3. DRR BENEFIT-COST FRAMEWORKS

The literature on how to assess the benefits and costs of DRR within a consistent framework is quite dispersed and varied. In general, it is fair to say that there has been no consensus on how to even approach this problem. In some regions, very rough cut analyses are performed indicating what the impact on market prices would have been had a certain amount of DRR been available on an extreme high price day. Rather than rely on formal benefit-cost tests, some policies have been based on benchmark analyses and what might be termed "views of the electric system" that when taken together seem to imply an obvious conclusion that some DRR is needed.

3.1 Benchmark Assessments of DRR

These benchmark studies take estimates of electricity supply elasticity (how much prices would have dropped in a given market for a given reduction in demand) and estimate the impact of price for a given reduction in demand. As examples:

- An EPRI study examining demand response in California indicated that "… a 2.5% reduction in electricity demand statewide could reduce spot wholesale prices by as much as 24%; and a 10% reduction in demand might slash wholesale prices by half."[23]
- A study of the United States market showed that having about 10% of retail load on a real-time pricing scheme would have mitigated the United States Midwest price spikes of 1998 and 1999 by about 60%.[24]
- A report by the U.S. Government Accountability Office (GAO) indicated that a 5% reduction in peak demand could have reduced California's highest peak prices by as much as 50%.[25]
- The GAO report also states that "reducing the need to build and maintain few peaking plants, the industry will need to build and maintain fewer [plants] overall, which will improve the overall efficiency of the industry."
  - 1,000 MW of peaking plants are estimated to cost about $300 million to build and avoiding their construction can substantially reduce industry investment committed to these little used plants.
  - Power plants in the United States with a total generating capacity of between 84,000 MW and 134,000 MW operated less than 10% of the time. In 2003, these seldom used plants accounted for about 14% to the total installed capacity in the United States.[26]

Similarly, general statements about the need for an efficient market to be based on the interaction of supply and demand abound in the literature, accompanied by a listing of the barriers to demand response that exist in current industry structures.[27]

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[23] Moore, T., "*Energizing Customer Demand Response in California*" EPRI Journal, Summer 2001, p.8.

[24] D. Caves, K. Eakin and A. Faruqui, "Mitigating Price Spikes in Wholesale Markets through Market-Based Pricing in Retail Markets," The Electricity Journal, April 2000.

[25] United States Government Accountability Office (GAO), *"ELECTRICITY MARKETS -- Consumers Could Benefit from Demand Programs, but Challenges Remain"* Report to the Chairman, Committee on Governmental Affairs, U.S. Senate, August 2004, p. 27.

[26] United States Government Accountability Office (GAO), August 2004. Ibid.

One problem with these general statements is that they are static and focus only on select days with a retrospective view. Solutions need to be assessed in a dynamic environment. For example, it is true that if demand were reduced by 5 to 10 percent on days where prices spiked, there likely would have been a substantial reduction in the magnitude of prices. It is also possible that, if on these days there had been more generation available, prices likely would also have been lower. Going forward, these general statements do not provide a framework against which different resources and system options can be assessed. Such a framework is still needed.

The issue of "not enough demand response" has been recognized across countries in work conducted by the International Energy Agency (IEA) and the Organization of Economic Co-operation and Development (OECD). "Demand response in existing markets is typically low, since market participants lack both the incentive and the means to respond. Regulated retail prices, out-dated metering technologies, a lack of real-time price information reaching consumers, system operators focused on supply side resources, and a historical legacy in which demand response was not considered important – all of these factors combine to produce the low levels of demand response seen in electricity markets today."[28]

In the United States, working groups and regional study efforts developed similar views without developing an estimation framework for estimating DRR value and costs. The New England Demand Response Initiative (NEDRI) was a collaborative effort spanning all the New England states and also included the U.S. Department of Energy and the U.S. Environmental Protection Agency, as well is the ISOs in New England and New York. Thematic statements from this collaborative effort include:

- There is "a growing realization among market participants and policy makers that the efficient integration of demand response resources (DRR) would be central to the long-term success of restructured electricity markets, power portfolios, and delivery systems."
- NEDRI members "agree that such demand responsiveness is an essential component of the wholesale market, and can be compatible with both competitive and franchise retail markets, implying that DRR is essential in both restructured as well as in vertically integrated markets."
- "Without effective demand response opportunities, customers who would be willing to reduce their consumption and balance the system at a lower price are not given a market opportunity to do so … this problem has weakened the functioning of wholesale power markets. Both market participants and regulators have focused a great deal of attention on the need for short-term, price-responsive load curtailments."[29]

