Demand Response Valuation Frameworks Paper

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Disclaimer

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Table of Contents

List of Figures

List of Tables

Abstract

While there is general agreement that demand response (DR) is a valued component in a utility resource plan, there is a lack of consensus regarding how to value DR. Establishing the value of DR is a prerequisite to determining how much and what types of DR should be implemented, to which customers DR should be targeted, and a key determinant that drives the development of economically viable DR consumer technology.

Most approaches for quantifying the value of DR focus on changes in utility system revenue requirements based on resource plans with and without DR. This "utility centric" approach does not assign any value to DR impacts that lower energy and capacity prices, improve reliability, lower system and network operating costs, produce better air quality, and provide improved customer choice and control. Proper valuation of these benefits requires a different basis for monetization.

The review concludes that no single methodology today adequately captures the wide range of benefits and value potentially attributed to DR. To provide a more comprehensive valuation approach, current methods such as the Standard Practice Method (SPM) will most likely have to be supplemented with one or more alternative benefit-valuation approaches.

This report provides an updated perspective on the DR valuation framework. It includes an introduction and four chapters that address the key elements of demand response valuation, a comprehensive literature review, and specific research recommendations.

Keywords: Public Interest Energy Research (PIER) Program, Demand Response Research Center (DRRC), demand response, valuation, Standard Practice Methodology (SPM), efficiency, advanced metering infrastructure (AMI), capacity value

Executive Summary

California's investor owned utilities have proposed an investment of $425 million over the period 2009-2011 to support demand response (DR) initiatives. Despite a general consensus that demand response is a valuable resource within California's resource plans, there is still disagreement regarding what DR is worth and whether utility resource plans include the right amount of DR. Establishing the value of DR is a prerequisite to determining how much and what types of DR should be implemented. The value of demand response is also a key factor in determining where DR should be located within each utility system and to which customers DR should be targeted. The value of demand response also establishes a benchmark for identifying and developing economically viable DR technologies for the utility and customer.

The lack of consensus regarding methods for DR valuation and cost-effectiveness has been of growing concern to regulators and policymakers at the state and federal levels. In response to these concerns the Demand Response Research Center (DRRC) in 2006 completed preliminary research on two distinct approaches to establishing a more comprehensive DR valuation framework. While results from these projects were instructive, they were not able to capture the broader perspective of DR impacts that is now evolving as a result of better pricing, new technology, and wholesale market initiatives.

This report provides an updated perspective on the DR valuation framework. It includes an introduction and four chapters that address the key elements of demand response valuation, a comprehensive literature review, and specific research recommendations. This report provides a foundation intended to support and expand a continuing and broadening discussion regarding how to value demand response and how to apply this valuation framework to establish program options and regulatory policy.

An introductory section summarizes the current status of research underpinning the development and application of approaches to valuing demand response.

The impetus for this project was recognition that existing economic analysis methods do not adequately quantify the range of benefits or value generally attributed to DR.[i] A principal weakness is the gap between the many non-resource benefits (e.g., the value to customers of greater reliability or enhanced pricing and service choices) that DR advocates allude to but cannot yet quantify. This results in an increasingly common situation in which regulators set goals for DR but cannot answer the basic question of "how much DR is enough"?[ii]

The introductory section also sets forth the objectives of the report: (1) summarize the recent DR valuation literature, including the previous DRRC-sponsored work; (2) identify the breadth of benefits and beneficiaries claimed for DR in various utility applications; (3) develop a logical framework for enumerating DR benefits; and (4) suggest priorities for further valuation DR research. This report is not intended to address DR costs or cost effectiveness. Where value is derived from the customer perspective or system resource and environmental impacts, costs are dictated by utility and regulator program design, technology choice, and other administrative decisions.

The second section describes a valuation framework derived from the demand response literature. Demand Response provides benefits to all electricity market participants, including commodity providers, system and market operators, transmission and distribution companies, and end-users, regulators, policy makers; and society as a whole. Three factors are identified which establish the value of demand response: (1) market structure, (2) ability of DR to participate in the market, and (3) whether customer DR options are driven by price or participation incentives.

This section identifies a composite list of six benefit, or value categories derived from dozens of prior industry studies, including: (1) direct financial benefits, such as customer bill savings; (2) reliability benefits which can include peak load reductions; (3) system and network benefits, such as reduced congestion or less-costly ancillary services provision; (4) market price benefits due to reduced wholesale energy and capacity prices; (5) environmental benefits, such as reduced emissions from reduced use of peak load generation, and; (6) other benefits, such as improved customer service and cost stabilization.

Several approaches have evolved for quantifying the value of DR; however almost all are based on utility system cost comparisons (usually expressed as revenue requirements) that compare utility resource plans with and without DR. While useful in capturing the effects of DR on the utility's cost of doing business, this "utility centric" approach does not necessarily account for the full range of value perceived by different market participants and cannot capture any benefits not expressed in utility revenue requirement terms. The revenue requirements approach is unable to capture DR impacts that lower energy and capacity prices, improve reliability, lower system and network operating costs, produce better air quality, and provide improved customer choice and control. Proper valuation of these benefits requires a different basis for monetization.

The mismatch between the DR value proposition and traditional means of valuation has grown with the development of organized wholesale markets and the emergence of price-responsive demand response applications (e.g., demand bidding and dynamic pricing). Suitable methods for quantifying many of these new DR benefits simply do not exist, making it easy for the utility planning and regulatory review process to discount or ignore them entirely relative to the more-traditional, tangible resource benefits.

It is important to remember that DR benefits and their corresponding value will occur unevenly across different market participants. In many cases what is a net benefit to one market participant may be a net cost to another. Therefore, in valuing DR it is critical to keep in mind not only the benefit (and cost) streams but the incidence of these benefits (and costs) across different stakeholders.

The third section of this report considers some of the practical problems involved in tailoring the valuation approach to the characteristics of specific DR applications and situations. This section stresses the importance of practicalities as well as comprehensiveness in constructing a suitable DR valuation framework. Some valuation problems are more straight-forward than others, and it does not make sense to apply complex formulations to relatively simple evaluation problems. Although we argue that no single methodology can fully capture all elements of DR value, it may often be the case that some DR value propositions may be modest or minimal when monetized. Consequently, the valuation framework must be structured differently to address the practical differences between applications.

For example, the valuation framework should be structured to match the problem purpose, timeframe, accuracy requirements, and comprehensiveness of the problem being addressed. The ex post cost effectiveness evaluation of a single DR option is much easier and very different than the selection of an optimal DR portfolio of options for a system wide DR plan; however, current practice does not always address these differences. To adequately address these variations, the DR valuation framework must consider four elements, including:

- Purpose. Is the valuation intended to screen demand response options for preliminary planning, to gain regulatory approval of infrastructure investments, or to evaluate the effectiveness of implementation efforts?
- Timeframe. Is the valuation to be done *ex ante* or *ex post?* Is the valuation timeframe short-run or long-run?
- Accuracy. What level of valuation accuracy is necessary to support DR investment portfolio recommendations and is this level more or less than what is necessary to support a general policy initiative?
- Complexity. DR options that affect only a few customers or focus on a single, narrow objective like economic response are much easier to address than options that address large, diverse customer populations or multiple, integrated economic, reliability and ancillary DR applications. Can the methodologies differentiate between these differences?

Some benefits are potentially larger than others, some are transient in nature, and other benefits are simply intangible. Because these benefits differ across the different stakeholders, it is important to broaden the consideration of different stakeholders/market participants at the same time as broadening the consideration of demand response valuation categories. All of these characteristics should be taken into account when constructing a valuation framework. Collectively, all of these considerations lead to the conclusion that no single valuation method will likely be comprehensive enough to address any but the simplest valuation problems.

This report includes a detailed description of the rather voluminous literature on demand response valuation. The review demonstrates the range of analytic approaches brought to bear and underscores the importance of market structure and economic (beneficiary) perspective in determining the type, scope and scale of benefits. The literature review supports the perspective that, ultimately, the differences in valuation methods reflect different views of the role of demand response in resource procurement, electricity markets, and system and customer operations.

Avoided costing approaches, like the California "Standard Practice Manual" (SPM), have been used since the early 1980's by regulators and utilities to guide the economic analysis of DR. Avoided cost approaches are simple to use, they can be structured to generate multiple economic test perspectives, and they can be effective in differentiating between individual DR options with different attributes. However, avoided costing approaches are not well suited to valuing integrated portfolios of multiple DR options. Avoided costing approaches also are not well suited for differentiating DR valuations across future supply-demand balances or for capturing changes in consumer or producer surplus.

Integrated Resource Planning (IRP) studies directly estimate utility-oriented financial benefits of demand response by comparing the difference in total utility costs between a "base case" and a "DR case" resource plan. These methods are well-suited to DR valuation because they can examine a time horizon long enough to reflect the risk management value of DR during high-consequence, low-probability events. IRP methods can also incorporate demand growth, changes in supply costs and different mixes of DR options not feasible with the SPM. However, IRP modeling is extremely data intensive, time consuming and complex, producing results that do not easily translate into DR valuations IRP methods also cannot easily capture other types of benefits, including participant bill savings, market price benefits, deferred network benefits, or environmental or customer benefits. As a result, dynamic IRP modeling is not a practical substitute for more-easily applied methods such as avoided costing and infrastructure business cases.

A growing application for Demand Response valuation is the regulatory business case process used to justify and rate base advanced metering and load control infrastructure investments. Three "business cases", one in California and two in Maryland are reviewed and compared to illustrate how the value of DR changes according to market structure and inclusion or exclusion of different DR benefit categories.

Other approaches found in the DR valuation literature are also described, including research and studies focused on modeling the market price benefits of DR, valuing the reliability benefits of DR using customer outage costs, option valuation of DR, and environmental and customer benefit of DR.

The review underscores the conclusion that no single methodology today adequately captures the wide range of benefits and value potentially attributed to DR. This suggests that in order to provide a more comprehensive valuation approach, any single method such as the SPM will most likely have to be supplemented with one or more alternative benefit-valuation approaches. At a minimum, this combination approach to valuation should attempt to include methodologies or proxies from the literature to guide and include estimates of DR market price, reliability, option value, network, system, and environmental benefits. Potential environmental benefits will become much more significant due to mandated resource portfolio standards and greenhouse gas reduction objectives. Unfortunately, the literature and research to-date is relatively weak in this area.

The concluding section of this report provides specific suggestions for DR valuation research. Seven research areas are identified for consideration, including:

- Avoided Costing and the SPM: Augmenting the SPM platform with supplemental methodologies that can capture DR value propositions beyond capacity value.
- Customer Infrastructure or "Business Case" Approaches: Reviewing business cases that may lend insight into innovations and protocols for valuing DR and developing new "business case" components that better capture market price, reliability value, and customer value propositions.
- Market Modeling: Examining the feasibility for market models to simulate pricing and other DR market impacts.

- Reliability Value and Value of Service Studies: Conducting studies to better quantify the value of DR reliability impacts using the option and insurance value approaches.
- System and Network Benefits of Demand Response: Studies and models to estimate the value attributed to DR in providing ancillary services, improving operational flexibility, deferring capacity additions, price dampening, reducing line losses, and network protection.
- Environmental Valuation: Scoping and other studies to better identify and estimate DR impacts on emissions, land use, and system operations.
- Customer Value: Studies to estimate and monetize the value of customer choice or consumer surplus that accompanies the unbundling of rates and introduction dynamic pricing.

1.0 Introduction

This paper was commissioned by the Demand Response Research Center (DRRC) under the Strategic Research element of its 2007-2008 work program. The impetus for the paper was recognition that the economic analysis methods for quantifying the benefits of Demand Side Management (DSM) are insufficient to capture the value of Demand Response (DR).[iii] Because DR comes in many varieties, and evolves in response to changing market conditions including supply-demand conditions and new organized markets (e.g., forward capacity and ancillary services), it is not surprising that economic analysis methods lag behind practical use. Equally important A recent DOE review noted that the sheer diversity of different market designs, operational considerations, resource portfolios, and regulatory jurisdictions and requirements makes it impossible to produce a meaningful estimate of the total benefits of demand response at the national level.[iv]

Reviewing the methods for valuing DR valuation is important and timely for several reasons. The principle reason is the gap between the many non-resource benefits that DR advocates attribute to DR and our ability to quantify them. The result is that regulators encourage and indeed set goals for DR but cannot answer the basic question of "how much DR is enough"?[v] Another reason is recent progress in developing new analysis methods making it possible to monetize some of these benefits. Some ISO/RTOs, including ISO-New England and New York ISO, now routinely estimate and report on the market, social welfare and reliability benefits of their DR programs.[vi] The California regulator is currently considering how to quantify the benefits of DR programs beyond strictly resource value in order that these benefits can be included in the cost-effectiveness analysis of programs.[vii] Other utilities, particularly those in PJM's service territory, have begun including the wholesale market price benefits of DR when calculating the cost-effectiveness of Advanced Meter Infrastructure (AMI) investments.[viii] This could prove problematic for regulators who must review and rule on infrastructure rate filings which may contain quite different benefit-cost estimation methods. Finally, new applications and markets continue to emerge for Demand Response as organized wholesale markets expand and new methods for planning and managing transmission networks (e.g., nodal pricing) take hold.[ix]

This paper represents a renewed foray by the DRRC into methods for valuing demand response. In 2004 the DRRC funded parallel efforts by two consultants to identify the benefits attributable to DR and develop methods to monetize these benefits.[x] This early effort did not proceed beyond the research scoping stage, but it did create an improved understanding of the complexity and variety of benefits and possible estimation methods. In 2007 DRRC Staff decided to resume research into DR valuation by commissioning this review of the DR valuation literature and development of a framework on which to plan future valuation research.

This paper has four objectives: (1) summarize the recent DR valuation literature, including the previous DRRC-sponsored work; (2) identify the breadth of benefits and beneficiaries claimed for DR in various applications; (3) develop a logical framework for enumerating DR benefits; and (4) suggest priorities for further research in this area. It must be noted at the outset that this frameworks paper does not contain any new theoretical, analytic or methodological development. Rather, it attempts to codify the literature while developing a logical framework in hopes of assisting the reader to think more comprehensively about the relationship of market structures, DR applications, value propositions and beneficiaries.

2.0 Elements of Demand Response Valuation

This section describes a valuation framework derived from the demand response literature which is used to identify valuation research needs. The DR valuation framework was constructed by elaborating four basic themes:

- Demand Response provides a range of recognized benefits to different power sector stakeholders – electricity market participants, including commodity providers, system and market operators, transmission and distribution companies, and end-users; regulators and policy makers; and society as a whole.
- The value of Demand Response can be quantified (monetized) in several ways, but with results that may not be strictly comparable and may or may not constitute double-counting.
- The value of Demand Response can be limited or enhanced according to the availability of organized markets and the eligibility of DR to participate in them.
- Economic perspective determines winners and losers due to Demand Response; adding more DR benefits and including more economic perspectives will require refining existing economic analysis methods.

2.1. Demand Response Provides a Range of Benefits to Stakeholders

Dozens of studies have attributed a wide range of benefits to demand response (See Table 1 and Annex 1). Most of the benefits cited are similar, with differences mainly in terminology. While methods have been established for estimating some benefits, other benefits have not been quantified and some benefits may be so intangible as to be unquantifiable.

This paper adopts a composite of benefit categories drawn from several sources[xi] selected to be suitable not just to demand response but any demand side resource. The categories include: Financial Benefits; Reliability Benefits; Network Benefits; Market Performance Benefits; Environmental Benefits; and Other, including Customer Benefits/Consumer Choice. This list is not exhaustive, but does capture the benefits most frequently cited.

Direct financial benefits include: (1) the participant-specific bill savings accruing to customers that adjust their electricity consumption in response to system or market conditions; and (2) the capacity and energy supply cost avoided due to DR, including lower reserve margin requirements. **Reliability benefits** include the added operational security because demand response lowers the likelihood of forced outages and the insurance or hedge value of DR under "stress case" forecast scenarios. **System and network benefits** include reduced network congestion, dampening of nodal or zonal prices, increased sufficiency of ancillary services (AS) bids, and reduced transmission line losses during high-demand periods. **Market price benefits** are the market-wide bill savings, sometimes called collateral benefits, for all electricity customers as a result of DR-induced lower wholesale prices and/or bilateral contracts. **Environmental benefits** accrue broadly to all of society, and include local and global benefits including reduced GHG and NOX emissions reductions and improved land and water use. **Other benefits** cited in various studies and regulatory filings include Customer Service, Customer Choice, and power cost stabilization. The review of the DR valuation literature contained in Chapter 4 describes the various approaches to estimating these benefits.

Federal and state legislators, policymakers and regulators recognize many of these benefits. The U.S. Energy Policy Act of 2005 (EPACT) states that it is the policy of the United States to encourage "time-based pricing and other forms of demand response" and encourage States to coordinate, on a regional basis, State energy policies to provide reliable and affordable demand response services to the public.[xii] The FERC has consistently emphasized the importance of preserving entry points and encouraging participation by demand response in standard market designs, regional transmission planning, markets for ancillary services, and mandatory reliability standards.[xiii] Although somewhat spottier, state regulators have also articulated the benefits that demand response can bring to reliable and affordable power system planning and operations. In California the benefits of demand response in for improving reliability are reflected in the Loading Order Preference established in the CEC's 2003 Energy Action Plan as well as mandatory goals for utility-implemented price-responsive demand response and provision of dynamic pricing to all retail customers.[xiv] Even the venerable General Accounting Office (GAO) concluded that Congress, Federal regulators and Government agencies should actively seek to overcome barriers and scale up demand response in order to realize the substantial savings potential for electricity consumers of all sizes.[xv]

Given this multi-faceted value proposition for Demand Response, it is surprising to find that the methods for actually quantifying DR benefits are rudimentary. This is why a key objective of developing a valuation framework is focusing attention on where analytic development is needed to further our understanding of DR's value.

Table 1: Benefits Attributed to Demand Response – Various Studies and Reviews

Reviewer	Study Vintage	Direct Financial Benefits	Market Benefits	Reliability Benefits	System & Network Benefits	Environmental Benefits	Other Benefits
Braithwaite & Faruqui[xvi]	2001	√	√				
Peak Load Management Association (PLMA)[xvii]	2002	√	√	√		√	Customer Service Risk Management
Regulatory Assistance Project (RAP)[xviii]	2003	√		√		√	Power cost stabilization
U.S. DOE Report	2006	√	√	√	√	√	Consumer Choice
IEA Task XIII Study[xix]	2006	√	√	√			
Quantec[xx]	2006	√		√	√	√	Customer Benefits
FERC[xxi]	2006	√	√	√		√	
ISO-NE[xxii]	2006	√			√		
The Brattle Group[xxiii]	2007	√	√				
Woychik[xxiv]	2008	√	√	√	√	√	√

2.2. Demand Response Benefits can be Quantified in Several Ways

Calculating the benefits of demand-side resources has been the subject of study and regulation since the 1978 passage of the Public Utilities Regulatory Policy Act (PURPA), which first required regulators and utilities to consider demand-side programs on a comparable basis with generation in resource planning.

Table 2 summarizes an extensive review of dozens of reports and papers focused on quantifying the benefits of Demand Response programs and tariffs. The review suggests that a useful way to differentiate between these efforts is according to the source of the benefits, or more simply the value proposition for Demand Response.

Early valuation procedures such as the California Standard Practice Manual reflected the electricity industry structure of the period, with large integrated monopolies charged with ensuring resource adequacy, retail tariffs based on average rather than marginal supply costs, and rate and service regulation provided by the states. A demand-side resource was beneficial if it could avoid the costs of a generator providing energy and capacity. Thus, the value proposition for DR was to improve the overall economic efficiency of producing and delivering electricity. A DSM program was cost-effective if the benefits of the program to society were greater than the costs of implementing the program, with the costs expressed in terms of utility revenue requirements.[xxv]

Valuation of demand-side resources grew more sophisticated with the development of integrated resource planning (IRP) methods, which considered demand side programs within an overall portfolio of supply and demand side resources. Demand side resources were integrated into resource planning in two ways: (1) decrementally, by reducing the load forecast by the amount of demand side resources that passed a cost-effectiveness screening and were within utility budget constraints; and (2) through portfolio optimization, which entailed simultaneous modeling of generation and DR in order to select the optimal (least cost) resource mix.[xxvi] Although more sophisticated, IRP methods still valued DR based on the differential revenue requirements (DRR) of two resource plans – one with and without demand response.

Another distinct valuation method used to justify large investments in customer level infrastructure is the Advanced Metering Infrastructure (AMI) Business Case. This is a highly-generalized method of cost-benefit analysis that also expresses value in terms of the NPV of savings in utility capital and operating costs. The benefit categories for an AMI business case include not only avoided costs of supply but also the many operating cost savings that result from remote metering and two-way communications with customers.[xxvii]

Although useful in capturing the effect of DR on the utility's costs of doing business, avoided costing, integrated planning and business case methods cannot capture any benefits that are not expressed in terms of the utility's revenue requirements (See

Table 2). Estimating the other benefits of demand response - lower energy and capacity prices, reliability benefits, lower system and network operating costs, environmental benefits, and customer benefits - requires either a different basis for monetization or a method that can express these other benefits in terms of utility revenue requirement. In fact, this constitutes a fundamental disconnect in efforts to more comprehensively capture the benefits of Demand Response. Some stakeholders maintain that DR benefits can only be expressed in terms of the avoided cost of generation, as a generator can equivalently deliver any application that a DR resource can deliver.[xxviii] This reluctance to consider the benefits of DR using formulations not based solely on a generation equivalent is a barrier to developing more-comprehensive valuation protocols.

The review of the DR valuation literature revealed a rapid evolution in thinking about the benefits of demand response and how to quantify them. With the development of organized wholesale markets and DR programs and tariffs that link price-responsive customers to these markets (e.g., demand bidding and dynamic pricing), new DR applications and value propositions have emerged. These new arrangements allow DR not only to simply substitute for generation, but to play an entirely new role: creating an autonomous form of price elasticity in aggregate electricity demand. With these new applications of demand response programs have come new attempts to estimate the financial benefits of price-responsive demand response for all electricity consumers.[xxix] The most seminal of these new studies was done for PJM Interconnection LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI) by The Brattle Group. This study used wholesale market price modeling methods to project the effect on short-term and medium-term energy and capacity prices of significant amounts of price-responsive demand during high-price conditions. This approach captures both the participant-specific bill savings to participants and the collateral financial benefits to all retail and wholesale electricity consumers. Although these bill savings constitute economic transfers from generators to consumers, they are nonetheless a large and legitimate source of value for DR from the viewpoint of ratepayers and participants. However, economic transfers are distinct from net efficiency gains and should be treated separately in a cost-effectiveness or benefit-cost analysis.

Other approaches grounded outside of the utility revenue requirement and avoided cost perspectives have been used to estimate the reliability value of DR. These methods include customer outage costs, which are based in contingent valuation by customers of their costs due to outages, or option valuation, which calculates the present value of a DR resource based on a probabilistic formulation of future trends (interest rates, price forecasts, weather, and DR availability). Similarly with other benefit categories such as network benefits, environmental benefits, and customer choice benefits, the valuation process relies on other monetization approaches (e.g., emissions externality adders). However, the valuation methodologies for these latter benefits are largely undeveloped as of yet.

