IEA DRR Task XIII

DRR VALUATION AND MARKET ANALYSIS

VOLUME I: OVERVIEW

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TASK XIII: DEMAND RESPONSE RESOURCES
TASK STATUS REPORT

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COMMISSIONERS' EX #2

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Dear Mr. Malme:

This is the companion document, *Volume I: Overview*, that accompanies the more detailed report, *DRR Valuation and Market Analysis – Volume II: Assessing the DRR Benefits and Costs.* This work represents a continuation of the ongoing research and debate regarding the role of demand response resources (DRR) in electricity markets, resource adequacy, and portfolios of resources. This Volume I draws out key elements of Volume II in a shorter, less technical paper.

We sent a draft of these two volumes at the end of September and received a number of comments from participating countries. We have worked to incorporate these comments into these two volumes. This effort is meant to illustrate the different approaches for valuating DRR, and it includes an examination of how DRR might be incorporated into a forward planning process such that DRR products can be appropriately offered and deployed to achieve market-wide objectives in electric markets.

Sincerely,

Dan Violette

VOLUME I – OVERVIEW: ASSESSING BENEFITS AND COSTS OF DRR

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E. EXECUTIVE SUMMARY

This report presents the results of an assessment of different approaches for determining the value of Demand Response Resources (DRR). It also includes a case study modeling effort which addresses a resource planning approach for valuing DRR. These efforts examine Subtask 4 (Demand Response Resource Valuation) of the IEA Task XIII Demand Response Resources (DRR) study. Specifically, different approaches for assessing DRR are presented, including basic benchmark approaches, applications of standard practice benefit-cost tests, and an approach for valuing DRR using a resource planning context. This last approach is described and compared with the other methods used to provide estimates of the value of DRR.

E.1 Benefits and Costs of DRR

An efficiently operating electricity market depends upon the appropriate interaction of supply and demand. Barriers to demand response are inherent in electric markets that have a history of regulated retail pricing, and which have been restructured – this has bifurcated the benefits of demand response. This bifurcation of benefits is an important issue. Demand response has the potential to provide benefits to commodity providers, reliability organizations, transmission companies, distribution companies, and electric end-users. However, it is difficult for a provider of DRR products and services to aggregate the market-wide benefits such that an efficient amount of DRR will be provided into the market.

The market-wide benefits of demand response include:

- Lower electricity prices;
- Reduced price volatility;
- Increased efficiency in one of the most capital intensive industries;
- Risk management, i.e., a physical hedge against extreme system events that are difficult to incorporate in planning and valuation frameworks;
- Increased customer choice and customer risk management opportunities;
- Possible environmental benefits; and
- Market power mitigation.

In addition to these market-wide benefits, there are a number of private entity benefits that include reduced capital, operation, and maintenance expenses for transmission and distribution systems. These benefits accrue to the owners of these systems. There is also the potential for benefits to accrue to aggregators of demand response resources for sales to commodity providers or reliability organizations.

DRR benefits do not come without associated costs. As with any product or service, DRR requires marketing, start-up capital, and ongoing operational costs in terms of both servicing the product and paying participants for their demand responsiveness. This latter cost is important in that a vital component of customer value is now realized, i.e., those customers that can vary their demand for electricity from peak periods to off-peak periods are now provided with a financial incentive to take these actions.

Simply stated, the electricity industry can only be viewed as efficient if it appropriately prices what is scarce, i.e., on-peak electricity use.

E.2 Approaches for Assessing and Valuing DRR Products

A number of approaches have been used to evaluate the benefits of developing products and programs that would allow for the demand for electricity to be more responsive to price or to events that reflect system reliability issues. The most common have used extensions of the standard practice tests that have been utilized to evaluate energy efficiency programs. These tests typically include the Total Resource Cost (TRC) test, the Participant Test, and the Ratepayer Impact Measure (RIM) test. Other approaches have examined the influence increased demand responsiveness can have on the reliability of a system, and have tried to develop measures of the change in reliability due to the availability of DRR, and then estimate values for that change.