The NEDRI effort also concluded that the issue was not confined to just the development of demand-side products to create responsive loads, but that "wholesale market rules that support short-term, price-responsive load curtailments are an essential element of an efficient wholesale market structure." Broadly stated, DRR include all intentional modifications to the electric consumption patterns of end-use customers that are intended to modify the quantity of customer demand on the power system in total or at

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[27] See "*Demand Response: Principles for Regulatory Guidance*," by the Peak Load Management Alliance, February 2002. Available at www.peaklma.com.

[28] "THE POWER TO CHOOSE: Demand Response in Liberalised Electricity Markets," prepared by the International Energy Agency (IEA) and the Organization for Economic Co-operation and Development (OECD), Paris, 2003.

[29] "Dimensions of Demand Response: Capturing Customer Based Resources in New England's Power Systems and Markets." Report and Recommendations of the New England Demand Response Initiative (NEDRI), July 23, 2003. Available at: http://nedri.raabassociates.org/Articles/FinalNEDRIREPORTAug%2027.doc.

specific time periods. There are many opportunities for customer-based DRR to add value to power systems and markets, and there are many types of DRR to call upon.[30]

The NEDRI effort was comprehensive in many respects and provides a good overview of the issues, particularly those that bridge the gap and help integrate wholesale and retail electricity markets. Still, the NEDRI effort did not address a planning framework or benefit-cost framework outside of making the recommendation that "the regional power system planning process should evaluate on an even-handed basis all feasible, comparable solutions to emerging problems including generation, transmission, and demand-response resources." The NEDRI report did develop 35 recommendations spanning DRR products, pricing and metering, energy efficiency, and power systems.

This shows that, at least in some regions of the United States, some policy statements can be made and actions taken without a detailed development and estimation of the benefits and costs of DRR. However, to sustain these into the future, NEDRI and other working groups[31] recognize that a planning process that does appropriately account for DRR along with all other system options will be needed.

A consistent assessment of DRR benefits is a difficult task as many of the benefits are hard to quantify. As a result, market actors commonly examine these benefits, as NEDRI did, and then are able to express a management or political judgment that the benefits of certain actions are likely to exceed their costs. However, making implicit judgments more explicit by using a structured analysis usually provides important insights, even if the structured assessment is only a first-order analysis which quantifies the judgments about benefits and costs and who receives them.

Comments that illustrate statements of belief by different parties regarding the role of DRR in markets include:

- California Energy Commission Order Instituting Rulemaking (June 17, 2003) states that the Commission will consider the acquisition of 2,500 MW of DRR (approx. 5% of peak demand) to moderate price increases and improve system reliability.
- ISO-NE's *Regional Transmission Expansion Plan* states that DRR can have significant benefits in terms of reliability and savings in congestion costs.
- New England Demand Response Initiative's *Final Draft Report* states that a small amount of DRR can enhance system reliability and substantially reduce market-clearing prices, producing significant benefits to consumers.
- The *ISO-NE 2002 DR Program Evaluation* states that magnitudes of DRR sufficient to clear the market at lower bid prices will reduce the price of energy for all purchasers in the spot market.
- The NYISO states that it has had a successful DRR program in operation through two summers which has delivered benefits to the grid in terms of reduced market price and improved system reliability.
- U.S. Federal Energy Regulatory Commission's White Paper on Standard Market Design (SMD) states that:

[30] NEDRI, 2003. Ibid. p. 6.

[31] The large customer DRR working group (i.e., California Energy Commission DR Working Group 2) has recommended that a process for valuing DR be instituted as a next phase of work, and a working group on DRR valuation is being sponsored by the Northwest Planning and Conservation Council (NPCC) with a strawman proposal released on September 16, 2005.

- *"Demand response is essential in competitive markets to assure the efficient interaction of supply and demand."*
- *"Demand response options should be available so that end users can respond to price signals."*

- California Public Utility Commission's R. 02-06-001, Order Instituting Rulemaking, June 6, 2002. states that "Demand Response is a vital resource to enhance electric system reliability, and reduce power purchase cost and individual consumer costs. "
- California Energy Commission's *2002 – 2012 Electricity Outlook Report* estimates that an increased level of DRR could have saved California $2.5 billion in the year 2000.

