOUs returned completed surveys; 14 of these entities offered some form of DR to their customers. In the MWDRI survey project, 35 utilities completed the survey with information on 141 DR programs and dynamic pricing tariffs; survey response was very good (~80%).[9]

In terms of wholesale market design, SPP administers an Energy Imbalance Service (EIS) market: participation is mandatory for load serving entities and generators and all real-time resources where imbalances are settled using the EIS market. MISO administers a day-ahead and real-time energy market with centralized economic dispatch and locational marginal pricing as well as ancillary services markets for regulation, spinning reserves and supplemental reserves. At the time of the survey, neither ISO/RTO had explicit wholesale DR programs that the ISO/RTO administered.

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[8] MWDRI was an initiative of the Organization of Midwest States (OMS) that resides primarily in the Midwest ISO (MISO) footprint.

[9] Four utilities were not members of MISO but operate in states that are part of OMS. Their responses were included in the study to provide a more comprehensive view of DR programs in the Midwest.

Table 1 – Overview of SPP and MWDRI survey results

	SPP			MWDRI		
	Incentive-based programs	Time-based rates	Voluntary response	Incentive-based programs	Time-based rates	Voluntary response
Survey Respondents	26	5	4	99	12	N/A
No. of Programs	36	5	6	122	19	N/A
Potential Coincident Peak Demand Reduction (MW)	1,352	200	N/A	4,406	321	N/A
Distribution of DR Resources	87%	13%	N/A	93%	7%	N/A

Source: [16] and [17]

As Table 1 illustrates, both SPP and MISO have a robust existing set of DR resources capable of reducing RTO system peak demand, roughly 4% and 5% respectively. Specifically, the SPP survey revealed that in 2008 there were a total of 47 different retail DR initiatives currently being offered in that RTOs footprint: 36 incentive-based DR programs, five time-based retail rates, and six voluntary response programs.[10] Retail DR as a whole in SPP is estimated to provide 1,552 MW of potential coincident peak demand reduction, 13% of which comes from customers on time-based rates while the remaining 87% is associated with incentive-based DR programs.[11] The MWDRI study indicated that as of late 2007 there were over 122 different retail incentive-based DR programs being offered to customers, and 19 different time-based retail rates in the region's utility tariffs. Collectively, DR is forecasted to reduce coincident peak demand in MISO by 4,367 MW, again the vast majority (93%) of which is coming from incentive-based DR programs.

The surveys also provided insights into how utilities in SPP and MISO are utilizing their DR resources. Respondents were asked to characterize the conditions (i.e., improving local reliability, mitigating system emergency conditions, and/or reducing exposure to high market prices) under which they chose to invoke load curtailments.

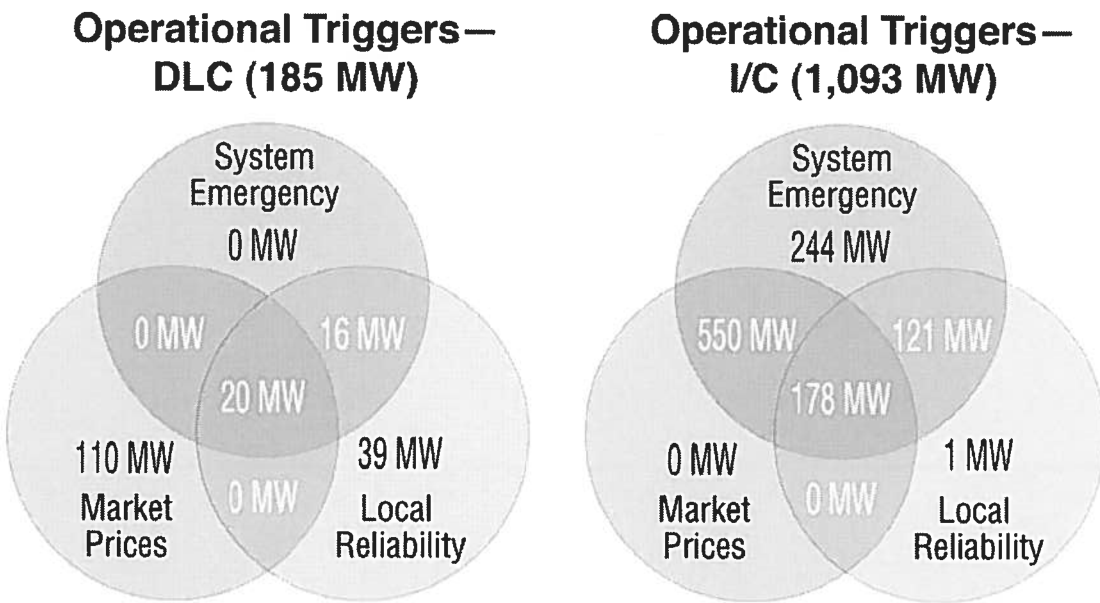
Historically, interruptible/curtailable (I/C) and direct load control (DLC) programs were justified primarily for reliability purposes and dispatched only during system emergencies. However, as competitive wholesale markets have developed and with the formation of MISO and SPP, most DR programs in these two regions currently have more than one operational trigger. A Venn diagram illustrates the universe of different conditions under which program administrators are invoking their DR resources and the expected load reductions associated with each combination of conditions.[12] The dark

[10] Incentive-based DR programs were defined to encompass interruptible/curtailable rates, direct load control programs, and economic (e.g., demand-bidding, demand buy-back) programs. Time-based retail rates include real-time pricing and critical peak pricing. Finally, voluntary response programs were defined to represent any program where customers provided their "best-effort" to reduce consumption when requested but were not provided any compensation for doing so.

[11] Although five of the voluntary response programs had been called at least once, none had been evaluated at the time the survey was administered and thus respondents had no estimates of the programs' likely contribution to reducing peak loads.

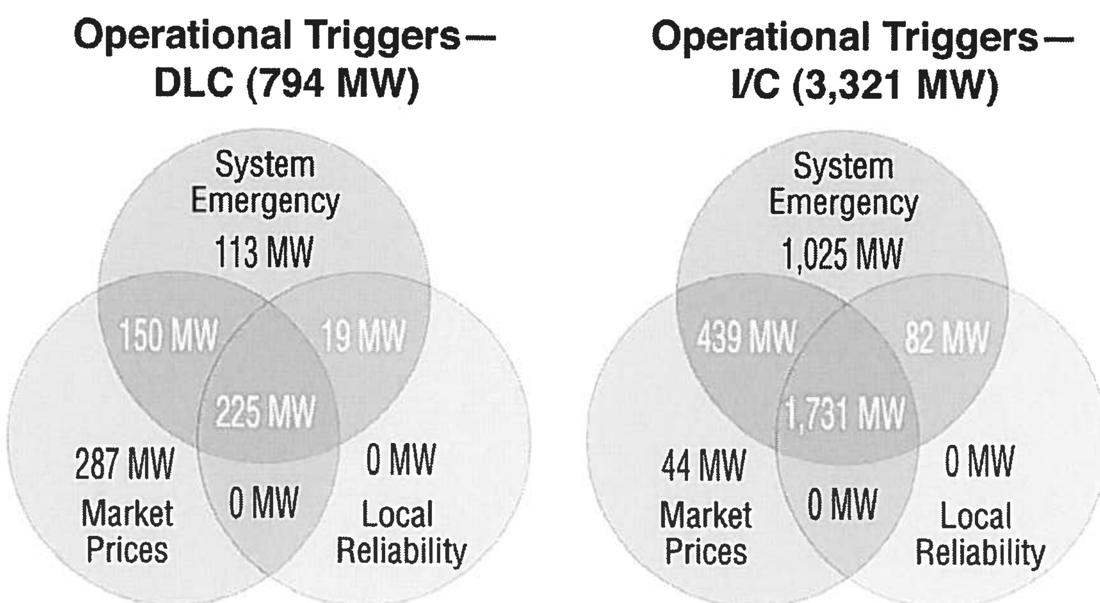
[12] In Figs 5 and 6, the different sets (circles) in the Venn diagram represent the different dispatch conditions (i.e., system emergency, local reliability, or market price) and the indicated MW values represent the magnitude of committed load reductions from enrolled participants for the indicated set of conditions based on program administrators' estimates. Parts of the sets that overlap each other represent committed load reductions that can be dispatched for the different indicated dispatch conditions. For example, 20 MW of

intersections in Figs 5 and 6 shows that in SPP and OMS states, about 69% and 64% respectively of survey respondents' enrolled DR (in MW), can be called for multiple conditions. An increasing number of utilities are now recognizing the flexibility these tariffs provide in the new wholesale market environment by also allowing for economic dispatch of these DR programs.



Source: [17]

Figure 5. Peak load reduction by operational trigger for DLC and interruptible DR programs in SPP



Source: [16]

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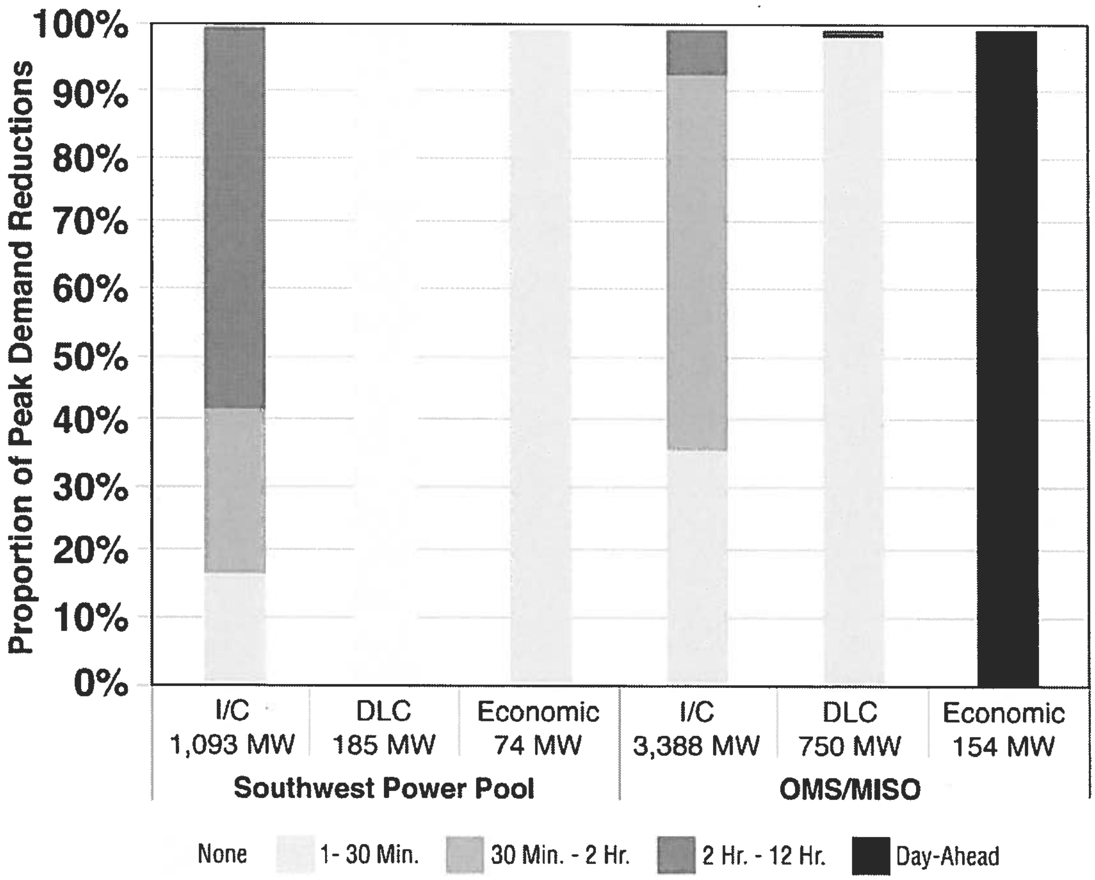
demand response in an SPP DLC program can be dispatched for any of the three conditions, whereas 39 MW can only be dispatched for local reliability reasons.

Figure 6. Peak load reduction by operational trigger for DLC and interruptible DR programs in OMS states

When utilities see or expect high prices, at least 66% of the peak demand reductions associated with a DR program (i.e., DLC or I/C) in SPP and OMS can be (or have been) dispatched (see Figs. 5 and 6). Utilities in OMS indicated that they wanted to reduce their exposure to high energy market prices but were reticent about bidding these resources into MISO's day-ahead market directly. So instead, the utilities themselves dispatched these programs closer to real-time when energy market prices rose above a certain level. In contrast, the distribution cooperatives in SPP who responded to the survey invoked their DLC programs for flattening out their load shape in order to minimize coincident transmission system peaks, thereby achieving substantial savings in their demand charge.



Source: [16] and [17]

Figure 7. Advance notification requirements for DR Programs

The surveys also requested that respondents specify the number of hours of advance notice required before demand can be reduced for each DR program. Advance notice requirements vary considerably across DR programs and by region (see Fig. 7). For example, DLC programs were uniformly reported to have no or very short notice requirements, which is not surprising given that equipment is cycled directly by utilities. In contrast, for interruptible/curtailable tariffs in MISO, ~90% of the enrolled load could be curtailed in less than 2 hours of advance notice with a significant amount of that load (1960 MW) available on just 30 minutes notice. However, among SPP member utilities, survey respondents reported that only 40% of the enrolled interruptible/curtailable load could be curtailed within 2 hours (see Fig. 7). Economic DR programs do not have significant amounts of enrolled load in either SPP or MISO, although notice requirements are much shorter in SPP (1-30 minutes) compared to MISO (day-ahead).

The relatively short event notification requirements associated with DLC programs make them perfect candidates to participate in wholesale real-time ancillary services markets, when such opportunities arise. If emergency and/or capacity DR programs are developed at SPP and/or MISO, then the vast majority of I/C resources could participate under existing retail program and tariff structures.

5. Role of Curtailment Service Providers in Wholesale Market DR Programs

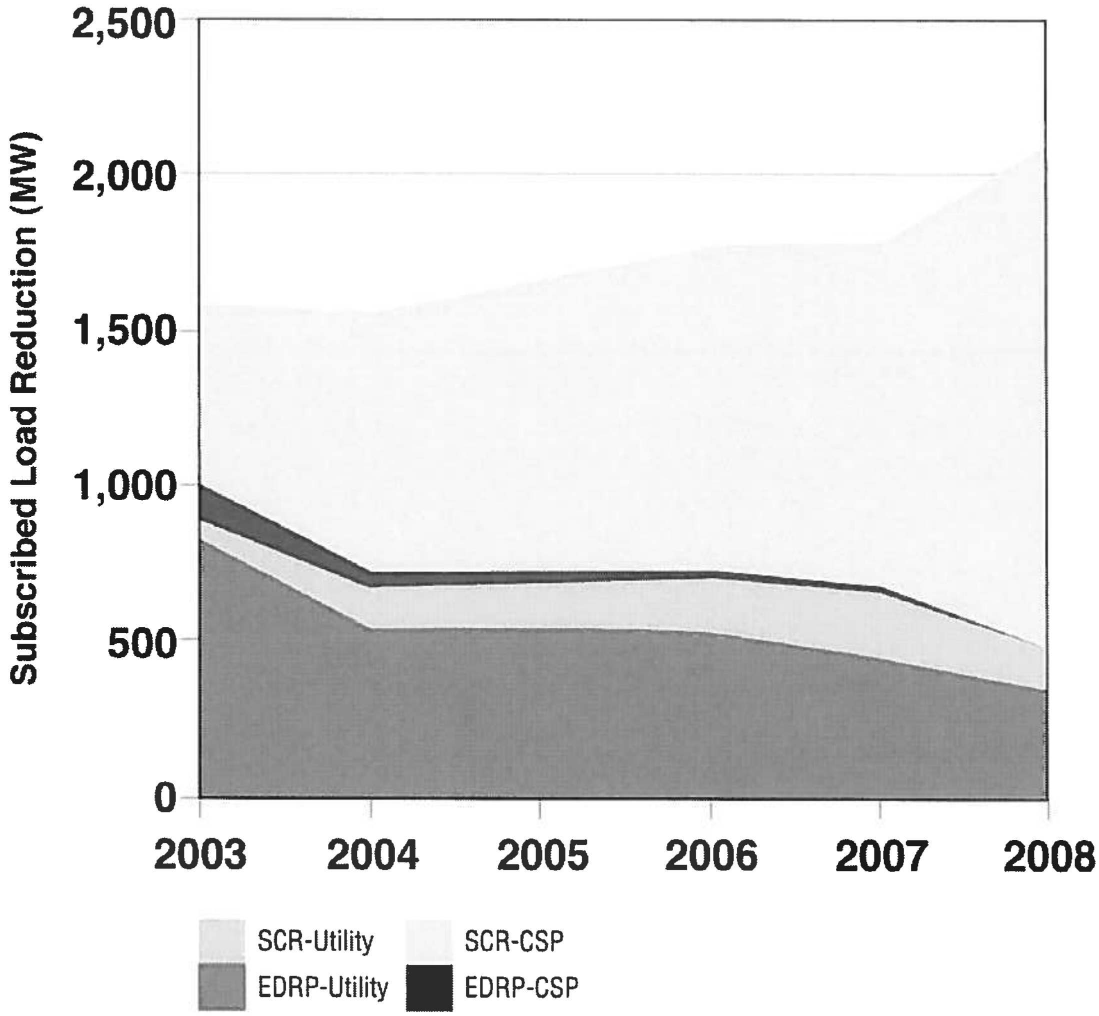
One of the arguments and intended benefits of competitive wholesale markets was service and product innovation. The emergence and increasing role of curtailment service providers provides an interesting case study that illustrates how strong public policy support by FERC and stakeholder support in organized wholesale markets created opportunities for new entrants to obtain a significant foothold and thus expand the DR industry.

In virtually all ISO/RTOs, "legacy" incentive-based DR programs offered by utilities were the initial participants in wholesale market DR programs. In states with retail competition, it was not long before competitive (non-utility) entities began offering customers similar opportunities. Each of the Eastern ISOs (ISO-NE, NYISO, and PJM) that developed opportunities for end-use customers to participate in their wholesale markets had to develop market and program rules for load aggregators that proposed to offer a customer's load reduction capability as a paid resource but were not the customer's load serving entity (LSE).

Program design and implementation issues that had to be addressed in order to facilitate participation by CSPs included: (1) a more sophisticated registration process for load aggregators (e.g., ensuring that customers' sites were not enrolled by multiple program providers), (2) notification procedures (e.g., notifying load serving entities that customers were enrolling in a incentive-based wholesale market DR program by a CSP), (3) metering and telemetry requirements (e.g., access by CSPs to customer's interval meter data) and (4) back-office software modifications at the ISO and incumbent utility in order to ensure timely and accurate processing and transmission of the interval data to CSP and ISO.

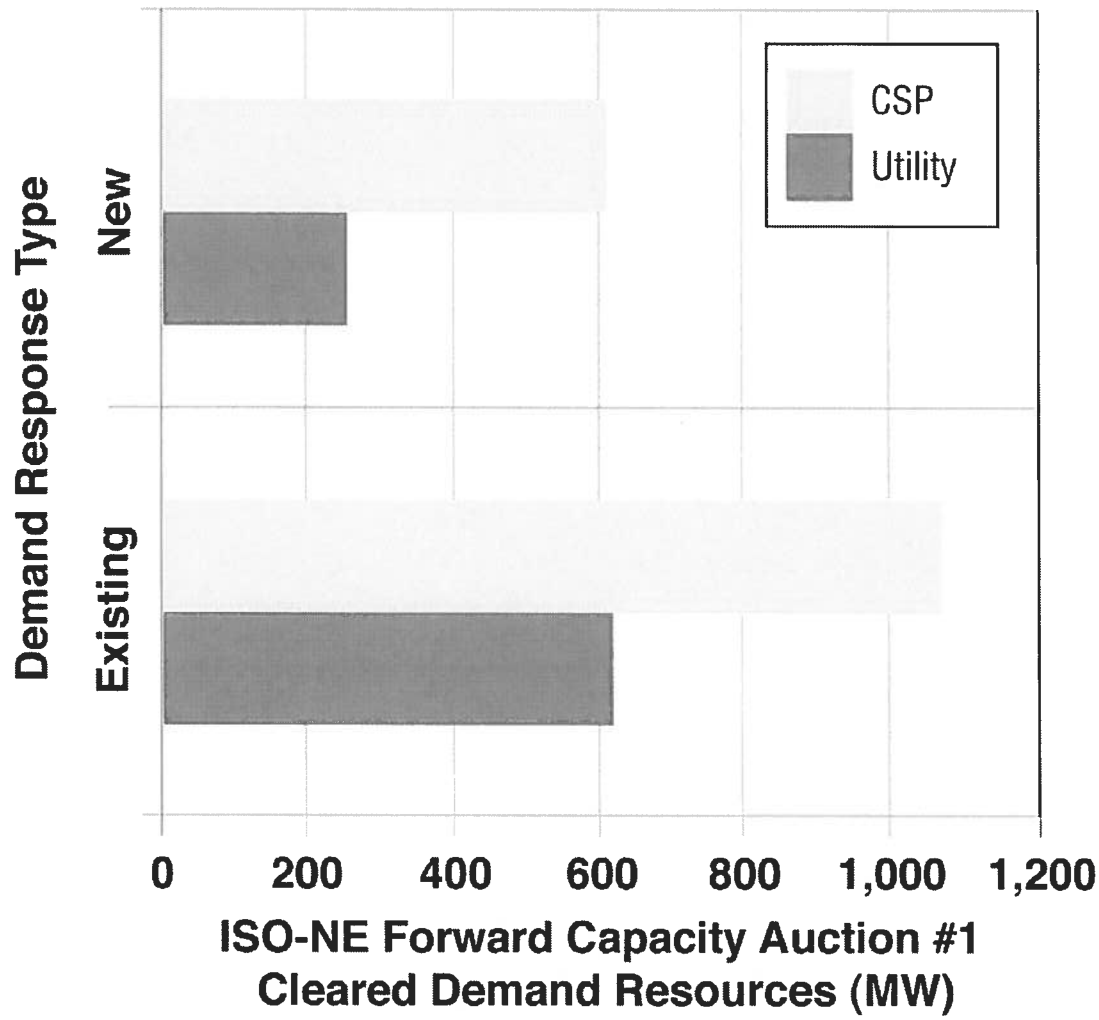
As new entrants, CSPs incurred substantial up-front costs which included marketing costs to enroll customers in a DR program, back-office and communications network infrastructure costs, and design, installation, financing, and maintenance of enabling technology at customer facilities (e.g. controls, onsite generation). CSPs required a source of revenue to make program participation a viable business opportunity. Energy payment for verified load reductions achieved by enrolled customers was an option, although CSPs would have to rely on the likelihood that events would be called by an ISO, which could be problematic. In contrast, utilities were typically allowed to recover program administration costs directly into retail rates.

CSPs soon gravitated towards incentive-based DR programs (e.g., capacity market, requests for emergency resources) that provided an upfront and ongoing reservation payment for committed load reduction by load aggregator (or customer). These programs provided a significant opportunity for CSPs to aggregate individual customer's willingness to curtail into a load curtailment resource, negotiate and share reservation payments with customers, provide energy payments to customers for performance during events, and allow CSP to compete on the basis of price and not just service. For example, Fig. 8 shows enrollment by the type of service provider (i.e., CSP or utility) in several DR programs administered by the NYISO. From 2003 to 2008, CSPs increased their share of subscribed load of DR resources from 44% to 77% in the emergency (EDRP) and capacity markets (Installed Capacity/Special Case Resources – ICAP/SCR). The ICAP/SCR program has been the main area of growth for CSP, accounting for well over 80% of the enrolled capacity in 2008. CSPs have heavily marketed the SCR program to customers by developing customized service packages and enabling technology that help customers to manage the risks associated with participation. Enrollment in the voluntary EDRP program has steadily eroded (i.e., 956 MW in 2003 but only 365 MW in 2008) as CSPs have shunned the EDRP program that provides energy payments only during events. The market share of utilities has steadily declined over this period.



Source: FERC filings, annual State of the Market reports, working group presentations.

Figure 8. NYISO DR program enrollment: utilities vs. CSP



Source: [19]

Figure 9. Distribution of cleared demand-side capacity in ISO-NE FCA #1

CSPs also have been successful in attracting new customers to enroll and participate as DR resources in wholesale market DR programs. Results from ISO-NE's Forward Capacity Market auction illustrate this phenomenon. In 2007, ISO-NE filed with FERC its approved Forward Capacity Market (FCM) rules, which would allow any resource, both supply and demand, to commit three years ahead of time to provide capacity to the system [18]. Demand resources in the FCM included both DR and energy efficiency, and load aggregators had to identify if the resource already existed (e.g., generator currently producing electricity, end-use customer currently enrolled in a DR program) or was new (e.g., planned generation addition, expected future enrollment in a DR or energy efficiency program). The results of the first Forward Capacity Auction (FCA #1) were made public in March 2008 [19].[13] Across the six New England states, CSPs were

[13] ISO-NE did not reveal the name of entities that submitted offers in the FCA#1 in the public results; however project names were provided. Based on project names, which were often descriptive enough to

responsible for attracting over 60% (1,681 MW) of the total demand-side capacity (2,553 MW) that cleared in the FCA #1 and 70% of the new demand-side resources (see Fig. 9). These results suggest that CSP were more aggressive in marketing and/or willing to take the business risk that they could deliver demand resources three years hence.

CSP still face significant institutional and regulatory barriers in many regions of the United States. For example, some states (e.g., Indiana) have precluded third party program providers or customers from directly participating in wholesale market DR programs. Many Public Utility Commissions (PUCs) also limit the share of program benefits that may be retained by the utility, opting to give the bulk of them back to consumers (e.g., New York). With CSP, the sharing of benefits is typically part of the contract negotiation process. PUCs are also concerned about the erosion of their authority to regulate the business and operations of incumbent monopoly utilities and its infrastructure. Some states have argued that they have a legitimate reason for not opening up their retail sector to aggregators of retail customers (or "ARCs") and such decisions should be respected. The FERC has attempted to finesse this issue in its recent Order 719 [20] in which the FERC agreed with the principle that load aggregators must be allowed to participate in ISO/RTO markets unless prevented under state law or regulation. However, FERC did not make it clear who was responsible for notifying the ISO/RTO that a state precluded customers from participating in wholesale DR programs with a non-utility entity.[14]

Traditionally, DR vendors provided load control and communication/notification technologies to utilities on a fee-for-service basis in load management programs. In recent years, encouraged (or required) by their state regulators, an increasing number of utilities have issued requests for proposals for "negawatts" to be provided by CSP on a pay-for-performance basis. These efforts are often characterized as a move toward "outsourcing" provision of DR services, which in some cases are driven by the utility's need to meet aggressive demand-side reduction goals established by a state PUC. For example, California's investor-owned utilities (e.g., Southern California Edison, Pacific Gas and Electric, San Diego Gas& Electric) have signed long-term contracts with CSP in order to meet aggressive goals established by the California Public Utility Commissions (CPUC). As more utilities consider "outsourcing" DR programs, existing and new CSPs are now competing to provide this service and many CSPs now have dedicated "utility" sales staff to develop retail market leads by convincing utilities that CSPs can do it "cheaper, faster, and better."