To date, most frameworks for assessing DRR have been retrospective in nature, i.e., they value load management events that have occurred in the past and do not take a forward-looking view of the role DRR can play in a longer-term resource portfolio. This report presents a number of DRR assessments from different points of view – the application of standard practice tests to DRR and the estimation of the impact of DRR on system reliability – that are generally based on past cases where DRR has been utilized. Few approaches have taken a comprehensive view of DRR that can account for the major benefits this unique resource can provide and answer the basic question inherent in determining the appropriate role of DRR in long term planning.

E.3 Case Study – Valuing DRR Using a Resource Planning Framework

A case study modeling effort was developed for valuing DRR using a resource planning context. This approach was also compared with other methods commonly used to provide estimates of the value of DRR. Changes in system costs with and without DRR 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 DRR for the electric system. The specific model used for this effort was New Energy Associates' Strategist® Strategic Planning Model.

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 DRR – and is able to address issues such as off-system sales/purchases and system constraints (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 Associates and Summit Blue's experience.

One hundred cases were created as data inputs to the Strategist model. They were calculated to represent a variety of possible futures. Monte Carlo methods were used to create the different future cases that represent the uncertainty in key future inputs. The key input variables around which uncertainty was dimensioned were: fuel prices (natural gas, residual oil, distillate oil, and coal); peak demand; energy demand; unit outages; and tie line capacities.

Four DRR products were included in the model as potential resources to meet future system needs, in combination with the full range of supply-side options generally modeled in resource plans. The products were: Large Industrial Interruptible, Mass-Market Direct Load Control, Dispatchable Purchase Transaction, and Real-Time Pricing. Real-time pricing was added to the model not as a callable program,

but as a reduction in peak demand and/or a reduction in energy demand, depending on the size of the program.

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

E.3.1 Case Study Results

Results from these analyses include the following:

- 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.
- 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 DRR to the system greatly reduced the "peakiness" of the hourly prices, reducing the maximum price by more than 50%. For example, in one peak day in July the total cost savings were $24.5 million.
- A substantial percentage of new capacity charges were deferred by the model because of the DRR availability. This amounted to savings of $892 million (2004 dollars) over the 20-year period.
- DRR provided significant benefits in those years in which it was used. While DRR provides considerable amounts of benefits on select days, there is a cost to building and maintaining the DRR capacity which is paid for in every year and in every case, even if DRR is not used. This results in there being some cases where there are costs but no savings from DRR. Looking at the 100 cases individually, in the scenario with DRR 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.
- Large amounts of DRR were used about once in every four years. Across all resource scenarios, small amounts of DRR were used in most of the years in the planning horizon, with near capacity use of DRR happening infrequently. The amount of DRR 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 DRR hours called across the 20-year planning horizon. As a result, the callable DRR retained their value as a hedge against extreme events even with pricing options that resulted in better utilization of system resources across all hours.
- There was a change in the risk profile associated with the planning scenarios with the addition of DRR. There were significant savings when looking at value at risk (VAR) at the 90th percentile (VAR90) and at the 95th percentile (VAR95). Results for the three scenarios are shown below.

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

- The addition of DRR 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 DRR 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.

In conclusion, this case study shows that a Monte Carlo approach, coupled with a resource planning model, can address the value of DRR given uncertainties in future outcomes for key variables, and can also assess the impact DRR has on reducing the costs associated with low-probability, high-consequence events. In this case study, the addition of DRR to the resource plan reduced the costs associated with extreme events and the likelihood of those events, and it reduced the net present value of total system costs over the planning horizon.

E.4 Summary and Conclusions

Four basic approaches were examined in this work effort:

Approach 1: Benchmark methods – Assessment of the impacts of DRR on a given day based on an actual event.

Approach 2: Application of the standard practice benefit-cost tests with a focus on the Total Resource Cost (TRC) test.

Approach 3: Assessments based on the increased reliability resulting from DRR, generally taken from historical data.

Approach 4: A portfolio approach based on explicit dimensioning of uncertainty; an assessment of the impact of DRR on the risks associated with high-cost, but low-probability events; and the overall impact of DRR on system costs.

Each approach produces valuable information as each represents a way of organizing data and information to address the value of DRR in a specific context. The first three approaches have been generally applied in a static framework and examined specific DRR products singularly rather than in a portfolio context. It is useful to know, for example, what the price reduction might have been if X amount of DRR had been available on a given day when electric price spikes occurred; or if DRR products are in place, how they impacted price and reliability on a given high demand day. However, these studies do not address important forward-looking questions regarding the potential role of DRR among a portfolio of resources.

