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Development of a Comprehensive/Integrated DR Value Framework

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Collaborative Report

Development of a Comprehensive / Integrated DR Value Framework

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PREFACE

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Commission), annually awards up to $62 million to conduct the most promising public interest energy research by partnering with Research, Development, and Demonstration (RD&D) organizations, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following six RD&D program areas:

- Buildings End-Use Energy Efficiency
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy
- Environmentally-Preferred Advanced Generation
- Energy-Related Environmental Research
- Energy Systems Integration

What follows is the final report for the Establish the Value of Demand Response Project, 500-03-026 Task 4.F, conducted by Summit Blue Consulting. The report is entitled "Development of a Comprehensive / Integrated DR Value Framework". This project contributes to the Energy Systems Integration Program.

For more information on the PIER Program, please visit the Commission's Web site at: http://www.energy.ca.gov/research/index.html or contact the Commission's Publications Unit at 916-654-5200.

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Abstract

This report addresses the research and development objectives of the Research Opportunity Notice RON – 1 issued by the Demand Response Research Center (DRRC). The DRRC was created by the California Energy Commission (ENERGY COMMISSION) and charged with conducting and disseminating near-term research that advances the multi-institutional needs for demand response (DR) in California. The objective is the description of a "comprehensive DR conceptual evaluation framework" (from RON – 1 R&D Objectives). This will involve developing and describing approaches, processes, and procedures for making good decisions regarding the role of DR in regional California electric markets. The framework that is described in this document uses as its organizing focus the investment decision in DR, i.e., what information is needed to make good decisions regarding the appropriate investment in DR to lower overall system costs and achieve market-wide objectives. This method is also designed to be able to address different stakeholder objectives. The report develops a "problem statement" for the valuation of DR, and an assessment of needs and objectives that should be met by a comprehensive valuation framework. The report presents an approach to developing a comprehensive valuation framework that consists of four Task Work Areas: 1) Price effects from DR portfolios; 2) Transmission investment avoided/deferred costs; 3) Distribution investment deferred costs; and 4) Market effects focusing on hard to quantify benefits.

Executive Summary

INTRODUCTION: This effort addresses the research and development objectives of the Research Opportunity Notice RON – 1 issued by the Demand Response Research Center (DRRC). The DRRC defines Demand Response (DR) as "actions taken to reduce load when contingencies (emergencies and congestion) occur that threaten the supply-demand balance, and/or market conditions occur that raise supply costs."[1] DR typically involves peak load reductions and strategies that differ from energy efficiency in that they represent transient versus permanent changes in peak period loads. DR will typically be associated with a customer load reduction in response to a market condition (often a price), or a customer response to a notification regarding a specific reliability contingency. For this report, this definition was extended to also include more decentralized forms of demand response such as real-time pricing where customers make individual choices to shift or reduce demand without direct communication with their utility or system operator.

PROJECT OBJECTIVES: The objective of this effort is to describe and outline the work required to develop a more comprehensive DR conceptual valuation framework. This includes analytic methods capable of addressing different stakeholder and resource perspectives.

PROJECT APPROACH: The development of this approach builds on considerable work done both in California and elsewhere. Ongoing work at the California Energy Commission Public Interest Energy Research (PIER) program on the integration of distributed resources into transmission and distribution planning (i.e., non-wires solutions), the considerable work performed by Center for the Study of Energy Markets, University of California, and work by the IOUs in California on integrating distributed energy into "gridside system planning" as part of CPUC Rulemaking 04-03-017. Other valuable sources of information include work done by Independent System Operators in New York, New England, and PJM, as well as conversations with utility planners in generation, transmission, and distribution at utilities in the Western Electricity Coordination Council. Finally, many of the ideas in this framework development are drawn from work performed for the International Energy Agency Demand-Side Programme.

PROJECT OUTCOMES AND RESULTS: The framework that is described in this document uses as its organizing focus the investment decision in DR, i.e., what information is needed to make good decisions regarding the appropriate investment in DR to lower overall system costs and achieve reliability objectives. This method is also designed to be able to address different stakeholder objectives. The report develops a "problem statement" for the valuation of DR, and an assessment of needs and objectives that should be met by a comprehensive valuation framework. The report concludes the presentation of an approach to developing a comprehensive valuation framework that consists of four Task Work Areas:

Task Work Area 1 – Generation expansion and production costing with transmission constraint to estimate price effects from DR portfolios.

Task Work Area 2 – Transmission investment avoided/deferred costs based on engineering approaches and modular cost estimation.

Task Work Area 3 – Distribution investment deferred costs based on engineering budget based estimates and longer-term project plans.

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[1] From "Research Opportunity Notice Overview Presentation, July 21, 2005.

Task Work Area 4 – Market effects focuses on hard to quantify benefits related to overall sector productivity, technology innovation, and customer benefits such as increased choice and the potential for enhanced customer services.

In addition, nine analytic steps are developed to form the basis for the analysis in each of the four work areas:

Step 1 – Base Case: Develop the base case set of resources that represent the without-DR scenario.

Step 2 – Pivot Factors: For the base case, identify the key pivot factors that cause the costs of providing electricity and related services to vary.

Step 3 – Distributions: Create a distribution of outcomes that represents a best estimate of the uncertainty around each of these pivot cost factors.

Step 4 – Create Joint Probability Surface: Use a set of random draws (e.g., a Monte Carlo analysis) to represent the joint probability surface for all the distributions developed around pivot cost factors.

Step 5 – Base Case Planning Model Runs/Analyses: The planning model will be run for each draw. One draw will consist of a full set of inputs for the relevant model or engineering analysis.

Step 6 – Benchmark DR Valuations: As part of the base case runs, benchmark willingness-to-pay DR values will be developed. This is done by simply specifying that some DR is available at specific locations during specific time periods that seem to represent viable future scenarios.

Step 7 – Develop DR Options: A representative set of DR programs/options will be developed with costs of initiation and ongoing operation included, along with realistic load reductions.

Step 8 – Estimate Value of DR Options: The base case model will be re-run with the various DR options.

Step 9 – Analysis of DR Value Results: The final step will take the information from the DR valuation model/engineering analyses and add estimates of the value associated with reductions in risk due to DR and changes in reliability.

CONCLUSIONS: A comprehensive DR conceptual valuation framework will involve multiple approaches in a layered structure to address the three levels of detail. The focus of this development of a comprehensive DR conceptual valuation framework requested in RON – 1 R&D objectives is on the broad level analysis. However, it should be recognized that other DR assessment tasks will use information developed in this overall framework, e.g., 1) program specific benefit-cost analyses and cost-effectiveness screening, 2) evaluation, and 3) event specific value of calling on DR. The overall value framework would be conducted periodically (e.g., every two years) and would provide the outputs that could be used to develop "adders" that approximate key values for program-specific benefit-cost tests and screening of new programs. A detailed comprehensive evaluation will not be warranted for a number of analytic exercises related to the development of specific DR options such as program screening and design.

The analytic challenges developed in this framework also imply that assessment of DR program/resource portfolios within a regional electric system will require approaches that can be based on existing planning tools, but adapting and emphasizing different aspects of these tools. It is difficult to change resource planning methods that have been used for years in the utility industry, but working to modify existing practices across generation, transmission, and distribution planning may be the best bet for actually incorporating decisions on DR investments in terms of timing and magnitude by type of DR and giving DR credibility as it may lead to more accurate side-by-side comparisons with conventional supply-side resources. DR assessments will require a foundation that dimensions uncertainty to allow for the unique attributes of DR to be addressed. As discussed in the approach section of the report, most of these methods and tools currently exist and have been used in a variety of resource valuation and planning assessments. The final section of this report discusses potential follow-on studies using the methods discussed in this report and the structure of their costs. The costs themselves are included in a separately bound confidential report.

Introduction

This effort addresses the research and development objectives of the Research Opportunity Notice RON – 1 issued by the Demand Response Research Center (DRRC).

The DRRC was created by the California Energy Commission and charged with conducting and disseminating near-term research that advances the multi-institutional needs for demand response in California. Key stakeholders include the ENERGY COMMISSION, California Public Utility Commission, California ISO, investor and municipal utilities, consumer groups, trade associations, technology providers, and other research organizations. The RON – 1 Research and Development (R&D) objective is to develop a *"more comprehensive DR conceptual valuation framework."*[2]

The overall objective of this effort is to give consideration to "(1) the development of a comprehensive DR conceptual valuation framework, and (2) develop more comprehensive stakeholder and resource perspectives."[3] While the DRRC presents a working definition of DR in its statement of objectives, a subtask in the task objectives asks the question – "How should DR be defined?" – in the context of recent advances such as appliance efficiency standards, improved digital controls, the internet, and other factors that may create a need to re-examine the basic definition and opportunities for the scope of DR. Two views of DR are presented below. Neither is advocated in this work as right or wrong, but each is appropriate for the context in which DR is being addressed and the objectives stated for DR. However, a comprehensive framework should be able to address both views. What is termed the "conventional view" is presented first with a more expansive view presented as a second approach to capturing values associated with DR.

A detailed comparison between the California Standard Practice Manual[4] (SPM) cost-effectiveness tests and the proposed comprehensive framework for assessing the value of DR is not performed here. Summit Blue did not begin this analysis with a critique of the current SPM and identification of gaps in the SPM. This was believed to be a limiting approach and not consistent with the R&D Objectives for this project stated by the DRRC. Summit Blue focused on the R&D Task Objectives as listed in the Research Opportunity Notice DRRC RON-1[5] which did not include such a comparison as an objective. Instead the focus of the notice was on the development of a more comprehensive DR conceptual valuation framework, unconstrained from a historical starting point. Still, the SPM is important as it is currently used in the benefit-cost assessment of individual DR programs. The development of a comprehensive framework for valuing DR; however, such a framework would allow a set of appropriate SPM-type tests to be derived.

A comprehensive framework analysis might only be conducted every several years and be used to assess the viability of the current SPM values. Due to the number of programs and variants that need to be evaluated, the SPM is viewed as an approach that has been simplified to allow for

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[2] DRRC RON – 01 R&D Task Objectives: Final - July 21, 2005

[3] R&D Task Objectives for the Research Opportunity Notice DRRC RON – 1, Final – July 21, 2005.

[4] California Standard Practice Manual – Economic Analysis of Demand-Side Programs and Projects, California Public Utilities Commission, October 2001 available on the CPUC website at www.cpuc.ca.gov/static/energy/electric/energy+efficiency/rulemaking/resource/5.doc.

[5] See: Pier Demand Response Research Center, Research Opportunity Notice DRRC RON – 01, R&D Task Objectives, Final – July 21, 2005

specific programs to be screened for cost-effectiveness. Instead, this effort focuses on the more complete framework that would serve as the foundation for a revised SPM.

A discussion of the SPM and how it might be adjusted based on a comprehensive value framework has been added as Section 6.0 to this revised report. This section has been added in response to reviewers' comments. This new section addresses gaps in the current SPM along with approaches to address these gaps.

Conventional View of DR – A Resource for Extreme Events

The definition of DR does vary across applications, but the most common definition views DR as a response to a system emergency or in response to extreme market events (e.g., extreme prices). In this regard, the DRRC defines Demand Response (DR) as "actions taken to reduce load when contingencies (emergencies and congestion) occur that threaten the supply-demand balance, and/or market conditions occur that raise supply costs."[6] DR typically involves peak-load reductions and strategies that differ from energy efficiency in that they represent transient versus permanent changes in peak period loads. DR will typically be associated with a customer load reduction in response to a market condition (often a price), or a customer response to a notification regarding a specific reliability contingency.

Two general types of DR are considered:[7]

<u>One</u> – Load response for reliability purposes, which includes:

- Direct load control, partial or curtailable load reductions
- Complete load interruptions

<u>Two</u> – Price response by end-use customers, including:

- Dynamic pricing: real-time pricing (RTP), coincident peak pricing (CPP), time-of-use rates (TOU)
- Demand bidding or buyback programs

Recent ongoing work by the U.S. Department of Energy[8] has developed working definitions for demand response in electric markets as:

> *Reductions in electric usage by end-use customers from their normal consumption patterns at times of high wholesale market prices or when system reliability is jeopardized in response to changes in the price paid for electricity or to incentives designed specifically to induce the reduction.*

The phrasing "normal consumption" can be problematic in that some pricing alternatives could result in a new "normal response to high market prices," if they represented the default pricing. However, this is addressed by making the distinction that DR occurs only when electricity

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[6] From "Research Opportunity Notice Overview Presentation, July 21, 2005.

[7] From Objectives and Scope of the DRRC, http://DRRC.lbl.gov. In this document, five quite broad areas of consideration are listed. The current use of the SPM was not included in these areas. Sub-items in consideration area 4, sub-element d) included:

iii) What methodologies can best support DR valuation and integration into current resource plans?

iv) What methodologies are used today?

This report discusses a forward looking approach that can integrate DR valuation into resource plans and with a discussion of methods that are used today.

[8] Communication with Dr. Chuck Goldman, Lawrence Berkeley National Laboratories regarding work supporting estimation of DR benefits.

market prices are at their highest. There are two components to this definition, reflecting two perspectives:

ONE – The function of DR from the perspective of the electric system as a whole is with the emphasis on *reductions* in usage *at critical times*.[9] Critical times are typically only a few hours per year, when wholesale electricity market prices are at their highest or when reserve margins are low due to unforeseen contingencies such as generator outages, downed transmission lines, or very severe weather conditions.

TWO – This involves the method by which DR is elicited from customers. This can be done either through a retail electricity rate that reflects the time-varying nature of electricity costs, or through a program – an attempt to induce customers to change their consumption behavior – that provides an incentive to reduce load at critical times. The incentive is unrelated to the normal price paid for electricity (e.g., a supplemental incentive) and may involve payments for load reductions, penalties for not reducing load, or both.

This definition takes the view that DR as an action undertaken by an end-use consumer in response to a stimulus and typically involves customer behavioral changes. The magnitude of this response or "change from normal" is the amount of DR produced. Given this magnitude of DR, its value is derived from the impacts it has on the entire electric system. Reconciling the two concepts expressed in the definition of Dr above – 1) reductions in energy use at "critical times," and 2) the method by which DR is elicited from customers -- is important for characterizing the available DR as well as valuing DR. This valuation needs to recognize the unique attributes of DR that give it value as well as identifying limitations that may apply in the use of DR to meet electric system needs and objectives. This insight is also used in this framework development as part of: 1) determining the type of end-use customer action and a measure of the magnitude of response; and 2) assessing the value of this response to the overall electric market.

This approach develops a construct that has a DR effect and a value of the effect. To assess the magnitude of the effect, it must be measured against a baseline of "normal load consumption." This effect may be complex in that it may involve costs and benefits to different entities, some of which are likely to represent management of risk and/or an increased number of options that can be exercised at "critical times." The value of the DR effect at these times has to be assessed within the construct of the overall electric system. This facilitates the examination of a number of factors contained in the R&D Task Objectives contained in the DRRC RON – 1 in that they are changes in the baseline against which the DR effect is measured. For example, one scenario that the framework should address according to the RON – 1 Task Objectives is a situation where CPP rates become the default tariff for all customers in California.

Expansive View of DR – Market Efficiency from Continuous Balancing of Demand and Supply

There is also a natural extension of the definition of demand response from one focused on critical system and market events to one that recognizes that some DR alternatives, specifically pricing alternatives as discussed by the DRRC such as time-of-use (TOU) combined with critical peak prices (CPP), and real-time pricing (both day-ahead and real-time in the market pricing. These pricing options can be viewed as influencing electricity demands for almost all hours, not just identified critical events, with impacts on market efficiency and resource allocation.

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[9] Note that DR may also result in an increase in electricity use during the hours when electricity prices are lower than average. This too can result in more efficient use of the electric system and may also promote economic growth.

This broader definition is not inconsistent with what was termed the "conventional view" with its focus on the use of DR to ameliorate extreme events, but simply extends the definition to hours that may not meet a definition of a "critical event." Whether a region, utility, or policy making entity wants to adopt this extension is a decision that they can make, but a comprehensive conceptual valuation framework should be able to look at the benefits/costs associated with this more expansive view, but the exact use of DR may be a policy decision by market and regional actors.

This more expansive view comes up in a number of discussions of DR. For example, one view is that DR is an extension or redefinition of customer service[10] which extends the application of DR from a focus on the use of DR for reliability events to applications which provide customers with appropriate price signals in every hour:

> *The view of demand response as a substitute for supply has to shift to also emphasize its role as a customer cost management resource.*[11]

This approach has also been taken in recent work for the International Energy Agency (IEA Report) which investigated a portfolio of DR programs including two pricing programs that embody customer service attributes:

> *If they are on a DR pricing product such as RTP or TOU with CPP they may receive bill savings and more control over their bills as well as more choices for managing their energy use.*[12]

In addition, the IEA Report showed large benefits to RTP pricing since it impacted load in every hour, not just those hours in an event, e.g., a defined CPP or load reduction event.

In a similar fashion, the ISO-NE Federal Energy Regulatory Commission (FERC) December filing on the status of demand response states:

> *The ISO-NE advocates integrating demand response directly into the wholesale market and into the retail rate structures that send customers price signals … Integrating DR into the fabric of the electricity market requires a concerted and coordinated effort on the part of Federal and State policymakers.*[13]

Summary of Views

These views are complementary in that both will address the role and value of DR as an option for ameliorating the impacts of critical system and extreme market events. The second, more expansive, view also brings in a judgment that efficient markets require both demand response and supply response, and that there are efficiency gains to be had by allowing customers to respond to time-varying prices that reflect costs and determine the appropriate amount of

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[10] This view of DR as customer service is compared to "a predominate focus on reliability-based demand response options" (p. 1-3) is developed in "New Principles for Demand Response Planning," EPRI EP-P6035/C3047, Final Report, Principal Investigator R. Levy, Levy Associates, March 2002.

[11] Ibid, p. ix.

[12] See page 20 in "DR Valuation and Market Analysis -- Volume II: Assessing the DR Benefits and Costs," Prepared for the International Energy Agency Demand-Side Programme, Task XIII, by Violette, D.M., R. Freeman, and Chris Neil, June 6, 2006.

[13] "Comments of the ISO New England, Inc., FERC Docket No. AD06-2-000, Notice of Proposed Voluntary Survey and Technical Conference, Assessment of Demand Response Resources, December 19, 2005.

electricity to use. An argument against this more expansive view is that customers do not want time-varying rates. Some customers may want to avoid the 'hassle' associated with these decisions by having a fixed price across all hours. In this research effort, this is not viewed as an argument against DR options comprised of time-varying rates, as transition or transaction costs can be counted as a consumer cost in a benefit/cost analysis, and in an efficient market these options should be available to customers from providers with the hedge costs incorporated into the fixed hourly price. The cost of providing the hedge would be accounted for in the valuation framework. There are examples where hourly pricing has worked well for both residential customers[14] and for larger customers,[15] although there is still a debate focused primarily on small customers where it has been argued that the metering and related costs required for customers to respond outweigh the benefits customers will receive.[16] This is an issue that should be addressed in the valuation framework, and it is also an issue for DR design in that some RTP efforts have had low technology costs.[17]

In summary, the approach to a comprehensive DR conceptual valuation framework is designed to work towards approaches that can fit with either of the two views of DR outlined above. Each will have its benefits and costs, and a comprehensive approach should provide insights into the merits of a reliability approach to DR (conventional view) as well as a broader overall market efficiency and customer service approach to DR (the more expansive view).

Organization of Report

The balance of this report is organized into four additional chapters:

- Chapter 2.0 develops a problem statement and identifies high level objectives for the DR conceptual valuation framework.

- Chapter 3.0 identifies the benefits and costs that should be addressed in a DR framework, both for the market as a whole and for different stakeholders.

- Chapter 4.0 lays out the framework of approaches with different approaches required to address different framework needs as developed in Chapter 3.0.

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[14] Evaluation of the 2004 Energy-Smart Pricing Plan[SM], Final Report, Prepared for the Community Energy Cooperative (Larry Kotewa), 2125 W. North Ave., Chicago, IL 60647; Prepared by: Summit Blue Consulting, Boulder, CO, March 2005.

[15] See Barbose, Galen, Charles Goldman and Bernie Neenan, "A Survey of Utility Experience with Real-Time Pricing," Lawrence Berkeley National Laboratory Working Paper No. LBNL-54238, December 2004.

[16] This argument was made the Eric Ackerman writing on behalf on EEI members participating in the Mid-Atlantic Demand Response Initiative (MADRI), where commenting on "Scoping Paper On: Dynamic Pricing" by Fredrick Weston and Wayne Shirley. Mr. Ackerman states in his letter of May 18, 2005 that "In general, RTP is not cost effective for small customers: the amount they can save by curtailing use during high cost hours is less than the cost of metering, communications, and load controls designed to achieve a demand response capability." (Item 1).

[17] The Chicago Cooperative Pricing experiment (footnote 11) was designed to test a low technology approach to RTP and avoid many of the more expensive elements of many small-customer RTP programs.

- Chapter 5.0 sets out the work plan recommendations for implementing the conceptual framework developed in the preceding chapters.

- Chapter 6.0 develops the links between the comprehensive DR value framework based on the use of existing utility resource planning approaches and a Standard Practice Manual (SPM) set of tests that can be readily used to assess DR program designs, program approvals, and conduct ongoing evaluation of DR programs.

- Chapter 7.0 presents possible follow-on projects implementing these DR assessment and valuation methods and the structure of costs for specific work assignments. Actual project cost estimates for each option are contained in a separately bound report.

Problem Statement

The objective is to describe a "comprehensive DR conceptual evaluation framework"[18] and develop the approaches, processes, and procedures for making good decisions regarding the role of DR in regional California electric markets. The framework that is described in this document uses as its organizing focus the *investment decision* in DR (i.e., what information is needed to make good decisions regarding the appropriate investment in DR to lower overall system costs and achieve reliability objectives). This method is also designed to be able to address different stakeholder objectives.

One principle embodied in this document is the belief that DR assessments should use the resource planning tools that have become standard approaches for the utility industry in developing resource portfolios. If DR assessments require a separate set of side calculations to assess its cost-effectiveness and role in the resource portfolio, then the value of DR as a resource may be not be readily accepted regardless of the number of regulatory decisions supporting DR's inclusion in resource plans. The utility industry has a long history of resource planning. The approach explored in this effort involves adapting these existing tools, to the greatest extent possible, such that DR can be assessed alongside other supply-side resource investments as part of the comprehensive portfolio assessment. It is difficult to change out such tools when they represent the current standard in the industry, but to work within the same framework to address important DR resource issues is a viable option, and this approach will leverage a considerable amount of existing work.

