A Comprehensive Framework for Evaluating Demand Response in a Resource Planning Context

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ABSTRACT

This paper describes a framework for evaluating demand response (DR) resources developed by the Ontario Power Authority (OPA) and Freeman, Sullivan & Co. (FSC). As a central part of OPA's mission is long-term resource planning, the OPA needed a DR evaluation framework to provide inputs into that process. The OPA required the framework to: fully recognize the option (or insurance) value of DR; specify minimum requirements to compare resources on common terms; not impose burdensome requirements; and remain relevant in a shifting policy environment, for a range of potential DR options. OPA's framework is based on that developed in California, with modifications to suit local needs and incorporate lessons learned. It includes eight load impact protocols that provide minimum requirements for the reporting of load impacts, while allowing flexibility of approach. Four categories of DR resource options are defined, and minimum reporting requirements specified for each. Future enrolment is treated as an exogenous variable, with load impacts estimated with sufficient granularity to support scenario development as part of cost-effectiveness analysis. The cost-effectiveness framework uses ex ante load impacts to assign avoided costs to DR resources under extreme (1-in-10 weather year) conditions. Cost-effectiveness is measured primarily through a total resource cost value, with avoided generation capacity providing the majority of DR value. As both DR and resource planning become more widespread, forward-looking evaluation models will likely be of broad interest.

Introduction

This paper describes a framework for evaluating demand response (DR) resources developed by the Ontario Power Authority (OPA) and Freeman, Sullivan & Co. (FSC). The OPA is a non-profit corporation established in 2005 to ensure the long-term reliability of the Ontario electricity system through resource planning and the procurement of supply- and demand-side resources.

In recent years, the Province of Ontario has adopted ambitious conservation[1] goals and assigned a leadership role to the OPA in ensuring that they are met. In planning to meet the current goal of 6,300 MW of peak demand reduction by 2025 (about 19% of forecast load) the OPA expects a significant contribution from customers enrolled in DR resources.

The OPA has adopted a framework for evaluating energy efficiency resources based on best practices developed from decades of efficiency program evaluation in other jurisdictions. For DR, evaluation methods are less well established and there are fewer examples to borrow from. Because resource planning is central to the OPA's mission, a primary goal of a DR evaluation framework is to provide inputs to that process. In other words, it was necessary to develop forward-looking estimates of the expected

[1] "Conservation" is an umbrella term used in Ontario for four categories of demand-side resource: demand management/conservation behavior; energy efficiency; fuel switching; and customer-based generation. Demand response is included in the first category.

performance and value of DR resource options. Examination of practices in other jurisdictions revealed that no existing framework would directly suit the OPA's needs.

In the early to mid-2000's, some Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) conducted evaluations of demand response programs they administered to determine how they performed in a given year (e.g., Neenan et al. 2005; RLW Analytics & Neenan Associates 2005), but these evaluations were not forward-looking and were focused on the effects of DR on wholesale and bilateral market prices. The recent trend toward forward capacity markets has led the focus of DR evaluation in many ISO/RTO-controlled regions toward settlement. For example, ISO-New England has adopted rules for the measurement and verification (M&V) of DR resources participating in its forward capacity market designed to ensure that resources meet their contractual obligations (ISO New England 2007). This is distinct from a resource planning perspective, where investment decisions are based on relative cost-effectiveness of resources over a long-term forecast of need and resource costs, rather than allocation in a capacity auction. At the time of writing, the North American Energy Standards Board (NAESB) was developing a draft wholesale demand response M&V standard that is similarly focused on settlement of DR resources.[2]

The OPA determined that California offered the most relevant case study for Ontario. The California Public Utilities Commission (CPUC) has adopted a set of DR load impact estimation protocols (CPUC 2008) and has made progress toward development of a DR cost-effectiveness framework; both take a forward-looking approach. In 2008, the OPA hired FSC, who had contributed to the California protocols, to develop a DR evaluation framework for Ontario. The resulting framework borrows from the California process and products, but incorporates lessons learned from their implementation and includes some changes to suit the Ontario market.

Context and Approach

The context for DR resources in Ontario is complex and continually evolving, and a DR evaluation framework needs to be flexible if it is to remain relevant.

