Integrating Demand Side Resource Evaluations in Resource Planning – An Industry Turning Point

Dr. Daniel M. Violette, Summit Blue Consulting, LLC, Boulder, CO
Rachel Freeman, Summit Blue Consulting, LLC, Boulder, CO

Abstract

The electric and gas industry is at a crossroads in its view of Demand-Side Resources (DSR). The costs of traditional approaches to meeting future energy needs may no longer be economic or acceptable due to fundamental changes in fossil fuel markets, environmental concerns, and the large investments needed for industry infrastructure. This investment includes generation, transmission, and fuel supply infrastructure (e.g., gas pipelines and rail lines). In addition, sizeable compliance costs associated with carbon mitigation and other environmental requirements are likely to increase in the future. The risks of pursuing traditional energy supply strategies have never been higher, and demand-side activities can have an important role in managing the risks associated with the cost of energy (i.e., reasonable rates) and its availability.

This paper extends work being done on integrating DSR within resource planning processes. This paper focuses on:

- The importance of planning approaches that address risk management across both supply-side and demand-side resources – including the role that DSR can play in managing resource cost risks.[1] A recent review of utility resource plans found that none of the plans "explicitly analyzed the risk-mitigation benefits of demand-side resources."[2]
- A dynamic planning process that considers the timing and sizing of DSR investments in resource portfolios. This moves the resource evaluation process away from static benefit-cost tests and towards the direct incorporation of DSR in planning assessments which can appropriately address important attributes of DSR including the flexibility of DSR.

A case study is used to illustrate issues in and some conclusions from looking at a select set of DSR resources in a supply plan with a focus on DR and pricing programs.

Background

The definition of Demand-Side Resources (DSR), as used in this paper, includes energy efficiency (EE) programs, demand response (DR) programs, and pricing programs[3] that induce a change in customer energy use due to program-induced stimuli. DSR has been a component of the electric and gas industry landscape for many years, with some variability in the dollars invested and the number of locations in which

[1] This certainly is not the first time this issue as been addressed. Hirst (1992) used sensitivity, scenario, and worst-case analysis methods to address uncertainty in two resource portfolios. His research indicated that it was feasible to analyze the effects on uncertainty of including DSM programs in a utility's resource mix. He recommended that "utilities, which to date have done very little such analysis, should conduct such studies as part of their integrated-resource planning activities."

[2] Two of the five key findings in this recent review of utility resource planning processes included: 1) "In most resource plans, energy-efficiency effects were implicit, or fixed, in the modeling process. Few utilities explicitly modeled energy efficiency as a resource, allowing it to compete with supply-side resources in identifying a least-cost portfolio;" and 2) While utilities have made significant progress in analyzing alternative resource portfolios under different risk scenarios, "none explicitly analyzed the risk-mitigation benefits of energy-efficiency resources." See Nicole Hopper, Charles Goldman, and Jeff Schlegel (2006), which examined the most recent resource plans for 14 utilities in the West.

[3] DR refers, in general, to load management programs designed to clip peak demand for only 80 to 120 hours per year. Pricing program refers to most time-differentiated methods of electricity pricing, including time-of-use (TOU) and real-time pricing (RTP).

demand-side strategies have been aggressively pursued. In general, EE, DR, and pricing programs have been viewed as appropriate activities, but not necessarily activities that are central to the future of the industry. This is about to change and, with this change, the demand-side community may need to adapt some of its program planning and evaluation practices to ensure that DSR is represented in the resource planning process and is appropriately incorporated in the resulting forward-looking resource plans.

Uncertainty and volatility have increased in virtually all aspects of traditional resource acquisition, including fossil fuel prices, energy and peak demands, weather, and infrastructure costs. Year-to-year, season-to-season, and even day-to-day volatility increases supply costs as infrastructure must be developed to handle the impacts on capacity. DSR programs offer viable alternatives that can be relied upon to reduce the risks associated with potentially adverse energy futures (i.e., 1 in 10 high energy cost scenarios).

