Demand Response Evaluation, Cost-Effectiveness and System Planning

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ABSTRACT

In order to realize Demand Response (DR) benefits, DR impacts must be incorporated into system planning. The valuation of Demand Response and its integration into planning varies substantially across North American jurisdictions. Utility planners take varying approaches to factoring in hours of availability, establishing and limiting total event hours, defining performance seasons and variations in resources into their valuation of Demand Response programs.

Using Ontario Power Authority's (OPA's) DR-3 program as a case study, the paper will describe how demand response evaluation was executed to simultaneously serve the multiple uses of demand response evaluations and produce results that directly tie to the system planning process and cost-effectiveness. The evaluation was aligned with a framework for comparing the insurance value of DR with that of generation after accounting for hours of availability, limits on maximum dispatch hours and other performance factors. To develop the framework, the yearly capacity value was time-differentiated by month and hour to estimate the effective load carrying capacity of DR. These new metrics better illustrate the true capacity of DR and allow it to be integrated into the system more effectively.

In parallel, the cost effectiveness framework was adjusted to incorporate the time-differentiated capacity value. The use of time-varying avoided costs in combination with the weather-adjusted load impacts ensures that the values used for cost-effectiveness are directly linked to those used for planning. It also allows cost-effectiveness and system planning to incorporate the negative impact of DR driven load increases during non-event hours that are a direct result of load shifting or snapback. The purpose was not only to be able to compare DR resources to each other (the traditional DSM basket), but also to allow comparison with supply resources and other demand side management resources.

Introduction

One of the major challenges facing the electricity industry as a whole is how to incorporate non-traditional resources into operations and system planning. While a substantial and growing body of research has been developed regarding how to incorporate wind and solar into system planning, far less work has been conducted on how to incorporate Demand Response (DR). To illustrate the evaluation process and metrics for system planning, we focus on a contractual demand response program (DR-3 program) operated by the Ontario Power Authority.

Like wind and solar, DR impacts can vary under different conditions and it is important to have metrics that quantify how well those resources align with the system needs. The term Demand Response is used to describe programs and rates designed to shift or reduce loads during specific hours. It includes a wide array of programs. Some DR programs contract for specific amount of load reductions and/or shifting and specify specific parameters such as when the resource needs to be available, how many total dispatch hours can be exercised and payments and penalties tied to performance. Other DR programs such air conditioner (AC) cycling are technology based, and the reduction is achieved through a load control device that actively reduces electricity demand when activated. While customer behavior provides the electric load, the device provides the load reductions. Yet other DR programs such as dynamic pricing are purely behavioral and lack a performance contract. In those cases, the customer behavior determines the electricity demand and the level of load reductions which are ultimately delivered. In the case of the last two types DR programs (AC cycling and dynamic pricing), load reductions can vary substantially based on weather conditions, though they are typically highly predictable. For example, in many jurisdictions, AC demand drives the system peaks. As a result, the potential load reductions from these types of DR programs are usually larger on days when the system is strained and resources are most needed. They also pose the conundrum of whether to integrate them as a supply resource or incorporate them into the demand forecasting. Most DR programs require active and continued participation. Once a customer is no longer enrolled in the program, electric loads revert back to normal patterns.

Integrating DR resources into the system is a challenge because these resources have different characteristics than typical thermal generators. However, in order to realize the true value of DR resources, they need to be incorporated into planning and operations. Since the primary value from DR programs is insurance against extreme system conditions, it is especially critical to properly integrate it into generation or "supply mix" system planning. In practice, there are four key questions that must be addressed in generation planning:

- What mix of resources should be used to meet electricity consumption needs?
- Is the supply mix able to meet peak demand levels? In other words, what is the likelihood of supply shortages?
- Is the system able to withstand shocks such as transmission of generation forced outages or unexpected demand levels?
- Are there sufficient load following resources to enable the operator to instantaneously balance supply and demand?

The stability and reliability of electricity supply systems depends critically on the ability to balance supply and demand virtually instantaneously at all times. Electricity travels at the speed of light, and, for all practical purposes, cannot be cost-effectively stored in large quantities. The instant someone turns on a light switch, a generator somewhere produces the electricity. Delays in balancing supply and demand can lead to frequency and voltage fluctuations that compromise the reliability of the electricity grid, often times across multiple states. In essence, this means that there must always be sufficient supply to meet demand. Historically, this has been accomplished through two means. First, operators usually maintain a sufficiently large amount of operating reserves to follow loads and quickly recover from shocks. Second, enough generation is built to meet extreme levels of electricity demand that occur in rare instances - e.g., one day out of every 10 years. In other words, sufficient generation capacity is installed to protect against extreme demand levels although it is not needed for normal day-to-day operations. This is generally where DR plays a role. DR can often times provide insurance against extreme system conditions at lower costs. However, the characteristics of the insurance it provides differ from the insurance provided by thermal generators.

Evaluation has typically focused on historical impacts. While some evaluations report the impacts for the "peak," practices vary extensively ranging from reporting average values for summer and winter peak hours to reporting impacts for the historical peak hour, to estimating load impacts under the weather conditions that underlie extreme and normal peaks. In practice, from a planning perspective, the hours that are near the system peak load are often as much of a concern as the peak load itself. Increasingly, there is a need to produce evaluation results which are useful for system planning and metrics that allow direct comparison between DR resources, thermal generation, renewable, energy efficiency and other resources. This paper focuses on one such attempt using OPA's DR-3 program to illustrate the type of metrics and output that can inform system planning. We also re-introduce an old metric, effective load carrying capacity (ELCC), which was initially introduced in 1966 and has found renewed life in assessing wind and solar resources. ELCC is a standard measure of the extent to which a new resource affects capacity planning reserves. It can be thought of as a measure of the degree to which a resource approximates a generator with perfect reliability. It is usually expressed as a percent of nameplate capacity but can also be expressed in terms of megawatts. A central theme of this paper is the need to routinely report this metric in order to allow direct comparisons. We discuss how to do so in a transparent manner given real world data constraints.

