Valuing Demand Response:

International Best Practices, Case Studies, and Applications

PREPARED FOR

EnerNOC

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January 2015

THE Brattle GROUP

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The authors would like to thank Phil Martin and Aaron Breidenbaugh of EnerNOC for insightful input and feedback throughout the development of this report. They would also like to thank Vince Faherty of EnerNOC and Bruce Tsuchida and Wade Davis of Brattle for valuable insights and research assistance.

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1. Introduction

1.1. Background and Purpose

Demand response (DR) programs have been utilized around the globe for decades as a cost-effective resource for maintaining a reliable electrical grid. By reducing load during a limited number of hours per year, DR can defer the need for new peaking capacity, reduce peak period energy costs, and lessen transmission and distribution (T&D) infrastructure investment needs, among other benefits.

In the United States, for example, a five percent reduction in peak demand through DR programs could lead to $35 billion in savings over a 20 year period.[1] If anything, this is a conservative estimate. A 2009 study commissioned by the Federal Energy Regulatory Commission (FERC) found that, under certain market conditions, peak demand in the U.S. could be reduced by two to four times this amount, effectively eliminating the need for the equivalent of between 1,000 and 2,500 peaking units.[2]

The benefits of DR are not just limited to U.S. markets – they are applicable internationally. In Europe, the financial benefits of smart grid-enabled DR have been estimated at over 50 billion Euros over a 20 year period.[3] In the Middle East, an assessment of demand-side management potential in Saudi Arabia revealed that DR could significantly reduce the country's dramatically growing capacity needs at a benefit of nearly $2 billion over 10 years.[4] A study of the National Electricity Market in Australia found that reductions in peak demand could provide between $4.3 and $11.8 billion in benefits over the next decade.[5] In the United Kingdom, a recent study found that the financial benefits of DR could amount to over $160 million annually.[6] Globally, it is estimated that annual spending on DR will be over $5.5 billion by 2020, with more than 20 million customers participating in a DR program worldwide.[7]

Policymakers, regulators, and utilities that are considering introducing or expanding their portfolio of DR resources face an essential question: Will the benefits of the new DR program outweigh its costs? An accurate and defensible estimate of the value of DR must be developed in order to provide an answer. At the most basic level, the principles for estimating the value of DR programs are the same regardless of geographical region, regulatory structure, or market design. However, the nuances of the valuation approach will depend on these factors.[8] The purpose of this paper is to discuss best practices for establishing the value of DR while accounting for nuanced differences across a range of market and regulatory structures.

While there are many types of DR benefits, this paper focuses on quantifying the financial benefits that are derived from avoided costs. Our primary focus is on avoided generation capacity costs, as this benefit has driven the majority of the business case for most recent DR programs. That is discussed in Section 2. Section 3 addresses other avoided costs such as reduced peak energy costs, avoided investment in new T&D capacity, and ancillary services benefits. Harder-to-quantify benefits are discussed briefly in Section 4.

The focus of this paper is specifically on quantifying the benefits of DR. In any valuation of a DR resource, the benefits should be weighed against the cost of the program. Examples of program costs would include equipment, marketing and customer outreach, participation incentive payments, and general program administration.[9]

1.2. Defining DR

For the purposes of this paper, we define DR to refer to customer actions that are taken to reduce their metered electricity demand in response to an "event," e.g., a dispatch signal, whether in response to the high price of electricity, the reliability of the grid, or any other request for reduction from a grid operator, utility, or load aggregator. This definition of DR implies the following:

- DR must be "dispatchable." DR is event-based and we do not consider a program to qualify as DR if it entails a permanent (i.e., daily or seasonal) load reduction. This is an obvious distinction between DR and energy efficiency (EE), the latter of which involves technological or behavioral change that is static in nature. This also means that a time-of-use (TOU) rate - in which the retail electricity price is higher during peak hours than during off peak hours on every weekday – is not considered DR because the peak period price does not change dynamically in response to system conditions.

- DR can include behind-the-meter generation. As long as it is dispatchable, our definition of DR includes the use of behind-the-meter generation. One example would be a standby diesel generator or a cogeneration unit at an industrial facility that can also be used to reduce the facility's demand for electricity from the grid during DR activations. Non-dispatchable forms of self-generation, such as rooftop solar panels, however, do not fall within our definition of DR.

- DR can be price-based or reliability based. Our definition of DR includes programs and markets in which activations can stem both from energy prices and system reliability. Pricing programs, such as critical peak pricing (CPP) or real-time pricing (RTP) charge prices that are higher during hours when it is more expensive to generate and deliver electricity, and lower when it is less expensive to do so. Reliability-based programs, including DR participation in wholesale capacity markets, typically provide an incentive payment for automated or behavior-based load reductions – these programs clearly also fall under this definition of DR.

1.3. Recent Examples of DR Performance

To put the specifics of DR valuation into context, consider a few recent cases where DR has provided significant tangible benefits under a range of system conditions.

In most parts of the world, DR is typically utilized during months when temperatures lead to a rise in use of electricity. If temperatures are very high, particularly for several consecutive days, there is a risk that demand for electricity will exceed supply. This was recently observed during the summer of 2013, when a heat wave caused record demand for electricity in parts of the Northeastern U.S. such as the New York and the PJM Interconnection markets (comprising much of the Mid-Atlantic U.S.). In these markets, where DR had already been procured through a centralized wholesale capacity market, the resource provided significant load reductions. Peak demand in New York was reduced by over 1,000 MW in response to reliability concerns. In PJM, the market operator utilized around 1,600 MW of the over 9,000 MW of DR at its disposal.[10] The DR programs that were utilized spanned a range of customer groups, including residential, commercial, and industrial customers.

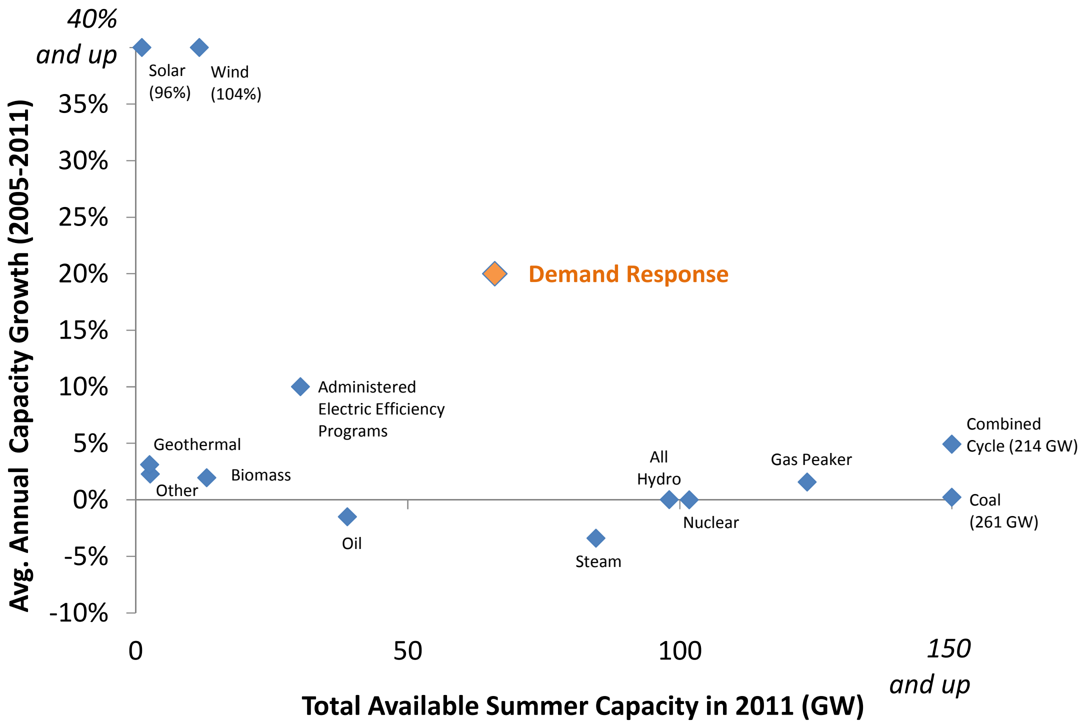
The value of DR is not just limited to hot summer months. The winter of 2013/2014 was one of the coldest in recent memory in parts of North America. Referred to as the "polar vortex," an Arctic cold front dropped temperatures to record lows in the Eastern and Southern U.S. This resulted in a sustained increased need for space heating, driving natural gas and electricity prices through the roof and raising serious concerns about maintaining grid reliability. This was particularly a concern in Texas, where the severe weather not only lead to a spike in demand but also caused outages at two major power plants. In response to these conditions, ERCOT (the grid operator) called on more than 600 MW of DR.[11] Within 45 minutes, the DR resources had reduced load to acceptable levels and the supply and demand balance had been stabilized, avoiding potential rolling brownouts.