These quotes all pertain to the market benefits of DRR and do not distinguish which entities should be paying for the programs, and how benefits are distributed among market entities. This is a question that stands directly in the path of delivering DRR, even if there is a consensus that market-wide benefits exceed costs.

3.2 DRR Benefit-Cost Frameworks – Extensions of Standard Practice Tests for Energy Efficiency Programs

The vast majority of benefit-cost analyses of DRR 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.[32] Since it was originally adopted in 1983 it has been updated a few times, with the 2001 version being the most recent. Some version of the SPM is in use in most regions in the United States, and it has been adapted to apply in other OECD countries as well.

The October 2001 SPM sets out four groups of tests for evaluating demand-side management programs. Each test group examines the program from a different perspective. The SPM describes those test groups and their perspectives as:

- **Total Resource Cost (TRC) Test:** "This test represents the combination of the effects of a program on both the customers participating and those not participating in a program. In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel...The benefits calculated in the Total Resource Cost Test are the avoided supply costs – the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost – for the periods when there is a load reduction...The costs in this test are the program costs paid by both the utility and the participants plus the increase in supply costs for the periods in which load is increased." (SPM, p. 18)
- **Ratepayer Impact Measure (RIM) Test:** "The benefits calculated in the RIM test are the savings from avoided supply costs. These avoided costs include the reduction in transmission, distribution, generation, and capacity costs for periods when load has been reduced and the increase in revenues for any periods in which load has been increased ...The costs for this test are the program costs incurred by the utility, and/or other entities incurring costs and creating or

[32] *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

administering the program, the incentives paid to the participant, decreased revenues for any periods in which load has been decreased and increased supply costs for any periods when load has been increased." (SPM, p. 13)

- **Participant Tests:** "The benefits of participation in a demand-side program include the reduction in the customer's utility bill(s), any incentive paid by the utility or other third parties, and any federal, state, or local tax credit received... The costs to a customer of program participation are all out-of-pocket expenses incurred as a result of participating in a program, plus any increases in the customer's utility bill(s)." (SPM, p. 8)
- **Program Administrator Test:** "The benefits for the Program Administrator Cost Test are the avoided supply costs of energy and demand, the reduction in transmission, distribution, generation, and capacity valued at marginal costs for the periods when there is a load reduction...The costs for the Program Administrator Cost Test are the Program costs incurred by the administrator, the incentives paid to the customers, and the increased supply costs for the periods in which load is increased." (SPM, p. 23)

3.2.1 Application of the SPM to Assess DRR in California

The clearest example of how the SPM has been applied to DRR 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[33], on Cost-Effectiveness Analysis, illustrates an effort made in response to a CPUC ruling that the WG2 should develop a plan for large customers that includes "a complete benefit-cost analysis."[34] 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 all DRR programs used the SPM. However, the WG2 also recognized that there were some concerns with using the SPM that should be addressed in future proceedings.[35]

A critical assumption concerns the costs that are avoided by the MW included in the DRR option. The only avoided costs used in this DRR benefit-cost application were those associated with a simple cycle gas turbine – in the high case a new turbine would have to be constructed and in the low avoided cost case, it was assumed that an existing peaker comprised the avoided costs. Avoided T&D costs were not addressed. The avoided cost assumptions for the simple cycle gas turbine used by the WG2 were:

Avoided Cost Case	Fixed Avoided Cost	Heat Rate	Fuel Cost
New Simple Cycle Gas Turbine:	85.00 $/kW-Yr	10,000 BTU/kWh	3.50 $/mmBtu

[33] *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.

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

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

Each DRR offer must project the demand reduction amounts that would be attained. For the proposals outlined above,[36] the demand reductions over the hours in which the demand is reduced for each proposal are shown in Table 3-1.

Table 3-1: Program Demand Reduction Amounts

Entity	Program	Demand Reduction MW	Hrs Reduced	Demand Reduction MWh
California Power Authority (CPA)	Call Option for Interruptible Loads	200.0	100	20,000
Joint Utilities	Critical Peak Pricing	140.0	84	11,760
SCE	Demand Bid Program	30.0	84	2,420
PG&E	Demand Bid Program	14.0	84	1,176
SDG&E	Demand Bid Program	8.0	4	32
SDG&E	Hourly Pricing option O	5.9	213	1,257

The results of the Total Resource Cost test for the Simple Cycle Turbine Avoided Cost Case is shown in Tables 3-2.