This paper is organized as follows. The first section provides a brief description of the OPA's DR-3 program and how it compares with thermal generation. Next, we present the *ex post* findings from the 2009 evaluation and, separately, the outputs produced for planning and cost-effectiveness purposes. Third, we discuss the issue of how to compare insurance value when hours and month of availability and dispatch operations are restricted. Once the theoretical framework is introduced, we apply it using the DR-3 results to concretely illustrate how to produce estimates of ELCC for DR given publicly available data. The fifth section highlights some of the inconsistencies in how DR is incorporated into planning and cost-effectiveness analysis in order to emphasize the need for consistent and comparable metrics. Finally, we conclude by summarizing some of the key findings from the paper.

DR-3 Program Description and Comparison with Thermal Generation

DR-3 allows participants and aggregators to enter into one, three or five year contractual agreements for load reductions with OPA. Participants can choose to enroll directly with OPA, provided they meet minimum load reduction criteria, or can participate through an aggregator. Under DR-3, an aggregator or direct participant must commit to deliver a specific load reduction amount between 12:00 to 9:00 PM during the summer months (June to September) and from 4:00 PM to 9:00 PM during the winter and shoulder months (October to May). At the time of enrollment, program participants elect to be called for a maximum of 100 or 200 hours per year. OPA has discretion regarding the timing of events and currently is determining event days based on the Ontario Independent Energy System Operator (IESO) day-ahead supply cushion estimates. In exchange for load reductions, the DR-3 program makes both availability (capacity) and energy payments. OPA can reduce payments if participants fail to provide the contractual load reduction or if they notify the IESO they are unavailable to provide load reductions.

DR-3 participants notify OPA and the IESO of any short-term fluctuations in their ability to deliver the contracted load reduction due to facility maintenance or down time. These days are classified as non-performance days and are analogous to generator outages. Knowledge of when they occur enables the IESO to better operate the system and schedule alternate resources for those days. For settlement purposes, compliance with the contracted load reductions is determined through day matching baseline methods. A more rigorous evaluation using regression methods is conducted on an annual basis.

The DR-3 program is highly analogous to peaking generator. They both have contracts specifying when the resource is available, the amount of resources to be delivered and mechanisms to notify the system operator if the resource is unavailable. However, there are four main differences. First, the hours when DR-3 is available are more limited than for a peaking unit. The peaking unit is not necessarily in operation during those peak hours but it can become available for almost any month or hour of the day should high demand levels be forecast far enough in advance. Second, DR-3 has an explicit limit on the number of hours it can be dispatched (100 or 200 hours per year), while a peaking generator does not. Third, while the output from a generator can be directly measured, measurement for DR programs is indirect. The load reduction delivered is calculated as the difference between electricity use with and without demand response. However, it is not possible to directly observe what customers would have used in absence of their demand response. To calculate the resource delivered, participant's load patterns in the absence of program participation – the counterfactual or reference load – must be estimated. In doing so, it is important to systematically eliminate or control for alternative explanations for the change in electricity consumption. This often times raises the question of DR performance: namely, does the DR resource in fact deliver what is expected of a day-ahead or same day basis. The fourth difference is that DR-3 relies on aggregating load reduction from multiple sources (e.g., facilities). Just as it is unlikely that 50 generators experience forced outages at the same time, it is highly unlikely that all the underlying sources of load reduction would be unavailable (or not perform) at the same time. These issues are the crux of making any meaningful comparisons between DR-3 and generation.

DR-3 Evaluation Outputs

As part of the DR-3 evaluation, the net load reductions delivered by the participants were quantified for each hour of each day the program was dispatched.[1] The primary goal, however, was to assess program performance in order to estimate the resources available for planning purposes. Given the program design of DR-3, the evaluations focused on three specific components:

- The total contractual resources that were dispatched in each event day;
- The share of those resources that are available based on a day-ahead basis; and
- How the demand reduction delivered compared to the day-ahead committed resources for each event day;

The contractual resources dispatched for any given event varied based on participant enrollment at the time and whether or not the 100 hour, 200 hour, or both groups were dispatched. The contractual resources varied mainly due to the changes in enrollment. Figure 1 reflects the ramp up of aggregate contracted load reduction since program inception through December 2009.