The literature review describes the valuation methods in use in more detail, following the organization of

Table 2. The conclusions of this introductory consideration of the breadth of potential DR valuation approaches are:

- Although the dominant form of valuation remains grounded in utility costs expressed as revenue requirements, other valuation methods exist;
- Care should be taken in comparing the value of different benefit streams using different valuation methods
- Suitable methods for quantifying many DR benefits simply do not exist, making it easy to discount them when comparing to the more-tangible resource benefits

- No single valuation method or protocol will be able to capture the diversity of benefits attributable to Demand Response

Table 2: Benefit Estimation Approaches for Demand Side Programs

Source of Benefits	Estimation Approach	Analytic Method	Example
Lower utility costs	Avoided Costing	Δ NPV of utility revenue requirement w/ & w/o a DR program	California SPM[xxx]
	IRP	Δ NPV of long-run system costs w/ & w/o DR in the resource portfolio	NW Power Council 5th Plan[xxxi]
	Infrastructure Business Cases	Δ NPV of utility fixed and variable operating costs w/ & w/o the infrastructure investment	SCE AMI Business Cases[xxxii]
Lower prices in wholesale markets	Market Price Modeling	Financial impact of a specified DR load impact on prices and power contracts	Brattle Group Study of DR market impacts for PJM [xxxiii]
Improved Reliability	Value of Lost Load	Incremental difference in loss of load * value of un-served energy (based on customer outage cost studies) as a result of a DR program	NYISO 2001-2002 Program Impact Analysis[xxxiv]
	Option Value	PV of a future option to curtail a given load, constructed to reflect forward energy curves as modified by forecast price & interest rate fluctuations	Goldman/Sezgen Study[xxxv]
Lower System and Network operating costs	Network and Transmission Planning Approaches	Improved economic efficiency in the provision of operating reserves and regulation; Reduction in congestion costs and nodal prices; Reduced Cap Ex requirements for peak-related network additions	Regional Transmission Plans[xxxvi] State of the Market Reports
Environmental Benefits	Environmental cost-benefit analysis	DR impacts on emissions output are calculated (e.g., per unit NO_X) & valued based on environmental externality values	Synapse Economics study for NEDRI[xxxvii]
Customer Benefits	Consumer Surplus	Consumption patterns adjust in response to higher peak and lower overall prices	Faruqui, Smith/Kiesling and others[xxxviii]

2.3. DR Value is Driven by Market Structure

The benefits of demand response are quite different in regions with organized energy markets (day-ahead or real-time) than in regions with vertically integrated utilities providing monopoly electricity services to end-users. Utilities with retail monopolies tend to assess the benefits of demand response only in terms of avoided power procurement costs (capacity and energy) as well as some network benefits, to the extent that peak load reductions decrease or defer the need for transmission or distribution capacity additions. A different view is taken in regions with organized wholesale markets, especially where demand response has been shown to affect short-term peak prices and longer-term capacity costs.[xxxix]

Referred to as collateral financial benefits or market price impacts, these benefits accrue to both load-serving entities and their retail customers, whether or not they participate in DR programs. *Short-term market impacts* are immediate and easily measured. In areas with organized day-ahead and real-time markets, demand response reduces wholesale market prices for all energy traded in the applicable market. The amount of savings from lowered wholesale market prices depends on the amount of energy traded in these short-term markets, rather than being committed in forward contracts. *Longer-term market impacts* depend on whether demand response can result in a permanent reduction in system or local peak demand, thereby displacing the need to build additional infrastructure or maintain high reserve margins, or by creating more competition in long-term bilateral contracts for capacity or energy.

This basic structural difference that allows DR to have an impact on short-term market prices in organized markets can be seen in Figure 1. This figure could represent demand and supply relationships in either a forward (e.g. day-ahead) or spot (e.g., real-time or imbalance) electricity market. The upward-sloping supply curve intersects an inelastic demand curve at two different points according to whether or not demand response is induced.[xl] The effect of participating loads is to reduce the market clearing quantity from Q_1 priced at P_1 to Q_2 priced at P_2. Participants directly benefit from the reduced quantity consumed and lower prices, as with any DR program; however, load-serving entities and non-participants benefit by the price difference P_1-P_2 for the entire volume Q_2 consumed during the period. As can be qualitatively seen from Figure 1, these collateral financial benefits, or market price impacts, for all electricity consumers can be much larger than the direct bill savings of DR program participants.

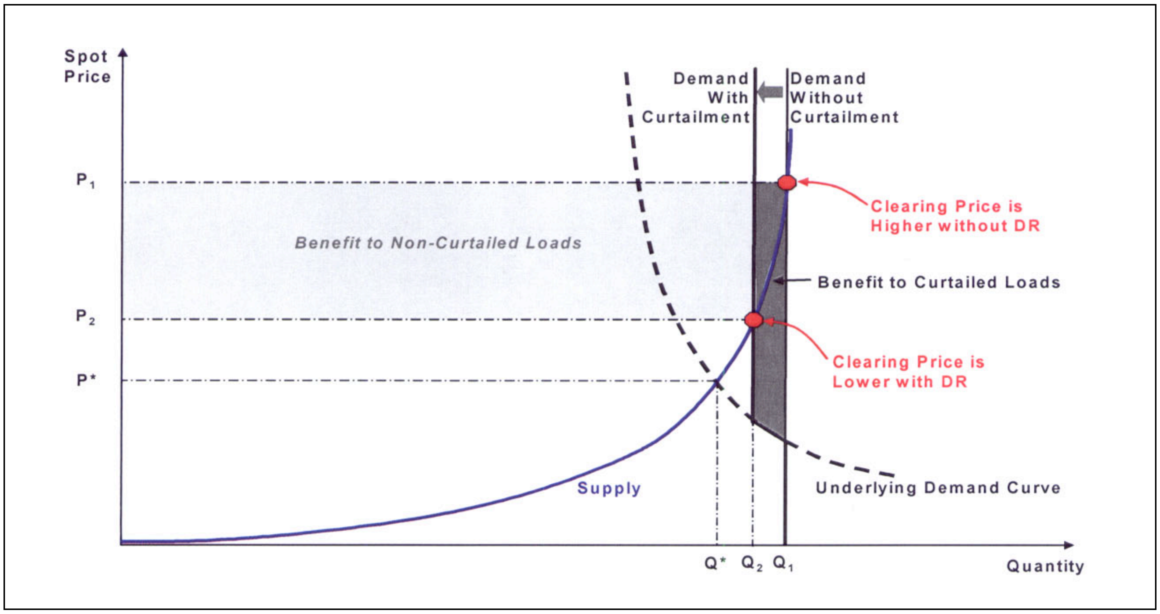

Figure 1: Direct and Collateral Financial Benefits of DR[xli]

It is important to note in Figure 1 that only the shaded area under the upward-sloping supply curve between Q_1 and Q_2 can be considered efficiency gains through avoided supply costs. The entire additional shaded area marked "Benefit to Non-Curtailed Loads" is considered an economic transfer between generators who would be quite willing to produce Q_1 worth of electricity at price P_1, but do not have the opportunity to do so because of Demand Response. It is thus a regulatory determination as regards which economic perspective - consumer or producer – should be considered when accounting for the benefits (and value) of Demand Response.

2.4. The Importance of Economic Perspective

As summarized above, investment in Demand Response can be evaluated for its beneficial impacts on participant bill savings, utility revenue requirements, wholesale market prices, reductions in un-served energy, network congestion alleviation, environmental impacts, or consumer surplus. These benefits, however, occur unevenly across different market participants. In many cases what is a net benefit to one market participant is a net cost to another.[xlii] Therefore, in valuing DR it is critical to keep in mind not only the benefit (and cost) streams but the incidence of these benefits (and costs) across different stakeholders.

Even in the simplest case of retail end-users served by electricity service providers, where the economic effect of DR is measured solely through changes in utility revenue requirement, the value of DR will be different from different economic perspectives. This is why standardized economic analysis methods such as the California Standard Practice Manual (SPM), which provides a basis for taking into account the different perspectives of different market participants, has proven useful. The SPM is a useful tool for regulators and policy makers as it provides the basis for trading-off the costs and benefits of each beneficiary class in making decisions about DR investments.

The symmetry of benefits and costs is apparent from Table 3. Some DR benefits for some market participants (e.g., incentive payments for program participation) are fully offset by costs that are borne by other market participants. However, if the costs of incentive payments and other costs are offset by avoided supply costs, the DR program can still be cost-effective. Now consider what happens when we introduce organized wholesale markets and DR programs and tariffs that link price-responsive customers to these markets (see italicized entries in Table 3). A new category of benefits – wholesale market price impacts – is introduced. A new economic perspective, e.g. generators, must also be included. The differential effect of this modification is clear: market price impacts are beneficial for participants and non-participants alike but constitute a cost for generators. The impact on the Utility/Administrator cost test will depend on several factors, including whether the utilities operate generators. Because economic transfers are excluded from the Total Resource/Societal perspective, the introduction of wholesale price impacts does not change this result.

Because the existing SPM focuses on retail market participants it may have limitations in keeping track of the economic perspectives of the wider range of market participants in organized wholesale markets. This is why one of the challenges in broadening the range of benefits attributed to DR will be developing new cost-effectiveness test perspectives to take into account these new market participants. Such considerations underscore the need to work in parallel paths in developing more comprehensive valuation methods for DR. It is not enough to monetize the benefit; rather, the incidence of costs and benefits across market participants in competitive wholesale markets, such as Generators, Distributors, Third Party Providers, Direct Access Customers, and ISO/RTOs, must be tracked as well.

Table 3: The "Algebra" of Cost-Effectiveness Evaluation[xliii]

Economic (Test) Perspective	Value Proposition	Benefits	Costs
Total Resource/Societal Test	Is overall economic efficiency improved?	Avoided supply costs	Utility program costs Customer costs Environmental costs
DR Program Participant	Is the participant better off?	Bill savings Incentive payments *Lower wholesale market prices*	Customer costs
DR Program Non-participant (Rate Impacts)	Do rates (prices) go down?	Avoided supply costs *Lower wholesale market prices*	Revenue losses Incentive payments Utility program costs
Utility or Program Administrator	Are revenue requirements lower?	Avoided supply costs *Lower wholesale market prices*	Utility program costs Incentive payments
Generators	Is producer surplus maximized?	Higher clearing prices	*Avoided supply costs* *Lower wholesale market prices*

There is already evidence of a new algebra of cost-effectiveness evaluation emerging in recent AMI business cases. Conventional AMI business cases even if they are conducted in areas with organized wholesale markets have in the past left out market price impacts, both because these price impacts are not necessarily reflected in utility operating costs because they do not constitute net efficiency gains. Rather, these business cases have focused on operating benefits (e.g., meter reading, billing, network operations, outage response, load research, and theft reduction), avoided supply costs (capacity and energy), and investment deferral. All of these costs are fixed and variable utility operating costs that can be expressed as a NPV of reduced revenue requirements.[xliv] In contrast, several more-recent AMI business cases have explicitly included the market price benefits of AMI as a result of lower peak loads during high-cost periods enabled by dynamic pricing and load control. Typically these estimated benefits are constructed by analyzing several supplier adjustment scenarios because, unlike avoided supply cost savings, market benefits derive from market price impacts which are short-lived, as suppliers adjust supply in response to lower prices from additional DR participation in markets. Even under conservative assumptions, these market price benefits can be very large for distribution utilities and their customers.[xlv]

As part of constructing an improved DR valuation framework we can anticipate the rising importance of new market participants as well as improved understanding of how DR produces quantifiable benefits beyond utility operating cost savings. **Table 4** provides a starting point for considering the incidence of a broader range of DR benefits (and costs) across an expanded list of market participants as found in organized wholesale electricity markets. The first two benefits category, lower utility costs and lower market prices, look substantially like Table 3, with generators bearing the burden of avoided supply costs and lower supply prices[xlvi] Beginning with the increased reliability benefits category and continuing through the System and Network Operating Costs it becomes apparent that the incidence of costs and benefits and the distinction between net efficiency gains vs. economic transfers needs to be worked out in more detail. Some potentially new economic transfers can be noted. Reduced Ancillary Services costs are likely to follow the same pattern as reduced supply costs – DR participation would likely produce a gain for all consumers and a corresponding loss for generators. However, deferred T&D capital expenditures could be a net efficiency gain (lower utility costs due to improved asset utilization) but also represent a cost to distribution utilities which would lose the return on T&D investments. Similarly, any distribution company which owns generation might have to ring-fence its distribution economic perspective and its generator economic perspective. The Environmental and Customer benefit categories seem straightforward in terms of incidence. Environmental benefits accrue to all market participants, while customer benefits would likely only accrue to participants and non-participants, with the cost borne by the distribution company and the non-participant. Other stakeholders will be directly or peripherally affected by the participation of DR in retail and wholesale markets. Third party providers, system operators, even regulators could be considered as additional stakeholders with a distinct economic perspective and outlook on DR.

Comparison of **Table 4** with the existing SPM underscores the need to update such economic analysis procedures to reflect new market participants and new categories of benefits.

Table 4: Distribution of DR Benefits and Costs in Organized Wholesale Markets

Benefit Category	Private Benefit (or Cost)	Net Efficiency Gains for Society	Economic Transfers		
			Benefit	From	To
Lower Utility Costs		Avoided supply costs			
	Participant Bill Savings				
			Participant Incentives	Ratepayers	Participants
			Revenue Losses	Ratepayers	Participants
	Participant costs				
Lower Market Prices			Lower capacity prices	Generators	Consumers
			Lower energy prices	Generators	Consumers
Increased Reliability	Participant Reduced svc level	Reduced outages			
Lower System and Network Operating Costs			Reduced AS costs	Generators	Consumers
		Reduced congestion			
		Reduced Network Cap Ex			
		Lower line losses			
Environmental Impacts		Reduced emissions			
Customer Benefits	Avoided risk premium				
		Customer Choice			

3.0 Tailoring the Valuation Framework

The valuation elements described above - type of benefits, economic perspective, monetization method, and market structure - can be used to develop a valuation framework that works for a given application. The practical aspects of a given valuation problem must be considered when constructing a valuation framework from these elements. Practical aspects to consider in tailoring a valuation framework include:

- Nature of the valuation problem
- Attributes of the demand response investment
- Trading-off relative scale of the benefit and complexity of the valuation method
- Diversity and complexity of stakeholders/market participants

3.1. Nature of the Valuation Problem

The valuation framework should match the problem dimensions in terms of purpose, timeframe, accuracy requirements, and comprehensiveness. Some valuation problems are easier than others – an *ex post* evaluation of the cost effectiveness of a demand response program is much easier than selection of an optimal demand response portfolio in the context of a long-run regional resource adequacy plan. The key dimensions to consider in selecting a valuation framework are:

- Purpose. Is the valuation to be used for preliminary screening of demand response options or for gaining regulatory approval of demand response infrastructure investments? Perfunctory valuation problems such as DR technology screening are better suited to simple methods such as avoided costing methods, while more critical valuation problems require more comprehensive approaches.
- Timeframe. Is the valuation to be done *ex ante* or *ex post?* Is the valuation timeframe short-run or long-run? Any *ex ante* value estimation is more difficult with greater uncertainty than an *ex post* evaluation, as all the parameters affecting value must either be forecast with uncertainty dimensioned or simply assumed to be static. Some methods, such as calculating incremental the reliability value from dispatching demand response during capacity shortages, are only possible on an *ex post* basis and thus have narrow applicability for valuation.
- Accuracy. Some valuation problems, such as choosing an optimal demand response portfolio within an IRP plan, require considerable quantitative accuracy. Other problems, such as justifying a general policy (e.g., California's merit order loading) can be solved using heuristic or even qualitative approaches.
- Complexity. Some valuation problems are much harder than others. To the extent that relatively few market participants are affected it is possible to use a simpler valuation framework. For example, a customer infrastructure business case submitted by a distribution utility need only demonstrate that utility costs as well as participant and non-participant rates go down in order to demonstrate the value of the investment.

3.2. Demand Response Functionality and Market Structure

Demand Response comes in many forms, from large blocks of consumption exposed to dynamic pricing tariffs to specific end-use loads controlled by a system operator. Demand response assets vary in their ability to deliver certain categories of benefits, and thus may require a more or less complicated valuation framework. A good example of this is the advent of retail dynamic pricing enabled by AMI infrastructure. Up until recently, business cases focused on fixed and variable operating cost savings such as meter reading costs, billing costs, disconnect and reconnect costs, etc. By including retail rates which are capable of creating autonomous price elasticity in aggregate demand, it becomes necessary to estimate a whole new category of benefits – market price impacts – in order to fully capture the impact of AMI plus dynamic pricing.

Dispatchable demand curtailment may substitute for a peaking generator in a resource adequacy plan and may provide additional operating reserves in response to a system emergency. It may be procured by a distribution company complying installed capacity requirements or bid into a forward capacity market. Depending on the circumstances and market structure the benefits of demand curtailment might be bound by the cost of an equivalent combustion turbine as a floor or the results of a capacity auction for the zone in which it is located. If the demand response can be mobilized to provide operating reserves or bid into day-ahead energy markets then it might gain proportionally greater value.

DR assets can and do combine elements or price-responsiveness and dispatchability in their design or by combination into a distinct DR portfolio or by virtue of being operated in a particular fashion or bid into particular markets. The literature review showed that most valuation approaches are suited to evaluating a particular type of demand response assets or monetizing a certain category of benefit (See Table 5). Avoided cost methods such as those embedded within the California SPM are effective at calculating the benefits of DR when it substitutes for a generation resource. However, avoided cost methods cannot estimate the insurance or hedging value of DR under "stress cases" when generation is unavailable nor can they estimate the market price benefits of dynamic pricing. The overall result is that DR programs and portfolios must be evaluated in their specific applications context and will likely require more than one estimation method to capture the full range of delivered benefits.

Market structure also drives the choice of valuation framework. Regions of the country without organized wholesale markets value DR mainly as a replacement or adjunct to supply within the context of a resource plan. Regions of the country with organized wholesale markets recognize the short-term and long-term market price impacts of DR, as directly reflected in forward capacity market valuations. Those organized wholesale markets that allow DR to provide ancillary services offer an additional value proposition for qualifying loads. The fundamental point is that markets confer value for DR, while lack of markets act to constrain the potential value of DR. Furthermore, the presence of markets changes the organization of economic test perspectives and beneficiary categories. For example, in the context of an AMI business case analysis conducted for regulators in jurisdictions with organized wholesale markets there are only two test perspectives of interest – participants, non-participants and the utility.

Table 5: Capturing the Benefits of Diverse DR Assets

	Dynamic Pricing	Demand Bidding	Curtailable Loads
Avoided Costing			●
Dynamic IRP Modeling		●	●
Infrastructure Business Cases			
Market Model	●	●	●
Value of Lost Load		●	●
Option Value	●	●	●
Network and Transmission Planning			●
Approaches Environmental Cost Benefit Analysis			●
Consumer Surplus	●		

All these considerations combine to conclude that no single valuation method will likely be comprehensive enough to suffice for any but the simplest valuation problems. Any valuation framework must be able to accommodate multiple methods in order to fully assess the benefit dimensions of most DR programs. Therefore, and in line with the USDOE report on demand response benefits, efforts should be spent developing and codifying streamlined multiple valuation approaches that can be accommodated within existing vehicles such as the California SPM. Ultimately, the choice of valuation methods should reflect an appreciation of the potential of demand response to affect resource procurement, electricity market dynamics, system operations, and customer wellbeing.

3.3. Balancing Scale and Complexity of DR Benefits

Some benefits are potentially larger than others. Some benefits are transient in nature, and other benefits are simply intangible. These characteristics should be taken into account when constructing a valuation framework for a given problem. A review of the valuation literature suggests that the **major categories** in terms of **scale of the benefits** are (See Figure 2) are:

- Market price benefits
- Avoided capacity costs
- Incremental reliability value

This comparison suggests that these three categories of benefits should be considered at a minimum in any valuation framework. Other benefit categories may or may not be comparable to these depending on the type of demand response asset.

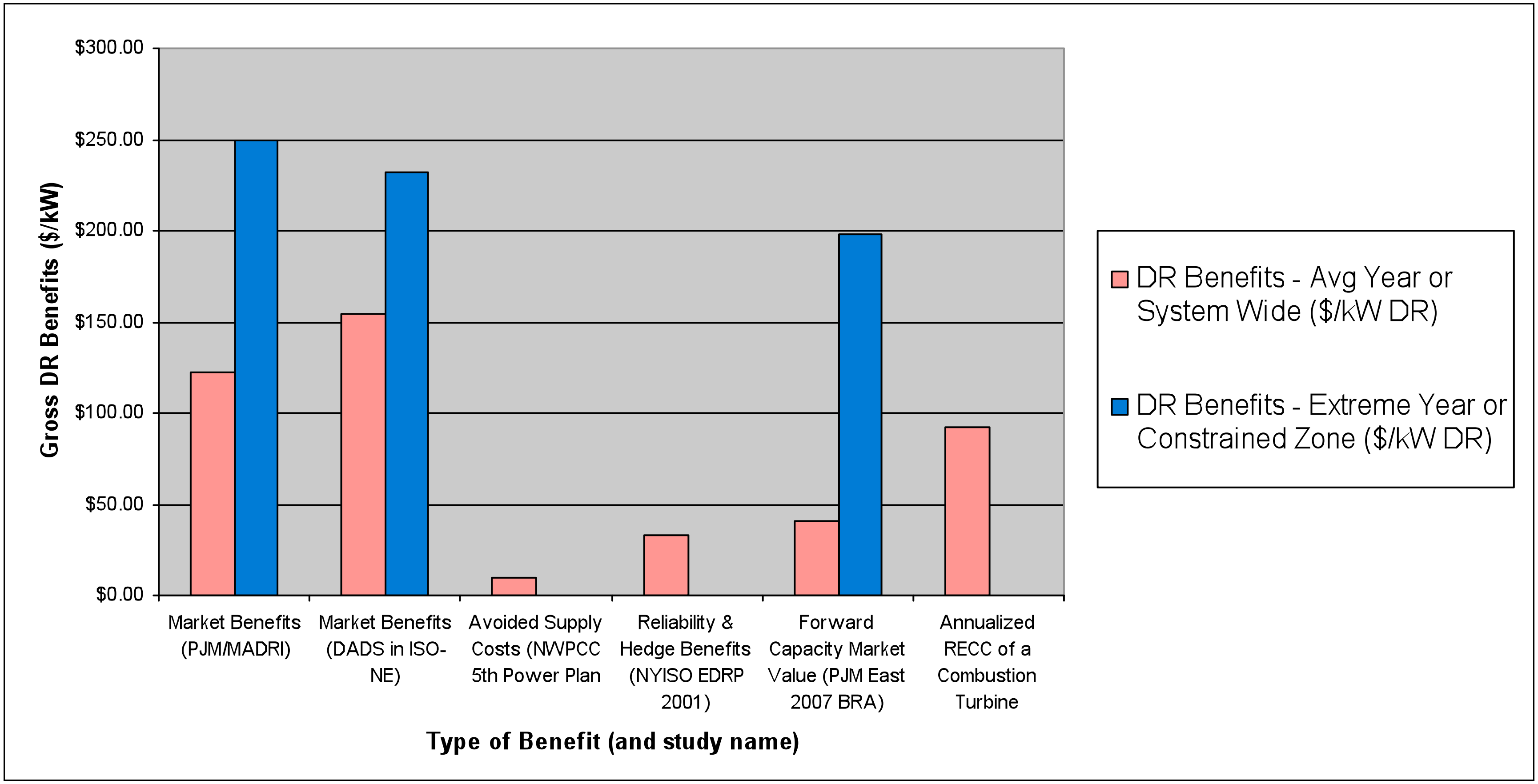

Figure 2: Comparison of Major Benefit Categories, Cost Proxies, and Auction Results

3.4. Diversity and Complexity of Stakeholders

The valuation framework is an instrument for making investment and/or policy decisions about demand response, and thus should also be constructed to reflect the diversity of stakeholders affected. In this sense a valuation framework should echo the larger stakeholder process, whether it is played out according to intervenors in a rate case or market participants in an organized wholesale market. Taking this viewpoint we can observe that many demand response valuation processes – such as customer infrastructure business cases and SPM analyses – are not currently effective at encompassing the full range of stakeholders. This is why it is equally important to broaden the consideration of different stakeholders/market participants at the same time as broadening the consideration of demand response benefit categories. Such considerations underscore the need to work in parallel paths in developing more comprehensive valuation methods for DR. It is not enough to monetize the benefit; rather, the incidence of costs and benefits across market participants must be tracked as well.