Recognizing these factors, recent actions taken across North America indicate that DSR activities are being counted on as future resources to a greater extent than any time in the past. This is demonstrated in the following illustrations:

- Governor Spitzer of New York (April, 2007) said, "It now costs one-third as much to save energy through energy efficiency programs as it does to produce the same amount of energy by building a new power plant. … We can spend billions of dollars to build every single one of the power plants needed … or we can invest far less to cut demand for energy by 15 percent. Common sense says we should take the second approach – that we should both build and conserve." The goal is to reduce energy consumption by 15% by 2015 (15 by 15). "This will be the most aggressive target in the nation."
- Governor Rendall of Pennsylvania (February, 2007) issued an Executive Order for an Energy Independence Strategy that will save Consumers $10 billion over 10 years, with a plan that includes energy efficiency programs, time of day rate structures, and smart metering.
- Governor Corzine of New Jersey (February, 2007) issued an Executive Order that will reduce future electricity consumption by 20 percent from projected 2020 consumption levels.
- The State Legislature of Minnesota (February, 2007) passed legislation with bipartisan support, setting targets for utilities that call for reductions in forecasted retail energy sales of 1.5% annually.
- Utilities have also become more aggressive. For example, Baltimore Gas & Electric announced a target of 10% reduction in residential energy use in 10 years, with potential savings in commercial and industrial sectors expected to be even higher (January, 2007).

Across North America, more industry leaders are recognizing that the costs and uncertainties associated with building our way out of a future shortfall in energy supplies are higher than ever before. The result is that more utilities, regulators and resource planners are looking to demand-side activities to provide tangible resources to meet future energy needs.

Integrating DSR within a Dynamic Resource Planning Framework

The framework described below uses as its organizing focus the *investment decision* in DSR. The framework can be used to develop the information needed to make good decisions regarding what is the appropriate investment in DSR, so that overall expected net system costs are lowered, reliability objectives are achieved, and the risk of adverse energy futures is managed.[4] Two principles are embodied in this framework:

<u>ONE</u>: A little analysis on key questions can provide a lot of information. Electric systems are complex and there is uncertainty at many levels within the system. When working to quantify uncertainty and

[4] This research on integrated planning is growing. Probably the most comprehensive framework integrating DSR and supply-side technologies was developed by the Northwest Power Planning and Conservation Council (NPCC) in their 5th Resource Plan (2005). Several utilities presented similar frameworks to the California Energy Commission (2007).

assess its implications for resource investment decisions, a focus on the most important factors is needed, with simple approaches to dimension high and low scenario ranges and an assessment of the resource planner's best estimate of where within this range the outcome is more likely to occur.

TWO: Assessments of DSR within a resource planning framework should, to the extent practicable, use the planning tools that have become standard for that utility or planning entity. If separate assessments are required to assess the role of DSR within the resource portfolio, then the value of the DSR as a resource may not be readily accepted by planners – regardless of the number of regulatory and executive decisions supporting the inclusion of DSR programs in the resource plan. Experience shows that when the utility believes DSR is a viable resource that contributes financially to creating a least-cost resource plan, then there is a greater commitment to actually attaining effective DSR.

Viewing commitments to DSR as an investment decision leads to a set of questions that should be addressed through the resource planning framework. These are discussed below.

Q1: Baseline Question: What is the value of existing DSR and is there a need for additional DSR? This is the definition of the baseline against which the value of new resources – both DSR and traditional supply-side resources – need to be compared, in order to develop estimates of net costs for new resources.

Q2: What types of resources should be included in the portfolio assessment? Data on supply-side alternatives have routinely been gathered by planning departments at utilities, and many of the companies that support resource planning models maintain databases on technologies that can be input into their model. Interestingly, these same firms that support resource planning models generally do not have any data on the costs and impacts of DSR. These have to be developed and added to the list of available data resources. The standard list of demand-side measures is no longer adequate for assessing DSR in resource portfolios. New programs that overlay direct load control and other time-differentiated pricing programs (e.g., TOU or day-ahead hourly pricing) are becoming options that offer a better value proposition to both customers and utilities. Additionally, combined/integrated EE and DR programs can provide greater impacts at lower costs. Therefore, the list of DSR programs to be included needs to be tailored to the particular utility (or region), taking into account current DSR programs and the characteristics of all its customer classes.