Unexpected extreme weather conditions are not the only driver of DR utilization, or local reliability concerns. In 2012, Southern California Edison (SCE) was forced to take its San Onofre Nuclear Generating Station (SONGS) offline due to equipment reliability concerns. This led to the retirement of more than 2,200 MW of generation in a part of the Southern California electricity grid that was significantly transmission constrained. In response to a potential capacity shortage in the region, SCE has ramped up its efforts to procure DR capacity. SCE has announced that of the 2,200 MW that were lost after the retirement, 1,300 MW could be replaced with DR.[12] This highlights not only DR's value as a local resource, but also its potential to provide new capacity on shorter notice than would be required to install a new power plant or build new transmission capacity to the region.

While the three previous examples illustrate the use of DR in response to emergency conditions, it is a low cost resource that also provides economic benefits. In the 2017/2018 PJM capacity auction, for example, it was estimated that bids from DR and energy efficiency reduced total expenditure on capacity by $9.3 billion in the market for that year alone.[13] There has been a trend recently toward greater utilization of DR for reducing energy costs. Many energy markets in the U.S. and Europe have been revised to facilitate competition between DR and traditional supply-side resources. While participation has not been as high as in capacity markets, some U.S. regions like PJM, California, and the southern Midwest have seen up to approximately two percent of peak period energy participation coming from DR resources. Some ancillary services markets have also experienced a substantial amount of DR participation. In PJM, where DR is able to participate in the synchronized reserve market, DR has often come up against the current administratively-set cap of 25 percent of the total requirement, which is now being increased due to the levels of DR successfully participating in the market.[14] ERCOT also has a significant amount of participation in its ancillary services markets through its Load Resources program.[15]

Given the demonstrated value of DR in these examples, it is no surprise that DR has been growing quickly as a resource in the U.S. over the past several years. Next to wind and solar generation, which have been heavily subsidized at the federal and state levels, DR is the fastest growing resource in the country in terms of average growth rate. Between 2005 and 2011, DR has grown by 20 percent per year. Figure 1 summarizes the size and growth of DR relative to other resources.

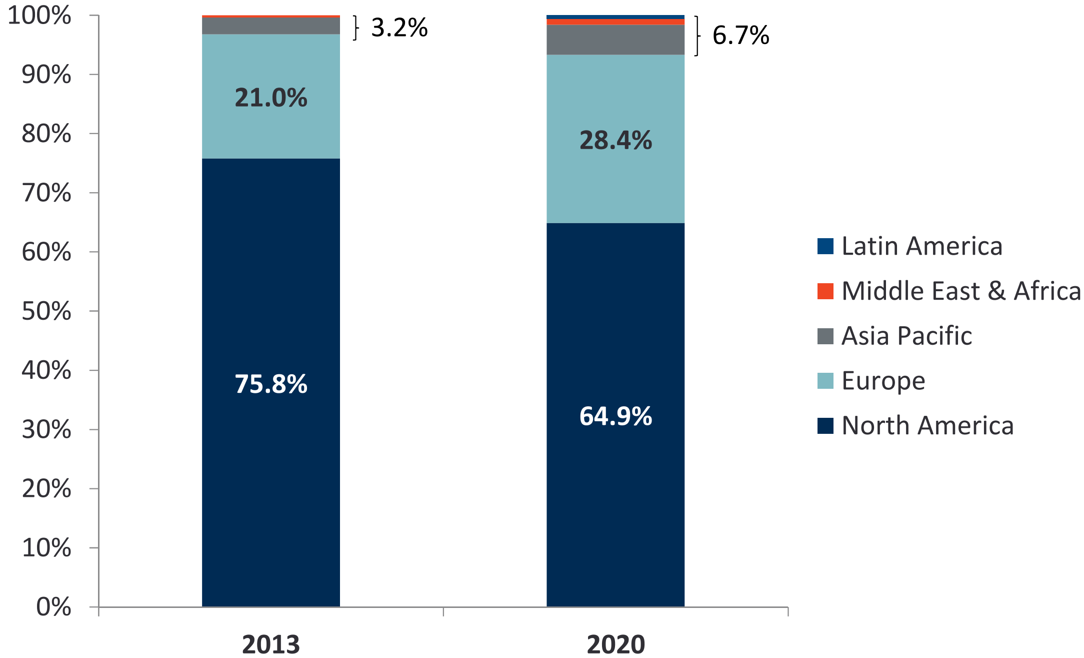
Figure 1: U.S. Available Capacity Resources and Growth in Resources



Notes:
Figure reproduced from Andy Satchwell and Ryan Hledik, "Analytical Frameworks to Incorporate Demand Response in Long Term Resource Planning," *Utilities Policy*, March 2014.
Source of generation capacity data is Ventyx Energy Velocity Database
Demand response data from FERC 2013 Assessment of Advanced Metering and Demand Response
Energy efficiency data based on actual peak reduction estimates from EIA-861
Summer capacity is total for generating units classified as "operating" with commercial online date before January 2012
Assumes 50% peak coincidence for solar and 25% peak coincidence for wind; all other types assume 100% availability for simplicity

This rapid growth in DR in North America is expected to be accompanied by even faster growth in DR in the rest of the world. Whereas North America represents around 75 percent of the worldwide DR market currently, this share is projected by Navigant Research to drop to approximately 65 percent by 2020.[16] Much of the international growth activity is expected to be in the commercial and industrial (C&I) sector, with the Asia Pacific region accounting for nearly 40 percent of all C&I DR participation by 2020. The projected growth in DR adoption outside of North America is illustrated in Figure 2.

Figure 2: Worldwide Share of DR Participation, 2013 and 2020



Source: Navigant Research, "Market Data: Demand Response," 2Q 2013.

2. Avoided Generation Capacity Cost

Avoiding or deferring the need for new generating capacity has long been the single largest source of value provided by DR. Often, this can comprise 80 to 90 percent of the value of a DR resource.[17] Since any electrical grid must have enough capacity available to serve load during the instantaneous time of highest demand (i.e., the coincident system peak), DR resources that are utilized to reduce the system peak lessen the need to invest in new generation capacity.

This basic calculation of the avoided generation capacity value of DR applies regardless of market structure, that is, whether in a traditionally regulated market or a restructured market. The computation requires determining the marginal cost of new capacity (i.e. the cost of serving a one kilowatt increase in system peak demand). In most regions, this is typically an open-cycle combustion turbine (OCCT), also referred to as a peaking unit. Relative to other sources of generation, peaking units have low capital costs and high operating costs, meaning they are cheap to build but expensive to run. For this reason, the units typically sit idle for most hours of the year and are only utilized during top peak load hours. Peaking units are typically the type of capacity avoided by DR because of their similar operational profile.[18]

Modifications to that installed cost of new capacity are then made to account for the energy and ancillary services value that the new generating unit would provide to the grid, as well as considerations for the availability and performance characteristics of the DR program. It is in these modifications that there are nuanced differences in the value calculation between restructured markets and regulated markets.

2.1. In Regulated Markets

In traditionally regulated markets where utilities own generation, transmission, and distribution and serve retail customers, all within a given territory, the utilities are responsible for planning to have enough capacity available to meet system peak demand. This is typically done through a resource planning process that is reviewed and commented upon by the regulator and stakeholders. Resource planning typically involves projecting peak demand over a multi-year period and then running sophisticated optimization models to determine the economically optimal timing and location of new generating capacity that would be needed to meet that peak demand.