This section reviews the literature on estimating the benefits of demand response programs. The organization of this section is broadly consistent with two recent comprehensive reviews, one commissioned by the US DOE under the requirements of the Energy Policy Act of 2005 and the second commissioned by the IEA under Annex XIII of the DSM Agreement.[xlvii] The review demonstrates the range of analytic approaches brought to bear, and underscores the importance of market structure and economic (beneficiary) perspective in determining the scope and scale of benefits. The literature review supports the view that, ultimately, the differences in valuation methods reflect different views of demand response in resource procurement, electricity markets and system operations.

3.5. Avoided Cost Approaches

Avoided costing approaches for economic analysis of demand side programs have been used by regulators and utilities for many years. A widely adopted reference for economic analysis based on avoided costs is the California "Standard Practice Manual" (SPM), originally developed in the 1980s for evaluating energy efficiency programs. Some version of the SPM is in use in most regions in the United States, and it has been adapted to apply to demand side programs in the US and other OECD countries. The analysis results are widely used to establish a threshold for the reasonableness of DSM program spending. One of the advantages of the SPM is explicit treatment of the incidence of benefits and costs among stakeholders, e.g., participants, non-participants, program administrator, etc. (See Table 6). The SPM tests are not intended to be used in isolation. Each perspective helps to characterize the economic attributes of a demand-side program – e.g., market potential, potential for efficiency gains, and impact on rates.

The SPM has been used in analyzing the benefits and costs of DR, with varying results. Under the SPM approach the value of DR derives from its application in avoiding supply costs, e.g., the amount of additional capacity or energy that would otherwise have to be procured. The ability of DR to avoid supply costs varies between different program types, according to the attributes and applications of a given DR program.

Avoided costing approaches such as the SPM have many advantages. They are simple to use, generate multiple economic test perspective results useful in DR program design, and are effective in differentiating according to the attributes of DR programs. These methods also have well-documented shortcomings, including: (i) they are ineffective in considering how DR benefits can vary according to different future supply-demand balances; (ii) They cannot capture the consumer or producer surplus resulting from consumption or electricity price level changes; and (iii) they are not conducive to examining an integrated DR portfolio or integrated DR-generation portfolio.[xlviii] Notwithstanding these limitations, avoided costing methods are the principle method in use for DR program valuation.[xlix]

Table 6: The Algebra of Benefits and Costs as Embedded in the SPM Test Perspectives[l]

Test	Key Question	Benefits	Costs
Total Resource Cost (TRC)	Is resource efficiency improved?	Avoided supply-side costs	Program costs (including those borne by the utility and the customer)
Participant (P)	Is the participant better off?	Bill decrease Customer incentives	Program costs (borne by the participant) Participation fees
Rate impact measure (RIM)	Are rates lowered?	Avoided supply-side costs Participation fees	Revenue loss Customer incentives Program costs (borne by the utility)
Utility cost (UC) /Program administrator cost	Are revenue requirements lowered?	Avoided supply-side costs	Program costs (borne by the utility) Customer incentives

There are efforts underway to improve the capacity of the SPM to capture the special characteristics of DR programs. In January 2007 the California Public Utilities Commission (CPUC) initiated Rulemaking R.07-01-041 on load impact and cost effectiveness protocols for demand response programs. A goal of this rulemaking was to establish interim methodologies to determine the cost-effectiveness of DR programs. Under R.07-021-041 a series of workshops on cost-effectiveness methods were conducted and a cost-effectiveness protocol tailored to handle DR programs was developed.[li]

The objectives of the utility "straw proposal" for cost-effectiveness analysis of Demand Response included:[lii]

- Developing methodologies that could quantify the benefits of a "broad variety of DR approaches";
- Providing a basis for comparing DR resources within the context of forward-looking resource planning;
- Capturing the effect of factors that affect system cost and reliability (e.g., fuel prices, demand growth, plant availability);

- Capturing the physical and financial hedge value of DR resources under different planning scenarios; and
- Considering whether and how to quantify other benefits posited for DR, including: (1) generator market power; (2) short-term market price reductions; (3) longer-term bilateral contract prices; (4) induced innovation in DR approaches; (iv) value of portfolio diversity; (5) hedging of adverse market outcomes; (6) locational network or generation constraints; (7) improved portfolio modularity in the presence of load growth uncertainty; (8) customer choice; and (9) environmental benefits.[15]

A proposed settlement between most of the Parties in R.07-01-041 and the Joint Utilities was filed in late-2007 which proposed interim recommendations for cost effectiveness evaluation of demand response. This Demand Response Cost-Effectiveness Evaluation Framework Proposal (DRCEEFP) reflected the policy concerns of various Parties, including:

- DR programs not in forward-looking resource plans still have resource value;
- Individual utilities can develop methods and input values tailored to their unique situation within the scope of their DR program applications;
- All parties acknowledged that DR provides benefits beyond resource adequacy, but appropriate valuation criteria need to be developed;
- Further research is needed to value other DR benefits, including price elasticity effects, market performance benefits, reliability impacts, and insurance value.[liii]

Following the filing of the DRCEEFP the Energy Division (ED) Staff of the CPUC filed additional recommendations for modifying the SPM to accommodate a broader range of benefits beyond avoided resource procurement costs. In particular the ED recommended that market impacts be addressed by utilities in DR cost-effectiveness analysis. These "market benefits" include "increased reliability, increased market efficiency improvement in overall system load factors, improved market performance (e.g., decreasing price volatility), increased flexibility, portfolio benefits, and others." Recognizing that market benefits were difficult to quantify, especially in the absence of organized wholesale markets, the ED recommended that utilities provide a qualitative analysis in order to "reduce the risk that the value of DR would be artificially low because we have neglected to consider and quantify market benefits that may emerge as the markets evolve." [liv] These qualitative impacts would appear as benefits under various economic test perspectives and be considered by policy makers in judging the merits of DR programs (See Table 7).

Table 7: Costs and Benefits Used in the Modified SPM Tests for DR

	TRC	PAC	RIM	Participant
Administrative costs	COST	COST	COST	
Avoided costs of supplying electricity	BENEFIT	BENEFIT	BENEFIT	
Bill Increases				COST
Bill Reductions				BENEFIT
Capital costs to participant	COST			COST
Environmental benefits	BENEFIT			
Incentives paid		COST	COST	BENEFIT
Increased supply costs	COST	COST	COST	
Market benefits	BENEFIT	BENEFIT	BENEFIT	
Non-monetary benefits				BENEFIT
Revenue gain from increased sales			BENEFIT	
Revenue loss from reduced sales			COST	
Transaction costs to participant	COST			COST
Value of service lost	COST			COST

Shaded rows indicate those costs and benefits which are not listed in the SPM but have been added to these Demand Response draft protocols.

Although still ongoing, the record in R.07-01-041 underscores the complexity of issues associated with comprehensive benefits evaluation of demand response programs. In particular, including methods to monetize additional categories of benefits beyond avoided resource costs will require significant new analytic developments.

3.6. Customer Infrastructure "Business Case" Approaches

A venue of growing importance for Demand Response valuation are filings seeking regulatory approval for new customer metering and load control infrastructure. Many utilities in California, Maryland, New York, Ohio, Illinois, Texas, Connecticut and elsewhere are proposing or studying large investments in Advanced Metering Infrastructure (AMI) and Demand Response Initiatives (DRI). The "business cases" developed to support these customer infrastructure investments often require identifying and monetizing the benefits and costs of demand response.

An AMI or DRI "business case" is similar to a cost-effectiveness or benefit-cost analysis: it estimates the financial benefits and costs of the investment from different economic perspectives. In order to see how these "business cases" incorporate the value of DR we compared three recent regulatory filings in California and Maryland.

3.6.1. California: SCE

The California utilities (PG&E, SCE, and Sempra Energy) were all required by State law and CPUC requirement to develop and file advanced metering initiatives.[lv] The CPUC and the CEC provided guidelines which identified four benefit categories to be considered in AMI business case filings: (1) System Operations Benefits; (2) Customer Service Benefits; (4) Demand Response Benefits; and (4) Management and Other Benefits. The only demand response benefits deemed to be quantifiable were procurement cost reduction (e.g., deferral of capacity due to lower on-peak consumption), improvements in system reliability or augmentation of reserve margins, and lower environmental emissions. [lvi]

Southern California Edison filed its SmartConnect program in 2005. SCE proposes installing 5.3 million advanced meters capable of automatic interval meter reading on its entire customer base including two-way communications, dynamic pricing, and end-use load control via Programmable Controllable Thermostats (PCTs). The AMI installation would provide 500 MW of price-responsive demand and another 500 MW of load control by 2013 at a deployment cost of $2 billion.

SCE's Business Case identifies DR as a major category of the $7.6 billion in nominal benefits from implementing AMI throughout its service territory. Demand Response benefits result from two categories of programs made possible by AMI: (1) Price Responsive DR (e.g., Critical Peak Pricing or Peak Time Rebates); and (2) End-Use Load Control activated in response to economic or system stability conditions. Together these two DR program categories will deliver 1,000 MW of peak demand reduction by full deployment in 2013 (See Figure 3).

DR benefits in SCE's Business Case include: (1) capacity procurement cost savings as a result of system peak demand reductions; (2) energy procurement cost savings of 1 percent as a result of the "conservation effect" of DR programs on participants; and (3) a 20 percent reduction in the costs of upgrading distribution infrastructure to accommodate network peak demand growth. DR benefits over the life of the AMI investment of $3 billion in nominal revenue requirements, or 40 % of total AMI benefits. On an NPV basis DR provides $842 million of $2.076 billion in total benefits, compared to a NPV cost of $1.967 billion. The SCE Business Case mentions and in some cases quantifies but does not include in the economic analysis several other benefit categories, including improvement in overall customer experience, reduced energy theft, environmental benefits, and improved customer security. The SCE Business Case does not include any reliability or market benefits.

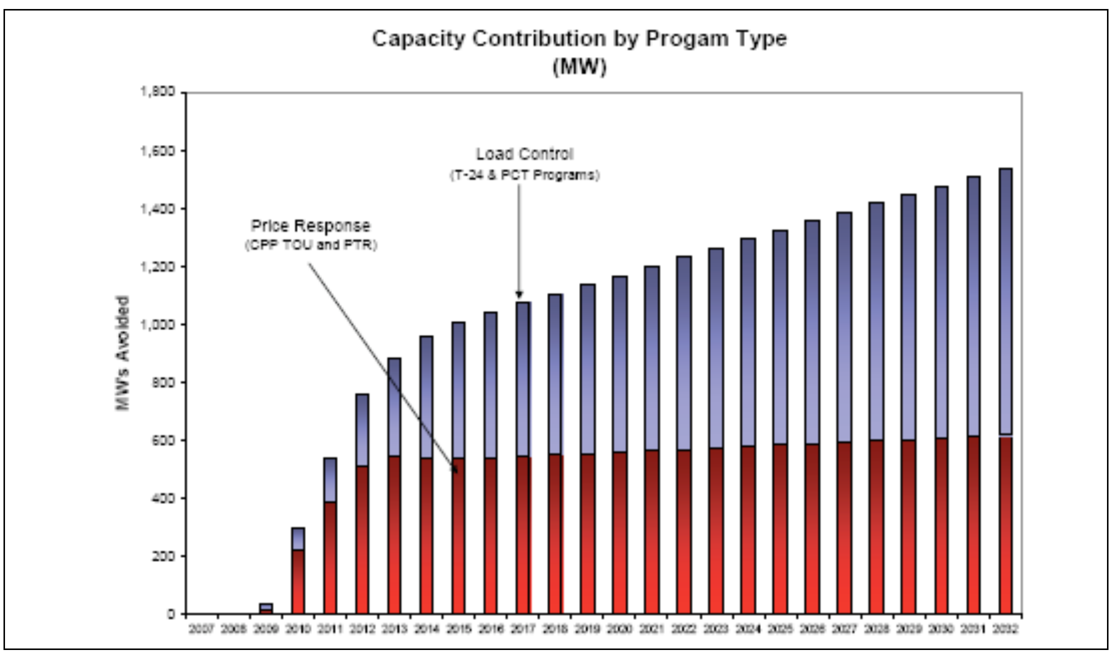

Figure 3: Estimated Peak Demand Reduction from AMI and PCT Roll-out[lvii]

3.6.2. Maryland: BGE and Pepco

In response to the federal Energy Policy Act of 2005 and recent State legislation (EMPOWER Maryland Act of 2008), the Maryland Public Service Commission (MPSC) is conducting an omnibus investigation (MPSC Case 9111) into demand-side issues, including advanced metering technical standards, conservation and energy efficiency, demand side management (DSM) cost effectiveness tests, and recovery of costs of advanced meters and DSM programs. All investor-owned Maryland utilities are required to submit business cases for advanced metering plus comprehensive proposals for demand response and energy conservation. The AMI and demand response business cases filed by the two largest Maryland utilities – BGE and Pepco – are described below.

In January 2007 Baltimore Gas and Electric (BGE) requested approval of its Smart Energy Savers Program and Advanced Metering Infrastructure (AMI) initiatives. The Smart Energy Saver's Program would install Programmable Controllable Thermostats (PCTs) with two-way communications on some 450,000 households, mobilizing 600 MW of aggregate load control at a cost of around $100 million. The companion Advanced Metering Infrastructure initiative would provide capability for automatic interval meter reading and two-way communications for 2 million gas and electric accounts. Together these initiatives would allow BG&E to manage 1000 MW of residential peak demand (about 25 percent of the residential class contribution to system peak demand) through a combination of dynamic pricing, load control, and enabling technologies.

The Smart Energy Savers Program will allow BGE to actively control the demand of its residential customers, whose air conditioners contribute about one-half of its peak demand (See Figure 4).[lviii] BGE will be able to recoup the costs of these DR investments by bidding the DR capacity into PJM's forward capacity market.

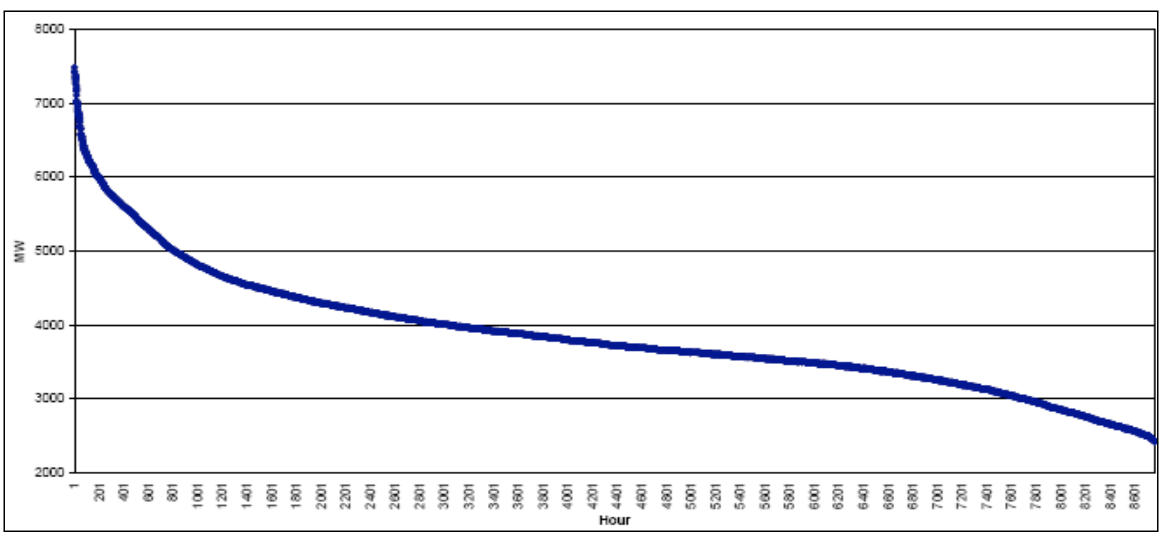

Figure 4: BGE Load Curve Summer 2006[lix]

Specific benefits included in the Business Case include:

- Value of peak load reduction, monetized via PJM's base residual auctions (BRA) and load reduction certification process (NPV=$195 million);
- Reduced capacity procurement costs resulting from increased demand response offered into the BRA (NPV = 1,500 million);[lx]
- Value of reduced wholesale energy purchases resulting from load reductions bid into PJM's day-ahead and spot markets (NPV= $42 million);[lxi]
- Reduced energy prices during tight supply conditions, as demand resource lowers forward market prices yielding lower prices for all (NPV = $102 million);[lxii]
- Reduced investment in distribution infrastructure needed to keep up with network peak demands (NPV=$61 million);[lxiii]
- Environmental benefits from reduced peak demand and the conservation effect of demand response and dynamic pricing, estimated at 2.0 billion pounds of CO_2 per year over a twenty year time horizon.

BGE considered the benefits and costs from three perspectives – utility, participant and non-participant. The difference between these perspectives is the incentive payments and slightly lower bill payments due to lower consumption of participants during control events. The overall program is highly cost-effective from all three perspectives.

Pepco Holdings, Incorporated (PHI) Maryland operating subsidiary filed its Advanced Metering Infrastructure proposal in 2007. Pepco Maryland proposes to install 530,000 electric advanced meters at a cost of $123 million, including the two-way communications and end-use devices needed to send price and/or control signals. Pepco evaluated several rate implementation and supplier adjustment scenarios in order to bracket the market value of lower peak loads enabled by dynamic pricing and load control. Key variables were: (1) whether the proposed CPP tariff is a voluntary rate or the default rate ("rate structure scenarios"); and (2) how quickly suppliers adjust to larger quantities of DR in wholesale energy and capacity markets ("supplier responsiveness scenarios"). In the mandatory CPP scenario (opt-out) participation is initially 100 percent falling to 80 percent by the second year; in the voluntary CPP scenario (opt-in) participation ramps from zero to 20 percent within two years. Pepco analyzed several supplier adjustment scenarios because, unlike resource cost savings from DR, market benefits derive from market price impacts which are short-lived, as suppliers adjust supply in response to lower prices from additional DR participation in markets. The "immediate" supplier adjustment assumes only one year of market benefits, whereas in the "delayed" supplier adjustment scenario market benefits persist for up to five years.

Figure 5 shows the sensitivity of DR value according to rate structure and supplier adjustment scenarios for a 30-year assumed life of the AMI asset. The market benefits (short term price impacts) derived from increased DR participation in capacity and energy markets are significant only in the case where supplier adjustment to additional capacity and energy supplied by DR is delayed. Even in the most conservative case the Present Value of capacity, energy and AS procurement cost savings is over $400 million, significantly more than the $124 million deployment and O&M costs for AMI. In the default CPP scenario with constraints on supplier adjustment (e.g., a scarcity market for new capacity) the NPV of benefits could soar to $1 billion, with market benefits making up one-quarter of this total. [lxiv]

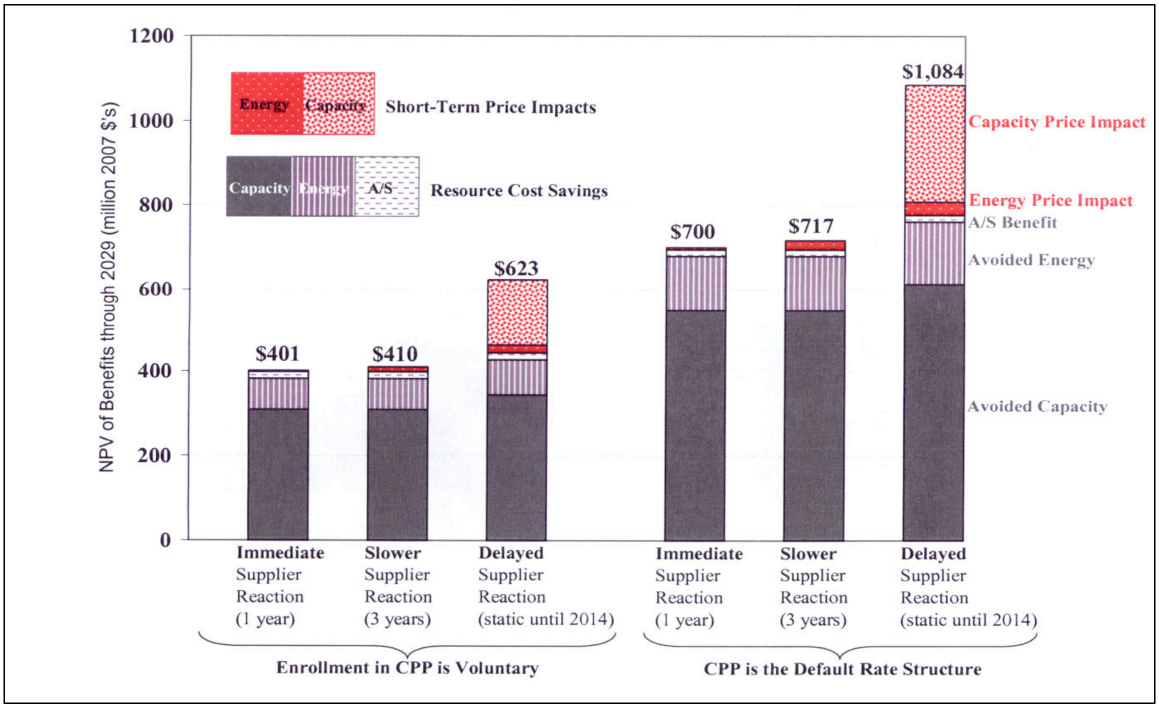

Figure 5: NPV of Monetized Benefits from Customer Load Reductions (30-year life)

3.6.3. Comparisons

The business cases for the three AMI initiatives are summarized in Table 8. For each case the benefits are separated into six categories typical of customer infrastructure business cases – Operating Benefits, Capacity Benefits, Energy Benefits, Market Price Benefits, Network Deferral Benefits, and Other. In the case of SCE's SmartConnect program, DR benefits make up a relatively small component of total benefits – about 1/3 of the total $2.1 billion savings. In contrast, DR benefits for the two Maryland businesses are more than half of the total expected savings and as much as 2/3 in the case of BGE.