The DRRC RON-1 R&D objectives and other ongoing work in California proceedings use a far reaching definition of DR which can incorporate many programs, each with different types of values and different magnitudes for values that are common. In preparing this document, this breadth of scope was daunting. In follow-on work, it may be appropriate to parse the problem into segments to allow issues posed by specific DR programs to be addressed in greater detail.

In general, there are a number of characteristics of DR that pose practical challenges for the development of a valuation framework that can appropriately assess DR. These include:

F1. Within the two categories of DR defined in Section 1.0 (Load Response and Price Response), there are many different types of DR with each producing different types of benefits. Each type of DR has to be estimated within an appropriate framework that can capture the magnitude and the value of the DR. For example, callable load programs can enhance reliability by serving as system reserves that can be called upon in response to a system event. Pricing programs can reduce peak hour demands as well as reduce demand during all high priced periods. These programs, however, are not directly dispatchable when system events require quick response to avoid a local or regional outage, or an extreme spike in prices. As a result, there are many DR program variants with each providing different types of benefits and each associated with different costs.

F2. Uncertainty must be dimensioned if the value of DR is to be appropriately addressed. This may seem somewhat extreme, but DR is meant to apply to extreme events whether they be market related or system related. These events, by their nature, are often low probability

[18] R&D Task Objectives for PIER Demand Response Research Center Research Opportunity Notice DRRC RON – 01, Final.

(i.e., infrequently occurring), high consequence events. An appropriate assessment of the probability of occurrence and the consequences (in dollar terms) is needed if the framework is to address key values of DR. These values include the risk management aspects of DR that are ever increasing in importance as energy prices rise and energy markets become more volatile. Important to the value of DR is its portfolio value (i.e., the value of increased resource diversification) and insurance against low-probability, high-consequence events. Tools for dimensioning uncertainty are needed if DR is to be appropriately valued using any general framework. Purely static approaches will not be able to address important attributes associated with DR.

F3. Categorization of DR programs. There are many types of DR programs, and it is not possible to develop a scheme that assesses all possible variants. This is also a problem when looking at more conventional supply-side resources. As a result, a representative subset of resources needs to be examined. This is discussed in more detail in the approach discussion in Section 5.

F4. Addressing the locational value of DR. The California Independent System Operator (CAISO) is working towards having functioning energy markets with both day-ahead and real-time markets in 2007. The Market Redesign and Technology Upgrade (MRTU)[19] calls for the use of three zones for pricing electricity to customers, and locational prices for generators will be determined. In addition, there are likely to be local transmission bottlenecks that will likely affect the value of DR. This implies that a generator and/or commodity-type of perspective is needed along with a transmission load flow to examine system constraints if the effects of DR are to be fully addressed.

F5. Customer-Side Benefits of DR. One of the challenges mentioned in the RON –1 task list concerned expressing the customer value of DR. There are the direct price benefits and lowered risks of higher future electricity prices at the system level, but there are also value propositions specific to customers. For example, a DR option such as implementation of an RTP alternative alone with the option to take a fixed price rate at an appropriate premium. The "appetite for risk" will vary across customers, as well the value they place on having the capability to better manage their electric costs (i.e., bill management). The heterogeneity across customers poses challenges for dimensioning these benefits and costs.

F6. Many of the values associated with DR are difficult to quantify. Such benefits/costs can include reduced market power, values associated with customer choice, changes in benefits/costs across customers and between resource providers, market-wide factors that improve overall operating efficiencies, and incentives for developing and deploying technologies that enable customer response to market and system events.

F7. A long-term view is needed for the appropriate assessment of DR. An assessment of DR requires a planning horizon similar to that used to assess the value of alternative supply-side technologies which might include simple cycle or combined cycle gas turbines (i.e., a

[19] Approved on June 24, 2004 by the ISO Board of Governors, the MRTU consists of two parallel programs: 1) market improvements to assure grid reliability and more efficient and cost effective use of resources, and 2) Technology upgrades to strengthen the entire ISO computer backbone.

15 to 20 year time horizon). This longer planning frame is also needed to fully capture the fact that DR is often designed to mitigate the impacts of low-probability, high-consequence events. These may occur only once every four to six years, and a time frame that allows for the development of scenarios that contain these events is needed. Also, this is warranted by the long-lived nature of many DR programs where utilities have maintained reliable DR programs for decades.

F8. Different levels of detail are needed to meet types of assessment needs. A framework addressing the appropriate investment of resources in DR programs will need to consider a number of different questions at different levels of detail. Three general uses of DR assessment are believed to be important components of a comprehensive framework. These include:

LEVEL 1: Value of DR in long-term resource planning assessments that provide benchmarks for the amount of DR that is economic over a 5, 10, 15, and 20 year time period. This is also referred to as the "resource planning" assessment and by its nature will have to work with categories of DR, possibly limited to four to six program types – several load response and several price response DR programs. This assessment will explicitly look at the synergies (positive and negative) between different types and levels of DR resources, as well as other resources (e.g., renewable and energy efficiency peak reductions). In addition, these assessments should look at how trade-offs between DR and other resources might affect commodity provision and/or alleviate transmission constraints, and thereby impact not only generation costs but also T&D capital and variable costs.

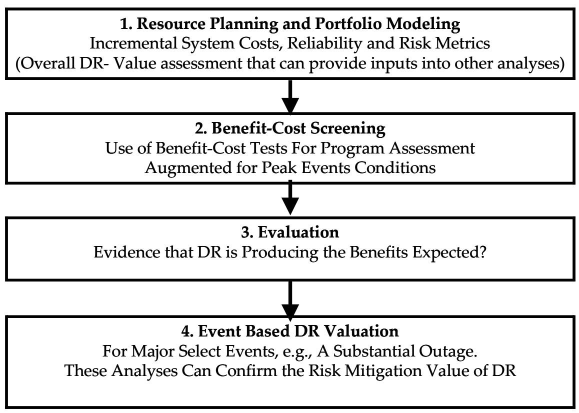
LEVEL 2: DR value for use in program specific design assessments that work from the information developed in the resource assessment to specify DR programs at a level of detail that will allow a program to be addressed in a benefit-cost framework to enable program design and implementation. This would be a construct similar to, if not a revision of, the California Standard Practice Manual. This regularly applied program design tool will require protocols that can compare the efficiency in meeting the overall resource objectives of DR programs with different structures, and the relative cost-effectiveness of programs. These design assessments will likely need some "short-form" tools that may approximate what would be obtained if a full long-term comprehensive planning assessment is performed. These design benefit-cost analyses may need to be applied to stand alone program assessment (as opposed to the full demand-side, supply-side portfolio assessment contained within the resource planning assessments).

LEVEL 3: Retrospective value of DR for specific program assessments/evaluations. The two assessments above are essentially prospective and forecast the value of DR under selected planning assumptions. This is done for any resource investment in any industry, but it is also important to look at the values attained over a historical period (e.g., a three-year period) to see if the expected values are, in fact, being attained. These retrospective evaluations are important not only for assessing the overall value of DR, but will probably be of greater importance for recommending changes in the specific design of DR programs. This will involve process assessments to ensure cost-effective program implementation and potential design changes allowing customers to provide greater magnitudes of DR under the program design. This is part of ongoing learning and assessment that is common to any resource investment, not just DR. Over time, the Level 3 evaluations will feed important information back into the Level 1 resource planning assessments, just as is done now for information on the operations and costs of supply-side and renewable resources.

<u>LEVEL 4</u>: <u>Event-Specific DR Value Assessments</u>. One of the benefits claimed for DR is that it can help mitigate the costs of low-probability, high-consequence events. These may be the one-in-five or one-in-ten events caused by extreme economic conditions (fuel shortages or extremely high costs), major plant outages, and/or transmission line outages or capacity constraints. These events could cause a spike in the price of electricity (particularly in wholesale markets). Callable and dispatchable DR is meant to mitigate the effects of these extreme events. As a proof-of-concept, it is likely to be important to assess the effects of DR when these events occur to see if DR had the intended effect.

These four levels of analyses are shown in Figure 0-1 below.

Figure 0-1. Analysis Flow – DR Assessment



The challenges discussed in this section imply that a comprehensive DR conceptual valuation framework will involve multiple approaches in a layered structure to address the four levels of detail shown above. The focus of this effort is on the comprehensive DR conceptual valuation framework, as requested in the RON – 1 R&D objectives, is on the more comprehensive level 1 analysis. It should be recognized that what has been termed level 2, 3, and 4 analyses will need to use outputs from the level 1 analysis to develop related proxy values. The detailed comprehensive assessment of DR values based on the resource planning and portfolio modeling would only be performed periodically. Data from this comprehensive analysis would they be used in the level 2, 3 and 4 analyses which relate to the design of specific DR options and the evaluation of whether DR is, in fact, providing the benefits expected.

These challenges in developing a comprehensive analysis framework also imply that assessment of DR program/resource portfolios within a regional electric system will require approaches based on existing planning tools, but emphasizing different aspects of these tools. Importantly, DR assessments will require a foundation that dimensions uncertainty to allow for the unique attributes of DR to be addressed, i.e., the ability to mitigate critical or extreme events. As discussed in the approach section, most of these methods and tools currently exist and have been used in a variety of resource valuation and planning assessments.

DR Framework Benefits and Costs

Demand response (DR) is characterized as products/programs or pricing options which send economic or reliability signals to reduce end-use demand or encourage distributed generation. Individual demand response resources constitute a continuum of measures, ranging from readily dispatchable load control to energy efficiency measures acting over a period of many years. In addition, DR is a somewhat amorphous entity in that some view DR as resources to respond to an event (system reliability or an extreme market event); while others include options such as TOU with CPP and RTP which can impact load each hour of a year or season. The discussion here attempts to lay out the categories of benefits and costs that the frame would need to address to be comprehensive.

One of the issues in making DR investments is that the entity that may have primary responsibility for developing and delivering the DR resource will incur most of the costs, but they do not necessarily receive the benefits of DR. For example, the distribution utilities in California may be in a good position to aggregate customers and implement DR options, but they may not benefit from market-wide reliability benefits that extend beyond their service territory or benefits to the transmission system that may reflect reduced costs. A bifurcation may result, between who incurs the costs of DR and who receives the benefits, such that the investing entity does not fully recover its costs.

This has bifurcation of benefits and costs can create barriers to the appropriate level of implementation. This can be addressed by the regulatory entities, as in California. Still, proper identification of the benefit recipient enables the measurement of stakeholder-specific cost-effectiveness, and may promote implementation by facilitating equitable investment sharing.

This section has two primary objectives:

(1) To identify and provide a listing of DR benefits (Section 3.1) and costs (Section 3.2), and

(2) To delineate the benefits according to the recipient stakeholder (Section 3.3).

Section 3.3 develops stakeholder views of these benefits. This involves the delineation of benefits and costs by stakeholder, namely participating customers, non-participating customers, load aggregators, distribution companies (DISCO), transmission companies (TRANSCO), load serving entities (LSE), the independent system operator (ISO), and generating companies (GENCO). This delineation is not straightforward for all benefits. While long-term price impacts benefit all customers, individual short-term benefits may accrue to private entities. Further, some benefits may be *market-wide* and shared between the local investing stakeholders and non-investing regional market participants. The results of this section are summarized in Tables 3-2 through 3-9.

Potential Benefits of Demand Response

Demand response (DR) represents a diversity of resources, each with unique impacts. Many of these impacts are inter-related and are therefore alpha-numerically identified in Table 3-1 for cross-referencing. The potentially beneficial impacts are identified in this section, and organized and discussed according to the following seven categories:

1) Direct Financial
2) Pricing
3) Risk Management and Reliability

4) Market Efficiency
5) Lower Cost Electric System & Service
6) Customer Services
7) Environmental

The category to which a potential benefit is assigned is not always clear cut, but to determine whether a framework is able to address a full range of benefits, a listing is needed. This listing by category is not easily developed and other analysts might group benefits differently. However, for the purposes of this report, Table 3-1 provides a list of potential benefits from DR. It is acknowledged that the boundaries between these benefit categories are not always clear cut and that care must be taken to both avoid missing key benefits and also double counting benefits. In addition, benefits to one party may be costs to another, but this stakeholder discussion is reserved to Section 3.3. It is also important to note that that different benefits may require different estimation approaches. An integrated resource planning approach can address some of the price and risk management benefits (e.g., those associated with the electricity commodity price and risks), but other studies which may be quite different in nature are needed to address potential benefits due to changes in transmission and distribution capital and operating expense. Also, the benefits in the market efficiency and customer service categories will require different analysis approaches. Identified benefits are listed in Table 3-1 and described more fully below.

Table 0-1: Listing of Potential DR Benefits by Category

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.

Each of these identified impacts is discussed below.

Direct Financial Category

DF1. Incentive payments to participating customer. Some types of demand response programs provide incentive payments to participating customers or entities that aggregate load response. Emergency response, direct load control, and call option products might offer various payment structures based on the product design. It might be a flat monthly payment for the peak months (summer or winter), or it might be based on the number of events and their duration.

DF2. Bill reductions from customer usage reductions/shifts. Demand response programs are designed to reduce peak consumption. The peak use reduction and any subsequent shift to lower cost periods provides can provide financial benefits to the customer, in addition to any incentive payment. The magnitude of this benefit depends on the customer’s usage patterns and the program’s pricing design.

DF3. Incentive Payments to a load aggregator or distribution company. In efforts to encourage an appropriate level of demand response investment, the cost of implementation may be shared through incentive payments from a benefiting entity (likely the ISO) to the demand response implementer (likely a load aggregator or the distribution company).

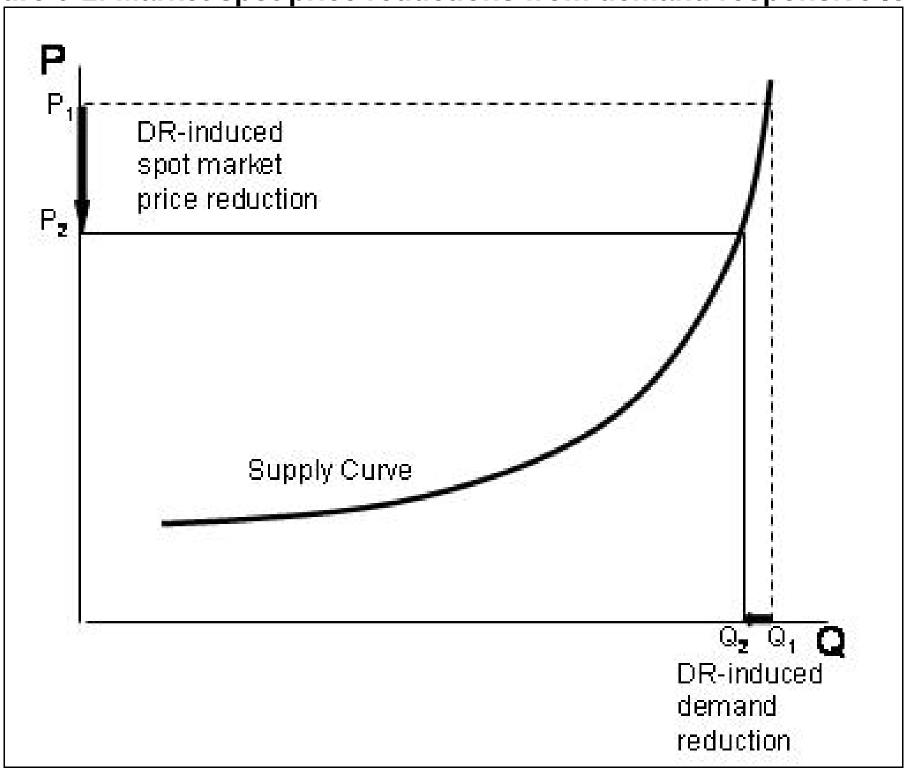
Pricing Category

P1. Wholesale market price reductions. Potential reductions in market prices are a major motivation for demand response valuation and investment. A small percentage of responsive loads can significantly mitigate peak prices. For example, the ISO NE demonstrated that a 2%

reduction in 2001 summer peak demand would have reduced the clearing price from $400 to $175 per MWh, or by about 56%.[20]

Demand response exerts both short term and long term forces on the regional market. DR acts to lower demand and its corresponding supply cost, thereby reducing the market clearing price, as illustrated in Figure 0-1.

Figure 0-1: Market spot price reductions from demand responsive load.



Valuing Long-Term Versus Short-Term Price Reductions -- In this static short term example, the price reductions received as benefits by customers may be viewed as a cost by the suppliers that would have provided the electricity. It is a reduction in revenue for them. However, if DR is viewed as a long-term commitment and DR forces can be expected by market participants for years into the future, then the supply side will take this into account. As a result, long-term equilibria can be reached where the impacts of DR on extreme market events are factored into decisions made by market actors. The end result can be a more efficient market with the appropriate balance between more capital intensive generators as an emergency resource complemented by DR. This should lead to an overall increase in capacity factors among generators if fewer units are built solely designed to operate only a few hours per year. Demand response may help reduce the requirements for long-term capacity expansion, in particular for peaking units.

P2. Reduced price volatility and hedging costs. The market impacts of DR reduce the maximum price for power and price volatility, lowering the exposure of the LSE and customers to price spikes. Because markets are volatile, commodity providers purchase hedged forward

[20] Bob Burke, Independent System Operator of New England, Remarks at the PLMA Spring Meeting on April 25, 2002. PLMA May Newsletter

contracts in advance of anticipated system peaks to avoid exposure to high market prices. The reduction of price maximum and price volatility reduces the necessary spending on these hedging instruments. This benefit is likely shared with all customers. It further places competitive pressure on bilateral contract prices, because the risk adjusted price of the spot market (price plus hedge) declines.

P3. Reduced market interventions. If customers are less exposed to the risk of price spikes (P2), the necessity for market intervention (price caps) declines. This benefits the generation companies through reduced risk from market interventions, improved planning, and improved ability to recover plant investment through equitable pricing.

P4. Reduced or deterred market power. Peak market prices may be caused by key generating units in constrained areas. More predictable DR measures may be scheduled into day-ahead markets, in advance of anticipated high market prices. This prospective demand response can deter market power. The net result is lower market prices and improved market efficiency (see E4 below).

Risk Management and Reliability Category – Event and Financial Risks

R1. Physical hedge against extreme events. DR provides reliability service through multiple mechanisms. Overall, DR reduces the frequency, magnitude, and duration of outage events. For short-term event response, curtailable loads (e.g., emergency response, direct load control, and call options) provide a physical hedge against the risk of extreme system events. Over the long-term, DR creates *real options* to deal with system capacity shortfalls and related reliability issues.

R2. Lower insurance cost of events. EPRI (2001) has estimated that "power interruptions and inadequate power quality already cause economic losses to the nation conservatively estimated at more than $100 billion a year." DR mitigates this risk. It can be called upon in the event of reserve shortage, thereby reducing the frequency of outages. In addition, DR may cost-effectively minimize the magnitude of an outage event, because loads can be shed in discrete amounts at strategic locations. Loads may be curtailed to facilitate event recovery, reducing the duration and total cost of the event.

R3. Real options / portfolio resource diversity. The diversity of DR resources functions to improve system reliability (or more cost-effectively achieve equivalent system reliability). DR provides physical options (both functionally and by location) for system operators to address events. These *real options* create flexibility in generation, transmission, and distribution that may provide a vehicle to mitigate unforeseen events using strategies that also were not fully planned out in advance. For example, the location of a demand response measure may become unexpectedly strategic, and provide a higher quality load balancing response than existing generator alternatives. Simply stated, the increased diversity that comes with the more direct incorporation of DR in markets provides more options to address unexpected events.

From another perspective, slowed growth in peak demand from pricing DR options can improve long-term reliability. By reducing peak demand growth, fewer generating units are required to support peak load, each unit carrying a probability of forced outage. Over the long term, reduced growth affords more time to adapt to changing circumstances, effectively prolonging the planning horizon. This effect accommodates corrections in errant forecasts and makes requisite infrastructure changes more gradual and economic.

R4. Improved ancillary services. DR may provide benefits through improved ancillary services if it:

- Reduces the amount of required ancillary service

- Provides lower cost service than the generator alternative
- Improves the quality of ancillary service

Operating reserves are a necessary function of a reliable electric system. Reserves ensure that demand fluctuations are matched by generation without significant voltage changes. In addition, they provide reactive power and system black-start capability. Reserves are typically segregated by their response time into regulation, spinning reserve, supplemental reserve, and replacement reserve. Regulation provides real-time response to load fluctuation using automatic generator control. Spinning reserve is synchronized to the grid and can immediately increase output. Supplemental reserve is similar to spinning reserve, but is not required to respond immediately. Replacement reserve is similar to supplemental reserve but with even longer response times.[21]

A distinct market exists for operating reserves. Similar to wholesale power, generators bid their availability to provide reserve service. Operating reserves are typically provided by generating units, however, many types of load are easily (and potentially profitably) capable of comparable or improved service, including residential water heating, commercial space conditioning, and a fraction of commercial and retail lighting. The storage capacity of municipal water pumping makes it an excellent candidate for spinning reserve in California, with Department of Water Resources' loads exceeding 1,500 MW; and, in fact, these loads are already in the California ISO plans for a DR resource.

In 2004, the California ISO indicated that current practices may inadequately distribute operating reserves (CISO 2004). The geographic dispersion of DR improves the flexibility and quality of reserve services, compared to a small number of generators which may not be equally capable of re-balancing load due to their location. DR resources have an inherently high probability of existing within load pockets, making it a potentially more effective load balancing resource.

R5. Opportunity to manage financial and outage risk. Retail energy providers must contend with continuously fluctuating power prices. By creating callable options (i.e., contracts for demand response), providers hedge against the risk of high prices. Risk adjusted pricing benefits all customers. For retailers obligated to serve load that are willing to face price volatility, the market price risk is mitigated. For customers who value certainty in energy costs, the retail provider has improved ability to offer price guarantees at lower costs due to reduced expected price volatility. This may or may not increase the margins that electricity retailers can obtain depending on the regulatory and competitive environments.

The customer participating in DR receives risk management benefits beyond the risk-adjusted prices offered by the provider. With DR, the customer can now manage their financial risks associated with energy costs as part of their overall risk management strategy. Depending on the type of DR program (e.g., voluntary response versus contracted for response), the customer has the option to choose the desired degree of energy cost hedging in accordance with their own valuation of risk.

Market Efficiency Category

E1. Equitable pricing. An important benefit for the electricity markets is that a key attribute of customer demand is now given an appropriate value. With most rate structures today, many

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[21] The impacts of DR on ancilliary services are discussed in Eric Hirst & Richard Cowart. "Demand-side Resources and Reliability: Framing Paper #2," New England Demand Response Initiative. March 20, 2002. Available at: http://nedri.raabassociates.org/

customers that have the ability to shift loads are provided little incentive to take these actions. An effective DR program now places a value on an important attribute – flexibility – that may not now be fully valued.[22] Flexibility in when a customer takes a portion of their electric load is valuable and can reduce overall system costs. This attribute needs to be appropriately valued in a comprehensive DR framework. For customers with flexible electric demand, price signals and incentives allow usage to economically align with costs, resulting in a more efficient use of the electric system.