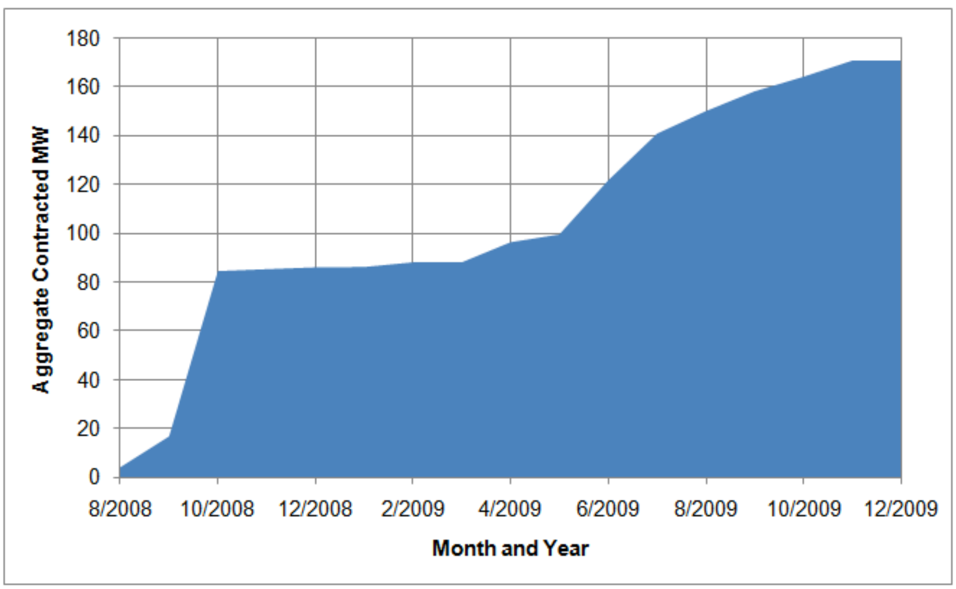

Figure 1. Aggregate Contracted Load Reduction by Month and Year

Since the program's launch in mid-2008, the DR-3 participant mix and load reduction capabilities have evolved substantially. The largest change in load reduction capability occurred with the enrollment of three large direct participants in September and October of 2008. In addition, aggregators have added participants since their contracts became effective and have continued to ramp up enrollment. As of December 31, 2009, a total of 167 MW has been contracted through the program, up from 85 MW in 2008.

The second key issue was the share of those resources that are available based on a day-ahead basis.

[1] The full evaluation report including extensive validation of the evaluation approach is available at the Ontario Power Authority's website (www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports), under the *2009 Impact Evaluation of Ontario Power Authority's Commercial & Industrial Demand Response Programs*

By default, DR-3 participants are available for dispatch unless they notify the IESO. Non-performance days are carefully tracked for each contributor, even if they participate through an aggregator. As a result, there was significant history on the share of the contracted load available for dispatch not only for event days but for all days. Pre-announced non-performance was higher in 2009 than in 2008, partially due to the effect of the economic downturn on direct participants. Using all days to estimate day-ahead availability provides a more robust estimate. Because the enrollment was changing substantially over the time period, the total resources available on a day-ahead basis were summed and divided by the sum of the contracted resources over the time frame. From 2008 and 2009, on average, 92% of the contracted MW was available for dispatch.

The third component was how well the program performed relative to day-ahead commitments when it was dispatched. The number of event days varied substantially each year. In 2008, a total of 14 events were called, occurring both in the summer and winter period. In 2009, there were only 6 events called, all occurring during the summer months of June through September. Note that in 2009, the Ontario supply cushion was large compared to 2007 and 2008 due to historically low market-demand and new supply-side resources.

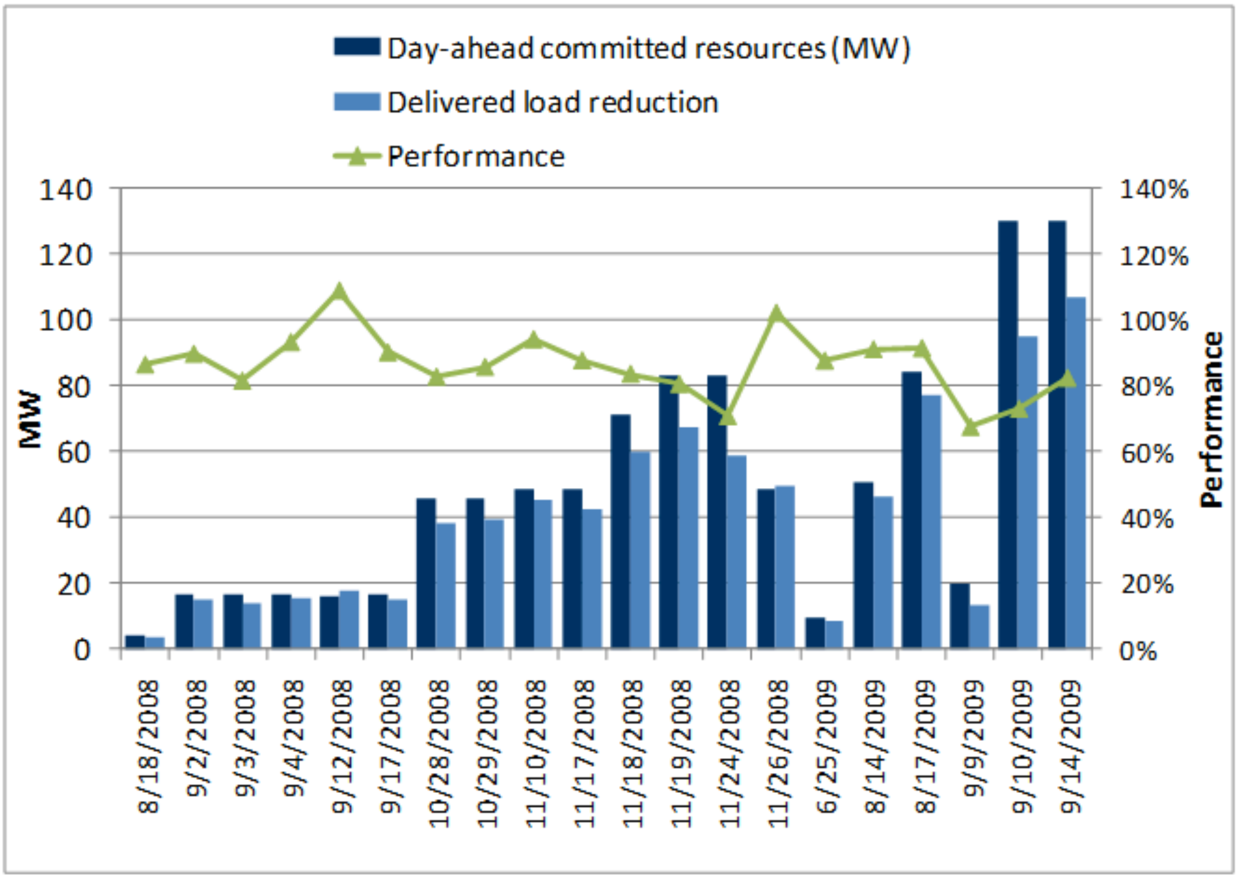

Figure 2. Comparison of Load Reductions Delivered to Day-Ahead Committed Resources