Figure 6 compares key parameters of the three business cases expressed on a per-kW of demand response basis, along with the overall benefit/cost ratio results. The BGE case has the largest total benefits expressed per unit of demand response – over $2500/kW compared with a deployment cost of $870/kW. The result is a benefit/cost ratio of almost 3.0. The Pepco Maryland "best case" scenario also has impressively high benefits and a high benefit/cost ratio. Even the Pepco Maryland "worst case" scenario has a significantly higher benefit/cost ratio (1.5) than the SCE case (1.05). The difference between the SCE case and the two Maryland cases stems from much higher market price benefits as well as comparable capacity benefits. The different approaches observed in these studies may create problems for regulators reviewing these regulatory filings and making decisions on which infrastructure investment to approve. One possible solution would be to develop standardized benefit cost protocols, including definition of allowable benefit categories and economic perspectives, to be used in customer infrastructure business cases.[lxv]

Table 8: Comparison of 3 AMI Business Cases (All Values in PV terms)

Utility and Program	Total PV Benefits[lxvi] (based on ΔRR)	Operating Benefits	Capacity Benefits	Energy Benefits	Market Price Benefits	Network Deferral Benefits	Other (Non-monetized) Benefits
SCE's SmartConnect AMI program 5.3 million meters 1,000 MW of DR $2 billion deployment cost	$2.109 billion (PV)	Meter Services Billing Operations Call Center Network operations $1.37 billion	Based on a CT avoided cost proxy $505 million	Avoided peak energy costs during operations + a 1 % Conservation effect Total: $149 million	None	$52 million of distribution upgrade deferrals	1. Improved customer experience 2. Reduced energy theft 3. Environmental benefits 4. Improved customer security
BG&E's Demand Response Infrastructure Service/AMI 2 million meters 600 MW of DR $520 million deployment cost	$1.52 billion (PV) (residential customers only)	Meter Services Billing Operations Outage response Reduced UFE Load research ($400 million)	Based on value of peak demand reductions bid into PJM's Forward Capacity Auction ($195 million)	Value of energy bid into day-ahead markets when programs are dispatched ($42 million)	Reduced capacity costs resulting from more DR participation in RPM auctions ($770 million) + Reduced wholesale energy prices due to sustained energy bids by DR ($53 million)	Deferred T&D additions due to lower peak demand ($61 million)	1. GHG emissions 2. Gas operations value 3. Reduced need to site new power plants
Pepco's "Blueprint for the Future" 530,000 meters 175-300 MW of DR $125 million deployment cost	Best Case: $440.5 million (PV) Worst Case: $184 million (PV)	Meter services Customer contact Asset optimization Theft reduction[lxvii] $74.5 million total	Based on bidding into PJM's Forward Capacity Auction Best Case: $213M Worst Case: $87M	Based on bidding into PJM's day-ahead markets Best Case: $51M Worst Case: $20M	Reduced energy prices, reduced capacity prices, reduced spot prices Best Case: $102M Worst Case: $2M	Not quantified	1. Customer benefits 2. Reduced T&D losses 3. Improved reliability 4. Reduced price volatility 5. Reduced need to site power plants

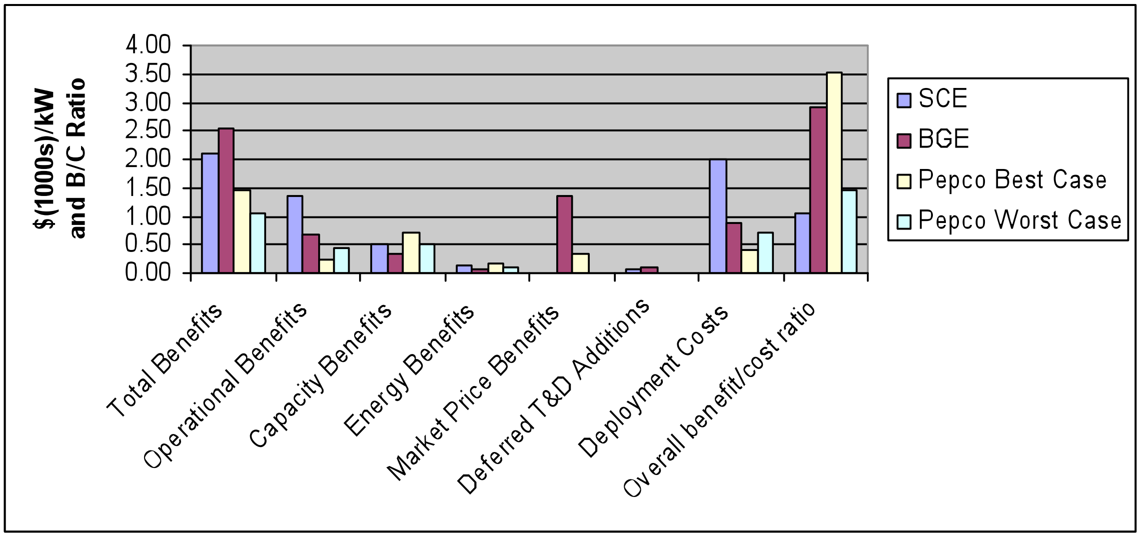

Figure 6: Comparison of SCE, BGE and Pepco Maryland AMI Business Cases

3.7. Integrated Resource Planning Approaches

Integrated Resource Planning (IRP) studies directly estimate the financial benefits of demand response by comparing the difference in total utility costs between a "base case" and a "DR case" resource plan. A variety of different "DR cases" makes it possible to gauge the benefits of different DR portfolios and choose one which maximizes the net present value of the reduced revenue requirement. Incorporating probabilistic techniques such as dynamic modeling into the IRP process brings additional benefits, allowing the physical and financial hedging value of DR during "stress events" to be captured. Dynamic IRP incorporates forecast and portfolio scenarios that quantify the net cost implications in expected value terms of hundreds of different long-term forecast scenarios. These methods are well-suited to DR valuation as they provide: (i) a sufficiently long time horizon to capture the risk management benefits of DR during high-consequence, low-probability events; (ii) a dynamic approach that allows incorporation of uncertainty regarding demand growth and supply costs; and (iii) the ability to include different types and amounts of demand response in order to identify the most robust combination. The impact of DR (or any other resource) on system costs is a probability-weighted calculation over a spectrum of forecast scenarios.

3.7.1. Example: Fifth Northwest Power Plan

The Pacific Northwest Electric Power Planning and Conservation Act created the Northwest Power and Conservation Council and charged it with developing quinqennial long-term power plans to assure the region of an adequate, sustainable and economical power system. The power plan covers a twenty-year planning horizon and must consider future uncertainties and realistic resource alternatives in developing a strategy that trades off power needs with resource and other impacts. The latest twenty-year plan, published December 2005, called for inclusion of 2,000 megawatts of DR in the portfolio.[lxviii]

The Fifth Northwest Electric Power and Conservation Plan used a Portfolio Analysis approach to value the inclusion of DR within the resource plan. The planning process included detailed analysis of the characteristics of major resource alternatives in different combinations (portfolios) when considered against a large number of futures (scenarios). Although energy efficiency has long been an integral part of Pacific NW electric power planning, demand response was considered for the first time in the Fifth Plan.

The Fifth Plan is also the first to explicitly consider risk on an equal basis with system cost in resource planning and portfolio selection.[lxix] Risk factors affecting future power system costs in the Pacific Northwest (See Figure 7) include wholesale market prices, plant availability, load growth uncertainty, fuel prices, hydroelectricity availability, and others. Considering the effect of risk factors on a resource portfolio is important because the distribution of possible system costs that can be asymmetrical rather than normal. Portfolio modeling outcomes are expressed with two parameters –an expected net present value of total system cost based on the central tendency of the distribution along with a risk parameter that captures any non-normal distribution of system cost outcomes.

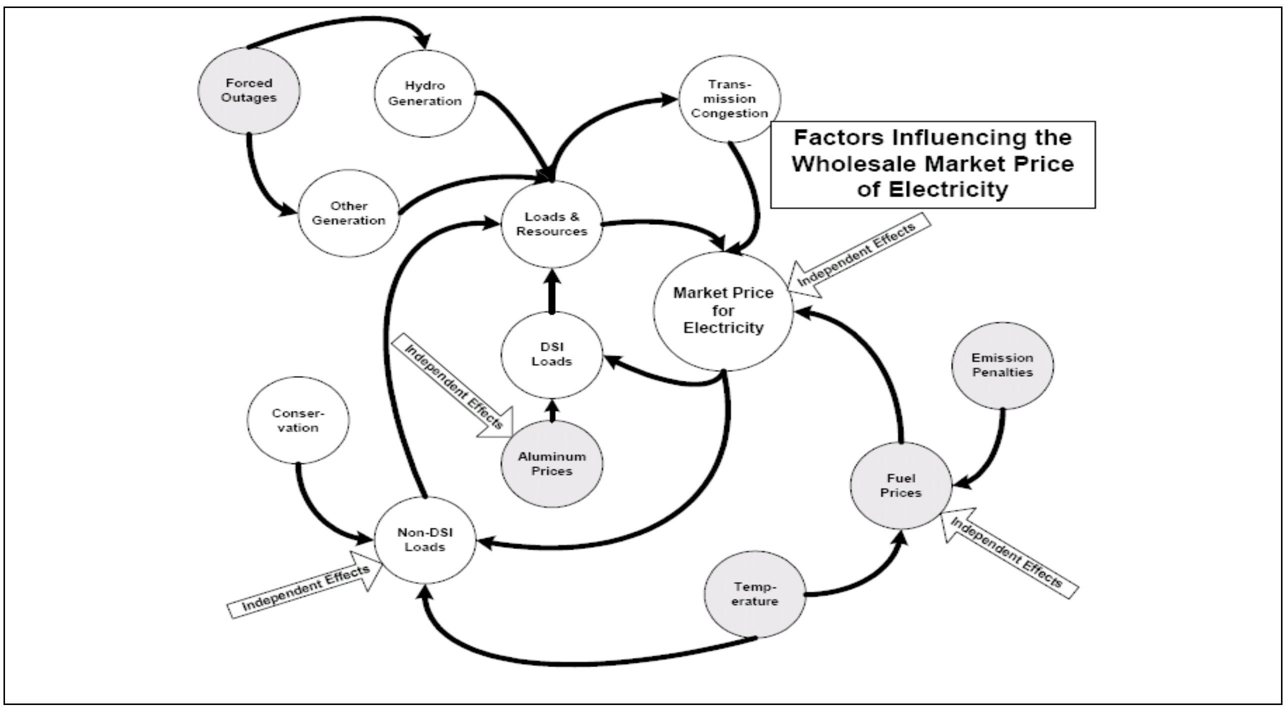

Figure 7: Major Risk Factors Affecting Power System Costs in the Pacific NW

A base case scenario of forecast power system needs was developed together with four distinct plans for meeting these needs – an absolute least-cost plan (A), an absolute least risk plan (D) and two intermediate plans (B and C). The plans differ mainly according to how much new generation capacity is added, what type, and when. The difference in new supply between plan (A) and plan (D) is quite large – 2500 MW of additional IGCC, CCGT, and wind power within 12-15 years. Two types of demand response resources were included - dispatchable price mechanisms and demand "buybacks". The analysis characterized demand response as a 2,000

MW peaking unit with a fixed cost of $5,000 per megawatt, a maintenance cost of $1,000 per megawatt per year and a variable cost of $150 per megawatt-hour.

The trade-offs between the four plans in terms of risk and average expected costs are shown in Figure 8. The least-cost Plan A relies on conservation and wholesale market purchases plus small amounts of CCGT, and as a result is susceptible to uncertainties in fuel and wholesale market prices. The other plans involve adding new CCGT, wind, and IGCC capacity in varying amounts, which reduces risk of outages or exceptionally high prices but at a higher average cost. The portfolio analysis comprised some 750 twenty-year simulations of each of the main plans plus variations, including with and without demand response. Simulation results showed demand response was dispatched in 83 percent of years in which it is available, but the demand response volume used was relatively small (in 85 percent of those years when demand response was called upon it was dispatched only 9 hours per year). Demand response found significant use (more than 10 percent, or 870 hours) in just 5 percent of all years.

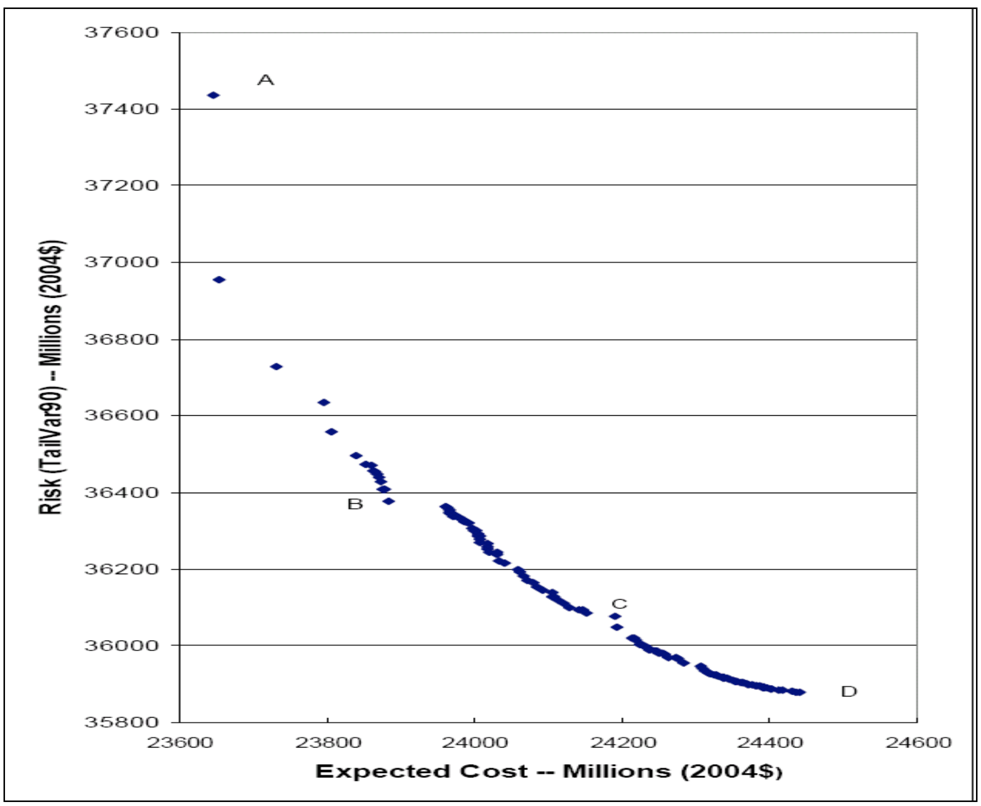

Figure 8: Portfolio Planning "Efficient Frontier" Results for Plans A-D

Although the volume of dispatched demand response was quite small, its impact on the efficiency frontier of risk-constrained least-cost plans was significant (See Figure 9). The "No Demand Response" cases comprise a risk-cost frontier shifted upwards and to the right (e.g., more expensive and riskier outcomes). The increments of lower cost and lower risk vary along the frontier, but on average withdrawing demand response from the plan increases expected cost by $300 to $500 million over the twenty-year period for a given risk level. These higher costs are mainly due to need for increased operation of high-priced gas-fired CTs and additional wholesale market purchases during years with poor hydro conditions or higher than forecast loads and/or wholesale power prices.

These results show how a dynamic IRP approach can estimate the reduction in long-term supply costs obtained by including demand response resources. They also show how demand response can help reduce the risk associated with a given resource portfolio. The reduction in risk associated with a given expected system cost is a direct expression of the **insurance value** of demand response. This insurance value is significantly larger for lower-cost plans (e.g., plans with fewer resource additions and more dependence on wholesale market purchases). In the case of the Fifth Five Year plan the risk-reducing benefits of demand response are well over $1 billion for the absolute least-cost plan.[lxx]

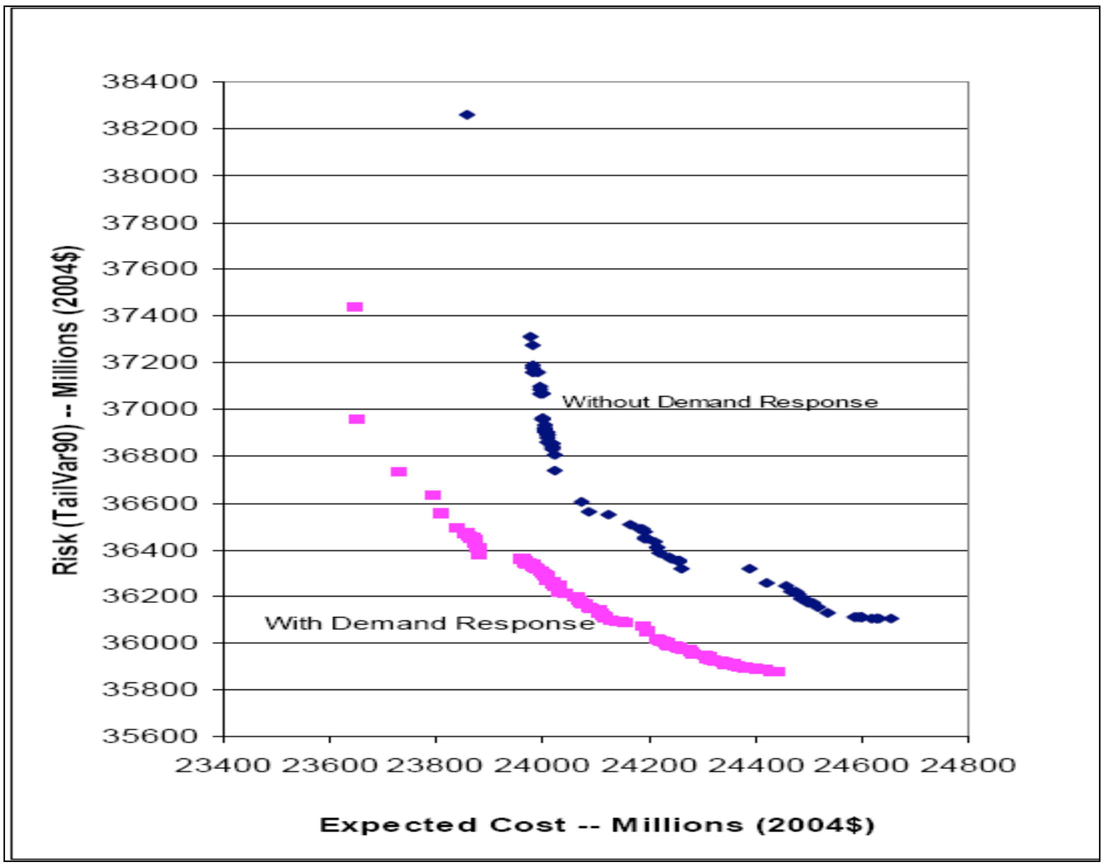

Figure 9: DR Impact on the Efficiency Frontier of Least-Cost Plans

3.7.2. Advantages and Limitations of Dynamic IRP

IRP methods offer considerable flexibility in defining realistic DR portfolios and then comparing them with supply-side resources in a least-cost planning framework. They avoid a key pitfall of an avoided costing approach, which caps the benefits of DR by reference to a static supply-side proxy (e.g., a combustion turbine). IRP methods that utilize probabilistic approaches to characterizing future power supply conditions (e.g., dynamic IRP) are able to isolate and quantify the additional risk mitigation (insurance) benefits of DR. IRP methods are also more effective at evaluating a portfolio of DR assets rather than an individual program or incremental load impact.

However, IRP methods are still grounded in capturing the supply cost savings of DR, monetizing them as changes in the net present value of total system costs. IRP methods cannot easily capture other types of benefit – participant bill savings, market price benefits, deferred network benefits, or environmental or customer benefits. Dynamic IRP modeling also has practical limitations. The modeling process is extremely data intensive, requiring complete characterization of generation system and network characteristics over the study horizon. An IRP study is also time consuming and numerically intensive, with results that do not lend themselves to a single expression of DR value. As a result, dynamic IRP modeling is not a practical substitute for more-easily applied methods such as avoided costing and infrastructure business cases. An additional difficulty with using IRP to evaluate DR is the need to address customer cost impacts associated with participation. When a customer's usage is curtailed, the customer incurs a "value of service loss" associated with the foregone use of electricity. This loss can be estimated as equal to the incentive paid for participation in the demand response program; however, this ignores any customer benefit from participation.

Recognizing the data requirements and complexity associated with dynamic IRP methods, some practitioners have suggested a biennial or even quadrennial integrated planning effort which would estimate "adders" approximating hard-to-quantify benefits (e.g., insurance or hedge value) that would then be incorporated into program-specific screening and benefit-cost tests. The results of this analysis would supplement other more-standard benefit-cost analyses.

3.8. Modeling the Market Price Benefits of Demand Response

Demand response programs have been shown to lower wholesale prices in capacity-constrained markets, yielding significant short- and medium-term financial benefits to electricity consumers.[lxxi] The benefits represent economic transfers from power producers to power consumers that can have a present value larger than the long-term avoided supply costs of the demand response investment. These market price benefits can be estimated *ex ante* through market simulations, assuming that sufficient market data is available to initialize the market model. Market simulations to estimate the price benefits of demand response participation in organized wholesale markets have been performed for ISO-New England, NYISO, PJM East and are underway in MISO. Two recent studies are described below.

3.8.1. Impacts of DR programs on Wholesale Market Prices

PJM Interconnection LLC in conjunction with the Mid-Atlantic Demand Response Initiative[lxxii] sponsored a study of the potential effects of peak period demand curtailment on PJM market prices. The study estimated the potential reduction in LMP from a three percent demand curtailment in the five PJM East control zones during the 20 highest-priced five-hour load blocks.[lxxiii] The study used 2005 market data which was normalized and then adjusted to simulate various load conditions and fuel scenarios (e.g., high and low peak load and fuel price cases).[lxxiv] For each case the study estimated the impact of demand curtailment on locational marginal prices (LMPs) and financial transmission rights (FTRs). Market simulations were performed using the Dayzer market simulation model developed by Cambridge Energy Solutions (CES).[lxxv]

Side-by-side market simulations for each scenario yielded the following market impact estimates due to demand response:

- A 3% curtailment of each selected zone's super-peak load reduced PJM's coincident peak load by 0.9%, enough to produce a short-term energy market price reduction of $8-$25 per megawatt-hour (5-8% of LMP) during the 150 hours of curtailment in one or more zones.
- Exposing all load in the MADRI states to day-ahead market prices, either directly or through a retail provider, could produce short-term market price benefits of $60-$180 million per year in MADRI states and $65-$200 million per year for all of PJM.
- Participants in the demand curtailment effort would receive bill savings from reduced consumption of $9 to $26 million per year
- Reduced super-peak loads also reduced the reserve margin requirements of retail providers, yielding $73 million per year in lower capacity procurement costs.