Q3: What should be the timing of and size of DSR deployment, including expansion and/or maintenance of the program in a steady state? Will this influence its value in a portfolio? One of the advantages of DSR 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 DSR products are not immediately needed due to excess generation capacity, a planned roll-out can schedule DSR products based on anticipated future needs. If reduced DSR commitment is warranted, the programs can be down-sized simply by not replacing exiting customers, or even asking some customers to leave the program.

Q4: Do different DSR products within a portfolio have positive and/or negative synergies? If real-time pricing is offered as a DSR option, 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 DSR will depend upon the portfolio of different DSR programs/options being assessed. A mix of DSR programs, ranging from energy efficiency programs (conceptually comparable to base-load generation) to near-real time dispatchable DSR programs (i.e., peaking plants) may provide the greatest value to the system. The relationship between DR and EE is examined in the report by York and Kushler, 2005.

Q5: What are the "insurance and portfolio benefits" from DSR due to increased diversity in resources (e.g., fuel inputs) and location (distributed near end-use loads)? The framework is meant to be an investment strategy designed to meet future system needs. This investment strategy is made under considerable uncertainty around key factors that will influence the system costs. These can include:

- The price and availability of input fuels for generation in the region (i.e. gas, oil, coal, and water levels at hydro facilities).
- Weather, which can impact both average seasonal and peak demands.
- The performance of power plants (i.e., occurrence of forced outages at major plants).
- Transmission delivery constraints due to unexpected events.
- Other costs such as carbon mitigation and other environmental compliance costs.

Recent research has shown the importance of these key factors. For example, the ISO New England Regional System Plan (2005) explicitly analyzed the short-term and long-term issues related to the diversity of fuels used to generate electricity. An assessment of these uncertainties in a study for the International Energy Agency (See Violette, Freeman and Neil, 2006) indicated that reasonable bounding of these uncertainties, when aggregated together, produced a range of system costs in which the high end of the cost range was approximately double the lower bound cost. These uncertainties indicate the importance of assessing whether DSR programs can provide fuel diversity and locational diversity which can mitigate some system risks. DSR 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, DSR can be viewed as a hedge that can reduce (but, not necessarily eliminate) the increase in costs due to extreme events. As such, it is a physical option that has value in reducing uncertainty in future system costs. It is important to be able to assess this value in a comprehensive framework.

Q6: What are the overall impacts on the electricity market – i.e., incentives for the development of appropriate technologies and mitigation of market power? The development of DSR 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 are no incentives for technology companies 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. Similarly, there may be other factors that become important as DSR is appropriately incented by the market. Consumers may become more knowledgeable about energy use if they can save money by participating in a pricing program. Other factors that may be hard to quantify might include mitigation of market power across a region. By increasing the elasticity of demand with respect to price signals or curtailment signals from the utility, variation in wholesale market prices for power may be mitigated, particularly during periods of high demand when there are fewer suppliers left to provide incremental power. Also, the locational flexibility of DSR may reduce the number of load pockets (where a limited amount of generation can influence the price of power in that pocket).

Overall Framework Needs Assessment

The six questions presented above illustrate the need for a planning framework that assesses the appropriate level of both initial and ongoing investment in DSR, based on market and technology circumstances. In addition, DSR products vary in their specifications, ranging from EE programs that may impact annual and/or seasonal energy use to DR programs that have limitations on the hours they can be called and the length of each event (although most all DR programs have a provision allowing them to be called during times of system emergency). These factors will affect the value of DSR, with the impact depending on the characteristics of the regional system. Therefore, a dynamic model is needed to assess different portfolios of DSR products within any specific electricity market.

This dynamic resource planning approach differs from the static benefit-cost test approach to examining the cost-effectiveness of DSR programs, as defined in the California Standard Practice Manual (SPM)[5] which has served as a starting point for variants of the benefit-cost tests used in many jurisdictions. This benefit-cost test approach does not, for the most part, explicitly address uncertainty (except through scenario analysis) and does not directly address the insurance and risk management benefits of DSR. In addition, this approach does not place a value on the flexibility of DSR resources – which can be ramped up, maintained (essentially held constant), and even ramped down, allowing them to follow system needs much more closely than a fixed-size supply-side resource. The resource planning framework discussed above is dynamic and more amenable to addressing uncertainty as system factors evolve over time. It also includes correlations between the key factors that drive net system costs. In fact, resource planning models are themselves benefit-cost frameworks that produce net system cost estimates, and the benefits of both DSR and supply-side resources are captured in this net system value along with the costs of enabling those contributions.