Figure 2 compares the resources available on a day-ahead basis to net impacts delivered in each event DR-3 was dispatched in 2008 and 2009. The solid line shows how DR-3 performed as a percent of the load reduction available on a day-ahead basis. Across all events, an average of 84% of the load reduction available on a day-ahead basis was delivered. The performance for individual events ranged from a low of 70% to a peak of approximately 110% and, overall, was relatively stable.

The difference between day-ahead commitments and delivered load reductions was explored further and found to be explained almost entirely by bias in the day-matching baselines used for settlement - which differ from the final impact evaluation methods (e.g., regression methods). In practice, aggregators and direct participants often manage load based on the settlement baseline because it determines settlement and whether they meet their contractual commitment. Bias in the baseline method created a situation in which some participants were in full compliance with program rules even though they reduced demand by less than the contracted load reduction. This issue is currently being addressed by the OPA. The underperformance had less to do with inability of DR-3 participants to meet obligations and more to do with an administrative rule.

The evaluation could have easily directly estimated the net impacts for each event and avoided the more detailed analysis of explaining gaps between contracted and delivered load reduction amounts. However, taking the more detailed evaluation approach allows for the DR-3 results to be presented in a way that made it easier to compare DR to generation and incorporate into system planning.

While the *ex post* impacts serve as the foundation for assessing performance, the main interest from a planning perspective is the net load reduction capability for specific hours and months, particularly under normal and extreme weather year system peaking conditions. These estimates factor in both scheduled non-performance and the extent to which participant load reductions deviate from day-ahead contracted resources. Estimates of load reduction capability are by nature forward looking or *ex ante*. *Ex post* performance can be misleading since they are tied to past conditions and enrollment at a given time. They sometimes do not reflect true load reduction capability because programs are not always dispatched in full. For example, looking back at event days in OPA's DR-3 program during 2008 and 2009, for several DR events, only customers under the 200-hour option were dispatched. The participants under the 100-hour options were not utilized because the additional resources were not needed that day. In addition, as Figure 1 shows, the amount of contracted load reduction at the end of the year was lower than enrollment in mid-summer due to increased enrollment in the DR-3 program.

Figure 3 show a simplified calculation of how the impacts for planning were produced. In order to produce estimates of load reduction, the contracted amount at the end of 2009 was multiplied by the two performance factors analyzed in the historical data. This approach was selected because of the contractual nature of the program, the relative lack of weather sensitivity of participants and to provide results in a lexicon familiar to planners. It is also important to estimate the *ex ante* impacts under a standard set of conditions that reflect normal and extreme year peaking conditions. This is particularly important for highly weather sensitive programs such as AC load control programs. In practice, the performance factors were applied to participant's loads for each hour of each month under normal and extreme peaking conditions for the month. This produced a grid for each hour of day and month (288 values) with the expected load reduction delivered for each contracted MW or load reduction. In addition, the uncertainty bands around the performance factors from the historical data were incorporated into the results.

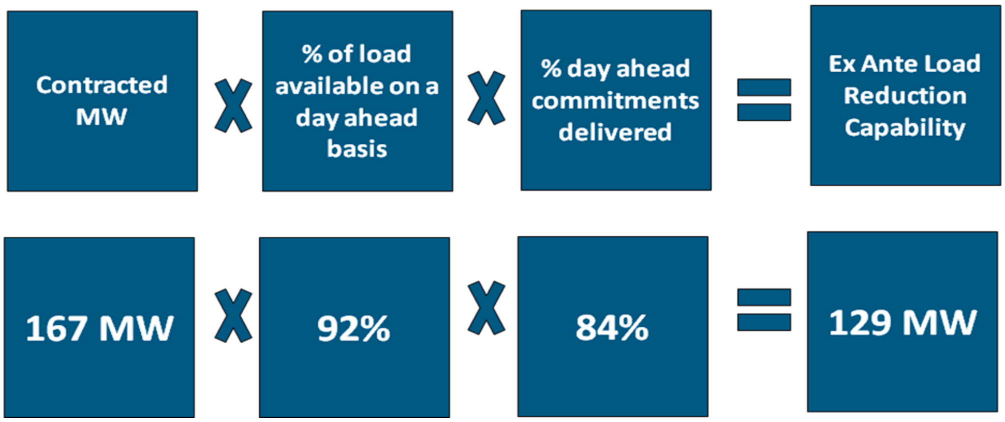

Figure 3. Simplified example of determining *ex ante* load reduction capabilities

Table 1 summarizes the *ex ante* load reduction estimates, along with the contractual load reductions and the expected day-ahead contracted load reductions for each month. Due to limited availability of historical pattern, for the *ex ante* estimates, it was assumed that a pre-announced non-performance did not have a seasonal pattern.