Table 3-2: TRC Test Results for the Simple Cycle Turbine Avoided Cost Case

Entity	Program	NPV ($1,000)	Benefits/Costs	$NPV/MWh
CPA	Call Option	$69,594	2.13	.32
Joint Utilities	CPP	$73,320	5.15	.57
SCE	DBP	$18,296	15.25	.66
PG&E	DBP	$7,958	9.12	.62
SDG&E	DBP	$4,981	79.90	14.15
SDG&E	HPO	5.9	213	1,257

These results show that for all of the proposed DRR options were viewed as cost-effective, i.e., they yield a net benefit and have a B/C ratio greater than one.

Limitations of the California WG2 SPM Benefit-Cost Application

The WG2 participants have noted that other items identified in the CPUC rulings have not been captured in this SPM-based analysis. The CPUC indicated that "a complete cost-benefit analysis … should include environmental values, insurance/reliability value, market effects, fuel price stability, and other criteria that are more difficult to quantify." And importantly, to assess 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

[36] There were more DRR proposals than those cited here, but this listing covers most of the different variants considered by the Working Group in California.

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. [37]

3.2.2 Updated Avoided Cost Method Proposed for DRR in California

A study from October 2004 looked at developing avoided costs for DRR based on market prices.[38] This avoided cost study estimates hourly prices by developing a forecast of prices and looking at the highest price hours. DRR products differ from energy efficiency programs that reduce load without a utility's active involvement. The DRR products studied were dispatchable load products, which typically give a utility the right, but not the obligation, to curtail a customer's load under agreed-upon circumstances. The utility's right is defined by program parameters such as advance notice requirement, maximum operation frequency per month or year, and maximum duration per operation.

3.2.3 Application of SPM Benefit-Cost Tests for DRR by Other Entities

A number of interviews were conducted with utilities in the U.S. and a study was obtained from Australia that produced a cost-effectiveness assessment based on the standard practice tests.

Alliant Energy[39]

Alliant Energy (AE) is a medium-sized vertically integrated electric utility headquartered in Cedar Rapids, Iowa. Conceptually, AE conducts benefit-cost analyses for its DRR programs in the same manner as its energy efficiency programs. They use the four California stakeholder perspectives: participants, non-participants/rate impacts, utility revenue requirements, and societal cost tests. AE estimates the avoided costs from DRR programs from avoided peaking generation capacity and energy costs, as well as avoided transmission and distribution costs. The Iowa Utilities Board (IUB) requires utilities to increase avoided costs estimates for electric DSM measures by 10% to account for environmental benefits from DSM programs. However, they do not include reliability or other benefits from DRR programs in their benefit-cost analyses. They also do not attempt to quantify the participants' costs of participating in the programs.

Commonwealth Edison[40]

Commonwealth Edison (ComEd) is a large electric distribution company headquartered in Chicago, Illinois. ComEd does not currently conduct long-term net-present-value based benefit-cost analyses of its DR programs. ComEd conducts short-term DRR program benefit-cost analyses that are focused on deciding whether or not to activate the DRR programs during a peak period. These analyses compare the

[37] The CPUC requested in a July 27, 2005 Ruling that the California investor owned utilities file supplemental testimony that provides cost-effectiveness results for their 2003, 2004, and, to the extent possible, 2005 programs, and their overall demand response (DR) portfolio, using the Standard Practice Manual (SPM) tests as the starting point. These testimonies were filed on August 26, 2005.

[38] 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.

[39] This information was gathered during a telephone interview with Tom Balster, AE DSM Programs Manager, on August 31, 2005.

[40] This information was gathered during a personal interview with Jim Eber, ComEd Product Portfolio Manager, on October 15, 2004.

day-ahead real-time electricity prices for the PJM power pool to the costs of activating the DRR programs. When the short-term costs that ComEd would avoid by activating one or more of its programs exceed the short-term program costs, including rate discounts and program operating costs, the company activates the programs that are cost beneficial.

Wisconsin Public Service[41]

Wisconsin Public Service (WPS) is a medium-sized vertically integrated electric utility headquartered in Green Bay, Wisconsin. Conceptually, WPS conducts benefit-cost analyses for DRR programs in a similar manner as for energy efficiency programs. WPS estimates the avoided costs from DRR programs solely from avoided peaking generation capacity and energy costs. They do not include avoided transmission and distribution costs, nor reliability or other benefits. They also do not attempt to quantify the participants' costs of participating in DRR programs. They assume that program impacts will last for 20 years at 100% of the initial impacts. WPS has developed a simplified spreadsheet benefit-cost analysis for its DRR program evaluation. The inputs for this spreadsheet were derived from their class-cost-of-service model that they used for their most recent rate case. WPS does not incorporate results from their generation planning modeling into their DRR program benefit-cost analysis.