E.4.1 Including DRR in a Portfolio of Resources

Questions that may arise when considering DRR as a resource in a portfolio of resources include the following:

Q1: Do any DRR products provide value to the electric system in excess of their costs? Given the large number of DRR products/programs already deployed around the world, some DRR will almost certainly be cost-effective in almost any system given an appropriate planning horizon.

Q2: If some DRR products are cost-effective, what specific products should be included in the portfolio? A wide variety of DRR products are available, including: 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. (A large MW response can be gained by having the largest customers participate in this last product offering.)

Q3: How should the different DRR products be sized (i.e., how many MW or MWh should be accounted for in each product)? Most DRR 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 DRR program can be over-built which will reduce the benefits from the DRR portfolio, as shown in the resource planning case study in Section 4.

Q4: What is the appropriate timing of DRR deployment, expansion, and maintenance in a steady situation, or a reduction in the MW capacity of a DRR product? One of the advantages of DRR 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 they are not needed at the moment due to excess generation capacity, a plan can be developed to roll out DRR products when they are expected to be needed in the future. Also, if there is a need to reduce the commitment to DRR, the programs can be down-sized simply by not enrolling new customers when current customers leave the program or, in the extreme, asking some customers to leave the program. However, eliminating a DRR product, only to find that there is a need for the product later on, could cost more than simply placing the program in a maintenance mode. DRR 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 DRR products within a portfolio have positive and/or negative synergies? One of the questions that commonly arises is that if real-time pricing is offered as a DRR product, then how will this impact the economics and value of, for example, a large customer interruptible program. Real-time pricing will cause the demands during peak hours to be reduced as customers respond to the higher prices in these hours. This will have an impact on the value of an interruptible program, since the number of MW that may need to be reduced during a high peak demand event will be lower, due to some customers already planning to reduce their demand due to the higher pricing.

Q6: What are the portfolio benefits from DRR due to increased diversity in resources (e.g., fuel inputs) and location (distributed near end-use loads)?

Q7: How should technological advances be addressed (i.e., when should an existing product be phased out to make way for a product based on a more advanced technology platform)? This issue is seen today in mass-market AC direct load control programs which are based on simple switches, and for which operators are considering a move to thermostat or even gateway technologies. Similarly, advanced metering and AMR technologies can be used both to control equipment and to incorporate innovative pricing options. In addition, this technology can be used to provide synergies where thermostats are adjusted during periods in which prices are high, thereby providing customers with additional benefits. DRR portfolios will need periodic assessment and transition plans to address changes in technology.

These seven questions illustrate the need for a planning and benefit-cost framework that assesses both entry investment into DRR and appropriate ongoing investment in DRR products based on market and technology circumstances. There is considerable variability in DRR product specification, in terms of the number of hours per season or year it can be called and the length of each event, and these factors will impact the value of DRR. In addition, their impact on value will vary by system. Therefore a dynamic model is needed to assess the different portfolios of DRR products within any specific electricity market.

E.4.2 Recommendations for Approaches to Valuing DRR

There is no question that the use of all four approaches addressed in this volume to examine DRR has provided positive information and will continue to do so. But there is also no getting around the tough questions that demand response products pose for overall resource planning and for running efficient electricity markets. The factors that influence electricity markets are dynamic, and a dynamic process is needed to assess their contribution to the overall robustness of the market.

This implies that a planning process that directly addresses difficult issues such as uncertainty, a time horizon that is long enough to include low-probability, high-consequence events, and the electricity market encompassing demand response as well as supply-side technologies is needed to assess impacts 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. These modeling efforts will be needed to fully value DRR. A plan for incorporating uncertainty in both generation and T&D capital budgeting, and also in developing budgets for annual operating and maintenance (O&M) costs, is needed. In some cases, utilities are beginning to examine these issues using appropriate tools; in other instances past procedures that do not account for the increasingly dynamic nature of electricity markets are still being used.

The use of benchmark studies, standard practice tests such as the TRC test, and event reliability assessments will become more valuable and useful when an overall construct of avoided capital costs (generation and T&D) as well as avoided O&M costs is developed from a resource planning perspective. Static analyses of specific situations are best addressed once a comprehensive framework has been developed.