Table 1. Summary of *ex ante* load reduction estimates by month for the OPA's DR-3 program

Month	Hours Resource is Available	Contracted MW	Expected MW Available on a Day Ahead Basis	*Ex Ante* Load Reductions for Planning [1]	90% Confidence Interval	
				MW	Lower bound	Upper Bound
January	4 PM to 9 PM	167.0	153.1	128.2	93.1	163.2
February	4 PM to 9 PM	167.0	153.1	128.2	93.1	163.2
March	4 PM to 9 PM	167.0	153.1	128.1	93.1	163.2
April	4 PM to 9 PM	167.2	153.2	128.3	93.2	163.4
May	4 PM to 9 PM	167.4	153.4	128.4	93.3	163.6
June	12 PM to 9 PM	168.2	154.2	129.1	93.8	164.4
July	12 PM to 9 PM	168.2	154.2	129.1	93.8	164.4
August	12 PM to 9 PM	168.2	154.2	129.1	93.8	164.4
September	12 PM to 9 PM	168.1	154.1	129.0	93.7	164.3
October	4 PM to 9 PM	167.5	153.5	128.5	93.4	163.7
November	4 PM to 9 PM	167.4	153.5	128.5	93.3	163.6
December	4 PM to 9 PM	167.1	153.1	128.2	93.1	163.3
AVERAGE		**167.5**	**153.6**	**128.6**	**93.4**	**163.7**

[1] Incorporates differences between day-ahead commitments and reductions delivered

While the *ex ante* load impact estimates factor in the scheduled non-performance and departures from the expected load reductions for operations, they do not directly account for limits on (a) when the program is available for dispatch, (b) maximum event duration, (c) maximum number of dispatch hours, or,

(d) though less relevant for DR-3, how well the timing and magnitude of available load reduction coincide with the need for additional capacity. Without incorporating those factors, it is not possible to directly compare one DR resource to another DR resource, much less to generation. The outputs produced for DR-3 were designed to allow planners to incorporate those differences and assess the extent to which DR resources provide planning capacity. However, not all planning models properly incorporate the characteristics of DR resources. Of those that models that can, they often require a substantial amount of work. When characteristics of DR resources are properly incorporated into planning, the ELCC is typically not reported.

ELCC can be thought of as a currency converter. For example, 1.0 megawatt of contracted DR-3 is equivalent to 0.70 MW for capacity for planning while 1.0 megawatt of single cycle gas turbine nameplate capacity is equivalent to 0.92 MW. In other words, it is a metric that calculates the insurance value of different resources for meeting extreme system conditions. Reporting a transparent metric that reflects the insurance value of different resources and allows direct comparison of resources is extremely useful not only for planners, but for program design, administration and policy setting.

Comparing insurance value

Comparing capacity from one resource (such as DR) to another resource (such as a single cycle gas turbine) is like comparing two car insurance quotes when the policies are different. When the car policy characteristics such as the deductible, bodily insurance limit, property damage limit and/or roadside assistance differ, the insurance quotes are not directly comparable. Different generators provide different types of insurance and different types of DR provide different types of insurance. In general, however, the characteristics of the insurance provided by DR usually differ from generation. Namely, the hours and months when they can operate may be different. Also, there can be differences in the amount of resources they can deliver for specific hours and months. In order to make adequate comparisons, it is necessary to quantify how the insurance value varies by hour and month and factor in the extent to which resource availability coincides with the capacity value.

The capacity insurance value of a resource is directly linked to how it affects risk of shortages in balancing demand and supply. All other factors being equal, a resource that can deliver when the risk of supply shortages is greatest should provide more insurance value than a resource which cannot. In most systems, extreme weather drives up the system demand, the likelihood of resource shortages and the need for additional capacity. Although unforeseen system shocks such as forced outages can occur during hours without extreme loads, the system is designed with sufficiently large operating reserves to absorb such contingencies and allow other installed resources to come online, ramp up, and meet demand.[2] At high system demand levels, it is more difficult to operate the system in general, and there is greater risk that unplanned outages will result in insufficient installed capacity. Put simply, the primary driver of additional capacity needs is demand.[3] This generally means that resources available in the summer mid-afternoon hours, when systems typically peak, have higher insurance value than resources available in shoulder or off-peak hours.

Figure 4 shows the load duration curves for the top 1,000 hours for Ontario over the period 2005-2009. The graph illustrates the fact that the top 10, 50 and 100 hours have substantially higher loads than all other hours. It also illustrates the fact that high system loads do not occur in each calendar year.

[2] Installed capacity shortages are altogether different than the ability to recover from system shocks, such as transmission or generation forced outages. Installed capacity includes operating reserves, generation online and generation off line. The system operator has separate criteria for adequate amounts of quick response operating and back-up reserves (ancillary services) to help balance the system and recover from any shocks.

[3] In some systems, scheduled outages for generator maintenance during shoulder months can also affect the likelihood of supply shortages. In incorporating scheduled outages, it is important to distinguish risk due to scheduling error from risk due to insufficient installed resources. In many systems, scheduling maintenance is a challenge, but it is also the case that, when done properly, the risk of a shortage in supply is relatively low in shoulder months compared to in the peaking months, which are usually during the summer.