The demand-side community, both evaluators and program designers, will need to develop and validate the information needed to address DSR in these planning assessments. Representing DSR in this way poses tough questions for both resource planning and efficient markets. Because the factors that influence the electric markets are dynamic, a dynamic process is needed to assess the contribution of DSR to the overall robustness of any resource plan. This implies that the framework should directly addresses difficult issues such as:

1) Uncertainty in key factors that 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 options and DSR programs/options, and evaluates their effect on overall system costs, reliability, and risks associated with extreme events.

There are a number of resource planning models in use across the industry. Most utilities run their own models, have trained personnel experienced in running the model, and have developed the data inputs to the model that appropriately represent their region.[6] Therefore, it makes the most sense to adapt existing utility methods, whenever possible, to address the unique challenges of DSR.

Robust Planning — Dimensioning Uncertainty and Assessing Risk

In order to develop key inputs to the resource planning model, the following steps will need to be taken:

- Determine how to represent uncertainty in key inputs that influence system costs using probability distributions.
- Examine correlations across inputs. For example, if the value of one variable, such as the price of oil, is high; then, it is likely that natural gas prices will also be high. Similarly, if monthly energy demand exceeds expectations, is it likely that peak-hour demands during that month will

5 The *California Standard Practice Manual, Economic Analysis of Demand-side Programs and Projects* is published by the California Public Utilities Commission

6 The authors have worked with a number of utilities that all use different resource planning models, yet the basic planning concepts have or can be applied using existing planning tools.. Also, by using their own models, it is more likely that the resource planners will believe in and support the viability of DSR to meeting future energy needs at acceptable levels of reliability.

also be higher than expected. It is the occurrence of these joint events, even if improbable, that creates adverse energy future scenarios and high resource planning risks.

- Appropriately characterize both DSR and supply-side resources in terms of what they can deliver, at what price, and what the uncertainty is in these characterizations.[7]
- Incorporate time-steps to capture the value of flexibility contained in different resource plans.

Developing the distributions to represent uncertainty can pose some challenges for data providers; however, the use of software packages like Crystal Ball and @RISK[8] makes constructing distributions routine as they can be created in Excel spreadsheets. As an example, consider a scenario analysis that provides a low case, a medium case, and a high case. Just knowing these three values – a low, medium and high case – may not tell us much and might not adequately capture the judgments and beliefs of the planners and utility management. What else would one like to know about these cases? Additional information that would be useful might include:

- How likely is each of these cases to occur?
- Are cases other than these three as likely or more likely to occur?
- What is meant by low, medium, and high? Is the low case the lowest conceivable value? Is the high case the highest conceivable value?

The next step is to form a rough distribution. The assessment of the likelihood of occurrence for the different cases adds additional, useful information. While this may be only a rough estimate of the likelihood of occurrence, it better represents the cases being assessed. Adding the probability of occurrence for each case would produce something like the information shown in Figure 1 below.