Currently, the majority of consumers in the Province pay fixed retail rates for electricity. Large industrial users who are "market participants" are an exception. These facilities pay wholesale market prices for their electric commodity—the Hourly Ontario Electricity Price (HOEP) published by the Independent Electricity System Operator (IESO). HOEP is an aggregation of 15-minute real-time market prices and is communicated ex post, so market participants would have to rely on third-party indices in order to respond to HOEP signals.[3] Moreover, a significant and increasing portion of the cost of supply is being recovered through the Global Adjustment Mechanism (GAM), a surcharge on all customers' bills that is not time varying and arguably dampens wholesale market price signals.

A Smart Meter initiative is underway that, when complete, will result in all classes of customers having interval meters installed. A pilot time-of-use (TOU) rate is in effect for some of the first customers to receive Smart Meters, and the Ontario Energy Board (OEB) is overseeing development of a TOU rate structure that would eventually apply to all retail customers across the Province.

Currently, the OPA offers three DR programs to non-residential customers: "DR-1," a voluntary demand-bidding program; "DR-2," a permanent load shifting program; and "DR-3," a capacity program. In addition, the OPA manages "***peaksaver***®[4]," a residential and small-commercial direct load control program

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[2] The draft standard is available at: http://www.naesb.org/dsm-ee.asp
[3] There is currently no day-ahead market in Ontario.
[4] ® Trademark of Toronto Hydro Corporation. Used under license.

that is operated by local distribution companies (LDCs). The IESO also maintains a resource of large electricity users that can be called to provide relief during system emergencies.

Going forward, new legislation has recently established a greater role for the Province's ~70 LDCs in delivering conservation, and this could include DR. The OPA will still be responsible for accounting for DR (and energy efficiency) load impacts and cost-effectiveness in long-term resource planning, although the evaluation of individual programs could be the responsibility of the delivering LDCs. Having a DR evaluation framework in place is critical to ensure that impacts across the Province are estimated and reported in a common format and can be defensibly combined in resource planning.

Given this backdrop, the OPA required the DR evaluation framework to:

- be defensible, transparent, and appropriately value the specific attributes of DR;
- be relevant throughout the resource planning and program delivery cycle;
- fully recognize the option (or insurance) value of DR;
- specify minimum requirements to enable DR resources from a potentially large number of sources to be included in resource plans on an apples-to-apples basis, without imposing burdensome evaluation requirements; and
- be relevant in a shifting policy and regulatory environment, and for a wide range of potential DR resource options.

The framework was developed through a staged approach. First, a white paper presented key concepts and made recommendations on basic requirements of a DR evaluation framework (George & Bode 2008). Then, a detailed proposal was presented to key OPA staff to raise issues and obtain consensus before proceeding with developing the final products: a set of protocols for estimating the load impacts of DR resources; and a spreadsheet tool for evaluating the cost-effectiveness of DR resources for program and resource planning, with accompanying documentation.

Lessons Learned from California

In designing the framework, the OPA had the advantage of learning from California's experience. Like the California protocols, the OPA protocols are designed for long-term planning and cost-effectiveness analysis. They also retain the focus on what impacts should be estimated and what should be reported in order to facilitate comparisons between DR resources and to allow trained reviewers to assess the accuracy, precision, and robustness of the evaluation methodology.

Unlike California, where DR load impact protocols and cost-effectiveness frameworks were developed through separate working groups and linked and tested post-hoc, OPA designed the various elements of its framework holistically, through a largely internal process. Based on their experience designing the California load impact protocols and later conducting evaluations in accordance with them, FSC recommended that OPA make several adjustments.

First, FSC cautioned against imposing too many requirements in the load impact protocols. In California, an unintended proliferation of outputs has confounded understanding the results. In Ontario, where numerous LDCs may be responsible for following the protocols, OPA felt it was important to ensure that minimum standards were met, while maintaining flexibility for a potentially wide diversity of program designs, enrolments, and LDC evaluation resources.