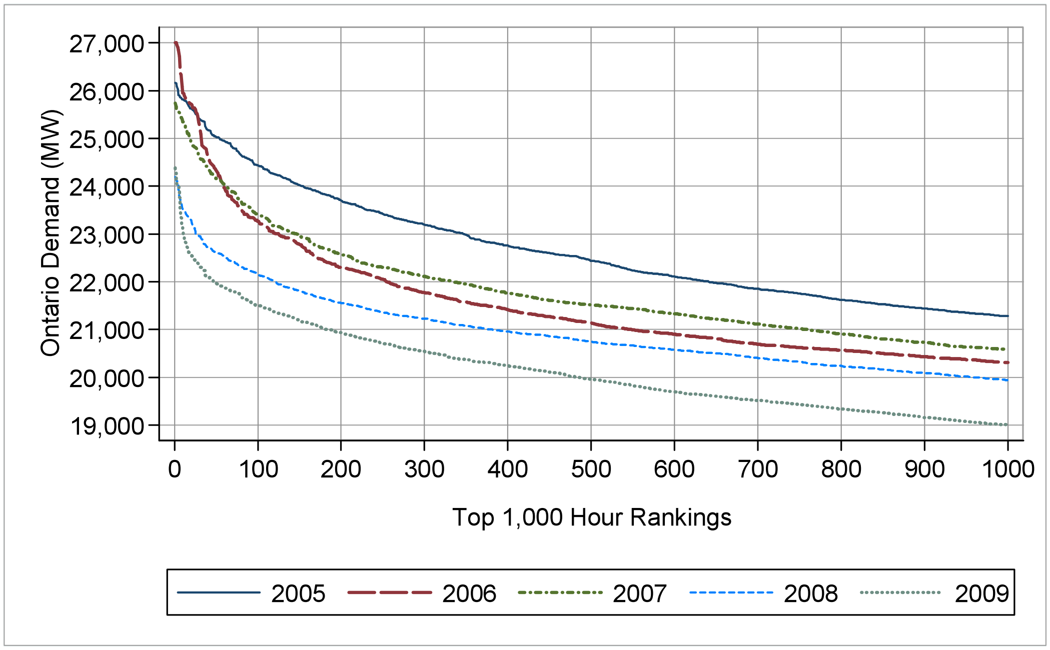

Figure 4. 2005-2009 Load Duration Curves for Ontario

The likelihood that demand exceeds installed system resources is highly concentrated on a limited number of hours and months. In practice, the weather (the primary driver of demand) varies from year to year and, in the case of an extreme weather year, the risk of a resource shortage is increased. Nevertheless, the planning criteria for the supply system ensure that the likelihood of a resource shortage occurring on any given day is extremely low.[4] This equates to a very low likelihood that there are more than a few hours in a year in which resource shortages can occur.

Many utilities and system operators directly model the risk of shortages to estimate the loss of load probability (LOLP), the expected number of shortage hours (LOLE) and/or the expected unserved energy (EUE). Often times these outputs are produced for each hour of the year in which they can be used to assess the share of the total risk in each hour of the year. When available, this data on the concentration of risk can be used to calculate the concentration of the need for capacity.

There are two main drawbacks to using these outputs, however. First, the output from the shortage risk models is typically confidential and may be unavailable to evaluators. The confidential nature of this data undermines the transparency. The second drawback is that output on the risk of resource shortages is not always available at an hourly level. Often times, it is produced on a daily or weekly basis. For example, the Ontario LOLP and the expected number of shortage hours were available to OPA but only on bi-weekly basis. Data on the risk of shortage across different hours of the day for different weeks or months was also unavailable.

There are several other alternatives for understanding and allocating insurance value based on publicly available data. It is usually safe to assume that the days and hours with the highest system load are the ones with the highest risk of shortages.[5] In most LOLP models, almost all of the risk of shortages is

[4] In other words, the Loss of Load Expectation (LOLE) is highly unlikely to exceed 20 or 50 hours, much less a 100 hours, given the existing planning criteria.

[5] Effectively, forced generation and transmission outages were treated as random. To incorporate scheduled outages, loads can be adjusted upward to reflect the decrease in installed resources available during those periods.

concentrated in the top 100 hours and very rarely is there any risk of shortage outside of the top 200 hours. Similarly, the concentration on top 100 system load hours and/or the concentration of load above a base value can be used to time-differentiate the insurance or capacity value across the hours and months of the year.[6] For simplicity, we illustrate this allocation approach using the top 100 hours. It is typically better to use data from multiple years to incorporate heat wave patterns from a range of years.

Figure 5 shows how the allocation of capacity need is developed. The left hand side of the figure shows concentration of the top 100 hours in each year from 2005 to 2009 - a total of 500 hours - by month and hour of day. The right hand side of the figure is identical except for the scale, which reflects the percent of 500 hours that occurred in each combination of month and hour of day. Note that the total for the allocation of capacity need across all months and hour of day adds up to 100%. As shown, the risk of high system loads is highly concentrated in the months of June and July with an occasional spike in the winter months. They are also highly concentrated in the afternoon hours. The need for installed resource capacity to meet extreme system loads is similarly concentrated. Based on the risk allocation, one can say, for example, that 4.8% of the risk is concentrated in the hours from 3 PM to 4 PM in July, or that 26.2% of the risk is allocated between the hours of 12 PM to 6 PM in the month of July.