E2. Innovation in retail markets. Providing a DR framework can result in new retail product and pricing innovations, ultimately benefiting the customer through increased choice and a better matching of the customers' needs with choices offered by electric markets. In markets, cost-reducing providers are rewarded and more expensive competitors penalized. If strategic DR investment enables a wholesale or retail provider to lower cost, that provider may realize an increase in revenues due to a competitive advantage. This may depend on the regulatory environment, but even a regulated entity can enjoy benefits from attaining cost reductions, either as a revenue gain between when rates are set and also through other pathways that may stem from improved customer satisfaction. Regardless, few regulated entities would argue that providing better customer services at lower costs would be bad. The issue is appropriate incentives and regulatory treatment.

E3. Incentive for development of efficient controls and end-use technologies.
The customer's potential for cost savings through load shifting creates a new market for technology that now has an appropriate value proposition and business case. This will help stimulate new end-use control and technology innovations that better manage energy use. DR now allows customers to benefit from these technologies and companies that can develop cost-effective technologies will market them to appropriate customer segments. The customer will not be burdened with researching all options and determining how to best shift energy use. These technology companies now have a business case that will allow them to work with customers to achieve these results.

E4. Reduced market power. Tight supplies and/or transmission constraints can lead to an excess of market power by a generating company. If demand response can be timed coincident with these constraints, or scheduled in advance of constraints, the market power may be mitigated. When the market is functioning well, these prices ensure the efficient dispatch of generation in the short run, provide transparent price signals that facilitate efficient forward contracting, and are a primary component of the long-term incentives that guide generation and transmission investment and retirement decisions.

A typical market analysis examines the constrained areas within the market, and whether any suppliers are either economically or physically withholding resources to raise prices. Market power can result from local reliability requirements for a constrained area that compel the ISO to commit generation outside of the market processes.[23] The use of DR as a locational-based resource can mitigate these effects.

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[22] This is common in other industries where 1-day shipping has a different price than 3-day shipping, and the transportation (air, water, and land) provides different prices for travel at different times which allows those customers with flexibility to incur different costs.

[23] Evidence of market power was found in a constrained area in New England. This is discussed along with the general concerns associated with market power in: **2004 Assessment of the Electricity Markets in New England,** By: David B. Patton and Pallas LeeVanSchaick, Potomac Economics, Ltd., Independent Market Monitoring Unit, ISO New England Inc., June 2005

E5. Overall productivity gains by better utilizing industry investment. Better pricing and the interaction of demand and supply can produce overall productivity gains by better utilizing the fixed investment that comprises one of the largest capital investments made by a country – even a 0.5% productivity improvement per year would be substantial. This benefit may be hard to quantify, but some determination regarding whether this is truly substantial is viewed as important.

Lower Cost Electric System & Service Category

ES1. Reduced short-term capacity requirements. Planning reserves help ensure adequate reliability by providing contingency capacity in excess of projected peak demands. DR may lower the planning reserve requirements and may also provide lower cost alternatives to capacity contracts. Direct load control and call options are functionally capable of meeting planning reserve requirements, and can directly displace peaking unit capacity or fixed contract investment.

If load under control is considered a demand reduction (as opposed to a capacity resource), the planning reserve requirements are further reduced. For example, assume a system with a 10,000 MW peak and a 15% planning reserve has 1,500 MW of planning capacity requirements, which could be met in part by 500 MW of load control. If the 500 MW of controlled load count towards a reduction in peak demand, the planning reserve requirement is reduced to 1,425 MW (9,500 x 0.15). In this case, the 500 MW of load controlled effectively provides 575 MW of capacity reduction**.**

ES2. Lowered transmission capital & operating expense. Estimating the avoided O&M and capital costs for distribution and transmission systems, while maintaining equivalent reliability, has been difficult.[24] Transmission constraint frequently occurs during system peak periods, when DR should have its most pronounced impact. Transmission is also constrained when load is distant from generation. DR resources are likely to occur within load pockets, making it possible to improve power flow. These effects could beneficially reduce transmission operating expense and defer transmission system infrastructure expansion.

ES3. Lowered distribution capital & operating expense. Demand response efforts have reportedly deferred distribution expenses when located at or near a substation that was nearing capacity, but where demand at that substation was growing slowly.[25] Only some substations, however, will meet these conditions. Demand response may provide more flexibility in distribution system O&M and capital expenditures than is currently being credited, as budgeting is based on precedent and may not capture the value of mitigating unforeseen events and substation issues. Recent work has shown greater potential for distribution system benefits.[26]

ES4. Decreased or shifted generating costs. Reducing peak-period load is one of the primary functions of demand response resources. By reducing load during peak periods, the operating

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[24] Dan Violette, et. al., "DR Valuation and Market Analysis Volume II: Assessing the DR Benefits and Costs." Report to the International Energy Agency Demand-side Programme, January 6, 2006.

[25] Jim Eber, ComEd Product Portfolio Manager, Personal Communication. October 15, 2004.

[26] A study was conducted in the Consolidated Edison service territory where distribution was to be re-enforced by placement of distributed generation units. The costs of a combination of wires/systems costs and DG were the cost baseline. DR was shown to have the potential to reduce costs by deferring distribution projects by up to five years. See Brad Johnson, "Enhancing the Business Case for DR in the Mid-Atlantic," presented at the National Town Meeting on Demand Response, Mid-Atlantic Distributed Resources Initiative (MADRI), January 24, 2006.

and fuel expenses from the most expensive generating units are avoided. Some of this cost may be shifted to off-peak periods, and the net-effect must therefore be calculated. The reduction in consumption at the load source should be credited with the equivalent kWh generation savings, plus compensation for additional avoided generation otherwise needed to overcome transmission and distribution losses.

ES5. Reduction in LSE commodity costs. By reducing load during peak periods, DR can reduce costs incurred by more expensive generating units. This reduces the commodity procurement costs of the LSE through bilateral contracts, and reduces market purchase and hedging. Some of this load is shifted to off-peak periods, increasing commodity costs during less-expensive off-peak periods. The net benefit between the peak and off-peak costs must be considered. It is also acknowledged that this benefit may be captured in P1 – Wholesale market price reduction and care is needed to avoid double counting.

ES6. Reduction in long-term resource adequacy requirements. DR uniquely focuses its impact on system peaks, and should have a pronounced effect on reducing long-term generating capacity requirements, and also transmission and distribution infrastructure. The impact of real time pricing and critical peak pricing presumably slows growth in peak demand over the long-term planning horizon. Again, this could also be captured in reductions on wholesale market prices if evaluated using a long-term planning framework and double counting must be avoided.

Customer Service Category

CS1. Increased Customer Choice. Demand response provides customers with greater control over their energy bills. This choice provides value to the customer as a means to manage energy costs and financial or outage risk, or potentially for improving the environment. Some customers place a value on having the flexibility to manage their electricity bills even if they do not take advantage of it immediately, but they know that in the future they have more choices and will receive greater benefits from reducing use during peak periods.[27] Improved customer service may further yield customer appreciation benefits to the utility or commodity provider, if the commodity is not provided by the utility.

CS2. Possible Increase in Customer Services. Integrating DR into electricity markets can result in new energy-using and energy-management technologies. In turn, this can offer customers with enhanced services now that they can benefit from any flexibility they have in electricity use, e.g., shifting use from high cost to low cost periods. The Gridwise Alliance[28] at Pacific Northwest National Laboratories (PNNL) is seeking out win-win opportunities for the electric system and higher levels of customer service.

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[27] This was one of the benefits found in the surveys of customers participating in the Chicago Energy Cooperative's Energy-Smart Pricing Plan℠ in evaluations conducted of the 2004 and 2003 program years. These are available from Mr. Larry Kotewa, at the Cooperative in Chicago, Ill. or from Summit Blue Consulting, Boulder, CO, which performed the work.

[28] The GridWise™ Alliance is a consortium of public and private stakeholders who have joined together in a collaborative effort to provide real-world technology solutions to support the U.S. Department of Energy's vision of a transformed national electric system. An electric system that will employ new distributed "plug and play" technologies using advanced telecommunications, information, and control approaches to create a society of devices that functions as an integrated transactive system. For more information see www.gridwise.org.

DR infrastructure allows utilities to respond faster to outages and to convey the cause and anticipated repair time to customers. This may provide both cost savings and customer satisfaction benefits (Harper-Slaboszewicz 2006).

Environmental Category

E1. Potentially Avoided Impacts. Demand response can yield reduced air, water, and land impacts through reduced electricity consumption and fuel procurement. However, the benefits will vary based on the portfolio of DR options under consideration and there are some options specifically focused on reliability by using distributed generation that may increase some environmental impacts when operated. Over the long-term, demand response may also reduce, defer, or avoid the land use impacts of new generation, transmission, and distribution infrastructure.

Potential Costs of Demand Response Investment

This section identifies the costs of DR programs, which can generally be divided into two categories, initial implementation costs and ongoing operating costs. The delineation of demand response program costs is far more straightforward than the delineation of benefits. It is important that the costs of the program be fully and appropriately dimensioned such that they can be compared to the benefits. There are costs to moving to a market where DR plays an integral role. In this regard, it is also important to examine both short-term and long-term costs and benefits to insure that appropriate time horizons that reflect the nature of the DR resource are considered. For the development of this framework, the potential demand response program costs are:

1) Initial Implementation Costs (fixed costs)
    - IC1. Program design.
    - IC2. Marketing.
    - IC3. Metering/communication equipment.
    - IC4. Business integration.
2) Ongoing Operating Costs (variable costs)
    - OC1. Incentive payments.
    - OC2. Ongoing administration and maintenance.
    - OC3. Customer opportunity costs.

Initial Implementation Costs (fixed costs)

IC1. Program Design. Before a program can be implemented, the program provider must design a demand response strategy that best accommodates the needs of their system.
IC2. Marketing. Marketing is required to achieve an appropriate level of customer participation. In addition to making customers aware of the programs, an educational component is required to assist the customer in understanding pricing structures, end-use response strategies, and potential

savings. For industrial customers, the provider may in turn learn about the customer's operations and limitations, resulting in changes to program design.

IC3. Metering/communication equipment. Once designed, the program provider must invest in and install the technology to carry out the program functions. Conversion from flat rates to dynamic pricing typically involves upgrading metering equipment to systems that monitor demand and consumption on a shorter (e.g., hourly) basis. Communication equipment may be required to control equipment, provide price or event information to the customer, or return customer usage data to the provider. The installation process likely involves some degree of pilot field testing. Installation, start-up, and training may yield higher O&M costs during the initial year of program operation.

Many current DR programs that are load management-based require software to signal and manage participation. The software manages signal tracking, curtailment, cycling, or temperature setback strategies, and data collection on equipment runtime and overrides. The physical location of equipment is distributed between the provider's system and the participant's premise.

IC4. Installation, training, and business integration. The provider may require changes or upgrades to their billing system to handle DR curtailment programs or dynamic pricing. The participant may also incur costs to integrate the required DR responsibilities into its operations management.

Ongoing Operating Costs (variable costs)

OC1. Incentive payments. Emergency response, direct load control, and call options products may provide payments to participating customers. Payment can vary dramatically based on the product design, but it might be a flat monthly payment for the peak months (summer or winter), or it might be based on the number of events and their duration.

OC2. Ongoing administration and maintenance. Ongoing marketing and customer service efforts are required to acquire new customers if the DR program is based on voluntary participation (as most are), incorporate new customers into the program, and provide customer service to customers (e.g., call center costs and basic informational communications), as well as manage those customers that exit or change the way in which they participate in DR. For DR options that are event-based, strategy and implementation of event notification must be managed by the demand response program provider. Program evaluation is necessary to assess impacts and cost-effectiveness and may prompt modifications to program design. Some maintenance effort may be required to check field equipment (e.g., check that switches in the field are functioning). Some vendors may have annual license and software fees.

OC4. Customer opportunity cost and burdens. These costs are borne by participants as a result of event curtailments. This may include the value of lost products or productivity during or due to an event. Other costs may be incurred while responding to an event, including labor to turn off equipment, and fuel expense for on-site generation. Additional labor (e.g., overtime pay) and operating costs may be incurred due to rescheduled production. Sacrifices in comfort and convenience may further curb productivity.

Overlay of Benefits and Costs by Stakeholder

While the delineation of costs is relatively straight forward, the same is not true for benefits. Benefits are shared between customers, local stakeholders, or market-wide entities. The electric industry today can be defined using a number of different stakeholder views. A restructured market is likely to have separate commodity providers or load serving entities (LSEs), a distribution company (DISCO), a transmission owning entity (TRANSCO), and a generating company (GENCO). With the revised re-structuring of the California market, some of these entities may have responsibilities that reflect a re-aggregation of responsibilities in a more traditional integrated utility framework. Still, most utilities have corporate separation. Regardless, a disaggregated look at where the benefits and costs may occur is useful. For this effort, the costs and benefits are delineated by the following stakeholders and market views:

1) Participating customers
2) Non-participating customers
3) Load aggregators
4) Distribution companies (DISCO)
5) Transmission companies (TRANSCO)
6) Load serving entities (LSE)
7) Independent system operator (ISO)
8) Generating companies (GENCO)
9) Market-wide (essentially all market participants)

Part of the difficulty in delineating benefits is temporal. Many benefits will directly accrue to a stakeholder in the short-term, but may be passed on (partially or in full) to customers or other stakeholders over the long-term. As a result, this is a difficult task to set out precisely. The nomenclature used to clarify this distinction is as follows:

- *Direct* refers to benefits/costs realized directly and relatively immediately by the stakeholder, and may be non-financial. While occurring infrequently, customer outage costs (R2) are considered direct, as they are incurred immediately and directly in response to an event.

- *Indirect* refers to benefits/costs which may be passed from the direct recipient to customers or other stakeholders.

- There is also the case that a beneficial impact for one stakeholder incurs a potential cost to another stakeholder.

The overlay of benefits and potential costs across the nine stakeholder perspectives and views is shown in Table 0-2 to Table 0-7. Direct costs are shown in Table 0-8 and Table 0-9 Addressing the seven categories of benefits with each sub-benefit categories listed across the nine different stakeholder "views" requires six tables to portray the different views and all of the benefits categories. Below, the information in the table is summarized by stakeholder.

Table 0-2: Demand Response Benefits by Stakeholder – Direct Financial

Benefit Category:	**Direct Financial**		
Demand Response Impact: **Stakeholder**	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.
Participating Customers	Direct	Direct	
Non-participating Customers			
Load Aggregators	Pot. Cost		Direct
Load Serving Entities (LSE)	Pot. Cost	Pot. Cost	
Distribution Companies (DISCO)			Direct
Transmission Companies (TRANSCO)			
Independent System Operator (ISO)			Pot. Cost
Generating Companies (GENCO)		Pot. Cost	
Market-Wide			

Notes:

Direct refers to benefits realized directly by the stakeholder, and may be non-financial.

Indirect refers to benefits which may be passed from the direct recipient to customers or other stakeholders.

Pot. Cost indicates when an impact is a potential cost to the indicated stakeholder.

Table 0-3: Demand Response Benefits by Stakeholder – Pricing

Benefit Category:	Pricing			
Demand Response Impact: **Stakeholder**	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).
Participating Customers	Direct / Indirect	Direct / Indirect	Pot. Cost	Indirect
Non-participating Customers	Indirect	Indirect	Pot. Cost	Indirect
Load Aggregators				
Load Serving Entities (LSE)	Direct	Direct	Pot. Cost	Direct
Distribution Companies (DISCO)				
Transmission Companies (TRANSCO)				
Independent System Operator (ISO)				
Generating Companies (GENCO)	Pot. Cost	Pot. Cost	Direct	Pot. Cost
Market-Wide	Direct	Direct		Direct

Notes:

Direct refers to benefits realized directly by the stakeholder, and may be non-financial.

Indirect refers to benefits which may be passed from the direct recipient to customers or other stakeholders.

Pot. Cost indicates when an impact is a potential cost to the indicated stakeholder.

Table 0-4: Demand Response Benefits by Stakeholder – Risk Management & Reliability

Benefit Category:	**Risk Management & Reliability**				
Demand Response Impact: / **Stakeholder**	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.*	RM4. Lower cost ancillary services to meet reliability criteria.	RM5. Ability of market participants to manage ongoing financial risks.
Participating Customers	Indirect	Direct	Indirect	Direct/ Indirect	Direct/ Indirect
Non-participating Customers	Indirect	Direct	Indirect	Indirect	
Load Aggregators					
Load Serving Entities (LSE)	Direct		Direct	Indirect	Direct
Distribution Companies (DISCO)	Direct		Direct	Direct	
Transmission Companies (TRANSCO)	Direct		Direct	Direct	
Independent System Operator (ISO)	Direct		Direct	Direct	
Generating Companies (GENCO)					
Market-Wide	Direct	Direct		Indirect	

Notes:

Direct refers to benefits realized directly by the stakeholder, and may be non-financial.

Indirect refers to benefits which may be passed from the direct recipient to customers or other stakeholders.

Pot. Cost indicates when an impact is a potential cost to the indicated stakeholder.

* "Real Options" also due to a larger set of options for meeting loads both ongoing and in emergency situations.

Table 0-5: Demand Response Benefits by Stakeholder – Market Efficiency Impacts

Benefit Category:	Market Efficiency Impacts				
Demand Response Impact: / **Stakeholder**	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.
Participating Customers	Direct	Direct	Indirect	Direct / Indirect	Indirect
Non-participating Customers		Direct	Indirect	Indirect	Indirect
Load Aggregators					
Load Serving Entities (LSE)				Direct	
Distribution Companies (DISCO)					
Transmission Companies (TRANSCO)					
Independent System Operator (ISO)	Direct			Direct	Direct
Generating Companies (GENCO)	Direct			Pot. Cost	
Market-Wide		Direct	Indirect	Indirect	Indirect

Notes:

Direct refers to benefits realized directly by the stakeholder, and may be non-financial.

Indirect refers to benefits which may be passed from the direct recipient to customers or other stakeholders.

Pot. Cost indicates when an impact is a potential cost to the indicated stakeholder.

Table 0-6: Demand Response Benefits by Stakeholder – Lower Cost Electric System & Service

Benefit Category:	**Lower Cost Electric System & Service**					
Demand Response Impact: **Stakeholder**	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
Participating Customers	Indirect	Indirect	Indirect	Indirect	Indirect	Indirect
Non-participating Customers	Indirect	Indirect	Indirect	Indirect	Indirect	Indirect
Load Aggregators						
Load Serving Entities (LSE)	Direct	Indirect	Indirect	Indirect/ Pot. Cost	Direct	Direct
Distribution Companies (DISCO)			Direct			Direct
Transmission Companies (TRANSCO)		Direct				Direct
Independent System Operator (ISO)						
Generating Companies (GENCO)	Pot. Cost			Direct/ Pot. Cost		
Market-Wide						

Notes:

Direct refers to benefits realized directly by the stakeholder, and may be non-financial.

Indirect refers to benefits which may be passed from the direct recipient to customers or other stakeholders.

Pot. Cost indicates when an impact is a potential cost to the indicated stakeholder.

Table 0-7: Demand Response Benefits by Stakeholder – Customer Services & Environmental

Benefit Category:	Customer Services		Environmental
Demand Response Impact: Stakeholder	CS1. Increase in customer choice.	CS2. Possible increase in services.	EN1. Potential avoided land-use, water, and air impacts.
Participating Customers	Direct	Direct	Direct
Non-participating Customers			Direct
Load Aggregators			
Load Serving Entities (LSE)	Indirect	Indirect	
Distribution Companies (DISCO)			
Transmission Companies (TRANSCO)			
Independent System Operator (ISO)			
Generating Companies (GENCO)			
Market-Wide			Direct

Notes:

Direct refers to benefits realized directly by the stakeholder, and may be non-financial.

Indirect refers to benefits which may be passed from the direct recipient to customers or other stakeholders.

Pot. Cost indicates when an impact is a potential cost to the indicated stakeholder.

Table 0-8: Demand Response Cost by Stakeholder – Implementation Costs

Benefit Category:	**Implementation Costs**			
Demand Response Impact: / **Stakeholder**	IC1. Program Design	IC2. Marketing	IC3. Metering/ communication equipment	IC4. Business Integration
Participating Customers	Indirect	Indirect	Direct	Direct
Non-participating Customers			Indirect	
Program Provider	Direct	Direct	Direct	Direct

Table 0-9: Demand Response Cost by Stakeholder – Ongoing Operating Costs

Benefit Category:	**Ongoing Operating Costs**		
Demand Response Impact: / **Stakeholder**	OC1. Incentive Payments	OC2. Administration & Maintenance	OC3. Customer Opportunity Cost and Burden
Participating Customers			Direct/Indirect
Non-participating Customers			
Program Provider	Direct	Direct	

The different stakeholder and resource views are discussed below.

Participating Customers

The direct benefits to customers come in the form of incentive payments and savings accrued from reduced or shifted usage. The reduction in market prices may be a direct or indirect benefit to customers, depending on the extent market pricing is embodied into the DR offer in which that customer is participating. The same is true for the "equitable pricing" (E1) benefit and "reduced market power" benefit. (E4).

The participating customer receives direct benefits from the reduced losses due to outage, although a long-term stochastic approach is required to value this benefit. Participating customers receive risk management benefits through increased ability to manage their energy costs within their overall business risk management strategy. Reductions in electricity system and service costs will likely be indirectly shared with customers over time. Although more difficult to quantify, the customer receives direct benefits from improved customer choice and customer service. Potential environmental impacts may provide all customers with direct (e.g., air quality) or indirect (e.g., long term land use) benefits.

The direct customer costs of participation may be significant, and include equipment (IC3) and business integration expenses (IC4), as well as the opportunity costs and burdens of participation (OC3). Costs born by the LSE (IC1 – IC4) may be indirectly passed through to the customer through rate mechanisms. The costs of DR are highly dependent on the design of the DR program.

Non-participating Customers

Non-participating customers also receive the benefits of reduced market prices although it is hard to determine if this is a direct benefit (if they are in the spot market) or a somewhat more indirect benefit that will occur over time as bilateral contracts expire. They do receive direct benefits from increased reliability. Many of the electricity system cost reductions (ES1-ES6) will likely be partially shared with all customers over time. Based on this same logic, market pricing and market efficiency benefits will likely accrue to non-participating customers over time. Costs born by the LSE (IC1 – IC4) may be indirectly passed through to the customer through rate mechanisms.