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identify the submitting party, we were able to develop estimates of DR resources provided by a utility or CSP.

[14] PJM decided to put the onus on the enrolling customer's electric distribution company (EDC). The proposed tariff changes indicate once PJM receives a new customer registration, that customer's EDC will be notified and requested to submit within 10 days a copy of the relevant legislative or regulatory statute or decision expressly barring end-use customer participation [21]. This tariff language was approved by the PJM Members Committee on January 22, 2008 and will go to FERC for final approval and subsequent formal inclusion in PJM's Open Access Transmission Tariff (OATT).

6. Conclusion

This paper provides empirical evidence on the evolution of DR resources in U.S. electric power markets. This evidence shows that DR is a growing industry in the United States, as evidenced by the increasing number of entities that offer DR programs and dynamic pricing tariffs and the emergence of wholesale market DR programs. Based on data reported by utilities, ISOs and CSPs, the currently existing DR resource contribution, in terms of potential peak load reduction, has increased since 2006 by about 10%.

The vast majority of entities offering DR do so in the form of time-based retail rates; although, this type of DR accounts for a small share (<10%) of the total potential peak load reduction of all DR resources. The relative contribution of time-based retail rates among all DR resources is expected to increase over time as more utilities install interval meters for residential and small commercial customers that enable these types of rates as part of Advanced Metering Infrastructure (AMI) deployments.[15]

The existing DR resource potential ranges from 3 to 9% of a region's summer peak demand in most regions, with the notable exception of the Midwest Reliability Organization region where DR resources represent ~20% of summer peak demand.

With respect to assessing the accuracy of DR resources' expected performance, participants in energy market DR programs substantially overestimated their expected performance during declared program events, while participants in capacity market DR programs were much better at assessing their likely performance.

DR resources that participate in capacity markets typically face penalties for non-compliance, which is often not the case for DR resources that participate in wholesale energy markets. Thus program design (e.g. compensation levels, penalties for non-performance, aggregation rules for small customers) can significantly influence the accuracy of DR resources' predicted performance.

There is significant year-to-year variability in DR performance at the portfolio level, particularly for economic DR programs. Over time, as customers gain experience and more ISOs (and utilities) offer economic DR programs, system operators will be in much better position to develop a "supply curve" that predicts the level of customer response over a range of different prices. This will be increasingly important if DR resources play a more substantial role in wholesale electricity markets.

However, the lack of standardized reporting practices and metrics for DR programs hinders reliability assessments. The North American Electric Reliability Council (NERC) has recognized this as a significant problem and has formed a Demand Response Data Task Force (DRDFT) to develop a system and protocol to collect DR event and market participation data to facilitate development of performance metrics [22].

[15] In the future, the relative contribution of dynamic pricing as a DR resource also depends on policy choices of state regulators (e.g. optional vs default tariffs), customer preferences and acceptance, marketing and education by utilities, and development and deployment of enabling technologies that facilitate price response.

Comprehensive surveys of utilities in recently formed organized markets (e.g. Midwest ISO and Southwest Pool Power) suggest that utilities are creating more flexible DR resources by adapting legacy load management and interruptible/curtailable DR programs to respond not only just to reliability concerns but also to reduce exposure to high market prices.

Finally, organized wholesale markets and policy support by the Federal Energy Regulatory Commission have facilitated new entry by curtailment service providers, which have expanded the DR industry and led to some product and service innovation.

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Retail Demand Response in Southwest Power Pool

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Environmental Energy Technologies Division

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Retail Demand Response in Southwest Power Pool

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Acronyms and Abbreviations

A/C	Air Conditioners
AMI	Advanced Metering Infrastructure
AS	Ancillary Services
BA	Balancing Authority
BDDR	Block Dispatch Demand Response
CBL	Customer Baseline Load
CPP	Critical Peak Pricing
DAM	Day-Ahead Market
DLC	Direct Load Control
DOE	U.S. Department of Energy
DR	Demand Response
EIA	Energy Information Administration (DOE)
EIS	Energy Imbalance Service
EDR	Emergency Demand Response
EEA	Electricity Emergency Alert
FERC	Federal Energy Regulatory Commission
HP	Horsepower
IOU	Investor Owned Utility
IRC	ISO/RTO Council
ISO	Independent System Operator
LMP	Location-based Marginal Price
LBNL	Lawrence Berkeley National Laboratory
LSE	Load-Serving Entity
MISO	Midwest Independent System Operator
MP	Market Participant
MRO	Midwestern Reliability Organization
MWG	Market Working Group
M&V	Measurement & Verification
NERC	North American Electric Reliability Corporation
OATT	Open Access Transmission Tariff
PUC	Public Utility Commission
PRR	Protocol Revision Request
RE	Regional Entity
RFC	Reliability First Corporation
RTO	Regional Transmission Organization
RTP	Real Time Pricing
SERC	Southern Electricity Reliability Council
SPP	Southwest Power Pool
VDDR	Variable Dispatch Demand Resource
TO	Transmission Owner

Abstract

In 2007, the Southwest Power Pool (SPP) formed the Customer Response Task Force (CRTF) to identify barriers to deploying demand response (DR) resources in wholesale markets and develop policies to overcome these barriers. One of the initiatives of this Task Force was to develop more detailed information on existing retail DR programs and dynamic pricing tariffs, program rules, and utility operating practices. This report describes the results of a comprehensive survey conducted by LBNL in support of the Customer Response Task Force and discusses policy implications for integrating legacy retail DR programs and dynamic pricing tariffs into wholesale markets in the SPP region.

LBNL conducted a detailed survey of existing DR programs and dynamic pricing tariffs administered by SPP's member utilities. Survey respondents were asked to provide information on advance notice requirements to customers, operational triggers used to call events (e.g. system emergencies, market conditions, local emergencies), use of these DR resources to meet planning reserves requirements, DR resource availability (e.g. seasonal, annual), participant incentive structures, and monitoring and verification (M&V) protocols.

Nearly all of the 30 load-serving entities in SPP responded to the survey. Of this group, fourteen SPP member utilities administer 36 DR programs, five dynamic pricing tariffs, and six voluntary customer response initiatives. These existing DR programs and dynamic pricing tariffs have a peak demand reduction potential of 1,552 MW. Other major findings of this study are:

- About 81% of available DR is from interruptible rate tariffs offered to large commercial and industrial customers, while direct load control (DLC) programs account for ~14%.
- Arkansas accounts for ~50% of the DR resources in the SPP footprint; these DR resources are primarily managed by cooperatives.
- Publicly-owned cooperatives accounted for 54% of the existing DR resources among SPP members. For these entities, investment in DR is often driven by the need to reduce summer peak demand that is used to set demand charges for each distribution cooperative.
- About 65-70% of the interruptible/curtailable tariffs and DLC programs are routinely triggered based on market conditions, not just for system emergencies. Approximately, 53% of the DR resources are available with less than two hours advance notice and 447 MW can be dispatched with less than thirty minutes notice.
- Most legacy DR programs offered a reservation payment ($/kW) for participation; incentive payment levels ranged from $0.40 to $8.30/kW-month for interruptible rate tariffs and $0.30 to $4.60/kW-month for DLC programs. A few interruptible programs offered incentive payments which were explicitly linked to actual load reductions during events; payments ranged from 2 to 40 cents/kWh for load curtailed.

1. Introduction

The Federal Energy Regulatory Commission (FERC) has expressed ongoing interest and support for ensuring comparable treatment of demand-side resources in organized wholesale electric markets administered by regional transmission organizations and independent system operators (FERC 2008b). Regional state organizations are also interested in ensuring that legacy DR resources are capable of participating effectively in emerging wholesale markets. However, the market data available regarding characteristics and operational features of DR resources are often insufficient to support policymakers in their assessment of opportunities and barriers. This study provides baseline information on the status, characteristics, barriers and opportunities for DR resources in the SPP region.

In its September 26, 2006 order, the Federal Energy Regulatory Commission (FERC) directed the Southwest Power Pool (SPP) to either file changes to its tariff allowing demand response (DR) resources to provide imbalance services in its Energy Imbalance Services (EIS) market or show cause for not making changes to the tariff by identifying the specific barriers and issues preventing such market participation. In response to FERC's order, SPP has filed four status and compliance reports regarding DR resources. In its first filing (August 2007), SPP noted that "while there are various aspects of the EIS Market that can currently accommodate various demand resources, there are other aspects that complicate further incorporation into the market." Specifically, SPP identified particular concerns related to the regulated retail nature of some of the potential participants that can offer DR resources.

In order to address these concerns, SPP has undertaken the following activities:

- established a Customer Response Task Force (CRTF) to explore the potential for incorporating DR resources in future markets;
- established a Demand Response Task Force (DRTF) under the Market Working Group (MWG) to assess the development of an economical method for controllable load to participate in the EIS market;
- started work with the ISO/RTO Council (IRC) on two initiatives to advance DR participation in wholesale energy markets; and
- sponsored a Demand Response Educational Forum in July 2008.

Recognizing that retail DR resources in SPP were not particularly well characterized, the CRTF approached the Lawrence Berkeley National Lab (LBNL) for help in planning and fielding a DR survey.[1] The goal of this project was to develop a comprehensive inventory of retail DR programs, dynamic pricing tariffs, and voluntary DR programs in the SPP footprint. This report is organized as follows. Section 2 provides an overview of the wholesale and retail electricity markets in the SPP footprint while Section 3 describes the DR program survey approach and

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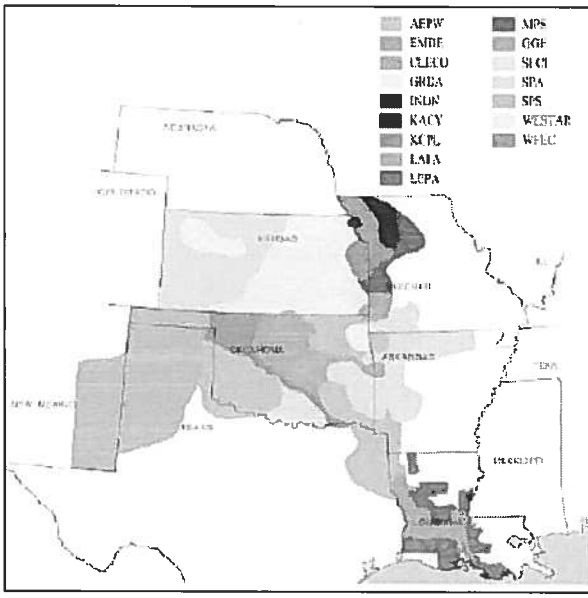
[1] With funding from DOE, LBNL has provided technical assistance to various regional demand response efforts including the New England Demand Response Initiative (NEDRI), Mid-Atlantic Distributed Resource Initiative (MADRI), Midwest Demand Resource Initiative (MWDRI), and the Pacific Northwest Demand Response Project (PNDRP). In 2007, LBNL assessed and characterized retail DR programs in the Midwest ISO foot-print (Bharvirkar et al 2008). This report is the latest in a series of studies that aim to educate and provide valuable information on DR resources to policymakers.

objectives. Sections 4 and 5 present survey results. Barriers to participation of retail DR in SPP wholesale markets are discussed in Section 6. Key findings and conclusions are discussed in Section 7, and recommendations for SPP management are provided in Section 8.

2. Wholesale and Retails Electricity Markets in SPP

The Southwest Power Pool (SPP) is one of nine Regional Transmission Organizations (RTO) approved by FERC to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity. SPP covers a geographic area of 255,000 square miles and manages transmission in Arkansas, Kansas, Louisiana, Missouri, New Mexico, Oklahoma, and Texas (see Figure 1). The SPP footprint includes 16 balancing authorities and 40,364 miles of transmission lines serving over 4.5 million customers and a system peak demand of over 43,000 MW. SPP's membership includes investor-owned utilities, municipal systems, generation and transmission cooperatives, state authorities, independent power producers, power marketers, and independent transmission companies.



Balancing Authorities in the RRO footprint:

CSWS (AEPW)	American Electric Power (formerly Central and South West Services)
CLEC	Central Louisiana Electric
EDE	Empire District Electric Company
GRDA	Grand River Dam Authority
INDN	Independence Power & Light
KACY	Kansas City Board of Public Utilities
KCPL	Kansas City P&L Power Supply
LAFA	City of Lafayette, Louisiana
LEPA	Louisiana Energy & Power Authority
MPS	Missouri Public Service Transmission
OKGE	Oklahoma Gas & Electric Transmission
SECI	Sunflower Electric
SPA	Southwestern Power Administration
SPS	Southwestern Public Service Company
WR	Westar Energy Generation
WFEC	Western Farmers Electric Cooperative

Figure 1. Southwest Power Pool Region Footprint and Balancing Authorities[2]

The SPP region currently has a reserve margin (i.e. generation capacity in excess of peak demand) of 14,074 MW (33%). As of end-2007, the composition of generating capacity in SPP was 54% natural gas-fired.[3] In 2007 there was another 31,000 MW of active generation interconnection requests, of which over three-quarters are for wind projects. SPP's Transmission Expansion Plan (STEP) reflects the need to accommodate new generation and maintain reliability and availability of existing generation, with some $2.2 billion of transmission investment scheduled for the period 2008-2017.[4]

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[2] http://www.spp.org/publications/SPP_Footprints.pdf - Note that Central and Southwest Services (CSWS) is now Central and Southwest Corporation (CSW).

[3] 2007 State of the Market Report Southwest Power Pool, Prepared by Boston Pacific Company, Inc., External Market Advisor for the Southwest Power Pool, April 24 2008. http://www.spp.org/publications/2007_State_of_Market_Report.pdf

[4] SPP Transmission Expansion Plan 2008-2017 – Public Version" Prepared by SPP RTO Staff SPP Engineering Planning ("STEP"), Approved by the SPP Board of Directors on January 29, 2008. http://www.spp.org/section.asp?group=1155&pageID=27

2.1 Wholesale Markets in the Southwest Power Pool

SPP administers an Energy Imbalance Service (EIS) market; participation in this market is mandatory for all balancing authorities, transmission owners, and generators in the SPP footprint. All real-time resource or load imbalances are settled using the EIS Market. However, Market Participants can decide whether to dispatch their own resources (i.e. power plants and/or bilateral contracts) or make their resources available for SPP to dispatch via the EIS Market.

In 2007, EIS market sales were 13.2 million MWh, roughly 8% of total power transactions within the EIS market footprint, with a total value of $670 million.[5] The independent Market Monitor concluded that there were trade benefits (e.g., production cost savings) of over $100 million in the first 11 months of operation in the EIS market, mostly due to dispatch of more efficient, lower-priced units to provide imbalance energy than would have been the case if each Balancing Authority had self-provided its imbalance requirements.[6]

SPP's Market Working Group (MWG) has reviewed the market designs of other organized markets and is considering whether to implement a Day-Ahead Market (DAM) and Ancillary Services Markets (ASM). A cost-benefit study is underway, including modeling of the SPP market over the period 2009-2016 to determine regional benefits. The modeling process will include simulating participation of DR at various levels (i.e., DR resources account for 0.5 % to 1.8% of system peak demand). The cost-benefit study will be broadly circulated to SPP stakeholders and will help inform SPP members whether to pursue additional market development.

2.1.1 DR Participation in SPP Wholesale Markets

In June 2007, the SPP Market Working Group established a Demand Response Task Force (DRTF), which was charged with considering how demand response might be incorporated into the EIS market, coordinating with utilities, state commissions, and other SPP working groups on DR, and drafting protocol revisions and tariff language as needed to incorporate viable forms of demand response into the EIS market. After reviewing industry best practices on DR participation in real-time markets, the DRTF recommended a focus on what MISO refers to as DRR Type II resources – that is, controllable loads, either loads with behind-the-meter generation or loads with the ongoing capability to meet specific reduction amounts based on dispatch instructions. These loads are capable of self-scheduling or being scheduled on a five-minute basis and can be committed and dispatched similar to generation resources.

The DRTF considered two types of controllable loads - Variable Dispatch DR (VDDR), which primarily consists of behind-the-meter generation fitted with SCADA-equivalent real-time telemetry, and capable of offering-in on a five-minute basis, and Block Dispatch DR (BDDR), which consists of fixed blocks of interruptible load each with a distinct price. BDDR is dispatchable only at hourly intervals, and requires after-the-fact interval metering for

[5] SPP EIS Market Footprint differs from the SPP RTO Footprint by the consumption of several entities which are SPP Balancing Authorities but are not SPP EIS Market Participants
[6] http://www.spp.org/publications/EIS%20Trade%20benefit%20report.pdf

performance evaluation. Settlement is possible only at the balancing authority level, as BDDR loads would not be fitted with real-time telemetry.

In August 2008, the DRTF concluded that it would accommodate only the VDDR resource in the existing EIS market, by virtue of its dispatchability within five minutes, interval metering requirements, and ability to accommodate rapid ramp-up and ramp-down. Tariff language to accommodate VDDR into the EIS market has been developed and was approved by MWG in August 2008. Pending development of other wholesale markets to be operated by SPP (e.g., DAM or AS markets), there are no plans to consider other DR resources at the regional level.[7]

2.2 Retail Electricity Markets in the SPP Footprint

SPP Members include many different Market Participants from cooperatives to a federal power-marketing agency (see Table 1). Five investor-owned utilities (American Electric Power, Oklahoma Gas and Electric, Westar Energy, Inc, Southwestern Public Service Company, and Kansas City Power & Light) account for about 75 % of the energy transactions in the SPP market, with rural cooperatives accounting for most of the current demand response activity.

Table 1. Southwest Power Pool Membership Composition[8]

Type of Entity	Number of Entities
Investor-owned utilities (IOU)	12
Cooperatives	11
Municipal utilities	8
State Agencies	2
Power Marketers	11
Independent Power Producers	4
Independent Transmission Companies	2
TOTAL	**50**

Balancing authorities provide ancillary services and coordination in SPP (see Table 2). As of 2007, the total non-coincident peak demand in SPP is 42,884 MW and the generation capacity is 56,050 MW - yielding a reserve margin of ~31% across SPP. However, the reserve margin varies substantially among the balancing authorities with highest (113%) for SWPA and lowest (-8%) for LEPA.

[7] PRR 176 Recommendation Report: Demand Response in the SPP EIS Market. http://www.spp.org/publications/MWG082208Minutes.pdf

[8] SPP membership at the time of our survey; recently three entities from Nebraska have joined SPP. http://www.spp.org/section.asp?pageID=4

Table 2. Balancing Authorities in SPP Region

Balancing Authority	Type of Entity	Sales (million MWh)	Non-coincident Peak Demand (MW)	Generation Capacity (MW)	Reserve Margin (%)
American Electric Power West	IOU	46.98	10,013	13,713	37
Oklahoma Gas and Electric	IOU	29.85	6,317	8,269	31
Westar	IOU	29.81	6,138	6,603	8
Southwestern Public Service	IOU	27.72	5,044	5,794	15
Kansas City Power and Light	IOU	16.89	3,689	4,612	25
Cleco Power	IOU	10.43	2,104	4,242	102
Missouri Public Service	IOU	9.04	1,999	1,947	-3
Southwestern Power Administration (SWPA)	Federal	7.50	1,632	3,475	113
Western Farmers Electric	Coop	7.09	1,369	1,328	-3
Empire District	IOU	5.51	1,177	1,377	17
Sunflower Electric	Coop	5.17	995	1,375	38
Grand River Dam Authority	State	4.48	909	1,607	77
Kansas City BPU	Muni	2.60	512	743	45
City of Lafayette	Muni	2.03	478	493	3
Independence City P&L	Muni	1.19	308	288	-6
Louisiana Energy and Power Authority (LEPA)	State	1.00	200	184	-8
SPP TOTAL		**20.73**	**42,884**	**56,050**	**31**

3. Survey Objectives and Approach

The primary objectives of the survey were to characterize existing retail DR programs and dynamic pricing tariffs administered by SPP member utilities and identify potential barriers to utilization of DR resources in wholesale and retail markets. The survey template was developed by LBNL with input from the SPP Customer Response Task Force (CRTF). The SPP CRTF transmitted the survey to all SPP members and requested their cooperation. LBNL compiled the survey data, conducted follow-up interviews (including interviews with several distribution cooperatives whose wholesale requirements were served by SPP members) and quality assurance/consistency checks on survey responses, supplemented survey data with information from other sources, and analyzed the survey results.

Utilities were asked to provide information on retail DR programs (e.g., interruptible, direct load control or DLC, emergency programs, and demand bidding programs where events are triggered by high prices), dynamic pricing tariffs (including Real Time Pricing, or RTP; and Critical Peak Pricing, or CPP), and voluntary DR programs (i.e., a program where customers voluntarily participate and make a "best efforts" attempt to curtail load when requested but are not compensated).

Interruptible rate programs provide a rate discount or bill credit to the customer for curtailing or shedding load upon request. Typically, interruptible programs are offered to larger industrial and commercial customers and often involve penalties if the customer fails to curtail load when requested to do so. DLC programs involve an end-user (typically, residential or small commercial) who agrees to allow their utility to control an appliance or device within certain pre-set limits of frequency and duration. Participants in DLC programs typically receive compensation in the form of bill credits and/or payments based on performance during events. Customers enrolled in a Demand Bidding or Economic DR program offer bids to curtail load based on market prices. These programs are mainly offered to large customers; however, some utilities also allow aggregation of small customer loads.

An RTP tariff provides variable hourly pricing for all hours of the year, while a CPP tariff provides variable pricing only for a relatively few number of hours per year when the utility calls a CPP event. A one-part RTP tariff assesses all volumetric (per kWh) charges based on variable hourly prices. A two-part RTP tariff incorporates a customer baseline (CBL) usage that establishes a long-term average hourly usage profile for each customer. Variable hourly prices are applied only to the differences between actual hourly load and the CBL. A two-part RTP tariff effectively provides a hedge against the implicit price-exposure risk of variable hourly prices as the bulk of a customer's consumption is billed on the customer's otherwise applicable tariff. Hourly prices can be indexed to wholesale energy market prices (i.e. either day-ahead or real-time) or utility marginal costs.

4. Survey Results: Overview of Existing DR Resources

The SPP Retail DR Survey was sent to all 50 SPP members, including utilities, generators, power marketers, and transmission companies.[9] Virtually all of the 30 load-serving entities (LSE) responded to the survey. Among this group, 14 LSEs offered a total of 48 demand response programs and/or dynamic pricing tariffs (see Table 3).

Table 3. SPP Retail DR Survey Response

Type of Entity	Number of Surveys Fielded	Number of Responses Received	Load-Serving Entities with DR Programs	Number of DR Programs and/or Tariffs
Cooperatives	11	11	6	13
Municipal utilities	8	8	1	5
Investor-owned utilities	12	10	7	30
State Agencies	2	2	0	0
IPPs	4	0	N/A	N/A
Power Marketers	11	0	N/A	N/A
Transmission Companies	2	0	N/A	N/A
Total	**50**	**31**	**14**	**48**

4.1 Existing DR Resources

The size of the DR resource is defined as the potential peak load reduction that the utility expects from the DR program or dynamic pricing tariff (this benchmark is consistent with the approach taken by FERC and EIA in earlier surveys). On this basis the utilities reported retail DR resources totaling 1,552 MW, with DR programs accounting for 87% of the total DR resource (see Table 4).

Table 4. Existing DR Resources in SPP

	DR Programs	Dynamic Pricing Tariffs	Voluntary Customer Response Initiatives
Entities with DR Activities	13	5	4
Number of Programs	36	6	6
Potential Coincident Peak Demand Reduction	1,352 MW *(26)*	200 MW *(5)*	N/A
Number of Eligible Customers	382,364 *(30)*	16,886 *(5)*	N/A
Number of Customers Enrolled	63,388 *(27)*	70 *(6)*	N/A

Note: Numbers in parentheses indicate the programs, tariffs, and initiatives that provided this information.

Our survey estimate of the existing DR Resource in the SPP region is consistent with earlier estimates developed by FERC (2006) and somewhat higher than the most recent estimate reported by the ISO/RTO Council (2007) and FERC (2008a). We attribute these differences to the higher response rate of SPP members in our survey. Our estimate of existing DR resources is also considerably higher than the most recent NERC Regional Reliability Assessment (NERC

9 Fifty entities were SPP members at the time of the survey; three entities from Nebraska have joined SPP recently.

2008). The difference in these aggregate numbers may be definitional, as NERC collected data on DR that is dispatchable by the operator to reduce load. Thus the NERC numbers may exclude Economic/Demand Bidding and Buyback programs as well as Dynamic Pricing Tariffs.

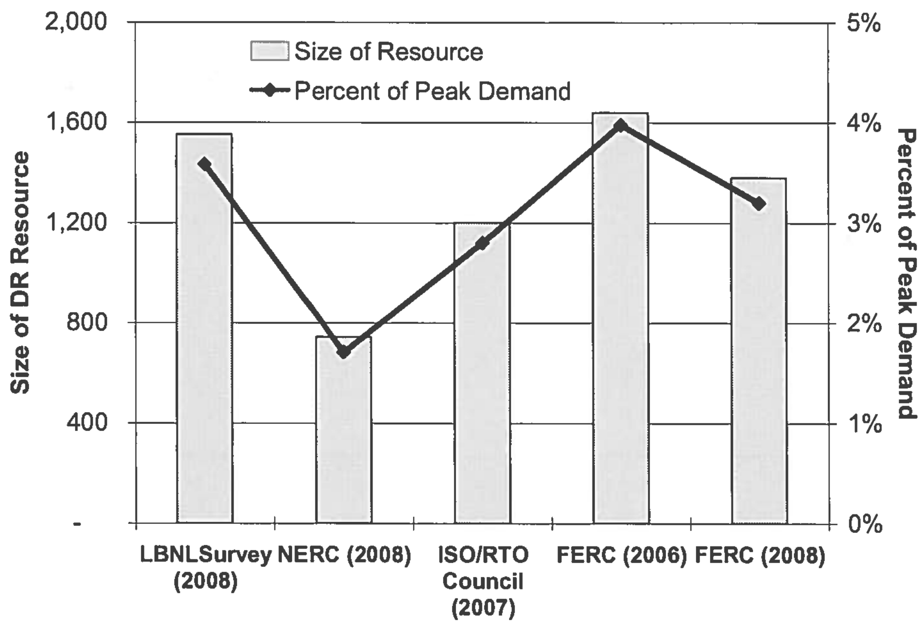

Figure 2. Estimates of existing DR Resources in the SPP Region

There is a large variation in the amount of DR Resources across the seven states partially or wholly contained within the SPP region (see Figure 3). For example, in Louisiana no DR resources were reported while Arkansas (i.e. parts that are contained within the SPP footprint) accounted for ~49% of the total DR resources in the region. Potential load reductions from all DR resources accounted for ~46% of the non-coincident peak demand in Arkansas - one of the highest DR market penetration levels in the US. Across the entire SPP footprint, existing DR resources account for ~3.7% of system peak demand, somewhat lower than the national average.