While the economic valuation of DR would ideally be integrated into this process, most utilities assess its value outside of their resource planning modeling.[19] This is a two-stage process. They first determine the amount and cost of new generating capacity additions that would be needed to meet peak demand. Then, they use this result to assess the value of a reduction in peak demand attributable to demand response. In detail, this valuation process consists of the following six steps.

Step 1: Identify the marginal cost of capacity. The cost of new capacity will typically be based on quotes or bids from manufacturers. There are also often public sources of cost estimates that can be used as a proxy for a more region-specific estimate. Recently in the U.S., where gas-fired combustion turbines are often the marginal unit, the overnight cost of a conventional CT has ranged anywhere from around $700 to over $1,400 per kilowatt of installed capacity, depending on location and the type of technology.[20]

Step 2: Levelize the installation cost as an annual value. To properly account for differences in the useful life of a DR program relative to a generator, it is necessary to levelize the installation cost of the power plant. This will require establishing a lifetime of the unit (typically 20 to 30 years) and an appropriate discount rate. At a useful life of 20 years and a hypothetical utility's weighted average cost of capital (WACC) of seven percent, the annual value of a $900/kW peaking unit would be approximately $85/kW-year. Fixed operations and maintenance (O&M) costs should be added to this estimate. For a combustion turbine, those could be approximately between $5 and $10/kW-year.[21] Adding a fixed O&M cost of $5/kW-year to the levelized installation cost brings the total cost of the hypothetical marginal unit to $90/kW-year.

Step 3: Subtract the energy and ancillary services profit margin of the marginal unit. In the absence of DR, the peaking unit would be installed and it would generate electricity during hours when its variable costs (fuel and variable O&M) are less than the marginal cost of energy (i.e. it would run when doing so is profitable). The difference between the marginal cost of energy and the unit's variable costs are its "energy margin." Similarly, the unit could provide ancillary services and further increase its profit margin. This profit margin represents the incremental energy and ancillary services value that the unit would have provided to the grid. When estimating the net avoided cost of DR, this profit margin should be subtracted from the capacity cost (in other words, it is a benefit that is avoided by DR).[22]

Energy and ancillary services margins will depend heavily on the economics of the system that is being analyzed. For instance, in a region with tight reserve margins and a high dependency on fuels with volatile prices, there is a greater likelihood of energy price spikes and a new peaking unit would have a better opportunity to earn high energy margins than in a region with a large amount of excess capacity. For illustrative purposes, assume the peaking unit in our example has energy margins of $20/kW-year.[23] Subtracting this from the levelized cost of the unit gives a net avoided cost of $70/kW-year.

Step 4: Derate the resulting net avoided cost to account for DR availability and performance. Unlike the around-the-clock availability of a combustion turbine unit, DR programs are typically constrained by the number of load curtailment events that can be called during the course of a year. Further, there are often pre-defined limitations on the window of hours of the day during which the events can be called, and sometimes even on the number of days in a row that an event may be called. It is also often the case that hour-ahead or day-ahead notification must be given to participants before calling an event. All of these constraints can potentially limit the capacity value of a DR program.

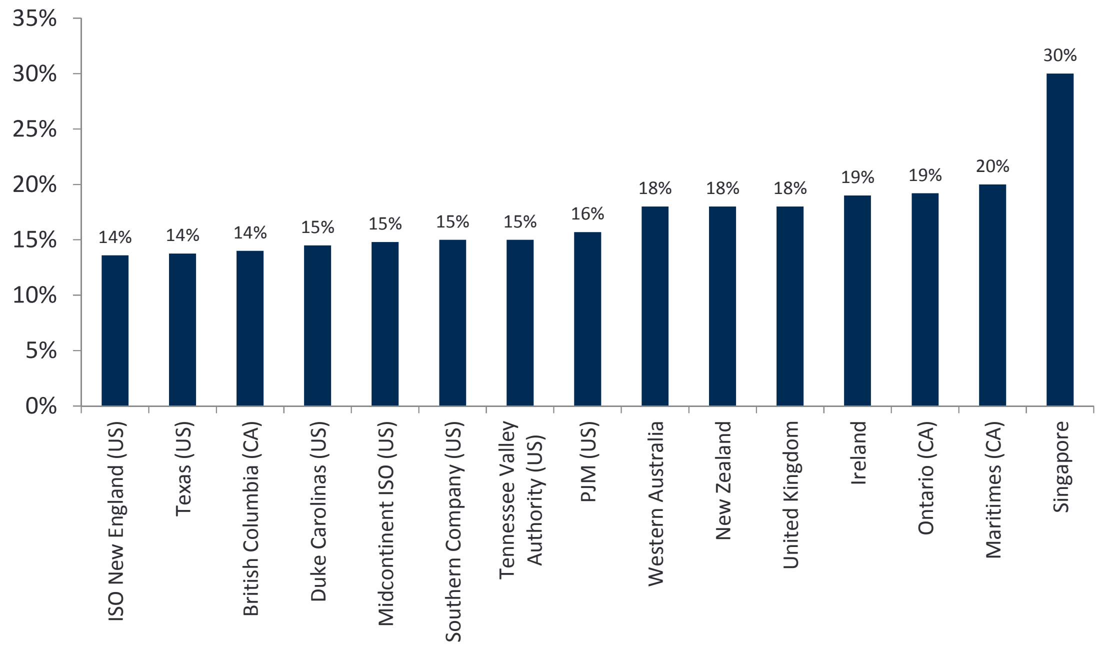
Some utilities account for this through a derate factor that is applied to the avoided capacity costs that are estimated for any given DR program. The derate factor is program-specific and is estimated through an assessment of the relative availability of DR during hours with the highest loss of load probability. Historically, depending on program characteristics and utility operating conditions, some derate factors have ranged from zero percent to roughly 50 percent of the capacity value of the programs.[24] The derate is program- and utility-specific. In California, programs with short response time and dispatch flexibility are derated by less than programs that do not have those characteristics. Historically in California, day-ahead programs with voluntary load reductions have been derated by as much as 60 percent whereas technology-enabled air-conditioning load control programs and aggregator-managed C&I programs with short response time could be derated by less than 20 percent.[25] In Colorado, Xcel Energy estimated that the capacity value of DR programs with a four hour dispatch limit per day and a 40 hour dispatch limit per year should be derated by around 30 percent, while unconstrained DR programs that could be dispatched up to 160 hours per year (a large number of hours for a DR program) should only be derated by five percent.[26] Very rough estimates by Portland General Electric (PGE) include derate factors of between five and 30 percent for direct load control programs and 50 to 60 percent for programs in which the load reductions are not automated. Many other utilities do not include any derate mechanism whatsoever, similar to DR valuations in wholesale capacity markets. While there is not a “typical” derate across markets due to the program-specific and system-specific nature of the adjustment, we find that 25 percent is a reasonable midpoint estimate to use as a representative value. Derating the $70/kW-year net avoided cost estimate in our example by 25 percent produces an adjusted avoided cost estimate of $53/kW-year.

Of course, the relative availability of peaking units should also be taken into account when establishing these derate factors. If rarely-used peaking units are found not to be reliable when needed during times of system emergencies, then the relative disadvantage of DR is not as significant as it may initially appear. For example, a recent analysis found that of 750 MW of peaking units in the San Diego area of Southern California, roughly 60 percent were available when called due to startup issues.[27] While DR resources have some dispatch limits, their availability and reliability during periods of system need could match or possibly exceed that of generation in some instances, enabling them to be comparably valued to a peaking resource by comparison in these instances.. ISO New England (ISO-NE) dispatched DR resources on July 19, 2013 for system reliability purposes and 95 percent of dispatched DR resources responded.[28] This also highlights the very system-specific nature of the derate calculation. It must be developed on a case-by-case basis with careful consideration for factors like the system load profile, DR program characteristics, and generating unit performance.

Step 5: Increase the avoided cost estimate to account for line losses and reserve margin. Demand response produces a reduction in consumption at the customer's premise (i.e. at the meter). Due energy losses on transmission and distribution lines as electricity is delivered from power plants to customer premises, a reduction in one kilowatt of demand at the meter avoids more than one kilowatt of generation capacity. In other words, assuming line losses of eight percent, a power plant must generate 1.08 kW in order to deliver 1 kW to an individual premise. Therefore, when estimating the avoided cost of DR, the avoided cost should be grossed up to account for this factor.