Load Aggregators

A load aggregator (Specialty Demand Response Provider) may receive incentive payments from a benefiting entity (e.g., at a cost to the ISO). The load aggregator may pass on this benefit, in part, to recruit participating customers. The load aggregator may be responsible for many of the costs of demand response implementation, including marketing (IC2), equipment (IC3), incentive payments (OC1), and administration and maintenance (OC2).

Distribution Company (DISCO)

If the DISCO entity in the utility is the primary provider of demand response programs, it holds primary responsibility for the design (IC1), marketing (IC2), metering and communications equipment (IC3), and business integration expenses (IC4). The LSE may be similarly responsible for much of the ongoing costs, including incentive payments (OC1) and administration and maintenance (OC2).

A distribution company may receive incentive payments from a benefiting entity (e.g., ISO) in return for demand response investment. This payment is a cost to the ISO. The DISCO may be able to avoid or defer short-term capital and operating expenses (ES3) as well as long-term infrastructure requirements (ES4). The DISCO further receives reliability benefits through the physical hedge (R1) and “real options” (R3) provided by demand response.

Transmission Company (TRANSCO)

Similar to the DISCO, the TRANSCO may avoid or defer short-term capital and operating expenses (ES2) as well as long-term infrastructure requirements (ES4). The TRANSCO also receives reliability benefits through the physical hedge (R1) and “real options” (R3) provided by demand response.

Commodity Provider/Load Serving Entities (LSE)

The LSE may be a primary provider of demand response programs, and as such incur many of the implementation costs, including design (IC1), marketing (IC2), metering and communications equipment (IC3), and business integration expenses (IC4). The LSE may be similarly responsible for much of the ongoing costs, including incentive payments (OC1) and administration and maintenance (OC2).

While the LSE is the primary beneficiary of many of the benefits of demand response, much of the value may be passed on to its customers. Reductions in wholesale market prices and deterred market power (P1, P2, P4) directly benefit the LSE by reducing its commodity costs, as does the cost saving from reduced short and long-term resource requirements (ES1, ES5, ES6).

The LSE may indirectly benefit through savings passed on from generation, transmission, and distribution capital and operating costs (ES2, ES3, and ES4). Because the LSE holds the obligation to serve, it directly benefits from the risk management (RM1) and reliability benefits of demand response: as a physical hedge against extreme events (R1), through the “real options” diversity in resources (R3), and improved ancillary services (R4). Finally, improved customer choice and service (CS1, CS2) may return customer appreciation benefits to the LSE.

Independent System Operator (ISO)

The ISO does not hold a financial stake in market transactions or infrastructure, so it is unlikely to receive significant financial benefit from demand response. As the ISO is responsible for dispatch of generation and operating reserves, the real options flexibility (R3), improved ancillary services (R4), and transmission relief (ES2) may allow more efficient system operation with less administrative cost. To the extent the ISO mission is to facilitate an efficient market, it may receive direct, but non-financial, benefits of market efficiency (E1, E4, and E5).

Generating Companies (GENCO)

If demand response enabled a more efficient marketplace, the reduced interventions (P3) would benefit the GENCO by enabling cost recovery on peaking capacity through equitable pricing (E1). Some of the benefits of demand response are arguably rent transfers, with the costs borne by the GENCO. Potential costs include revenue lost to reduced customer consumption (DF2), pricing reductions (P1, P2, P4), reduced market power (E4). Shifted generation costs (ES4) may reduce revenues for peaking plant operators but add revenue to off-peak plant operators.

Market-wide Effects

If demand response investments are made unilaterally across the regional market, then each market will receive some reciprocal value from the others. If demand response is implemented in only a portion of the market, however, some of the benefits will be directly shared market-wide. These include pricing reductions and hedging costs (P1, P2, P4), reliability benefits mitigating likelihood and costs of extreme events (R1, R2, R3, R4), and potential environmental benefits (E1). The greater market also benefits indirectly through market efficiency improvements (E2, E3, E4, and E5).

Summary: DR Benefits and Costs

The importance of the role of demand response in making markets efficient is clearly understood. Markets require the interaction of demand and supply if they are to efficiently operate. If there are obstacles to the appropriate balancing of demand and supply through market or regulatory mechanisms, then the market will not achieve its objectives in terms of efficiency, equitable allocation of resources and benefits. As a result, demand response is a necessity and there has always been demand response in electric markets. The questions that have been raised are concerned with: 1) whether there is the appropriate flexibility and 2) whether the market signals now in place encourage demand response that promotes market efficiency and equity.

Delineating the benefits and costs of policy changes to encourage more DR has shown that a wide range of approaches have been used and could be used singularly or in various combinations. This diversity of DR options and the different ways in which DR might affect stakeholders leads into complex analyses.

This chapter’s cost-benefit discussion shows that the wide variety of methods, programs, and approaches to DR (ranging from direct load control, to voluntary response to notifications, and to pricing options such as CPP and RTP) inhibit precise definitions that apply in general across all approaches to increase the amount of DR in electricity markets.

In this analysis, we developed seven categories of benefits along with up to four subcategories of benefits within these overall categories:

Categories of Benefits

1) Direct Financial
2) Pricing
3) Risk Management and Reliability
4) Market Efficiency
5) Lower Cost Electric System & Service
6) Customer Services
7) Environmental

The costs of DR pose their own challenges, but two major cost categories were identified, each with several subcategories.

1) Initial Implementation Costs (fixed costs)
    - IC1. Program design.
    - IC2. Marketing.
    - IC3. Metering/communication equipment.
    - IC4. Business integration.
2) Ongoing Operating Costs (variable costs)
    - OC1. Incentive payments.
    - OC2. Administration & maintenance.
    - OC3. Customer opportunity costs.

The different stakeholder and resource perspectives were developed using the nomenclature of a re-structured market, which seems appropriate even in California which has revised its approach to the market. As most of the utilities in the market maintain corporate organization reflecting these basic market functions, it was deemed reasonable to keep the perspectives at this organizational level. If a utility has re-integrated these functions (e.g., commodity provider and distribution), then the perspective is the aggregate view of the two separate stakeholder views. It seems easier to aggregate up, rather than to break out new stakeholder views if that is needed. The stakeholder views that were identified for the framework involved nine views:

1) Participating customers
2) Non-participating customers
3) Load aggregators
4) Distribution companies (DISCO)
5) Transmission companies (TRANSCO)
6) Load serving entities (LSE)

7) Independent system operator (ISO)
8) Generating companies (GENCO)
9) Market-wide (essentially all market participants)

This matrix of seven categories of benefits, the two basic cost categories – initial implementation (fixed costs) and ongoing operating costs (variable costs), and the nine stakeholder/resource perspectives bounds this initial look at the framework. It is not clear whether a full framework would require tests that illustrate the benefits and costs to each of these identified entities. Most of these specific different perspective tests would make use of different subsets of the benefits and costs dimensioned in Sections 3.1, benefits, and Section 3.2, costs, according to the overlays shown in Section 3.3.

DR Valuation Framework: Needs Assessment

What are the appropriate objectives for a comprehensive DR conceptual valuation framework? Such a framework should be able to address certain critical questions, identified in the following *needs assessment*. This needs assessment does not start with the California SPM tests, but takes a step back to assess the overall RON-1 R&D objectives as they pertain to the value of DR.

Introduction – Setting Objectives

There is recognition in California that past planning processes, predicated largely on unrestrained customer consumption at a constant price, are no longer viable. Under these assumptions, investment is targeted to meet forecasts of peak demand plus a reserve margin. Prices of electricity and potential price elasticities and flexibility in customer demand were generally not considered. Different growth rates in demand were often included as scenario analyses, but directly incorporating flexible demand and shifting of loads from high cost periods to low-cost periods were not explicitly addressed. At an intellectual level, using engineering-modeled supply options to meet electricity demand based on constant prices is widely acknowledged as inefficient.

It has become generally recognized that efficient markets are based on the interaction of supply and demand in response to appropriate price signals. Failure to harness the ability of customers to change their demand in response to prices reduces overall market efficiency, particularly, given the volatility electricity prices. Without responsive demand, efforts to create efficient electricity markets are destined to fail.

> *Simply stated, if a market does not appropriately price what is scarce (i.e., electricity during peak periods), there will be no incentive to appropriately manage these scarce supplies, attain efficient resource allocation, and develop value propositions for technology development and deployment that will enhance the ability of demand to appropriately respond to and balance supply-side considerations.*

The resource valuation tools designed to minimize electric system costs have been developed over 50 years of industry planning and operations and are not easily changed or adapted. There is always the possibility that hasty policy decisions could have unintended consequences that might, at least in the short-run, result in high costs and reductions in efficiency.

There would seem to be several fundamental questions addressed in a comprehensive value framework for DR. One of the complexities is that customer demand response encompasses such a wide range of variations:

- Event-Based Dispatchable Demand Response -- At one end, there are centralized forms of dispatchable demand that can be monitored and committed by system operators.

- Non-Event-Based Demand Response -- At the other end of the DR spectrum are decentralized forms such as price based response by consumers who make individual decisions to shift or reduce demand without direct communication with the utility or system operator. A non-event based real-time pricing program would fall into this category. This would mean that customers would respond to real time prices (day-ahead or real-time market prices) every day, not just on days that the utility deems are "event days."[29]

- Energy Efficiency -- Extending this range beyond DR to include all forms of demand-side activities would then include energy efficiency. Energy efficiency would result in essentially permanent reductions in peak demand. The customer choice component is limited to the decision to install the energy efficiency equipment, i.e., they would not be responding to market or system stimuli across time periods either through prices, event signals, or by allowing operator dispatch.

A traditional supply-side planning exercise recognizes the value of different resources and typically produces a *least cost* generation plan, consisting of a portfolio of resources (ranging from high capital cost baseload generation to low capital cost, high variable cost peaking plants) to meet the given load requirements.

A comprehensive assessment of DR (and DSM options), similarly designed to attain the highest system benefits, would also result in a portfolio of options: 1) energy efficiency comparable to base-load generation, 2) a decentralized price-response option to address certain DR objectives, and 3) event-based system operator-controlled dispatchable DR to address select system emergencies or critical market events.

As with any type of resource allocation, it is likely that some forms of DR will be subject to diminishing returns as increasing amounts of that type of DR are provided. In addition, from a portfolio perspective, there will be interaction effects between different forms of DR. For example, energy efficiency and/or RTP will reduce peak demand. With these resources/policies in place, a dispatchable, system operator-controlled DR program may have less value since the likelihood of system emergencies and critical market events have been mitigated by the energy efficiency and pricing demand-side activities.

The framework challenges discussed in Section 2.0 along with the benefits and costs discussed in Section 3.0 quite directly lead to a number of questions that should be addressed by a "comprehensive DR conceptual valuation framework" as called for in RON – 1. The following section sets out what are believed to be some of the objectives that such a framework should meet.

Framework Needs Assessment

This section discusses some of the questions that a comprehensive DR framework will need to address. Some of these questions are the same types of questions that electric system planners address in any type of resource assessment. A basic set of questions that a framework should address are presented below.

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[29] A discussion of the issues associated with "dispatchable DR" and more decentralized price-response by consumers who make individual choices can be found in Bushnell, J., "*Electricity Resource Adequacy: Matching Policies and Goals*," Center for the Study on Energy Markets (CSEM), University of California Energy Institute, Working Paper CESM WP 146, August 2005. This paper argues that restricting the focus to a regulatory standards approach that focuses on dispatchable DR options may foreclose the opportunity for broader and more effective DR from these decentralized pricing programs which emphasize individual customer decisions in response to price signals.

Q1: BASELINE QUESTION – WHAT IS THE VALUE OF EXISTING DR AND IS THERE A NEED FOR ADDITIONAL DR?

There already exist a certain number of DR programs and pricing options in California. The starting point, therefore, is a threshold question concerning the value of existing DR: Is there a need for more aggressive policies and programs to promote DR? This question establishes the baseline against which DR value is assessed.

This is an important question. The value of any resource is defined against an alternative. If the resource is lower cost or provides a higher quality service than the selected base case, then that that provides the means for measuring value for that resource. The base case for a value framework analysis should, at a minimum, contain:

- A base case demand forecast.
- An existing set of generation resources.
- Existing levels of transmission and distribution resources and capabilities. The Western Electric Coordinating Council (www.wecc.biz) contains information on the current transmission system.
- Existing levels of demand response and or demand resources – even today, as prices (average or marginal) go up, there are some changes in demand; and some DR programs currently exist. An assumption that backs out existing DR and develops a demand forecast adjusted for this changed assumption could be made.

In summary, a baseline against which the value of expanded DR is defined is needed. The baseline represents the without new DR scenario against which the with DR scenario is compared to develop estimates of net benefits. The selection of a baseline that represents what would happen in the industry, absent new programs, policies, or options, is a critical component of any assessment framework.

Q2: WHAT TYPES OF DR PRODUCTS/OPTIONS SHOULD BE ASSESSED AS PART OF A DR PORTFOLIO?

A wide variety of DR products are available ranging from: 1) mass-market direct load control of appliances that can provide load relief in a matter of minutes; 2) under-frequency relays installed on specific equipment that will be tripped the second voltage drops to unacceptable levels; and 3) large customer interruptible programs where several hours' notice may be required. There are many variants on mass-market and large customer DR programs/options ranging from those that are dispatchable and under the control of system operators to pricing policies that are decentralized. In addition, there are many different specifications for event based DR that might include requirements such as notifications of 30 minutes to 2 hours, 4 hours, or even 8 hours, as well constraints on the number of times a load can be curtailed during a given period (week, season, or year). In addition, there can be pricing programs that are event based, e.g., the current Day Ahead pricing program is only activated upon notice by the local utility that an "event" day is being called.

Where dispatchable DR is at one end of the spectrum, energy efficiency could be viewed as being at the other end of the DR spectrum. As energy prices increase on average, more investments in energy efficiency will become economic, which will lower overall peak demand.

As a result, the framework needs enough flexibility to look at many DR alternatives with sufficient detail to accurately capture program performance and any program-embodied constraints.

Q3: HOW SHOULD THE FRAMEWORK DETERMINE WHAT SIZE OF THE DIFFERENT DR PRODUCTS IS MOST APPROPRIATE (I.E., HOW MANY MW OR MWH SHOULD BE ACCOUNTED FOR IN EACH PRODUCT)?

Most DR portfolios will be comprised of several different products. Some consideration must be given to which products provide the greatest value to a specific regional electric system or market, and which should be more aggressively deployed. A DR program can be over-built which will reduce the benefits from the DR portfolio, as shown in the resource planning case study in Section 4.

Q4: DOES THE TIMING OF DR DEPLOYMENT, EXPANSION, AND/OR MAINTENANCE IN A STEADY SITUATION INFLUENCE THE VALUE OR DESIRED MW CAPACITY OF A DR PROGRAM/OPTION?

One of the advantages of DR products is their flexibility. They can be deployed on a quick hit basis to aggregate a considerable amount of responsive load in a short period of time, or they can be rolled out, possibly at a lower cost, over a longer period of time. If DR products are not immediately needed due to excess generation capacity, a planned roll-out can schedule DR products based on anticipated future needs. If reduced DR commitment is warranted, the programs can be down-sized simply by not replacing exiting customers, or in the extreme, asking some customers to leave the program.

The start-up costs of DR products should not be underestimated. Eliminating a DR product only to find that there is a need for the product, even in a five- to six-year timeframe, could cost more than simply placing the program in a maintenance mode (i.e., new customers are not enrolled and annual and variable costs are reduced to minimal levels). This maintains the program and allows for increased capacity when needed. DR has greater flexibility, as a resource that follows the need for capacity, than most supply-side technologies that have higher fixed costs which need to be recovered through operations.

Q5: DO DIFFERENT DR PRODUCTS WITHIN A PORTFOLIO HAVE POSITIVE AND/OR NEGATIVE SYNERGIES?

If real-time pricing is offered as a DR option, then how will this impact the economics and value of, for example, a large customer interruptible program? This question arises frequently. Real-time pricing will reduce the demands during peak hours, as customers respond to the higher prices by reducing demand in these hours. This will have an impact on the value of an interruptible program, since the MW reduction that may be needed during a peak demand event will be lower. This implies that the value of DR will depend upon the portfolio of different DR programs/options being assessed. Above, it was argued that a mix of DR with some energy efficiency (conceptually comparable to base-load generation) to near-real time dispatchable DR at the other end of the spectrum may provide the greatest value to the system. This compares directly to fact that supply-side planning develops a mix of supply ranging from high capital cost plants to high variable cost peaking resources.

Q6: <u>WHAT ARE THE "INSURANCE AND PORTFOLIO BENEFITS" FROM DR DUE TO INCREASED DIVERSITY IN RESOURCES (E.G., FUEL INPUTS) AND LOCATION (DISTRIBUTED NEAR END-USE LOADS)</u>?

One way of looking at the framework is as an investment strategy designed to meet future electricity needs. This investment strategy is made under considerable uncertainty around key factors that will influence the system costs. This can include:

- The price and availability of input fuels for generation (gas, oil, and coal) in the WECC region.
- Weather which can impact both average seasonal and peak demands.
- Water levels at hydro facilities.
- The performance of power plants (i.e., occurrence of forced outages at major plants).
- Transmission delivery constraints due to unexpected events.
- Uncertainty regarding the costs and performance of future resources (e.g., how will future environmental regulations impact resource costs).

The fact that this is an important consideration is underscored by recent research. For example, the ISO New England Regional System Plan explicitly analyzed the short-term and long-term issues related to the diversity of fuels used to generate electricity.[30] An assessment of these uncertainties in a study for the International Energy Agency[31] indicated that reasonable bounding of these uncertainties when aggregated together produced a range of system costs for each year where the high end of the range for each year in the planning analysis had a high cost that was approximately double the lower bound estimated system cost for each year in the planning horizon.

The magnitude of these uncertainties make it important to assess whether DR programs/options provide benefits. As such, DR can provide a diversification away from fossil fuels and also locational diversity which can mitigate some transmission/distribution system risks. DR can provide a hedge against low-probability, high-consequence events by mitigating the financial impacts of extreme market events or facility outages. In this context, DR can be viewed as a hedge that can mitigate (not necessarily eliminate) the costs of extreme events. As such, it is a physical option that has value in reducing the uncertainty in future system costs. It is important to be able to assess this value in a comprehensive framework.

Q7: <u>HOW WILL THE OVERALL IMPACTS ON THE ELECTRICITY MARKET BE ASSESSED – INCENTIVES FOR DEVELOPMENT OF APPROPRIATE TECHNOLOGY AND SUCH THINGS AS MITIGATION OF MARKET POWER</u>?

The development of DR mechanisms in markets now provides a value to customers that can shift load or otherwise use electricity in a flexible manner. Under a regime of constant prices, there

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[30] ISO New England, "2005 Regional System Plan," October 20, 2005.

[31] Violette, D., R. Freeman, and C. Neil. "*<u>DR Valuation and Market Analysis -- Volume II: Assessing The DR Benefits And Costs</u>*," Prepared for the International Energy Agency, Demand-Side Programme, Task Xiii: Demand Response Resources, Task XIII, January 6, 2006

are no incentives for technology companies such as Honeywell or Johnson Controls, among many, to develop technologies that help customers be more flexible in their use of energy. Now, with customers able to benefit financially from shifting loads, a business case for the development of these technologies exits. If there is reasonable certainty that this will persist into the future, it is expected that additional technology will be developed that will help customers manage their energy use. An EPRI report[32] indicated that the number of load control vendors peaked in the 1980's and 1990's in parallel with the amount of demand response investment levels reported to the U.S. Department of Energy. As the market declined through the period of industry restructuring, companies merged or moved investment into other business lines. Similarly, there may be other factors that become important as demand response is appropriately incented by the market. Consumers may become more knowledgeable about energy use and their options since they now have an opportunity to save money by participating in a pricing DR tariff or program. Other factors that have been mentioned include more incentives for the building of new generation that now balances supply with demand, and the mitigation of market power (e.g., by reducing the number of load pockets where a limited amount of generation can influence the price of power in that pocket).

Summary – Overall Framework Needs Assessment

These questions presented above illustrate the need for a planning and benefit-cost framework that assesses both entry investment into DR and appropriate ongoing investment in DR products based on market and technology circumstances. In addition, DR products vary in their specifications for the number of hours per season or year it can be called and the length of each event. These factors will affect the value of DR, the impact of which is dependent on the characteristics of the system. Therefore, a dynamic model is needed to assess the value of different portfolios of DR products within any specific electricity market.

[32] Levy, R. "New Principles for Demand Response Planning," EPRI Final Report EP-P6035/C3047, March 2002.

Comparison to an SPM-type Benefit-Cost Analysis

This dynamic resource planning approach differs from the current SPM approach[33] which, for the most part, does not explicitly address uncertainty (except possibly through scenario analyses) and is not able to directly address the insurance and risk management aspects. In addition, the current SPM does not place a value on the flexibility of DR resources as they can be ramped up, maintained (essentially held constant), and even ramped down. This allows DR to more closely follow demand growth and system needs than does a fixed investment in a supply-side resource. In general, the current SPM is a static approach to assessing the benefits and costs of DR resource programs where a resource planning approach is dynamic and more amenable to addressing uncertainty as system factors (e.g., fuel costs, demands, etc.) evolve over time and include correlations over time and across key factors that drive net system costs. The net system costs produced as part of a resource planning framework is itself a benefit-cost framework in that both the contributions of DR and supply-side resources as well as the costs of enabling those contributions are accounted for in the analysis.

Developing Practical Benefit-Cost Tests for DR Program Design and Approval

The resource planning framework for assessing the benefits of DR in a forward-looking resource portfolio can address a number of questions pertaining to the role of DR in a resource plan and the overall target magnitudes of different types of DR. Still, specific DR programs need to be planned and approved. There is no question that there is a need for a short-form approach to DR assessment similar to the SPM used for energy efficiency programs. It is simply impractical to run this type of comprehensive resource planning analysis every time a DR program concept is considered. This means that outputs from and, in some cases, approximations of the comprehensive analysis will be needed to provide inputs into a standard-framework type of analysis. The development of an appropriate and practical benefit-cost framework will depend upon the DR program categories assessed in the comprehensive framework. If the categories of DR programs contained in the comprehensive assessment span the range of program types that are considered for specific implementation, then the values of these programs can be approximated from values produced in the comprehensive analysis.
The specific program design efforts will then focus on being cost-effective focusing on:

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[33] There have been numerous comments, workshops, and regulatory filings that have addressed both some of the shortcomings for of the current SPM for DR as well as making suggestions for improvements to the SPM to address some of these factors. The three sets of testimony updating the application of the Standard Practice Manual tests for DR filed in August 2005 are:

1) "Supplemental Testimony Supporting Southern California Edison's (U 338-E) Application for Approval of Demand Response Programs, Goals, and Budgets for 2006-2008 – Cost-effectiveness of Demand Response Programs and Overall Portfolio" Application No.: A.05-06-008, Before the Public Utilities Commission of the State of California, August 26, 2005. Witnesses – L. Ziegler, M. Whatley, S. Kiner, and D. Reed.