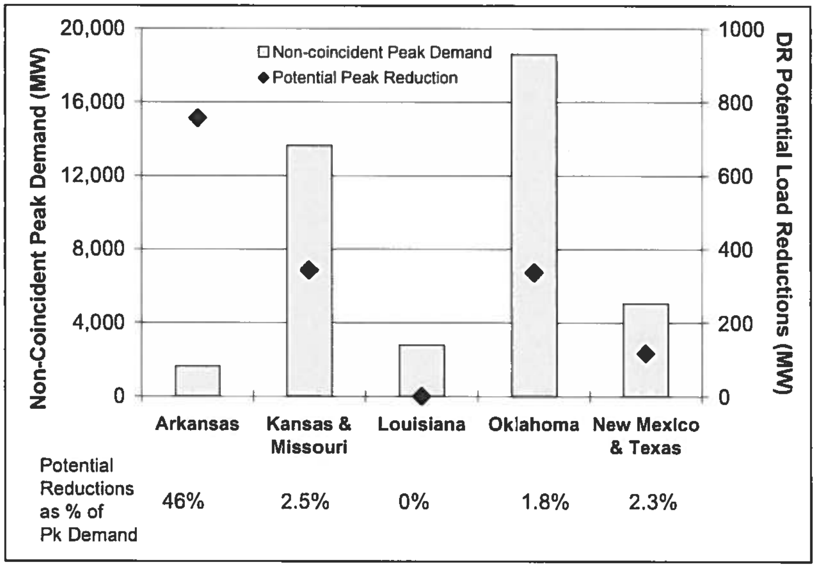

Figure 3. Demand Response Resources by State

Cooperatives account for 80% of the DLC resource and 53% of the interruptible/curtailable resource; the majority of which is located in Arkansas (see Figure 4). Investor-owned LSEs in Missouri, Kansas and Oklahoma account for the bulk of the remaining DR resources in the SPP footprint.

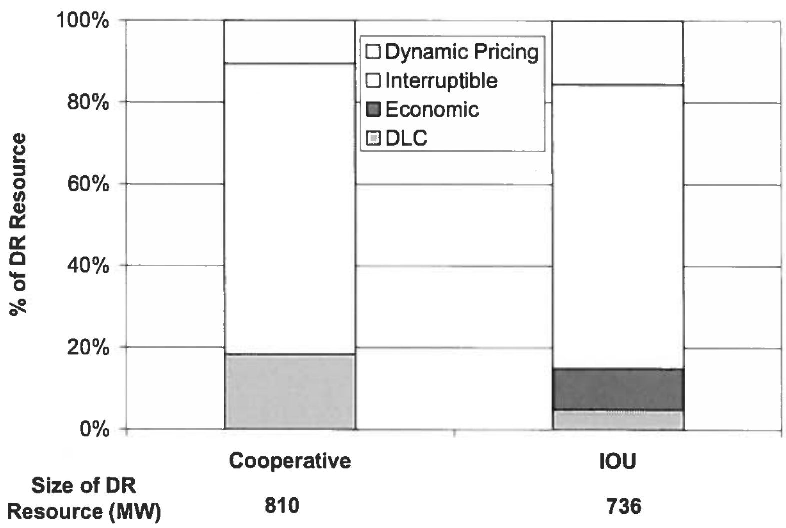

Figure 4. Existing Demand Response Resources by Type of Entity

Large portions of western Arkansas are served by 17 electric distribution cooperatives that also collectively own the generation and transmission assets serving their load. Investment in DR is mainly a result of the need to reduce summer peak demand that determines the demand charge for each distribution cooperative.[10] Transmission network interval load data is shared over the Internet, allowing the distribution coops and their retail customers to anticipate the coincident peak demand day and reduce their demand accordingly. Mass market DR programs such as direct load control for irrigation pumping, household and commercial air conditioners, and water heaters are used extensively in order to minimize non-coincident peak demand and maintain a high load factor.

The very high penetration levels of demand response in Arkansas cooperatives can be traced to three factors: (i) long-term stability in the type of price signals sent; and (ii) sufficient bill savings potential to gain active customer participation and interest; and (iii) avoiding over-payment of incentives, so there is sufficient savings for participants, non-participants, and utility management.

4.2 DR Program Characteristics

The survey requested detailed information on a range of DR program characteristics, including operational triggers, frequency of events, advance notice provided, program duration, participation requirements (e.g. size thresholds, market segments, etc.), communications arrangements, and monitoring and verification protocols. This section discusses these program characteristics and their implications for DR participation in SPP's EIS and planned day-ahead and ancillary services markets.

4.2.1 Operational Triggers

Respondents were asked to describe conditions that triggered the operation of their DR Programs. The options provided in the survey question included maintaining system reliability (e.g., system emergencies), reducing the cost of procuring power during high price periods (e.g., responding to market conditions), addressing local reliability or congestion problems, and meeting contractual obligations.

The dispatch trigger pattern is quite different for DLC and interruptible programs (see Figure 5). Seventy percent of DLC resources are triggered based on market conditions, while only 20% and 41% of DLC resources are dispatched for system emergency and local conditions, respectively. This likely reflects the use of DLC by distribution cooperatives for flattening out their load shape and minimize coincident transmission system peaks, thereby achieving substantial savings in their demand charge.

In contrast, almost 100% of the DR resources available from interruptible programs in the SPP region could be interrupted for system emergencies. Approximately, 67% of interruptible resources could also be dispatched in response to market conditions and 27% could be deployed for addressing local conditions. This is consistent with trends in MISO and elsewhere and suggests that these interruptible tariffs could be reconfigured to be bid into SPP's existing and future wholesale markets.

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[10] The bulk power tariff includes a ratcheted demand charge based on each coop's contribution to the previous summer's transmission system peak demand. Large retail customers have interval meters and are subjected to the same ratcheted demand charge structure as distribution coops.

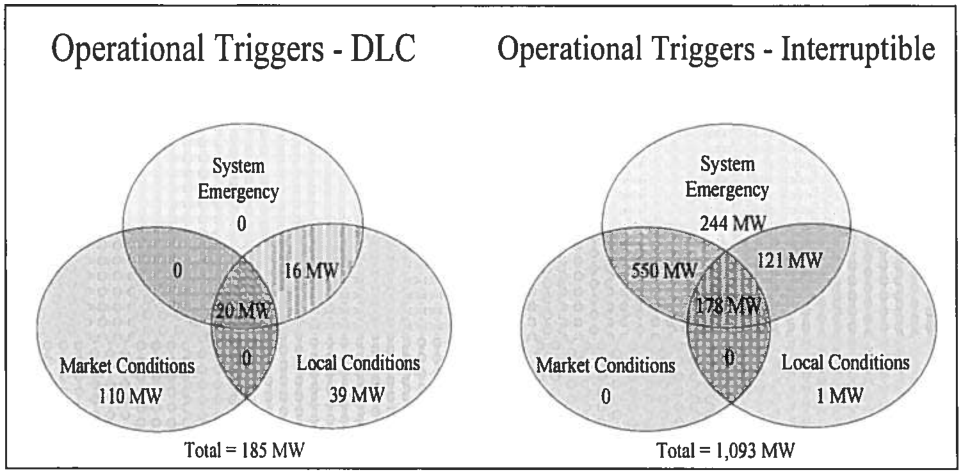

Figure 5. Operational Triggers for Direct Load Control and Interruptible Tariffs in SPP

Several respondents noted that operational triggers are in rapid flux. For example, one cooperative reported that starting in 2008 up to half the allowed hours of operation allowed under Interruptible Load contracts can be for any reason, including economics. This is in contrast to past rules, which restricted interruptions to capacity shortages and exposure to coincident peak demand charges.

4.2.2 Advance Notice Requirements

Advance notice requirements vary considerably across DR Program types (see Figure 6). DLC programs were uniformly reported to have no notice requirements. This lack of advance notice would be a real advantage in configuring DLC resources for SPP's EIS market and potentially in a future AS market, provided the stringent operational requirements are met.

All of the reported Economic/Demand Buyback resources require less than 30 minutes notice, suggesting that this resource as well could be reconfigured for the EIS market. In contrast, about 58% of the DR resources on interruptible tariffs require more than two hours of advance notice, which is unacceptable for the EIS or ancillary services markets but could work for day-ahead energy markets.

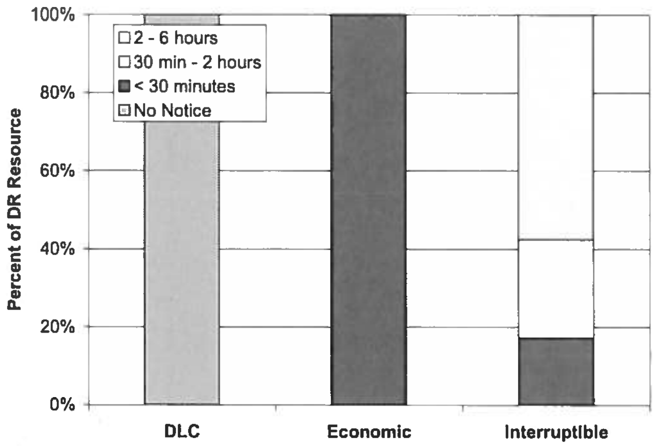

Figure 6. Advance Notice Requirements for SPP DR Programs

4.2.3 Participation Requirements

Respondents reported relatively few minimum requirements for participation in DR Programs. DR programs accounting for 64% of the total DR resource reported no minimum load reduction requirements. This suggests relatively flexible and customer-friendly program rules, which could contribute to rapid scaling-up of DR should sufficient incentives be made available via wholesale or retail markets.

4.2.4 DR incentive payments

Respondents were also asked to report on how participants were compensated for participating in DR programs, as well as the basis for determining incentive levels. We found significant differences in incentive design and compensation levels across cooperatives and IOUs and also across states, and program types. Incentives were provided in three forms:

1. Capacity payments (i.e. $/kW offered per month),
2. Performance payments ($/kWh paid according to a single event)
3. Capacity-performance payment combinations (i.e. both $/kW and $/kWh).

Many cooperatives calculate the incentive for partial or total control of various end uses based on a flat monthly per-kW incentive, converted into a flat monthly incentive based on the control strategy and the coincident demand of the end use. For example, participants in a residential air conditioner load control program might get $5 off on their summer monthly bill, while participants in a water heater load control programs might get $1 off their bill year round.

For larger customers, coops and IOUs offer a choice of firm and non-firm service for specific loads such as pumps or processes. Commercial and industrial customers can access large discounts on the fixed charge for non-firm service, levied as a horsepower or demand charge, in exchange for taking non-firm service. For example, large pumping loads served by a Kansas distribution cooperative would face a monthly firm service charge of $13 per hp ($17.42/kW) but a non-firm charge of only $1.75 per hp ($2.35/kW). Non-firm irrigation pumping loads are controlled on a regular schedule allowing growers sufficient flexibility to work around the hours of interruption.

Only 17 of the 36 DR programs provided information on incentive levels and design. Five DLC and six interruptible programs provide a capacity-type incentive that ranges from \$0.3 to \$4.6/kW-month and \$0.4 to \$8.3/kW-month, respectively. Five interruptible tariffs provide only a performance payment ranging from 2 to 40 cents/kWh. One interruptible tariff provided a combination of capacity and performance payment (\$1.2/kW-month and \$0.20/kWh).

We also asked respondents about the basis used for setting incentive levels for DR programs. Respondents reported that they typically looked at more than one factor in setting incentive levels (see Table 5). Consideration of marginal capacity costs and the cost of a peaking unit (e.g., a natural gas-fired combustion turbine) were used as the basis by DR programs accounting for ~70% of the potential load reductions. Programs accounting for ~18% of the DR resources used the cost of onsite generation as the basis to set incentive levels.

Table 5. Basis for Compensating Demand Response Program Participants

Cost/Compensation Basis	DLC (MW)	Economic (MW)	Interruptible (MW)	TOTAL (MW)
Marginal Capacity Costs (MCC)	39	74	128	241
MCC & Peaking Unit Proxy	16		563	579
MCC & Customer-owned generation			60	60
Peaking unit proxy			63	63
Value of Service			27	27
Cost of customer-owned generation			239	239
Negotiated			8	8
Not Applicable (no incentive)	20			20
Unknown			5	5
Varies for each member coop	110			110
TOTAL	185 MW	74 MW	1,093 MW	1,352 MW

Clearly, opening up SPP's EIS Market to participation by certain types of qualifying DR resources will create an important new benefit stream and provide a new reason for Market Participants to expand existing or develop new DR programs. If SPP establishes additional markets (e.g., Day-Ahead Energy and Ancillary Services), this will further expand opportunities for existing (and new) DR resources.

4.2.5 Recent Performance and Frequency of DR Events

Respondents were asked to report how frequently their DR programs operated, including recent performance. Respondents reported (see Table 6) that DR programs accounting for 96% of the total resource in SPP were deployed at least once in 2007. However, dispatch was relatively infrequent, with ~70% of the DR resources deployed less than five times.

Table 6. Recent Performance of Demand Response Programs

Frequency of DR Events	DLC (MW)	Economic (MW)	Interruptible (MW)	TOTAL (MW)
No events	39	12		51
1 to 5	16	62	864	942
5 to 25	20		8	28
> 25			14	14
Varies by member coop	110			110
Unknown			208	208
TOTAL	185 MW	74 MW	1,093 MW	1,352 MW

It should be noted that DR programs accounting for ~15% of the resource did not provide information about program performance. This infrequent utilization is likely a function of high reserve margins currently enjoyed by many LSEs in the region. However, many respondents indicated that demand growth in their service territories could result in increased DR operations over the next few years.

5. Dynamic Pricing Tariffs and Voluntary Customer Response Activities

In section 4, we focused on DR programs that can be triggered by the distribution utility through either interruption or control requests. We also asked survey respondents about two other types of DR activities – dynamic pricing tariffs and voluntary customer response initiatives - which are described in this section.

5.1 Dynamic Pricing

The survey identified five utilities (3 investor-owned and 2 cooperatives) offering one CPP and five RTP tariffs in four states (Oklahoma, Kansas, Missouri, and Arkansas) in the SPP footprint. Four of the five RTP tariffs were of the two-part design (i.e. only incremental load above a base amount was billed at RTP).

In 2007, a total of 70 customers were enrolled, accounting for 304 MW of peak demand and 200 MW of potential demand reduction. The largest demand reduction achieved as a result of the dynamic pricing tariff was 133 MW when prices reached $0.28/kWh.

Eligibility for participation in dynamic pricing tariffs in all cases was restricted to commercial and industrial customers. All but one of the tariffs operated on a year-round basis, and recruitment was strictly on an "opt-in" basis for all utilities. In most (5 of 6) cases customers taking service on a dynamic pricing tariff were not allowed to participate in other DR programs.

Price notification was by Internet for all five of the RTP tariffs and based on day-ahead wholesale prices. All of the participants had access to their interval load data in some form, with two tariffs offering near real-time interval load data availability and two more offering interval data on a day-after basis. Load impact estimation methods varied, with only half reporting on M&V and several methods reported (e.g., day-matching, econometric, customer baseline).

Only two of the five utilities allowed the forecast load impacts of dynamic pricing to be counted towards Reserve Margin requirements. However, none of the dynamic pricing impacts were considered in scheduling Residual Unit Commitments or meeting real-time imbalance requirements.

5.2 Voluntary Customer Response Initiatives

Six voluntary customer response initiatives were reported by four utilities (two IOUs and two cooperatives) in six states (Oklahoma, Texas, Louisiana, Kansas, Missouri, and Arkansas). One IOU accounted for half of these in three of the states. Recruitment for participation in these initiatives has been through existing account management initiatives and in one case through radio appeals.

Large customers ($\geq$ 750 kW) were typically targeted and requests for load reductions were made via email. No monetary compensation was offered for any of the voluntary DR initiatives. Five of these programs have been called at least once, but none have been evaluated; thus the utility did not provide an estimate of peak demand reduction for this voluntary DR initiative.

6. Barriers to Retail DR

We also conducted follow-up telephone interviews of SPP member utilities, which focused on barriers encountered in implementing or scaling-up demand response activities and suggestions for SPP management.

These interviews revealed considerable disparity in the level of effort focused on demand response implementation across the respondents. The lowest DR program participation levels (on the order of 1-2 % of system peak demand) appear to be a result of either lack of DR programs offered or promoted, an unwillingness on the part of customers to be inconvenienced, or incentives that are set too low to attract participants.

Several municipalities in Oklahoma previously attempted DLC programs that did not work because the air conditioners were too small and thus the cycling caused customer discomfort that was unacceptable, given the incentive levels. Other respondents reported that incentive levels based on marginal capacity costs less program expenses were insufficient to attract and hold customers.

Several municipal and investor-owned utilities reported previous unsuccessful efforts with retail demand response programs. Several utilities had programs "on the books" but with no participants and no active marketing efforts because reserve margins are high at present.

A number of respondents offered suggestions for SPP management to consider that could help overcome barriers to DR. These include:

Technical Assistance - A few respondents suggested that both customers and utility employees should be made aware of the value of DR programs and provided with technical assistance in designing and implementing them. DR is a relatively new concept in SPP and respondents from utilities that crossed several jurisdictions noted that DR participation is much lower in their Southwestern operating subsidiaries than in other areas of the country that they serve.

Education/Information - A number of survey respondents suggested that SPP can play an important role in promoting initiatives such as establishing common terminology for DR and common understanding of DR concepts across the membership. SPP could promote education and awareness about DR programs and facilitate dialogue among stakeholders (e.g., customers, utility management, and regulators) that need to participate and support DR. A regional initiative similar to that undertaken in other regions can provide a versatile platform for informing and facilitating DR policies. Finally, it was suggested that SPP should track and report on DR implementation experience and best practice throughout the region.

Changes to Market Rules - Several respondents suggested that SPP should accelerate efforts to integrate DR resources in SPP's existing wholesale market (EIS). Although some progress has been made by the DRTF, SPP should consider expanding its outreach efforts to Market Participants in order to help identify existing retail DR program participants that might be eligible to offer Variable Dispatch DR (VDDR) resources in the EIS market and expanding eligibility to include Block Dispatch DR (BDDR) resources.

7. Findings and Conclusions

The primary objectives of this study were to provide policymakers, regulators, and other stakeholders in SPP with baseline information on existing DR resources and barriers to integrating retail DR programs in existing and proposed wholesale markets.

Fourteen SPP member utilities reported existing retail DR resources totaling 1,552 MW, of which ~81% comes from interruptible rate tariffs targeted at large industrial and commercial customers. Across the entire SPP footprint, existing DR resources account for ~3.7% of system peak demand. The SPP region has a somewhat lower level of DR participation in retail and wholesale markets compared to other ISOs/RTOs. This may be due to historically high reserve margins, although our interviews with SPP members suggest that lack of awareness of the importance of demand response in reducing costs and increasing market efficiency may also be factors.

We found significant variation among states in the deployment of existing DR resources. For example, in Louisiana, SPP members reported no DR resources, while in Arkansas, potential load reductions from existing DR resources account for ~46% of the non-coincident peak demand. A very strong incentive structure in the form of ratcheted demand charges is one of the main reasons behind the widespread use of DR programs in Arkansas.

We found considerable diversity in DR program characteristics among LSEs. This suggests that integration of existing retail DR programs and tariffs in the SPP market may require significant effort initially to develop consistent program requirements and protocols. At the same time, certain aspects of existing DR programs such as lack of minimum participation requirements, eligibility of on-site generation to participate, and use of multiple operating triggers suggests that existing retail DR program designs are flexible and can be reconfigured to meet the needs of the existing and future SPP wholesale markets.

Retail DR programs operated by distribution cooperatives can provide a potentially large DR resource to the SPP market. The cooperatives account for ~80% of the DLC resource, a large portion (~70%) of which is routinely triggered based on market conditions and require no advance notice prior to dispatch. These cooperatives have already proven to be leaders in configuring their DR programs for optimal economic benefit to customers and may be able to extract additional benefits for their customers from bidding DR resources into existing and emerging wholesale markets.

A few investor-owned utilities are offering voluntary real-time pricing for large customers. However, the reported contributions are small relative to dispatchable DR (200 MW reported vs. 1352 for DR programs), and the forecasted demand reduction from dynamic pricing are not currently included in resource adequacy planning. Some respondents noted that regulators and senior managers at utilities are considering smart meters and Advanced Metering Infrastructure (AMI). Widespread deployment of AMI can allow expansion of dynamic pricing tariffs to more customers.

SPP could help facilitate the development of DR resources and their effective participation in the SPP wholesale markets through activities such as raising awareness of DR benefits and costs, providing technical assistance, and creating a forum for developing consensus among stakeholders (e.g. policymakers, regulators, utilities, and others). In Table 7, we offer a number of suggestions for SPP to consider as part of an action plan that could enhance awareness and promote consideration of DR in wholesale and retail market and system operations.

Table 7. Suggested Activities for SPP to promote Demand Response

Suggested Activity for SPP	Suggested Action Plan and potential next steps
Promote basic standardization, such as common terminology for DR and common understanding of DR concepts across the membership;	1. Consider adopting a DR terminology section within the SPP operating manuals 2. Review existing DR terminology/glossary chapters from PJM, NYISO 3. Begin participating in the NAESB Wholesale DR committee 4. Develop a brochure on DR opportunities for SPP Members
Facilitate awareness building and dialogue among entities that need to participate and support DR	1. Increase participation in ISO/RTO Council (IRC) DR activities 2. Set specific goals and objectives and end states or outcomes for an SPP regional initiative on DR 3. Enter into a dialogue with other ISO/RTO that have participated in regional DR initiatives in order to assess potential value
Identify specific RTO actions that could be taken to support development of more retail DR	1. Consider pro-active efforts, such as pilot projects (e.g., auto-DR, residential smart-stats), to increase opportunities for existing retail DR to bid into SPP wholesale markets 2. Outreach to key distributor groups – e.g., NRECA – to identify most-promising DR opportunities
Track and report on implementation experience in the SPP footprint	1. Actively cooperate with NERC and FERC on DR data gathering for the SPP market 2. Work with state regulators & regional reliability entities to coordinate reliability assessments, resource adequacy planning 3. Prepare case studies that highlight best DR practices, drawing from SPP DR survey results 4. Follow-up on good practice gaps identified in this study, such as lack of standardized M&V procedures

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Coordination of Retail Demand Response with Midwest ISO Wholesale Markets

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May 2008

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Coordination of Retail Demand Response with Midwest ISO Wholesale Markets

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Acronyms and Abbreviations

A/C	Air Conditioners
CBL	Customer Baseline Load
CPP	Critical Peak Pricing
DLC	Direct Load Control
DOE	U.S. Department of Energy
DR	Demand Response
EIA	Energy Information Administration (DOE)
EDR	Emergency Demand Response
EEA	Electricity Emergency Alert
FERC	Federal Energy Regulatory Commission
IRC	ISO/RTO Council
ISO-NE	New England Independent System Operator
LMP	Locational Marginal Price
LBNL	Lawrence Berkeley National Laboratory
LSE	Load-Serving Entity
MISO	Midwest Independent System Operator
MP	Market Participant
MRO	Midwestern Reliability Organization
MWDRI	Midwest Demand Resources Initiative
M&V	Measurement & Verification
NYISO	New York Independent System Operator
PJM	PJM Interconnection, LLC
PUC	Public Utility Commission
RAP	Regulatory Assistance Project
RFC	Reliability First Corporation
RTO	Regional Transmission Organization
RTP	Real Time Pricing
SERC	Southern Electricity Reliability Council

Abstract

The Organization of Midwest ISO States (OMS) launched the Midwest Demand Resource Initiative (MWDRI) in 2007 to identify barriers to deploying demand response (DR) resources in the Midwest Independent System Operator (MISO) region and develop policies to overcome them. The MWDRI stakeholders decided that a useful initial activity would be to develop more detailed information on existing retail DR programs and dynamic pricing tariffs, program rules, and utility operating practices. This additional detail could then be used to assess any "seams issues" affecting coordination and integration of retail DR resources with MISO's wholesale markets.

Working with state regulatory agencies, we conducted a detailed survey of existing DR programs, dynamic pricing tariffs, and their features in MISO states. Utilities were asked to provide information on advance notice requirements to customers, operational triggers used to call events (e.g. system emergencies, market conditions, local emergencies), use of these DR resources to meet planning reserves requirements, DR resource availability (e.g. seasonal, annual), participant incentive structures, and monitoring and verification (M&V) protocols. This report describes the results of this comprehensive survey and discusses policy implications for integrating legacy retail DR programs and dynamic pricing tariffs into organized wholesale markets. Survey responses from 37 MISO members and 4 non-members provided information on 141 DR programs and dynamic pricing tariffs with a peak load reduction potential of 4,727 MW of retail DR resource. Major findings of this study area:

- About 72% of available DR is from interruptible rate tariffs offered to large commercial and industrial customers, while direct load control (DLC) programs account for ~18%. Almost 90% of the DR resources included in this survey are provided by investor-owned utilities.
- Approximately, 90% of the DR resources are available with less than two hours advance notice and over 1,900 MW can be dispatched on less than thirty minutes notice. These legacy DR programs are increasingly used by utilities for economic in addition to reliability purposes, with over two-thirds (68%) of these programs callable based on market conditions.
- Approximately 60% of DLC programs and 30% of interruptible rate programs called ten or more DR events in 2006. Despite the high frequency of DR events, customer complaints remained low. The use of economic criteria to trigger DR events and the flexibility to trigger a large number of events suggests that DR resources can help improve the efficiency of MISO wholesale markets.
- Most legacy DR programs offered a reservation payment ($/kW) for participation; incentive payment levels averaged about $5/kW-month for interruptible rate tariffs and $6/kW-month for DLC programs. Few programs offered incentive payments that were explicitly linked to actual load reductions during events and at least 27 DR programs do not have penalties for non-performance.
- Measurement and verification (M&V) protocols to estimate load impacts vary significantly across MISO states. Almost half of the DR programs have not been evaluated in recent times and thus performance data for DR events is not available. For many DLC programs, M&V protocols may need to be enhanced in order to allow

participation in MISO's proposed EDR schedule. System operators and planners will need to develop more accurate estimates of the load reduction capability and actual performance.

1. Introduction

The unusually hot summer of 2006 broke peak electricity demand records in most parts of the country, including the Midwest. The success of system operators across the nation in "keeping the lights on" despite record peak demands was partially due to the use of demand response (DR) resources (Hopper et al. 2007). The Midwest Independent System Operator (MISO) called on retail DR programs and tariffs to provide emergency operating reserves on both August 1 and 2, 2006. On these days MISO operators declared an Energy Emergency Alert (EEA) Level 2 and requested Load Serving Entities (LSEs) to interrupt non-firm load. A 3,000 MW drop in peak demand (see Figure 1) on August 1^{st} and 2,000 MW on August 2^{nd} were sufficient to avoid triggering scarcity pricing and helped minimize the possibility of outages.