Second, predicting future program enrollment was separated from load impact estimation. In California, ex ante load impact estimates were required to be produced for all expected future enrollment scenarios. Not only did this contribute to the proliferation of results, but it forced impact evaluators into forecasting the future and added false precision to otherwise robust evaluations. OPA decided that program enrolment was best treated as an exogenous factor, to be assessed as part of resource and/or program planning functions. The load impact protocols thus focused on ensuring that load estimates are produced at a sufficient level of granularity to produce "building blocks" (e.g., impacts by customer characteristics, weather variables, etc.) that could then be used to forecast impacts and cost-effectiveness under varying program enrolment scenarios.

Third, the OPA load impact protocols require that evaluations provide a comparison between actual and regression-predicted customer demand, by temperature and under system peaking conditions, in order to enable non-technical reviewers to assess the accuracy and the validity of the impact evaluations.

Finally, the OPA load impact protocols defined categories of DR options that better fit the types of resources being pursued in Ontario.

A Comprehensive DR Evaluation Framework

A primary goal of the DR evaluation framework is to provide tools to support program planning and to provide inputs to long-term resource planning. Nonetheless, it can also inform a variety of questions that arise throughout the life cycle of a DR resource—including evaluation, operations, settlement, program planning and resource planning. Figure 1 conceptualizes the roles of the load impact protocols and DR cost-effectiveness analysis in these terms.