The benchmark approaches and standard practice tests likely will continue to be used in the near term and these are useful as "proof-of-concept" analyses, and to justify the startup of selected DRR product development. But questions about how much DRR is enough, and the dynamics inherent in the timing of investment decisions, will likely need the development of a full resource adequacy assessment for an electricity market. This assessment likely will have resource planning constructs for both generation and T&D.

E.4.3 Lessons Learned from the Resource Planning Case Study

The modeling effort done for this study was an attempt to use a Monte Carlo approach in combination with the Strategist model framework in order to value DRR as part of a resource plan. This work demonstrates the key steps that need to be carried out in order to perform this type of analysis, and also presents the types of results that can be produced. Some lessons were learned during the process, including:

- Improvements can be made to the model specification, including the specification of DRR products and pricing products. Feedback loops can be incorporated in the model to take into account the ability of DRR to ramp up or go into a maintenance mode as needed, and this would avoid the "over building" of DRR capabilities which was shown to occur in this effort. This would have reduced the costs of the DRR without affecting their system benefits.
- The incorporation of DRR into the resource plan produces substantial increases in reliability as measured in loss of load probabilities (LOLP). No value was accorded to DRR for this increased reliability. Methods for developing estimates of the dollar value of this increase in reliability are important in that these benefits might be large – possibly as large as the decrease in net system costs found in this case study.
- Within the model, DRR was allowed to compete only with combustion turbines in providing capacity. The addition of DRR capacity resulted in the full deferral of all new combustion turbine capacity over the study horizon. A close examination of the model results showed that as a result some older generation units with high energy costs remained on-line in the latter years of the planning horizon. This increased the costs of providing energy that in some cases was not fully offset by DRR since the number of hours that DRR can be used is limited. A "re-optimization" task, which would look at whether some fossil units might be economic by considering both capacity and energy, might lower the average system energy costs in the "with DRR" scenario, leading to greater savings.
- The system being modeled is very large, with several hundred generation units, and therefore not as vulnerable as a smaller system to stress. It is not clear if the "stress" scenarios which were inserted into the model were really as extreme as could be the case for this system. For example, none of the stress cases (i.e., the cases in which there were significant unit outages) included a simultaneous reduction in tie line capacity and import capability from other regions. It is also possible that some might think the stress cases were too extreme. Either way, further work would improve upon the development of realistic stress cases.
- Care should be taken when discussing "price" and "marginal costs" as they are not interchangeable terms. The model that was used estimated engineering-based marginal costs and not electricity prices. In fact, open market prices may not be strictly related to marginal costs. To estimate prices more accurately, an overlay model may be needed which relates marginal costs to market prices.
- The electricity system used in this case study was a very large one, and so the savings due to DRR, as a fraction of total system costs, appear to be very small. This is due to an enormous amount of money already having been invested in the system over the preceding 30 to 50 years. However, the savings due to DRR are a much higher fraction of incremental system costs, or the "total cost to serve new load." Looking at savings in total system costs, when billions of dollars have already been invested, is not as relevant as looking at the cost of serving incremental loads and reducing costs on the margin.

1. INTRODUCTION

The objective of this effort is to focus on three work areas related to assessing appropriate levels of investments in demand response resources (DRR). These work areas are:

1. Consider benefit-cost frameworks that appropriately assess the economic case for DRR as part of a resource plan. These frameworks would be used to evaluate the cost-effectiveness of DRR, if installed DRR is cost-effective or not, and if additional DRR would be cost-effective or not. The objective is to establish a level playing field in the assessment of DRR against other resources when making planning decisions.
2. Identify approaches for determining the value of DRR in a resource portfolio. This would be only one part of a full benefit-cost test, i.e., the value of DRR. This then must be compared to the appropriate cost factors. The issues around the valuation of DRR within a resource portfolio are believed to be substantive enough to warrant a separate focus.
3. Discuss approaches for evaluating and verifying the benefits and costs of DRR once placed into the field. The purpose is to determine if DRR capacity, once attained through the offering of DRR products and/or programs, continues to have value exceeding costs.