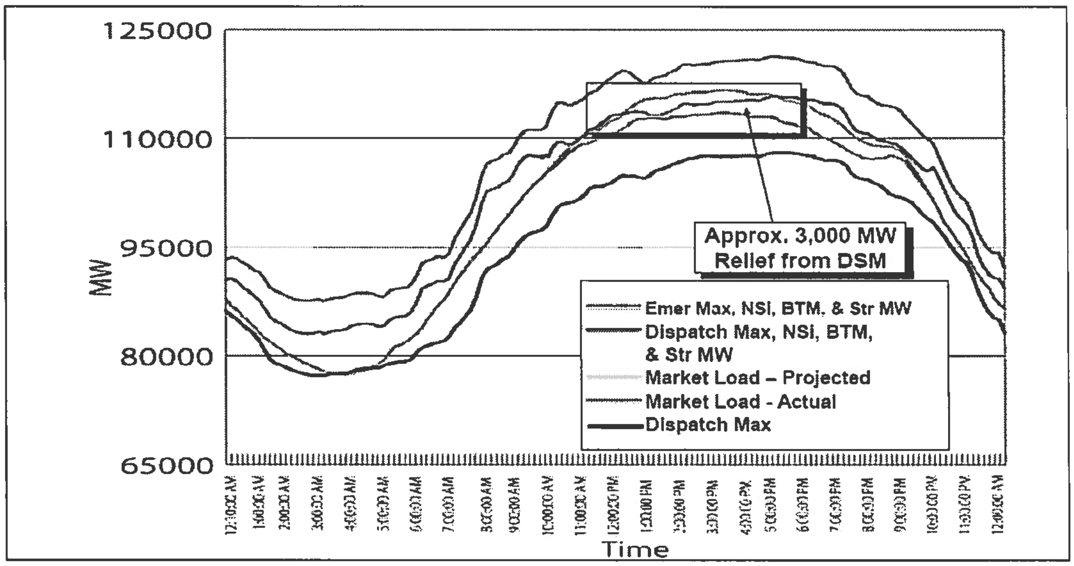

Figure 1: Midwest ISO August 1 2006 Generation and Load Summary (MISO, 2006)

Although an impressive demonstration of the value of demand response, these emergency operations revealed discontinuities between the needs of regional system operators and the organization of retail demand response programs. Since MISO did not have a regional emergency demand response program in place, load reductions were achieved according to the legacy retail program procedures of individual LSEs and states.[1] MISO was unable to predict or control the amount of DR resources needed to maintain system reliability, and the load reductions undertaken by LSEs and their customers could not be compensated by MISO.[2] Moreover, some LSEs and large customers were actually penalized for responding to the MISO dispatcher request for load interruptions during the August 1-2, 2006 emergency because of

[1] "Legacy" retail programs refer to those DR programs administered by LSEs that existed before the formation of MISO.

[2] In some cases utilities compensated retail customers for load reductions according to the tariffs (e.g. interruptible contracts).

MISO market rules governing departures from scheduled generation and deviations from accepted load offers at the balancing authority level.[3]

Inclusion of retail DR resources in resource adequacy planning and use of these resources in regional transmission operations requires coordination between wholesale and retail electricity markets. When MISO called for emergency demand response in August 2006, not much was known on a region-wide basis about the quantity and type of retail DR resources that could be expected to respond and under what conditions. These retail programs range from legacy interruptible contracts with large customers to load control programs for small residential and commercial customers.

This report describes a survey undertaken to inventory retail DR resources that can provide sufficient aggregated loads to be valuable as an emergency resource at the regional level. The survey collected detailed information regarding the operational capabilities and limitations of retail DR resources. An important objective of the study was to help identify issues that MISO members, state regulators and other stakeholders may need to address in incorporating legacy retail DR programs and dynamic pricing tariffs into MISO wholesale markets. The study is organized as follows. Section 2 provides an overview of the wholesale and retail electricity markets in the Midwest while Section 3 describes institutional arrangements and stakeholders in the Midwest ISO and Organization of Midwest States. Section 4 reviews the existing and future role of DR resources in MISO markets and operations. The DR program survey approach and scope is described in Section 5, while survey results are presented in Sections 6 and 7. Key findings and conclusions are discussed in Section 8.

[3] FERC subsequently waived these penalties (also referred to as "uplift charges") retroactively and proposes to eliminate them in its Notice of Proposed Rulemaking, "Wholesale Competition in Regions with Organized Electric Markets" (Docket Nos. RM07-19-000 and AD07-7-000), February 22, 2008.

2. Wholesale and Retail Electricity Markets in the Midwest

Established in 2001, MISO is one of nine independent and regional transmission organizations (RTOs) that the FERC has approved to carry out regional system and market operations. MISO extends over a broad reach of Midwestern North America, from eastern Montana and the Canadian province of Manitoba through the upper Midwest and south to parts of Kentucky and Missouri (see Figure 2). MISO is responsible for the reliable operation of nearly 94,000 miles of interconnected high voltage power lines serving more than 100,000 MW of demand and 40 million people throughout the Midwest, as well as administering one of the world's largest energy markets, and ensuring that the Midwestern bulk power infrastructure expands to meet the growing regional demand for power.

Figure 2: MISO Reliability "Footprint" (Source: ICF, 2007)

Development of a regional transmission operator and organized wholesale markets in the Midwest has taken a distinctive path compared to other RTOs such as New England or PJM. In 2005 MISO became the first multi-state RTO without a history of tightly-pooled power sharing arrangements to implement organized wholesale energy markets (day-ahead and real time) with centralized economic dispatch and locational marginal pricing. In doing so MISO and its stakeholders grappled with several complicated issues: (i) the need to accommodate the reliability rules of four different regional reliability entities (Mid-America Interconnected Network or MAIN, East Central Area Reliability Coordination Agreement or ECAR, Mid-Continent Area Power Pool or MAPP,; and SERC, or SERC Reliability Corporation); (ii) 16 retail jurisdictions with varying approaches towards retail competition and mix of electric utility ownership structures;[4] and (iii) the need for a single transmission tariff that could accommodate regional variations in marginal losses (Drom et al. 2005).[5]

MISO has subsequently developed ancillary services market designs that provide for Regulation, Spinning Reserves, and Supplemental Reserves to be acquired via bid and auction markets instead of bilateral procurement.[6] This new Ancillary Services Market, scheduled for a September 2008 launch, will allow co-optimization of energy and ancillary services provision and increased participation of demand response (MISO 2007a). A key element of the introduction of co-optimized Energy and Ancillary Services Markets is consolidation of the multiple (i.e. 23) Balancing Authorities now responsible for providing reliability services into a single regional Balancing Authority under the auspices of MISO (see Figure 2). Because of the vast territory contained within the regional footprint, MISO is also developing a zonal scheme for managing the procurement and provision of Operating Reserves.[7]

Although MISO does not operate a capacity market, it coordinates regional planning processes to ensure that sufficient generation and transmission capacity is added to meet the reliability and demand growth needs of the region (MISO 2007b).

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[4] Three states (Illinois, Michigan, and Pennsylvania) have implemented retail competition, eight states (Missouri, Kentucky, Iowa, Montana, Minnesota, North Dakota, South Dakota, Wisconsin) retain monopoly provision of retail electric service, one state (Ohio) allows retail competition for certain customer classes, and one state (Nebraska) is fully served by public power.

[5] ECAR and MAIN have ceased operations and the region they covered is not part of ReliabilityFirst Corporation or RFC. MAPP has been replaced by Midwest Reliability Organization or MRO.

[6] At present Transmission Customers must provide for their own Operating Reserves through: 1) self-supply; 2) bilateral contracts; 3) take cost-based service from the Balancing Authority in which their Load is located; or 4) as a last resort, request the Midwest ISO to procure the necessary Operating Reserves on their behalf.

[7] These Reserve Zones will allow transmission constraints and other physical limitations to be taken into account in meeting reliability requirements imposed by NERC. The Reserve Zones will also disperse the clearing of Operating Reserve on Resources throughout the Midwest ISO Balancing Authority Area. Separate requirements will be established for Regulating Reserve, Spinning Reserve and Supplemental Reserves.

3. Institutional Arrangements and Stakeholders

Since inception MISO has stressed close coordination among state regulators in the development and operation of the regional transmission grid and electricity markets. The Organization of Midwest ISO States (OMS) was formed in 2003 to advise MISO and the FERC and provide a technical resource to the individual state regulators.[8] The OMS coordinates electricity transmission and wholesale market policy and planning oversight among the states within the MISO footprint, provides recommendations to MISO, FERC, and other government entities, and intervenes in FERC proceedings. The OMS has a Board of Directors and an Executive Committee, and topical working groups that cover key issues including congestion management, market power mitigation, pricing, resource adequacy, demand response, market implementation, transmission planning, and seams issues.

In 2004 MISO formed a Demand Response Working Group (DRWG) within its Market Subcommittee. The DRWG consists of MISO staff and stakeholders including regulators and Market Participants (MPs) and develops recommendations to allow existing and potential DR resources full participation in MISO markets. The DRWG is responsible for developing new business practices, tariff language and protocols governing the participation of DR in day-ahead and ancillary services markets and for emergency purposes.[9]

In October 2006, the Organization of Midwest ISO States (OMS) launched the Midwest Demand Resource Initiative (MWDRI). The goal of the Initiative is to identify and develop remedies to retail barriers to the deployment of DR resources in the MISO region, including state and regional policies and market-enabling activities. MWDRI efforts are focused on retail DR programs and dynamic pricing tariffs and are intended to complement the ongoing efforts of MISO Working Groups that address demand response (e.g., DRWG and Resource Adequacy Working Group).

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[8] URL: http://www.misostates.org/

[9] DRWG Charter and DRWG 2008 Management Plan. Both available at: http://www.midwestiso.org/publish/Folder//30a6c2_101ed99cd65_-7fe40a48324a

4. Status of Demand Side Management in Midwest ISO

There are two principal types of demand-side management (DSM) resources: energy efficiency (EE) and demand response (DR). While the objective of EE is to permanently reduce the demand for energy in intervals ranging from seasons to years, DR's objective is to change customer demand in intervals that range from minutes to hours during specific conditions (e.g., high demand, congested networks, or high prices). This study focused specifically on DR resources.

Figure 3 presents the main types of DR resources. DR resources can be characterized in terms of whether they are dispatchable by the system operator (or program administrator) or the customer alone decides when to reduce load (i.e. non-dispatchable). Customers enrolled in dynamic pricing tariffs (e.g. hourly pricing, critical peak pricing, and time-of-use pricing) would typically fall under the non-dispatchable DR resources category while direct load control, interruptible rate programs, and demand bidding programs would be under the dispatchable category - see NERC (2007) for a detailed discussion of DR program typology.

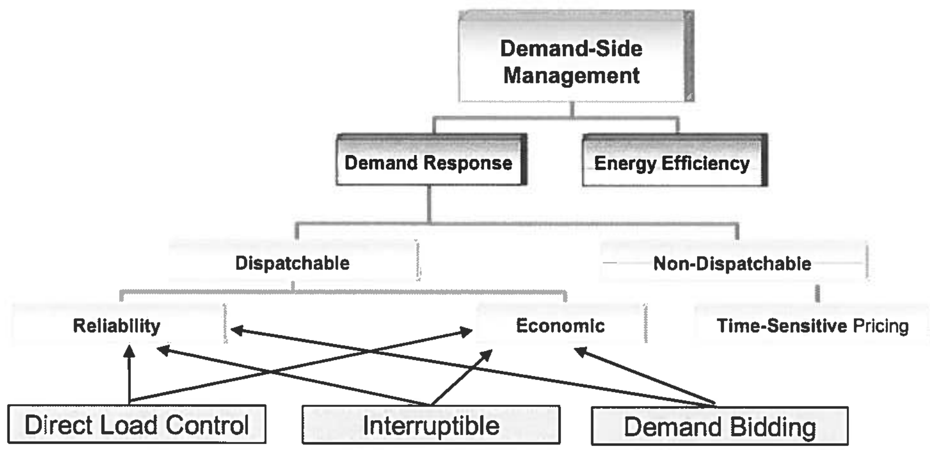

Figure 3: Types of Demand-Side Management Resources (Source: NERC, 2008)

MISO coordinates with utilities in their role as Balancing Area Authorities to dispatch demand response resources for the benefit of the entire MISO interconnected system (IRC 2007). The various ways (existing and future) in which DR resources can participate in MISO markets and operations are shown in Table 1.

Currently, DR resources formally participate in MISO operations through the wholesale energy market only. LSEs can offer DR resources, similar to generation resources, in the day-ahead or real-time energy market. In this case MISO decides whether to dispatch the DR resources or not. Alternatively, LSEs can also use DR resources as part of their price-sensitive demand curve. In this situation, the LSE decides whether to dispatch its DR resources or not in an effort to manage its wholesale market price risk.

In the future, DR resources will be able to participate in Ancillary Services Markets. Recently, FERC also approved MISO's proposal to allow DR resources to satisfy the resource adequacy requirements of LSEs as described in Module E of MISO's Transmission Tariff. DR resources would receive capacity credits comparable to those received by generators. DR resources receiving capacity credits would be dispatched during emergency conditions in accordance with business rules that are still under development. [10] Unlike several other RTOs, MISO does not directly administer DR programs at the present time.

Table 1: How DR resources can participate in MISO markets?

MISO Platform	Method of DR Participation
Non-Dispatchable by MISO	
Day-ahead and Real-time energy markets	Price-sensitive demand: LSEs indicate how much energy they will buy for a given price.[11]
Dispatchable by MISO	
Day-ahead and Real-time energy markets	DRR offers: LSEs can bid DR resources in the energy markets similar to generation resources. If offer is accepted then LSE must deliver the load reduction or pay a penalty.
Ancillary services market (ASM)	DRR offers: LSEs can bid DR resources in ASM similar to generation resources. During power system contingencies, LSEs must deliver load reductions. *(Note: ASM will begin operations in September 2008).*
Resource adequacy requirements (Module E)	LSEs can utilize their DR resources to meet their resource adequacy requirements. When EEA2 alert is issued, LSEs must reduce load as defined in Module E.
Emergency demand response program (Schedule 30)	DRR offers: LSEs can bid DRR in this program. During EEA2, if MISO has exhausted resources in energy markets, ancillary services market, and Module E then offers bid into Schedule 30 will be according to ascending order of offer prices. *(Note: FERC has not yet approved Schedule 30. However, MISO has begun the process of developing the business process manual.)*
Only for Planning Purposes	
Long-term planning	MISO has proposed that it would include DR resources formally in its planning process in future.

Source: Mike Robinson, MISO 2008

On December 31, 2007, MISO filed a proposed Emergency Demand Response (EDR) Schedule 30 with FERC, which provides payments from MISO to load-serving Market Participants (MP) that curtail loads during emergency events (i.e., EEA2 and EEA3).[12] Only authorized MPs would be allowed to participate in Schedule 30, which would be the first DR program to be directly administered by MISO. In order to be compensated under this proposed program, participants will be required to submit an EDR offer to MISO at least 30 days ahead of the calendar month in which the offer is valid. Each offer must remain in force for one month and include: (1) minimum and maximum amounts of demand reduction; (2) minimum and maximum

[10] One issue of contention among stakeholders is the advance notice requirements for DR resources in order to qualify as a load-modifying resource under Module E.

[11] Anecdotal evidence suggests that currently, a significant portion of DR resources participates in the MISO market in this manner. LSEs adjust their daily load projections for expected DR reductions for those days they intend to use DR resources.

[12] On April 22, 2008 FERC conditionally approved MISO's Emergency Demand Response Schedule 30. However, FERC also directed MISO to address several issues not included in the proposal. Currently, MISO is working with various stakeholders to address the issues raised by FERC.

number of continuous hours of demand reduction; (3) any shutdown costs associated with the demand reduction; (4) number of hours of advance notice required before reduction and any time of day limitations; and (5) a firm offer price (subject to a $3,500/MWh cap). MISO will issue instructions regarding the start time, reduction amount, and necessary duration of curtailment during emergency events for accepted bids. Compensation would be based on the higher of the real-time LMP or the EDR Offer price for the amount of demand reduction included in MISO's instructions. In case of non-compliance, a penalty would be incurred.

In terms of operations during system contingencies, MISO will first dispatch the generation and DR resources offering bids in the Ancillary Services Market according to merit order. If ASM resources are unable to meet the demand, MISO will begin issuing sequential warnings and emergency alerts. When an EEA2 alert is issued, MISO will first ask LSEs to dispatch the resources accredited under Module E. If the Module E resources are not sufficient to meet the demand, MISO will dispatch the DR resources enrolled under EDR Schedule 30 according to merit order.[13]

[13] It should be noted that this order of dispatch may be revised in the future.

5. Purpose and Approach of the Survey

Market participants (MP) administering retail DR programs and state regulators are concerned whether the requirements that MISO includes in its EDR Schedule 30 and Ancillary Services market for DR resources are consistent with the requirements already embedded in legacy programs and tariffs. To better inform this discussion and assess differences and similarities among existing retail DR programs and dynamic pricing tariffs in the MISO footprint, MWDRI decided to conduct a detailed survey.

A team comprising the Lawrence Berkeley National Laboratory (LBNL) and the Regulatory Assistance Project (RAP) surveyed the retail DR programs and dynamic pricing tariffs administered by MISO member utilities as well as other utilities operating in OMS member states. The survey template was developed by the DR program design subgroup of MWDRI with input from OMS members. State regulatory commissions transmitted the survey to utilities in their states and requested their cooperation in describing their retail DR programs and dynamic pricing tariffs. The survey coverage generally included all load serving MISO MPs along with several utilities that are not MISO members but whose service territories are in OMS states. In some states, surveys were not sent to rural cooperatives and municipal utilities either because PUCs did not have jurisdiction or utility staff contacts. LBNL staff compiled the survey data, conducted follow-up interviews and consistency checks to ensure accuracy of the survey responses, supplemented survey data with information from other sources, and analyzed the data.

Utilities were asked to provide information on retail DR programs (e.g., interruptible, direct load control or DLC, emergency programs, and demand bidding programs where events are triggered by high prices), dynamic pricing tariffs (including Real Time Pricing, or RTP; and Critical Peak Pricing, or CPP), and voluntary DR programs (i.e., a program where customers voluntarily participate and make a "best efforts" attempt to curtail load when requested but are not compensated).

Interruptible rate programs provide a rate discount or bill credit to the customer for curtailing or shedding load upon request. Typically, interruptible programs are offered to larger industrial and commercial customers and often involve penalties if the customer fails to curtail load when requested to do so. DLC programs involve an end-user (typically, residential or small commercial) who agrees to allow their utility or a curtailment service provider to control an appliance or device within certain pre-set limits of frequency and duration. Participants in DLC programs typically receive compensation in the form of bill credits and/or payments based on performance during events. Customers enrolled in a Demand Bidding or economic DR program offer bids to curtail load based on market prices. These programs are mainly offered to large customers; however, some utilities also allow aggregation of small customer loads.

An RTP tariff provides variable hourly pricing for all hours of the year, while a CPP tariff provides variable pricing only for a relatively few number of hours per year when the utility calls a CPP event. A one-part dynamic pricing tariff assesses all volumetric (per kWh) charges based on variable hourly prices. A two-part dynamic pricing tariff incorporates a customer baseline (CBL) usage which establishes a long-term average hourly usage profile for each customer. Variable hourly prices are applied only to the differences between actual hourly load and the CBL. Two-part CBL-based real-time tariffs are a hedge against the implicit price-exposure risk of variable hourly prices as the bulk of a customer's consumption is billed on the customer's otherwise applicable tariff. Hourly prices can be indexed to wholesale energy market prices (i.e. either day-ahead or real-time) or utility marginal costs.

6. Survey Results: Overview of Existing DR Resources

Thirty-five utilities responded to the survey with information on 141 DR programs and dynamic pricing tariffs. Of these, four utilities (that reported information on 13 DR programs and 3 dynamic pricing tariffs) are not members of MISO but operate in states that belong to OMS. The analysis reported here includes all 141 programs.

The size of the DR resource is defined as the potential peak load reduction that the utility expects from the DR program or dynamic pricing tariff, which is consistent with the approach taken by FERC and EIA. The utilities reported retail DR resources totaling 4,727 MW, of which 757 MW are from MISO non-members (~16%).Response to the survey was quite good as MISO member utilities reported DR program resources of ~3,649 MW of DR resources, compared to the 4,099 MW reported in the latest FERC DR report (FERC 2007).

The distribution of DR resources by state is shown in Figure 4. States with the most DR resources include Minnesota (1,245 MW), Indiana (731 MW), and Michigan (822 MW). Note that OMS member states such as Illinois and Pennsylvania have large DR resources, although some utilities in these states were not sent or did not respond to the survey because they were not MISO members (e.g., Commonwealth Edison is a member of PJM).

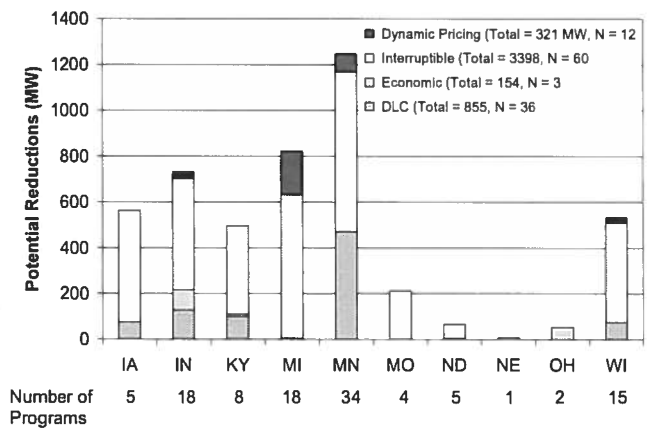

Figure 4: State-Level Distribution of DR Resources

Figure 5 shows how survey respondents characterized their retail demand response program offerings. Interruptible tariffs account for ~72% of the DR resource, while DLC programs account for ~18%, and economic programs account for ~3% of existing DR resources. Interruptible tariffs and DLC programs are offered in almost all OMS member states, however, economic programs were offered by LSEs only in Indiana and Ohio.

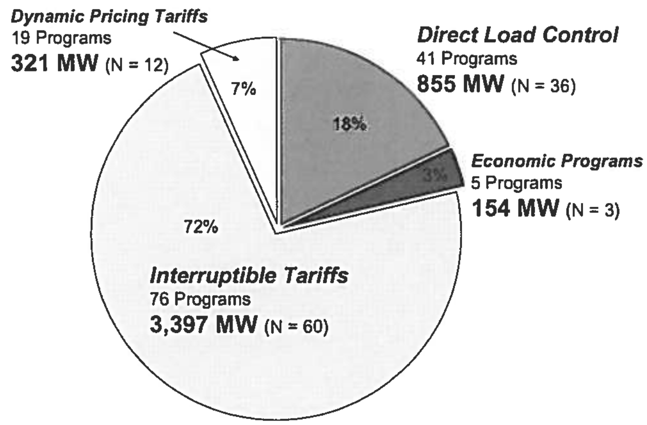

Figure 5: Distribution of DR resources by program type

Dynamic pricing tariffs account for ~7% of the total DR resource. Fifteen entities reported that they offer 19 dynamic pricing tariffs in their service territories. However, utilities reported information on potential peak load reductions for only 13 dynamic pricing tariffs. Survey respondents estimated that customers enrolled in these dynamic pricing tariffs could provide 321 MW of potential load reductions in aggregate. It is important to note that customer enrollment (and potential load reductions) for dynamic pricing tariffs vary significantly across utilities with five utilities accounting for 92% of the potential load reductions (see Table 2). CPP tariffs accounted for only 7 MW of DR resources. Only one utility called its CPP tariff in 2006 (approximately 60 events) that yielded ~4 MW of actual load reductions.

Table 2: Dynamic Pricing Tariffs: Top five utilities ranked by potential load reduction and peak demand of enrolled customers.

Utility	Potential Peak Load Reductions (MW)	Peak Demand of Enrolled Customers (MW)
Utility A	150	360
Utility B	72	84
Utility C	29	60
Utility D	25	25
Utility E	20	40
Remaining utilities	25	229
TOTAL	321 MW	798 MW

Almost 50% of the RTP tariffs (all two-part tariff design) rely on the utility's marginal cost to determine the hourly component of the price, while the remaining RTP tariffs are indexed to either MISO's real-time or day-ahead energy market price. The RTP tariffs primarily target non-residential customers. With one exception, the design of dynamic pricing tariffs involves an "opt-in" approach as customers must voluntarily choose to enroll on a dynamic pricing as opposed to an "opt out" approach where dynamic pricing tariff is designated as the default tariff. None of the potential load reductions from the dynamic pricing tariffs are currently bid into the

MISO wholesale energy markets. Six utilities count the potential load reductions from their dynamic pricing tariffs towards their planning reserves.

Eighteen utilities reported that they operate voluntary, emergency DR programs that do not offer compensation for load curtailments. Approximately ~61% of these programs recruit customers actively through public appeals, advertising, customer education, and targeted marketing to large customers. Five utilities reported that they have enrolled ~138 customers in these voluntary DR programs. Only four utilities have called these programs in recent years and six utilities periodically contact enrolled customers to see if they are willing to participate in the program in future.

7. Survey Results: Retail DR Program Characteristics

The survey requested detailed information about a range of DR program characteristics, including operational triggers, frequency of events, advance notice provided, program duration, participation requirements (e.g. size thresholds, market segments, etc.), communications arrangements, monitoring and verification protocols, and others. This section discusses these DR resource characteristics and their potential implications for participation in MISO markets by DR resources.

7.1 Operational Triggers

Respondents were asked to describe what triggered the operation of DR programs. The most-frequent uses of DR programs reported were maintaining system reliability, reducing the cost of procuring power during high price periods, maintaining system demand below contracted levels, and addressing local reliability or congestion problems (see Table 3).

Table 3: Operational Triggers for DR Programs

Program Type	System Emergency	High Prices	Maintain demand below contracted levels	Local/utility reliability/ congestion
DLC	28	25	21	16
Economic	1	5	0	1
Interruptible	66	49	35	42
TOTAL	95	79	56	59

Approximately ~81% of programs and ~87% of potential peak load reductions are triggered for system emergencies. Interestingly, over two-thirds (~68%) of all DR programs (~70% of enrolled load reductions) are triggered for economic reasons. This result is somewhat surprising as historically DLC and interruptible rate programs were justified primarily for reliability purposes and dispatched only during system emergencies. These results suggest that many Midwest utilities have found additional benefits in dispatching DR programs in response to market conditions (e.g. high day-ahead or real-time market prices) and system conditions (manage contracted demand to lower overall utility system costs, relieve congestion). Some survey respondents noted that regulators have given them additional flexibility in recent years to decide how DR resources are deployed and the number of times they can be deployed. LSEs also reported an increase in DR events triggered by economic conditions since MISO markets began operating.