The short-term market impacts are shown graphically in Figure 10. The supply curve is upward-sloping while the demand curve is depicted as a vertical line, reflecting the fact that most retail customers are not directly exposed to spot prices. Demand response via curtailment decreases the quantity demanded from Q1 to Q2, causing the spot price to drop from P1 to P2. The market price savings ("Benefit to non-curtailed loads") is given by the area bcde.

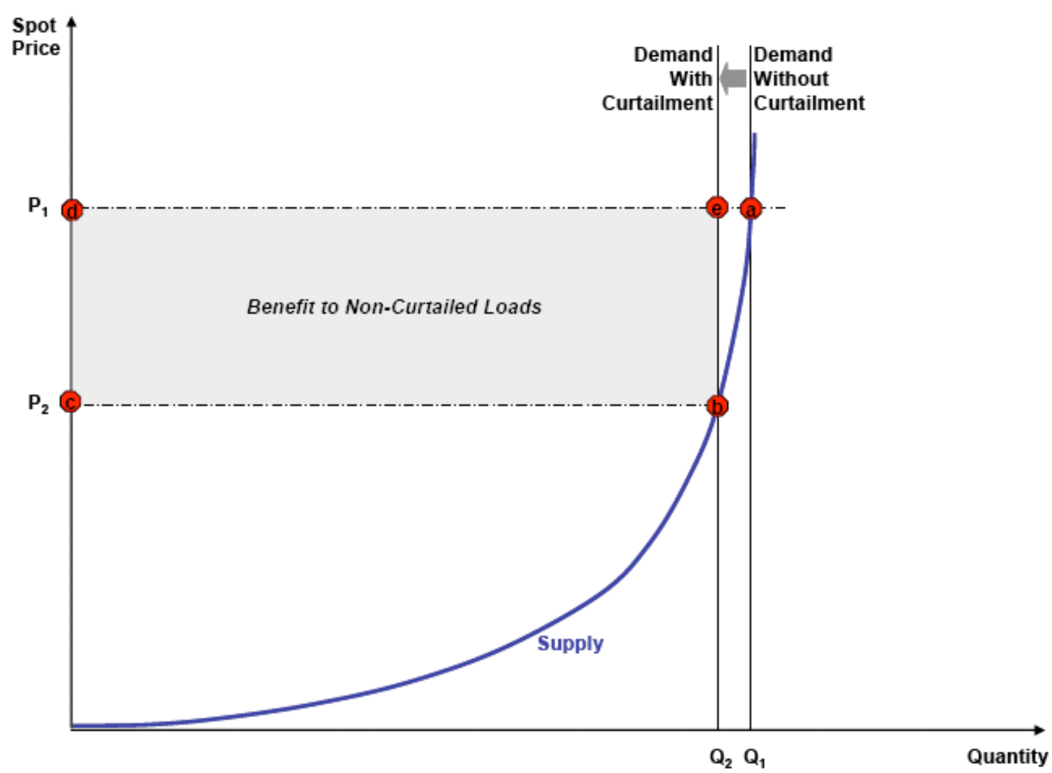

Figure 10: Market Price Benefits of Demand Curtailment

The study did not attempt to estimate the other benefits of DR, including improved market performance and competitiveness of energy and capacity markets, provision of insurance against extreme reliability or price events outside the realm of the scenarios considered, or any investment deferral or network congestion benefits. It also did not capture any additional benefits from demand curtailment in response to real-time market prices, which can be considerable. The study also did not consider any offsetting effects, such as participant load shifting or supplier adjustments (e.g., accelerating the retirement of old capacity or constructing new, less expensive capacity).

The market simulation results show how the value of demand response in lowering market prices varies according to market conditions. When markets are tight, a small reduction in demand yields a large reduction in market prices (the supply curve in Figure 10 slopes more steeply upwards under higher demand conditions). Market benefits also vary according to average price levels, which are driven by fuel price and weather. For hot years or high fuel price years the total benefits were twice as large as for cool or low-fuel price years (See Table 9).

Table 9: Annual Benefits from a 3 % Demand Curtailment in MADRI States

	Quantified Benefits in MADRI States	Quantified Benefits in Other PJM States	Unquantified Benefits	Caveats
Benefits to Non-Curtailed Load	**$57-182 Million** (energy only) (5-8% price reduction in curtailed hours)	**$7-20 Million** (energy only) (1-2% price reduction in curtailed hours)	• Capacity price decrease due to reduced demand; • Enhanced competitiveness in energy and capacity markets; • Real-time vs. day-ahead; • Value of reduced volatility; • Insurance against extreme events; • Avoided T&D costs.	• Probably significantly offset in long-run equilibrium as capacity and capacity prices adjust; "long-run" might not be so long. • Load shifting and demand elasticity offest some benefit in short-term.
Energy Benefits to Curtailed Load	**$9-26 Million** (**$85-234/MWh** price reduction in curtailed hours)	n/a	n/a	• Based on simplifying assumptions regarding the value of load that is curtailed.
Capacity Benefits to Curtailed Load	**$73 Million** (assuming $58/kW-Yr)	n/a	n/a	• Based on generic long-run cost of avoided capacity; • Ignores costs of equipment and DR program administration.
Total Annual Benefits	**$138-281 Million**	**$7-20 Million**	• Additional benefits to non-curtailed load could be large.	• Includes both the solid economic efficiency gains to curtailed load and the less robust benefits to non-curtailed loads.

Estimated energy and capacity market price benefits for participating and non-participating load are on the order of $100-$250 million annually – far in excess of the likely cost of implementing such a program. These market price benefits may be added to the calculated avoided capacity costs or resource adequacy contributions of the demand response program to estimate the total benefits of Demand Response. This was the approach used in the Pepco and BGE AMI Business Case Analyses described earlier.

3.8.2. Impacts of Autonomous Price Response on Wholesale Markets

In 2005 ISO-NE commissioned a study to quantify the potential market price benefits of dynamic pricing retail rates linked retail to ISO-NE's day-ahead energy market. The benefit of such a default retail rate (Day Ahead Default Service, or DADS) was compared to continued reliance on the ISO-NE's existing voluntary Day-Ahead Load-Response Program (DALRP) as a means of retail-wholesale linkage. [lxxvi]

Market simulations of DADS used price elasticities derived from NMPC's experience offering default-service energy rates for large customers indexed to hourly prices in the organized day-ahead market. The DALRP simulations used historical program results broadened to cover all large (> 100 kW) New England customers. Simulations were run over several five-year market scenarios including "normal" and "extreme" years.

Both DADS and DALRP created broad market price benefits for all customers. These benefits are in fact transfer payments, because lower prices due to load reductions cause an equivalent reduction in the producer surplus of generators. A second, longer-term effect of reduced market-price volatility is lower bilateral contract prices. If price response reduces system peak then the costs of installed capacity (ICAP) requirements are less for both customers and retail providers. A final but much smaller benefit is the net welfare improvements resulting when consumption decisions are made based on the marginal supply cost rather than on average rates.

The study also found that customers taking service on a DADS rate benefit in ways that a customer participating in DALRP cannot. A DADS customer avoids paying the hedge premium associated with flat-rate service, and has the opportunity to adjust consumption in response to hourly prices on an everyday basis instead of just when the DALRP operates.

Figure 11 displays the cumulative benefits over five years for the DADS and DALRP cases, including direct financial benefits to participants (customer bill savings and incentive payments), energy market price benefits to all ratepayers (producer to consumer economic transfers), ICAP market savings (collateral or indirect long-term capacity cost savings), and social welfare improvements. Because market price benefits depend on market conditions and weather, the results were calculated for a five year period that included a mixture of years (cooler than normal, normal, and extreme). The main benefit of both types of DR is customer bill savings, especially in cooler-than-normal and normal years. However, in extreme-weather years the energy market price benefits and the ICAP market savings become large.

In addition to demonstrating how to quantify the energy and capacity market price benefits of demand response, this study also makes a powerful argument for moving towards dynamic pricing for all customers in a position to benefit. Creating such a retail-wholesale linkage would have benefits that dwarf the costs to install hourly interval meters and other enabling technology.

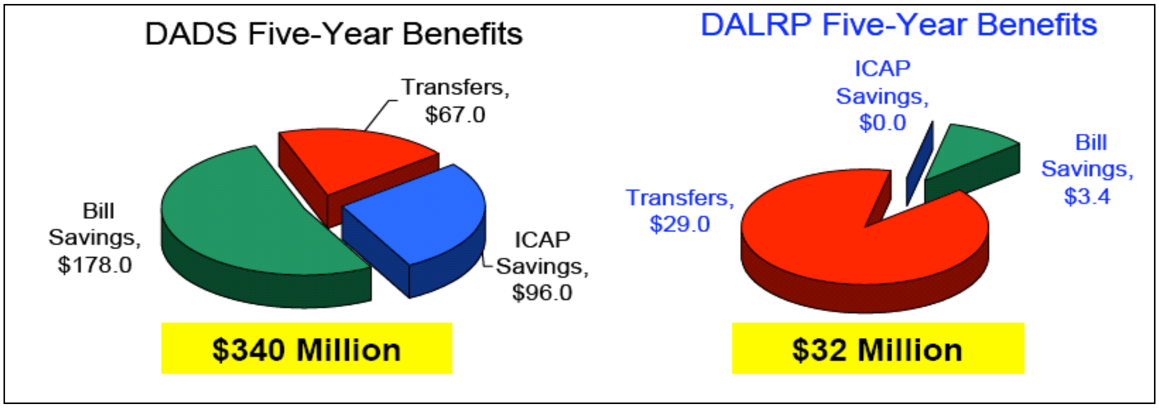

Figure 11: Comparison of Market and Customer Benefits of DADS and DALRP

3.8.3. Comparison of Market Price Benefit Studies

We can compare the results of these studies (See Figure 12) as they both express benefits on a gross basis (e.g., without subtracting program costs), evaluate a similar type of large-scale demand response asset, focus on similar category of benefits, and express the results in annualized terms ($/kw-year). The estimated benefits including short-term market price impacts and long-term bilateral contract price impacts for the PJM/MADRI and ISO-NE/DADS cases are quite similar, and display a similar pattern according to whether the impacts are for an "average" or "extreme" year in terms of weather, supply conditions, and fuel prices. For comparison purposes the Real Economic Carrying Cost (RECC) of a Combustion Turbine, a typical benchmark for long-run avoided capacity costs, is shown on the same scale. The reason why the value of market impacts is significantly larger than the proxy for avoided capacity is because in both these market price impact studies a relatively small amount of DR is leveraging large financial benefits in terms of lower market prices.

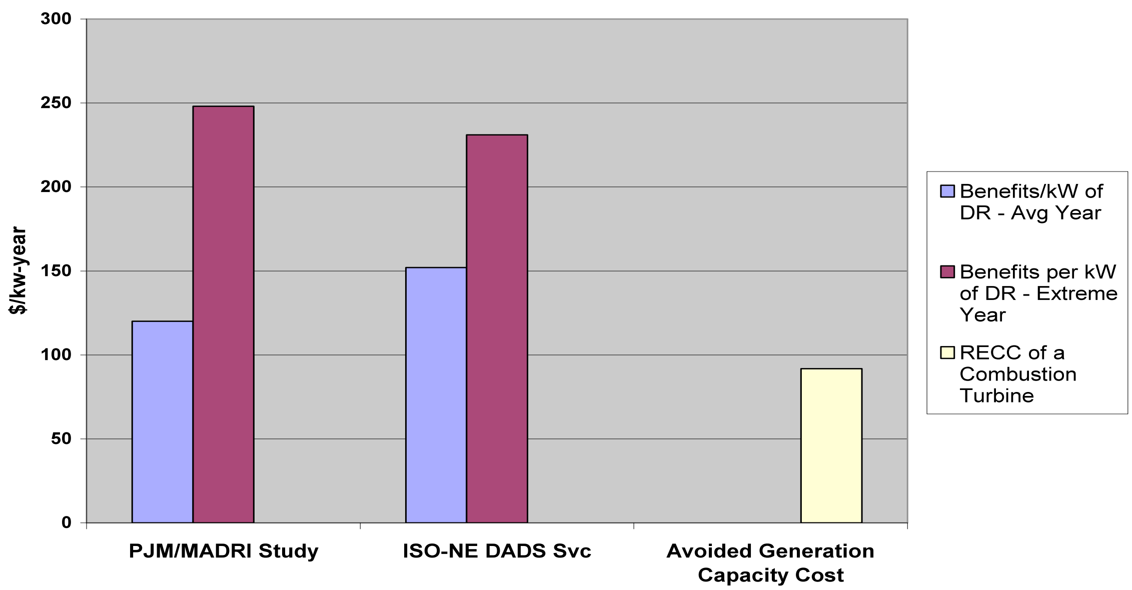

Figure 12: Market Impacts of Price Responsive Load in PJM and ISO-NE[lxxvii]

3.9. Value of Reliability Using Customer Outage Costs

Demand response has been shown to have value in improving power system reliability during "stress conditions" including system emergencies.[lxxviii] Improved reliability is the basis for most wholesale Demand Response programs operated by system operators such as PJM, NYISO, ISO-New England, and ERCOT. This section briefly reviews efforts to quantify the incremental reliability benefits during emergency operations using customer outage costs. A particular *ex post* evaluation of the incremental system reliability contributions of NYISO's Emergency Demand Response Program during 2001-2002 is described.

The system reliability benefits of DR can be estimated by looking at how an increase in operating reserves would reduce the Loss of Load Probability (LOLP) and thereby reduce the costs associated with brownouts and blackouts as result of emergency operations. The relationship between LOLP and operating reserves is shown graphically in Figure 13. Under normal system conditions operating reserves are adequate and the LOLP is vanishingly low (point a). The incremental reliability value of DR emerges during those operating conditions when system operators forecast a reserve shortfall (point b). Dispatching DR restores reserve margins in proportion to system conditions and available load resources. If sufficient data is available to characterize LOLP as a function of reserves then a relationship between load reduction and LOLP can be developed.

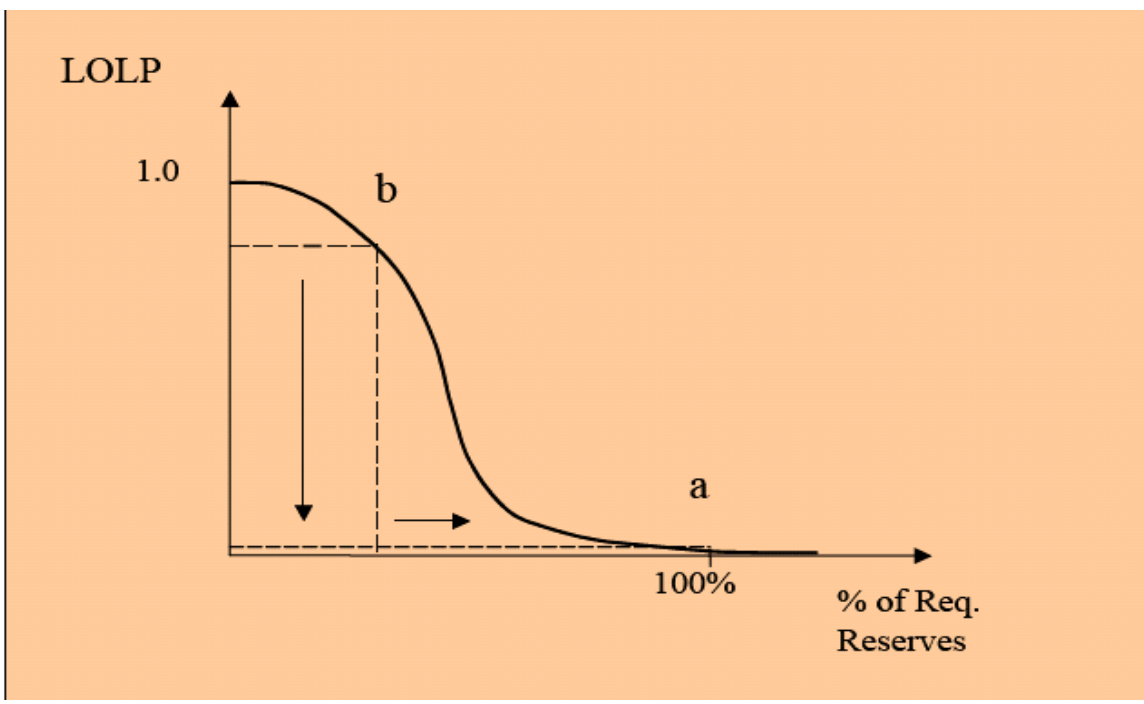

Figure 13: Calculating the Value of Expected Un-served Energy[lxxix]

The incremental reliability value is realized from reductions in the probability of forced outages and in the severity of the outages made possible by dispatching demand response. The more likely a system is to experience outages under given conditions, the greater the value of demand

The incremental reliability value is realized from reductions in the probability of forced outages and in the severity of the outages made possible by dispatching demand response. The more likely a system is to experience outages under given conditions, the greater the value of demand response. The more widespread the potential outage is, the larger the potential benefits. The incremental reliability benefits of DR can be monetized given three parameters: (i) data on the relationship between the system reserve margin and the probability of an outage (Δ LOLP); (ii) data on the cost incurred by customers from an outage (outage cost/MW); and (iii) data on the amount of un-served energy associated with a given reserves margin situation (un-served load in MW). The reliability benefits of DR are then the value of the reduction in expected unserved energy summed over the hours of operation of DR, or:

$$\Delta VEUE = \sum (hrly\ \Delta LOLP) * (Outage\ Cost/MW) * (Un\text{-}Served\ Load\ in\ MW) \qquad (1)$$

Although each factor in Eqn. (1) is based in engineering and economic principles, they are nonetheless difficult to estimate or quantify. Even with outage costs values from other studies, the relationship between LOLP and un-served load remains to be estimated. This function could be derived from a full-blown production system simulation analysis, as was done in the IRP studies described earlier. In the NYISO analysis a heuristic approach was taken whereby amount of load at risk necessary to offset the costs of the DR program was calculated, e.g., load at risk in order for the program to "break even" based only on system reliability benefits.

NYISO and ISO-NE have both evaluated the incremental reliability value of their DR products on an event-by-event basis.[lxxx] NYISO's 2003 program evaluation examined the incremental reliability benefits of the Emergency Demand Response Program (EDRP), together with collateral savings (market price benefits) and hedging benefits for both 2001 and 2002.[lxxxi] Figure 14 shows that both reliability and hedging benefits are highly variable from year to year, as they are driven by the occurrence of system "stress events". Note that this sort of cost and benefits analysis cannot be done on an *ex ante* basis but only retrospectively. The estimated incremental reliability value is also not inconsiderable –cost of the EDRP including incentive payments and administrative costs was around $5 million per year, or less than one-quarter of the 2001 reliability benefits alone.[lxxxii]

There are relatively few other studies of the reliability benefits of DR– even though many programs are called "reliability programs". The use of customer outage cost data to derive reliability value is complicated by the high variability of outage costs across different types of customers. A recent review of some 30 studies conducted by 12 utilities over a period of 15 years yielded outage costs of $0.30/kWh for residential customers to $8.00/kWh for industrial customers.[lxxxiii] Other data derived from real-time pricing programs suggest the VOLL is within the range $3-$5/kWh.[lxxxiv]

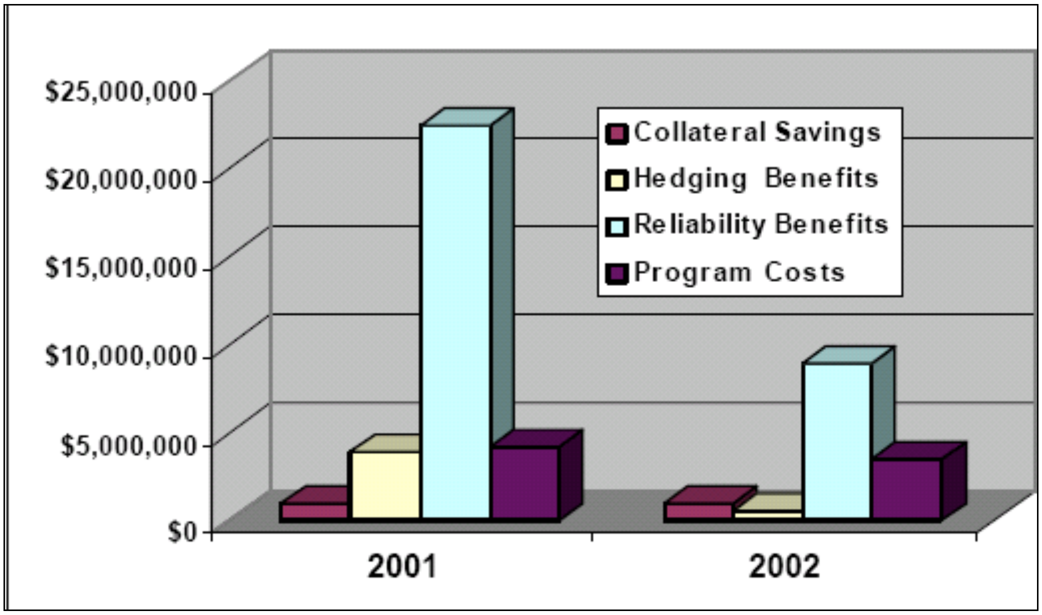

Figure 14: Benefits and Costs of NYISO DR Programs in 2001-2002

3.10. Option Valuation of Demand Response

A traditional discounted cash flow valuation of a demand response program calculates the potential savings based on how the program affects exposure to a forecast of average electricity prices. This static approach does not account for the stochastic variability of the electricity prices due to factors including fuel prices, market conditions, and weather. An alternative method would calculate the range of benefits for a demand response program under different operational conditions based on historical distributions of hourly prices. This approach bounds the variability of benefits but would not be helpful in valuing future demand response operations.

An alternative approach, referred to as Option Valuation, is to view customer demand response decisions as real options and apply option pricing methods to value them. At any given time a facility operator has the option to but is not required to shift or reduce demand. It is possible then to calculate the value of a specific demand response option (e.g., curtail load, shift usage to another hour) using methodologies designed for evaluating options in equity, commodity and currency markets. A key complication in evaluating electricity market options, however, is that electricity cannot be stored.