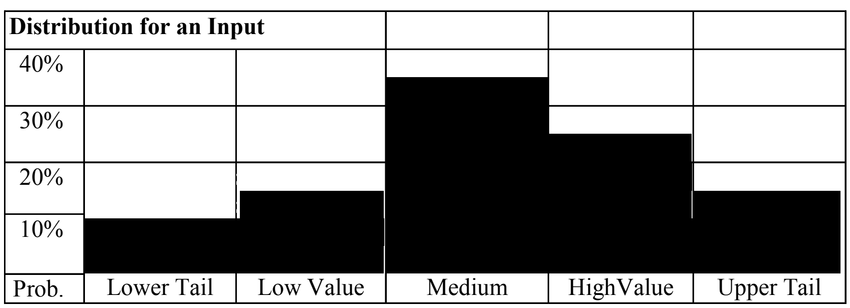


Figure 1: Example Distribution Based on Scenario Analysis

A common representation of uncertainties in traditional resource planning applications is the "tornado diagram" shown in Figure 2 below. This figure is taken from a utility IRP completed in 2006. It shows the sensitivity of cumulative present worth costs (CPWC) for specific scenarios that are assessed one at a time. While this is useful information, it is easy to see that if the high growth, high fuel prices, and carbon tax scenarios occurred at the same time, this would increase the cumulative NPV of the costs of this plan by about $4 billion, over the "expected" $10 billion incremental expansion plan cumulative NPV costs. This would be a 40% increase in plan costs. Work on incorporating uncertainty into resource planning shows that, at five to ten years out, the 95% confidence is often in the range of plus/minus 50% from the mean system costs for each year throughout the planning time horizon.

[7] Mills, Kromer, and Weissc (2006) discuss dimensioning uncertainty in DSR projects along with references in that paper.
[8] Crystal Ball software is offered by Decisioneering, Inc. and @RISK is offered by Palisades, Inc.

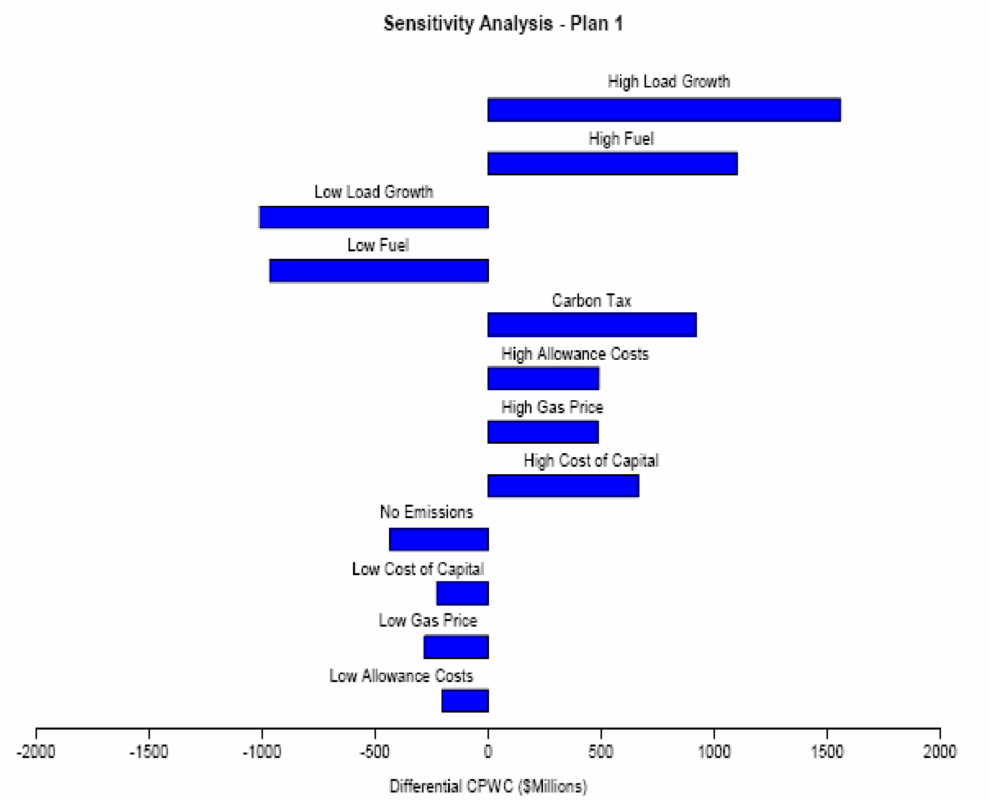


Figure 2: Tornado Diagram of Scenarios from a 2006 Utility IRP (discussed above)

Application of DSR within the Resource Planning Approach

The effect of uncertainty on the net present value costs of a resource plan are considerable, as illustrated above. While the range of values can be substantial, the extreme cases are generally represented by low probability but high consequence events. Questions to be addressed are: can DSR be used as a hedge against these types of events, and can DSR be appropriately sized through these approaches?

The interest in portfolio approaches is demonstrated by the work that is on-going in California as part of the California Energy Commission (CEC) 2007 Integrated Energy Policy Report.[9] In addition, interest among regulators is shown by the recent report prepared for NARUC (2006) on the application of portfolio theory to resource planning. The NARUC report states "Regulatory guidance and oversight will be critical to achieve the goals of portfolio management, and to ensure that utilities have clear direction."