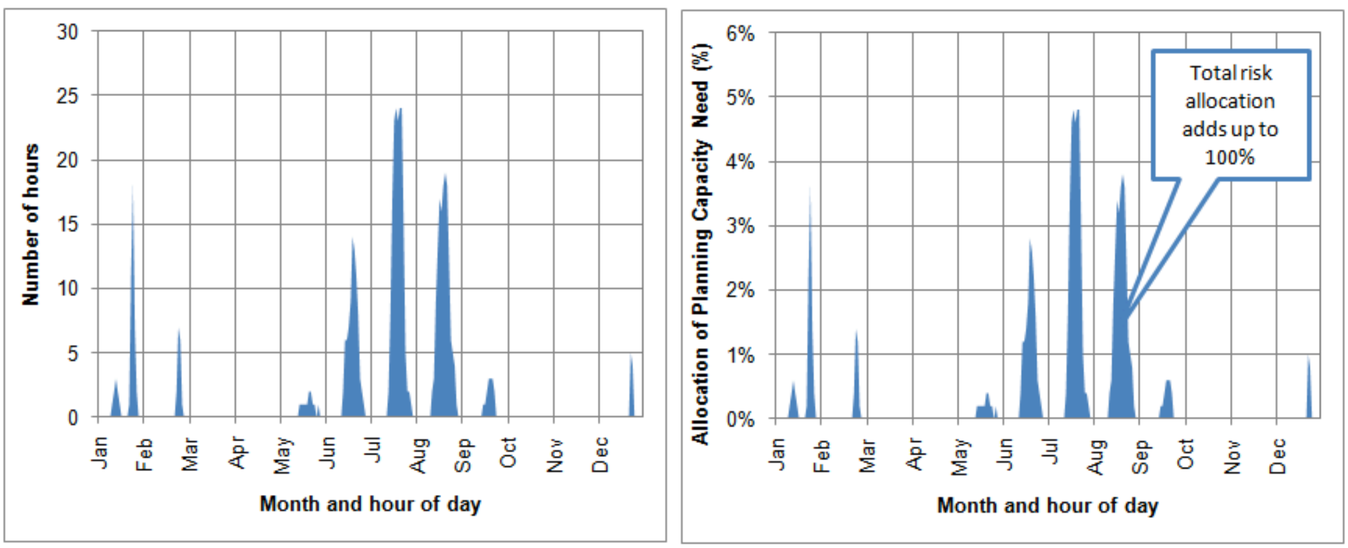

Figure 5. Example of Allocation of Capacity Need Using Top 100 System Load Hours from 5 years

The allocation of capacity need can be used to time-differentiate capacity value. It can also be used to link the magnitude of available load reductions with the extent to which planning capacity is needed, factoring in limits on the month, availability, and maximum event duration of resources. The application for time-differentiation capacity values is typically more intuitive, so we first describe this process and then describe how this information can be used to calculate an ELCC value.

For illustration, we assume the value of incremental capacity is $120 per kW-year. We use the information about the concentration of the need for capacity, to allocate the capacity value across 288 monthly and hourly cells in a matrix (12 x 24 = 288). If 4.8% of the overall allocation is concentrated in the 3 PM to 4 PM hour of the month of July, $5.76 of the total capacity value (4.8% x $120 = $5.76) is allocated to that time period. It is highly instructive to compare a time-differentiated allocation of capacity value to a

[6] Not all the top 100 hours have the same risk. Higher risk hours are better reflected by using load above a certain base value. Using a base value equal to the load on the 100th highest system load is typically recommended.

flat allocation. Figure 6 contrasts a flat allocation of capacity value with time-differentiated capacity value. In the illustration, a flat allocation would pay \$0.417 (3.47% x \$120 = \$0.417) for each month-hour, regardless of demand level and likelihood of installed capacity shortages. For most hours, it would provide payments even though there is no need for capacity. For key hours, it underpays for capacity.

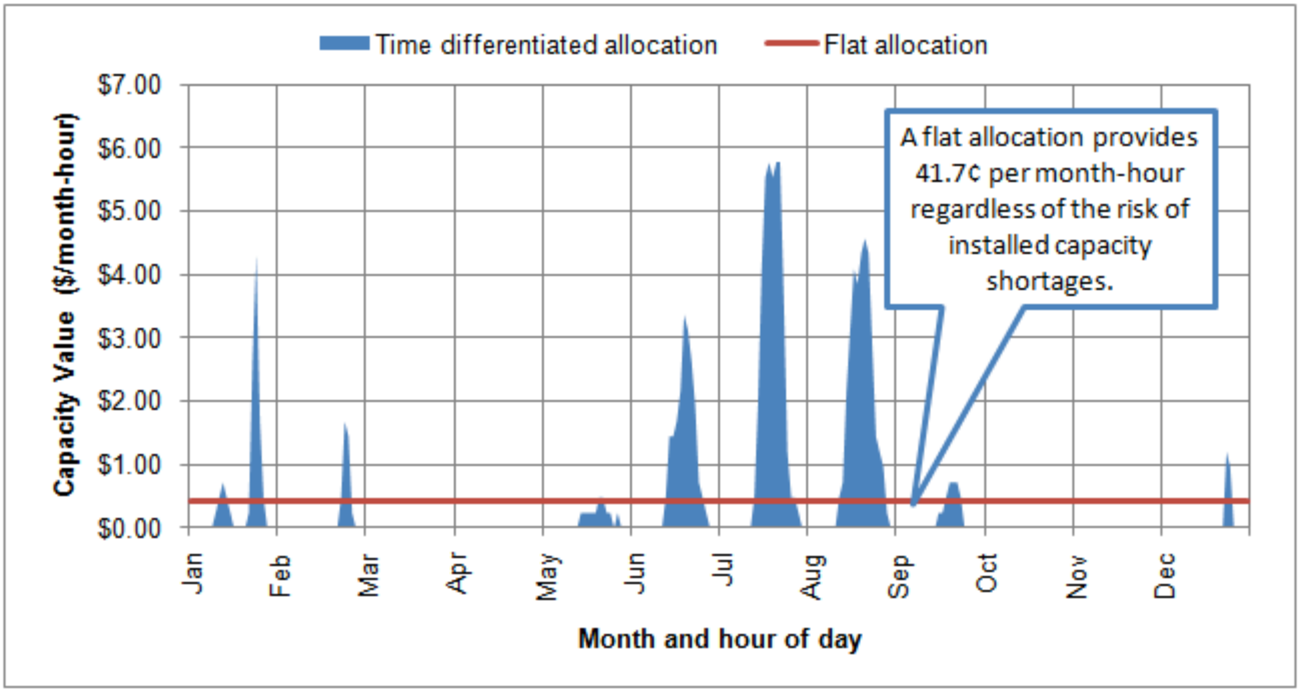

Figure 6. Comparison of a Flat Capacity Value Allocation to A Time Differentiated Approach