The key inputs to establishing the option value of a demand response program are forward curves of energy prices, expressions of price volatility, and interest rates. A 2005 LBNL report demonstrated the application of option valuation to several demand response investments. The option value was greater or less depending on program cost, resource availability (e.g., frequency of operations), and strike price.[lxxxv]

This highly-generalized method has some similarities to both market modeling and dynamic IRP modeling, as it relies on forward energy price curves and reflects year-to-year stochastic variability in market conditions. Several valuation practitioners including DRRC's contractors in the earlier valuation effort have recommended pursuing option valuation as method to estimate the insurance value of demand response under stress conditions and to differentiate between demand response programs with different attributes.[lxxxvi]

3.11. System and Network Benefits of Demand Response

This is a broad category of benefits and one that is so far relatively undeveloped other than through analysis conducted pursuant to specific regulatory filings. The potential system and network benefits of Demand Response include:

- Reduced cost of ancillary services (regulation and reserves) due to participation of demand response in AS procurement;
- Improved operational flexibility, especially in accommodating intermittent generation sources, due to availability of demand response;
- Potential for demand response to reduce peak loading and thus defer or reduce the need for network expansion or transmission upgrades;
- Dampening of nodal price volatility or substation overloads

Ancillary services markets in several ISO/RTOs, including ERCOT, PJM, and ISO-NE are open or in the process of being opened to participation by Demand Response, in line with FERC orders.[lxxxvii] Demand Response has already been demonstrated to be a versatile tool for system operators, both in maintaining operational reliability and in accommodating intermittent generation resources on the grid.[lxxxviii] Demand Response has also been argued to have the potential to defer or reduce large new transmission interconnection requirements.[lxxxix] Demand Response can also be locally targeted in order to relieve area overloading or reduce nodal prices and network congestion.[xc]

The literature on quantifying system and network benefits of demand response is in a rudimentary state. Most of what is available is in the form of evaluations done by specific ISO/RTOs that have opened new markets or applications to demand response. For example, PJM's 2007 State of the Market Report reviewed the first year of performance of Demand Side Resources (DSR) providing synchronized reserves and concluded "Participation of demand response grew significantly in 2007. Not only did more participants offer DSR, but demand response was generally less expensive than other forms of synchronized reserve. In 19 percent of hours during 2007 all of the synchronized reserve cleared for the Mid-Atlantic Subzone was provided by DSR" (See Figure 15).

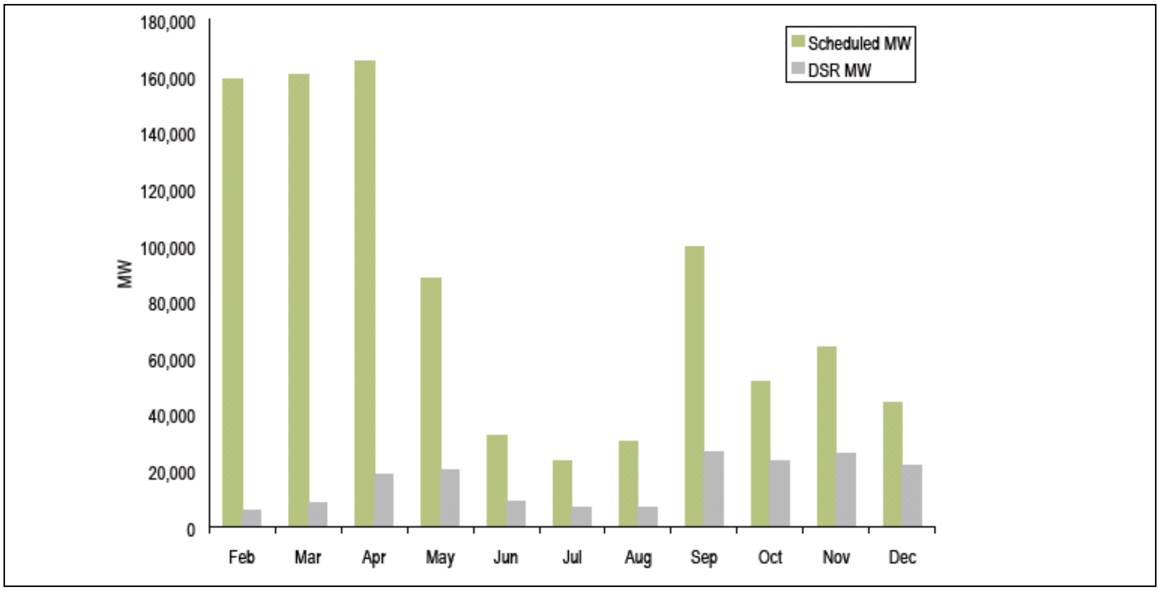

Figure 15: PJM Synchronized Reserve Scheduled MW: 2007[xci]

ERCOT is the other ISO/RTO with well-developed demand response participation in ancillary services markets. Demand response has operated effectively on a half-dozen emergency events over the past several years, but no specific documentation is available publicly regarding the quantified benefits of demand response providing regulation and reserves.[xcii]

Other work has been done on the network benefits of demand-side programs generally, but less so on the specific benefits of demand response. A recent IEA project focused on the network benefits of distributed resources, including voltage regulation, load following, active/reactive power balancing, frequency response, supplemental reserve and spinning reserve. The report observed that in a functionally unbundled power system these benefits tend to be spread across multiple stakeholders, making it more difficult to identify a single demand response sponsor whose total benefits justify the DR investment. This suggests that the most likely candidate for demand response administrator would be either a load serving entity located in a congested zone or regional entity with the ability to capture the range of network benefits and aggregate and allocate (e.g., socialize) demand response costs across the widest range of beneficiaries.[xciii]

Finally, the US DOE Consortium on Electricity Reliability and Technology Solutions (CERTS) sponsored research on demand response providing ancillary services. This review of international experience of system operators in mobilizing demand response to provide ancillary services found that the market value of demand response in this role was small (less than 10 percent) relative to the total transactions in a regional wholesale market. However, in some market designs – especially real-time or imbalance energy-only markets –ancillary services could represent the primary wholesale application for demand response.[xciv]

Care should be taken to avoid double-counting in the case of demand response deferring or reducing the need for network expansion or transmission upgrades. These potential benefits are commonly found within the avoided utility cost benefit category. For example, both the BGE and SCE customer infrastructure business cases described earlier include proportional reductions in T&D capital expenditure forecasts based on the impact of demand response on network peak demand. The benefits are clearly stated in the form of reduced revenue requirement or avoided T&D capacity costs. However, there is a potential benefit category in terms of the potential impacts of demand response on large network expansion project. The literature here is mainly in public convenience and necessity regulatory filings regarding large network expansions and in the regional transmission plans that by FERC order must include reflect DR in transmission planning and operations.[xcv] In response to the FERC order several ISO/RTOs have taken steps to better integrate DR into transmission planning, including identifying opportunities for DR to be reflected in transmission planning or operations. ISO-NE now provides an opportunity in the early stages of its planning process for "non-wires" alternatives, such as DR, to be considered in meeting all or part of a regional or zonal transmission needs.[xcvi]

PJM is in the process of implementing a new economic planning protocol that would incorporate DR into all aspects of system and market planning. According to its compliance filing in Docket No. ER06-1474, PJM will analyze the economic impacts of proposed new transmission projects to help determine the most efficient solutions to reliability issues and present the results to its Transmission Expansion Advisory Committee for approval. The CAISO is preparing similar protocols to guide its future transmission planning.[xcvii] Despite these modifications to the regional transmission planning process some intervenor groups argue that large-scale transmission expansion projects do not adequately consider the potential for demand-side programs including demand response to reduce or eliminate the capacity addition. These groups have filed testimony arguing that selective use of distributed resources could have very large benefits in terms of transmission deferrals or elimination.[xcviii] However, such filings have not gone so far as to systematically quantify the expected benefits of demand response or other distributed resources.

There is an extensive literature on the potential benefits of demand-side programs including demand response on local network planning, but relatively little literature that introduces nodal pricing into the equation.[xcix] To the extent that DR defers or reduces network additions, the benefits can be captured under a traditional avoided costing approach. The effects on nodal pricing will depend on the application and scale of demand response, and are a promising subject for future research as described in the following section.

3.12. Environmental Benefits

Potential environmental benefits cited for demand response programs include reduced local air emissions (NO_x), greenhouse gases (CO_2) and land and water impacts. These environmental benefits could result from: (i) overall net electricity savings; (ii) reduction in electricity demand during peak periods (when dirtier generators are operating); (iii) reduction in electricity demand during poor air quality events (high ozone and high electricity demand often are correlated), (iv) deferral or reduction in new capacity requirements (generation and networks); and (v) enabling the scaling-up of intermittent renewable energy generation, especially wind energy.[c] Two principle approaches may be found to estimating environmental benefits. On the one hand many of these prospective environmental benefits are suggested for consideration as discrete and distinctive DR benefits under the CPUC's R.07-01-041.[ci] On the other hand it can be argued the environmental benefits of demand response reside entirely in the avoided emission compliance cost of the generation capacity and energy that demand response replaces.

The Staff Report in R.07-01-041 suggests an expansive list of environmental impacts to be considered in cost-effectiveness evaluation of demand response: (i) residual benefits of avoiding criteria air pollutants above and beyond the level of existing environmental regulation; (ii) environmental justice, particularly for supplying electricity in urban areas; (iii) human health and safety; (iv) impacts on cultural resources; (v) diminishing visual resources (e.g., due to power plant stacks or transmission towers); (vi) land use, including impacts of energy infrastructure on local ecosystems; (vii) water quality/consumption; and (viii) noise pollution. However, the report goes on to concede that there are many environmental benefit-cost methods and many potential impacts, and "until such time as it can be determined exactly which methods to use and how to use them, any environmental benefits above the costs of complying with existing environmental regulation should not be counted in the calculation of the SPM tests."[cii] The exceptions are any specific situations where additional environmental impacts attract the attention of environmental regulators, and the monetization of greenhouse gas emissions, for which there is already clear precedent in valuation of energy efficiency programs. Accordingly, the Staff suggests case-by-case (e.g., demand response program by program) consideration of any positive or negative environmental impacts, including the special case where back-up generators may have an adverse environmental effect.

We conclude that quantifying the environmental benefits of demand response other than through emission compliance cost avoidance is another area where the literature is relatively weak.[ciii] The principle work has been estimating the reduction in air emissions during emergency operations of demand response programs in the Eastern ISO/RTOs. A key result of this work is that, although demand response can significantly reduce emission of NO_x and SO_x during declared emergencies, these reductions can be largely offset if back-up generators using diesel are a significant part of the demand reduction strategy.[civ]

One recent promising area of analysis is the environmental benefits of advanced metering and dynamic pricing, which have been shown to increase an overall awareness of energy consumption patterns and energy savings opportunities both in households and businesses.[cv] A meta-study of both TOU pricing and dynamic pricing programs which utilized advanced metering technology demonstrated that price-responsive demand response had a measurable and consistent "knock-on" effect in terms of energy conservation effect.[cvi] This conservation effect is already acknowledged in some customer infrastructure business cases and demand response cost effectiveness filings.

3.13. Customer Choice

One last category of demand response benefits are the benefits to customers. The nature of customer benefits has been described in different ways from different viewpoints. Smith and Kiesling[107] argue that retail customers should have price-responsive rate options – what they call double-sided markets - from both equity and economic efficiency viewpoints. Customers should have the *opportunity* to see electricity prices that vary from hour to hour, reflecting wholesale- market price variations, because having options "is an essential component of competitive markets and a key to improving customer well-being". Customer choices make sense from an economic efficiency viewpoint also, as it enables customers to avoid the price risk premium built into all flat retail rates and instead modify electricity usage in response to changing prices, increasing usage during low-price periods and cutting usage during high-price periods. Providing options which allow the electricity commodity price and the financial insurance premium components of the price to be unbundled and offered separately enables customers to choose how much of that price risk they are willing to bear, and how much they are willing to pay to avoid.[cvii] The principle of double-sided markets can be applied to other attributes of electric service besides price, such as reliability and level of service. Non-firm rates, for example, were an early form of a double-sided market in which customers could choose a lower commodity rate in return for a lower (non-firm) level of service quality.

One approach to quantifying customer choice in the context of dynamic pricing looks at the gains in consumer surplus when customers are exposed to marginal instead of average costs. Consumer surplus is simply the difference in the value that a customer derives from their consumption and the amount that they spent. In an average-cost world consumer surplus tends to shrink or go in relation to changes in average prices. The situation changes when time-differentiated prices are introduced, and customers have a choice of shifting as well as reducing their consumption in response to price variations. As customers make rational decisions to modify consumption based on own- and cross-price elasticity, economic efficiency will improve along with both bill savings and consumer surplus. This formulation thus introduces a new metric that can be used to measure the customer value of demand response options.[cviii]

Although well grounded in economic principles, the value of customer choice in the context of demand response and double-sided markets has not been well developed. An effort was made in the mid-1990s to introduce the Consumer Surplus concept into cost-effectiveness; these concepts and approaches may well have currency today.[cix]

3.14. Summary and Comparison

The literature review reveals the breadth of estimation methods in use.

Table 2 summarizes the conventional valuation approaches typically in common use today and the emerging methods that have promise but need further development. It is useful to categorize them in terms of how demand response is monetized.

Avoided Costing Methods, *Customer Infrastructure Business Cases*, and *Integrated Resource Planning Methods* all state the value of demand response in terms of lower utility costs, usually expressed as net present value of a lower revenue requirement.

Avoided cost methods as represented by the California SPM is the dominant benefit-cost evaluation tool in use today, but is limited in its ability to represent all DR assets and all categories of DR benefits. The strength of this approach is its relative simplicity and transparency in calculating the avoided supply costs of a DR program. There is nothing in the SPM itself that would rule out including benefits other than avoided costs, such as market impacts, reliability impacts, insurance value, or environmental impacts. In fact, there is already precedent for including "adders" that can increase (or decrease) the avoided costs of DR programs.[cx]

Customer Infrastructure Business Cases are a highly generalized approach to evaluating the present value of a long-term stream of benefits and costs associated with a utility investment.

The avoided supply costs due to demand response enabled by a customer infrastructure are usually just one part of a long list of fixed and variable cost savings from investments in AMI and similar infrastructure. These Business Cases are important because they represent an important venue for innovation in quantifying the benefits of AMI and similar infrastructure. An example is the recent AMI and demand response infrastructure business cases of BGE and Pepco, both of which include large amounts of market price benefits due to price-responsive load in amongst the other more-traditional benefit categories such as metering cost savings. Developments in business case methodology are worth tracking closely both because they are a potential "first use" of new benefit calculation methods and because this innovation could cause comparison problems for regulators.

Integrated Resource Planning Methods take a quite different methodological approach, even though the results are ultimately expressed in comparable terms, e.g. present value of revenue requirement. IRP methods consider the benefits of demand response within the context of an overall resource portfolio and a planning simulation process which considers the effects of many combinations of weather, fuel price and other forecasts on the contributions of demand response. The dynamic nature of these IRP methods captures the hedge or insurance value of demand response under a variety of conditions including "stress events". These IRP methods can thus isolate and quantify the insurance and resource adequacy value of demand response. Unfortunately IRP methods have many practical drawbacks and limitations and may not be suitable to all jurisdictions. One possible compromise might be to undertake infrequent or truncated IRP exercises to calculate certain adders – such as hedge value – which are otherwise difficult to quantify.

Studies of the *Market Price Impacts of DR* use the same with-and-without comparison methods of resource planning studies. However, a DR market impact study can take a prospective view with a longer term horizon – assuming that sufficient market and customer data is available to populate appropriate market price simulation and load response models. DR market studies do not capture avoided supply costs or reliability value but do capture the short-term and long-term direct and collateral financial benefits of curtailable loads and dynamic pricing.

Value of Reliability studies are important because they explicitly introduce the customer perspective into the valuation process. The combination of production costing analysis of Loss of Load Probability (LOLP) combined results of customer value of service studies (VOSS) allows an explicit expression of the hedging value of demand response. A key appeal of this approach is that the monetization of benefits is not dependent on an avoided cost or differential revenue requirement calculation – rather, it draws directly on the customer's contingent valuation of reliability and/or quality of service. Despite considerable promise, the literature applying customer outage costing methodologies to valuation of demand response is under-developed. The only actual applications of this approach have been in *ex post* evaluations of wholesale demand response programs operated by ISO-New England and NYISO. Developing this approach for *ex ante* valuation is a promising avenue for research.

System and Network Benefit studies spans a broad range of benefits and valuation approaches. *System benefits* could include provision of operating reserves and regulation at lower cost and lower-cost accommodation of generation intermittency (e.g., wind energy). *Network benefits* include deferral value of network capacity additions, nodal price dampening, and congestion management. Valuation of demand response in terms of system and network benefits is in its infancy. Some anecdotal evidence of lower market clearing prices for synchronized regulation as a result of demand side bids has been reported in State of the Market reports, but nothing systematic. The deferral value of demand-side resources is well-established but usually included in avoided cost or differential revenue requirement calculations. Virtually nothing exists on nodal price dampening or congestion management, suggesting another avenue for future research.

Environmental Benefit and *Customer Benefit* studies are also in a rudimentary state of development, at least in terms of their application to demand response. The existence of environmental benefits is acknowledged and listed by most analysts but is not quantified. Most analysts agree that demand response will have strategic value in mitigating poor air quality episodes, as high electricity prices, hot weather, and high ozone levels are correlated. However, systematic study of this potential benefit has not been done. The existence of customer benefits is also noted but considered intangible or assumed to be part of the participant calculus rather than an efficiency gain. There are promising avenues for development here, especially in the context of dynamic pricing and the consumer surplus resulting from unbundling the risk premium and commodity price volatility from average price retail rates.

4.0 Research Needs

The literature review suggests considerable opportunities and needs in both refining existing demand response benefits estimation methods and further develop promising new methods. This is consistent with the conclusions of the earlier US DOE report to the Congress, which recommended a voluntary and coordinated effort (by regional entities, state regulatory authorities, electric utilities, trade associations, demand response equipment manufacturers and providers, customers, environmental and public interest groups, and technical experts) to strengthen demand response analysis capabilities. The goal of such an effort would be establishing universally applicable methods and practices for quantifying the benefits of demand response.[cxi] The specific work suggested by DOE is summarized in

Table 10 and is worth considering in its entirety by DRRC, especially in a specifically California context. The balance of this section provides specific research suggestions following the organization of demand response benefits estimation approaches in

Table 2 and Chapter 4.

Table 10: US DOE Recommendations for Demand Response Valuation

1. Stakeholders should collaborate to adopt conventions and protocols for estimating the benefits of demand response and develop standardized tests that evaluate demand response program potential and performance
2. These protocols should: (1) clarify the relationships and potential overlap among categories of benefits attributed to demand response to minimize double counting, (2) quantify various types of benefits, and (3) establish qualitative or ranking indices for benefits that are too difficult to quantify.
3. Develop methods to estimate demand response impacts on wholesale electricity costs and reliability, and the benefits and savings that are passed through to retail customers
4. FERC and state regulatory agencies should work with interested ISO/RTOs, utilities, other market participants, and customer groups to examine how much demand response is needed to improve the efficiency and reliability of wholesale and retail markets.
5. Planning initiatives should be established on a regional basis to examine how demand response is characterized in supply planning models and how the benefits are quantified, with the possibility of modifying existing models or developing new tools to more accurately characterize certain types of demand response.
6. Where organized wholesale markets exist, ISO/RTOs should work with state regulators and others to incorporate the potential benefits of future demand response into regional transmission expansion plans.
7. Establish a database of existing demand response programs to: (1) document a track record of program performance with respect to reliability protection, (2) gain insight into the factors that influence performance, and (3) identify ways to use demand response most effectively to deal with reliability challenges.

4.1. Avoided Costing and the SPM

The Standard Practice Manual remains a sturdy economic analysis platform that mainly suffers from lack of updating. In fact, you could continue using the SPM platform by augmenting the avoided cost methods to capture other benefit categories and broadening the economic test perspectives to capture the additional market participants. Three areas of research to augment and update the SPM are described below:

- Develop new test perspectives and an expanded benefit-cost algebra to capture the sometimes-nuanced market position of certain stakeholders and the inclusion of new benefits (See Table 4). For example, one new economic test perspective might be the "Distributor" (or "Utility Shareholder") perspective, which might better capture the market position of an investor-owned utility which earns returns from constructing generation, transmission and distribution capacity that could be deferred or eliminated with demand response investments.[cxii] Similarly, introducing "System Operator" and "Generator" perspectives would facilitate identifying and allocating the new category of system and network benefits from demand response. Developing these new test perspectives would anticipate new financial relationships between that the existing SPM overlooks (e.g., a Distributor that also owns Generation).
- Considering and remedying certain gaps in the existing SPM that are well-documented in the literature (see Section 4.1), especially the inability of the SPM to capture increased consumer surplus due to dynamic pricing.
- Additional work on the nature of the Combustion Turbine proxy itself and how it affects Avoided Cost results.[cxiii]

4.2. Customer Infrastructure "Business Case" Approaches

We have described how customer infrastructure "business cases" have become a sort of incubator for new benefits estimation methods. This is both an opportunity for the valuation researcher and a potential problem for regulators trying to maintain some standardization. A research program centered on demand response valuation would comprehensively review recent customer infrastructure business cases to identify new innovations and also seek to establish some basic protocols for treating the demand response aspect of the benefit-cost analysis. Only three AMI business cases were reviewed here, but this small cross-section showed considerable variations in method and results. Such an effort could be undertaken collaboratively with the several organizations that actively track and facilitate the scaling-up of advanced customer infrastructure (e.g., Edison Electric Institute, Demand Response and Advanced Metering Coalition, Peak Load Management Association). Such a research effort would be very consistent with the USDOE's recommendations.

4.3. IRP Modeling Approaches

We have seen that IRP modeling efforts and avoided costing methods both focus on the resource procurement benefits and utility cost savings from demand response. IRP modeling in fact has advantages over avoided costing methods in that it can isolate the insurance or hedge value of demand response. Although theoretically appealing, IRP modeling has certain (fatal) flaws, especially in regions where there is not a well-developed capacity and inclination towards data sharing and long-term planning cooperation. Since it is unlikely that IRP modeling approaches such as those in use in the Pacific NW would find traction in California, no research is suggested.

4.4. Market Modeling

There is wide body of evidence showing that demand response lowers wholesale energy prices in the short-term and capacity contract prices in the medium and long term. These price impacts provide tangible financial benefits to all electricity consumers, with or without organized wholesale markets. Autonomous price response from retail customers taking service on day-ahead hourly or critical peak rates should be even more effective. Any analysis of DR that does not include these market price benefits will underestimate the benefits of DR.