Similarly, most utilities incorporate a planning reserve margin into their capacity investment decisions. Reliability standards can be incorporated into planning decisions in a variety of ways (e.g., establishing a maximum target number of allowable reliability "emergencies" per year, or establishing a minimum amount of installed capacity in excess of peak load during a high load year due to unexpected weather). Figure 3 illustrates the range of reserve margins that are implied in the reliability standards of various markets around the globe.[29]

Figure 3: Implied Reserve Margin Requirement in Markets with Reliability Standard



Source: Sam Newell and Kathleen Spees, "Resource Adequacy in Western Australia: Alternatives to the Reserve Capacityi Mechanism," prepared for EnerNOC, August 2014.

A common target reserve margin is 15 percent, meaning the utility will plan to have enough capacity available to meet its projected peak demand plus 15 percent of that value.[30] In this sense, a reduction of one kilowatt at the meter level reduces the need for 1.15 kW of capacity. Combining the adjustments for both 8% line losses and a 15% reserve margin in our hypothetical example increases the avoided capacity cost from $53/kW-year to $66/kW-year.[31]

Step 6: Calculate the present value of avoided capacity over the lifetime of the DR program. The final step in quantifying the avoided capacity cost of a DR program is to account for the expected life of the program and the extent to which this aligns with new capacity needs. The life of a DR program will vary by program type and will be determined by the life of equipment that is being used (e.g., a switch on the compressor of an air-conditioner) and expectations about the amount of time that participants will choose to stay enrolled in the program. In our hypothetical example, assume that the utility's resource plan has determined that new capacity will first be needed three years from now due to a short-run capacity surplus. In valuing a DR program that would be offered today, the avoided capacity cost in years one and two would be near zero.[32] Assuming our hypothetical DR program has a 10 year life, it would have capacity value of $66/kW-year for the remaining eight years of its life.

Table 1 summarizes the six steps in determining the capacity value of DR for a vertically integrated utility in a regulated market.

Table 1: Steps to Calculate Avoided Generation Capacity Cost for Vertically Integrated Utility

Step	Description	Value	Calculation
[1]	Identify the marginal cost of capacity	$900/kW	Assumption
[2]	Levelize the installation cost (including O&M)	$90/kW-yr	(7% x [1]) / (1 - (1 + 7%)^-20) + $5/kW-yr
[3]	Subtract energy & ancillary services margins	$70/kW-yr	[2] - $20/kW-yr
[4]	Derate to account for DR availability and performance	$53/kW-yr	[3] x (1 - 25%)
[5]	Gross up for line losses and reserve margin	$66/kW-yr	[4] x (1 + 8%) x (1 + 15%)
[6]	Calculate present value over life of DR program	$344/kW	Present value over 10 years with avoided cost starting in year 3

Notes:
[1] Based on overnight cost of gas-fired combustion turbine
[2] Assumes discount rate of 7%, useful life of unit of 20 years, and fixed O&M cost of $5/kW-year
[3] Assumes energy & ancillary services margin of $20/kW-year
[4] Assumes derate factor of 25%
[5] Assumes line losses of 8% and reserve margin of 15%
[6] Assumes 7% WACC, 10 year life, and new capacity need in year 3

2.2. In Restructured Markets with Capacity Mechanisms

In restructured markets with centralized capacity mechanisms, there is a wholesale market that is designed to encourage investment in an economically optimal amount of capacity to meet the expected peak demand (plus a reserve margin). Capacity markets produce an annual marginal price of capacity that is paid to sellers in the market (i.e., generators and DR aggregators). This capacity price is the cost that is avoided if DR is procured in the market. Therefore, in a sense, it is simpler to assess the value of a new DR program in the context of a centralized capacity market – the price is published and does not require the multi-step computations that it would when valuing DR for a vertically integrated utility.

Capacity prices can be set in different ways depending on the specific mechanics of the capacity market, although most capacity markets share a basic set of common elements. First, the market operators will determine the gross cost of new entry (CONE).[33] Gross CONE is the marginal cost of new capacity, the same basic starting point that was discussed in Section 2.1 for vertically integrated utilities. Gross CONE is typically determined as a bottom-up engineering estimate or through a survey of recent power plant additions, and ultimately vetted through a public stakeholder process.[34]

Second, the market operators will subtract energy and ancillary services margins to produce Net CONE. Similar to the discussion in Section 2.1, and for the same reasons discussed in that section, an estimate of the likely profit margin that would be earned by the marginal generating unit is subtracted from Gross CONE to produce an estimate of Net CONE. In a state of perfect market equilibrium, Net CONE would be the marginal price of capacity.

Third, the market operators will establish a process through which to adjust the capacity price to balance the supply of and demand for new capacity. Due to the cyclical nature of power generation development, markets typically fluctuate between conditions of excess capacity and of tightened reserve margins. The pricing mechanism is designed to reflect these conditions. The price rises as the need for new capacity rises, and vice versa. The specific mechanism through which this happens is very specific to the market design. While a comprehensive detailed review of the nuances of the price setting process is beyond the scope of this paper, the following are examples of how it is done in a few existing markets.[35]

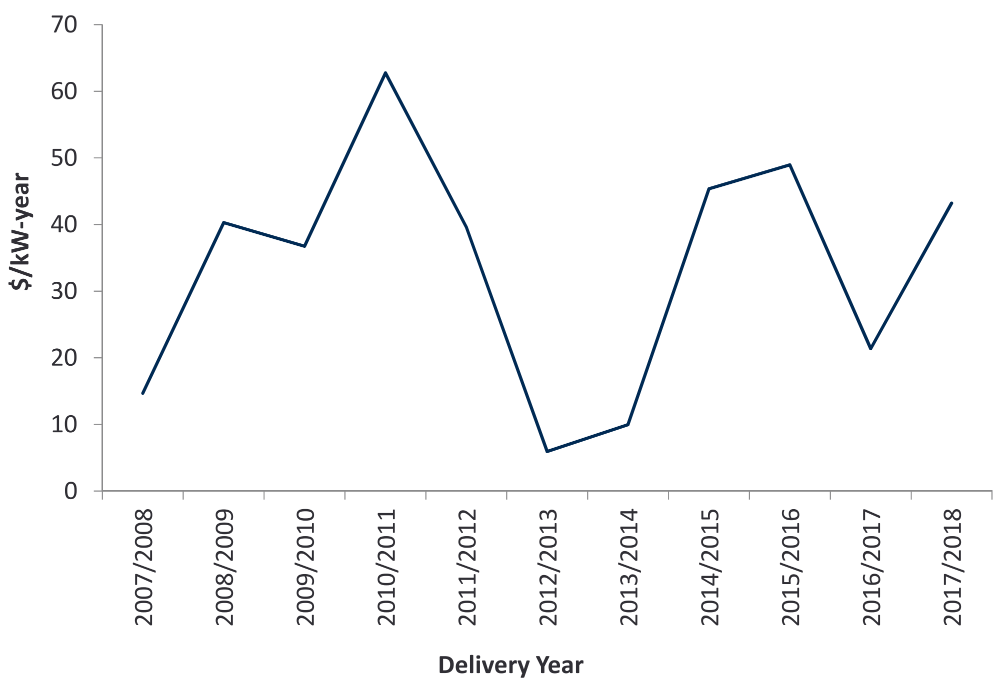
- **PJM:** A downward sloping "demand curve" is established to represent the price that will be paid for capacity at various reserve margin levels. When the reserve margin is low, supply is short and a high price would be paid for new capacity. The price progressively decreases for increasing amounts of capacity. The curve is anchored on a price that is equivalent to the Net CONE value, which would be paid for capacity that produces the target reserve margin level. PJM then conducts an auction into which participants bid their capacity. This creates a supply curve of capacity, and the intersection of the supply and demand curves determines the capacity price that is paid to all accepted bids. PJM conducts their auction annually on a three-year forward looking basis, meaning bids in the current year's auction are a commitment to provide capacity three years out.[36]

- **Western Australia:** As in PJM, Western Australia' Wholesale Electricity Market (WEM) starts with an estimate of net CONE and establishes this as a payment level that is associated with a target level of capacity procurement. Unlike in PJM, however, the capacity price is not ultimately set through an auction process. Rather, retailers and generators establish bilateral contracts for capacity, or sell to the market operator directly. If the amount of capacity procured through these bilateral transactions meets the target amount of capacity that is needed in the market, then the entities that are selling capacity are awarded a payment that is close to Net CONE. If the amount of capacity traded is higher than the target amount, then the payment level is progressively reduced from this price. Alternatively, if an insufficient amount of capacity has been procured, then the market operator would hold a supplemental capacity auction to procure enough capacity to meet the target. In Western Australia, procurement happens two years in advance of the delivery date.