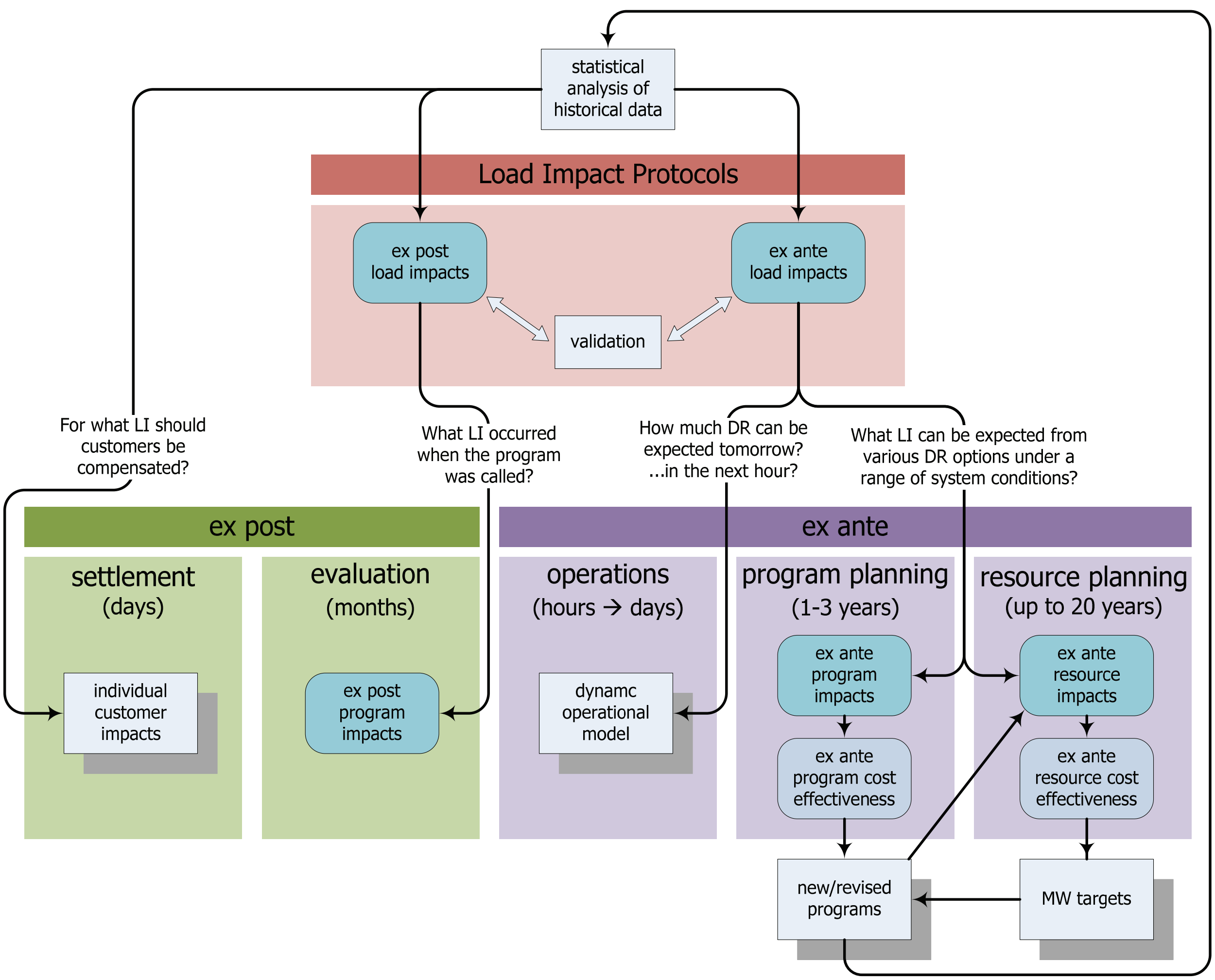

Figure 1. Context and Uses for the DR Evaluation Framework

As Figure 1 suggests, the load impact protocols guide the development of two types of estimates: ex post and ex ante. Ex post load impacts are *reflective*. They describe the past impact of an existing resource option. In other words, they quantify the demand reduction that occurred during a defined historical period, under the conditions that were in effect during that time. Because ex post performance is tied to past conditions such as weather, price levels or system conditions that determine the extent to which resources are needed at the time, the impacts may not reflect the full option value of the DR resource. As such, it would be inappropriate to use ex post impacts to determine DR program cost-effectiveness. Ex post load impact estimation is primarily a means to an end—it is an important step in developing and validating ex ante impact estimates.

Ex ante load impacts are *forward-looking*. They describe the expected load impact under a range of potential conditions of interest, such as extreme weather, high prices or increased program participation. Ex ante load impacts are an important input to DR cost-effectiveness analysis, both for program planning (comparing different DR program designs) and resource planning (comparing archetypal DR options against other conservation and supply resources). For these purposes, ex ante impacts should be based on the extreme conditions for which the system is designed (e.g., 1-in-10 weather year conditions) in order to capture the full option (or insurance) value of DR.

Although the focus of this framework is on ex post evaluation and ex ante estimation for program and resource planning, load impact estimation can also contribute to program operation. Ex ante load impact estimates can form the basis for developing dispatch models to predict, in near-real time, the impact of DR programs as they are activated.

DR program settlement can also be informed by load impact estimation, although the protocols as developed by OPA do not provide direct guidance to do so. Nonetheless, similar methods and data sources can be used to determine how accurately a program's settlement methodology compensates participants for their demand reductions. Going a step further, it may be possible to develop dynamic settlement models based on the same statistical methods (e.g., regression analysis) that are typically used for ex ante impact estimation.

The two principal elements of the OPA framework, the load impact protocols and the cost-effectiveness framework, are discussed in more detail below.

Load Impact Protocols

At its core, evaluating DR load impacts involves estimating the difference between a customer's actual (observed) electricity demand, and the amount of electricity the customer would have used in the absence of the DR program incentive. This latter quantity cannot be observed and must be estimated—it is often referred to as a "reference load." This principle is illustrated in Figure 2 for a particular DR program event.

Because different types of DR programs are exercised differently—for example, a reliability program may only be dispatched during infrequent emergency conditions, while dynamic pricing rates are in effect all the time—or program rules may limit their availability to certain seasons, days of the week, or a maximum number of hours per year; the number of times that a diagram such as Figure 2 could be produced for a given DR resource varies significantly. In the extreme case, an hourly pricing tariff could result in 8760 different "events" per customer and year.