Respondents indicated that 79 DR programs can be triggered for economic reasons (i.e. high prices); however, only 13 DR programs (9 interruptible and 3 DLC accounting for ~580 MW) actually bid into MISO's day-ahead energy market. It appears that many LSEs are acting as "price-takers" instead of having to commit to reduce a specific amount of load if their bid is accepted.

Most DR programs have more than one operational trigger: 83% of DR programs which account for 94% of enrolled load reductions. Figure 6 and Figure 7 show the potential load reductions respectively for DLC and interruptible rate programs for each type of operational trigger. The Venn diagram representation allows one to readily see the use of multiple triggers.

For example, about 47% of potential load reductions from DLC programs are dispatched for both reliability (system-wide and/or local) and economic purposes. Potential DLC load reductions triggered for purely economic reasons (i.e., high prices) account for ~37% of the total load reductions while DLC programs triggered for purely reliability purposes account for ~17% of the total load reductions.

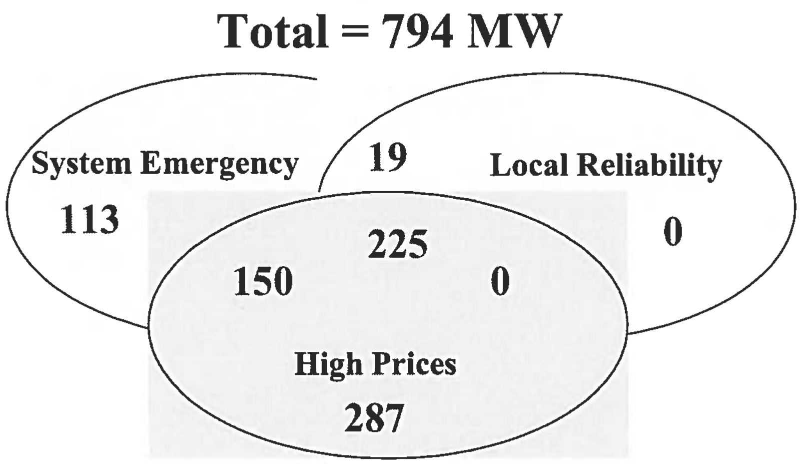

Figure 6: Overlap of operational triggers for DLC programs

In contrast, the potential load reductions from interruptible programs that are triggered purely for economic reasons account for only ~1% of the total potential load reductions. Approximately 33% are triggered for purely reliability purposes and ~65% for both reliability and economic purposes. A much larger portion of potential load reductions (~52% compared with ~28%) from interruptible rate programs are triggered for all three purposes as compared with those from DLC programs.

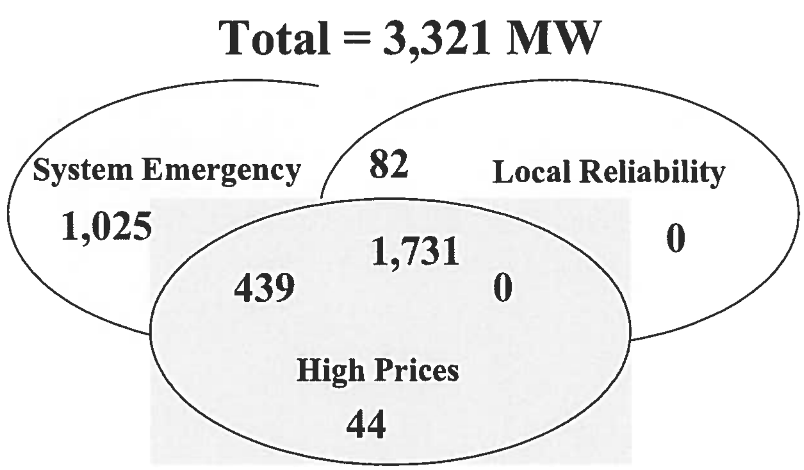

Figure 7: Overlap of operational triggers for interruptible rate programs

This wide-spread use of DR resources for economic reasons suggests that program operators are capable of valuing the resource purely in economic terms as opposed to using it as a last resort for ensuring system reliability. For participation in MISO's energy markets or the proposed EDR schedule (and possibly future ancillary services market), program administrators will need to develop an offer price for their DR resources. Past experience in monetizing the value of DR resources should make it easier for program administrators to develop offer prices.

7.2 Frequency of DR Events

Respondents were asked to provide information on program operating limits as well as operational experience in recent years. More than one-third (~36%) of respondents reported that their DR programs did not have any limits on operational frequency.

Survey respondents also indicated that more than 60% of DLC programs and 30% of interruptible rate programs were called ten or more times in 2006 (see Figure 8). Follow-up discussions with some utilities suggest that the large number of DR events is a consequence of using economic criteria as operational triggers. Utilities also indicated that there were not many customer complaints despite the high frequency of DR events.

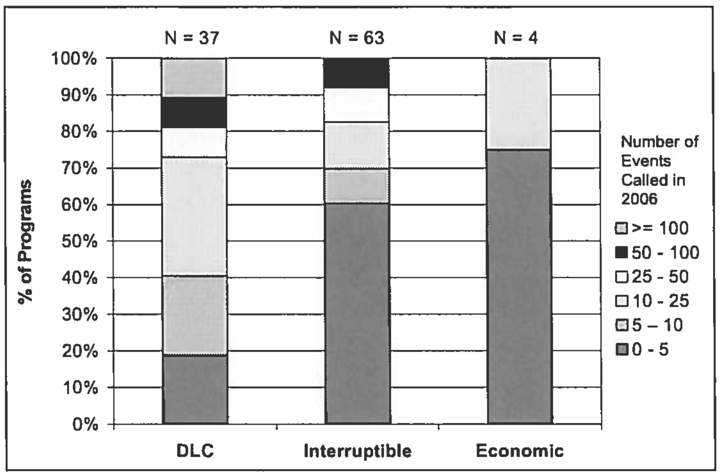

Figure 8: Frequency of DR Program Operations (2006)

The lack of annual limits on maximum number of events called or maximum hours of load reductions coupled with the fact that LSEs do not report significant customer satisfaction issues suggests that many LSEs may have the flexibility to continue calling and relying on DR resources for a variety of needs (e.g., emergency, economic, local congestion).

7.3 Advance Notice Requirements

The proposed EDR Schedule 30 calls for participants to specify the number of hours of advance notice required before demand can be reduced. Therefore, the advance notice requirements for existing retail DR programs are of interest. As shown in Table 4, 83% of DR programs (representing 89% of potential load reductions) require less than 2 hours advance notice. Nearly all DLC programs provide either no or less than 30 minutes of advance notice to customers, which is not surprising given that equipment (e.g. air-conditioning unit, water heater) is cycled directly by the utility. Surprisingly, over one-third (~36%) of interruptible programs provide relatively short notice (i.e., less than 30 minutes advance notice) to customers. Utilities reported that over ~1900 of customers were on interruptible rate programs that provide 30 minutes to 2 hours notice. The majority of economic programs are "day-ahead" programs, bidding load curtailments into the day-ahead energy market.

Table 4: Advance Notice Requirements for DR Resources

Program Type	Potential Enrolled Load Reductions (MW)				
	Less than 30 minutes	30 minutes – 2 hrs	2 - 4 hrs	4 - 12 hrs	Day-ahead
DLC	740	10	0	0	0
Economic	0	0	0	0	154
Interruptible	1,221	1,927	202	7	31
TOTAL	1,961	1,937	202	7	185

The survey results suggest that over 90% of the existing DR resource could provide load curtailments with two hours or less of advance notice. A significant amount of that load (1960 MW) is available on just 30 minutes notice. One of MISO's challenges in implemented EDR Schedule 30 will be "stacking" the DR resource offers for dispatch according to the relative merit order of advance notice and other characteristics. The proposed Schedule 30 language notes that dispatch instructions will be sent to accepted offers in the event of EEA2 and EEA3 alerts, but does not specify exactly when the alerts are initiated and dispatch instructions sent to the DR resources.

7.4 DR Resource Availability

Over the past two years MISO has called on DR resources to provide operating reserves in both the summer (danger of demand exceeding supply) and the winter (equipment failure).[14] This suggests that access to DR resources throughout the year has value for MISO system operators. Although certain DR resources will always be available only seasonally (e.g., air-conditioner load control), it is possible to develop a portfolio of DR programs that provides operating reserves year-round.

The survey results suggest that almost all of the DR programs and tariffs are available during summer months (either because the programs require year round or summer availability), when the probability of a DR event is higher (see Table 5). Surprisingly, more than two-thirds of all DR programs and tariffs, at least on paper, can be operated year-round (~50% of DLC programs, and ~75% of interruptible rate programs). However, it is likely that some DR programs never get called during off-peak months (e.g., air conditioner or agricultural pump load control). Consequently, the potential load reductions available during non-peak months (e.g. winter season in lower Midwest region) could be much lower than reported.

Table 5: Seasonal availability of DR resources

Program Type	Number of Programs				
	Summer only	Summer & Winter	Winter only	Year-round	TOTAL
DLC	16	3	2	20	41
Economic				5	5
Interruptible	15	2	2	57	76
TOTAL	31	5	4	82	122

[14] Hopper et al. (2007).

The proposed MISO EDR Schedule 30 requires market participants to specify their offers one month in advance and to provide one months notice if the offer is to be changed. The offer must describe the restrictions on the availability of the DR resource (i.e. minimum and maximum hours, times during the day, days during month when the load reduction is available). Hence, DR program administrators will have to develop resource availability estimates by month in order to develop appropriate offers for participation in the MISO EDR program.

7.5 Participation Requirements

Some DR programs establish eligibility or threshold criteria for enrollment, or target specific customers. For example, DLC programs are targeted to residential and small commercial customers while interruptible rate programs are targeted to large industrial and commercial (including government, educational institutions, and others) customers. Respondents indicated that other types of eligibility criteria were also employed in lieu of or in addition to market segment.

The most commonly cited criteria were the minimum size of load reduction offered by customer, minimum level of customer peak demand, presence of specific types of equipment or appliances (e.g., air conditioners) and access to onsite generation (see Table 6). The category "other" referred to contracts negotiated between an individual customer and the utility. Approximately 25% of DR programs explicitly indicated that they had no specified eligibility criteria. About 48% of DR programs allow participating customers to meet their program commitments using onsite generators in lieu of load reductions.

Table 6: DR Program Participation Requirements (MW)

Program Type	Certain End-uses Required	Min. Size of Load Reduction	Minimum Customer Demand	Other
DLC	191			301
Economic		154		
Interruptible	8	841	1,008	247
Total	199	995	1,008	548

The survey results indicate that minimum size thresholds for curtailable load and customer maximum demand are most commonly used as program eligibility criteria. These eligibility criteria allow LSEs to target larger customers whose participation is easier to administer. However, if aggregation is allowed, then a load aggregator may be able to enroll many smaller customers in these programs. The proposed MISO EDR Schedule 30 does not include any eligibility criteria or aggregation rules; hence, potentially all existing DR resources may be able to participate.

7.6 Measurement and Evaluation

Participation in MISO's proposed EDR schedule or in MISO energy markets requires the ability of the LSE to accurately measure and evaluate the actual load reduction. However, survey respondents indicated that barely half (~54%) of retail DR programs have been evaluated in the last 2-3 years. Many of these LSEs may be relying on older evaluations or engineering estimates of load reductions, rather than evaluation of actual load reduction results from recent DR events. A robust measurement and evaluation (M&E) protocol is necessary to estimate actual load reductions.

Only half (~50%) of the respondents provided detailed information on measurement and evaluation (M&E) protocols for their DR programs. Of these responses, the great majority (~80%) used interval meter data for evaluating the load impacts from interruptible programs. Customer baselines for measurement of actual load reduction were defined as part the M&E protocol.

The most common M&E method used for DLC programs (~77%) used substation level SCADA data to measure aggregate load impacts during DR events. This technique does not measure or estimate actual load reduction for each participating customer. Exclusive reliance on this method might prove to be a barrier in aggregating these loads for participation in MISO's proposed EDR Schedule 30, where compensation depends on actual and verifiable load reduction from participating customers.

Less than one-quarter (~19%) of the DLC programs used load research or other statistical methods to improve the accuracy of their load reduction estimates.[15] These methods are commonly used for non-interval metered participants in ISO DR Programs in other regions (e.g., ISO-NE, NYISO, and PJM).

Overall, the survey response suggests that M&E protocols vary quite a bit across the MISO footprint. MISO does not include a specific M&E protocol in its proposed EDR schedule; rather, the proposed EDR Schedule 30 provides for MISO review and approval of M&E protocols on a case-by-case basis. Although this approach may expedite initial approval of the program, in the long-run, MISO needs an M&E protocol that is applied uniformly and yields comparable results.

7.7 Program Incentive Design and Compensation Levels

The survey also requested information on DR program incentive design, the type and size of incentives provided, and the basis for determining incentive levels. The results show considerable variability in incentive design and compensation levels across LSEs, states, and program types. Incentives were provided via bill discounts (i.e. $/month, $/season, $/year), capacity payments (i.e. $/kW offered per month or season or year), performance payments ($/kWh paid according to a single event), and capacity-performance payment combinations.

The most commonly offered incentive design is the capacity or reservation payment with or without a pay-per-event performance payment. MISO proposed EDR schedule 30 offers only a performance payment for load curtailed as its incentive. Hence, for many DR programs, LSEs and state regulators may need to address the issue of aligning the compensation received by LSEs from MISO for curtailing load during emergency events with the actual incentives currently paid to the end-use customer through the existing retail tariff.

[15] This methodology consists of extrapolating the measured actual load reductions for a sample of participants to the population of participants in a DLC program using various statistical methods and data analysis techniques.

Figure 9 and Figure 10 present the monthly capacity payments provided for interruptible rate programs and DLC programs, respectively. Reported capacity payments were converted to a common metric -- $/kW-month - in order to compare incentives across programs. The average incentive was $5/kW-month for interruptible rate programs, although there is significant variation across utilities (e.g. incentives ranged from $1 to $12/kW month).

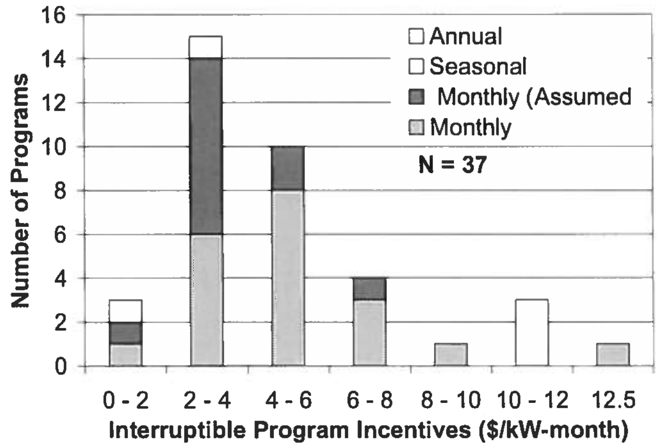

Figure 9. Distribution of incentives offered to interruptible tariff customers

Figure 10 segments the DLC program incentives in terms of the end-use appliance targeted by the program (i.e., air conditioners, and water heaters). The average size of the incentive provided to customers is $6/kW-month for the 22 DLC programs that provided this information. The variation in incentive levels across DLC programs is less than that observed among interruptible tariffs. For example, ~77% of the programs provide incentives between $4/kW-month to $8/kW-month. Incentives offered to customers in water heating DLC programs are relatively lower than those offered to customers in air-conditioning (A/C) programs. About 55% of A/C DLC programs provide incentives greater than $6/kW-month, while ~88% of water-heater DLC programs provide incentives less than $6/kW-month.

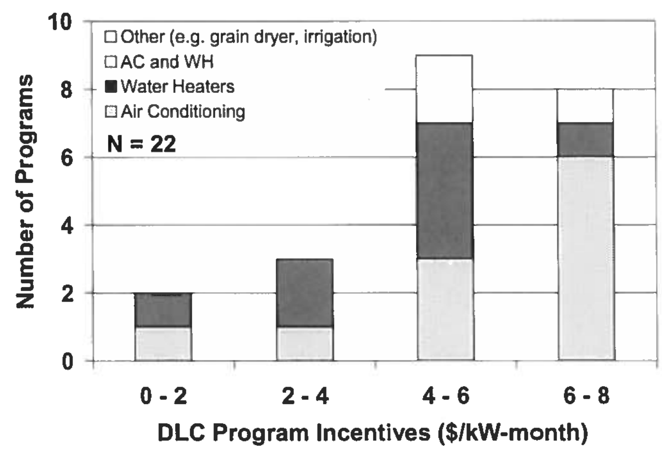

Figure 10. Distribution of incentives offered to DLC program customers

Approximately 30% of the 122 DR programs indicated that they have some type of penalty provision if customers do not curtail load during a DR event. Utilities use a variety of approaches to ensure that enrolled customers actually curtail during events: 25 programs include a monetary penalty for non-performance; four programs include mandatory "buy-through" provisions (i.e., the customer is required to pay the real-time market price for load not reduced), and seven programs include provisions that remove enrolled customers from future participation in the program (and loss of incentives) for failure to perform. Survey respondents indicated explicitly that there were no adverse consequences for non-performance in 27 DR programs. The penalty described in MISO EDR schedule is of the form $/MWh.

The most commonly used valuation basis for determining the size of incentives is the cost of a peaking unit (e.g., a natural gas-fired combustion turbine). As shown in Figure 11, more than 80% of DLC programs and more than 60% of interruptible rate programs use this valuation basis. About 17% of interruptible programs report using wholesale energy prices and ~12% used avoided costs (i.e. these include avoided transmission and distribution costs in addition to generation costs) to set incentive levels.

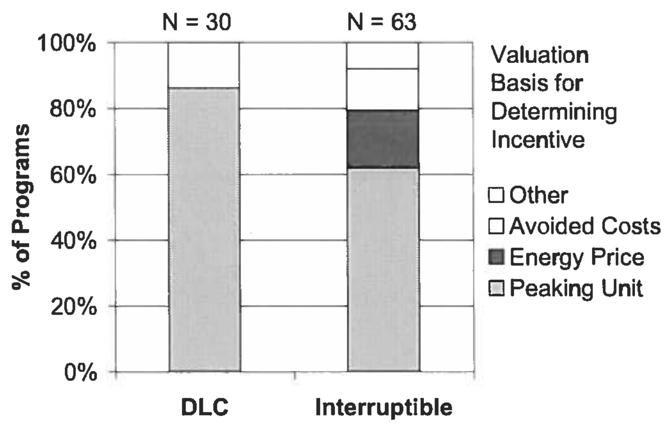

Figure 11. Valuation basis for DR program incentives

Many retail DR programs were approved prior to the formation of MISO and were justified primarily on reliability grounds. However, although "emergency" DR programs are increasingly being utilized for economic reasons, this reality is not fully reflected in cost-effectiveness screening practices used in some MISO states. Anecdotal information also suggests that many LSEs provide "price-sensitive demand bids" in MISO day-ahead energy markets and use high prices from energy markets to trigger their DR programs. Going forward, state regulators may want to direct utilities to consider and assess the full range of DR program applications in MISO markets in cost-effectiveness screening and in setting appropriate incentive levels.

8. Findings and Conclusions

This study provides the first comprehensive assessment of legacy DR resources in the MISO foot-print. The size of the DR resource that responded to this survey is 4,727 MW of which ~84% is available in the MISO service territory through 141 DR programs and dynamic pricing tariffs. Interruptible programs account for ~72% of the DR resource, while DLC programs account for ~18%. Almost 90% of the DR resources included in this survey are provided by investor-owned utilities.

Approximately 87% of the DR resource utilizes an operational trigger linked to system emergency conditions, although most programs allow for multiple triggers. Surprisingly, about 70% of the DR resource can also deployed by LSEs for economic reasons. The frequency of use of DR programs for economic reasons has increased since MISO markets began operating. Approximately 60% of DLC programs and 30% of interruptible rate programs called ten or more DR events in 2006. Despite the high frequency of DR events, customer complaints remained low. The use of economic criteria to trigger DR events and the flexibility to trigger a large number of events suggests that DR resources can help improve MISO wholesale markets.

Approximately, 90% of the DR resources are available with less than 2 hours advance notice and over 1,900 MW are available with less than 30 minutes notice. Almost all of the DR resources are available in summer and 67% of the programs throughout the year. However, the fact that a program operates throughout the year does not mean all potential load reductions from the program are available in each month. System planners will have to develop estimates of DR resource availability by season (or month) instead of using the existing estimates.

M&V protocols vary across MISO foot-print. For many DLC programs, M&V protocols may need to be enhanced in order to allow participation in MISO's proposed EDR schedule. MISO is in the process of developing M&V protocols that are consistent across its service territory. Almost half of the DR programs have not been evaluated in recent times. Hence, data on performance during DR events is not available. System operators and planners will need to develop more accurate estimates of the load reduction capability and actual performance.

Most legacy DR programs offered a reservation payment ($/kW) for participation; incentive payment levels were about $5/kW-month for interruptible rate programs and $6/kW-month for DLC programs. Most utilities indicated that the avoided cost of a peaking unit was used as the valuation basis in cost-effectiveness screening and in setting incentive levels. Few programs offered incentive payments that were explicitly linked to the actual load reduction during an event and at least 27 DR programs do not have penalties for non-performance.

If MISO's proposed revisions to its emergency procedures are approved by FERC, it is unclear to what extent utilities will actually enroll their customers in this new MISO DR program. LSEs and participating customers would receive additional incentive payments during emergency events (up to $3,500/MWh), but LSEs will incur additional transaction costs, and LSEs and participating customers will face penalties for non-performance. For example, an LSE will have to specify the minimum and maximum amounts of curtailed load, the number of hours of advance notice required and whether such reductions are limited to certain hours, periodically bid and update offer prices for curtailed load, accurately estimate load curtailments or be subject to penalties, and develop and negotiate an acceptable M&V protocol with MISO.

Participation and enrollment of legacy DR resources in the MISO emergency DR protocols may ultimately hinge on whether it is made a requirement for LSEs that want to take resource adequacy credit for their DR resources as part of the MISO reliability planning process. At a minimum, utilities and state regulators may have to rethink and possibly revise some provisions of legacy DR programs that relate to customer's obligations and incentives for curtailing load during system emergencies, penalties for non-performance, periodic testing of existing DR assets, and more consistent M&V protocols.

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR REVIEW, MODIFICATION, AND CONTINUATION OF EXISTING, AND ADDITION OF NEW DEMAND-SIDE MANAGEMENT AND ENERGY-EFFICIENCY PROGRAMS	)))))))	CASE NO. 2011-00134

O R D E R

On April 14, 2011, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively the "Companies") filed a joint application ("Application") pursuant to KRS 278.285 requesting approval of their proposed Demand-Side Management ("DSM") and Energy Efficiency Program Plan ("Program Plan"), their proposed Demand-Side Management Capital Cost Recovery Component ("DCCR") mechanism, and their proposed DSM rates.

The Companies requested that the Commission issue a final order in this proceeding by October 13, 2011, with the Companies' revised tariff sheets to be effective six weeks after the date of the Commission's final Order approving them. On May 10, 2011, the Commission issued an Order suspending the proposed DSM rates from May 13, 2011 up to and including October 12, 2011. The following sought and were granted full intervention: the Attorney General's Office of Rate Intervention ("AG"), the Association of Community Ministries, Inc. ("ACM"), the Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc. ("CAC"), Metropolitan Housing Coalition ("MHC"), the Lexington-Fayette Urban County Government, and The Kroger Co. ("Kroger").

A procedural schedule was established allowing for two rounds of discovery and the filing of testimony. The Companies were subject to one round of data requests from the AG, two rounds of data requests from ACM, CAC, Kroger, and MHC, and three requests from Commission Staff. ACM, CAC, and MHC filed testimony and each responded to the one set of Staff data requests. ACM opposed the Application as filed and made general recommendations relating to low-income consumers of LG&E. CAC supported the Application as filed, but expressed concern for low-income customers of KU. MHC opposed the Application as filed, expressing concern with affordability to low-income households and the returning of collected DSM funds back to certain zip codes in LG&E's service territory. The Companies filed rebuttal testimony on August 29, 2011, after which an informal conference ("IC") was held September 21, 2011. On September 28, 2011, the Companies filed responses to Commission Staff's requests for information from the IC.

On August 29, 2011, the Companies filed a Motion to submit the case for decision on the record. No intervening parties requested a hearing in this matter.

The Companies' Application addressed three categories of DSM programs. The three different categories are discussed below.

Existing Unchanged Programs

The Companies propose that five currently authorized residential or commercial DSM programs which were approved in Case No. 2007-00319,[1] remain unchanged and continue at their currently approved funding level and duration of program service through December 31, 2014. Those programs as described by the Companies are:

1. Residential High Efficiency Lighting – The Companies state that this program is to facilitate market transformation by creating a shift in LG&E and KU consumer purchasing from incandescent light bulbs to Compact Fluorescent Lights. The Companies further state that they provide customer education materials and opportunities, select and develop partnerships with retailers, ensure appropriate documentation for payment of incentives, and maintain program data.

2. Residential New Construction – This program is designed to reduce residential energy usage and facilitate market transformation by creating a shift in builders' new home construction to include energy efficient construction practices. The Companies intend to utilize this program to educate builders, contractors, and customers to increase awareness of environmental and financial benefits of whole-house energy efficient building practices. To facilitate this introduction into customers' homes, the program will partner with homebuilders' associations within the state of Kentucky to adopt and implement the Department of Energy's Energy Star new homes energy efficiency program.

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[1] Case No. 2007-00319, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company Demand-Side Management for the Review, Modification, and Continuation of Energy Efficiency Programs and DSM Cost Recovery Mechanisms (Ky. PSC Mar. 31, 2008).

3. Residential and Commercial HVAC Diagnostic and Tune-up – The objective of this program is to reduce peak demand and energy use by conducting a diagnostic performance check on residential and small commercial unitary air conditioning and heat pump units, air-restricted indoor and outdoor coils, and over- and under- refrigerant charge. The program will target customers with probable Heating, Ventilation, and Air Conditioning ("HVAC") system performance issues.

4. Customer Education and Public Information – The objective of this program is to increase public awareness and understanding of both the urgent need for more efficient use of energy and the environmental and financial impacts created by climate change issues. This program will also increase customer awareness and encourage utilization of the energy efficiency products and services included in the Application in this case.

5. Dealer Referral Network – The program is a web-based Dealer Referral Network designed to deliver the following services to program constituents:

- Assisting customers in finding qualified and reliable personnel to install energy efficiency improvements recommended and/or subsidized by the various energy efficiency programs;
- Identifying energy-related subcontractors for contractors seeking to build energy-efficient homes or improve energy efficiency of existing homes; and
- Fulfillment of incentives and rebates.

Enhanced and Expanded Existing Programs

The Companies' Application proposes that the following five currently authorized residential or commercial DSM programs, which were approved in Case No. 2007-00319, be enhanced and extended through 2017. Those programs are:

1. Program Development and Administration – This program was established to capture costs incurred in the development and administration of energy efficiency programs where it is difficult to assign costs specifically to an individual program. The Companies are proposing to add three full-time positions to the Program Development and Administration infrastructure.