- **Ireland:** In Ireland's Single Electricity Market (SEM), there is no auction process. Rather, pre-established capacity prices are paid to market participants for each half hour period of the year, depending on the participant's availability to provide capacity in each half hour interval. Depending on projected reliability conditions during each time interval, the capacity price can vary widely. In periods when supply and demand conditions are expected to be tight, the price is set higher. This allows the participants flexibility in the timing and duration of their commitment to provide capacity over the course of the year. All prices are derived from a common starting point, which is Net CONE. Unlike both the PJM and WEM markets, there is no forward procurement mechanism in the SEM.

These examples illustrate that there is likely to be fluctuation in the capacity price over time. In PJM, for example, prices have varied significantly over the decade that the capacity market has been in place (as well as across its various geographic zones). This annual volatility is illustrated in Figure 4.

Figure 4: PJM Capacity Prices[37]



Regardless of the specific price setting mechanics of the capacity market, the basic methodology for calculating the avoided capacity cost attributable to DR follows the same three steps:

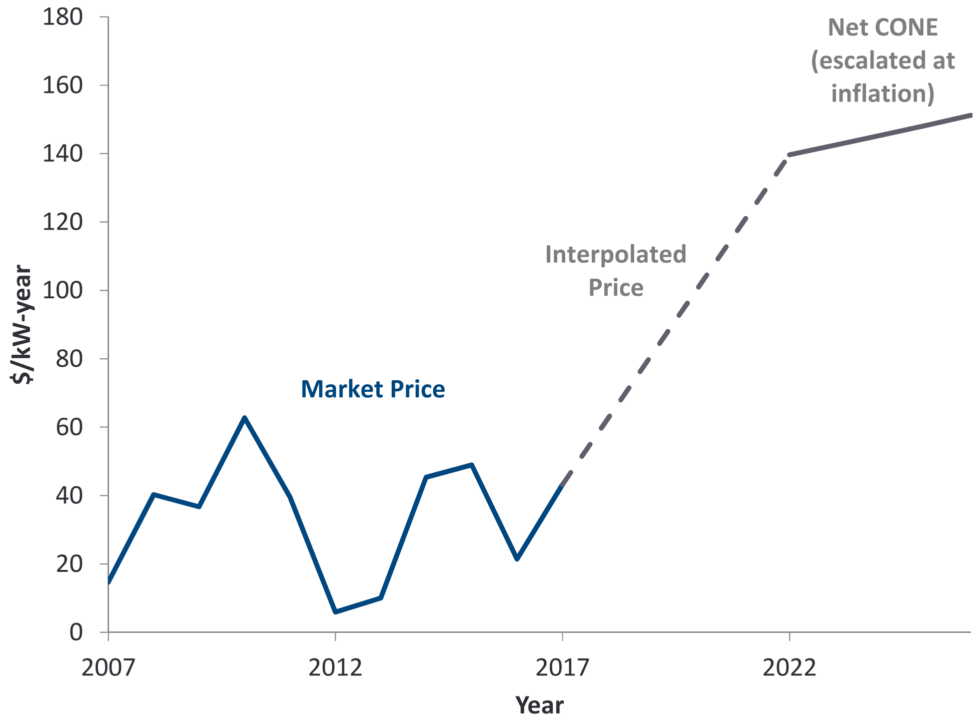
Step 1: Identify the capacity price for all relevant years. The market price for capacity should be used for all years available. For instance, since PJM is a three-year forward auction, there would be three years of capacity prices that would be used as the short-run avoided cost of capacity.[38]

Step 2: Establish Net CONE as the long-run equilibrium capacity price. Analysis of DR benefits in organized wholesale markets is sometimes short-sighted in the sense that it limits the evaluation to prices based on recent market results.[39] In the long-run, however, prices are likely to evolve and eventually would be expected to reach an equilibrium state. Economic theory suggests that, in the long run, supply and demand will equilibrate and the marginal cost of capacity will eventually stabilize at Net CONE. Thus, for the outer years of the forecast, Net CONE is used as the avoided capacity cost.

Step 3: Interpolate in intermediate years to create a smooth transition from market prices to the long-run equilibrium price. To account for a multi-year transition from the market price to the long-run equilibrium price, it is common practice to interpolate between the two prices over a three to five year period. Linear interpolation is sufficient.

Illustrative results of this three step process are summarized in Figure 5 using PJM capacity prices. In PJM, various economic factors and fluctuations in the market design have kept the capacity price from reaching Net CONE (for the 2017/18 auction, Net CONE was around $127/kW-year). In this specific case, if there is a belief among the evaluators of the DR program that these factors would continue to depress the capacity price, then the long run equilibrium price could be set below Net CONE. Some judgment is necessary when projecting capacity prices.

Figure 5: Capacity Price Forecast for PJM



Unlike in the previous discussion of DR valuation in regulated markets, no derating mechanism is used to account for operational constraints of the DR programs. Rather, these constraints are accounted for by the market rules that specify how a DR product must perform in order to be accepted as a resource in the market. For example, a market rule might specify a minimum number of hours for which the DR resource must available, a maximum lead time for notification, or specific technologies that must be used for communications and settlement purposes. Therefore, the market design includes a "screening" process that ensures that accepted DR bids will provide the same value to the market as a generating unit. As a result, in all of these wholesale capacity market constructs, DR receives the same remuneration for capacity as a traditional supply-side resource.

2.3. In Restructured Energy-Only Markets

Some restructured markets do not have a centralized mechanism for procuring capacity. These are commonly referred to as "energy-only" markets. The theory in these markets is that, as reserve margins tighten, energy prices will rise to a point that economically supports a sufficient amount of new entry of capacity into the market.[40] The Electric Reliability Council of Texas (ERCOT), the Ontario Power Authority (OPA) in Canada, and Australia's National Electricity Market (NEM) market are three examples of energy-only markets.

In these markets, since energy prices are intended to represent the cost of energy as well as capacity, there is no specific capacity price per se that is used to specifically evaluate the generation capacity value of DR. However, the operators of these markets will often create specific "products" that are designed to encourage DR resources to be available for capacity purposes. Payments are made to DR providers to be available for curtailment when needed and/or on a pay-for-performance basis. In this sense, the capacity value of DR programs in these markets is determined by the payment that is made to the DR providers.

These DR products exist in several energy-only markets. For example, in ERCOT's Emergency Response Service (ERS) program, customers are paid for providing load reductions on 10 or 30 minutes notice. Load reductions are procured for different time periods (varying by season and time of day). In the 30-minute ERS program (a pilot program at this point), prices are set through an auction process. Prices in the ERS program have cleared between $60 and $200/kW-year and are continuing to fluctuate as the product definition evolves.[41] In Canada, the Ontario Power Authority (OPA) has a mandatory, capacity-based DR program called "DR3".[42] Prices vary across the three programs and across locations on the OPA's grid. In Toronto, payments in the DR3 program, have been in the range of $100/kW-year to $170/kW-year.

To determine the capacity value of DR in these types of programs, the first step is to determine whether the DR program being evaluated meets the specific performance requirements of the market product (or, if multiple products are offered, as in the examples described above, determine which product, if any, is the best fit in this regard for the DR program being considered). The performance requirements are typically publicly available documents published on the market operator's website. Then, determine how much of a load reduction will be provided by the DR program. This load reduction is then multiplied into the published payment schedule to determine the overall monetizable value of the DR program.

3. Other Avoided Costs

While avoided generation capacity costs have driven the bulk of DR benefits historically, there are other avoided costs that can also be attributed to DR. This section discusses other avoided costs, including T&D capacity costs, energy costs, and ancillary services costs.