As described previously, considerable progress has been made in developing the market modeling methods required to estimate the short- and long-term market price benefits of demand response. However, these efforts have so far been restricted to regions with organized wholesale markets. In California, no estimate of the market benefits of demand side programs has been made since the analytic work commissioned during R. 04-04-025.[cxiv]

Estimating market benefits is a big job, requiring an economic supply model of the wholesale power market. Partly because of the lack of an organized market in California since the demise of the PX, and partly because most data on power costs is contained in confidential bilateral contracts, very little work has been done on this topic.[cxv] However, the feasibility of developing market benefits estimation methods in the California context is one of the key issues still under discussion in the CPUC's demand response cost-effectiveness proceeding.[cxvi]

In this context a scoping study on the feasibility of constructing a market simulation of the effects of dynamic pricing for price-responsive customers in California would be timely and relevant. The scoping study would consider the practicality and requirements to develop a power supply model which anticipates the MRTU but uses historical market data to predict the impacts of demand response programs and rates. Possible research approaches include simulating California market conditions using tools such as the Dayzer curve or developing an Option Value formulation for DR using power market data from Platts or other comparable sources.

4.5. Reliability Value and Value of Service Studies

The value of DR in preventing brownouts and black-outs during emergencies is well established.[cxvii] However, this value is not captured in current avoided costing methods, which cap the benefits of demand response as the long—run avoided costs of a generator. A full IRP modeling effort can effectively bracket the value of DR in reducing the price or outage risk of a given resource plan, but these are very expensive and time consuming to perform. Some system operators have attempted to calculate the reliability benefits of demand response on an *ex post* basis, by estimating the reduction in outage possibilities as a result of dispatching demand response programs and combining it with available data on customer value of service.

This reliability valuation gap represents a big opportunity for research, and there are several promising avenues deserving of research support by the DRRC. These include:

- Valuing operating reserves as a public good.[cxviii] While energy consumed is clearly a private good, providing sufficient reserves to maintain reliability for all can be interpreted as a public good. The social value of a load reduction in the case of a market disequilibrium resulting from lack of capacity would reflect the collective value of the expected outage costs for all potentially-affected end-users. This value may bear little relationship to market prices that reflect "normal" conditions.

- Option value of demand response assets.[cxix] This approach is suggested as a more accurate representation of the direct financial benefits for an end-user with demand flexibility. Other approaches that use a long-term forecast of future prices or incorporate historical price variability will not account for the stochastic variability and fundamental uncertainty of future prices in uncertain market conditions. The approach is very similar to that used by traders valuing commodity options in future markets.
- Insurance value of DR. Several analysts have described the potential of DR as a hedge against price volatility or capacity shortfalls. There are several approaches which are worthy of further study, including the development of reliability value based on outage costs and effect of DR reserves on LOLP or direct estimates of portfolio hedge value using customer value of service data to construct value of lost load (VOLL) variation in portfolios with and without DR.[cxx]

4.6. System and Network Benefits of Demand Response

Demand response has been associated with a variety of system and network benefits, including reduced ancillary services (regulation and reserves) costs, improved operational flexibility, especially in accommodating intermittent generation sources, deferral of network capacity additions, dampening nodal price volatility, network asset protection, and line loss reduction. Some very specific system and network benefits came to light during interviews with respondents in R.07-01-041, such as preventing substation overloads and secondary transformer failures, reducing reliability must run (RMR) requirements, and reducing ancillary services bid insufficiency. This long list of system and network benefits suggests a separate scoping study to identify, further illustrate, and characterize these potential benefits. Referring to Figure 16, this research component would focus on network and system benefits of DR for both the system operator and the distribution company.

	Nodal Level	System
Operator Benefits		Reducing RMR dispatch Accomodating intermittent generation Ancillary services bid insufficiency
Network Benefits	Alleviating network overloads Network asset protection Reducing nodal prices	Deferring network investment Reducing line losses Alleviating transmission congestion

Figure 16: Distribution of DR Benefits

Demand response has been proven to be an effective source of reliability services in other jurisdictions. Both ERCOT and PJM have adopted business rules that do not differentiate between supply and demand resources in the economical provision of both reserves and regulation.[cxxi] The CAISO is working with SCE and CERTS to demonstrate the use of residential air conditioner direct load control to provide spinning reserves.[cxxii] As part of the Post Release 1

MRTU activities CAISO has developed a proposal for Reserve Scarcity Pricing, which anticipates a significant role for DR in providing operating reserves during high-price conditions.[cxxiii] DRRC should support efforts to increase the participation of loads in providing reliability services, especially in California, by documenting best practice (including targeting certain types of loads, developing workable telemetry systems, and developing business rules that overcome barriers to equivalent treatment of generators and loads) suitable to adoption by CAISO.

In the strictly California context there is a major research opportunity for DRRC in capturing the additional benefits of demand response in the context of the Release 1 MRTU. CAISO is required as part of the roll-out to consider how to better integrate demand response into the operations of the California wholesale markets.[cxxiv] Although Release 1 creates only limited space for demand response (only "Participating Loads" with extensive telemetry are allowed to bid into day-ahead and real-time markets), administrative procedures have been proposed providing additional opportunities for demand resource providers.[cxxv] Possible new value propositions for demand response include: (i) providing CAISO the opportunity to adjust day-ahead Residual Unit Commitments (RUC) to reflect demand response availability; and (ii) modifying short-term unit commitments as a result of adjustments in the CAISO Forecast of CAISO Demand (CFCD) due to day-of demand response

DRRC should work closely with CAISO to identify and undertake research supporting the inclusion of demand response in the new day-ahead and real-time energy markets. Possible collaborative CAISO-DRRC research projects would include:

- Developing empirical frameworks for estimating the direct and collateral financial benefits of Non-Participating Loads that are aggregated by Demand Response Providers and submitted into the Day-Ahead and Real-Time market (this would support CAISO's ability to reflect DR in its compliance reports to FERC);
- Evaluating the effect of demand response submitted into the Day-Ahead market on RUC requirements;
- Linking Resource Adequacy and Market Participation requirements
- Examining the benefits of retail dynamic pricing vs. bid-in demand response in reducing RUC requirements and lowering real-time prices

4.7. Environmental Valuation

As described above this value proposition is often referred to but seldom quantified, other than by reference to the emissions compliance costs component of avoided generation. In fact more work has been done on the potential environmental costs of demand response, due to use of back-up generators to enable customer load reduction, then on non-emissions-compliance-related environmental valuation. We suggest an environmental valuation research agenda that follows the Staff Recommendation in R.07-01-041: be on the look-out for case-by-case opportunities where a demand response program or its application may have a particular or leveraged environmental benefit. One example of this would be to build on earlier work done for the USEPA regarding the strategic value of demand response in mitigating poor air quality episodes due to the high correlation of high electricity prices, hot weather, and high ozone levels.

4.8. Customer Value

This is an overlooked but potentially very significant value proposition, especially for dynamic pricing retail rate options. As with many other benefits categories, the value of customer choice or consumer surplus value of unbundling rate premiums for time-differentiated commodity prices is often cited but seldom quantified. Accordingly there is considerable scope for path-breaking valuation research in this area for DRRC to undertake. One early research project would be to revisit the several improvements to the SPM proposed in the mid-1990s by Braithwaite, Herman and others and more recently by Faruqui.

Glossary

ACR	Assigned Commissioner and ALJ Ruling.
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
AS	Ancillary Services
BGE	Baltimore Gas and Electric
BRA	Base Residual Auctions
CAISO	California Independent System Operator
CCGT	Combined Cycle Gas Turbine
CEC	California Energy Commission
CEE	Cost Effectiveness Evaluation
CERTS	Consortium on Electricity Reliability and Technology Solutions
CES	Cambridge Energy Solutions
CFCD	CAISO Forecast of CAISO Demand
CLECA	California Large Energy Consumers Association
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission
CT	Combustion Turbine
DADRP	Day Ahead Demand Response Program
DADS	Day Ahead Default Service
DALRP	Day Ahead Load Response Program
DAM	Day Ahead Market
DOE	Department of Energy
DR	Demand Response
DRCEEFP	Demand Response Cost-Effectiveness Evaluation Framework Proposal
DRI	Demand Response Initiatives
DRR	Differential Revenue Requirement
DRRC	Demand Response Research Center
DSM	Demand Side Management
DSR	Demand Side Resources
ED	Energy Division
EDRP	Emergency Demand Response Program
EMS	Energy Management System
EPA	Environmental Protection Agency
EPACT	Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
GAO	Government Accounting Office
GHG	Greenhouse Gas
ICAP	Installed Capacity Market
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IRP	Integrated Resource Planning

ISO	Independent System Operator
ISO NE	Independent System Operator New England
kW	Kilowatt
LMP	Locational Marginal Prices
LOLP	Loss of Load Probability
LSE	Load Serving Entity
MADRI	Mid-Atlantic Distributed Resources Initiative
MISO	Midwest Independent System Operator
MPSC	Maryland Public Service Commission
MRTU	Market Redesign and Technology Update
MW	Megawatt
NMPC	Niagara Mohawk Power Company
NPV	Net Present Value
NYISO	New York Independent System Operator
O&M	Operating and Maintenance
OECD	Organization for Economic Co-operation and Development
PAC	Program Administrator Test
PCT	Programmable Communicating Thermostat
PECO	Philadelphia Electric and Gas Company
PEPCO	Potomac Electric Power Company
PG&E	Pacific Gas and Electric
PHI	Pepco Holdings, Incorporated
PIER	Public Interest Energy Research
PJM	Pennsylvania, Jersey, Maryland Power Pool
PSEG	Public Service Electric and Gas
PURPA	Public Utility Regulatory Policy Act
RECC	Real Economic Carrying Cost
RIM	Ratepayer Impact Measure
RMR	Reliability Must Run
RPM	Reliability Pricing Model
RS	Reliability Services
RTO	Regional Transmission Organization
RTP	Real Time Pricing
RUC	Residual Unit Commitment
SCE	Southern California Edison
SPM	Standard Practice Manual
T&D	Transmission and Distribution
TOU	Time of Use
TRC	Total Resource Cost
VOLL	Value of Lost Load
VOSS	Value of Service Study
VRR	Variable Resource Requirement

Appendix A. DR Benefit Categories

Table 3-2. Benefits of Demand Response

Type of Benefit	Recipient(s)	Benefit		Description/ Source
Direct benefits	Customers undertaking demand response actions	Financial benefits		• Bill savings • Incentive payments (incentive-based demand response)
		Reliability benefits		• Reduced exposure to forced outages • Opportunity to assist in reducing risk of system outages
Collateral benefits	Some or all consumers	Market impacts	Short-term	• Cost-effectively reduced marginal costs/prices during events • Cascading impacts on short-term capacity requirements and LSE contract prices
			Long-term	• Avoided (or deferred) capacity costs • Avoided (or deferred) T&D infrastructure upgrades • Reduced need for market interventions (e.g., price caps) through restrained market power
		Reliability benefits		• Reduced likelihood and consequences of forced outages • Diversified resources available to maintain system reliability
Other benefits	• Some or all consumers • ISO/RTO • LSE	More robust retail markets		• Market-based options provide opportunities for innovation in competitive retail markets
		Improved choice		• Customers and LSE can choose desired degree of hedging • Options for customers to manage their electricity costs, even where retail competition is prohibited
		Market performance benefits		• Elastic demand reduces capacity for market power • Prospective demand response deters market power
		Possible environmental benefits		• Reduced emissions in systems with high-polluting peaking plants
		Energy independence/ security		• Local resources within states or regions reduce dependence on outside supply

Source: U.S. DOE

Table 1. Potential Benefits of Demand Response

Benefit Category	Value Factors	Basis for Valuation	Range of Values
Market-wide	• Overall economic efficiency (better alignment of supply and demand) • Reduction in average price of electricity in the spot market • Reduced costs of electricity in bilateral transactions • Reduced hedging costs, e.g., reduced cost of financial options • Reduced market power • Private entity (e.g. aggregator) benefits	Not Quantified	Not Applicable
Utility System	• Avoided capacity costs (generation) • Avoided energy costs • Avoided T&D losses • Deferred grid system expansion	Benchmarking (peaker unit) Benchmarking (market prices) Adders Marginal (local) T&D costs	\$50-\$85 Variable 6%-10% Variable
Customer	• Incentives • Reduced power bill (participants) • Greater choice and flexibility	Value of payment Rates, demand charges Cash-flow, Option model	Variable Variable Variable
Reliability Benefits	• Increase in overall system reliability • Value of insurance against low-probability/high-consequence events • Option value (added flexibility to address future events) • Portfolio benefits (increase in resource diversity)	Change in LOLP Value of un-served energy (customer outage costs) Not Quantified Not Quantified	Not Available \$3-\$5 per kWh Not Applicable Not Applicable
Environmental Benefits	• Avoided emissions • Avoided future carbon taxes	Environmental "adder" Not Quantified	8%-12% Not Applicable

Source: Quantec

1. Direct Financial
DF1. Incentive payments to participating customer.
DF2. Bill reductions from customer load usage reductions or shifts in use.
DF3. Incentive payments to load aggregator or distribution company.
2. Pricing
P1. Wholesale market price reduction – short term spot and long term as supply adjusts.
P2. Reduced price volatility & hedging costs.
P3. Reduced market interventions.
P4. Deterred market power (as compared to "reduced market power" shown below).
3. Risk management and Reliability
RM1. Physical hedge against extreme events – system or market.
RM2. Lower "insurance costs" for market participants against extreme events.
RM3. "Real Options" due to the increased resource diversity and a larger set of options for meeting loads both ongoing and in emergency situations.
RM4. Lower cost ancillary services to meet reliability criteria
RM5. Ability of market participants to manage their ongoing financial risks
4. Market Efficiency Impacts
E1. Equitable pricing.
E2. Incentive for innovative competitive retail markets.
E3. Incentive for development of efficient controls and end-use technologies.
E4. Reduced market power.
E5. Overall productivity gains by better utilizing industry investment.
5. Lower Cost Electric System & Service
ES1. Reduced short-term capacity requirements.
ES2. Lowered transmission capital & operating expense.
ES3. Lowered distribution capital & operating expense.
ES4. Decreased or shifted generating costs.
ES5. Reduction in LSE commodity costs.
ES6. Reduction in long-term resource adequacy requirements.
6. Customer Services
CS1. Increase in customer choice.
CS2. Possible increase in services.
7. Environmental
EN1. Potential avoided land-use, water, and air impacts.

Source: Summit Blue Consulting

[i] "Towards a New Paradigm for Valuing Demand Response", R. Earle and A. Faruqui", **The Electricity Journal**, May 2006. v. 19. # 4. Downloadable at: http://www.puc.state.nh.us/Electric/06-061/epact%20articles/EJ%20Toward%20a%20New%20Paradigm%20for%20Valuing%20Demand%20Response.pdf

[ii] *The State of Demand Response in California*, prepared by The Brattle Group for the CEC, April 2007 (http://www.fypower.org/pdf/CEC-200-2007-003-D.PDF)

[iii] "Towards a New Paradigm for Valuing Demand Response", R. Earle and A. Faruqui", **The Electricity Journal**, May 2006. v. 19. # 4. Downloadable at: http://www.puc.state.nh.us/Electric/06-061/epact%20articles/EJ%20Toward%20a%20New%20Paradigm%20for%20Valuing%20Demand%20Response.pdf

[iv] *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them* – A Report to the U.S. Congress pursuant to Section 1252 of the Energy Policy Act of 2005, prepared by the U.S. Department of Energy, Feb. 2006 (http://eetd.lbl.gov/EA/emp/reports/congress-1252d.pdf)

[v] *The State of Demand Response in California*, prepared by The Brattle Group for the CEC, April 2007 (http://www.fypower.org/pdf/CEC-200-2007-003-D.PDF)

[vi] These ISO/RTOs report these estimated social welfare benefits to the FERC as part of their annual "State of the Market" filings. See for example NYISO *2004 Demand Response Program Evaluation*, Presented at PRLWG, January 4, 2005, Neenan Associates.

[vii] OIR.07-01-041, Order Instituting Rulemaking Regarding Polices and Protocols for Demand Response Load Impact Estimates, Cost Effectiveness Methodologies, Megawatt Goals and Alignment with California Independent System Operator Market Design Protocols. (http://docs.cpuc.ca.gov/published/proceedings/R0701041.htm).

[viii] These market price benefits are derived from *Quantifying Demand Response Benefits in PJM*, prepared by The Brattle Group for PJM and the Mid-Atlantic Demand Response Initiative in January 2007. See: http://www.energetics.com/madri/pdfs/BrattleGroupReport.pdf

[ix] The FERC has been proactive in eliminating barriers and ensuring entry points for DR in, for example, transmission planning and ancillary services markets (See: 2007 Assessment of Demand Response and Advanced Metering - Staff Report, Federal Energy Regulatory Commission, September 2007 (http://www.ferc.gov/legal/staff-reports/09-07-demand-response.pdf

[x] See: *Development of a Comprehensive / Integrated DR Value Framework*, Dr. Daniel M. Violette, Summit Blue Consulting, LBNL-60130, March 2006 and Phase 1 Results: Establish the Value of Demand Response, Orans, Ren et al., Energy and Environmental Economics, Inc., LBNL-60128, April 2006.

[xi] In addition to the 2006 USDOE study other useful benefit typologies may be found in *Final Report - Demand Response Proxy Supply Curves*, Prepared for PacifiCorp by Quantec, LLC, September 8, 2006 and DRR Valuation and Market Analysis – Volume II: Assessing the DRR Benefits and Costs, prepared for the IEA DSM Program Task XIII by Dan Violette, January 6, 2006 (http://62.121.14.21/Files/Tasks/Task%20XIII%20-%20Demand%20Response%20Resources/DR%20Valuation%20Reports/Vol%20II%20Final%20-%20DRR%20Valuation%20Market%20Analysis%20Volume%20II%20Rev(2).pdf)

[xii] Public Law 109-58, August 8, 2005

[xiii] "Recognizing the Importance of Demand Response: The Second Half of the Wholesale Electric Market Equation", **Energy Law Journal Volume 28, No. 2** (2007), Hon. Jon Wellinghoff and David L. Morenoff

[xiv] 2005 CEC Integrated Energy Policy Report. (EAP2)

[xv] *ELECTRICITY MARKETS: Consumers Could Benefit from Demand Programs, but Challenges Remain*. Report to the Chairman, Committee on Governmental Affairs, U.S. Senate, August 2004. GAO-04-844. http://www.gao.gov/new.items/d04844.pdf

[xvi] The Choice Not to Buy: Energy Savings and Policy Alternatives for Demand Response, Braithwait and Faruqui, **Public Utility Fortnightly,** March 15, 2001.

[xvii] Demand Response: Principles for Regulatory Guidance, prepared by Peak Load Management Alliance, February 2002. Downloadable at: http://www.peaklma.com/files/public/PLMAPrinciples.pdf

[xviii] "Revealing the Value of Demand Response: Regulatory and Market Options", EPRI Demand Response Workshop. Presented by Richard Cowart of the Regulatory Assistance Project, October 29, 2003. Downloadable at: http://www.raponline.org/Slides/EPRI-DRWorkshop10-03(07)-RegOpps(RC).pdf

[xix] DRR Valuation and Market Analysis – Task Status Report, Prepared for the International Energy Agency DSM Program Task XIII on Demand Response Resources by Dan Violette, January 2006 (http://62.121.14.21/Files/Tasks/Task%20XIII%20-%20Demand%20Response%20Resources/DR%20Valuation%20Reports/Vol%20I%20Final%20-%20DRR%20Valuation%20Market%20Analysis%20Volume%20I%20Rev(2).pdf)

[xx] Demand Response Proxy Supply Curves – Final Report, prepared for PacifiCorp by Hossein Haeri and Lauren Miller Gage of Quantec, LLC, September 8, 2006. Downloadable at: http://www.nwcouncil.org/energy/dr/meetings/2007_07/Quantec-DRProxyCurve-FinalReport_090806.pdf

[xxi] Assessment of Demand Response and Advanced Metering, FERC Staff Report, Docket No. AD-06-2000, August 2006. Downloadable at: http://ferc.gov/legal/staff-reports/demand-response.pdf

[xxii] ISO-NE Electricity Costs White Paper, June 1, 2006. http://www.iso-ne.com/pubs/whtpprs/elec_costs_wht_ppr.pdf.

[xxiii] Quantifying Demand Response Benefits in PJM, Prepared by The Brattle Group, Prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI), Jan. 29 2007. Downloadable at: http://www.energetics.com/madri/pdfs/BrattleGroupReport.pdf

[xxiv] "Optimizing Demand Response: A comprehensive DR business case quantifies a full range of concurrent benefits", **Public Utilities Fortnightly** May 2008 (http://www.ferc.gov/EventCalendar/Files/20080521081541-Woychik%20Attachment,%20Comverge.pdf)

[xxv] *Primer on Demand-Side Management with an emphasis on price-responsive programs*, prepared for The World Bank by Charles River Associates, February 2005 (http://siteresources.worldbank.org/INTENERGY/Resources/PrimeronDemand-SideManagement.pdf)

[xxvi] *Demand Response Proxy Supply Curves – Final Report*, prepared for PacifiCorp by Hossein Haeri and Lauren Miller Gage of Quantec, LLC, September 8, 2006. Downloadable at: http://www.nwcouncil.org/energy/dr/meetings/2007_07/Quantec-DRProxyCurve-FinalReport_090806.pdf

[xxvii] For a good overview of AMI Infrastructure and its benefits see: *Deciding on "Smart" Meters: The Technology Implications of Section 1252 of the Energy Policy Act Of 2005*, prepared for: Edison Electric Institute by: Plexus Research, Inc., September 2006 (http://www.eei.org/industry_issues/electricity_policy/federal_legislation/deciding_on_smart_meters.pdf)

[xxviii] However, all stakeholders did recognize the potential existence of network-related (T&D) benefits and environmental benefits.