2) "Supplemental Testimony of David T. Baker, San Diego Gas & Electric Company," Application Nos.: A.05-06-006, A.05-06-008, A.05-06-017, Before the Public Utilities Commission of the State of California, August 26, 2005.

3) "Pacific Gas and Electric Company Demand Response 2006-2008 Programs – Supplemental Testimony," Application No.: 05-06-006, Before the Public Utilities Commission of the State of California, August 26, 2005. Witnesses: Antonio J. Alverez and Corey A. Mayers.

- Program designs that provide the largest amounts of MW impacts at the lowest implementation cost, i.e., what is the most cost-effective implementation approach.

- Effective marketing plans for DR programs to achieve adequate levels of participation at a reasonable level of marketing, sales, and fulfillment cost for the program.

- Appropriate evaluation of DR programs to test both the expected impacts of the DR program as well as testing to see if the costs of the program are within the expected range. These evaluations would be designed to confirm the design-based benefit-cost tests of DR programs.

Needs Summary

There is also no getting around the tough questions that DR products pose for overall resource planning and for running efficient electricity markets. The factors that influence the electric markets are dynamic, and a dynamic process is needed to assess their contribution to the overall robustness of the electricity market.

This implies that the framework should directly addresses difficult issues such as:

1) Uncertainty in key factors that the impact system costs (e.g., peak demands, fuel prices, plant outages, and transmission line constraints).

2) A time horizon that is long enough to encompass the occurrence of low-probability/high-consequence events.

3) A process that fairly addresses the tradeoffs between supply-side technologies (generation and T&D) and DR programs/options on overall system costs, system reliability, and risks associated with extreme events.

The utility industry has become expert at applying the types of models needed to address these questions for both costs related to generation and costs related to the transmission and distribution (T&D) systems. Ideally, the framework would incorporate uncertainty in generation and T&D capital budgeting, and also in annual operating and maintenance (O&M) budgeting. In some cases, utilities are beginning to examine these issues, but most efforts will require some innovation and adaptation to address these framework needs. Finally, the issues can be viewed in a resource planning context that uses existing utility methods and tools in resource planning with adaptations to address the unique challenges of DR.

DR Valuation – A Comprehensive Framework

This section presents a proposed valuation framework for DR that can address specific DR portfolios and encompass the value of DR as it pertains to the benefits and costs identified in Section 3. The initial focus is on assessing the benefits in terms of the overall cost of meeting the demand for electricity, and impacts on system reliability. This section describes four Task Work Areas, and a set of steps for determining baseline conditions to costing out DR alternatives and assessing the value of DR. The final section of this report, Section 6.0: Comparison of the Value framework for DR to the Current SPM, discusses how the framework can be used to address issues in the current SPM that would allow for DR to be more appropriately assessed.

Introduction

The framework approach proposed in this section adapts planning tools and processes that are in general use across the utility industry. It is believed that working with methods and techniques that are familiar to the utility industry will produce a framework that will be better understood by industry actors, i.e., the utilities, major customers, regulators, and other industry stakeholders. The focus of this section is not on developing adjustments to the current SPM that might provide an interim fix for shortcomings in the way the SPM addresses DR. Instead, this section lays out a R&D research plan that would allow DR to become a more integral component in utility resource planning decisions. The discussion of the SPM is included in Section 6.0. Examining an approach separate from “fixing the SPM” is viewed as an important R&D objective to ensure that a case is made for different approaches for valuing DR.

A forward-looking planning approach is taken since the value of DR will come in the future as programs/options are implemented, and their value will be based on the avoided costs of alternatives that would have been selected if the DR option had not been available. Thus, much of the value of DR will stem from lowered system costs related to generation, transmission, and distribution. The benefits and avoided costs from these analyses can be re-organized to develop different stakeholder perspectives. This approach will allow for the overall magnitude of DR in a resource portfolio to be addressed as well as the timing (need for DR), and the locational value of DR.

The proposed approach is organized into four Task Work Areas. The first three will adapt planning processes that are currently used in the utility industry. The Fourth Task Work area addresses many hard to quantify benefits and will use a scenario analysis approach to estimate market effects that are not addressed by the utility planning models:

- **Task Work Area 1** – Generation resource planning and production costing with transmission constraint to estimate price effects and related risk management impacts from DR portfolios.

- **Task Work Area 2** – Transmission investment avoided/deferred costs based on engineering approaches and modular cost estimation.

- **Task Work Area 3 –** Distribution investment deferred costs based on engineering budget based estimates and longer-term project plans.

- **<u>Task Work Area 4</u> –** Market and Customer effects related to overall productivity, customer choice, and enhanced service benefits.

The fourth task work area – market and customer effects – will be developed to assess effects that are not captured in traditional utility planning approaches. This will be based on scenarios designed to assess:

- Possible innovation in technologies now that customers can benefit from load shifting, thereby providing a business case for technology development to assist customers in managing their demand.

- Possible impacts of reduced or deterred market power.

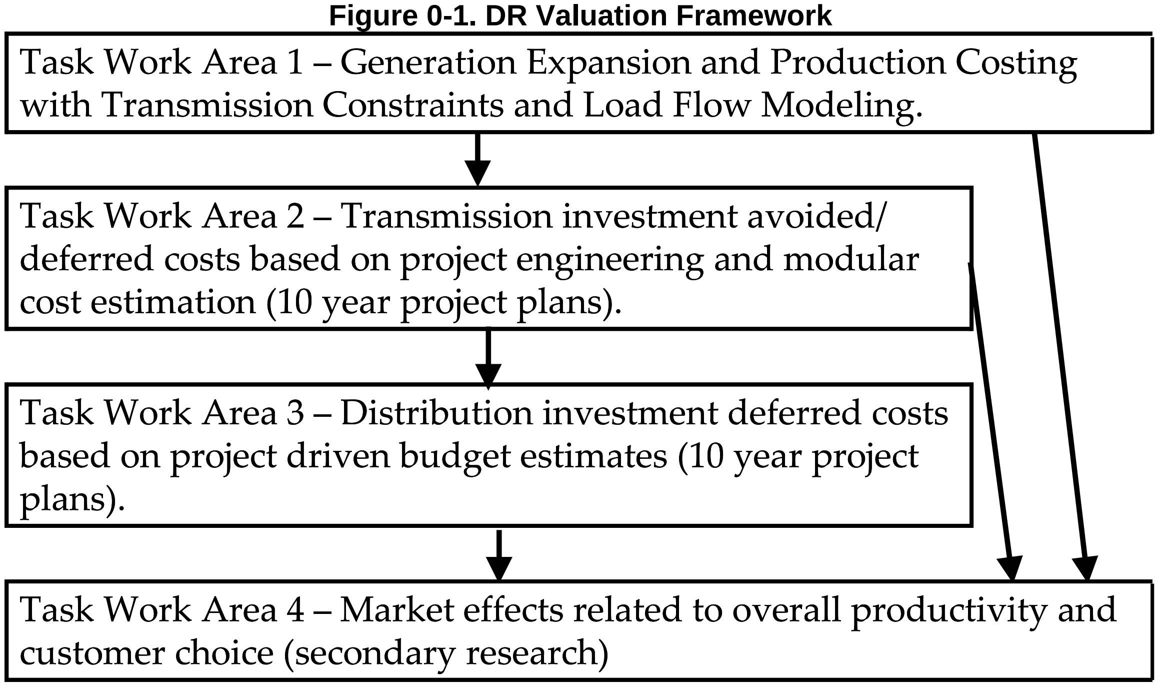
- Potential overall industry productivity benefits due to aligned incentives for a capital intensive industry.

- Customer benefits that may come from increased customer choices related to energy cost management and the potential for additional customer services.

There is a direct link between generation and transmission, i.e., both are needed to meet the needs at load centers, so the first of the four valuation task work areas look at generation and transmission jointly.

Figure 5-1 outlines this four task evaluation framework.

Figure 0-1. DR Valuation Framework



These proposed approaches conform quite closely to planning methods currently in use by the three IOUs in California. As a result, the Summit Blue proposal provides for the opportunity to work in partnership with one of the IOUs to test the framework in the areas where the IOUs have existing modeling capabilities. If such a joint effort were developed, the implementation of the framework could be undertaken by one or more of the utilities using planning tools and methods at that utility adapted as outlined in the framework discussion below. If an IOU in California has the resources available and sees a benefit in testing the framework, working in conjunction with a utility would provide a number of advantages in terms of market knowledge and current data. However, if the frame work is implemented entirely by outside consultants, all the model vendors cited maintain data on both generation and transmission resources in the WECC. Developments in building these resource planning capabilities are not only occurring at the IOUs in California, but also at the Western Electricity Coordinating Council (WECC). A report by WECC[34] reviewed a number of models used for generation and transmission planning and selected the NewEnergy Suite of Models as the "best" for constrained analyses. From the report:

> The Production Simulation Program Task Force (PSPTF) was formed to make recommendations on WECC's implementation of production cost simulation. The original tasks were to:
>
> 1. Recommend a production simulation program for WECC staff to use to input data and check for errors. The recommendation should address the following:
>   (a) Develop WECC's requirements for a program,
>   (b) Review the various programs available,
>   (c) Work with program vendors,
>   (d) Coordinate the task force's recommendations with SSG-WI, and
>   (e) Recommend to PCC a specific program that WECC should procure.
> 2. WECC members have been supporting a policy of having a publicly available database. PSPTF will consider and make recommendations regarding issues that arise that WECC might consider regarding this policy. PSPTF is not requested to review this policy, but rather undertake due diligence regarding issues raised regarding this policy decision.
> 3. Identify and make recommendations on options regarding database maintenance.
> 4. Review and make recommendations regarding related issues that might be raised during the course of this work.

Subsequently, these tasks were expanded to evaluate programs suitable for WECC's implementation of its new economic transmission expansion planning function and possibly for resource adequacy assessments.

This work led to a number of recommendations. The WECC task force Recommendation 1 is:

> **Recommendation 1 --** After a lengthy process the PSPTF met on January 20th to determine a recommended program. While there was not unanimous support for a single program, the final three programs: PROMOD IV, PLEXOS, and ABB Gridview under consideration considered in the final selection process where deemed adequate for WECC's future role in production simulation. The majority of the PSPTF programs selected New Energy Associate's PROMOD IV software package as the program best suited for WECC staff' use for database management, production power cost scenario simulation and resource adequacy

[34] See: "WECC Production Simulation Program Task Force --Recommendations and Report to the Planning Coordination Committee" February 6, 2006. This report can be found at: http://www.wecc.biz/documents/meetings/PCC/2006/March/WECC_PSPTF_Final_Recommendations_and_Report_2-6-2006.pdf . Members of the task force included almost all California utilities and Western region utilities. The task force was comprised of: PSPTF Members: Chris Reese - Chair – PSE; Jamie Austin - PAC; Sherman Chen - PG&E; Donald Davies - WECC Staff; Don Deberry – SMUD; Chuck Falls – SRP; Jim Filippi - PG&E; Irina Green – CAISO; John Greenlaw – WAPA; Mark Hesters – CEC; Darrell Holmes – SCE; Mary Johannis – BPA; Harris Lee – SRP; John Martinsen – SNOPUD; Octavian Ngarambe – BPA; Les Pereira – NCPA; Dennis Phillips – BPA; David Yu – SDGE.

assessment. Therefore the PSPTF recommends that the PROMOD IV program package be procured for use by WECC Staff.

The importance of the above citation to the ongoing WECC work is not the specific choice of model, but the commitment by WECC to develop these forward-looking planning capabilities. One candidate DRRC activity might be to work with the WECC production simulation team to help ensure that these planning and resource adequacy assessments appropriately include DR. These models are the tools used by decision-makers to make investments in resources. It is difficult to change out such tools when they represent the current standard in the industry, but to work within the same framework to address important DR resource issues is a viable option, and it will leverage a considerable amount of existing work.

Finally, databases on resources and the grid system are already maintained by most vendors of resource planning software, and the WECC maintains its own database for the region. As a result, data are available to undertake the analysis outlined below.

TASK WORK AREA 1: Approach and Analysis Steps

Task Work Area 1 focuses on generation expansion and production costing with transmission constraint to estimate commodity price and risk management effects from DR portfolios. This constitutes a potentially large fraction of the benefits of DR, some of the most visible benefits to consumers, and it is an area where existing tools can be used to address these values.

The approach proposed for the development of this framework is meant to address current changes in the energy industries. Traditional planning and decisions systems were designed to optimize outcomes in a more stable environment with many of the analyses focused on single-point, most-likely forecasts, balanced with selected sensitivity analysis. A recent article[35] argues that rational decision making is best made when risk-reward trade-offs are evaluated explicitly. The complex electric industry environment is best served by considering the range of risks to which utilities and other market actors are exposed. Since DR is one method of hedging against a number of different risks ranging from fuel prices to uncertainty about meeting future environmental regulations, explicitly addressing risk and uncertainty is a key component of the DR valuation framework. Appendix I presents some case study results using this resource planning framework from an IEA case study on valuing DR.

The overall approach will consist of nine steps for this Task Work Area on generation planning and production costing under transmission constraints. These steps are discussed below:

STEP 1 – BASE CASE: Develop the base case set of resources that represent the without-DR scenario. This base case is needed to assess the value of DR as an option to what would have occurred had the DR programs/options not been offered. The base case will encompass the three planned CA ISO zones as well as account for power interchange between California and other regions in the WECC.

STEP 2 – PIVOT FACTORS: For the base case, identify the key pivot factors that cause the costs of providing electricity and related services to vary (e.g., fuel costs, energy demand, peak

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[35] A discussion of how traditional utility planning and decision making approaches have failed in key instances is discussed in Fayne, H. M. et al., "By Executive Decision: A Better Framework for Making Decisions," Public Utilities Fortnightly, October 2005. The authors argue that these failures were due to not explicitly dimensioning risks and also accounting for "unexpected events" that can doom a project or an entire company – "even though they are virtually certain to occur once or possibly even twice during the course of a 25-year planning horizon."

demand, plant availabilities, delivery system/line capacities, and the cost of environmental compliance).

STEP 3 – DISTRIBUTIONS: Create a distribution of outcomes that represents a best estimate of the uncertainty around each of these pivot cost factors. These distributions will focus on establishing a range that represents a 90 percent confidence interval along with a likelihood function defines intervals within that range and the likelihood that the pivot factor or variable will be in that interval. The recent IEA report and work recently undertaken by the Northwest Power and Conservation Council (NPCC) on its 5th Power Plan indicated that reasonable representations of these uncertainties can be developed. Specifically, the NPCC states:

> *Planning for the future requires assessing risk. This involves characterizing the key uncertainties the power system faces. Can planners, through experience, analysis, and informed judgment, develop reasonable characterizations of future uncertainty that will help illuminate resource choices for the region? The Council believes the answer is "yes."* (p. ES-5 of the NPCC 5th Power Plan).

Given that one of the key values of DR is as a hedge that mitigates the costs of low-probability, high-consequence events, a framework that fully addresses the value of DR must explicitly address uncertainty.

STEP 4 – CREATE JOINT PROBABILITY SURFACE: Use a set of random draws (e.g., a Monte Carlo analysis) to represent the joint probability surface for all the distributions developed around pivot cost factors.

STEP 5 – BASE CASE PLANNING MODEL RUNS/ANALYSES: The planning model will be run for each draw with each representing a full set of inputs for the relevant model or engineering analysis. In some cases, this may require some adjustments to the planning models to reduce run times. However, it is not uncommon for some planning models to have lengthy runtimes.[36] This will produce a distribution of system costs that incorporates the uncertainties contained in the distributions around the pivot factors.

STEP 6 – BENCHMARK DR VALUATIONS: As part of the base case runs benchmark willingness-to-pay DR values will be developed. This is done by simply specifying that some DR is available at specific locations during specific time periods that represent viable future scenarios. These runs will produce an estimate of the value of the load reductions placed into the model. This should represent the maximum willingness-to-pay for this DR, given the constraints regarding the costs addressed by the model. This produces some representative "what if" gross values for DR; then, assessments of how likely it is that DR options can be developed to provide that load reduction at a cost less than the estimated gross value can be made. To have positive net benefits, the DR costs have to be less that the gross value from the benchmark runs. This process also serves as a test of the DR valuation method prior to having to specify specific DR options for analysis.

STEP 7 – DEVELOP DR OPTIONS: A representative set of DR programs/options will be developed with costs of initiation and ongoing operation included, along with realistic load

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[36] Conversations with planning personnel at the NPCC and with other utilities in the WECC indicated that base case and core capacity expansion model runs can take several days. The problem of estimating the value of DR requires a realistic approach that looks at the generation, transmission, and distribution systems. Such a systems analysis is complex, but no more so than many of the planning problems that utilities now work on, and are worked on by other industries. Multiple sets of input data can be developed to facilitate the modeling in groups of runs.

reductions. This work was done as part of the IEA study where the DR programs included a number of DR programs/options as a means to meet future system needs, in combination with the full range of supply-side options. Five DR programs which are representative of a cross-section of DR program types might include:

a. Interruptible Product – A known amount of load reduction based on a two-hour call period. Customers are paid a capacity payment for the MW pledged and there are penalties if MW reductions are not attained.

b. Direct Load Control Product – A known amount of load reduction with 5 to 10 minutes of notification. This is focused on mass market customers. As a result, it has a longer ramp-up time to attain a sizeable amount of MW capacity.

c. Dispatchable Purchase Transaction – A call option where the model looks at the "marginal system cost" and decides to "take" the DR offered when that price is less than the marginal system cost. This program can also be classified as a day-ahead pricing program.

d. TOU/CPP Pricing Product – Modeled as a resource using price elasticity factors to calculate demand reduction in each time period. This product is also called in response to a high critical peak price on select event days when reserve margins drop below specified levels or prices exceed specified levels (marginal system costs serve as a proxy for prices).

e. Real-Time Pricing Product – This DR pricing option is modeled as a reduction in demand from the base case based on estimated price elasticities and the resulting reduction or increase in demand based on recent estimates from the literature.

The exact specification of the DR programs/options to be analyzed would be developed during the course of implementing the framework and will incorporate feedback from the DRRC advisory group. The specifications of these DR programs in the IEA case study included estimates of costs for each DR program – fixed, annual, monthly, and incremental customer variable costs. It also specified the capabilities of each program in terms of MW, the number of times the program could be called (if appropriate), the notification period (if appropriate), and the number of hours in each called event.

The pricing programs could be applied to different customer sets and different amounts of load. In the IEA study, these programs were only applied to 25 percent of the load with elasticities that were representative of the price response of larger customers. This meant that no additional costs for metering were included since it was assumed that all large customers already had advanced interval meters. During the project execution, it will be determined whether this specific set of assumptions will be deemed appropriate or whether another set of assumptions might be more appropriate.

STEP 8 – ESTIMATE VALUE OF DR OPTIONS: The base case model will be re-run with the various DR options. This produces some representative "what if" gross values for DR; then, assessments of how likely DR options can be developed to provide that load reduction at a cost less than the estimated gross value can be made. To have positive net benefits, the DR costs have to be less that the gross value from the benchmark runs. This process also serves as a test of the DR valuation method prior to having to specify specific DR options for analysis.

Several different DR portfolios will be analyzed including just the callable, event-based programs (a, b, and c); just the pricing programs; and the event-based callable DR programs with each pricing program.

It is important to model the value of other DR products when a pricing program is also in place as the price elasticity due to RTP will lower peak demand on extreme days. This mitigates some of the price and cost volatility in the market. In turn, this might reduce the value of other DR programs.

This specification of DR programs will allow this framework to address the relative value of different types of DR. Specifically, it will allow for the examination of the more traditional event-based DR options as well as an examination of the decentralized pricing programs.

STEP 9 – ANALYSIS OF DR VALUE RESULTS: The final step will take the information from the DR valuation in Step 8 and perform analyses that:

1) Develop hedge values for the reduction in risk calculated as resulting from DR portfolios, and
2) Develop values for changes in reliability resulting from DR.

The development of hedge values for the reduction of risk would be based on changes in Value-at-Risk (VAR). Changes in the VAR between base case runs without DR and runs with DR can be used to estimate the hedge value of different DR portfolios. Changes in the value of reliability would come from estimates of the costs of outages developed in prior literature reviews.[37]

The four valuation task work areas that comprise the comprehensive value framework are discussed below.

Task Work Area 1 – Generation and Transmission Load Flow Model Choice

This work area uses traditional utility planning models for generation expansion analyses and production costing. No specific model is identified but the three models are considered to be candidates due either to their use by WECC member utilities or the availability of data for a base case. As discussed above, WECC has recently selected the PROMOD IV set of tools for the development of their constrained resource analyses, but other utilities in WECC currently use a variety of models. Three that are known to be used are:

1) STRATEGIST®/PROMOD IV® by NewEnergy Associates, a Siemens Company;
2) ProSym from Global Energy Decisions (formerly Henwood Energy) as part of the Capacity Expansion Module in Global Energy's Planning and Risk Solution set; and
3) AURORA model by EPIS, Inc.

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[37] Much of this work has been reviewed by: LaCommare, K and J. Eto, "*Understanding the Cost of Power Interruptions to U.S.Electricity Consumers*," Lawrence Berkeley National Laboratory, LBNL-55718, September 2004; and Lawton, L, et al., *A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys*," Prepared for Energy Storage Program, Office of Electric Transmission and Distribution, U.S. Department of Energy, LBNL-54365, November 2003. le see: Lawton, L., M. Sullivan, K. Van Liere, A. Katz, and J. Eto, 2003 "A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys", Lawrence Berkley National Laboratory: LBNL-54365, November.

Other models in addition to these three could be used. However, these are models with which the project team has had some experience[38] and are known to be used by utilities conducting planning studies in the WECC region. All three models can incorporate transmission constraints and line loadings. The model selected from these three will form the basic analysis engine for examining changes in nodal commodity prices. For a select set of portfolio options, a pure load flow model would be used to identify transmission overload conditions on lines or transformers. There are two candidate load flow models:

1) General Electric's Positive Sequence Load Flow (GE PSLF) model.[39] The GE PSLF model was recently used in an ENERGY COMMISSION PIER project to address the question of whether distributed generation (DG), demand response (DR), and localized reactive power (VAR) sources, or distributed energy resources (DER), can be rigorously shown to enhance the performance of an electric power transmission and distribution (T&D) system.[40]

2) A second load flow model is the Power System Simulator for Engineering (PSS/E) model[41] offered by Siemens Power Technologies International (Siemens PTI). NewEnergy Associates, which offers PROMOD IV, is also a Siemens Company and while either the GE PSLF or the Siemens PSS/E models can be used, if the work were to be done fully by an outside consulting team (i.e., without working in partnership with a California IOU), then the use of the Siemens company tools would be viable. Research has shown that the California IOUs generally use the ProSym tool set for generation modeling, and that would likely be the tool used if the implementation of the framework is performed in collaboration with one of the utilities.