3.1. Avoided Transmission and Distribution Capacity

Reductions in peak demand lessen the need to expand the T&D system. A portion of T&D investment is driven by the need to have enough capacity available to move electricity to where it is needed during peak times while maintaining a sufficient level of reliability. Geographic expansion of the system requires T&D investment, and that is often correlated to growth in peak demand. By reducing peak demand, DR reduces the need for new T&D capacity. In 2012, for example, the U.S. market of PJM cancelled plans for a new transmission line (the “PATH” line) that would improve import capability in its transmission-constrained eastern portion of the power grid, citing an increase in DR in the east as a reason for canceling the project.[43]

There are also aspects of T&D system expansion that are not driven by growth in peak demand. For example, some reliability-driven projects are built to ensure that enough capacity is available to address congestion during mid-peak and off-peak periods. Other projects are driven to integrate new generation additions which may be built as baseload resources rather than peaking generation. As a result, when calculating avoided costs for valuing DR programs, utilities will often calculate the total amount of expected T&D infrastructure investment and then derate it to account for the share of that investment that is driven by peak demand.

Utility estimates of avoided T&D costs vary significantly and are very system specific. In a review of utility DR filings and marginal cost studies, and interviews with utility engineers, avoided T&D costs typically ranged from $0 to $75/kW-yr. Table 2 summarizes avoided T&D cost estimates from recent DR studies. While the range is broad, we find that avoided costs of $20 to $30/kW-year are the most commonly accepted assumption in regulatory settings as well as in several unpublished studies for utilities.

Table 2: DR Avoided T&D Costs

Entity		State(s)	Avoided Cost ($/kW-year)
[1]	Pepco Holdings, Inc	DE, DC, MD, NJ	$0.00
[2]	Portland General Electric	OR	$18.00
[3]	Pennsylvania Statewide Evaluator	PA	$25.00
[4]	Connecticut Light & Power	CT	$29.20
[5]	Xcel Energy	CO, MN	$30.00
[6]	Southern California Edison	CA	$54.60
[7]	San Diego Gas & Electric	CA	$74.80
[8]	Pacific Gas & Electric	CA	$76.60

Note: Where multiple avoided cost scenarios were considered, the base case value was used
Sources: Utility DR potential studies, state regulatory decisions

In addition to avoiding system peak-driven T&D investment, DR can be deployed selectively in specific geographic locations to address local congestion issues on the transmission or distribution system.[44] For example, some utilities have used DR to manage loads at specific substations and transformers that were at or near capacity. Reflecting this location-specific value, Con Edison, a distribution utility in the U.S. state of New York, has developed its Distribution Load Relief Program (DLRP) which offers customers in congested parts of the grid incentive payments that are twice as high as those of customers in uncongested parts of the grid.[45]

Wholesale energy and capacity markets do not specifically address T&D system expansion needs. In both regulated and restructured markets, this is done through a centralized planning process. Therefore, there are not significant differences in the way T&D capacity benefits are estimated for DR in restructured and regulated markets. There are a few options for establishing the avoided cost of T&D:

<u>Option 1: Rely on estimates from a recent marginal cost study.</u> Many utilities will conduct marginal cost studies, primarily for the purpose of designing their retail rates. Among many calculations, these studies will include estimates of the portion of T&D costs that are driven by growth in the system peak. This estimate can be used as the basis for the avoided T&D cost of DR that is dispatched to reduce the system peak.

<u>Option 2: Use an estimate from a review of assumptions in other utility filings.</u> In the absence of marginal T&D cost estimates that are specific to the region or service territory being analyzed, an estimate of avoided T&D costs can be established based on a review of estimates in other regions, such as those summarized in Table 2 above. The results can be tailored to the service territory in

question by restricting the survey to similarly situated utilities (e.g. similar geographic region, urban versus rural utility, etc.).

Option 3: Develop a bottom-up engineering estimate of the avoided cost of T&D. In instances where the utility is considering establishing a new DR program in a congested part of the grid in order to avoid or defer the expansion of the T&D system to that part of the grid, the specific cost of the T&D project in question should be taken into consideration. This will be a very project-specific estimate that most likely cannot be derived from other studies.

3.2. Avoided Energy Costs

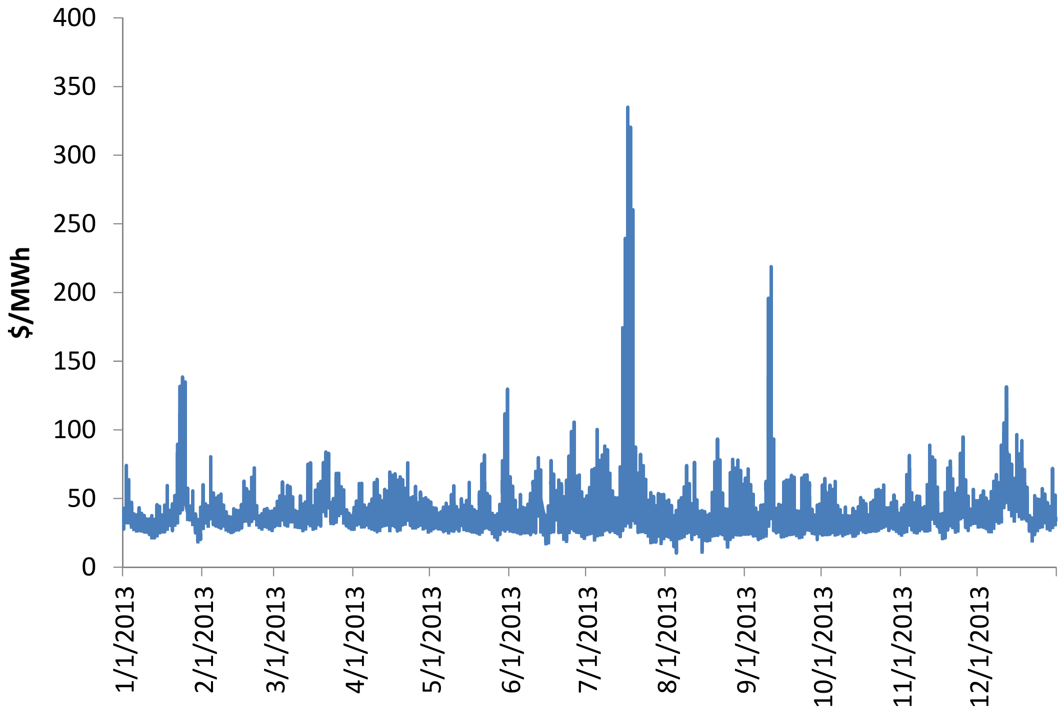
Reductions in consumption will avoid the marginal cost of generating electricity (primarily fuel costs, as well as variable O&M). This is typically a primary benefit of energy efficiency programs, which derive most of their value from overall reductions in consumption. For DR programs, avoided energy costs have historically made a relatively minor contribution to the total benefit, since consumption reductions are concentrated in a small number of hours in the year. However, when these reductions occur during hours of very high electricity prices – particularly in restructured energy-only markets – the benefit can be significant. There is a growing trend toward incorporating DR into wholesale energy markets in order to provide comparable opportunities to those of generating units, and to facilitate broader market participation and competition.

Avoided energy costs are a time-dependent source of value. Reductions during peak times avoid a higher marginal cost, because less efficient generating units are on the margin during these times. These costs also vary by season for the same reason – in the summer, when demand is often higher due to air-conditioning load, energy prices also tend to be higher.

The methodology for determining energy benefits is generally the same in restructured and regulated markets, with the only difference being the source of data for the marginal cost of energy. Steps for estimating the avoided cost are summarized below:

Step 1: Establish an hourly projection of marginal energy costs. In a restructured market, hourly energy prices – often referred to as the locational marginal prices (LMPs) - are established in the energy market. For a vertically integrated utility, marginal energy costs are simulated using a production cost model and represented by something referred to as a “system lambda.” In either case, recent historical hourly marginal energy costs for a year with normal weather are typically used as the basis for estimating avoided costs. Figure 6 illustrates the hourly day ahead LMP in the Eastern Hub of PJM for each hour of the year 2013. The energy price exceeded $100/MWh in 89 hours in 2013.