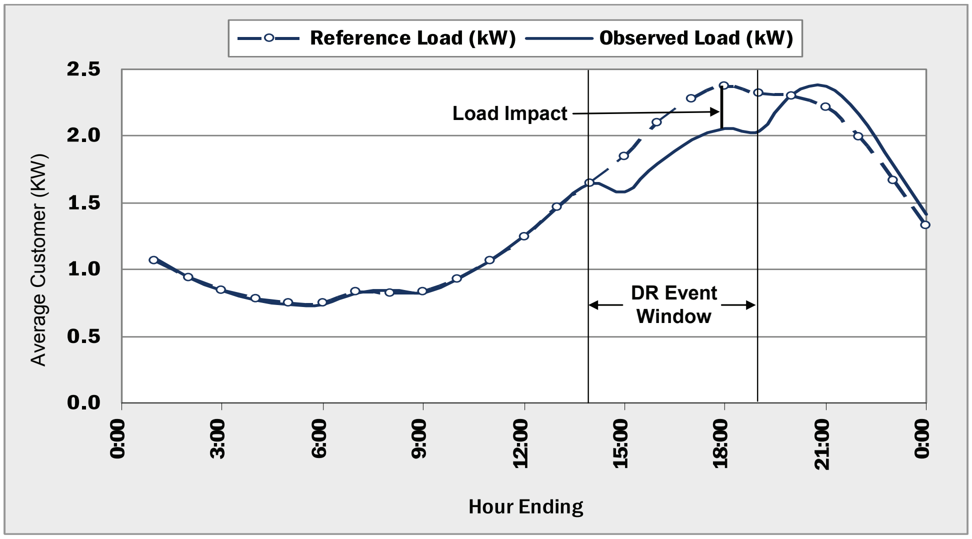

Figure 2. Load Impacts of DR Resources

To keep the results meaningful, DR resources were classified along three characteristics that affect the analytical requirements of load impact estimation: frequency of use, event timing and duration, and number of participants called. From this, four resource categories were developed, reflecting current and prospective DR programs and pricing options in Ontario (see Table 1). The requirements of the ex post load impact protocols were then tailored for each of these resource classifications.

Table 1. Characteristics of DR Resource Options

DR Resource Characteristics	Limited Frequency Resources	Limited Variation Resources	High Frequency Resources	Continuous Use Resources
Frequency of Use	Very Infrequent	Moderate (5 to 25 Days per Year	Very High (25+ Days per Year)	Continuous (Non-event Based Resources)
Variation in Event Timing & Duration	Highly Variable	Little or No Variation	Highly Variable	Not Applicable
Variation in # of Participants Called Across Events	Highly Variable	Little or No Variation	At Discretion of Participant or Market Conditions	None
Examples	Interruptible Rates Emergency Dispatched Load Control (OPA's ***peaksaver*** program)	Critical Peak Pricing Economically Dispatched Load Control	Demand Bidding (OPA's DR-1 program)	Real Time Pricing Static TOU Permanent Load Shifting (OPA's DR-2 program)

Because the protocols were pared down to minimum requirements, the protocol document includes guidance to assist evaluators and program managers in deciding whether and when to undertake incremental evaluation efforts to provide greater granularity of results, or to investigate additional issues that may be of interest. Evaluation issues and methods are also described at a high level to provide guidance to program administrators and evaluators in planning to meet the protocols. More detailed information on statistical methods and sampling issues is provided in appendices.

Each of the protocols is summarized below. At the time of writing, the protocols were in a final draft form but had not yet been formally adopted. Thus, some of the details presented here are subject to change, but the basic structure and concepts are expected to remain unchanged. For more details, see George & Bode (2009).

Protocol 1—Evaluation Planning. Before undertaking a DR load impact evaluation, an evaluation plan must be provided, detailing the methods that will be used to estimate load impacts. In addition, evaluators must identify whether they will estimate ex post impacts, ex ante impacts, or both, and whether and how they will include a number of optional elements identified in the protocol.

Protocol 2—Time Periods. DR load impacts can occur in the hours adjacent to a DR program event "window." For example, customers responding by reducing air conditioner load may pre-cool prior to the event and/or their air conditioner may surge after the event concludes. To account for these effects, this protocol requires that estimates be provided for each hour of the day.

Protocol 3—Reporting Format. This protocol specifies a standardized format for reporting load impacts. For each hour of each day (or day type) reported, the load with and without DR, the load impact, and the temperature must be reported.