This proposed approach is similar to an approach proposed for a DR benefits study of the PJM system.[42] The strawman approach proposed by PJM to the Mid-Atlantic Demand Response Initiative involved setting a given percent reduction of load (3% was suggested) during 100 peak

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38 The NewEnergy Associates tools were used by Summit Blue in a recently completed study for the International Energy Agency, ProSym has been used by members of Summit Blue, and Summit Blue has been working with utilities engaged in integrated planning using the AURORA model.

39 This model is described by GE as the load-flow component of the GE power systems analysis package for power systems modeling. The GE PSLF load flow database describes the positive sequence network, and the GE PSLF load-flow solution gives the steady state condition of the network as described by the database. According to GE, load-flow solutions provided by GE PSLF can adjust tap changers, static Var devices, generators, and direct current inverters to control bus voltages.

40 See: "Optimal Portfolio Methodology for Assessing Distributed Energy Resources Benefits for the Energynet℠," Prepared For: California Energy Commission Public Interest Energy Research Program (PIER), by Peter B. Evans, New Power Technologies, April 2005.

41 From Siemens PTI: PSS/E is a software tool used for electrical transmission planning, it is the standard Siemens offering serving this market and is currently in use in 123 countries. Since its introduction in 1976, the Power System Simulator for Engineering tool has become the most comprehensive, technically advanced, and widely used commercial program of its type. It is widely recognized as the most fully featured, time-tested, and best performing commercial program available.

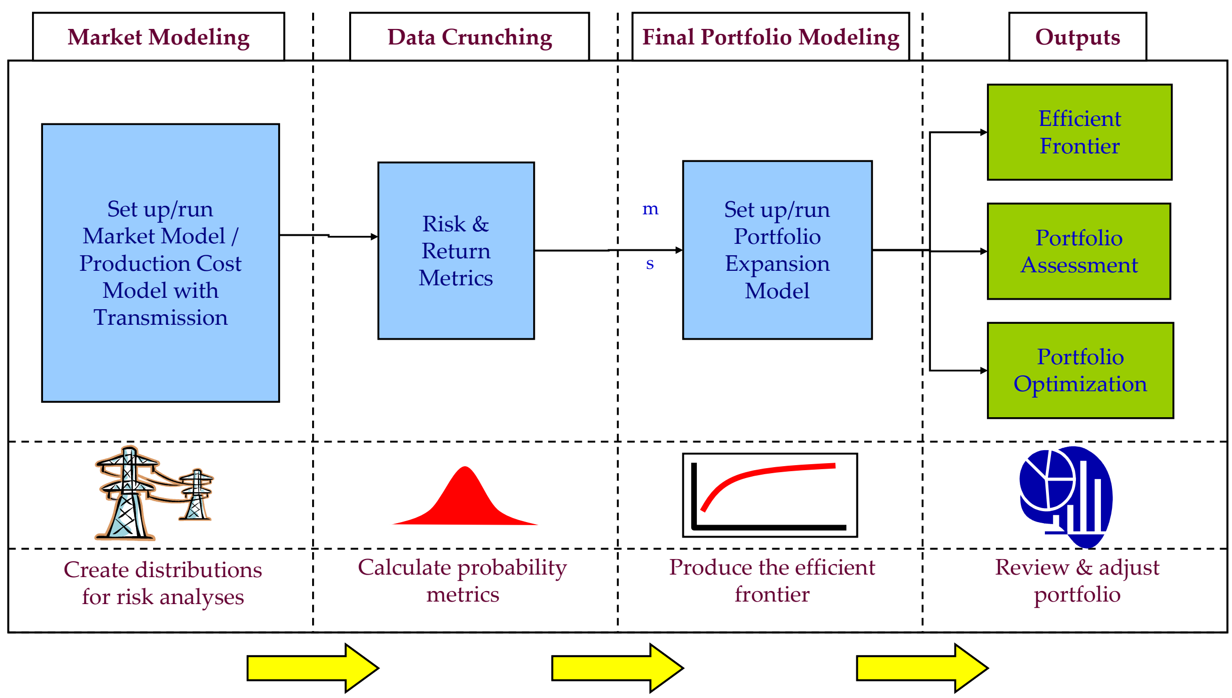
42 Bladen, J. "Conceptual Approach to DR Benefits Study, presented at the Mid-Atlantic Distributed Resources Initiative, December 2005 (www.energetics.com/MADRI).

hours. The reduction in nodal prices would be calculated using a model capable of complete re-dispatch of the grid for a given study period. The model will need to be based on an accurate topology of the transmission system. PJM indicated that they were not available to conduct such a study, but could support such a study effort with data and topology information to any party retained to conduct such a study. This re-dispatch of the system with and without DR is the same basic approach proposed in this framework to estimate the reduction in nodal prices.

Overview of Task Area I Generation Resource Planning and Production Costing with Transmission Constraints

An overview of the work effort for Task Area 1 is shown in Figure 0-2.

Figure 0-2. Two Stage Modeling Approach



The incorporation of DR into generation resource planning is likely to be the area where substantive near-term benefits of DR can be most easily identified. Deferred transmission and distribution benefits are more difficult to quantify, as discussed below. As a result, key aspects of the value of DR as it pertains to lowering overall prices, mitigating price volatility, reducing the likelihood and magnitude of price shocks, and the other related risk management benefits for use in SPM-like benefit-cost tests are more likely to be developed as "adders" for these areas of DR value.

<u>TASK WORK AREA 2</u> – Transmission DR Options Analysis

The load flow models only show areas of transmission overload, but do not develop solutions for alleviating these overload conditions. The next step is to use standard transmission planning approaches to develop estimates of the cost of alleviating the transmission needs. Interviews were conducted with planners at ISOs and several utilities in the WECC region. The approaches used for transmission expansion planning were very different than those used to plan for generation expansion. Where generation planning relies heavily on a least-cost planning model, transmission planning was not as model dependent. Due to the planning approaches in use today, the incorporation of DR into a generation planning framework is more direct and can follow an explicit set of steps for categories of DR program types.

The transmission planning approach typically had three steps.

STEP 1: Identification of Transmission System Needs: This step identifies areas of transmission overload to develop specific transmission system projects to alleviate these system problems.

The identification of transmission system problem areas and constraints that need to be addressed begins with the application of a transmission load flow analysis in combination with the generation expansion plan. This is part of Task Work Area 1 and is done to ensure that sited resources can deliver its generation to load centers. Typically, this step also identifies areas of constraint, but does not include within the model any transmission upgrade projects to alleviate these constraints. In addition, these load flow studies are augmented by analysis of historic load flow data as well as the development of load growth forecasts by area to better define the timing and magnitude of the transmission system overloads.

STEP 2: Development of Candidate Transmission Projects: This step identifies projects designed to alleviate transmission constraints

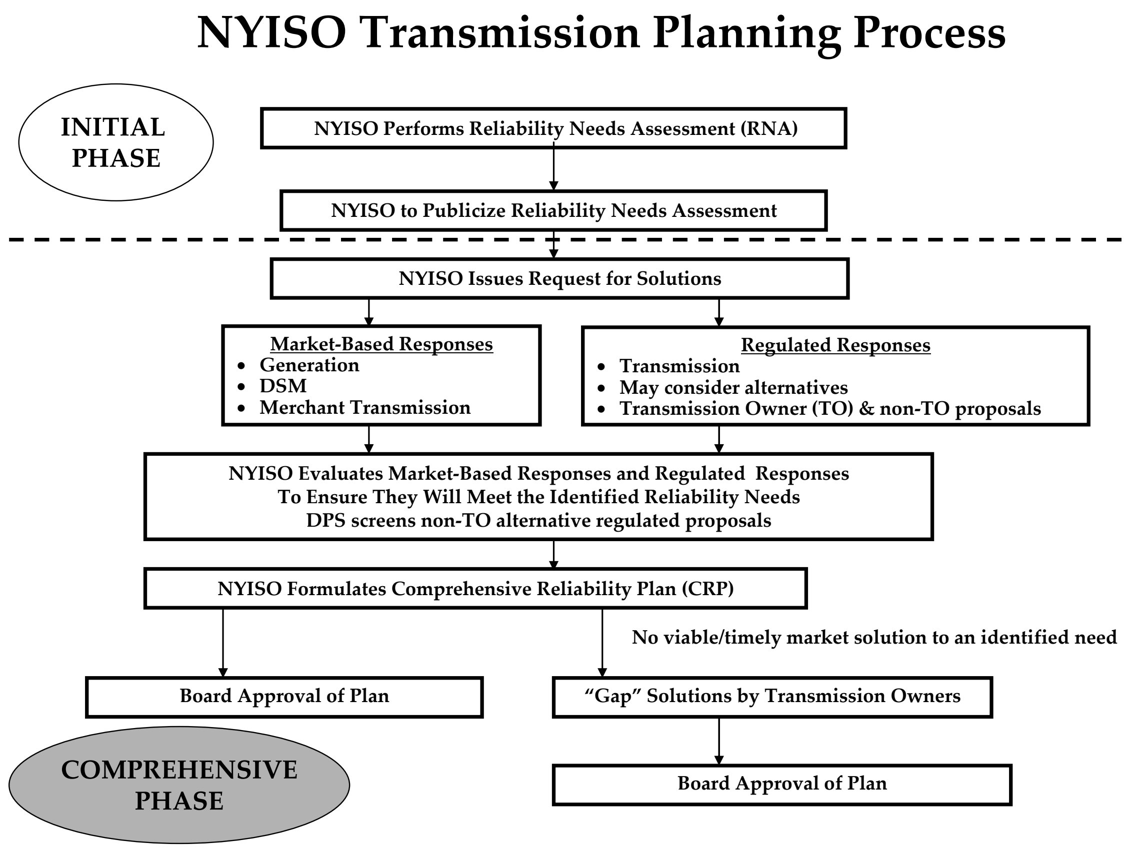
Once the transmission system problems are identified, an engineering analysis is performed to identify the costs of different options to ameliorate these problems. This typically is not done by any form of optimization model, but is simply a listing and initial prioritization of candidate engineering-based options and an assessment of their costs. For DR to make the list of candidate options, site or area-specific DR options need to be identified and included in the list of options identified. These first cut estimates for alleviating transmission overloads can be derived from what is essentially a modular estimation system where costs are expressed per mile of line, or as typical transformer costs. These initial budget estimates for transmission projects should be adequate for assessing at a rough level whether DR can be cost-effective in competing with the engineering solutions.

STEP 3: Prioritization of Transmission Projects: The list of candidate projects is prioritized with the most cost-effective projects selected for each transmission overload condition.

This step involves a more detailed analysis of the candidate projects designed to address the identified transmission system problem. This includes a more detailed analysis of the historical line loadings, projections of growth on the system, and the siting of new resources. This information is combined with a more detailed project-specific engineering cost estimates for the priority projects. For DR to compete with conventional transmission system upgrade projects, the costs and contribution of DR to line loadings would have to be included in this detailed step. This effort is being undertaken by several utilities, but the skepticism that load reduction DR can provide a reliable resource to defer (or delay) transmission projects is quite high among the planners contacted. However, the addition of a distributed generation facility at a substation or at a customer site is viewed as a viable option. These can be assessed within the current planning models.

An overview of the transmission system planning process used by the New York Independent System Operator (NYISO) is shown below as Figure 0-3 below. As the figure indicates, the planning tends to be done on a project-by-project basis. Being in a restructured state, the NYISO first looks for market solutions, i.e., having the competitive market provide project options. If these are not forthcoming from the market, then there are transmission owner and related regulatory options. But, all the work is done at a project-by-project basis targeted at identified transmission system needs.

Figure 0-3. Transmission Planning Flow Chart[43]



In California, there is work ongoing at the utilities regarding nonwires alternatives to traditional wires solutions. The CPUC Rulemaking R.04-03-017 states that PG&E, SCE, and SDG&E shall file an update on their plans to incorporate DG into gridside system planning. Each of the utilities submitted filings setting forth the methodology they planned to use to evaluate DG alternatives to traditional wires solutions. The outcome of these studies might provide information that can be used to develop a deferred transmission cost adder. Work on incorporating DR in wires planning is also being undertaken at the Bonneville Power Authority and at First Energy.[44]

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[43] This was presented by Mr. David Lawrence of the NYISO at the Spring 2006 Peak Load Management Alliance (PLMA) meetings with the full presentation available at www.peaklma.com. Mr. Lawrence was one of the planners interviewed for the initial version of this report.

[44] Presentations on both the Bonneville Power Administration approach to including DR in transmission planning and the work ongoing at First Energy were made at the Spring Peak Load Management meetings, Marsh 13, 14, Hyatt Crystal City, 2006. These presentations can be found on the PLMA website at www.peaklma.com. Both presentations contain additional citations.

TASK WORK AREA 3 – Distribution System DR Options Analyses

Essentially, the same three step approach is taken in distribution system planning as is taken in transmission system planning:

STEP 1: Identification of Distribution System Needs: This step identifies areas of distribution system overload to develop specific transmission system projects to alleviate these system problems. These areas of overload are identified not so much through a "model" as they are through an assessment of historical load data at substations, line loadings, and projections of future local growth that would impact these distribution facilities.

STEP 2: Development of Candidate Distribution Projects: This step identifies projects designed to alleviate transmission constraints.

STEP 3: Prioritization of Transmission Projects: The list of candidate projects is prioritized with the most cost-effective projects selected for each transmission overload condition.

This approach based on localized assessments and appropriate engineering analysis performed in conjunction with utilities has been the approach taken by the California Energy Commission PIER projects. A presentation at a July 2005 workshop on incorporating DG in distribution planning stated:

- For each utility, our project team worked with utility engineers and used engineering tools to determine the best locations on the system.

- Value is very dependent on location, and without utility planning involvement, difficult to identify the high value locations.[45]

The key phrase in the quoted bullets above concerns the need for the involvement of utility planners in addressing the impacts of DR/DG on distribution system planning. This three step planning approach was used in Summit Blue's work with New England distribution utilities, as well as in discussions with distribution system planners at several WECC utilities.

The standard approach to distribution system planning has fewer modeling options. Typically, substation, transformer, and feeder line analyses are based on an examination of data on loads and projects developed based on standard reliability measures and forecasts of load growth. Specific projects are identified and ranked. Annual budgets and forecasted budgets out to 10 years may be developed by the distribution planners. Once distribution projects are identified and budgeted, they can be compared to DR alternative including distributed generation and load response. Again, load reduction DR is considered by many to be not reliable enough, and many distribution planners are skeptical about such projects. However, distributed generation is being looked at in a number of areas.

Some practical criteria[46] for integrating DG in distribution planning include:

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[45] Quoted bullets taken from "Local Value of Renewable Distributed Generation" Power Point Presentation at July 1, 2005 CEC workshop, by Energy and Environmental Economics. Presentation at: http://www.energy.ca.gov/2005_energypolicy/documents/2005-07-01_workshop/presentations/2005-07-01_SNULLER_PRICE.PDF. This effort focused on distribution systems for Alameda Power and Telecom, City of Palo Alto, Sacramento Municipal Utility District, and San Francisco PUC/HH. No specific CEC PIER report citation was included in the slide presentation.

- Would a DG installation help address local distribution-system issues on a given circuit or substation?
- What (if any) system upgrades are planned that might be addressed or deferred with the DG project?
- Are they driven by general load growth or infrastructure development?
- What amounts (MW, MVA, MVAR) of local load relief are needed to address system issues?
- How many years might be impacted?
- Is a DG installation of adequate size viable?
- What are the issues related to the environment – siting, run time constraints, permitting, and community impacts?
- Are there large customers on the line?
- What are the operational requirements, e.g., integration with System operations, Communications requirements? Response time?

The CEC PIER has been conducting research on whether distributed generation (DG), demand response (DR), and localized reactive power (VAR) sources, or distributed energy resources (DER), can be shown to enhance the performance of an electric power transmission and distribution (T&D) system. A recent report[47] presents a methodology to systematically determine the characteristics of DER projects that enhance the performance of a power delivery network and quantify the potential benefits of these projects. The report concludes that DG and DR projects in the right locations and with the right characteristics and operating profiles can improve the performance of a given network. The potential improvements include reduced real power losses, reduced VAR flow and consumption, reduced network voltage variability and eliminated low- and high-voltage buses, reduced network stress, increased load-serving capability, and avoided or deferred network improvements in both the distribution and transmission portions of the network. The report demonstrated a methodology to systematically identify these beneficial projects and quantify their benefits. This research represented an initial demonstration of this methodology, using the transmission and distribution network of SVP, a municipal utility serving a single city. The Energy Commission has funded a second project that will demonstrate the methodology in a much larger, more complex subject power system of a major California investor-owned utility.

Within an SPM-type framework, this ongoing work at the Energy Commission is at a level of detail beyond that needed to develop benchmark estimates of the potential capacity and operating cost that DR might be able to defer for use as adders in a SPM-type of benefit-cost framework. A more traditional engineering approach is expected to be used based on distribution projects by the IOUs, assuming that this information will be shared by the utilities. The key will be the

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[46] These were presented by Chris Siebens at the Spring 2006 Peak Load Management Alliance meetings. The full presentation is available at www.peaklma.com. Mr. Siebens was one of the planners interviewed for the first version of this report.

[47] "Optimal Portfolio Methodology For Assessing Distributed Energy Resources Benefits For The Energynet^{SM}," *Prepared For:* California Energy Commission Public Interest Energy Research Program (PIER), by Peter B. Evans, New Power Technologies, April 2005.

reliability of the DR in that a transmission or distribution system project deferral will require near certainty in the load reductions from DR at that location. Still, some research has supported the notion that DR can resulted in substantive cost reductions in distribution.[48]

TASK WORK AREA 4 – Market Effects and Customer Values

The fourth area – market effects and customer values – is an area where the DR may have high values but there has been little research conducted into the potential magnitude of these impacts. This is due, in part, to the difficulty of designing studies that can develop credible estimates of these impacts. However, it is known that these impacts are not zero and assuming that they are zero is as arbitrary as working to select a positive, but arguably a conservative number.

Candidate Work Efforts to Support TASK WORK AREA 4 – Market Effects and Customer Values

A number of separate studies are needed to assess the value of DR in an overall market efficiency and customer value context. These are values that would not be captured in the augmentation to utility planning approaches discussed in the work areas discussed above, i.e., Work Area 1, 2 and 3. The benefits to be examined in this component of the analysis will include four studies with each discussed below:

1) **STUDY 1: Industry Productivity Study** -- The potential for an increase in overall industry productivity benefits due to the financial incentives for both generators and customers to be more appropriately aligned given that the utility industry is very capital intensive. An increase in overall productivity given that the electric utility industry represents one of the largest investments of capital by this country could provide sizeable benefits. If load factors in existing plants could be increased and more cost-effective methods of meeting peak demands other than building power plants, the benefits across the industry could be sizeable. If DR is expected to be in-place and supported long term by the generation industry, then this would impact their future investments such that these investments are made under the expectation of a DR resource being in place in the future. This could lead to future investments that are more efficient now that the demand-side is able to respond to changes in prices and help reach market equilibria.

   Approach: The method for conducting this study would likely have to be a scenario analysis assuming some plausible and conservative amount of increased productivity. The Bureau of Economic Analysis, U.S. Department of Commerce, contains information on annual capital inflows by industry, and the Bureau of Labor Statistics maintains information on labor productivity. These data could be combined with an assumed increase in productivity, e.g., 0.5% per year, to see if the magnitudes of these possible market efficiency numbers are large enough to warrant an additional study.

[48] Based on a five year deferral of distribution projects in the Consolidated Edison service territory, the potential value of DR in distribution was judged as substantial. See "Enhancing the Business Case for DR in the Mid-Atlantic," presented by Brad Johnson, Mid-Atlantic Distributed Resources Initiative (MADRI), at the National Town Meeting on Demand Response, Washington, D.C., January 24, 2006. This presentation can be found at http://www.demandresponseinfo.org/id82.htm.

2) **<u>STUDY 2: Benefits of Innovation</u>** -- Possible benefits of innovation now that there is a business case for the development of technologies that can assist customers in managing their demand. This would be a difficult area to study as is any study of technical innovation.

   <u>Approach</u>: Data exist on the number of manufacturers of key DR components (e.g., load switches, smart thermostats, energy management systems) and these can be tracked over time. An EPRI report[49] indicated that the number of load control vendors peaked in the 1980's and 1990's in parallel with the level of demand response investment levels reported to the U.S. Department of Energy. As the market declined through the period of industry restructuring, companies merged or moved investment into other business lines. Similar trend analyses could be used to establish some bounds on this value, and determine whether this is an important factor that should be accounted for in developing the demand-side of the electricity market.

3) **<u>STUDY 3: Possible Impacts of Reduced or Deterred Market Power</u>** -- One of the claimed benefits for demand response is that it can act as a deterrent to the existence and use of market power. Independent System Operators (ISOs) all have market monitors that examine the market for uses and abuses of market power. Any market that has locational-based pricing is also a candidate for locational market power. While there are a number of methods ranging from oversight to capping prices during times of system constraints, demand response is one method of ameliorating market power. When prices increase, demand will decline. The value this brings to the market is uncertain, likely to be market specific, and location specific within markets.

   <u>Approach</u>: The methods for estimating a value for reduced or deterred market power could be based on market-based simulations where scenarios are developed with locational market. The prices that could be imposed on the system or location can be estimated. Then, the influence of DR and price elasticity in mitigating these market power effects can be estimated. Another approach would be historical and look at events where market power may have been exercised and assess what the influence of demand response (e.g., a more price elastic demand curve) might have ameliorated the rise in electricity prices. It is not known in advance if this might be a large value or a small value, or an insurance-type of value if a market structure that is designed to limit market power breaks down.