2. Residential Conservation/Home Energy Performance Program – This program is designed to help customers reduce home energy costs using on-line or on-site energy audits. The intent of this program is to work with LG&E and KU customers to identify specific steps they can take to reduce energy costs, making them better energy managers. The Companies are proposing one full-time employee position. The Companies also propose new on-site audit incentives for this program.

The Companies propose that the Tier One On-Site Audit will be comparable to the existing Onsite Audit. The proposal is for customers to pay a fee of $25 to encourage them to keep their scheduled appointments and receive recommendations of ways to reduce energy usage by a targeted 10 percent. At the completion of the Tier One On-Site Audit, the participant may qualify for either Tier Two or Tier Three incentives after a test-out follow-up audit. Participants who achieve a 20 percent total annual energy savings from pre-audit levels will qualify for a Tier Two On-Site Audit incentive of $500. Participants who achieve a 40 percent total annual energy savings from pre-audit levels will qualify for a Tier Three On-Site Audit incentive of $1,000.

3. Residential Low Income Weatherization Program ("WeCare") – This program is an education and weatherization program designed to reduce energy consumption of LG&E and KU low-income customers. The Application indicates that the program is designed to provide energy audits and energy education, perform blower door tests, and install weatherization and energy conservation measures on qualified houses. Eligible WeCare households will include but not be limited to those residential customers who qualify for Federal Low-Income Weatherization Assistance Program or Low Income Home Energy Assistance Program services.

The Companies seek additional funds that will allow for increased weatherization measures for low-income customers, an increase in the number of customers served under the program plan, and to extend the WeCare program through year seven of the proposed program plan.

The enhanced program costs compared to the 2007 DSM filing from 2011 to 2014 are as follows:

	2011 $000	2012 $000	2013 $000	2014 $000
Proposed Program	$2,368	$3,001	$3,957	$4,947
Original Program	$1,868	$1,893	$1,947	$2,003
Program Increase	$500	$1,108	$2,010	$2,944

The current and proposed customer incentive per tier is:

Tier	Annual Energy Consumption	Proposed Allowable Weatherization Cost	Current Allowable Weatherization Cost
A	Up to 1,299 Ccf or up to 11,499 kWh	$ 350	$ 200
B	1,300 to 1,800 Ccf or 11,500 to 16,000 kWh	$1,000	$ 750
C	Greater than Tier B	$2,100	$1,700

The Companies' proposed participation goals by year are as follows:

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
LG&E	600	850	1,100	1,350	1,600	1,850	2,100	9,450
KU	600	850	1,100	1,350	1,600	1,850	2,100	9,450
Total	1,200	1,700	2,200	2,700	3,200	3,700	4,200	18,900

4. Residential and Commercial Load Management/Demand Conservation – The Companies indicate that the existing program is voluntary and has been in operation since 2001. They state that this program employs switches in homes and small businesses to help reduce the demand for electricity during peak times and that the program uses one-way paging signals to communicate with the switches to cycle central air conditioning units, heat pumps, electric water heaters, and pool pumps off and on through a predetermined sequence. The Companies indicate that they have reached a market saturation rate of approximately 20 percent, but recognize the potential growth to reach approximately 33 percent over the proposed plan period.

The Companies propose the following enhancements to the existing program. They seek to add another full-time employee to assist in outreach efforts to the multifamily and commercial customer segment; the ability to modify and increase the financial incentives to attract those customers who have not been interested in this voluntary customer program; to capitalize newly installed load-control switches and programmable thermostats; and to extend the current Residential and Commercial Load Management/Demand Conservation Program through year seven of the proposed Program Plan. The Companies seek increased autonomy to modify these incentives to include both monetary and non-monetary mechanisms with a value range beginning at $20 per year, increasing to a maximum benefit of $40 per year. They propose that this incentive be in addition to any applicable installation bonus that customers may receive for enrolling in the program. The Companies state that all modifications to the program incentives will be designed to increase customer enrollment throughout the future life of the program. They point to data provided by a consultant indicating that there is a distinct correlation between the level of financial incentive and the amount of customer participation. The various incentives and marketing strategies used to engage the customer will be analyzed for effectiveness on a regular basis and changes will be made as needed.

5. Commercial Conservation/Commercial Incentives Program – This program is designed to provide energy efficiency opportunities for the Companies' commercial customers through energy audits and to increase the implementation of the energy efficiency measures identified through the audits by providing financial incentives to assist with replacing aging and less efficient equipment.

The Companies propose to enhance this program by adding energy efficiency retrofits eligible for incentives to include Refrigeration; by adding Commercial

Customized Incentives to encourage sustained energy efficiency retrofits eligible for customers which are not covered by the existing Commercial Conservation/Incentive Program; and extending the current Commercial Conservation component of the program through year seven of the proposed program plan.

The Companies' proposal states that the incentive portion of the program will provide a financial incentive to customers to install sustainable energy efficient equipment. To ensure equal incentive opportunities for all commercial customers, the Companies are proposing that the maximum annual incentive permitted be $50,000 per facility, but that commercial customers be permitted to receive multi-year incentives in a single year where such multi-year incentives do not exceed the aggregate amount of $100,000 per facility, if no incentive was provided in the immediately preceding year. Where appropriate, one customer may be entitled to more than one rebate. Incentives available to all customers in this program's rate classes will be developed based on $100 per kW calculated efficiency improvements.

New Programs

The Companies' Application proposes the addition of three new Demand-Side Management/Energy Efficiency ("DSM/EE") programs to their current offerings, and requests approval for implementation of these programs through 2017. The three newly proposed programs are the Smart Energy Profile Program, Residential Refrigerator Removal Program, and Residential Incentive Program.

1. Smart Energy Profile Program – The objective of this program will be to educate customers about their energy consumption, encourage them to reduce consumption and empower them to use energy more wisely. The program will use

available customer data and technology to create an individualized household report for each participating customer containing a collection of customized information. This program will target high-energy users. Energy users below average energy consumption produce minimal savings. The Companies are proposing program labor for one-half full-time employee.

2. Residential Refrigerator Removal Program - This program is designed to provide removal and recycling of inefficient secondary refrigerators and freezers from LG&E and KU customer households. The removal of these inefficient units will reduce consumption and demand. The Companies are proposing one-half full-time position for this program. Further, the Companies propose incentives to start at $30 per unit, with the ability to increase the incentive incrementally in later years if participation levels decline.

3. Residential Incentive Program – The Companies' objective of this program is to encourage customers to purchase various Energy Star appliances, HVAC equipment, or window films that meet certain requirements, qualifying them for an incentive. As proposed, this program will be open to all residential customers. The Companies are proposing .75 full-time employee for a program manager and .75 full-time employee for a customer service associate for internal needs for this program.

The Companies have proposed the following customer incentives:

Item	Incentive
Heat Pump Water Heaters	$300 per Qualifying Item Purchased
Washing Machine	$75 per Qualifying Item Purchased

Refrigerator	$100 per Qualifying Item Purchased
Freezer	$50 per Qualifying Item Purchased
Dishwasher	$50 per Qualifying Item Purchased
Window Film	Up to 50% of material cost only; max. of $200 per customer account; product must meet applicable criteria
Central Air Conditioner	$100 per Energy Star item purchased plus an additional $100 per SEER improvement above minimum*
Electric Air-Source Heat Pump	$100 per Energy Star item purchased plus an additional $100 per SEER improvement above minimum*

* The federal minimum is 14 SEER (Seasonal Energy Efficiency Ratio). Incentives are proposed to be pro-rated for 0.5 increases in SEER ratings.

Cost Effectiveness of the Programs

The Companies applied to their existing and proposed DSM/EE programs the industry standard cost-benefits tests set out in the California Standard Practice Manual: the Participant test, the Ratepayer Impact test, the Total Resource Cost test, and the Utility Cost test. The Application states that each of the new and enhanced programs proposed in the application passed the Participant and Total Resource Cost tests.

DSM Cost Recovery

The Application states that the current Cost Recovery Mechanism does not account for any Company-owned capital assets to be used in advancement of energy efficiency throughout the service territory. The Companies have proposed to add a fifth element to their DSM Recovery Component ("DSMRC") to account for the capital expenditure needed to develop the Residential and Commercial Load

Management/Demand Conservation Program in the DSM/EE Program Plan. The proposed added element – proposed to be identified as the DCCR – would allow the Companies to earn an approved return on equity ("ROE") exclusively for the capital expenditures outlined within the Residential and Commercial Load Management/Demand Conservation Program. The Companies propose a 10.50 percent ROE for capital expenditures outlined within that program and no party to the case opposed that return. In its Orders in Case Nos. 2009-00548[2] and 2009-00549,[3] the Commission approved the Stipulation and Recommendation ("Stipulation"). The requested 10.50 percent is within the reasonable range for each company set forth in the Stipulation as approved by the Commission.

Findings

Having reviewed the record, and being otherwise sufficiently advised, the Commission finds that:

1. The Companies' proposal not to change or amend the five unchanged existing programs and to allow these programs to remain in effect with their Commission-approved budgets through December 31, 2014 is reasonable and should be granted.

2. The Companies' request to add a fifth element to the DSMRC to account for the capital expenditure needed to develop the Residential and Commercial Load Management/Demand Conservation Program in the DSM/EE Program Plan is

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[2] Case No. 2009-00548, Application of Kentucky Utilities Company for an Adjustment of Base Rates (Ky. PSC July 30, 2010).

[3] Case No. 2009-00549, Application of Louisville Gas and Electric Company for an Adjustment of Electric and Gas Base Rates (Ky. PSC July 30, 2010).

reasonable and should be granted. This approval will allow the Companies to earn an approved ROE exclusively for the capital expenditures outlined within the Residential and Commercial Load Management/Demand Conservation Program.

3. The Companies' request for a 10.50 percent return on equity for capital expenditures outlined within the DSM/EE Program Plan for its Residential and Commercial Load Management/Demand Conservation Program is reasonable as it is within the range of ROE allowed by the Commission for KU in Case No. 2009-00548 and for LG&E in Case No. 2009-00549 and should be granted.

4. The Companies' request to enhance and extend through 2017 the Residential and Commercial Load Management/Demand Conservation Program; the Commercial Conservation/Commercial Incentive Program; the Residential Conservation/Home Energy Performance Program; the Residential Low Income Weatherization Program (WeCare); and its Program Development and Administration, is reasonable and each of the aforementioned programs should be approved as proposed in the Application.

5. The Companies' proposal to implement three new programs to operate through 2017 the Smart Energy Profile Program, the Residential Refrigerator Removal Program, and the Residential Incentives Program is reasonable and each of the aforementioned programs should be approved as proposed.

6. In order to evaluate program performance and effectiveness, the Companies should be required to file an interim three-year analysis of the five enhanced programs referred to in finding paragraph 3 and the three new programs referred to in finding paragraph 4.

7. The Companies request that the program budgets and metrics be prorated to begin six weeks following the date of an Order so that any remaining balance from the calendar year one budget may be applied to an eighth calendar year of program activities, thereby allowing the approved budgets to cover a full seven years of programming, is reasonable and should be granted.

8. The Companies' joint application for their DSM programs is reasonable and should be approved as filed.

9. The Companies' motion to submit the case for decision on the record should be granted.

IT IS THEREFORE ORDERED that:

1. The Companies' proposed Demand-Side Management and Energy Efficiency Program Plan joint application is approved as of the date of this Order.

2. The Companies' request not to change or amend the five unchanged existing programs and to allow these programs to remain in effect with their Commission-approved budgets through December 31, 2014 is granted.

3. The Companies' request to add a fifth element to the DSMRC to account for the capital expenditure needed to develop the Residential and Commercial Load Management/Demand Conservation Program in the DSM/EE Program Plan is granted.

4. The Companies' request for a 10.50 percent ROE for capital expenditures outlined within the DSM/EE Program Plan for its Residential and Commercial Load Management/Demand Conservation Program is granted.

5. On or before December 31, 2014, the Companies shall file an interim three-year analysis of the five enhanced programs referred to in finding paragraph 3 and the three new programs referred to in finding paragraph 4.

6. The Companies' request that their program budgets and metrics be prorated to begin six weeks following the date of this Order so that any remaining balance from the calendar year one budget may be applied to an eighth calendar year of program activities is granted.

7. The DSM cost recovery mechanism rates and charges for LG&E electric customers, as set forth in Appendix A hereto, are fair, just and reasonable rates for LG&E and are approved to become effective on the date of the first billing cycle for the month of January 2012, which begins on December 30, 2011.

8. The DSM cost recovery mechanism rates and charges for LG&E gas customers, as set forth in Appendix B hereto, are fair, just and reasonable rates for LG&E and are approved to become effective on the date of the first billing cycle for the month of January 2012, which begins on December 30, 2011.

9. The DSM cost recovery mechanism rates and charges for KU customers, as set forth in Appendix C hereto, are fair, just and reasonable rates for KU and are approved to become effective on the date of the first billing cycle for the month of January 2012, which begins on December 30, 2011.

10. The Companies' motion to submit the case for decision on the record is granted.

11. Within 20 days of the date of this Order, the Companies shall file their revised DSM tariffs with the Commission showing the date of issue, the effective date, and that they were issued by authority of this Order.

By the Commission

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KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Executive Director

Appendix A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2011-00134 DATED NOV 09 2011

Louisville Gas & Electric Company - Electric Customers
Demand-Side Management Cost Recovery Mechanism

Residential Rate RS, Volunteer Fire Department VFD, Residential Responsive Pricing Rate RRP, and Low Emission Vehicle Service LEV		Energy Charge	
DSM Cost Recovery Component (DCR)	$	0.00164	per kWh
DSM Revenues from Lost Sales (DRLS)	$	0.00150	per kWh
DSM Incentive (DSMI)	$	0.00007	per kWh
DSM Capital Cost Recovery Component (DCCR)	$	0.00048	per kWh
DSM Balance Adjustment (DBA)	$	(0.00163)	per kWh
Total DSMRC for Rates RS, VFD, RRP, and LEV	$	0.00206	per kWh

General Service Rate GS and General Responsive Pricing Rate GRP		Energy Charge	
DSM Cost Recovery Component (DCR)	$	0.00080	per kWh
DSM Revenues from Lost Sales (DRLS)	$	0.00121	per kWh
DSM Incentive (DSMI)	$	0.00004	per kWh
DSM Capital Cost Recovery Component (DCCR)	$	0.00006	per kWh
DSM Balance Adjustment (DBA)	$	(0.00044)	per kWh
Total DSMRC for Rates GS and GRP	$	0.00167	per kWh

Commercial Service Under Power Service Rate PS		Energy Charge	
DSM Cost Recovery Component (DCR)	$	0.00026	per kWh
DSM Revenues from Lost Sales (DRLS)	$	0.00066	per kWh
DSM Incentive (DSMI)	$	0.00001	per kWh
DSM Capital Cost Recovery Component (DCCR)	$	0.00000	per kWh
DSM Balance Adjustment (DBA)	$	(0.00047)	per kWh
Total DSMRC for Rate PS	$	0.00046	per kWh

Commercial Time-of-Day Secondary Service Rate CTODS and Commercial Time-of-Day Primary Service Rate CTODP		Energy Charge	
DSM Cost Recovery Component (DCR)	$	0.00024	per kWh

DSM Revenues from Lost Sales (DRLS)	$	0.00065	per kWh
DSM Incentive (DSMI)	$	0.00001	per kWh
DSM Capital Cost Recovery Component (DCCR)	$	0.00000	per kWh
DSM Balance Adjustment (DBA)	$	(0.00032)	per kWh
Total DSMRC for Rates CTODS and CTODP	$	0.00058	per kWh

Industrial Service Under Rate PS
Industrial Time-of-Day Secondary Service Rate ITODS
Industrial Time-of-Day Primary Service Rate ITODP
and Retail Transmission Rate RTS

		Energy Charge	
DSM Cost Recovery Component (DCR)	$	0.00000	per kWh
DSM Revenues from Lost Sales (DRLS)	$	0.00000	per kWh
DSM Incentive (DSMI)	$	0.00000	per kWh
DSM Capital Cost Recovery Component (DCCR)	$	0.00000	per kWh
DSM Balance Adjustment (DBA)	$	0.00000	per kWh
Total DSMRC for Rates PS, ITODS, ITODP, and RTS	$	0.00000	per kWh

Appendix B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2011-00134 DATED NOV 09 2011

Louisville Gas & Electric Company - Gas Customers
Demand-Side Management Cost Recovery Mechanism

Residential Rate RGS and Volunteer Fire Department Rate VFD		Energy Charge	
DSM Cost Recovery Component (DCR)	$	0.01238	per Ccf
DSM Revenues from Lost Sales (DRLS)	$	0.00172	per Ccf
DSM Incentive (DSMI)	$	0.00057	per Ccf
DSM Capital Cost Recovery Component (DCCR)	$	0.00551	per Ccf
DSM Balance Adjustment (DBA)	$	0.00379	per Ccf
Total DSMRC for Rates RGS and VFD	$	0.02397	per Ccf

Commercial Customers Served Under Firm Commercial Gas Service Rate CGS, As Available Gas Service Rate AAGS, Firm Transportation Rate FT, and Gas Transportation Service/Standby Rider TS		Energy Charge	
DSM Cost Recovery Component (DCR)	$	0.00080	per Ccf
DSM Revenues from Lost Sales (DRLS)	$	0.00000	per Ccf
DSM Incentive (DSMI)	$	0.00000	per Ccf
DSM Capital Cost Recovery Component (DCCR)	$	0.00052	per Ccf
DSM Balance Adjustment (DBA)	$	(0.00020)	per Ccf
Total DSMRC for Rates GS and GRP	$	0.00112	per Ccf

Appendix C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2011-00134 DATED NOV 0 9 2011

Kentucky Utilities Company
Demand-Side Management Cost Recovery Mechanism

Residential Service Rate RS, Volunteer Fire Department Service Rate VFD, and Low Emission Vehicle Service Rate LEV		Energy Charge	
DSM Cost Recovery Component (DCR)	$	0.00144	per kWh
DSM Revenues from Lost Sales (DRLS)	$	0.00088	per kWh
DSM Incentive (DSMI)	$	0.00006	per kWh
DSM Capital Cost Recovery Component (DCCR)	$	0.00048	per kWh
DSM Balance Adjustment (DBA)	$	(0.00045)	per kWh
Total DSMRC for Rates RS, VFD, and LEV	$	0.00241	per kWh

General Service Rate GS		Energy Charge	
DSM Cost Recovery Component (DCR)	$	0.00077	per kWh
DSM Revenues from Lost Sales (DRLS)	$	0.00083	per kWh
DSM Incentive (DSMI)	$	0.00004	per kWh
DSM Capital Cost Recovery Component (DCCR)	$	0.00007	per kWh
DSM Balance Adjustment (DBA)	$	0.00006	per kWh
Total DSMRC for Rate GS	$	0.00177	per kWh

All Electric School Rate AES		Energy Charge	
DSM Cost Recovery Component (DCR)	$	0.00024	per kWh
DSM Revenues from Lost Sales (DRLS)	$	0.00014	per kWh
DSM Incentive (DSMI)	$	0.00001	per kWh
DSM Capital Cost Recovery Component (DCCR)	$	0.00000	per kWh
DSM Balance Adjustment (DBA)	$	(0.00014)	per kWh
Total DSMRC for Rate AES	$	0.00025	per kWh

Commercial Customer Served Under Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, and Time-of-Day Primary Service Rate TOPD

		Energy Charge	
DSM Cost Recovery Component (DCR)	$	0.00021	per kWh
DSM Revenues from Lost Sales (DRLS)	$	0.00023	per kWh
DSM Incentive (DSMI)	$	0.00001	per kWh
DSM Capital Cost Recovery Component (DCCR)	$	0.00000	per kWh
DSM Balance Adjustment (DBA)	$	(0.00029)	per kWh
Total DSMRC for Rates PS, TODS, and TODP	$	0.00016	per kWh

Industrial Customers Served Under Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Retail Transmission Rate RTS

		Energy Charge	
DSM Cost Recovery Component (DCR)	$	0.00000	per kWh
DSM Revenues from Lost Sales (DRLS)	$	0.00000	per kWh
DSM Incentive (DSMI)	$	0.00000	per kWh
DSM Capital Cost Recovery Component (DCCR)	$	0.00000	per kWh
DSM Balance Adjustment (DBA)	$	0.00000	per kWh
Total DSMRC for Rates TODS, TODP, and RTS	$	0.00000	per kWh

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Demand-Side Management and Energy Efficiency Programs in Kentucky

Presentation to the Georgian National Energy and Water Supply Regulatory Commission

Frankfort, Kentucky
May 2010

Aaron Greenwell, Assistant Director, Financial Analysis Division
John Rogness, Manager, Management Audits Branch
Jeff Shaw, Manager, Electric and Gas Revenue Requirements Branch
Kentucky Public Service Commission

Agenda

- Demand-Side Management ("DSM") and Energy Efficiency Programs - Objectives
- Federal Legislation
  - Public Utility Regulatory Policies Act
  - Energy Policy Act of 2005
  - Energy Independence and Security Act of 2007
- Governor Ernie Fletcher's Energy Plan
- Governor Steven L. Beshear's Energy Plan
- Kentucky Legislation
  - Enacted
  - Proposed
- The DSM Statute, KRS 278.285
- Funding Energy Efficiency – National Action Plan for Energy Efficiency

Demand-Side Management and Energy Efficiency Programs - Objectives

- Defer or eliminate need for additional capacity
- Provide opportunities for customer to reduce usage / bills
- Reduce output of highest cost generation / fuel costs
- Reduce level of emissions
- Free-up capacity to make off-system sales

Federal Legislation - Public Utility Regulatory Policies Act

- PURPA

- Purpose
  - conservation of energy supplied by electric utilities
  - optimal efficiency of electric utility facilities and resources
  - equitable rates for electric consumers (PURPA section 101)

- Originally included six Federal standards

- Five of the standards concerned customer rate determination and design
  - cost of service
  - declining block rates
  - time-of-day rates
  - seasonal rates
  - interruptible rates

- Sixth federal standard
  - load management techniques

PURPA - Kentucky Commission Action

- Initiated Administrative Case No. 203 in March 1979
- Reviewed – purposes of PURPA
  - Conservation
  - Utility Efficiency
  - Equitable Rates
- Other Commission Objectives
  - Minimize economic dislocation – rate continuity - gradualism
  - Rate structure to allow for stable earnings – revenue stability
  - Simple and understandable rates – understandability

PURPA - Kentucky Commission Action (continued)

- Commission adopted -
  - Cost of service standard
    - Rates based on cost with rate continuity
    - Embedded cost of service study
    - Marginal cost of service study
  - Declining block rates
    - Replace with flat or inverted block volumetric rate
    - May continue with declining block with COSS support
  - Time-of-Day Rates
    - Shift usage from peak to off-peak
    - Gradual implementation
      - mandatory for certain industrial customers
      - load research
      - implement for a target group – load research
      - cost-benefit study

PURPA - Kentucky Commission Action (continued)

- Commission adopted -
  - Seasonal Rates
    Implement when cost-justified
    Kentucky Utilities – Kentucky Power
    Monitor load research and COSS
  - Interruptible Rates
    Required each electric utility file an interruptible rate tariff
    Recommended each set a percentage goal for interruptible load
    Allowed each to limit interruptible requirement to a minimum demand
  - Load Management Techniques
    Company evaluations were in progress
    Established a task force to continue review

Federal Legislation – Energy Policy Act of 2005

- EPAct 2005
- Enacted August 8, 2005
- Five New Federal Standards
  - Net Metering
  - Fuel Diversity
  - Fossil Fuel Diversity
  - Time-Based Metering and Communications (“Smart Metering”)
  - Interconnection Standards

EPAct 2005 - Kentucky Commission Action

- Initiated Administrative Case No. 2006-00045 on February 24, 2006
  - Smart Metering
    - Time-of-use pricing
    - Critical peak pricing
    - Real-time pricing
  - Interconnection
- Did not adopt either standard
  - Smart Metering
    - Low rates
    - Significant costs
    - Uncertain benefits
  - Interconnection
    - Existing interconnection requirements
    - Existing net metering tariff

EPAct 2005 - Kentucky Commission Action (continued)

- Initiated Administrative Case No. 2007-00300 on August 2, 2007
  - Fuel source diversity
  - Fossil fuel generation efficiency
- Did not adopt either standard
  - Consideration required in Integrated Resource Plan
  - Prevailing statutes

Federal Legislation – Energy Independence and Security Act of 2007

- EISA 2007
- Enacted December 19, 2007
- Four New Federal Standards
  - Integrated Resource Planning
  - Rate Design Modifications to Promote Energy Efficiency
  - Smart Grid Investments
  - Smart Grid Information

EISA 2007 - Kentucky Commission Action

- Initiated Administrative Case No.2008-00408 on December 13, 2008
  - Still In Progress
  - Considering each new standard
- Smart Grid and Smart Meters
  - Commission has initiated collaborative process to consider
  - Parties in the administrative case participating

Kentucky's Energy Opportunities for Our Future Governor Ernie Fletcher, 2005 – General Highlights

Energy Efficiency: Saving Energy, Saving Money, and Protecting the Environment

- Kentucky government agencies and institutions to reduce energy use
- Procurement policies to encourage energy efficiency
- High performance, efficient design for new construction of state facilities
- Public-private partnerships to promote energy efficiency through education
- Initiatives to help business improve profitability through energy efficiency
- Examine building codes and specifications relative to energy efficiency
- Strengthen energy education for school children

Intelligent Energy Choices for Kentucky's Future – Kentucky's 7-Point Strategy for Energy Independence Governor Steven L. Beshear, November 2008

General Highlights

- **GOAL: Energy efficiency to offset 18% of projected energy demand in 2005**
- Improve energy efficiency of homes, building, industries, and transportation fleet
- **Near-Term Actions (1-3 Years)**
  - Improve energy efficiency of state facilities and transportation fleet fuel economy
  - Energy Efficiency Resource Standard ("EERS") – reduce energy consumption by 16% of projected 2005 consumption
  - On-going public energy efficiency awareness and education program
  - Incentives for plug-in hybrid electric vehicles and highly fuel efficient vehicles

Intelligent Energy Choices for Kentucky's Future – Kentucky's 7-Point Strategy for Energy Independence Governor Steven L. Beshear, November 2008 General Highlights (continued)

- **Mid-Term Actions (4-7 Years)**
  - Develop a "Smart Grid" Policy to facilitate next generation of DSM Programs
  - Evaluate Rate Design and Ratemaking alternatives to enhance cost-effective energy efficiencies
- **Long-Term Actions (> 7 Years)**
  - Integrate advanced "Smart Grid" technologies and communication systems into the power grid
  - Reevaluate the EERS goal to determine if additional reductions are achievable

Kentucky Legislation Enacted

- 2007 Second Special Legislative Session

- House Bill 1 – Incentives for Energy Independence Act
  - Provides tax credits and other incentives
    - Energy efficiency
    - Alternative fuel facilities
    - Related investments