Protocol 4—Day Types and Event Conditions. This protocol defines the typology of DR resources shown in Table 1, and specifies the "day types" and event conditions that must be reported for each when estimating ex post and ex ante load impacts (see Table 2). The requirements are designed to simplify the output for programs with large numbers of event days, by providing results on representative day types of interest. Not only does this minimize the reporting burden, but it pares down the results to a manageable level. The final two rows in the table contain requirements designed to assess the validity of the impact estimates.

Protocol 5—Portfolio Analysis. When analyzing the response of customers who are concurrently enrolled in or subject to multiple DR resources, it is important to avoid double counting. In such cases, load impacts should only be counted toward the "dominant" DR resource. This may be specified by program rules. If not, the evaluator must decide which takes precedence and report that assumption.

Protocol 6—Statistical Reporting and Validation. This protocol specifies the statistics and data that must be reported when load impacts are evaluated using regression analysis. This is to enable a knowledgeable reviewer to assess the quality and validity of the analysis underlying the impact estimates.

Protocol 7—Analysis Based on Sampling. For impact evaluations that are based on data from a sample of program participants, this protocol specifies minimum requirements related to the selection of samples and treatment of bias.

Protocol 8—Reporting and Documentation. The last protocol concerns the presentation of results. Reports must contain the following elements: an executive summary; introduction and purpose of study; description of the DR resource(s) contained in the study; study methodology; validity assessment of the study findings; detailed study findings; and recommendations. Additional requirements for the contents of the study methodology, validity assessment and study findings sections are also included in this protocol.

Table 2. Day Types and Event Conditions for which Load Impacts shall be Provided

Purpose	Day Type	Limited Frequency Resources	Limited Variation Resources	High Frequency Resources	Continuous Use Resources
Ex Post Impact Estimation	**Each event day**	Yes (Based on actual # of participants called)	No	No	No
	Average event day	No	Yes (based on day-weighted average # of program participants)	No	No
	Each of top 5 system load days	Already incorporated in each event day requirement	Yes Based on the actual # of participants called for each event		Yes
Ex Ante Impacts	**Average of top 15 system load days—normal weather year**	Yes For time period from noon to 6 pm unless maximum event window is less than 6 hours, in which case use maximum event window ending at 6 pm Assume all participants are called for event-based resources			
	Average of top 15 system load days—extreme weather year	Same as above			
	Monthly system peak day—normal weather year	Yes Only for months during which DR resource is available For time period from noon to 6 pm unless maximum event window is less than 6 hours, in which case use maximum event window ending at 6 pm Assume all participants are called for event-based resources			
	Monthly system peak day—extreme weather year	Same as above			
Validation	**Actual & predicted load by temperature**	Yes Only for months during which DR resource is available For time period from noon to 6 pm unless maximum event window is less than 6 hours, in which case use maximum event window ending at 6 pm Assume all participants are called for event-based resources			
	Actual & predicted load by hour for average of top 15 system load days	Same as above			

Cost-Effectiveness Framework

The second element in the OPA DR framework involves incorporating ex ante load impact protocols into a cost-effectiveness framework. At the time of writing, the cost-effectiveness framework had not been completed as OPA staff was still debating certain elements of the framework. However, the basic questions and concepts were clear.

The central concept behind the proposed cost-effectiveness framework is capturing the option value of demand response. DR provides its greatest value under the extreme conditions for which the electric system is built. Even in years when those conditions do not occur, having DR in effect is like having insurance—just because it was not used does not make it less valuable. As a result, assessing the cost-effectiveness of DR resources is inherently an ex ante process, with DR value assessed under a set of conditions designed to align with system planning. Because DR resources can vary based on the participant mix, weather and other factors, aligning DR resource availability with the system-wide need for resources is a key factor in determining the value of DR.

As with energy efficiency, DR value can be viewed in terms of the avoided cost of supply. For efficiency measures, which are in effect whenever the affected end use is in service, avoided energy is a large portion of this value. However, because DR is typically in effect for only a few hours a year, the majority of its value is derived from avoided generation capacity costs. In local areas, avoided transmission or distribution capacity costs may provide additional value if DR can defer network upgrades.