4) **<u>STUDY 4: Customer Values</u>** -- Customer benefits beyond the price benefits and deferred capital investments addressed by augmenting industry planning processes to include demand response (i.e., Work Areas 1, 2 and 3) that may come from increased customer choices related to energy cost management and the potential for additional customer services. As examples:

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[49] Levy, R. "New Principles for Demand Response Planning," EPRI Final Report EP-P6035/C3047, March 2002.

a. Customers may value the increased ability they now have to manage their electric costs and energy bills.[50] Customers that have the ability to shift loads from periods of high system costs to periods of lower system costs would now have an incentive to make this shift which would benefit all ratepayers. In this case, an important customer attribute would now receive a value. However, care must be taken to avoid double counting. The price change impacts would already have been counted in the resource planning model DR application (Work Area I), and the only value here is the intrinsic value that customers have by being more in control of their expenditures.

b. Even if customers do not take advantage of load shifting to adjust their bills today, they may have an option value that pertains to having the capability to be on a rate that would allow them to better manager their electric bills in the future. For example, if their economic circumstances changed due to a job shift (or other change), the customer would have the ability to decrease their bill by a greater amount by both reducing use in high system cost periods and shifting use from high cost to lower cost periods.

c. Customer equity may be improved in terms of payments for electricity use and the costs that customers impose on the system. While this may be viewed as a societal benefit, customers that mostly use electricity in lower cost periods now pay lower bills, and an important attribute that can cause lower overall system costs, i.e., the ability to use electricity flexibly, is now given a value. From the perspective of those customers who impose lower costs on the system, this would be seen as a benefit to them that is appropriate given the costs they impose on the system.

<u>Approach</u>: These customer benefit categories can not be easily quantified. The increase in equity is likely to be a social value that will be particularly hard to quantify, but should not be ignored. However, customer values that related to increased choice, ability to manage electric costs, and the option value of having rates that would allow a customer to manage their bills in the future if their economic or living circumstances changed could be valued through customer research methods. These methods could use a variety of valuation methods such as willingness-to-pay, conjoint valuation analyses, but scenarios can be developed based on pragmatic assumptions that will indicate a likely order of magnitude in benefits.

<u>Developing a research agenda for assessing customer values poses a number of difficulties</u>. First, customers may not know how they value a product or program if they have limited experience with that product (e.g., load shifting to manage bills). Under this situation, it is likely that customers will exhibit tendencies of inertia and prefer the status quo. As technology changes, that value may also change over time. In addition, this value is likely to be quite variable across customers as their situations differ.

<u>As DR programs are implemented, it is expected that customer surveys will be part of the evaluation of these programs.</u> A set of customer value questions should be incorporated into

[50] A survey of residential customers participating in the Chicago Energy Cooperative's Energy Smart Pricing Program which provided customers with hourly prices on a day-ahead basis indicated that the ability to better manage their energy bills was an important attribute of the program. This 2nd year survey corroborated the results from the year 1 survey. See: **"Evaluation of the 2004 Energy-Smart Pricing Plan"** Prepared for the Community Energy Cooperative, Chicago, Ill. by Summit Blue Consulting, Boulder. CO, March 2005.

each evaluation. This would allow information on whether customers value the increased ability to manage their bills above what they gain from market price and bill reductions.

Summary – TASK WORK AREA 4 – Market Effects and Customer Values

This fourth work area is more difficult to address than the three previous work areas. However, the value of DR in terms of providing incentives for innovation, increased efficiency in the use of capital assets, and customer values associated with DR are likely to be non-zero. Increased overall industry efficiency from better pricing and proxy pricing through callable DR programs could account for a large dollar value, even if the increase is small due to the large capital investment that comprises generation plants, and transmission and distribution facilities. However, much of this gain in efficiency could be captured in lower market electricity prices and reduced price volatility. Care would have to be taken to ensure that the market-wide efficiency benefits do not double count the price effects captured in Task Work Areas 1, 2, and 3.

Of the four work areas outlined, this fourth work area is given a lower priority due to the difficulty in estimating the appropriate DR values and the potential for overlap with benefits captured in Task Work Areas 1,2, and 3. However, there should be some possibilities for benchmarking the potential magnitudes of these DR values using existing data and acquiring information through customer surveys that are part of program evaluations.

Given this assessed lower priority, it is suggested that the focus should first be on appropriately incorporating DR in utility generation resource planning; then focus on incorporating DR as an option in utility transmission and distribution planning. The values for market effects and other customer values would be handled as a sensitivity adder pending information on assessing the potential magnitude of these values.

Comparison of DR Value Framework to the Current SPM

This section takes the value framework and suggested analyses in the four work areas from Chapter 5 and discusses how the results of these analyses could be used to adapt an SPM-style set of tests for the assessment of DR program designs. The starting point assumption made in Section 5.0 was that the comprehensive assessment of the value of DR was best viewed in the context of resource investment decisions and that tools in use by the industry to make those decisions can provide a framework for assessing DR. However, these resource planning assessments require time and effort beyond what would be appropriate for the real-time design and screening of specific DR programs. As a result, it is important to have a simplified set of criteria (e.g., a set of SPM-like tests) that can be used in designing specific programs and providing regulators with adequate information to judge the cost-effectiveness of these programs. These tests would incorporate information from the more comprehensive value assessments, and would be updated based on scheduled updates to the comprehensive DR and full resource portfolio assessment. The design of such a set of tests was not the primary objective of this research effort. This research focused more directly on the R&D objective contained in the RON-1 objectives statement calling for the development of a comprehensive framework for determining the value of DR. This objective was believed to be in line with the DRRC's R&D focus. However, a comprehensive framework, when applied, should be able to serve as the basis for a set of tests that can be used to assess and select specific DR programs. The links between the comprehensive resource planning assessments and SPM-type tests is made here, with suggestions on how to adapt the current SPM to better address DR.

Use of the SPM to Address DR

The vast majority of benefit-cost analyses of DR have used an extension of what has become known as the "Standard Practice Manual" (SPM) which was originally developed in California for evaluating energy efficiency programs.[51] The October 2001 SPM sets out four groups of tests for evaluating demand-side management programs: 1) the Total Resource Cost (TRC) test; 2) the Ratepayer Impact Measure (RIM) test; 3) Participant Tests; and 4) a Program Administrator test. Each are discussed in the October 2001 SPM report.

Application of the SPM by California Working Group 2

One example of how the SPM has been applied to DR products is found in the CPUC and CEC Working Group 2 (WG2) proceedings. The California Working Group 2 is comprised of the California Power Authority and the three California IOUs, and it was established by the California Public Utilities Commission. Chapter IV of their third report[52], on Cost-Effectiveness Analysis, illustrates an effort made in response to a CPUC ruling that the WG2 should develop a

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[51] *California Standard Practice Manual – Economic Analysis of Demand-Side Programs and Projects,* California Public Utilities Commission, October 2001. It can be found at the California Public Utilities Commission (CPUC) website at www.cpuc.ca.gov/static/energy/electric/energy+efficiency/rulemaking/resource5.doc.

[52] *R.02-06-001 Third Report of Working Group 2 on Dynamic Tariff and Program Proposals: Addendum Modifying Previous Reports*, January 16, 2003 – California Public Utilities Commission Order Instituting Rulemaking on Policies and Practices for Advanced Metering, Demand Response, and Dynamic Pricing.

plan for large customers that includes “a complete benefit-cost analysis.”[53] The CPUC offered as an option that the “Standard Practice Manual (for DSM programs) methodology be used as a tool since it allows an assessment of demand reductions from multiple viewpoints: society, customer, utility, and ratepayer.” Based on this direction, cost-effectiveness analyses for the DR programs considered by the WG2 used the SPM. However, the WG2 also recognized that there were some concerns with using the SPM that should be addressed in future proceedings.[54]

The WG2 was focused on DR programs for customers with over 200 kW peak demand. SPM test assessments were undertaken for programs put forth by the utilities. In general, there were four program types ranging from a large customer call option program (the CPA demand reserves partnership), to some programs proposed by the utilities in California including: 1) a demand bidding program; 2) a critical peak pricing proposal; and 3) a day-ahead hourly pricing program.[55]

The WG2 made a number of modifications to the protocols contained in the SPM in assessing these DR programs.[56] The principal change concerned the avoided costs for the DR options assessed by WG2. The avoided costs used were changed to reflect the costs of avoiding peak capacity and energy. The high cost case used the avoided fixed costs and variable costs of a new simple cycle gas turbine.

The WG2 participants have noted that other items identified in the CPUC rulings have not been captured in this SPM-based analysis. Specifically cited was the fact that the following benefits had not been captured:

- Avoided Transmission & Distribution (T&D) upgrade costs;
- Benefit of any net reduction in air emissions (and other environmental externalities); and
- Value to customers of more timely and accurate information about electricity use.

Additionally, the CPUC adds that a complete cost-benefit analysis should include:

- insurance/reliability values,
- market effects,

[53] These California working group reports on cost-effectiveness analyses of DR can be found at www.energy.ca.gov/demandresponse/documents/index.html#group2.

[54] As of the time of writing this report, no additional work on benefit-cost frameworks for DR has been done in California, although some different ways to apply the SPM have been developed (as discussed in the text).

[55] SCE, SDG&E, and PG&E all had recommended program variants that were considered by the WG2.

[56] These changes are discussed on page 58 of the Second Report of WG2 and represented generally practical changes including: 1) recognizing price changes as well as quantity changes from the DR option; 2) using total benefits and costs, as opposed to differential values that might miss certain benefits and costs; 3) discarding unconsidered benefits and costs; 4) using a continuum of benefits and costs where some benefits might change sign and rather than put them in the cost term, they were retained as a negative benefit; 5) limiting reported results to only the Net Present Value (NPV) and the Benefit-Cost ratio; and 6) eliminating the Program Administrator test as these programs were to be implemented by utilities and costs recovered by the utilities.

- fuel price stability,
- environmental values, and
- other criteria that are more difficult to quantify.

Assessing the insurance and reliability values in a complete cost-benefit analysis requires that uncertainty be dimensioned around key inputs (e.g., demand forecasts, fuel costs which are assumed constant in the SPM analysis, and system events such as plant outages or transmission constraints). Key benefits related to enhanced reliability and the insurance/hedge value of providing options for meeting low-probability/high-consequence events are not addressed in this form of static analysis with no dimensioning of uncertainty. The WG2 report recognized these issues in the benefit-cost framework used and recommended that alternative frameworks be considered in future work.

Ongoing Work on the SPM

Work is ongoing in different regulatory proceedings in California related to assessing DR in a set of SPM-type tests. One improvement to the SPM has been the development of avoided costs for DR. A study from October 2004 looked at developing avoided costs for DR based on market prices.[57] This avoided cost study develops hourly prices by developing a forecast of prices and looking at the highest price hours. A three period approach for forecasting prices is used in the study:

– **Period 1 (Market)**: Used through 2006, years before load-resource balance and with electricity forward trading. This period has observable forward prices.

– **Period 2 (Transition)**: This contains the transition years between the end of Period 1 and the beginning of Period 3, (i.e., years 2006 and 2007) and is calculated as a linear trend.

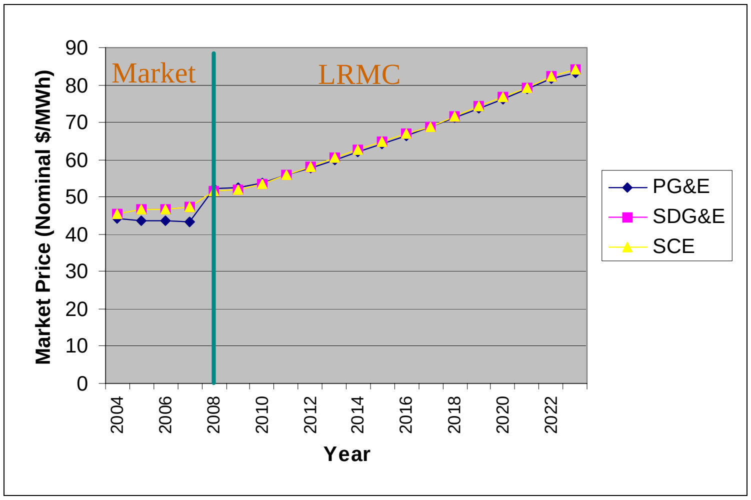
– **Period 3 (Resource Balance)**: A workably competitive market environment implies a flat supply curve as defined by the Long Run Marginal Cost (LRMC), the all-in per MWh cost of new generation to meet an incremental demand profile. For the period from 2008 through the end of 2023, it is assumed that the annual average cost of electricity will be equal to the full cost of owning and operating a combined cycle gas fired generator (CCGT).[58]

The result is a forecast of average prices predicated on the avoided cost of a specific supply-side technology as shown in Figure 0-1 taken from the study.

[57] See "*Methodology and Forecast of the Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs*," prepared for the California PUC, by Energy and Environmental Economics, Inc. (E3), October 25, 2004.

[58] See "*Methodology and Forecast of the Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs*," prepared for the California PUC, by Energy and Environmental Economics, Inc. (E3), October 25, 2004.

Figure 0-1: Annual average price forecasts by utility (E3 Report)



Prices to the left of the resource balance year in 2008 are derived from energy forward and future markets, and prices after 2008 are based on the LRMC of a CCGT.

The approach to assessing the value of a dispatchable DR is to select the highest-cost hours given user-specified inputs such as energy strike price and maximum dispatch hours per day, month, and year. The shaping of prices to hours is based on past correlations.[59] This means that the avoided cost applied to DR will be higher than the annual average LRMC used as the proposed avoided costs for energy efficiency programs. Any standard practice formulation will require some approximations and simplifying assumptions to be used. In this case, the one key assumption is that the price patterns (e.g., number of high price hours and relationship to the average) are based on an historical allocation using past price patterns. If the SPM test has a planning period of 10 years (or more likely 20 years to account for coal as a resource), then this pricing pattern is assumed to last throughout this planning period.

Linking the General Valuation Framework to SPM Tests

There are several issues that need to be addressed in extending and adapting the current SPM set of tests or a new variant of the SPM to the assessment of DR programs. These closely follow the needs assessment as developed in Section 4.0 of this report. Specifically, the questions asked in this section of the report are the questions that one would like a set of SPM tests to address. These are:

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[59] E3 allocates the annual generation prices to hours of the year using an hourly shape derived from the California PX hourly NP15 and SP15 zonal prices from April 1998 - April 2000 (p.49). Table 41 in the E3 report presents dispatchable program avoided costs as a function of hours per dispatch and dispatches per year (assumes no constraint on dispatches per month). The range of avoided costs is from $18.91 to $109.19 per kW-year depending on the number of times the resource can be dispatched (between 10 times and 160 times per year) and the number of hours allowed in each dispatch (between 1 hour to 16 hours). The report indicates that each dispatchable resource is dispatched during the highest price hours possible. [Note: These 1998 to 2000 data can be updated when the California ISO becomes operational with zonal pricing and nodal generator payments.]

1) Baseline Question – What is DR being compared against? Any assessment of change, i.e., to implement a DR program/product requires a baseline value against which its value can be compared to determine the net benefits of implementing the DR program/product.
    - Base case demand forecast.
    - Existing generation resources.
    - Existing transmission and distribution resources.
    - Existing levels of demand response or DSM resources.
2) What types of DR products/options should be assessed as part of a DR portfolio?
3) What size of DR products/options is appropriate?
4) Timing of DR deployment, expansion, and/or maintenance?
5) Do different DR products have positive or negative synergies?
6) What are the "insurance" and "portfolio" benefits of DR?
    - Diversity in resources, e.g., mix of fuels.
    - Locational diversity, e.g., located near load centers.
7) How to assess the overall impacts on the electricity market now that incentives exist to shift loads?
    - Technology innovation.
    - Customer innovation in use of energy.
    - Deterred market power.
    - Appropriate use of supply-side capital investment.

There is also no getting around the tough questions posed by DR investments. In addition, the expansive definitions for DR that have been used in California addressing both price response and load response program types requires a large number of potential values and pathways to be analyzed. The factors that influence the electric markets and DR values are dynamic, and a process that can incorporate these dynamic factors is needed to assess the contribution of DR to the overall robustness of the electricity market.

This implies that the framework should directly address difficult issues such as:

1) Uncertainty in key factors that impact system costs. This would include uncertainty in monthly energy demand, monthly peak demand, fuel prices, plant outages, transmission line outages, and extremes in weather.

2) A time horizon that is long enough to encompass the occurrence of low-probability/high-consequence events.

3) A process that fairly addresses the tradeoffs between supply-side technologies (generation and T&D) and DR programs/options on overall system costs, system reliability, and risks associated with extreme events.

The general DR value framework proposed in Section 5.0 contained four work areas:

- **Task Work Area 1** – Generation resource planning and production costing with transmission constraint to estimate price effects and related risk management impacts from DR portfolios.

- **Task Work Area 2** – Transmission investment avoided/deferred costs based on engineering approaches and modular cost estimation.

- **Task Work Area 3** – Distribution investment deferred costs based on engineering budget based estimates and longer-term project plans.

- **Task Work Area 4** – Market and customer effects related to overall productivity, customer choice, and enhanced service benefits.

Summit Blue proposes that the results from the DR value framework be used as inputs to the SPM. Each work area would provide a set of adjustments or adders to the current SPM tests. It is important to recognize that the specifics of the adder calculation would depend upon the results of the resource planning effort.

A key contribution of the general value framework would be a dimensioning of the overall need for DR within the California and regional market. For example, is it 5%, 10%, or 15% of peak demand? This dimensioning of the overall magnitude would then lead to the use of cost-effectiveness tests to determine who to meet this overall need in the most cost-effective manner. Of course, the sum of all the DR program costs should not exceed the value as determined by the resource planning model. However, the model has incorporated the costs of the DR portfolio in the analysis, so it is unlikely that if the model showed sizeable benefits for DR that the sum of the program costs across utilities would exceed that value. But, that would be one check on any overall target set for DR.

Adders and Adjustments from Work Area 1 – Generation Planning

Work Area 1 on generation resource planning would incorporate a portfolio of DR programs designed to span the basic types of DR programs anticipated to be components of the California utility's DR efforts. This work would provide estimates of:

1) Changes in Net System Costs – The overall reduction in net system costs resulting from this DR portfolio.

2) Reduction in Peak Period Prices – The reduction in peak prices (based on the marginal production costs from the model) resulting from the DR portfolio. The use of marginal production costs as a proxy for prices poses some issues. In most markets that have been studied, periods of tight supply have produced market prices that are well above the marginal cost of production, often by a factor of 4 to 5. As a result, this would be a conservative estimate. These data could be provided by pricing zone, by day-type, and for stress events examined by the model. Once the CAISO is operating, the difference between marginal production costs and market price formation can be compared and a relationship developed.

3) Value of Flexibility – The value of flexibility in DR programs, i.e., the ability to easily delay start-up if not needed, to ramp-up quickly if needed, to maintain a steady position if there is no additional need for the DR, and to grow or even decline if that is what is most cost-effective in the market. This means that DR can follow the demand growth (energy and peak), and market need for peak capacity. This can be addressed by moving the timing of the DR programs within the model. It may be argued that the lead time for a gas-fired peaker is only 1 to 2 years so the value of flexibility may not be that great, but this may not always be true. (Note: there may also be an adequate approximation to this that could be calculated outside the model.) In addition, if the comprehensive resource planning study is performed every two years with updated information, the information

used in the SPM-type tests for DR would stay current and any trends in key market factors (e.g., energy costs, demands, generation, and T&D system performance) could be incorporated as well. The value of flexibility would involve the resource plan's ability to keep system costs low across a range of changing futures.

4) Risk Management – The benefits of reduced risk in terms of events that might cause very high system costs can be addressed through the Monte Carlo approach to resource planning. Prior work has shown that the uncertainty faced in today's resource planning environment represents a range of almost 100% in system costs from the low cost to what might be the high cost with an adverse future (i.e., a future with higher than expected fuel costs, higher than expected peak demand, and some unexpected transmission or plant outages just five years into the future. (See Appendix I for a discussion of the range of risk in planning and the determination of value-at-risk.) The model would show, by pricing region, the change in Value-at-Risk (VAR) at different levels (e.g., 90% and 95%). This combined with an assumption that the change in price volatility is proportional to the change in VAR between the with DR and without DR scenarios provides an estimate of the hedge value of DR that can be turned into an adder that can be used in an SPM test.

5) Reliability – The resource planning model can show changes in various reliability measures including loss of load probability (LOLP) for zones, holding a reserve margin constant. This change in LOLP can be valued using prior studies on outage costs that have been developed.[60]

These adders would address many of the issues explicitly raised by the CPUC in its July 27 rulemaking requesting the California investor owned utilities file testimony providing cost-effectiveness results for their 2003, 2004, and, to the extent possible, 2005 DR programs, and their overall demand response (DR) portfolio, using the Standard Practice Manual (SPM) tests as the starting point.

Adders from Work Area 2 – Transmission Investment and Planning

This work would have to be performed in conjunction with either the Western Electric Coordinating Council or with the California utilities as they would be the entities that would have information of planned transmission upgrades and whether (and how) DR could defer some of that investment.[61] Other utilities have developed generic adders per kW (for example, Xcel Energy using $106/kW) in benefit-cost analyses of DR programs. One challenge in developing a transmission adder is that actual deferred costs will be very location specific.

Summit Blue would recommend that there be two adders: 1) a generic small adder that accounts for the general increase in transmission options if DR exists at a load center; and 2) a second

[60] Two potential sources for this information are: LaCommare, K and J. Eto, "Understanding the Cost of Power Interruptions to U.S.Electricity Consumers," Lawrence Berkeley National Laboratory, LBNL-55718, September 2004; and Lawton, L., M. Sullivan, K. Van Liere, A. Katz, and J. Eto, 2003 "A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys", Lawrence Berkley National Laboratory: LBNL-54365, November 2003; however, this would also be an area with additional research could be beneficial.

[61] Note that this same conclusion has been reached in prior CEC PIER work. See Footnote 45 on "Local Values of DG on Distribution Costs."

adder for specific locations that are transmission constrained based on research showing the DR actually can impact the transmission costs in that area. Work currently being done in California, specifically the CPUC Rulemaking R.04-03-017, calls for PG&E, SCE, and SDG&E to incorporate DG into gridside system planning. Each of the utilities submitted filings setting forth the methodology they planned to use to evaluate these alternatives to traditional wires solutions. The outcome of this effort should provide information that can be used to develop a deferred transmission cost (and likely a distribution cost) adder.

Adders from Work Area 3 – Distribution Investment and Planning

It is expected that there are some cases in which DR can defer some investments in distribution systems, e.g., defer some substation upgrades. Incorporating DR into current utility distribution system planning efforts should address this issue. The CPUC rulemaking R.04-03-017 cited above does not specify distribution versus transmission, but focuses on "gridside" wires planning. It is likely that a combined transmission and distribution adder can be developed, but there is likely to be a strong location component to this adder. A decision would have to be made whether this value should be averaged over a pricing zone or made location specific.

Adders from Work Area 4 – Market Effects and Customer Values

These adders most closely approximate a "societal adder" that addresses increased productivity in the energy industry from both technology innovation and customer innovation regarding how they use electricity. The Work Area identifies four studies that could be done to bracket the order of magnitude of these values.