Calculating DR Effective Load Carrying Capability

The concept of ELCC was initially proposed by Garver in 1966. Since then, calculations of ELCC have grown more complex. There are generally two approaches that have been employed. The first approach jointly models each resource, its availability, production output and risk of failure or underperformance. To assess how resources compare, one resource is substituted for another until the risk of installed resource shortages is identical. The second approach is to use the output from models that analyze the risk of resource shortages and allocate that risk across the different hours and months of the year. In others, the need for capacity is time-differentiated. As noted earlier, both of these approaches involve models and outputs that are not public, lack transparency and, often times, cannot easily accommodate DR. In contrast, the proposed approach for allocating capacity need and estimating the ELCC value of DR is simple, transparent and can be applied in almost all jurisdictions.

Once the allocation of capacity need is established, calculating the ELCC is much like time-differentiating capacity value. The magnitude of the load reduction that can be delivered in each hour and month of the year is multiplied by the capacity need allocation for the respective month and hour and summed up. Mathematically, this is expressed by:

$$ELCC = \sum_{h=1}^{24} \sum_{m=1}^{12} MW_{m,h} \times Allocation\ of\ Capacity\ Need_{m,h}$$

In practice, this means that if a resource is unavailable for a particular set of hours, it does not meet the capacity need for those hours, and therefore does not receive any credit. For a resource such as AC cycling that provides different amounts of load reduction during each monthly system peak day, the calculation factors in both the magnitude of the resource and the capacity need during the month and hour. To better understand the process, we illustrate it with a simplified example using the OPA's DR-3 program. To simplify matters, we assume that the net load reduction from DR-3 is constant which is more or less true.

The DR-3 program has 167 MW of contractual resources (nameplate capacity), is available 92% of time (with no seasonal pattern) and has a track record of delivering 84% of the committed load reduction. Before adjusting for hours and months of availability, the resource is expected to deliver a net load reduction of 129 MW. Notice that that these value match up with the *ex ante* estimates delivered as part of the evaluation. After adjusting for avoided line losses (6.7%), the program provides the equivalent of 137.7 MW, or 82.5% of the nameplate MW. However, the restrictions in the hours it is available and the maximum event duration needs to be factored in. In total, 82.9% of the capacity need is allocated to the hours and months when the program is available − 12 to 9 PM from June to September and 4-9 PM on all other months.[7] However, DR-3 cannot be dispatched for more than 4 consecutive hours in any given day. To factor in this limitation, within the availability period, only the four hours that have the most capacity need allocated to them are considered within each month. In total, those hours include 59% of the capacity need. This translated into a an ELCC of 81.2 MW or 48.9% of the 167 MW nameplate value.

But how are the maximum number of dispatch hours and amount of advance notification factored in? It is often argued that DR should be de-rated even further to account for those characteristics. However it is important to remember how often installed resources shortages are likely to occur and to distinguish those instances from short term needs for fast resources that help the system recover from system shocks - ancillary services. As mentioned earlier, operators usually maintain a sufficiently large amount of operating reserves to follow loads and quickly recover from shocks. These criteria are entirely independent of the need for additional capacity. Most electricity systems are designed to experience at most 24 hours of installed capacity shortages over a 10 year period.[8] While those shortage hours are often concentrated on extreme weather years, the maximum number of event hours DR programs are available is usually magnitudes larger. For DR-3, participants are contracted to deliver 100 or 200 dispatch hours. The extra availability, allows room for imperfect targeting of extreme hours for DR to not only target actual installed capacity shortages, but dispatches where the electricity system nears installed capacity shortages. In other words, from a capacity standpoint, there is a safety cushion already built in.

Conclusions

In practice, the ELCC value of DR resources is rarely calculated. Instead of calculating the ELCC, many jurisdictions have adopted the practice of specifying fixed windows for specific months when the resource must be available in order to be incorporated into resources adequacy. This can misrepresent the insurance value of DR, leading to values that are too low or too high depending on the characteristics of the DR resource. This also creates a disconnect between how cost-effectiveness of DR is assessed and how it is incorporated into planning. In several jurisdictions, DR cost-effectiveness analysis actually links the magnitude and availability of the resource across different hours and months to a time-differentiated allocation of capacity need. This creates a situation where the cost-effectiveness calculations factor in the

[7] In practice, the time-differentiated allocation of capacity if more concentrated if one factors in the concentration of system load.

[8] The few instances when resource shortages were far more frequent, such as the 2000 California energy crisis, the shortages were not due lack of installed resources, but due to market manipulation.

DR ELCC (or something close to it), but resource adequacy planning does not. By consistently producing outputs useful for system planning and the ELCC metric, DR evaluations can help better incorporate DR into system planning.

References

Freeman, Sullivan & Co., 2010. *2009 Impact Evaluation of Ontario Power Authority's Commercial & Industrial Demand Response Programs*, prepared for the Ontario Power Authority, San Francisco, CA.