[xxix] "The Long-Run Efficiency of Real-Time Pricing", Severin Borenstein, **The Energy Journal** 26(3):96-116, 2005 (http://repositories.cdlib.org/cgi/viewcontent.cgi?article=1036&context=ucei/csem)

[xxx] California Standard Practice Manual for Economic Analysis of Demand-Side Management Programs and Projects, CPUC, October 2001 (http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF)

[xxxi] The Fifth Northwest Electric Power and Conservation Plan, prepared by the Northwest Power and Conservation Council, Council Document 2005-07. (http://www.nwcouncil.org/energy/powerplan/plan/Default.htm)

[xxxii] Edison SMARTCONNECT™ Deployment Funding and Cost Recovery, Exhibit 3, submitted to the CPUC July 31, 2007. (http://www.energetics.com/madri/toolbox/pdfs/business_cases/sce_financial_assess_cba.pdf)

[xxxiii] Quantifying Demand Response Benefits in PJM, Prepared by The Brattle Group, Prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI), Jan. 29 2007. (http://www.energetics.com/madri/pdfs/BrattleGroupReport.pdf)

[xxxiv] *How and Why Customers Respond to Electricity Price Variability: A Study of NYISO and NYSERDA 2002 PRL Program Performance*, prepared for NYISO and NYSERDA by Neenan Associates, Lawrence Berkeley National Laboratory and Pacific Northwest National Laboratory, January 2003. (http://certs.lbl.gov/certs-load-pubs.html)

[xxxv] Option Value of Electricity Demand Response, Osman Sezgen, Charles Goldman, P. Krishnarao Environmental Energy Technologies Division October 2005. (http://eetd.lbl.gov/EA/EMP/reports/56170.pdf)

[xxxvi] ISO New England's "Strawman" Proposal for Regional Transmission Planning, filed pursuant to FERC's Order 890 Final Rule, May 29, 2007. (http://www.iso-ne.com/trans/rsp/2007/order_890_planning_strawman.pdf)

[xxxvii] Modeling Demand Response and Air Emissions in New England Prepared by Synapse Energy Economics for U.S. EPA, September 4, 2003 (http://www.raponline.org/pubs/nedri/synapse-report-epa-ne-dr.pdf)

[xxxviii] "Towards a New Paradigm for Valuing Demand Response", R. Earle and A. Faruqui", **The Electricity Journal**, May 2006. v. 19. # 4. Downloadable at: http://www.puc.state.nh.us/Electric/06-061/epact%20articles/EJ%20Toward%20a%20New%20Paradigm%20for%20Valuing%20Demand%20Response.pdf

[xxxix] *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them:* A Report to the U.S. Congress pursuant to Section 1252 of the Energy Policy Act of 2005, prepared by US DOE, February 2006. Downloadable at: http://www.oe.energy.gov/DocumentsandMedia/congress_1252d.pdf

[xl] The same effect can be illustrated using a single slightly elastic demand curve. It makes no difference in illustrating the example whether the demand response is price-induced or curtailed under contract

[xli] From: Quantifying Demand Response Benefits in PJM, Prepared by The Brattle Group, Prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI), Jan. 29 2007. (http://www.energetics.com/madri/pdfs/BrattleGroupReport.pdf)

[xlii] In economic terms a benefit captured by one market participant that is offset by an equal cost to another market participant is a transfer payment. Therefore, it is critical when analyzing the benefits of DR to clearly state from which market participant perspective the transaction is being viewed.

[xliii] As modified from: *Primer on Demand-Side Management With an emphasis on price-responsive programs*, prepared for The World Bank by Charles River Associates, February 2005 (http://siteresources.worldbank.org/INTENERGY/Resources/PrimeronDemand-SideManagement.pdf)

[xliv] See for example: Edison SMARTCONNECT™ Deployment Funding and Cost Recovery, Exhibit 3, submitted to the CPUC July 31, 2007. (http://www.energetics.com/madri/toolbox/pdfs/business_cases/sce_financial_assess_cba.pdf)

[xlv] *Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs*, prepared by The Brattle Group for Pepco Holdings, Inc, September 21 2007.

[xlvi] Table 4 does not include a Total Resource or Societal Cost column; however, per the SPM this economic perspective is simply the sum of all the other perspectives.

[xlvii] *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them:* A Report to the U.S. Congress pursuant to Section 1252 of the Energy Policy Act of 2005, prepared by US DOE, February 2006 (http://eetd.lbl.gov/EA/emp/reports/congress-1252d.pdf) and *IEA DSM Task XIII Project Guidebook,* Chapter 5 – DR Valuation, prepared for the International Energy Agency Demand-Side Program Task XIII on Demand Response Resources by Daniel M. Violette, Rachel Freeman and Chris Neil of Summit Blue Consulting, November 2005. (http://dsm.iea.org/ViewTask.aspx?ID=17&Task=13&Sort=1#ancPublications3)

[xlviii] "Towards a New Paradigm for Valuing Demand Response", R. Earle and A. Faruqui", **The Electricity Journal**, May 2006. v. 19. # 4. Downloadable at: http://www.puc.state.nh.us/Electric/06-061/epact%20articles/EJ%20Toward%20a%20New%20Paradigm%20for%20Valuing%20Demand%20Response.pdf

[xlix] For a recent example outside California see: New Jersey Central Air Conditioner Cycling Program Assessment, prepared by Summit Blue Consulting, June 4 2007, filed under Docket EO 06040297 (May 2006) of the New Jersey Board of Public Utilities.

[l] *Primer on Demand-Side Management*, prepared for The World Bank by Charles River Associates, February 2005. Downloadable at: http://siteresources.worldbank.org/INTENERGY/Resources/PrimeronDemand-SideManagement.pdf

[li] Assigned Commissioner and ALJ Scoping Memo and Ruling (ACR) in R. 07-01-041, April 18 2007(http://docs.cpuc.ca.gov/efile/RULC/66952.pdf); Staff Guidance for Straw Proposals on Load Impact Estimation and Cost-Effectiveness Methods for DR (http://docs.cpuc.ca.gov/efile/RULINGS/68298.pdf)

[lii] Straw Proposals for Load Impact Estimation and Cost Effectiveness Evaluation of Southern California Edison Company, San Diego Gas & Electric Company, and Pactific Gas & Electric Company Pursuant to the Assigned Commissioner and Administrative Law Judge's Scoping Memo and Ruling dated April 18, 2007. http://www.naesb.org/pdf2/dsmee072607w3.pdf

[liii] Joint Comments of CLECA, Comverge, DRA, EnergyConnect, Enernoc, Ice Energy, PG&E, SDG&E, SCE, and TURN Recommending a Demand Response Cost Effectiveness Evaluation Framework, November 19, 2007 (Downloadable at: http://docs.cpuc.ca.gov/efile/CM/75556.pdf)

[liv] Draft Demand Response Cost Effectiveness Protocols, prepared by the Energy Division of the CPUC, filed April 4 2008 under R. 07-01-041

[lv] CPUC Rulemaking 02-06-001

[lvi] *Draft Report - Recommended Framework for the Business Case Analysis of Advanced Metering Infrastructure (R.02-06-001),* prepared by Moises Chavez (CPUC) and Mike Messenger (CEC), April 14, 2004. http://www.energetics.com/madri/toolbox/pdfs/business_cases/framework.pdf

[lvii] Edison SMARTCONNECT Deployment Funding and Cost Recovery, Volume 4: Demand Response, submitted to the California Public Utilities Commission, July 31, 2007. http://www.energetics.com/madri/toolbox/pdfs/business_cases/sce_vol4_dr.pdf

[lviii] BGE's load duration curve is very steep, with only 43 hours (0.5% of all hours) accounting for 10% of unrestricted peak demand

[lix] Baltimore Gas and Electric Company - Supplement 392 to P.S.C. Md. E-6, Case No. 9111, January 23, 2007. http://webapp.psc.state.md.us/intranet/casenum/submit.cfm?DirPath=C:\Casenum\9100-9199\9111\Item_1\&CaseN=9111\Item_1

[lx] Increasing the amount of resources that clear in any given RPM auction will reduce the price of capacity, as long as the amount of resources that clear falls within a reserve margin band of 12% and 20%. This is because the incremental capacity cost reduction is given by the variable resource requirement (VRR) curve used in the RPM auctions, which is flat at reserve margins below 12% (changes in resources cleared will have no impact on the clearing price) and vertical at a 20% (no value to additional capacity) with a segmented linear slope for the Southwest MAAC of -$0.14/MWDay between 12 and 16% and -$0.22/MWDay between 16 and 20%.

[lxi] Assumed the program operated for the top five contiguous hours over twelve days when, based actual 2006 values, the average location marginal price (LMP) was $325/MWh. The average DRI load reduction is 1.07 kW based on BGE pilots and energy benefits are net of the 25% "shared savings" with participants.

[lxii] The value of energy price mitigation was derived from The Brattle Group's report entitled "Quantifying Demand Response Benefits in PJM" (January 29, 2007), with total benefits for Maryland customers in allocated to BGE's residential customers on a load ratio basis, and unitized on a per-kW of DR basis.

[lxiii] Estimated using replacement costs for the transmission import and distribution substation infrastructure prorated on a per-MW of peak demand, a LCC of 12 % and reduced to reflect the life spans of T&D assets vs. the DRI asset.

[lxiv] Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs, prepared by The Brattle Group for Pepco Holdings, Inc, September 21 2007.

[lxv] Quantifying the Benefits Of Dynamic Pricing In the Mass Market. Prepared by: Ahmad Faruqui, Ph.D. and Lisa Wood, Ph.D., The Brattle Group, Prepared for: Edison Electric Institute, January 2008

[lxvi] Values are in present value terms for a 30 year investment life except for Pepco, which is 15 years

[lxvii] Quantified at $15 million annually but not included in savings calculations

[lxviii] *The Fifth Northwest Electric Power and Conservation Plan*, prepared by the Northwest Power and Conservation Council, Council Document 2005-07. Downloadable at: http://www.nwcouncil.org/energy/powerplan/plan/Default.htm

[lxix] Risk is a probability-weighted measurement of the bad outcomes from the distribution of all outcomes associated with a given plan when analyzed against all future scenarios. The Fifth Power Plan adopted a risk measure called TailVaR90, which is the average value for the worst 10 percent of outcomes.

[lxx] Section 7 – Portfolio Analysis and Recommended Plan, Fifth PNW Planning Council

[lxxi] The Power of Five Percent: How Dynamic Pricing Can Save $35 Billion in Electricity Costs, Brattle Group Discussion Paper, May 16 2007 (http://webapp.psc.state.md.us/Intranet/CaseNum/NewIndex3_VOpenFile.cfm?filepath=%5C%5CColdfusion%5CEWorkingGroups%5CDRDG%5C%5CGeneral%20Documents%5CBrattle%20Power%20of%205%20Percent%20Discussion%20Paper.pdf)

[lxxii] MADRI seeks to identify and remedy retail barriers to the deployment of distributed generation, demand response and energy efficiency in the Mid-Atlantic region. MADRI was established in 2004 by the public utility commissions of Delaware, District of Columbia, Maryland, New Jersey and Pennsylvania, along with the U.S. Department of Energy (DOE), U.S. Environmental Protection Agency (EPA), Federal Energy Regulatory Commission (FERC) and PJM

[lxxiii] BG&E, Delmarva, PECO, PSEG, and PEPCO

[lxxiv] The High Peak and Low Peak cases were constructed from the Normalized case by inflating or deflating load to reflect one-in-twenty-year conditions. Twenty-year conditions were determined by comparing actual peaks to weather-normalized peaks for each year from 1984 to 2004.

[lxxv] *Quantifying Demand Response Benefits in PJM*, Prepared by The Brattle Group, Prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI), Jan. 29 2007. Downloadable at: http://www.energetics.com/madri/pdfs/BrattleGroupReport.pdf

[lxxvi] *Improving Linkages Between Wholesale and Retail Markets Through Dynamic Retail Pricing*, Prepared by B. Neenan, P. Cappers, D. Pratt, J. Anderson (Neenan Associates) for ISO New England Inc. December 5, 2005. Downloadable at: http://www.iso-ne.com/genrtion_resrcs/dr/rpts/improving_linkages_12-05-2005.pdf

[lxxvii] Source of CT costs: PG&E Response to ALJ July 16 2008 Ruling in R.07-01-041, July 30 2008

[lxxviii] The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response, prepared by the Energy Analysis Department of LBNL, May 2007 (http://eetd.lbl.gov/ea/EMS/EMS_pubs.html)

[lxxix] *How and Why Customers Respond to Electricity Price Variability: A Study of NYISO and NYSERDA 2002 PRL Program Performance*, prepared for NYISO and NYSERDA by Neenan Associates, Lawrence Berkeley National Laboratory and Pacific Northwest National Laboratory, January 2003. Downloadable at: http://certs.lbl.gov/certs-load-pubs.html

[lxxx] For the ISO New England results see: An Evaluation of the Performance of the Demand Response Programs Implemented by ISO-NE in 2005. Prepared for: ISO New England Inc. by: RLW Analytics, LLC and Neenan Associates, LLC, December 30, 2005. Downloadable at:

[lxxxi] Hedging benefits reflect the longer run impacts of lower price variance resulting from program curtailments. They will vary in proportion to market price volatility.

[lxxxii] NYISO December 2002 Semi-Annual Demand Response Report to FERC (http://www.nyiso.com/public/products/demand_response/index.jsp)

[lxxxiii] *A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys*, Prepared for the U.S. Department of Energy by Population Research Systems, LLC and Lawrence Berkeley National Laboratory, LBNL-54365, November 2003. Downloadable at: http://certs.lbl.gov/pdf/54365.pdf

[lxxxiv] *A Survey of Utility Experience with Real Time Pricing*, Lawrence Berkeley National Laboratory and Neenan Associates, LBNL-54238, December 2004. Downloadable at: http://eetd.lbl.gov/certs/pdf/54238.pdf

[lxxxv] Option Value of Electricity Demand Response, Sezgen, Charles Goldman, and Krishnarao, Environmental Energy Technologies Division, LBNL, October 2005 (http://eetd.lbl.gov/ea/EMS/reports/56170.pdf)

[lxxxvi] *Phase 1 Results: Establish the Value of Demand Response*, Ren Orans, et al. Energy and Environmental Economics, Inc., LBNL-60128 Collaborative Report, April 2006. Downloadable at: http://drrc.lbl.gov/pubs/60128.pdf and Development of a Comprehensive / Integrated DR Value Framework, Dr. Daniel M. Violette, Summit Blue Consulting, LBNL-60130 Collaborative Report, March 2006. Downloadable at: http://drrc.lbl.gov/pubs/60130.pdf

[lxxxvii] Assessment of Advanced Metering and Demand Response, FERC Annual Report 2007

[lxxxviii] *ERCOT Demand Response Program Helps Restore Frequency Following Tuesday Evening Grid Event*, ERCOT Press Release (http://www.ercot.com/news/press_releases/2008/nr02-27-08)

[lxxxix] DIRECT TESTIMONY OF REN ORANS, Ph. D ON BEHALF OF VIRGINIA'S COMMITMENT, LLC BEFORE THE STATE CORPORATION COMMISSION OF VIRGINIA CASE NOS. PUE-2007-00031, PUE-2007-00033

http://www.pecva.org/_downloads/powerlines/documents/statefilings/VA_VaCommitment_ROransTestimony_120407.pdf

[xc] *Southern California Edison Continues Calling for Conservation as High Temperatures and Record Demand are Predicted for Today*, SCE Press Release, Sept. 4 2007, (http://www.chinohills.org/DocumentView.asp?DID=7140)

[xci] PJM 2007 State of the Market Report (http://www.pjm.com/markets/market-monitor/som.html)

[xcii] Demand Response in ERCOT: A Snapshot , Paul Wattles, ERCOT DSWG. http://www.goodcompanyassociates.com/files/manager/demand_response_in_ercot__paul_wattles.pdf

[xciii] Assessment and Development of Network-driven Demand-side Management Measures

Research Report No 2 Task XV of the International Energy Agency Demand Side Management Program, Prepared by Energy Futures Australia Pty Ltd, 27 October 2006 (http://www.ieadsm.org/Files/Tasks/Task%20XV%20-%20Network%20Driven%20DSM/Publications/IEADSMTaskXVResearchReport2.pdf)

[xciv] Loads Providing Ancillary Services: Review of International Experience, prepared jointly by LGNL, ORNL and PNNL for CERTS, May 2007 (http://certs.lbl.gov/pdf/62701.pdf)

[xcv] The Energy Policy Act of 2005 directed FERC to identify "steps taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment." FERC recently released Order 890 which required transmission service providers to include consideration of demand response alternatives for all transmission enhancement proposals.

[xcvi] *ISO New England's "Strawman" Proposal for Regional Transmission Planning*, filed pursuant to FERC's Order 890 Final Rule, May 29, 2007. Downloadable at: http://www.iso-ne.com/trans/rsp/2007/order_890_planning_strawman.pdf

[xcvii] Demand Response Review - A Survey of the Demand Response (DR) Programs and Initiatives In Each of the Six Commission-Approved RTOs/ISOs, Raksha Krishna, Manager, Regulatory Analysis, Edison Electric Institute, July 2007. Downloadable at: ftp://www.nerc.com/pub/sys/all_updl/pc/dsmtf/demand_response_RTOs%20and%20ISOs_formatted_2.pdf

[xcviii] See for example: http://www.pecva.org/anx/index.cfm/1,215,0,0,html/500-kV-Transmission-Line

[xcix] Incorporation of DSM Measures into Network Planning - Research Report No 3, Task XV of the International Energy Agency Demand Side Management Program, 3 April 2007 (http://www.ieadsm.org/Files/Tasks/Task%20XV%20-%20Network%20Driven%20DSM/Publications/IEADSMTaskXVResearchReport3.pdf)

[c] These environmental benefits are listed in *Demand Response Proxy Supply Curves*, Prepared for PacifiCorp by Quantec, LLC, September 8, 2006 and DRR Valuation and Market Analysis – Volume II: Assessing the DRR Benefits and Costs, prepared for the IEA DSM Program Task XIII by Dan Violette, January 6, 2006 as well as the CPUC's *California Demand Response: A Vision for the Future* (http://www.caiso.com/1fe3/1fe3ebb5d860.pdf)

[ci] STAFF GUIDANCE FOR STRAW PROPOSALS ON: LOAD IMPACT ESTIMATION FROM DR AND COST-EFFECTIVENESS METHODS FOR DR.,07-01-041, Energy Division, CPUC, May 24, 2007

[cii] Energy Division Staff Report in R.07-01-041, Cost Effectiveness Protocols for Demand Response (http://docs.cpuc.ca.gov/efile/RULINGS/80858.pdf)

[ciii] Some TAG reviewers disagreed with this assertion. The comments noted studies by E3 for the CPUC on energy efficiency evaluation and by TIAX for the CEC on self generation program evaluation. However, the point of debate is whether these studies adequately addressed DR program impacts on emissions.

[civ] Modeling Demand Response and Air Emissions in New England, prepared by Synapse Energy Economics for the U.S. Environmental Protection Agency, September 4, 2003 (http://www.synapse-energy.com/Downloads/SynapseReport.2003-09.US-EPA.NE-DR-and-AE-Modeling.03-01.pdf)

[cv] Testimony Of Dan Delurey, Demand Response and Advanced Metering Coalition (DRAM) Before the Senate Finance Committee, Energy, Natural Resources and Infrastructure Subcommittee, May 24, 2007 (http://www.senate.gov/~finance/hearings/testimony/2007test/052407testdd.pdf)

[cvi] "The Green Effect – How Demand Response Programs Contribute to Energy Efficiency and Environmental Improvement", Nemtzow, Delurey and King, Public Utilities Fortnightly, March 2007

[cvii] *Market-Based Model for ISO-Sponsored Demand Response Programs: End Goals, Implementation and Equity*, prepared by Vernon Smith and Lynne Kiesling for the Center for the Advancement of Energy Markets (CAEM), August 2005

[cviii] For discussions of the Consumer Value test see: *Toward a New Paradigm for Valuing Demand Response,* Robert Earle and Ahmad Faruqui, **The Electricity Journal, vol. 19 # 4,** May 2006

[cix] Braithwait, Steven D. "What 'Standard Practice' Tests Don't Tell Us About DSM and Induced

Price Impacts," in Proceedings: 1994 Innovating Electricity Pricing, EPRI TR-103629, February 1994.

[cx] Methodology and Forecast of Long-Term Avoided Costs for the Evaluation of California Energy Efficiency Programs, prepared for the CPUC by Energy and Environmental Economics, Inc, October 25, 2004. Downloadable at: http://www.ethree.com/CPUC/E3_Avoided_Costs_Final.pdf

[cxi] Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them – A Report to the U.S. Congress pursuant to Section 1252 of the Energy Policy Act of 2005, prepared by the U.S. Department of Energy, Feb. 2006 (http://eetd.lbl.gov/EA/emp/reports/congress-1252d.pdf)

[cxii] One of the TAG reviewers noted that the suggestion of a utility shareholder perspective for the SPM was actually discussed and rejected in the early 1980's. According to the reviewer, the discussion prompted the development of ERAM, which neutralized the adverse effect of conservation on utility shareholders.

[cxiii] For example the characteristics of an "idealized" or "theoretical" CT proxy may be different from the as-installed characteristics of a commercial CT built on short notice and is certainly different from the characteristics of in-service peaking units.

[cxiv] See Methodology and Forecasts of Long-Term Avoided Costs for the Evaluation of California Energy Efficiency Program, prepared for the CPUC by Energy and Environmental Economics, Inc., October 2004 Downloadable at: http://www.ethree.com/CPUC/E3_Avoided_Costs_Final.pdf

[cxv] For a broad review see: Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets, Severin Borenstein, Michael Jaske, and Arthur Rosenfeld, CSEM WP-105,October 2002. Downloadable at: http://www.ucei.berkeley.edu/PDF/csemwp105.pdf

[cxvi] Comments of SDG&E on Staff Cost-Effectiveness Framework and Related Issues, R. 07-01-041, filed April 25 2008.

[cxvii] *Load As a Reliability Resource in Restructured Electricity Markets,* CEC Consultant Report, Prepared by the CERTS Program Office, LBNL, Lawrence Berkeley National Laboratory, P500-03-092F, October 2003. Downloadable at: http://certs.lbl.gov/pdf/load-reliability.pdf

[cxviii] *Social Welfare Implications of Demand Response Programs in Competitive Electricity Markets*, Prepared by Dick Boisvert and Bernie Neenan for Chuck Goldman, Lawrence Berkeley National Laboratory, LBNL-52530, August 2003. Downloadable at: http://repositories.cdlib.org/lbnl/LBNL-52530/

[cxix] Option Value of Electricity Demand Response Osman Sezgen, Charles Goldman, P. Krishnarao Environmental Energy Technologies Division October 2005

[cxx] See discussion in*: Phase 1 Results: Establish the Value of Demand Response*, prepared for the DRRC by Ren Orans, et al, Energy and Environmental Economics, Inc., LBNL-60128 – Appendix, April 2006. Downloadable at:

[cxxi] *Loads Providing Ancillary Services: Review of International Experience*, prepared by Grayson Heffner, Charles Goldman, Michael Kintner-Meyer, and Brendan Kirby for CERTS. LBNL-62701, May 2007. Downloadable at:
ftp://www.nerc.com/pub/sys/all_updl/pc/dsmtf/Loads_Providing_Ancillary_Services.pdf

[cxxii] Demand Response Spinning Reserve Demonstration, Prepared for Energy Systems Integration/Public Interest Energy Research Program/California Energy Commission, by LBNL, SCE, and RLW. LBNL-62761, May 2007. Downloadable at : http://certs.lbl.gov/pdf/62761.pdf

[cxxiii] Scarcity Pricing is a mechanism that lets market prices rise automatically beyond any applicable bid, when there is a shortage of supply. CAISO has been ordered by the FERC to develop and implement a scarcity pricing mechanism in the Post Release 1 MRTU. See: California ISO Revised Straw Proposal Reserve Scarcity Pricing Design, November 19, 2007. Downloadable at:
http://www.caiso.com/1c9b/1c9bd08c63920.pdf

[cxxiv] FERC Docket No. ER06-615-000

[cxxv] CAISO Demand Response Resource User Guide - Guide to Participation in MRTU Release 1, November 29, 2007 (Version 3.0). Downloadable at: http://www.caiso.com/1ca6/1ca67a5816ee0.pdf