Essential Services Commission of South Australia

A study commissioned by Essential Services Commission of South Australia includes benefit-cost analysis of five different programs run by ETSA Utilities, the distribution company of South Australia.[42] This study is unique in that it applied the cost-effectiveness analysis to examine whether it was possible to defer augmentation of constrained network elements on ETSA Utilities' distribution system. Constraints on the South Australian distribution system are the result of short-term peak loadings on extremely hot summer weather weekdays. Delaying the need to build or acquire additional supply-side capacity to meet these short-term peaks, through DSM or innovative pricing strategies, will result in reduced capital expenditure for network expansion, and ultimately lower energy prices to the consumer.

The programs examined in the report are:

1. Standby Generation
2. Curtailable Load Control
3. Power Factor Correction
4. Medium Business Voluntary Load Control (VLC)
5. Residential and Small Business Direct Load Control (DLC) of Air Conditioning

The cost-effectiveness of the DRR programs was assessed from three perspectives. This approach, which is based on the Standard Practice Manual (SPM) reflects the fact that benefits and costs accrue to different stakeholders, as follows:

- Participant Benefit-Cost Ratio (BCR) – measures the quantifiable benefits and costs of a demand-side program to a participating customer;

[41] This information was gathered during a telephone interview with Mary Klos, WPS Customer Value and Support Services Analyst, on August 31, 2005.

[42] "*Assessment of Demand Management and Metering Strategy Options,*" produced for the Essential Services Commission of South Australia by Charles River Associates, August 2004.

- Utility BCR – measures the change in total costs to the utility resulting from implementation of a demand-side program; and
- Total Resource Cost (TRC) BCR – measures the change in the average cost of energy services across all customers.

Benefits and costs were estimated over the regulatory period 2005 to 2010 using standard discounted cash flow analysis to estimate the present value of future benefits, costs, and net benefits. These network-driven DRR programs focused on dealing with least-cost solutions to capacity constraints. However, they can also deliver additional benefits to the network service provider, such as being able to bid short-term load reductions in the spot price market in response to high wholesale prices. This resource is particularly attractive to electricity retailers who require physical hedges to offset market price spikes resulting from reduced generation or network capacity.

Program benefits were calculated by looking at the Distribution Network augmentation avoided cost savings, and at the revenue income for the ETSA of selling physical hedges to retailers, at a 50% sharing ratio. Based on network benefits only, not all of the programs had a benefit-cost ratio of higher than 1 for each test.

3.3 DRR Cost-Effectiveness Frameworks Based on Reliability Benefits

A number of ISOs have developed DRR products. Given that the principal goal of an ISO is to maintain system reliability, a number of cost-effectiveness studies of ISO DRR products have focused on the reliability benefits of DRR. These programs provide resources that can be dispatched to maintain reliability at acceptable levels. However, treating controllable loads as supplemental reserves necessitates development of a method for quantifying the value of such reserves. The valuation philosophy adopted by some ISOs in the United States focuses on the marginal value of the additional reliability provided by the curtailment capability.

This marginal value is realized from reductions in the probability of forced outages and in the severity of the outages. The more likely a system is to experience outages, the greater the value of curtailable load will be. The severity of an outage can be measured by its impact on customers. If conditions warrant disconnecting a single feeder, the impact is smaller than if a large portion of the system load must be disconnected. The number of consumers and the collective load affected are also important; the more widespread the outage, the greater the costs to consumers.

Establishing the value of curtailable loads to the system therefore involves determining the following:

1. Expected reduction in the occurrence and duration of outages.
2. Expected load disconnected during outages if they were to be necessitated by system conditions.
3. Impact on customers, in terms of the value of the time without electrical service.