STUDY 1: Industry Productivity Study

STUDY 2: Benefits of Innovation

STUDY 3: Possible Impacts of Reduced or Deterred Market Power

STUDY 4: Additional Customer Values

It should be possible to bracket the benefits in these areas and use them in a sensitivity analysis. Some of them could be important, but the difficulty in obtaining reliable estimates of their value makes the use of anything but very conservative values suspect in terms of adding information to a program investment decision.

Summary – SPM-Type Tests

The four work areas discussed in Section 5.0 should provide a set of data and an information source that will allow for the design of an SPM-like set of screening tests. The overall framework would be useful for setting system goals for the amount of DR and the different types of DR. However, a set of tests and screening criteria will need to be applied, in order to determine which specific programs will be the most cost-effective at meeting the DR requirements, including the amounts and types of DR, which were developed in the comprehensive resource planning study.

The fact that the value of DR is time dependent and location dependent to a greater extent than most energy efficiency programs makes the development of these SPM-type tests and program design screens more difficult. However, the use of a dynamic model should provide the insights and information that can be used to develop the adders identified above that will make for a useful set of standard practice tests.

Summary of Cost Proposal Structure

A separately bound document sets out the estimated costs for developing the comprehensive DR value framework using the resource planning approach presented in this report. This approach works to embed DR within traditional utility planning methods such that the DR resource will be viewed as an integral component of a utility's resource plan similar to other peaking resources in the plan. This approach does not use the current SPM as its starting point, but attempts to step back and assess approaches for appropriately valuing DR and appropriately incorporating DR into resource plans; then, this comprehensive assessment would feed information into a revised SPM-type test framework that could be used for program design, approval, and evaluation. This perspective was viewed to be appropriate for an R&D project and to provide different views from simply continuing to add on to the SPM tests. It is expected that the comprehensive resource assessment with DR would be performed every 2 to 3 years to keep the information in the SPM-type tests current.

This cost proposal is divided into three sets of options:

1) Option Set 1 -- Direct Comprehensive DR Value Studies -- options presents cost estimates for projects that are ambitious by design in that they are meant to develop comprehensive views of the value of DR. Three variants of the analysis are presented which are based on the degree of utility collaboration in the project and the detail required in the outputs of the analyses. The duration of this comprehensive effort is expected to range from 9 months to 12 months depending of the option.

2) Option Set 2 -- Adapting the Current SPM to Address DR -- presents the added work of taking the results of the general DR value assessment and, following the work outlined in Section 6.0 of the report, the SPM would be adapted/revised to better address DR. The duration of this analysis will vary depending upon whether this is meant to be done in an interactive stakeholder working group setting, or it is to be a technical report presenting one option for adapting the current SPM which would then serve as the starting point for stakeholder discussion.

3) Option Set 3 -- Small Step Approach - Next Step Feasibility and Validation Assessment – This approach is a low cost effort designed to validate the aspects of the resource planning approach outline in that it takes a next step approach and addresses the use of a feasibility assessment to hone in on the most appropriate next research steps. During the project, the ability to fully explain the resource planning option to the right people in the utility planning departments was not available. This was due to a number of reasons including time (both contractor and utility) and budget constraints. Utility personnel were time constrained during the course of this effort and other responsibilities made it difficult to obtain the amount of time required from utility planning staff to both understand the proposed approach and obtain from them the information on models and data availability needed to develop a more detailed research agenda. As a result, some assumptions are made concerning the utility planning processes that are viewed as reasonable given industry experience. Under most any scenario, involvement of the IOU utility planning departments is likely to be needed. As a result, a more detailed feasibility assessment with utility planning departments might be a reasonable next step.

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Appendix I:

Select Issues in the Resource Planning Framework Approach

The basic approach discusses as Task Work Area 1 – generation resource planning discussed in Section 5.2 is designed to adapt existing planning methods used by utilities in the areas of generation expansion and resource planning such that the attributes of DR are incorporated into the analysis. This approach has been applied to the assessment of commodity prices in the IEA study[62] where net benefits attributable to DR for different portfolios of programs were developed. A generation capacity expansion and production cost framework was used to develop estimates of system costs with and without DR using similar concepts to that proposed in Section 5.2.

A case study modeling effort was developed for valuing DR using a resource planning context. Changes in system costs with and without DR included in a portfolio of resources were examined. The difference in system costs over a 19 year time horizon provides an estimate of the value of DR for the electric system. The specific model used for this effort was New Energy Associates' Strategist® Strategic Planning Model.[63]

The base case for the model was developed to realistically represent an electricity market that allows for appropriate trade-offs between resources – both supply-side and DR – and is able to address issues such as off-system sales/purchases and system constraints (e.g., transmission constraints).[64]

Model Inputs

One hundred cases were created as data inputs to the Strategist model. They were calculated so that a wide variety of possible futures was represented. Monte Carlo methods were used to create these different future cases that represent the uncertainty in key future inputs. To accomplish this, a number of pivot factors were identified and the uncertainty around these factors was dimensioned. Data was provided for the years 2005 to 2023. In addition, data sets for four demand response programs were developed as inputs to the model.

The key input variables around which uncertainty was dimensioned were:

1. Fuel prices – natural gas, residual oil, distillate oil, and coal
2. Peak demand
3. Energy demand
4. Unit outages
5. Tie line capacities

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[62] Violette, D., R. Freeman, and C. Neil. "*DR Valuation and Market Analysis – Volume II: Assessing The DR Benefits and Costs*," Prepared for the International Energy Agency, Demand-Side Programme, Task Xiii: Demand Response Resources, Task XIII, January 6, 2006.

[63] Eric Hughes with New Energy Associates (EHughes@newenergyassoc.com) assisted with all of the resource planning model runs and provided insights regarding the interpretation of results.

[64] The base case system was developed using data compiled by New Energy Associates, based on publicly available information for a selected region in the National Electric Reliability Councils (NERC), i.e., the Mid-Atlantic Area Council (MAAC) region. The initial data came from the Platts-McGraw Hill Base Case database for the region with some adjustments to the data based on New Energy Associates' and Summit Blue's experience.

Four DR products were included as potential resources to meet future system needs, in combination with the full range of supply-side options. The four types of DR programs were:

- Interruptible Product – A known amount of load reduction based on a two-hour call period. Customers are paid a capacity payment for the MW pledged and there are penalties if MW reductions are not attained.
- Direct Load Control Product – A known amount of load reduction with 5 to 10 minutes of notification. This is focused on mass market customers. As a result, it has a longer ramp-up time to attain a sizeable amount of MW capacity.
- Dispatchable Purchase Transaction – A call option where the model looks at the "marginal system cost" and decides to "take" the DR offered when that price is less than the marginal system cost. This program can also be classified as a day-ahead pricing program.
- Pricing Product(s) – The real-time pricing program posed a challenge in that there is no feedback loop built into the model that looks at the marginal hourly cost and the demand for that same hour. As a result, two pricing products were examined:
    1. One was a peak-period pricing program which produced a reduction in peak demand and little impact on load in other hours. This is similar to a critical peak pricing product, with the overall monthly and annual energy demand largely unaffected.
    2. The second was a standard RTP program that produced a reduction in peak demand and also an overall energy efficiency effect, resulting in reductions in weekly, monthly, and annual energy demand – this is consistent with the RTP literature.

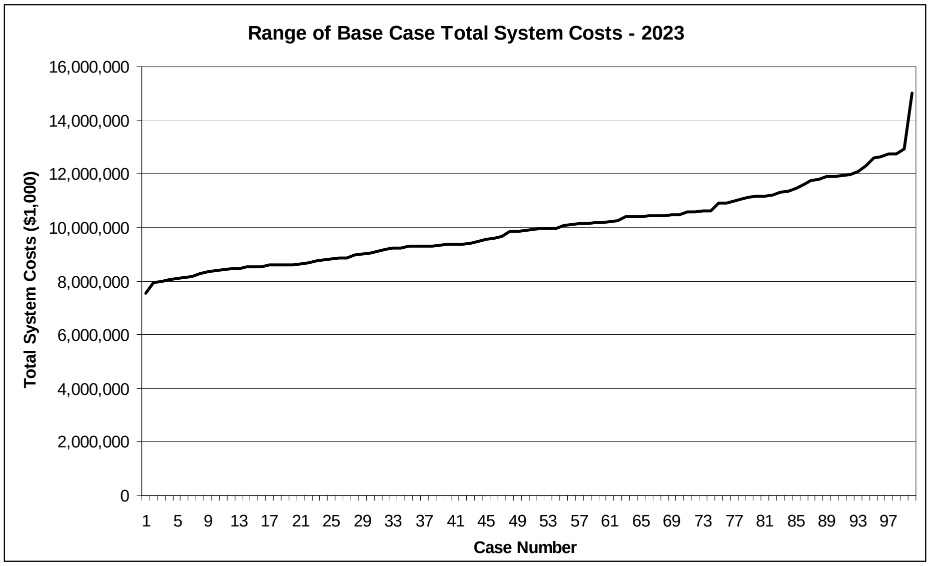
Data from each product design were then used to develop inputs to the Strategist model such that each program could be treated consistently by the model. All dollar values were inflated at a rate of 2.5% per year. The following data was supplied for each product for the years 2005 to 2023:

• One Time Costs • New Customers per Year • New Customer Cost • Annual Customer Cost • Annual O&M Cost • MW/Customer • Total MW Capacity	• Months in Year Available • Firm % • Maximum Control Actions per Day • Maximum Control Actions per Year • Maximum Control Hours per Action • Maximum Control Hours per Year

Case Study Results

Results from these analyses include the following:

- **IMPORTANCE OF DIMENSIONING UNCERTAINTY:** The importance of looking at the distribution of system costs is shown in the figure below. The distribution of potential system costs in this year for each of the 100 cases in the base scenario is quite large, and there are a few cases where costs can be much higher than average.

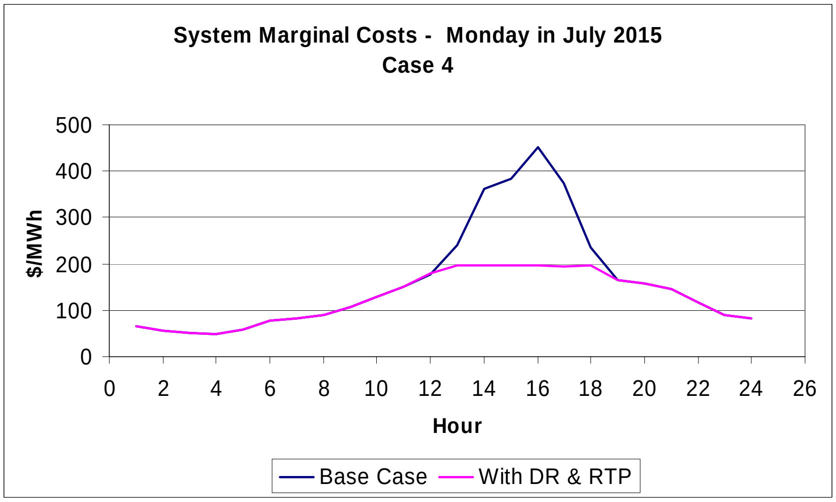


In the base case, the overall uncertainty in total system costs for each year (100 cases per year) is quite large across these cases – indicating that the uncertainty in the modest number of variables selected does result in a wide range of net system costs for each year in the 20 year planning horizon. On average, the range was 100%, i.e., the highest cost in the range was roughly double the lowest cost for almost every year in the planning horizon.

Range of Total System Costs for Selected Years - Base Case
($ Billions)

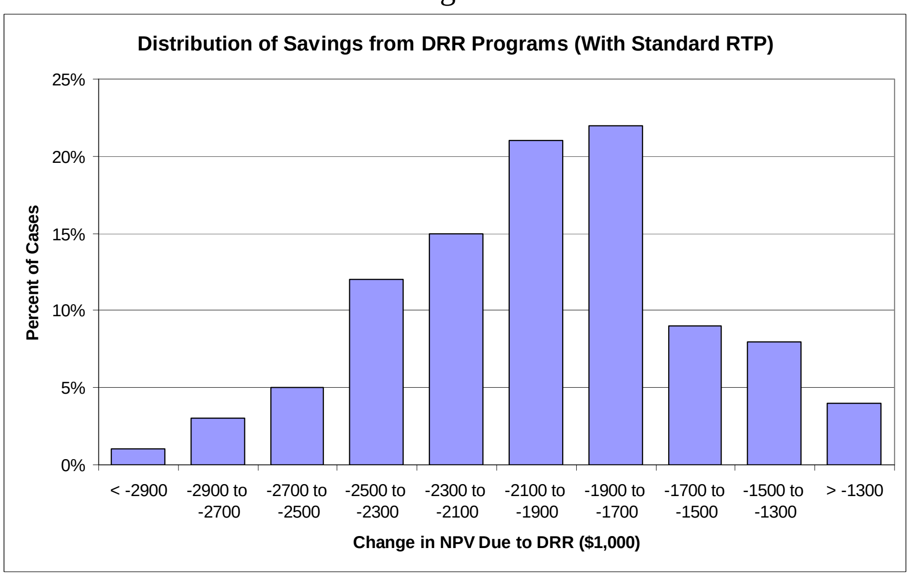
Year	2010	2012	2015	2018	2020	2023
Maximum	7.7	8.2	10.2	10.3	12.4	15.0
Minimum	3.5	3.8	5.1	5.6	6.5	7.5
Range	4.2	4.5	5.1	4.6	5.9	7.5
Ratio	118.5%	118.8%	101.7%	82.2%	89.9%	99.3%

- **HOURLY COSTS:** On a peak demand day with additional system stresses, such as 10% of generating capacity being offline, savings in marginal production costs are substantial. The addition of DR to the system greatly reduced the "peakiness" of the hourly costs, reducing the maximum by more than 50%. For example, in one peak day in July the total cost savings were $24.5 million.



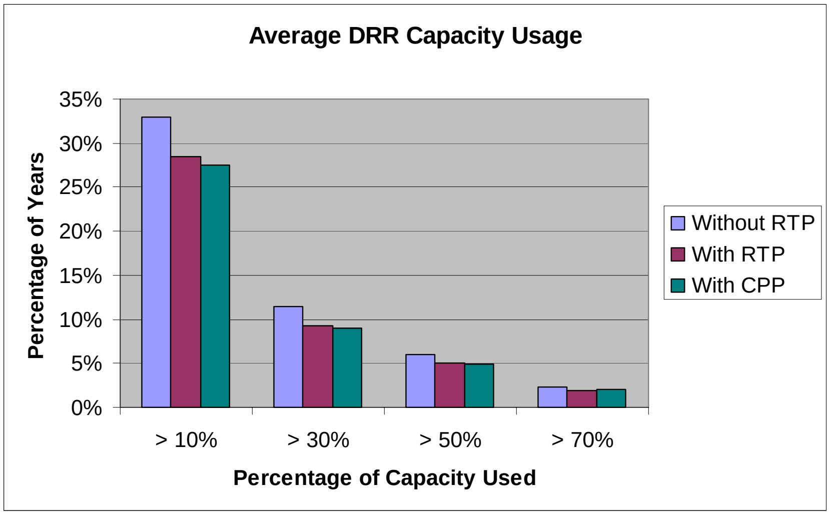
- **CAPACITY CHARGES:** A substantial percentage of new capacity charges were deferred by the model because of the DR availability. This amounted to savings of $892 million (2004 dollars) over the 20-year period.

- **SAVINGS IN EACH YEAR:** DR provided significant benefits in those years in which it was used. While DR provides considerable amounts of benefits on select days, there is a cost to building and maintaining the DR capacity which is paid for in every year and in every case, even if DR is not used. This results in there being some cases where there are costs but no savings from DR. Looking at the 100 cases individually, in the scenario with DR but no RTP, 36% of the 100 cases showed savings in total system net present value (NPV) compared with the base case, and with the full RTP scenario 97% of the cases showed savings.



- **DR CAPACITY USAGE:** Large amounts of DR were used about once in every four years. Across all resource scenarios, small amounts of DR were used in most of the years in the planning horizon, with near capacity use of DR happening infrequently.

The amount of DR that was called upon did not vary much across the three scenarios, e.g., the "with full RTP" resource option only resulted in a 10% reduction in DR hours called across the 20-year planning horizon. As a result, the callable DR retained their value as a hedge against extreme events even with pricing options that resulted in better utilization of system resources across all hours.



- **COST RISK PROFILE:** There was a change in the risk profile associated with the planning scenarios with the addition of DR. There were significant savings when looking at value at risk (VAR) at the 90th percentile (VAR90) and at the 95th percentile (VAR95). The VAR90 is the reduction in costs averaged across the 10% worst case outcomes, i.e., the highest cost futures. Results for the three scenarios are shown below.

Risk Metrics – Reduction in System Costs at Risk ($M)		
	VAR 90	VAR 95
Callable DR	238	213
Callable DR with Critical Peak Pricing	924	966
Callable DR with Real Time Pricing	2,673	2,766

One estimate of the benefit of reduced market volatility attributable to DR can be developed using a risk management framework. At the micro level, individual energy consumers utilize forward commodity contracts to reduce energy cost exposure. The energy consumer purchases a hedge from a marketer in return for price certainty. From the perspective of the marketer, the price of the hedge is the fair market value of the expected price risk. The underlying financial engineering methods in effect value risk. These same tools can be utilized to value reductions in price volatility attributed to DR. The market benefit of a reduction in price volatility is analogous to the fair value of a hedge in exchange for price certainty.
The idea of using financial engineering to value DR is not new. Sezgen et al. (2005) examine the option value of demand response using traditional financial engineering

methods based on the Black and Scholes approach. In their paper three common demand-response strategies are valued: load curtailment, load shifting or displacement, and short-term fuel substitution – specifically, distributed generation. Oren (2005) considers the value of generation adequacy using option analytics. In his paper, the value of long-term reserve capacity is explicitly valued using call options. This method could be applied to the long-term availability of DR is analogous to long-term capacity options.

The Sezgen et al. paper shows that the Black and Scholes method can calculate the value of an option by:

1. Changing the probability measure for price stochastic processes to a risk-neutral measure.

2. Simulating this new process to generate realizations of prices in the future.

3. Calculating payoffs.

4. Discounting these payoff values using the risk free rate.

5. Averaging the values calculated for each realization of prices.

While not developed in the IEA study, a Black and Scholes approach for developing an estimate of the dollar value of the reduction in risk and overall price volatility can be used as part of the price impacts from DR calculated in the extended framework that would be applied in this project.

- **Loss of Load:** The addition of DR decreased the loss of load (LOL) hours substantially across all cases. The base case had an average value for loss of load hours of 7.64 hours across the cases, but values for some individual cases were as high as 30 hours. For the DR with Peak Pricing, the average loss of load hours averaged across all cases was lowered to 0.33 hours. The magnitude of the savings due to enhanced reliability across all the years in the planning horizon could be quite high, but no estimate has been calculated at this time and this estimate may vary by the number of customers impacted and the characteristics of different systems.

  The IEA study did not take the step of attempting to place dollar values on these reliability benefits. As a result, the net benefits figures do not include a value for the higher level of reliability achieved with the addition of DR to the available resources. The magnitude of the savings due to enhanced reliability across all the years in the planning horizon could be quite high. In this extended framework, it is expected that recent work on the average cost of outages conducted at LBL can be used to develop scenarios that would provide an order of magnitude estimate of the benefits of this improved reliability.[65]

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[65] Two references that can provide useful information for estimating the value of changes in reliability are: LaCommare, K and J. Eto, "*Understanding the Cost of Power Interruptions to U.S.Electricity Consumers*," Lawrence Berkeley National Laboratory, LBNL-55718, September 2004; and Lawton, L, et al., *A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage*

- **Total System Cost:** Overall, the incorporation of DR results in some reduction in the average total system cost NPV in all three scenarios with DR (callable DR, DR with CPP, and DR with standard RTP). In the scenario with the standard RTP program, savings are about 3.5 times those in the scenario with the critical peak pricing program, and similarly, savings in the scenario with the critical peak pricing program are approximately twelve times those with only the callable DR programs.

System costs savings ($M)	
	Average NPV over 20 years
Callable DR Only	48
Callable DR with Critical Peak Pricing (peak hour load reduction only)	574
Callable DR with Standard RTP – (reduction in demand in all high price hours)	1,984

- **Incremental System Cost:** As the system being studied is a very large system, it is meaningful to look at the incremental costs of meeting energy demand, as opposed to a percentage of the total system cost. On average, the savings in incremental costs due to DR (year on year) were 10% for the scenario with peak pricing and 23% for the scenario with standard RTP. For the scenario with the standard RTP program there was a range of savings of -73% to +320%, and in 53% of the cases the incremental costs in the callable DR scenario were less than or equal to those in the base scenario. In a few cases the DR provided large reductions in incremental costs.

Overall, this case study shows that a Monte Carlo approach, coupled with a resource planning model, can address the value of DR given uncertainties in future outcomes for key variables, and can also assess the impact DR has on reducing the costs associated with low-probability, high-consequence events. In this case study, the addition of DR to the resource plan reduced the costs associated with extreme events, and it reduced the net present value of total system costs over the planning horizon. This is an important finding. It can be compared to being paid to buy life insurance. Not only does DR reduce the expected or mean net system costs of meeting load growth, but it also greatly reduces the impacts of adverse events by between 1 and 2.5 billion dollars – a considerable sum and a sizeable reduction in risks to ratepayers.

The outcomes of this case study are illustrative of both a method for assessing DR portfolios along supply-side portfolios, and the potential magnitude of the benefits. The role of demand response resources is important for both cost effectiveness and risk management. As a result, any AMI structure developed should be aligned with the development of DR resources.

As a final note, the total DR capacity across all the DR options was approximately 15% of system peak demand in 2015. A large DR capability was initially viewed as

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Cost Surveys," Prepared for Energy Storage Program, Office of Electric Transmission and Distribution, U.S. Department of Energy, LBNL-54365, November 2003.

appropriate for this case study. As the results section indicates, this level of DR capability was found to be an over build for this system, i.e., DR values of between 7% and 10% of total system peak would probably have been more appropriate for this system. This indicates that any resource will have diminishing returns at some level and, as with any resource, it can be overbuilt.

The IEA work produced a number of insights, particularly as they relate to price effects of DR, effects on risk metrics from DR, and reliability. These insights will inform the work performed in the implementation of the value framework, and serves as a point from which work in Task Area 1 can build upon. Two general conclusions from the IEA work that are relevant to the development of the comprehensive framework and presentation of results can be drawn from this analysis:

1. It is important to look at the distribution of system costs across the different future cases.
2. The DR products examined seem to be quite successful at addressing those days that had extremely high marginal production costs.[66]

[66] Marginal production costs were used as a proxy for market prices. In general, on days that have high demands and are defined as "tight capacity" days, the process of market price formation has shown market prices to exceed the marginal costs of production. From this perspective, the impact of DR is likely underestimated by using marginal production costs.