1.1 Volume I Objective – Insights into Application

The objective of this Volume I is to focus on the lessons learned from the more detailed Volume II review of methods and case study application. Approaches for assessing DRR addressed in this work effort include:

- Benchmark approaches that examine DRR in the context of short-term or single events, e.g., the California energy crisis. The information from these benchmark events are used as a guide to what DRR might be able to accomplish in the future.
- The application of Standard Practice Tests traditionally used to evaluate energy efficiency programs, but adapted to address DRR products/programs. These tend to be evaluations of utility or distribution company DRR programs.
- Assessment of DRR in the context of improved reliability. These studies tend to focus on DRR programs offered by reliability organizations, e.g., independent system operators (ISOs). Some of these studies used as examples also include a more comprehensive look at DRR benefits and costs, but an assessment of reliability is one of the focal points of these applications.
- A case study application using a resource planning framework that explicitly dimensions and examines uncertainty to allow for an assessment of the "insurance" benefits of DRR as a hedge against low-probability, high-consequence events. This framework also examines the portfolio benefits of DRR, as the model allows for an explicit economic tradeoff between different types of DRR products and supply-side resources.

1.2 Application in Different Markets and for Different Market Actors

This report may be used to gain insight into valuing DRR in many different counties and electricity markets around the world. Although many of the test cases and methodologies shown in this report have originated in the USA, the approaches are general and can be adapted to suit specific markets. Most

countries have their own equivalent tests to the California Standard Practice Manual[1] tests – which include the Total Resource Cost (TRC) and Ratepayer Impact Measure (RIM) tests – and these country-specific tests can be substituted for the California Standard Practice Manual tests where appropriate.[2] In fact, the California Standard Practice Manual tests are really international in their scope and development, and they have been adopted widely, across many countries. The "California" designation is used to simply indicate the specific document that was used as a basis for this set of approaches.

A test case for a resource planning approach to valuing DRR was performed for the Nordic market, and a summary of that modeling effort is included in this report. It may be interesting for the reader to compare the Nordic model with the US one, and note the differences between them. These differences are apparent in both the methodology and the results, and they are partly due to the different mix of resources in the two markets (the Nordic model has a large hydro and wind component). A comparison of these two models can be useful for anyone designing a DRR valuation study in their own market, as it may contain aspects of both the US and Nordic markets.

The case study outlined in this report was done from the perspective of a regional planning organization. For markets that have not restructured, the vertical utilities have the responsibility for procuring electricity to meet the needs of their customers, and this case study approach is directly applicable to planning efforts for such utilities as well as regional planning entities.[3] However, this case study modeling effort is equally applicable to liberalized markets. Other market actors who could make use of the methodology given in this study are:

- Reliability organizations in Europe such as UCTE (continental Europe), JESS (UK), and Nordel (Nordic countries) which may have overall responsibility for ensuring that future demands for electricity can be met by the market. While some indicate that long term supply planning is not a mandate for reliability organizations, there is a need to assess 10-year to 20-year resource plans for the electricity markets, even in competitive markets, to ensure that appropriate structures and prices are in place to incent appropriate long-term planning by market participants.
- Commodity providers as they will want to meet their customer demands with the least cost resource plan. This might include procuring supplies from supply-side resources as well as integrating DRR to address short-term peaks and to manage both price and quantity risks.
- Government departments and regulating authorities, to assess the system benefits of DRR and evaluate the need for support – e.g., R&D funds, pilot studies, and removing barriers to DRR.

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[1] *California Standard Practice Manual – Economic Analysis Of Demand-Side Programs And Projects,* California Public Utilities Commission, October 2001.

[2] For example, a set of benefit-cost tests are shown in "Guidebook for B/C Evaluation of DSM and Energy Efficiency Service Programs" prepared for the EU Commission in 1996, provided by Mr. Casper Kofod, of Energy Piano (epiano@image.dk). In addition, the four California Standard Practice tests were used as the basis for assessing the investments in distribution resources in Australia -- "*Assessment of Demand Management and Metering Strategy Options,*" produced for the Essential Services Commission of South Australia by Charles River Associates, August 2004. This shows that these approaches to benefit-cost analyses of demand response programs are truly international, and can essentially be judged as one approach

[3] In the Northwestern States (Oregon, Washington, and Idaho) of the United States, the individual utilities conduct resource planning incorporating both supply-side and demand-side resources, but the Northwest Planning and Conservation Council also prepares regional plans that are presented to regulators in each State.