The total resource cost (TRC) test was determined to be the most relevant benefit/cost measure for the purpose of assessing the cost-effectiveness of DR resources. This is because it assesses whether a DR resource improves economic efficiency by meeting demand at lower cost than the available alternatives. The differential impact of benefits and costs on various stakeholders is an important, secondary consideration, but the TRC is the primary focus and the central output of the spreadsheet tool.

In order to calculate the TRC, it is necessary to determine the avoided cost of the capacity that DR replaces. Since DR is a peaking resource, there is general agreement that the avoided cost should be based on the avoided cost of a single-cycle combustion turbine (SCGT). However, not all DR resources are available in all hours of the year, and many have restrictions on their timing and number of hours of use that do not apply to an SCGT. For example, air conditioner (A/C) cycling programs provide larger load reduction resources as temperatures increase and may not be available at all during the winter months.

Whether and how to calculate the effective capacity of DR to account for this difference has not yet been resolved by OPA. The problem breaks into two components: aligning DR resources with capacity value; and deciding whether to employ load impacts under 1-in-10 or 1-in-2 weather year conditions.

The following methods have been proposed for aligning DR resources with capacity value:

- **Relative loss-of-load probability (LOLP)**—This method allocates the need for capacity across all 8760 hours of the year based on the likelihood of resource shortages, and then overlays the availability of specific DR resources to determine the share of this resource need they capture. This method, which was adopted in California, allows capacity value and load impacts to be linked on an hourly basis, so that different DR resources can be compared against each other. Its disadvantage is a lack of transparency, as LOLP models are complex and not easily understood.
- **Relative expected unserved energy (EUE)**—This method extends the LOLP method to capture not only the probability, but also the severity, of resource shortages.
- **Supply cushion**—The supply cushion, published by the Ontario Independent Electricity System Operator (IESO) is a simple measure of the amount of excess supply available on an hourly basis. It has been proposed as a more transparent alternative to the LOLP and EUE methods of allocating resource need. Its disadvantage is that, unlike LOLP and EUE models, it only reflects relative supply and demand, and does not also incorporate the likelihood of outages, which is determined by factors such as extreme weather events and transmission congestion.
- **Capacity markets**—The outcomes of organized capacity markets provide tangible capacity revenues to DR resources that meet pre-established criteria (e.g., NYISO, PJM). Unlike the previous methods, capacity value and load impacts are not linked on an hourly basis. To date, capacity markets have not been designed to time-differentiate the value of capacity–they assume that capacity value is the same for all months in the auction period. This option

was raised as it is in widespread use, but as Ontario does not currently have such a market, it is not being considered.

- **Judgmental adjustments**—This method involves assigning an adjustment factor to de-rate DR relative to an SCGT. It is simple, but does not differentiate between DR resources, and the adjustment is arbitrary.
- **No adjustment**—A final option is not to de-rate the capacity value at all. The argument has been made that, regardless of how few hours a DR resource is available, in its absence a whole SCGT would need to be constructed to meet the load it reduces. However, this argument is only valid in a system that is at or near capacity limits and where the DR resource is truly able to target the hours needed to prevent the need to build additional peaking capacity.

The weather conditions underling estimated load impacts can have a significant effect on valuation, particularly if the DR resources are weather sensitive. Because sufficient capacity is needed to meet demand during extreme weather years, most jurisdictions, including Ontario, have set reserve margin requirements. In several jurisdictions that have reserve margin requirements, DR is valued on the demand side. The reserve margins reflect the resource hedging in the form of extra capacity needed for the system to withstand extreme conditions. The lower the demand under normal weather year conditions, the lower the amount of resources that must be procured to meet the hedging requirement. Under this construct, the load impact resource value is typically based on normal weather conditions and grossed up for line losses and the reserve margin.

For DR resources that are highly sensitive to temperature, using normal weather year impacts may undercount the resources that are available under extreme weather conditions. For example, for an A/C cycling program, hotter weather leads to more A/C load, increasing the available A/C load reduction resource.[5] Figure 3 illustrates hourly A/C load profiles for a representative utility for the highest system load day and the average summer weekday under 1-in-10 and 1-in-2 year weather conditions. The benefits attributed to this program would vary significantly if the highest-system-day load reduction resources were employed instead of the average-summer-weekday resources. Likewise, the calculated benefits vary significantly if load impact resources available under an extreme weather year are employed instead the resources available under a normal weather year. Depending on the resource, the load impacts under the extreme conditions for which capacity is needed may exceed those from a normal weather year grossed up for reserve margins.