The first two items, taken together, can be used to estimate the reduction in expected "unserved energy" (in MWh per year), defined as:

Expected Unserved Energy (MWh per year) = **(Eq. 1)**
Expected Outages (hours per year) x Expected Disconnected Load (MW)

Expected unserved energy normalizes the implications for changes in system reliability by converting any situation into an equivalent level of energy. To those customers who lose service, unserved energy equates to monetary losses in the form of reduced production, lost sales, spoiled goods, and any other losses associated with a business activity or the value of services received by non-business customers. The lost value to customers from outages is described as the value of lost load (VOLL), expressed in dollars per unit of unserved energy ($/MWh). The expected value of the curtailable load in avoiding or mitigating outages can then be expressed as the product of the Expected Unserved Energy (the consequences in physical terms) and the VOLL (the monetary measure of those consequences).

Value of Curtailable Load ($ per year) = **(Eq. 2)**
Expected Unserved Energy (MWh per year) x VOLL ($/MWh)

Substituting the formula for Expected Unserved Energy (Eqn. 1) yields the following equation:

Value of Curtailable Load ($ per year) = **(Eq. 3)**
Expected Outages (hrs per year) x Expected Disconnected Load (MW) x VOLL ($ per MWh)

According to this formula, the value of curtailable load, and by association the value of the demand response program that creates it, is based on the *expectations* of future outages, not on a *retrospective* look at how many times the curtailable load was called upon. This reflects the fact that demand response programs have value as a hedge against generation outages and higher-than-expected demand, regardless of whether they are ultimately needed, or how much they are actually used in any given year. Outage history may affect future expectations, and therefore value, but it is the expectations upon which value is estimated.

In order to estimate the value of demand response programs, estimates must be derived for the three inputs to the Value of Curtailable Load formula (Eq. 3). These estimates can be based on information available to most utilities and on appropriate use of the body of knowledge on the value of lost load.

In general, most applications of the value of reliability approach have been in DRR assessments conducted by the New York ISO and the ISO New England.[43]

[43] ISO studies that have addressed the value of reliability include: 1) *A Study of NYISO and NYSERDA 2002 PRL Program Performance*, Neenan Associates, January 2003; 2) NYISO Seventh Bi-Annual Compliance Report on Demand Response Programs and the Addition of New Generation in Docket No. ER01-3001-00, December 1, 2004; and 3) An Evaluation of the Performance of the Demand Response Programs Implemented by ISO-NE in 2004, prepared by RLW Analytics and Neenan Associates, December 29, 2004.

4. CASE STUDY – A RESOURCE PLANNING FRAMEWORK FOR DRR VALUATION

This section includes the background and results of a case study for DRR valuation within a resource planning context. Section 4.1 describes this approach and compares it to other methods which can be used to provide estimates of the value of DRR. It should be noted that the resource planning approach to DRR valuation is a somewhat labor-intensive analysis method, and the simpler benefit-cost tests or benchmark valuation methods presented in Sections 3.1 and 3.2 can also be used.

There are unique aspects of DRR, when viewed as a resource, that make a resource planning construct a useful valuation tool, as compared to the alternatives of using standardized benefit-cost tests or other approaches that tend to focus on past events, or frameworks that are not dynamic over time. However, each approach has strengths and weaknesses, and each can be useful in addressing specific situations.

4.1 Background: Valuing DRR in a Resource Planning Framework

One of the stated objectives of this valuation analysis is to develop a framework that appropriately supports the analysis of DRR as part of a forward-looking resource plan. This can only be accomplished if the framework appropriately addresses both the costs and benefits of DRR, and also allows for tradeoff analyses to be conducted with other resource options, e.g., peaker plants such as gas combustion turbines.

The case study approach used in this section is not meant to represent a specific resource plan for any region. The results of the case study results, by themselves, are not meant to indicate that any specific resource should be deployed or preferred to any other resource. A more detailed resource planning study, based on the specifics of the system and region being addressed, would be needed before a specific conclusion can be reached.

This case study approach does illustrate how the unique attributes of DRR can be represented in a resource planning study. Resource planning has a long history in the electric utility industry. A wide range of models has been developed over the years that compare the costs of various electric generation resource mixes to meet given weekly, monthly, or annual electricity demands. These tools can be used to examine how changes in the mix of resources can influence the system costs, i.e., the costs of meeting the system electric demand.

One premise underlying this approach for DRR valuation is that if the costs and attributes of DRR are appropriately incorporated within these models, then a comparison of a resource plan without DRR available as a resource can be compared to a plan with DRR. The difference in costs between the two resource plans is one measure of the "value of DRR." Resource planning has been the process that the electric industry has used for years to assess cost-effective resource plans and examine tradeoffs between different resource alternatives. Given this history, it seems appropriate to address the value of DRR within this planning context.