Figure 6: Eastern PJM Hourly Energy Price (2013)



Step 2: Define the period when DR is likely to be utilized. The DR program will only be dispatched during a limited number of hours per year. A key question is whether the DR program is being dispatched for reliability purposes or economic purposes (or both). If it is being dispatched for reliability purposes, the demand reductions will likely coincide with the highest system load hours of the year. If it is being dispatched for economic purposes, the demand reductions will often coincide with the highest priced hours of the year.[46] In both cases, the top hours should be identified and restricted to the likely total number of hours that the program will be dispatched (typically 50 to 100 hours per year, primarily focused on the season of the system peak, which in the U.S. is typically the summer season). To illustrate, consider an economically-dispatched DR program that can be utilized up to 10 days per summer between the hours of 2 pm to 7 pm. In 2013, this program would have been dispatched during 10 days between the months of May and September in PJM (with the exception of one day in December during the Polar Vortex), as these were days with the highest average peak period prices. Table 3 identifies the top 10 days and the average day ahead LMP during the 2 pm to 7 pm window on those days.

Table 3: 10 Highest Priced Days in Eastern PJM, 2013

Date	Average Peak Period Price ($/MWh)
7/17/2013	297.30
7/18/2013	267.80
7/19/2013	214.04
7/16/2013	209.65
9/11/2013	185.11
7/15/2013	152.91
9/10/2013	148.64
5/31/2013	106.12
12/12/2013	101.37
5/30/2013	94.65
Average	**177.76**

Step 3: Calculate the average energy price during the hours when the DR program is utilized. The average marginal energy cost during the hours of dispatch represents the energy value of the DR program. In the example above, the average energy price during the 50 hours of dispatch was approximately $178/MWh.[47] This value would be multiplied by the total amount of energy reduced during that period to determine the total annual energy value of the DR program. Converted to a dollars-per-kilowatt-year estimate for comparability to the avoided capacity cost estimates discussed previously, this equates to approximately $9/kW-year. Thus, in this example, the avoided energy cost is a fraction of the range of avoided capacity cost estimates that have been discussed, but it is still a material financial benefit to be considered.

3.3. Avoided Ancillary Services Costs

The use of DR to provide ancillary services is becoming a topic of increasing interest in the industry due to growing concerns regarding the ability to reliability integrate large amounts of intermittent resources into the grid. Regardless of whether a utility is regulated or in a restructured market, DR could provide value by acting as a fast-response resource that would decrease or even increase load in response to unpredictable fluctuations in power generation. Specifically, there are four reliability-related problems that must be addressed when variable generation is adopted at high levels:[48]

- Increased intra-hour variability in supply

- Large magnitude of overall ramping requirements
- Over-generation concerns
- Near-instantaneous production ramps.

Newly emerging technologies and DR initiatives could eventually help to address some of these barriers. "Smart" appliances, home energy management systems (HEMS) and automated DR systems for the C&I sector are being developed and are becoming commercially available. These technologies can be programmed to respond to fluctuations in the real-time price of electricity. Initiatives are underway to open the market for these devices.

To be valuable in this new environment, ancillary services DR will likely need to be used in new and innovative ways. Specifically, it is likely that DR will need to be able to respond not just during peak hours, but during many of the 8,760 hours of the year. Additionally, there will be value not only in load reductions but also in the ability to *increase* load to maintain balance on the grid. The valuation techniques that have been discussed in this whitepaper are generally applicable in estimating the value of this type of "flexible" DR. For instance, to the extent that DR can be utilized in this environment to provide services that are comparable to those of an OCCT, then the same basic approach to estimating avoided capacity cost would be used. But if the operational characteristics of DR make it a unique resource that is not directly comparable to a generating resource in this environment, then a more sophisticated valuation approach may be needed. This could require a multi-step process, including:

1. Identify the customer segments and end-use loads that are the best candidates for participation in a "flexible DR" program, meaning those end uses that can be controlled with automating technology and used to both increase and decrease load (e.g., residential water heating);

2. Determine the total potential load increase/decrease in those end-uses and the cost associated with enrolling them in a DR program;[49]

3. Characterize the operational constraints of the portfolio of DR participants, such as the number of hours of allowable interruption per year and per day, and the response time;

4. Include this DR portfolio in a resource planning model with a level of granularity that accurately accounts for the volatility in electricity production from intermittent resources of generation;

5. Use the model simulations to determine the extent to which the inclusion of the DR portfolio reduces overall system costs.[50]

4. Other Benefits

It is important to consider additional benefits that are difficult to quantify but which certainly add to the overall attractiveness of DR programs. Qualitative factors such as these should be taken into consideration when conducting a detailed assessment of the benefits and costs of moving forward with a new portfolio of DR offerings.

4.1. Wholesale market price mitigation

When DR bids are accepted in a market, they displace bids from higher cost resources that otherwise would have been accepted. This serves to reduce the market price (a result that one would expect from increased competition in any market). This reduction in market prices can significantly benefit buyers in the market. As described earlier, DR and energy efficiency are estimated to reduce capacity expenditures by billions of dollars per year annually in the PJM capacity market.[51] In the energy market, a study found that a three percent reduction in peak demand through new DR programs could reduce energy prices by between five and eight percent, varying by geographic zone.[52]

However, whether wholesale price mitigation should be considered a benefit depends on one's perspective. While buyers in the market benefit from reduced prices, this represents a loss to suppliers. In this sense, wholesale price mitigation is simply a wealth transfer without a significant net benefit at the societal level. Additionally, the impact of wholesale price mitigation may only persist in the short run. In the long run, reduced prices could lessen the incentive for new market entry, and the market could return to equilibrium at prices similar to those prior to the introduction of DR. Finally, there is a tradeoff to consider between energy and capacity markets. The introduction of new DR will replace relatively efficient new generating capacity that would otherwise have entered the market. This will reduce capacity prices, but could put upward pressure on energy prices over time.

4.2. Possible environmental benefits

To the extent that a DR program results in a net reduction in energy consumption, there could be environmental benefits in the form of reduced greenhouse gas (GHG) emissions. Even in the absence of overall conservation, load shifting may lead to a small reduction in emissions, although this will depend on the emissions rates of marginal units during peak and off-peak hours.[53] For example, if DR causes load to be shifted from hours when an inefficient oil- or natural gas-fired unit is on the margin to hours when a more efficient gas-fired combined cycle unit is on the margin, one could expect a net decrease in GHG emissions. However, in a different service territory, there might be a gas-fired unit on the margin during peak hours and a coal unit on the margin during off-peak hours. In this situation, an increase in GHG emissions could arise.

Peak period load reductions could also reduce other types of generator emissions such as criteria and hazardous air pollutants. In the U.S., for instance, these reductions would be particularly valuable in designated "non-attainment areas" where pre-determined emissions levels cannot be exceeded.

To the extent that peak demand reductions result in avoided investment in new generation capacity or T&D capacity, the result would be a smaller geographical footprint of the grid. This would reduce the impact to wildlife habitat and sensitive ecosystems.

Finally, if DR is offered in the form of time-varying retail rates, this could facilitate the adoption of renewable sources of energy. For example, a strong time-of-use rate could improve the economics of rooftop solar by aligning the higher priced peak pricing period with the time of highest output from the system. To the extent that time-varying rates encourage adoption of technologies that automate load changes in response to prices, this could be valuable for integrating variable renewable energy resources (as discussed previously).

4.3. Option value

Assessment of DR value often relies on point estimates of factors like the peak demand forecast and generating unit availability. By limiting the analysis to a few discrete scenarios, the full spectrum of extreme events that could occur on a system is often underrepresented. In fact, it is in response to uncertain and extreme events that DR has been found to provide the most value; this is described as the "option value" of DR.[54] Studies have shown that being able to avoid blackouts in extreme reliability situations through the use of DR programs could justify investment in the programs even if they happen only once every five or ten years.[55]

4.5. Improved post-outage power restoration

After an outage, it is necessary to control the rate at which power is restored to the grid in order to avoid over-stressing the system. Some load control technologies have a feature which brings the controlled end-uses online in a staggered fashion in order to "spread out" the ramping of load over time.