A Case Study

A generation capacity expansion and production cost framework was used to develop estimates of system costs with and without DSR. The Strategist® Planning Model was used in this case study and the base case for the model was designed to realistically represent an electricity market that allows for appropriate trade-offs between resources – both supply-side and demand-side – and is able to address issues such as off-system sales/purchases and system constraints (e.g., transmission constraints).[10]

The case study focused on evaluating DSR within a resources portfolio with the following design:

[9] A Staff Workshop on the use of Portfolio Analysis in Electric Utility Resource Planning was held on June 4, 2007 and the workshop papers are available on the CEC website -- http://www.energy.ca.gov/2007_energypolicy/index.html.
[10] The Strategist Model is a New Energy Associates (a Siemens Company) product who also provided the base case system using information for a selected region in the National Electric Reliability Council (NERC).

1) Only DR and pricing programs were explicitly modeled in this case study. It should be noted that EE programs were not examined.[11] However, it is expected that EE programs would provide risk management benefits similar to those provided by the RTP pricing variant since both would impact energy use in many hours during the year, including peak period hours. As with pricing programs, EE program costs are uncorrelated with input fuel prices, plant outages, and other temporal system constraints. The most effective portfolio of DSR resources would likely include EE, DR, and pricing.
2) The case study did not include uncertainty about the DR and pricing programs themselves. The case study examines the effect on system costs programs that could, in fact, meet their target design parameters in terms of delivery and cost. Future analyses should take into account the fact that different DSR programs will also have uncertainties associated with them regarding cost and contribution.[12] Information on the reliability of DR programs is increasing and includes: a study by Hopper et al. (2007) on the summer of 2006 being a milestone for DR; PJM testimony on 2006 and the contributions from DR; and information being gathered on mass-market DR programs.
3) Conservative assumptions on program costs and contributions were used (See Violette et al. 2006).
4) The case study focused on electric system uncertainties - peak demand, energy demand, input fuel prices, plant outages, and transmission capabilities. Uncertainty in compliance costs for meeting future environmental standards such as carbon mitigation was not addressed. However, DSR programs have a minimal environmental footprint. The inclusion of environmental cost uncertainties in the model would most likely increase the ability of the DSR programs examined to mitigate risks, as their costs are uncorrelated with different environmental mitigation futures. The costs of meeting carbon mitigation requirements in the future may be substantial and will most likely increase the running costs of fossil fuel units. For example, in Figure 2, the carbon tax case was $1 billion higher than the base case.

Model Description. 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. Uncertainty was dimensioned around: 1) Fuel prices – natural gas, residual oil, distillate oil, and coal; 2) Peak demand; 3) Energy demand; 4) Plant outages; and, 5) Tie line capacities.

Three DR programs and two pricing variants were included as potential resources to meet future system needs, in combination with the full range of supply-side options. These included:

- <u>Interruptible Loads</u> – Customers are paid a capacity payment for the MW pledged and there are penalties if MW reductions are not attained. Customers are given a two-hour call period.
- <u>Direct Load Control</u> – A known amount of load reduction with 5 to 10 minutes of notification. This is a mass market program and, as a result, requires a ramp-up period to attain its target participation.
- <u>Dispatchable Purchase Transaction</u> – 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.
- <u>Two Pricing Variants</u>:

[11] EE programs and expenditures are often the result of a negotiated settlement based on a EE potential study and avoided kWh costs that are shown to be lower than supply-side costs. As a result, system planners often view EE as a given change in the energy and peak demands that they cannot influence. As a result, there is a tendency to focus on resources that can be impacted by the planning analyses. However, future work should incorporate EE as a resource to allow for information to be gained on its impact as a hedge against future risks. In this analysis, EE was viewed as having a potentially similar effect to the real-time pricing DSR variant as both impact energy use across a wide range of hours, but this should be tested.

[12] Uncertainty in DSR programs is important, but not the focus of this case study which was designed to determine if well executed DSR programs would be useful in limiting selected risks. The issue of uncertainty in DSR costs is addressed in California Public Utilities Commission (2006) and published work such as to Mills, Kromer, and Weiss (2006).