As discussed in Section 3.2, many of the early attempts to place values on DRR have used benefit-cost tests that were designed originally for energy efficiency programs. These tests can provide useful results and serve as benchmarks when comparing different DRR products, e.g., direct load control of water heaters, or load reductions at large end-user facilities. Energy efficiency programs generally produce reduced energy use across a large number of hours. For example, replacing a refrigerator with a more efficient refrigerator saves energy during every hour in which the refrigerator is operating.

Demand response differs in that it is a peaking resource that is meant to be used only for a few hours, and only during periods of very high electricity prices and/or periods where there are reliability issues. In the assessment of the energy savings from a high efficiency refrigerator, it is appropriate to use average energy costs since the appliance operates all the time. However, DRR tend to be used during extreme events, when energy costs can be very high. These might be hot summer days or cold winter days, when the electric system is under stress in terms of being able to meet the demand, or during periods when major generating units are unexpectedly off line and there are system reliability concerns. Therefore, models and market representations that can address both average and extreme events are best suited for examining the cost-effectiveness of these two types of resources.

One of the most commonly used benefit-cost tests for demand-side management assessment is the Total Resource Cost (TRC) test. This test includes a variety of benefits characterized as avoided costs or avoided cost adders.

- Avoided generation costs
- Avoided transmission costs
- Avoided distribution (T&D) costs
- Line loss reductions
- A reliability adder
- Waste heat utilization benefits
- A price elasticity adder

Avoided generation costs, avoided transmission costs, and avoided distribution costs are likely to be dramatically different for energy efficiency alternatives and demand response alternatives. During peak periods and periods of high system stress, when DRR is most valuable, the avoided generation costs will represent high-cost peaking units; transmission costs may be high due to congestion on the lines (and due to lower throughput capacities on hot days); and distribution costs may also be high as the capacity of a substation is reached or nearly reached.

DRR benefits need to be calculated for events such as high peak demand and extreme system stress. These events may only occur once in every five years. As a result, DRR may not see much use for a number of years. However, DRR could provide substantial benefits for that one-in-five- or one-in-ten-year event, when a combination of circumstances stresses the system and leads to unusually high system costs. As a result, one week or month with several extreme events might result in benefits from DRR large enough to cover the costs of the DRR products for five to ten years.

4.2 Case Study – Resource Planning Analysis Framework

The basic approach taken during this case study was to examine the change in system costs, over a 19-year time horizon, with and without DRR included in the portfolio of resources. This difference in costs provides an estimate of the value of DRR to the electric system being examined. The specific model used for this effort was New Energy Associates' Strategist® Strategic Planning Model.[44] However, most

[44] The full Strategist model contains a number of different modules including financial, load forecasting, and market decision modules. For the purposes of this effort, the modules used were the Load Forecast Adjustment module, the

production planning/capacity expansion models can be used by following the basic template outlined in this case study. The goal of this effort is not to advocate the use of any specific model or modeling techniques, but to illustrate a process that can be used to appropriately credit DRR with the benefits it provides.

It is important to note that this is one of several activities that are being undertaken in this area. This effort focuses on modeling a North American electric system that is based on fossil and nuclear fuel. A model of the Nordic system was also be run to examine the use of DRR under a different pricing regime, different system constraints, and with substantial hydro resource availability (see Section 4.11) . In addition, another ongoing task is the development of benefit-cost frameworks for assessing DRR that may not require the use of a full resource planning model.

This section outlines the structure of the model framework which was used. The basic approach for the case study was presented at the IEA Task XIII experts meetings, as well as at other expert forums.[45]

Appropriately incorporating DRR in forward-looking resource plans requires the planning effort to embody two critical capabilities:

1. A planning framework with a sufficiently long time horizon to allow for the benefits of DRR to be captured. DRR has the potential to reduce the costs of low-probability, high-consequence events that impact system reliability, but these events may occur only every 5 or 10 years.
2. DRR can reduce the risks of high electricity prices during periods when several factors combine to create shortages or high system costs. To address this risk management aspect of DRR, the planning framework must explicitly address the uncertainty that is present around key factors, including fuel prices, weather, and system factors such as transmission constraints and plant operation. If the risks that impact the costs of electricity are not dimensioned in the planning process, then the value that DRR offers in terms of risk management cannot be assessed.