4.6. More equitable retail rates

Demand response can be offered in the form of retail prices that are higher during peak periods and lower during off-peak periods (i.e., time-varying rates). By providing a price signal that more accurately reflects the cost of supplying electricity over the course of a day, time-varying rates are more equitable than a flat rate and reduces the cross-subsidization that currently exists between customers with “peaky” or “flat” load shapes.

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8 For instance, the specific mechanics of evaluating the capacity value of DR in a region with a centralized wholesale capacity market will be inherently different than those of valuing DR for a vertically integrated utility, despite the fact that the value is derived in both cases from the avoided or deferred cost of a new peaking unit.

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[18] Depending on the specific economic conditions of the system, such as load shape and mix of existing generation resources, a different type of generating unit, such as a combined cycle (CCCT), could be the marginal unit. For simplicity, we use a combustion turbine as a proxy for marginal generation capacity cost throughout this report. System-specific modeling will reveal which technology makes the most sense, but generally the most "pure" form of generation capacity (lowest capital and highest operating costs) will be an open-cycle combustion turbine.

[19] Ideally, a supply curve of DR resources would be developed and incorporated into the modeling such that they are competing against conventional generation resources. For further discussion, see Andy Satchwell and Ryan Hledik, "Analytical Frameworks to Incorporating Demand Response in Long-Term Resource Planning," Utilities Policy, March 2014.

[20] The U.S. Energy Information Administration (EIA) estimates costs of between $900 and $1,000/kW. The Northwest Power and Conservation Council provides examples as low as $700/kW (2014$) and above $1,400/kW, depending on technology. Energy & Environmental Economics, a consulting firm, estimated costs in California between $825 and $1,200/kW. See EIA, "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants," April 2013. "Overnight cost" refers to the cost of installation if no interest were incurred during construction. http://www.eia.gov/forecasts/capitalcost/. See also, Gillian Charles, "Preliminary Assumptions for Natural Gas Peaking Technologies," Northwest Power and Conservation Council, February 2014. http://www.nwcouncil.org/media/6940212/Draft7pSCCT.pdf. See also, E3, "Capital Cost Review of Power Generation Technologies," prepared for the Western Electric Coordinating Council," March 2014.

[21] Ibid.

[22] Of course, DR would also potentially provide energy and ancillary services value that would offset some or all of this "avoided" benefit. The energy and ancillary services value of DR is discussed in Section 3.

[23] For instance, consider a new peaking unit with an average variable cost of $60/MWh. If the plant ran for 500 hours of the year and the average marginal price of electricity during these hours was $100/MWh, the energy margin would be ($100/MWh - $60/MWh) x 500 hours = $20,000/MW-year or $20/kW-year.

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30 If the system peak is projected to be 1,000 MW, the utility would have 1,150 MW of available capacity.

31 $53/kW-year x (1 + 8%) x (1 + 15%) = $66/kW-year.

32 It is possible that some old, inefficient, excess peaking capacity would be retired if DR is added to the system, in which case the fixed O&M associated with that capacity would be an avoided cost attributable to DR.

33 CONE is commonly accepted industry terminology, although various markets will use alternative terms for the same concept.

34 For an example of Gross CONE estimation, see Samuel A. Newell et al, "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM," prepared for PJM Interconnection, May 15, 2014. http://www.pjm.com/~/media/documents/reports/20140515-brattle-2014-pjm-cone-study.ashx

35 For more detailed discussion, see EnerNOC, "Best Practices of Demand Response in Capacity-Based Markets and Programs," June 2014.

36 PJM also runs annual interim auctions.

37 RTO clearing prices for the Base Residual Auction. Other zones have cleared at higher prices to due transmission constraints. See PJM Website: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-base-residual-auction-report.ashx

38 Note that PJM pays variations of the market clearing price for DR products with different performance characteristics. Similar to the derate that is applied in some regulated markets to account for the availability and flexibility of a DR program, PJM provides higher payments for more reliable and flexible DR products and lower payments for less flexible products. This type of price variation should be accounted for if it is a feature of the specific market being analyzed.

39 U.S. Department of Energy, "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them," February 2006. http://energy.gov/oe/downloads/benefits-demand-response-electricity-markets-and-recommendations-achieving-them-report

40 These market constructs typically have a "scarcity pricing" mechanism through which energy prices are administratively increased during emergency conditions in order to encourage new entry into the market.

41 See Constellation website: http://www.constellation.com/documents/government%20case%20studies/ercot%20load%20response%20snapshot.pdf

42 IESO, "OPA Demand Response Programs," January 17, 2011. http://www.ieso.ca/Documents/icms/tp/2012/01/IESOTP_256_7b_OPA_Demand_Response_Programs.pdf. See also the Save ON Energy website: https://saveonenergy.ca/Business/Program-Overviews/Demand-Response.aspx

43 PJM letter to Transmission Expansion Advisory Committee, August 28, 2012 http://www.pjm.com/~/media/committees-groups/committees/teac/20120913/20120913-srh-letter-to-teac-re-mapp-and-path.ashx

44 At the distribution level, this may be a particularly valuable aspect of DR in the future if there is significant growth in electric vehicle adoption; direct control of charging could help to manage potential reliability issues on the distribution system.

45 ConEd website. Tier II customers receive payments of $6/kW-month and Tier I customers receive payments of $3/kW-month. Due to its very densely populated urban service territory in New York, ConEd is an

example of a utility with potentially very high peak-driven T&D costs. One study found that these costs could grow in excess of $200/kW-year over time. Josh Bode, Stephen George, and Aimee Savage, "Cost-Effectiveness of CECONY Demand Response Programs," November 2013. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BBE9E7304-DA3C-4C06-B18B-ADD0D4568E3F%7D

[46] This may not always be the case, as unplanned unit outages can lead to reliability concerns during mid-peak or even off-peak hours of the day.

[47] This is a weighted average, with the weights being the amount of energy reduced in each hour attributable to the DR program. In our example, we assume the same load reduction in each hour.

[48] Kiliccote, Sila et al, "Integrating Renewable Resources in California and the Role of Automated Demand Response," Lawrence Berkeley National Laboratory, November 2010. http://poet.lbl.gov/drrc/pubs/lbnl-4189e.pdf

[49] For example, see EnerNOC Utility Solutions and The Brattle Group, "The Role of Demand Response in Integrating Variable Energy Resources," prepared for the Western Interstate Energy Board, December 2013. http://www.westernenergyboard.org/sptsc/documents/12-20-13SPSC_EnerNOC.pdf

[50] For further discussion, see National Renewable Energy Laboratory, "Grid Integration of Aggregated Demand Response, Part 2: Modeling Demand Response in a Production Cost Model," December 2013. http://www.nrel.gov/docs/fy14osti/58492.pdf

[51] Monitoring Analytics, "The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses," July 10, 2014. http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_Revised_20140826.pdf

[52] The Brattle Group, "Quantifying Demand Response Benefits in PJM," prepared for PJM and MADRI, January 29, 2007. http://www.brattle.com/system/publications/pdfs/000/004/917/original/Quantifying_Demand_Response_Benefits_in_PJM_Jan_29_2007.pdf?1379343092

[53] Ryan Hledik, "How Green is the Smart Grid?" *The Electricity Journal*, April 2009. http://sedc-coalition.eu/wp-content/uploads/2011/06/Hledik-09-04-01-Carbon-Emissions-Benefits-of-Smart-Grid.pdf Also see Pacific Northwest National Laboratory, "The Smart Grid: An Estimation of the Energy and CO2 Benefits," January 2010. http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19112.pdf

[54] Osman Sezgen, Charles Goldman, and P. Krishnarao, "Option Value of Electricity Demand Response," Lawrence Berkeley National Laboratory, October 2005. http://emp.lbl.gov/sites/all/files/REPORT%20lbnl%20-%2056170.pdf

[55] Daniel M. Violette, Rachel Freeman, Chris Neil, "DRR valuation and market analysis, volume II: Assessing the DRR benefits and costs." International Energy Agency (IEA) DRR Task XIII, January 6, 2006. http://www.demandresponsecommittee.org/id81.htm