  - LEED rating system in building construction

  - Replace 50% of state vehicles
    - Hybrid vehicles
    - Alternative fuel source vehicles

  - Kentucky Alternative Fuel and Renewable Energy Fund Program

Kentucky Legislation Enacted (continued)

- House Bill 1 – Incentives for Energy Independence Act (continued)
  - Section 50 – directs PSC to
    - Study statutes and regulations
    - Identify impediments to energy efficiency
    - Make recommendations to General Assembly
  - Electric Utility Regulation and Energy Policy in Kentucky ("Section 50 Report")
    - Few impediments – KRS 278.285, the DSM Statute
    - Encourage diversification – amended KRS 278.465, Net Metering
    - No reason to account for externalities under current regulatory scheme
    - Commission currently has ability to modify rate structure

Kentucky Legislation Proposed

- 2010 Regular Legislative Session – Did Not Pass

- House Bill 3 – An Act to advance clean energy use and production
  - Objectives
    - Diversify sources of generation
    - Increase efficiency – supplier and consumer
    - Reduce carbon emissions
    - Develop
      - renewables,
      - clean coal,
      - carbon storage, and
      - energy efficiency

  - Clean Energy Portfolio Standards
    - Percentage benchmarks – nonindustrial demand
      - Renewable energy resources
      - Low-carbon resources and efficiency measures

  - Gradual increase to 2017, then 12% efficiency

Demand-Side Management ("DSM") Statute – KRS 278.285

- Enacted in 1994 – Foundation laid in 1983
- Major Features –
  - Stand-alone applications
  - Industrial opt out
  - Surcharge mechanism
    - Class specific
    - Program costs
    - Lost revenues
    - Financial rewards

Demand-Side Management Programs

- Regulatory Considerations
  - Policy Goals – Purpose of DSM
  - Resistance by Utilities, Customers
- Regulatory Incentives
  - Cost Recovery
  - Means of Recovery
- DSM Programs of Utilities in Kentucky
  - Direct Load Control Programs
  - High Efficiency Appliance Rebates
  - New Construction Incentives
  - Weatherization – Energy Assistance

Energy Efficiency Measures in Kentucky

- Regulatory efforts to introduce Energy Efficiency
- Developing an Energy Efficiency Strategy in Regulation
- Timeline
  - Long Process – 1983
  - DSM Statute – 1994
  - Changing Economics

Energy Efficiency Programs Delivered by Utilities in Kentucky

Residential Programs

Energy Audits/Analysis

Comprehensive Energy Education

Direct Load Control of Air Conditioners / Water Heaters

Geothermal Cooling and Heating Incentives

High Efficiency -

- Heat Pumps
- Refrigerators – Energy Star
- Lighting
- Mobile Homes – New Construction

Programmable Thermostats

Low-Income Weatherization

Compact Fluorescent Bulbs

New Home Construction – Energy Star

High Efficiency -

- Clothes Dryers – Energy Star
- Air Conditioners – Energy Star
- Water Heaters
- Heat Pump – Mobile Home Retrofit

Low-Income Energy Assistance

Energy Efficiency Programs Delivered by Utilities in Kentucky (continued)

Commercial Programs

New Construction

Efficient Refrigeration

Efficient Heating, Ventilation, and Air Conditioning (“HVAC”)

Efficient Lighting

HVAC Diagnostics and Tune-Up

Direct Load Control of Air Conditioners / Water Heaters

Demand Response

Industrial Programs

Demand Response (Load Shedding)

Demand response (Supply Generation)

High Efficiency Motors

Variable Speed Drive Motors

Combine Heat and Power (“CHP”) Projects

Energy Efficiency Programs

- Evaluating Utility Energy Efficiency Programs
  - Third Party Evaluations
    - Impact Evaluations
    - Efficiency Evaluations
- Funding Energy Efficiency Programs in Kentucky
  - Base Rates
  - DSM Surcharges

Funding Energy Efficiency
National Action Plan for Energy Efficiency ("NAPEE")

- Action Plan developed by a Leadership Group – July 2006
  - Utility Commissioners
  - Utility representatives
  - Representatives of Stakeholder Groups
- Facilitated by –
  - U.S. Department of Energy ("DOE")
  - U.S. Environmental Protection Agency ("EPA")
  - Number of Expert consultants
- Discusses policy, planning, and program issues based on a formal work plan

Funding Energy Efficiency NAPEE (continued)

- Recommendations
  - Recognize energy efficiency as high-priority energy resource
  - Need long-term commitments to implement cost-effective energy efficiency
  - Communicate benefits of, and opportunities for, energy efficiency
  - Promote sufficient, timely, and stable funding to deliver cost-effective energy efficiency
  - Modify policies to create utility incentives to deliver cost-effective energy efficiency
  - Modify ratemaking practices to promote investments in energy efficiency

Funding Energy Efficiency NAPEE (continued)

- Funding – Ability to recover energy efficiency costs in timely manner
  - Revenue requirement or resource procurement funding
  - System benefits charges
  - Rate-basing
  - Shared-savings
  - Incentive mechanisms

Funding Energy Efficiency NAPEE (continued)

- Modify policies to align incentives
  - Address “throughput” incentive
    - Decoupling
    - Increased customer charges
    - Tariff rider (surcharge)
    - System benefits charge
    - Increase Return on Equity (“ROE”)
    - On-Bill Financing
  - Eliminate rate designs that discourage energy efficiency
    - Declining block rates
  - Adopt rate designs which encourage energy efficiency
    - Inclining block rates (inverted)
    - Time-of-use rates – seasonal, time-of-day
    - Dynamic rates – real-time pricing, critical peak pricing
    - Two-part rates – base level of usage

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Rates and energy resources:
The regulatory process in Kentucky

East Kentucky Power Cooperative
DSM/Renewable Energy Collaborative
Lexington
July 19, 2011

JEFF SHAW, DIVISION OF FINANCIAL ANALYSIS
QUANG NGUYEN, OFFICE OF GENERAL COUNSEL
KENTUCKY PUBLIC SERVICE COMMISSION

Kentucky:

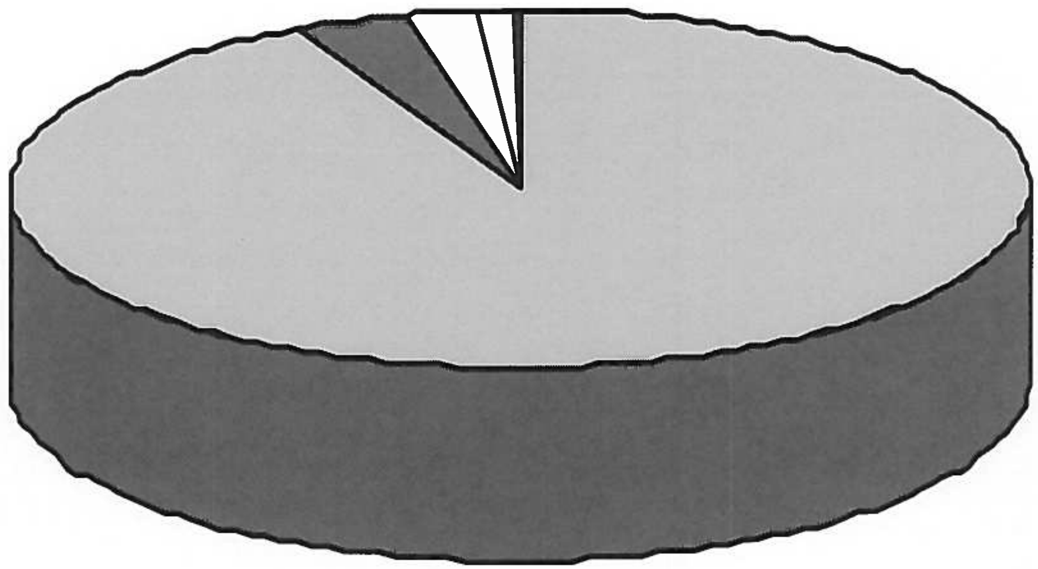
electric generation

20,160 MW generating capacity

72% of capacity is coal-fired

90 million MW-hours (2009)

Kentucky Actual Electric Generation by Fuel - 2009



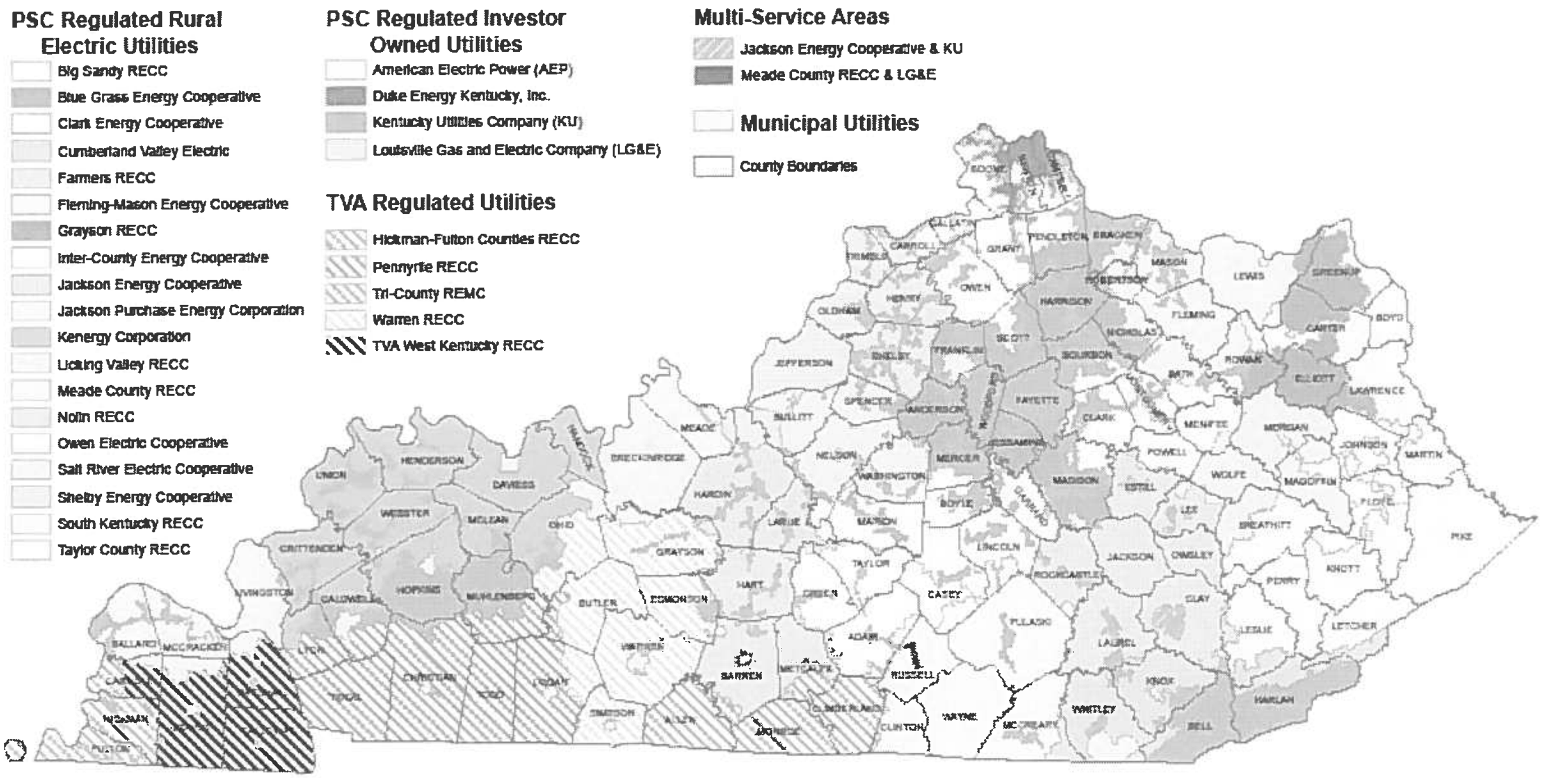
Coal – 92.7%

Kentucky: inexpensive electricity

"all-in" prices as of March 2011
(cents per kwh)

	KY	US
All customers	6.81 (5)	9.66
Residential	9.15 (12)	11.64

Electric Distribution Service Areas



Kentucky has 30 municipal systems serving over 300,000 customers. Twelve of these are provided wholesale power by the Tennessee Valley Authority (TVA) and are regulated by them. The others are self-regulated by the municipality. The boundaries for the municipal systems were either derived from the Public Service Commission's certified territory maps, or from boundaries submitted for informational purposes to the PSC from the municipals. If the municipal service area boundaries were unknown, a circle was placed around the urbanized area.

The electric service areas are compiled from certified territory maps on file with the Public Service Commission. These are legal documents which define the retail service area of electric suppliers regulated by the Commission (Kentucky Statute 278.017). The legal certified territory boundaries are drafted on 1:24,000 USGS topographic maps, and can be assumed to have an accuracy of 100 feet. This map, which was compiled from the data, is for informational purposes only, and has no legal standing.

Kentucky Public Service Commission
July 14, 2009

Applicable regulatory mechanisms:

- Integrated resource plans (IRPs) - 807 KAR 5:058
- Certificate of public convenience and necessity (CPCN) - KRS 278.020 (1)
- Ratemaking authority - KRS 278.030 and others
- Demand-side management – KRS 278.285

<u>Operation of all mechanisms is determined by statute, regulation and legal precedent</u>

Integrated resource plans:

- Applies to all jurisdictional electric utilities with generating facilities
- Requires filing of IRPs every three years
- Plans include load forecasts, resource needs and plans for meeting those needs
- Supply-side and demand-side solutions must be included
- PSC staff evaluates plans and issues reports, but the Commission does not approve or deny IRPs

The CPCN process:

- Construction of generation/transmission facilities requires a CPCN
- Statute is general – parameters of PSC decision have evolved over time through legal precedents
- Applicant must show a need for proposed facility
- Utility must show it has considered reasonable options
- Wasteful duplication is not allowed
- "Least cost" principle flows from absence of wasteful duplication
- Grant of a CPCN leads to a presumption of future cost recovery

Ratemaking:

- Kentucky is non-restructured
- Jurisdictional electric utilities are vertically integrated and fully regulated as to rates and service
- Rates must be "fair, just and reasonable"
- Cost-based ratemaking
- Fuel costs, environmental compliance costs and demand-side management programs are separated from base rates and assessed separately
- Statutes set forth not only PSC authority, but the process itself

Ratemaking:

- Notice of intent is required (KRS 278.180)
- Public notice to customers (807 KAR 5:001(10))
- 10-month deadline for PSC decision (KRS 278.190)
- Test year requirement – test year may be historic or prospective (KRS 278.192)
- PSC may suspend proposed rates for five or six months, depending on type of test year (KRS 278.190)
- After suspension, rates may be placed into effect by utility, subject to refund (KRS 278.190)

Demand-side management:

- Utilities may propose plans
- PSC has no authority to require DSM
- Programs may include smart meters, home energy assistance programs
- Cost-effectiveness

  PSC evaluates a variety of factors

  "California" tests
- Consistency with IRP

Demand-side management:

- Recovery of program costs, including incentives
- Recovery of DSM costs includes foregone revenue
- All investor-owned utilities have DSM programs – all are expanding
- Electric cooperatives DSM programs are somewhat less extensive than IOU programs
- Several utilities have pilot programs to test smart grid technologies in combination with time-of-day or demand-based variable rate structures

Demand-Side Management and Energy Efficiency Programs - Objectives

- Defer or eliminate need for additional capacity
- Provide opportunities for customer to reduce usage / bills
- Reduce output of highest cost generation / fuel costs
- Reduce level of emissions
- Free-up capacity to make off-system sales

Demand-Side Management ("DSM") Statute – KRS 278.285

- Enacted in 1994
- Major Features –
  - Stand-alone applications
  - Industrial opt out
  - Surcharge mechanism
    - Class specific
    - Program costs
    - Lost revenues
    - Financial rewards

DSM/Energy Efficiency Programs Delivered by Utilities in Kentucky

<u>Residential Programs</u>

Energy Audits/Analysis

Comprehensive Energy Education

Direct Load Control of Air Conditioners / Water Heaters

Geothermal Cooling and Heating Incentives

High Efficiency -
- Heat Pumps
- Refrigerators – Energy Star
- Lighting
- Mobile Homes – New Construction

Programmable Thermostats

Low-Income Weatherization

Pilot on-bill financing program for energy efficiency improvements

Compact Fluorescent Bulbs

New Home Construction – Energy Star

High Efficiency -
- Clothes Dryers – Energy Star
- Air Conditioners – Energy Star
- Water Heaters
- Heat Pump – Mobile Home Retrofit

Low-Income Energy Assistance

DSM/Energy Efficiency Programs Delivered by Utilities in Kentucky (continued)

Commercial Programs

New Construction

Efficient Refrigeration

Efficient Heating, Ventilation, and Air Conditioning ("HVAC")

Efficient Lighting

HVAC Diagnostics and Tune-Up

Direct Load Control of Air Conditioners / Water Heaters

Demand Response

Industrial Programs

Demand Response (Load Shedding)

Demand response (Supply Generation)

High Efficiency Motors

Variable Speed Drive Motors

Combine Heat and Power ("CHP") Projects

DSM/Energy Efficiency Programs in Kentucky (Examples)

Air conditioner load control (LG&E/Kentucky Utilities)

Similar programs in place at most jurisdictional electric utilities

- Radio-controlled device mounted on outside AC unit
- Allows AC compressor (not interior ventilation fan) to be turned off remotely for 10 minutes per hour during times of peak demand – weekdays only
- Customer receives $5 monthly credit during four-month heating season (June-Sept.) for $20 total
- Capacity to reduce loads by 220 MW during peak times

DSM/Energy Efficiency Programs in Kentucky (Examples)

Smart meter pilot program (LG&E)

- Testing whether residential customers will modify electric usage in response to price signals
- Pairs "smart meters" with in-home devices that display usage and rates
- Tiered rates that rise as overall system demand rises
- Expanded to include appliances that automatically respond to price signals

DSM/Energy Efficiency Programs in Kentucky (Examples)

Energy efficiency rebates (East Kentucky Power Cooperative/member distribution cooperatives)

Heating and cooling systems

- Old system must be at least 10 years old
- New system must meet certain efficiency standards
- Rebate of up to $500

Insulation

- Sealing of homes to reduce heating/cooling losses
- Incentives of up to $410

New home incentives

- Incentives of up to $250 for purchasers who choose to purchase new homes meeting certain energy efficiency standards

Recent DSM cases

Duke Energy Kentucky 2010-00445

Kentucky Power 2011-00055

- Both largely renewal of existing programs
- Some expansion of residential programs
- Reduction of residential surcharges
- Neither raised substantial regulatory issues

Recent cases involving renewable energy

Kentucky Power wind energy 2009-00545

- Company proposed 20-year contract to purchase 100 MW of wind power
- KP said purchase would position company for future compliance with renewable mandates or carbon constraints
- Purchase opposed by AG and KIUC
- PSC rejected on grounds of no immediate need for power; higher cost

Recent cases involving renewable energy

KU/LG&E wind power contracts and surcharge 2009-00353

- Joint purchase of 110 MW
- Proposed surcharge for cost recovery

(71¢/mo for LG&E, 92¢/mo for KU)

- PSC rejected surcharge request on procedural grounds – said costs should be considered in general rate case
- Case closed in April 2010 when companies withdrew request

Future of energy efficiency in Kentucky

- Kentucky lags in energy efficiency
- Low electric costs are a barrier to energy efficiency programs
- Financial incentives to consumers can help overcome lack of economic imperatives, but are not as persuasive as high energy costs
- Attractiveness of energy efficiency will increase as electric costs rise
- Kentucky already has abundance of "low-hanging fruit"
- Governor's comprehensive energy plan has major focus on improving efficiency, increasing conservation

Kentucky's electric costs will increase

- More stringent Clean Air Act standards for SOx, NOx, particulates and mercury; new water quality regulations related to ash and scrubber wastes and cooling water
- Added controls on newer coal units; old units retired and replaced with natural gas; more emphasis on DSM
- Utilities expect total electric costs to rise 20-25%
- Additional increases if coal ash declared a hazardous waste
- Possible carbon constraints not yet factored in

Opportunities for increasing energy efficiency in Kentucky

- Residential sector has lagged behind commercial and industrial users
- High proportion of older and substandard housing – small investments in weatherization and other improvements can have big returns
- Recent base rate increases have increased interest in energy efficiency
- With expected rate impacts over next 5 years, demand for energy efficiency programs, especially at residential level, expected to increase

QUESTIONS

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KIUC_Goins_WPs_2012-00221-00222-dg.xls
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Table 1. KU/LG&E: Current CSR Rates

Item	CSR10	CSR30
Notice (minutes)	10	30
Curtailment Hours		
Physical	100	100
Buy-Through	275	250
Total	375	350
Credit ($/kW-mo)		
Primary	5.50	4.40
Transmission	5.40	4.30
Customers		
KU	3	0
LG&E	1	1

Table 2. KU/LG&E: Proposed CSR Credits

	Credit ($/kW-mo)		
	Pres	Prop	Chng
CSR10			
Primary	5.50	2.80	#######
Transmission	5.40	2.75	#######
CSR30			
Primary	4.40	2.30	#######
Transmission	4.30	2.25	#######

Proposed CSR credits = $/kVA-mo. Credits shown above assume PF=1, where PF is Power Factor.

Table 3. KIUC: Proposed CSR Credits

	Credit ($/kW-mo)		
	Pres	Prop	Chng
CSR10			
Primary	5.50	5.64	3%
Transmission	5.40	5.54	3%
CSR30			
Primary	4.40	4.51	3%
Transmission	4.30	4.41	3%

Proposed CSR credits = $/kVA-mo. Credits shown above assume PF=1, where PF is Power Factor.

Table x. KU/LG&E: DSM Costs

Source: 2011 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company, Volume 1, 8-75 and 8-76

Rate	Unit		Summer	Winter	Avg	CSR/Firm Ratio CSR10	CSR30
PS-Pri	KW	Present	13.72	11.45	12.40	44.37%	35.50%
		Proposed	14.75	12.73	13.57	20.63%	16.95%
TODP	kVA	Present	7.26		7.26	74.38%	59.23%
		Proposed	8.60		8.60	31.98%	26.16%
RTS	kVA	Present	6.69		6.69	80.72%	64.28%
		Proposed	8.10		8.10	33.95%	27.78%
FLS-Pri	kVA	Present	5.28		5.28	104.17%	83.33%
		Proposed	5.59		5.59	50.09%	41.14%
FLS-Tra	kVA	Present	4.53		4.53	119.21%	94.92%
		Proposed	4.84		4.84	56.82%	46.49%

PS-Pri	9.49%
TODP	18.46%
RTS	21.08%
FLS-Pri	5.87%
FLS-Tra	6.84%

Implied CSR @ Target

CSR10	**CSR30**
10.18	7.46
6.45	4.73
6.08	4.46
4.19	3.07
3.63	2.66

Weights	
Summer	0.416667
Winter	0.583333

		CSR10	**CSR30**	
KU_pres				
	Pri	5.50	4.40	80.00%
	Tran	5.40	4.30	79.63%
KU_prop				
	Pri	2.80	2.30	82.14%
	Tran	2.75	2.25	81.82%
Change				
	Pri	-49.09%	-47.73%	
	Tran	-49.07%	-47.67%	

Target Ratio	
CSR10	0.75
CSR30	0.55

		CSR10	
	Voltage	**Present**	**Proposed**
	Trans	5.40	5.54
	Primary	5.50	5.64
Increase	Trans		0.14
	Primary		0.14

CSR30	
Present	Proposed
4.30	4.41
4.40	4.51
	0.11
	0.11

KU and LG&E CT Data

Plant	2007 MW	2007 Hrs	2007 Wtd Hrs	2008 kW	2008 Hrs	2008 Wtd Hrs
KU						
Brown	670	317	103	836	121	42
Paddy's Run 13	74	165	6	82	51	2
Haefling	36	10	0	42	3	0
Trimble County	630	1,014	309	709	533	157
LG&E						
Brown	179	317	27	203	121	10
Cane Run	14	33	0	14	1	0
Paddy's Run	119	165	10	134	17	1
Trimble County	330	1,014	162	371	533	82
Zorn	14	24	0	16	0	0
Total	2,066	3,059	617	2,407	1,380	294

MW = net continuous capability (MW)
Hrs = hours connected to load

Source: KU and LGE 2007 and 2008 FERC Form 1 beginning at 402.

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATE FOR THE CONSTRUCTION OF A COMBINED CYCLE COMBUSTION TURBINE AT THE CANE RUN GENERATING STATION AND THE PURCHASE OF EXISTING SIMPLE CYCLE COMBUSTION TURBINE FACILITIES FROM BLUEGRASS GENERATION COMPANY, LLC IN LAGRANGE, KENTUCKY	)	CASE NO. 2011-00375

O R D E R

On September 15, 2011, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "Joint Applicants") filed an application pursuant to KRS 278.020, 807 KAR 5:001, Sections 8 and 9, and KRS 278.216, requesting a Certificate of Public Convenience and Necessity ("CPCN") and a Site Compatibility Certificate for the construction of a 640 MW natural gas combined cycle combustion turbine ("CR 7") at the Joint Applicants' Cane Run Generating Station ("Cane Run") in Louisville, Kentucky, and for the purchase of natural gas simple cycle generation facilities in LaGrange, Kentucky from Bluegrass Generation Company, LLC ("Bluegrass Generation") which include three turbines with a combined capacity of 495 MW. The estimated cost of constructing the facilities at Cane Run, including a 20-inch natural gas pipeline, is $583 million. The cost of the Bluegrass Generation purchase is $110 million. Joint Applicants propose an optimal ownership split of CR 7 with KU owning 78 percent and LG&E owning 22 percent.[1] For the Bluegrass Generation facilities, the Joint Applicants propose an ownership arrangement of 31 percent for KU and 69 percent for LG&E.[2] The ownership split balances the production cost savings of CR 7 and balances each company's individual reserve margins through 2020. The proposed natural gas generating facilities are intended to replace the energy and capacity currently provided by the Joint Applicants' Cane Run, Tyrone, and Green River coal-fired units, which are slated to be retired in 2016.

The following parties were granted full intervention in this matter: (1) the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention; (2) Kentucky Industrial Utility Customers, Inc. ("KIUC"); and (3) Sierra Club and Natural Resources Defense Council (collectively "Environmental Intervenors"). On October 18, 2011, the Commission issued an Order establishing a procedural schedule for the processing of this matter. The procedural schedule provided for two rounds of discovery on the Joint Applicants, an opportunity for the filing of intervenor testimony, one round of discovery on intervenor testimony, and an opportunity for the Joint Applicants to file rebuttal testimony.

The Commission scheduled and held a public meeting in Louisville, Kentucky on March 8, 2012 to receive public comments on the Joint Applicants' proposal to construct a combined cycle natural gas combustion turbine at Cane Run and the proposed acquisition of the simple cycle gas combustion turbines from Bluegrass Generation. A

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[1] Application, ¶ 11; Direct Testimony of David S. Sinclair ("Sinclair Testimony"), Exhibit DSS-1, Joint Applicants' 2011 Resource Assessment, p. 35.