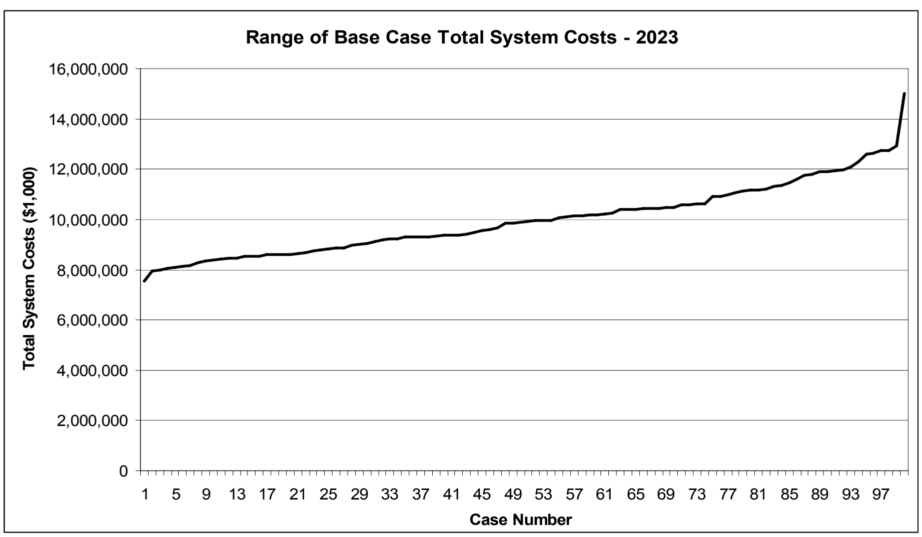
1. A peak-period pricing program that was ramped up over four years to apply to 25% of the load and held constant at that level in subsequent years. This produced a 15% reduction in peak demand and little impact on load in other hours. This is similar to a critical peak pricing (CPP) product, with the overall monthly and annual energy demand largely unaffected.
2. A RTP program for large customers ramped up over four years to 25% of the load and held constant at that level. This produced a reduction in peak demand of about 15% for participating customers (when prices are highest) and also an overall energy efficiency effect, resulting in reductions in daily, weekly, monthly, and annual energy demand of 4%. These figures were viewed as consistent with the RTP literature for large customers.

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

Four sets of model runs were developed addressing the following DR and pricing options: 1) a base case resource option; 2) a resource option with three new DR callable programs; 3) an option with the three callable DR programs and a peak-period pricing program; and 4) a resource option with the three callable DR programs and the Real-Time Pricing (RTP) product.

Importance of Dimensioning Uncertainty. The importance of looking at the distribution of system costs is shown in table 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.



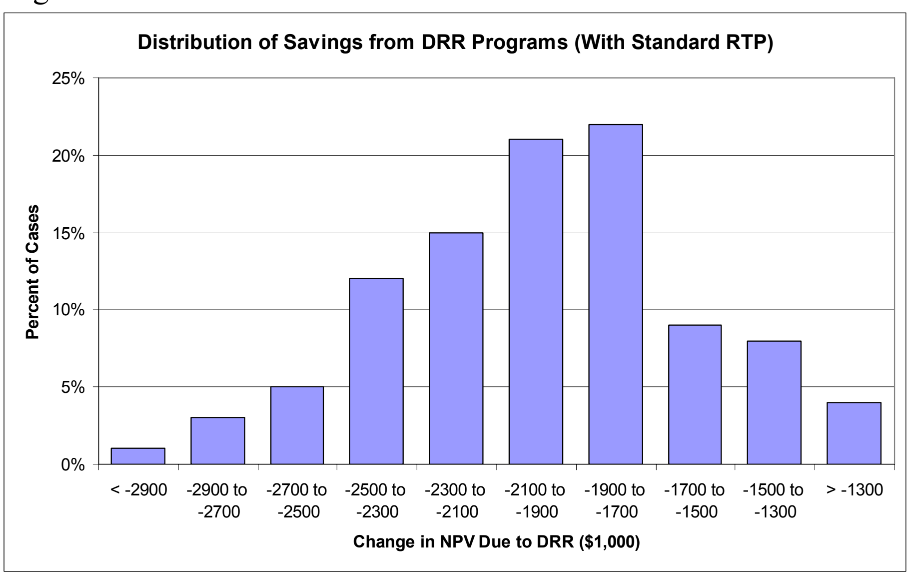
In the base case, the overall uncertainty in total system costs for each year (100 cases per year) is quite large across these cases – indicating that the uncertainty in the modest number of variables selected (recall that uncertainty in environmental compliance costs was not included) does result in 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%.