Overall, the process used included developing system planning "scnarios" that represent different futures against which DRR was valued. This process can be summarized as consisting of six steps:

Step 1: Determine pivotal factors influencing the market costs of electricity.

Step 2: Assess uncertainty around these factors and express that uncertainty via probability distributions.

Step 3: Create a combination of these factors, i.e., combine the probability distributions to create a joint probability surface.

Step 4: Draw a set of discrete futures (termed "cases") from the probability surface. Each draw includes a value for each key factor (100 draws).

General and Fuel module that provides estimates of production cost of electricity for different resource mixes, and the PROVIEW resource optimization module.

[45] Presentations have been made at the ***Eighth National Symposium on Market Transformation,*** Washington, D.C., 2004, sponsored by the American Council for an Energy Efficiency Economy, and at the ***Demand Response Program Seminar***, sponsored by the California Energy Commission, Public Interest Energy Research Program, February 2004.

Step 5: Run each future through a resource planning model, which provides 100 values for system costs, which can be incorporated into a distribution of costs for a given set of available resources.

Step 6: Repeat Step 5 for different portfolios of resources to determine the cost differential and reliability differential for "with DRR" and "without DRR" options.

It should be noted that the emphasis on modeling the costs of meeting low-probability, high-consequence events stretches the current abilities of most planning models, including the model used in this analysis. Models designed to minimize overall system costs to serve a given load projection often make simplifying assumptions and trade-offs regarding these peak events, to better estimate the costs of serving the vast majority of the hours in the planning period. This is appropriate for typical planning, but a task that is focused on looking at the resources and costs of serving peak periods suffers somewhat from the standard planning assumptions. One example is the way unforced and forced outages are handled by Strategist (and by alalmost all planning models):

- Unforced Outages – These are planned plant outages and are scheduled to occur during specific times, usually for regular maintenance or, in the case of nuclear units, refueling of the plant. The model builds in this scheduled maintenance at specific times and the plant is assumed to be unavailable for those periods.
- Forced Outages – These are unplanned plant outages and stem from the unplanned need to repair or replace equipment. Roughly speaking, annual forced outage rates are around 15% for nuclear units, 10% for coal units, and around 5% for gas units. Since these occur unexpectedly, it is not possible for a planning model to consider all the possibilities for the time and duration of forced outages. Therefore, the forced outage rate is built into the model by derating the generation unit. For example, the capacity of nuclear units are derated by 15% for every hour of the year. As a result, the operational, cost, and reliability impacts of having a number of units be simultaneously off-line because of forced outages is considered only indirectly. Rather than use this average derating approach, this case study included three "stress" events in which the timing of forced outages at major facilities was specified, similar to what can actually occur in electric systems.

Most business and policy planning models, across many sectors, use averaging assumptions when the number of possible variations is extremely large, or when extreme events are few and occur in a somewhat unpredictable manner. This approach produces good estimates of expected system costs, but less precise estimates of the cost impacts of extreme events.[46] This is not an inherent weakness of the models, however, because they were not designed specifically to examine extreme events.

Finally, planning models should be viewed as producing strategic or tactical decision making information from a framework that requires that a consistent set of assumptions be used. Planning models are approximations of the systems they are meant to represent. As a result, models provide useful information to decision makers, but they do not produce decisions themselves.

[46] The forecasting and analysis of extreme events is almost always a more complex problem than estimation of the expected value (or average) of system costs (or other objectives) over a planning horizon. As a result, most models use assumptions that average out the effects of extreme events since they happen unexpectedly and infrequently.

4.3 Base Case Electric System

This process uses a base case against which alternative resources can be assessed. The base case was developed to realistically represent an electricity market that will allow for appropriate trade-offs between resources – both supply-side and DRR – and in which issues such as off-system sales/purchases and system constraints can be addressed, e.g., transmission constraints. 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 and Summit Blue's experience.

This approach allowed for the use of baseline data that had already been compiled for other client resource planning analyses. This saved time in specifying the base case, and allowed the analysis to focus on representing uncertainty around key pivot factors and defining the DRR products. The starting point database was a large system that included five distribution utilities, interchange capabilities with two other regional systems, and a customer base of nearly 6 million. The availability of interchange power is an important factor as this system was modeled as a net importer of power.

4.4 Modeling Methodology

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

Four DRR products were included as potential resources to meet future system needs, in combination with the full range of supply-side options. The four DRR 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 DRR offered when that price is less than the marginal system cost. This program can also be classified as a day-ahead pricing program.