[2] *Id.*

formal hearing was conducted at the Commission's offices in Frankfort, Kentucky on March 20, 2012. The parties submitted post-hearing briefs on April 3, 2012. The matter is now before the Commission for a decision.

JOINT APPLICANTS' PROPOSAL

Joint Applicants maintain that their self-build proposal, as well as the proposed Bluegrass Generation acquisition, represents the least-cost option to comply with certain new and pending environmental regulatory requirements under the Federal Clean Air Act as amended. Joint Applicants state that the decision to retire their coal-fired generating facilities at Cane Run, Green River, and Tyrone was driven by the proposed Cross-State Air Pollution Rule ("CSAPR"), the Mercury and Air Toxics Standards ("MATS")[3] rule, and the National Ambient Air Quality Standards ("NAAQS").

CSAPR, which was finalized by the EPA on July 6, 2011, requires certain states to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states.[4] CSAPR imposes significant

[3] At the time of the filing of the instant application, the national emission standards for hazardous air pollutants aimed at reducing mercury, other metals, acid gases, and organic air toxics was known as the HAPS rule. On December 21, 2011, the federal Environmental Protection Agency ("EPA") finalized the National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial–Institutional Steam Generating Units. The final HAPS rule became effective on April 16, 2012 and is now known as the MATS rule or the Utility Maximum Achievable Control Technology "Utility MACT" rule.

[4] On December 30, 2011, in civil actions for review brought by several stakeholders, the United States Court of Appeals for the District of Columbia Circuit entered an order staying the implementation of CSAPR pending the court's resolution of the various petitions for review. The EPA is to continue administering the Clean Air Interstate Rule pending the court's resolution of the petitions for review.

reductions in sulfur dioxide ("SO_2") and nitrogen oxide ("NO_x") emissions that cross state lines beginning in 2012, with still more stringent SO_2 reductions in 2014.[5] Joint Applicants note that "CSAPR creates more stringent state-specific allowance budgets (or 'caps') for SO_2 and NO_x, and would allow for only limited interstate allowance trading to ensure that individual states actually have to make the reductions EPA desires . . . ."[6]

The MATS rule for power plants would reduce emissions from new and existing coal- and oil-fired electric utility steam generating units larger than 25 MW that produce electricity for consumption by the public. Any units which began construction after May 3, 2011 will be considered a new source and must be in compliance within 60 days after the rule is published in the *Federal Register*,[7] or upon startup, whichever is later. Existing units, or those units constructed on or before May 3, 2011, will have three years, plus 60 days after the rule is published in the *Federal Register,* to be in compliance (or April 16, 2015). There is also a possibility that a one-year extension may be granted to install the control devices. In addition, the EPA is providing a pathway for reliability critical units to obtain a schedule with up to an additional year (for a total of 5 years possible) to achieve compliance.[8] MATS would reduce emissions of

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[5] Kentucky is one of 16 states that will be subject to further SO_2 reductions in 2014 under CSAPR.

[6] Direct Testimony of Gary H. Revlett at p. 6.

[7] The MATS rule was published in the *Federal Register* on February 16, 2012, under 77 Fed. Reg. 9,304 (to be codified at 40 C.F.R. pts. 60 and 63).

[8] *See* December 16, 2011 Policy Memorandum issued by the EPA's Office of Enforcement and Compliance Assurance, re The Environmental Protection Agency's Enforcement Response Policy for use of Clean Air Act Section 113(a) Administrative Orders in Relation to Electric Reliability and the Mercury and Air Toxics Standard. Available at: www.epa.gov/compliance/resources/policies/civil/erp/mats-erp.pdf.

heavy metals, including mercury, arsenic, chromium, and nickel; and acid gases, including hydrochloric acid and hydrofluoric acid. These requirements would require the installation of Maximum Achievable Control Technology.

Lastly, Joint Applicants point out that air quality in Jefferson County currently fails to meet SO_2 requirements and the EPA's NAAQS will further restrict NO_x and SO_2 emissions beginning in 2016 and 2017. LG&E performed an evaluation of NAAQS compliance and concluded that retiring the Cane Run facility, constructing CR 7, and installing a scrubber at its Mill Creek Generating Station would reduce SO_2 in Jefferson County by 70 percent. Given these actions, Jefferson County should achieve attainment of SO_2 NAAQS and the Cane Run generation station would be in compliance with NO_x NAAQS.

In Case Nos. 2011-00161[9] and 2011-00162,[10] the Joint Applicants sought and received Commission approval of their 2011 Environmental Compliance Plans, which plans were the result of a comprehensive analysis that determined, on a unit-by-unit basis, whether it would be more cost-effective to install identified pollution control facilities or to retire the unit and buy replacement capacity. Based on the operating characteristics, age, and size of the units, the Joint Applicants determined that the cost of additional emission controls on their six coal-fired units at the Cane Run, Green

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[9] Case No. 2011-00161, Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of its 2011 Environmental Compliance Plan for Recovery by Environmental Surcharge (Ky. PSC Dec. 15, 2011).

[10] Case No. 2011-00162, Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of its 2011 Compliance Plan for Recovery by Environmental Surcharge (Ky. PSC Dec. 15, 2011).

River, and Tyrone generating plants could not be justified and that they should be retired by the end of 2015. The six coal-fired units to be retired have a combined capacity of 797 MWs.

Based on the joint load forecast that was used to prepare the Joint Applicants 2011 Integrated Resource Plan ("IRP"), the retirements of the Cane Run, Green River, and Tyrone coal units would contribute to the Joint Applicants experiencing a capacity shortfall of 877 MWs beginning in 2016 and increasing to 1,066 MWs in 2018.[11] Joint Applicants' projected total annual demand through 2018 reflects the difference between forecasted peak load and peak reductions, which reductions include the impacts of interruptible demands and Demand-Side Management ("DSM") programs.[12] The retirement of the Cane Run and Green River coal units would also impact the Joint Applicants' energy needs.[13] From 2006 through 2010, the combined energy produced by these coal units averaged 4,225 GWh.[14] Joint Applicants' 2011 IRP projects combined energy sales in 2016 to be 36,615 GWh and, in 2017, to be 37,074 GWh.[15] Lastly, the retirements will result in a 2016 reserve margin of approximately 4 percent versus Joint Applicants' target reserve margin of 16 percent.[16]

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[11] Sinclair Testimony, p. 15; Exhibit DSS-1, Joint Applicants 2011 Resource Assessment, p. 11.

[12] *Id.*

[13] *Id.*

[14] *Id.*

[15] *Id.*

[16] *Id.*

To address the projected capacity and energy deficit beginning in 2016, the Joint Applicants issued a request for proposals ("RFP") on December 1, 2010 for capacity and energy to more than 116 potential energy suppliers.[17] The RFP sought responses from parties with resources that would qualify as a Designated Network Resource for transmission purposes.[18] The RFP encouraged offers for firm summer and winter capacity ranging between 1 MW and 700 MW with the Joint Applicants having the flexibility to procure more or less than 700 MW, as well as the authority to aggregate capacity and energy from multiple parties to meet its needs.[19] Joint Applicants received 18 responses containing 50 offers.[20] The responses included power purchase agreements and asset sale offers for gas, coal,[21] nuclear, wind, biomass, and solar technologies.[22]

Joint Applicants' analysis of the RFP responses was conducted in two phases.[23] Phase I consisted of an initial screening of the responses through a scoring system,

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[17] Sinclair Testimony, p. 16; Exhibit DSS-1, Joint Applicants' 2011 Resource Assessment, p. 13.

[18] *Id.*

[19] *Id.*

[20] *Id.*

[21] Although the Joint Applicants received asset sale offers for coal as part of the responses to their RFP, they did not develop a site specific cost estimate for a new coal unit at Cane Run because the Joint Applicants' 2011 IRP did not identify coal as part of the companies' least-cost resource plan. *See* Sinclair Testimony, p. 17.

[22] Joint Applicants' Post-Hearing Brief, p. 3.

[23] Sinclair Testimony, p. 17; Exhibit DSS-1, Joint Applicants' 2011 Resource Assessment, p. 4.

which evaluated certain criteria such as cost, term, and site availability.[24] The scoring system was developed as follows: First, responses with unacceptable terms or sites were eliminated; second, the responses were ranked based on two cost measures: (a) levelized revenue requirements per MWh; and (b) levelized revenue requirements per firm capacity-year.[25] The 24 offers that scored the most favorable in both cost categories were selected for Phase II consideration.[26]

The Phase II analysis was conducted in two parts.[27] First, the preliminary Phase II analysis evaluated the top 24 Phase I offers, both individually and in various combinations, in more detail.[28] Joint Applicants utilized the Strategist resource planning software to assess each response's impact on future capacity needs and to determine capital revenue requirements.[29] Joint Applicants also utilized the PROSYM production costing model to evaluate the production cost revenue requirements associated with each offer.[30] A total system revenue requirement for the study period was then calculated using the capital revenue requirements, the production cost revenue requirements, and the revenue requirements for any fixed operation and maintenance

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[24] *Id.*

[25] Exhibit DSS-1, Joint Applicants' 2011 Resource Assessment, p. 15.

[26] *Id.*

[27] Sinclair Testimony, p. 17; Exhibit DSS-1, Joint Applicants' 2011 Resource Assessment, p. 16.

[28] *Id.*

[29] Joint Applicants' 2011 Resource Assessment, p. 16.

[30] *Id.*

expenses, gas transportation costs, and firm electric transmission costs.[31] Strategist was then used to develop the least-cost expansion plan for each offer.[32] Production costs were then developed for each expansion plan and each alternative was analyzed based on its impact on the Joint Applicants' ability to serve native load only.[33] The offers were further evaluated under two limited economy market purchase scenarios: (1) no economy purchases; and (2) limited economy purchases.[34] The analysis was conducted relative to a base case scenario for natural gas and electric prices.[35]

The final Phase II analysis consisted of the Joint Applicants meeting with the top respondents and asking them to update their offers to best and final offers.[36] The updated offers were evaluated along with additional self-build options and were analyzed similar to the preliminary Phase II analysis.[37] Based on the RFP and self-build analysis, the Joint Applicants determined that the least-cost alternative for meeting their future capacity and energy needs was to build a new natural gas combined cycle combustion turbine at Cane Run and to purchase from Bluegrass Generation its existing simple cycle combustion turbine facilities in LaGrange, Kentucky.

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[31] *Id.*

[32] Joint Applicants' 2011 Resource Assessment, p. 18.

[33] Joint Applicants' 2011 Resource Assessment, p. 19.

[34] *Id.*

[35] *Id.*

[36] *Id.*

[37] *Id.*

ENVIRONMENTAL INTERVENORS' POSITION

Environmental Intervenors recommend that the Joint Applicants' proposal be denied. Environmental Intervenors argued that the "exclusively natural gas generation" proposed by the Joint Applicants is not the least-cost alternative to address the Joint Applicants' capacity shortfall. Environmental Intervenors maintain that a diversified portfolio that combines additional DSM programs, renewable energy, and natural gas would be a lower-cost option for the Joint Applicants' ratepayers because it would delay or reduce the need for more expensive natural gas capacity additions.[38]

Environmental Intervenors contend that the Joint Applicants failed to identify a least-cost plan that included all cost-effective DSM programs beyond those programs that were approved by the Commission in the Joint Applicants' most recent DSM application, Case No. 2011-00134.[39] Environmental Intervenors point out that the 0.52 percent level of annual energy savings that the Joint Applicants' existing DSM programs are projected to achieve is substantially below the level of energy savings being achieved by DSM programs in other states.[40] Environmental Intervenors further point out that the Joint Applicants' own DSM consultant, ICF International ("ICF"), issued a report that indicated, among other things, that the benefits of the Joint Applicants' DSM

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[38] Environmental Intervenors' Post-Hearing Brief, p. 23.

[39] Case No. 2011-00134, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New Demand-Side Management and Energy-Efficiency Programs (Ky. PSC Nov. 9, 2011).

[40] Environmental Intervenors' Post-Hearing Brief, p. 12.

programs outweighed their costs by a ratio of three-to-one or more.[41] According to the Environmental Intervenors, this high benefit-to-cost ratio establishes that the Joint Applicants could achieve more energy savings if they were to expand on their existing DSM programs or implement new DSM programs such as in the commercial and industrial customer classes.[42] Environmental Intervenors note that a more robust DSM portfolio that would achieve annual energy savings of at least one percent would reduce the present value revenue requirement ("PVRR") for the Joint Applicants' energy production, thereby delaying the need for capacity and/or reducing the amount of capacity needed.[43]

Environmental Intervenors also asserted that the Joint Applicants engaged in a perfunctory review of alternative renewable resources.[44] Noting that potential energy suppliers had only a six-week time frame over the Christmas and New Year's holidays to provide complete proposals, Environmental Intervenors argue that the Joint Applicants' "RFP process was abbreviated to the point where it was unlikely to result in a wide array of renewable energy resource proposals."[45] In addition, Environmental Intervenors also claimed that, by assigning a 15 percent capacity factor to wind resources, the Joint Applicants focused only on capacity that wind generation could provide at periods of peak summer energy demand and failed to recognize the

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[41] Environmental Intervenors' Post-Hearing Brief, p. 14.

[42] *Id.*

[43] Environmental Intervenors' Post-Hearing Brief, p. 12.

[44] Environmental Intervenors' Post-Hearing Brief, p. 19.

[45] *Id.*

"significant contribution that wind resources can make to meeting the Companies energy needs."[46] Based on the Joint Applicants' own modeling, Environmental Intervenors maintain that evaluating a one percent DSM energy savings combined with the wind resource proposals received during the RFP would delay the Joint Applicants' need for additional gas generating capacity in 2020 until 2025.[47]

Lastly, Environmental Intervenors argue that the Joint Applicants have arbitrarily assigned a value of $0 to likely future greenhouse gas regulations.[48] Environmental Intervenors contend that the value assumed by the Joint Applicants does not accurately reflect the future costs of CR 7 and that such a value skews the analysis in favor of natural gas and coal-fired generation and against DSM and renewable generation.[49]

<u>KIUC'S POSITION</u>

In its post-hearing brief, KIUC states that it does not oppose the Joint Applicants' decision to retire the six coal-fired units at the Cane Run, Tyrone, and Green River generating stations. KIUC also stated that it did not oppose the Joint Applicants' proposal to construct a natural gas-combined cycle facility at Cane Run and purchase three existing simple cycle gas combustion turbines from Bluegrass Generation in order to meet the capacity deficiency that results from retiring the six coal units. Agreeing with the Joint Applicants, KIUC maintains that the Joint Applicants' proposal is

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[46] *Id.*

[47] Environmental Intervenors' Post-Hearing Brief, p. 21.

[48] *Id.*

[49] *Id.*

reasonable and cost-effective in light of the new EPA air emissions regulations impacting coal generating units and the current low price of natural gas.

KIUC disagreed with the Environmental Intervenors' position that the Joint Applicants' capacity deficit could be met through a combination of wind generation purchases and DSM. KIUC noted that the evidence presented by the Joint Applicants established that the wind generation bid in response to the Joint Applicants' RFP was neither cost-effective nor reliable when compared to the Joint Applicants' proposal. Lastly, KIUC contends that the Environmental Intervenors' argument that the Joint Applicants should expand their DSM portfolio to include industrial customers would violate KRS 278.285(3)[50] and that the Joint Applicants' "large industrial load is not the untapped DSM resource that the Environmental Intervenors imagine it to be."[51]

DISCUSSION

No utility may construct any facility to be used in providing utility service to the public until it has obtained a CPCN from this Commission.[52] To obtain a CPCN, the

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[50] KRS 278.285(3) provides, in relevant part, as follows:

> The commission shall allow individual industrial customers with energy intensive processes to implement cost-effective energy efficiency measures in lieu of measures approved as part of the utility's demand-side management programs if the alternative measures by these customers are not subsidized by other customer classes. Such individual industrial customers shall not be assigned the cost of demand-side management programs.

[51] KIUC's Post-Hearing Brief, p. 2.

[52] KRS 278.020(1).

utility must demonstrate a need for such facilities and an absence of wasteful duplication.[53]

"Need" requires:

> [A] showing of a substantial inadequacy of existing service, involving a consumer market sufficiently large to make it economically feasible for the new system or facility to be constructed or operated.
>
> [T]he inadequacy must be due either to a substantial deficiency of service facilities, beyond what could be supplied by normal improvements in the ordinary course of business; or to indifference, poor management or disregard of the rights of consumers, persisting over such a period of time as to establish an inability or unwillingness to render adequate service.[54]

"Wasteful duplication" is defined as "an excess of capacity over need" and "an excessive investment in relation to productivity or efficiency, and an unnecessary multiplicity of physical properties."[55] To demonstrate that a proposed facility does not result in wasteful duplication, we have held that the applicant must demonstrate that a thorough review of all reasonable alternatives has been performed.[56] Selection of a proposal that ultimately costs more than an alternative does not necessarily result in

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[53] *Kentucky Utilities Co. v. Pub. Serv. Comm'n*, 252 S.W.2d 885 (Ky. 1952).

[54] *Id.* at 890.

[55] *Id.*

[56] Case No. 2005-00142, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of Transmission Facilities in Jefferson, Bullitt, Meade, and Hardin Counties, Kentucky (Ky. PSC Sept. 8, 2005).

wasteful duplication.[57] All relevant factors must be balanced.[58] The Commission has long recognized that the principle of least cost is one of the fundamental foundations utilized when setting rates that are fair, just, and reasonable and that this principle is embedded in KRS 278.020(1).[59]

Based on the evidence of record, the Commission finds that the Joint Applicants have established that the proposed facilities are needed to address significant capacity shortfalls beginning in 2016 due to the need to retire the coal-fired generating units at the Cane Run, Green River, and Tyrone Stations, as well as projected load growth. Joint Applicants' decision to retire these coal units was the result of an extensive analysis to determine the least-cost alternative to comply with the aforementioned new and pending air emissions standards. Moreover, the Joint Applicants have sufficiently demonstrated that, absent additional capacity resources, their joint load forecasts and projected energy savings from DSM and energy efficiency projects indicate capacity shortfalls of 877 MW in 2016 and increasing to 1,066 MW in 2018 due to the retirements of the aforementioned coal units and projected load growth.

With respect to the Joint Applicants' proposed Bluegrass Generation acquisition, the parties to this matter have voiced no objection to this proposal. On the contrary,

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[57] *See Kentucky Utilities Co. v. Pub. Serv. Comm'n*, 390 S.W.2d 168, 175 (Ky. 1965). *See also* Case No. 2005-00089, Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity for the Construction of a 138 kV Electric Transmission Line in Rowan County, Kentucky (Ky. PSC Aug. 19, 2005).

[58] Case No. 2005-00089, East Kentucky Power, Order dated August 19, 2005, at 6.

[59] Case No. 2009-00545, Application of Kentucky Power Company for Approval of Renewable Energy Purchase Agreement for Wind Energy Resources Between Kentucky Power Company and FPL Illinois Wind, LLC (Ky. PSC Jun. 28, 2010).

both Environmental Intervenors and KIUC expressly support approval of the purchase of the Bluegrass Generation facility. The Commission agrees and finds that the purchase of the Bluegrass Generation assets is part of the least-cost solution to the Joint Applicants' capacity needs. The evidence establishes that the purchase price of $110 million, or approximately $222/kW, is significantly less expensive than the estimated $850/kW cost to construct a comparable simple cycle gas combustion turbine as set forth in the Joint Applicants' 2011 Integrated Resource Plan. The evidence further establishes that the Bluegrass Generation facilities will assist the Joint Applicants in managing the reliability risks associated with Cane Run, Green River, and Tyrone as these units approach retirement; they will also help the Joint Applicants manage risks while CR 7 is being constructed and placed into operation; and they will allow the Joint Applicants to defer by one year the need for future generating capacity.

With respect to the proposal to construct CR 7, the Commission finds that the record is sufficient to demonstrate that the proposed construction project, combined with the Bluegrass Generation purchase, represent the least-cost resources to meet the Joint Applicants' capacity needs beginning in 2016. The Commission further finds that the proposed facilities are reasonable and will not result in wasteful duplication of utility facilities. The proposed facilities have the lowest net PVRR among all the alternatives that were considered.

Concerning the Environmental Intervenors' argument that the Joint Applicants failed to identify a least-cost plan that included all cost-effective DSM programs and that a more robust DSM portfolio would delay the Joint Applicants' need for capacity and/or reduce the amount of capacity needed, the evidence established that, even under a robust DSM portfolio that achieved one percent annual energy savings, the Joint Applicants' peak load would be reduced by only 125 MW. Compared with the Joint Applicants' total capacity need of 877 MW in 2016, the Environmental Intervenors' scenario would still leave the Joint Applicants needing 752 MW. Even taking into consideration the Joint Applicants' unopposed proposal to purchase the 495 MW Bluegrass Generation combustion turbines, the Joint Applicants would still be faced with a capacity shortfall of 257 MW and, because the Bluegrass Generation assets provide only peaking energy, Joint Applicants would experience a considerable energy shortfall of almost 3.2 million MWh.[60] Thus, even under Environmental Intervenors robust DSM scenario, construction of CR 7 would still be necessary.

Notwithstanding our finding above, the Commission does share the concern of Environmental Intervenors that the Joint Applicants have not adequately addressed one of the recommendations set forth in the ICF Louisville Gas and Electric Company/Kentucky Utilities Company DSM Program Review Report ("ICF Report").[61] In particular, the ICF Report recommended that the Joint Applicants commission a potential study or market characterization study to be used to help plan programs that capture savings where potential is greatest and/or most cost-effective.[62] Based on the market characterization study of the commercial sector, ICF also recommended that the Joint Applicants should develop additional DSM programs targeting the commercial

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[60] Rebuttal Testimony of David S. Sinclair ("Sinclair Rebuttal Testimony"), pp. 6-7.

[61] *See* Sinclair Rebuttal Testimony, Rebuttal Appendix A.

[62] ICF Report, p. 9, 75.

sector.[63] Although the ICF Report noted that the Joint Applicants continued to offer cost-effective programs, their DSM portfolio could improve its cost-effectiveness through additional commercial programs.[64] Accordingly, the Commission will direct the Joint Applicants to commission a potential or market characterization study as recommended in the ICF Report. We do, however, want to take this opportunity to recognize that the ICF Report indicated that the Joint Applicants' DSM portfolio contained many elements of best practices, including cost effectiveness, broad targeting, and flexible design.[65] We strongly encourage the Joint Applicants to continue with this approach and to leverage their corporate relationship with PPL Corporation to garner additional best practices that can be adopted.

As to Environmental Intervenors' argument that the Joint Applicants' RFP process produced a limited "array of renewable energy resource proposals," the Commission finds the Joint Applicants' RFP process to be reasonable. The RFP was sufficiently comprehensive and the six-week deadline provided reasonable notice to potential energy suppliers to produce a complete and comprehensive response. The Commission further finds that the evidence supports the Joint Applicants' proposal as being least-cost even when compared to a scenario which assumes Environmental

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[63] *Id.*

[64] ICF Report, p. 75.

[65] The Commission further acknowledges that the Joint Applicants proposed, and received approval for, a significant expansion of their DSM portfolio, totaling $263.8 million over a seven-year period. Joint Applicants' expanded DSM portfolio contains DSM and energy efficiency programs that were found to be cost-effective and broad based. *See* Case No. 2011-00134.

Intervenors' robust DSM position and purchasing the largest quantity of wind achievable from the RFP options.

With respect to Environmental Intervenors' argument that the Joint Applicants' modeling was skewed in favor of natural gas units due to the zero cost assigned to potential greenhouse gas regulations, the Commission finds such an assumption to be reasonable given the circumstances in the matter at hand. As the Joint Applicants point out, the EPA issued proposed New Source Performance Standards ("NSPS") on March 27, 2012, for new fossil-fueled power plants.[66] The proposed standard would apply a CO_2 emission limit of 1,000 lb/MWh to new generating units that do not have permits and start construction within 12 months of the proposal.[67] Joint Applicants' proposed facilities would not be affected by the proposed regulation because the Bluegrass Generation facilities are existing generating units and CR 7 is projected to have a CO_2 emission rate of about 800 lb/MWh. If the proposed NSPS is indicative of potential future greenhouse gas regulation, the cost-effectiveness of the proposed CR 7 and the Bluegrass Generation facilities would not be impacted. Given the specific type of generation technologies proposed in this matter, the Commission finds that the modeling of a carbon price would not have altered the outcome of this case. Moreover, although they contend that the Joint Applicants should consider a diverse portfolio of generation mix, Environmental Intervenors readily admit that natural gas should be a part of that generation mix if it is determined that natural gas represents the least cost

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[66] Joint Applicants' Post-Hearing Brief, p. 25.

[67] *Id.*

alternative. The Commission is of the opinion that the natural gas facilities proposed herein are the least cost alternative.

SITE COMPATIBILITY CERTIFICATE

Joint Applicants indicate that there are good operational reasons to place the proposed CR 7 unit at Cane Run: (1) there is existing electrical transmission that the proposed CR 7 will be able to use; (2) using the existing Cane Run site, where 563 MW of existing coal-fired generation will be retired, will allow CR 7 to effectively "net out" of the Prevention of Significant Deterioration air permitting process that would be required if CR 7 were placed at the Joint Applicants' Brown Generating Station; and (3) having a geographical diversity of gas-fired generating units increases the overall reliability of the Joint Applicants' generating fleet by minimizing the impact of possible natural gas delivery disruption at a particular site. More significantly, the Joint Applicants' Site Assessment Report indicates that the Cane Run site was designed to accommodate additional generating units and that the addition of CR 7, while retiring the existing coal units, would not cause a negative impact to local property values, unduly increase traffic or noise, or materially change the visual impacts of the facility from current conditions.

The Commission finds that the Joint Applicants have satisfied the requirements of KRS 278.216 for the issuance of a Site Compatibility Certificate for CR 7.

IT IS THEREFORE ORDERED that:

1. Joint Applicants are granted a CPCN to construct a new 640 MW natural gas combined cycle combustion turbine unit at the Cane Run station and to purchase from Bluegrass Generation the natural gas simple cycle generation facilities, which include three turbines with a combined capacity of 495 MW in LaGrange, Kentucky.

2. Within 30 days of the completion of the construction of CR 7, Joint Applicants shall file with the Commission the actual cost of the construction.

3. Joint Applicants are granted a Site Compatibility Certificate to construct CR 7 at the Cane Run Station site in Louisville, Kentucky.

4. Within three months of the issuance of this Order, Joint Applicants shall commission a potential or market characterization study as recommended in the ICF Report.

5. Joint Applicants shall file with the Commission the potential or market characterization study within 30 days of the date it is completed and finalized.

6. Any documents filed in the future pursuant to ordering paragraphs 2 and 5 herein shall reference this case number and shall be retained in the utility's general correspondence file.

By the Commission

ENTERED
MAY 03 2012
KENTUCKY PUBLIC
SERVICE COMMISSION

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