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 the dispatchable resources were used. While dispatchable 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 and no RTP, 36% of the 100 cases showed savings in total system net present value (NPV) compared with the base case. With the full RTP scenario, 97% of the cases showed savings.



DR Capacity Usage. Large amounts of DSR were used about once in every four years. Across all resource scenarios, small amounts of DSR were used in most of the years in the planning horizon, with near capacity use of DSR happening infrequently. The amount of DSR that was called upon did not vary much across the three scenarios, e.g., the "with RTP" resource option only resulted in a 10% reduction in DSR 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 RTP that resulted in better utilization of system resources across all hours. This capacity utilization indicates that the dispatchable DR programs may have been oversized. Sizeable DR programs were designed to ensure that DR was available when needed, but this may have created some over-capacity of dispatchable DR after the ramp-up period. Based on data from the initial model run, a "right-sizing" of the DSR portfolio was performed. Under the right-sizing scenario, net system costs declined as there were fewer years where DR went unused.

Cost Risk Profile. There was a change in the risk profile associated with the planning scenarios with the addition of DSR. 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 for the initial DSR scenario with RTP and DR levels.

Table 1: Risk Metrics with Initial Size of DSR Programs

Risk Metrics – Reduction in Net System Costs at Risk ($M)		
	VaR 90	**VaR 95**
Mass Mkt DLC and Callable DR	**238**	**213**
DLC/Callable DR with Critical Peak Pricing	**924**	**966**
DLC/Callable DR with Real Time Pricing	**2,673**	**2,766**

Table 2: Risk Metrics after Right Sizing DSR (not shown in Violette, Freeman, and Neil. 2006)

Risk Metrics – Reduction in Net System Costs at Risk ($M)		
	VaR 90	**VaR 95**
Mass Mkt DLC and Callable DR	**1,071**	**1,096**
DLC/Callable DR with Critical Peak Pricing	**1,786**	**1,828**
DLC/Callable DR with Real Time Pricing	**3,535**	**3,628**

Conclusions

In this case study, the DR/pricing DSR portfolio reduced the risks associated with adverse energy futures. Traditional EE programs were not included in this case study; however, it seems like aggressive EE programs would have attributes similar to the RTP variant examined above in terms of being both flexible in its deployment over time, influencing energy use across many hours, and being uncorrelated with supply-side uncertainties.

The DR and pricing portfolio reduced the cost of the 1 in 10 "high cost future" by over $3.5 billion. The case study also showed that sizing dispatchable DR correctly based on system characteristics can have a significant effect on the value of these DR programs. When dispatchable DR was sized too large for the system, the reduction in risk was reduced to $2.7 billion. On average, the net savings in incremental costs of meeting future demands due to this DR/pricing portfolio were 10% for the scenario with DR and peak period pricing, and 23% for the scenario with DR and RTP.

Overall, this case study shows that a Monte Carlo approach coupled with a resource planning model can evaluate the impacts of a DSR portfolio on system costs, and can also assess its ability to mitigate risk, i.e., costs associated with low-probability, high-consequence events. The addition of the DR/pricing programs to the resource plan reduced the costs associated with extreme events by up to $3.5 billion, and it also 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 this DR/pricing portfolio reduce the expected costs of meeting load growth, but it also reduces the impacts of adverse events producing a sizeable reduction in risks to ratepayers. In future analyses, this methodology could be expanded and used to examine:

- The explicit inclusion of EE along with the DR and pricing portfolio examined in this case study.

- The determination of when DR programs should be initiated and how fast they should grow. This can be done by, for example, by adding programs at different times and analyzing model results to see the effect on total system costs.

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