Once the two issues associated with calculating effective capacity have been resolved, FSC will proceed with developing a cost-effectiveness spreadsheet tool. It is intended to screen potential DR options, refine existing programs and provide inputs to resource planning. It will link the available DR resources, which can vary by hour and month, to the capacity value associated with the time periods when they are available using whichever methodology is ultimately adopted. Where available, ex ante load impact estimates based on evaluations of Ontario programs will be fed into it. For options that are new to Ontario, estimates from similar DR resources in other jurisdictions may be borrowed, with adjustments to account for local conditions, until Ontario-specific results become available.

[5] Depending on the cycling strategy, A/C cycling can also be more effective under hotter weather conditions. Not only is there more load to reduce, but the percent load reductions are larger. For simplicity, the example in Figure 3 does not focus on the differences in percent load reductions as a function of temperature.

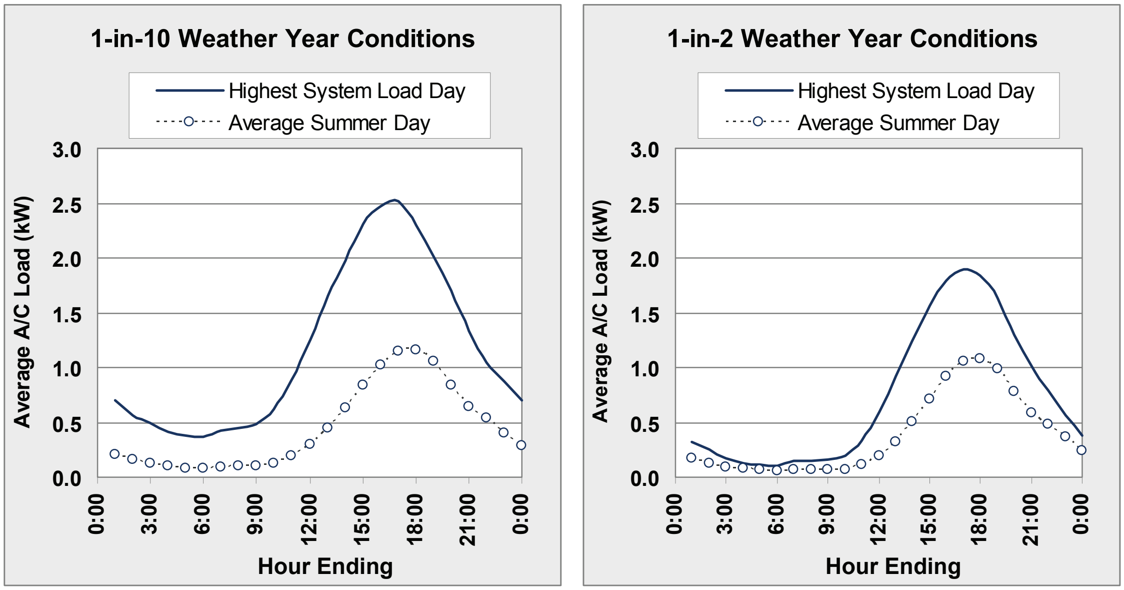

Figure 3. Example Hourly A/C Load Profiles By Weather Year and Day Type

The tool will support sensitivity analysis so that program planners can view the results of changes in enrolment, program designs, and other factors. Because DR resources are highly variable with respect to factors such as weather, customer behavior, enrolment, and avoided costs, explicit recognition of uncertainty is imperative to DR cost-effectiveness analysis. Monte Carlo simulation will be included in the tool so that potential DR options can be compared not only based on average TRC values, but on the likelihood that those values will occur.

Conclusions

The work described in this paper is unique in that load impact estimation and cost effectiveness were developed together in a comprehensive framework designed to capture the option value of DR resources, and to inform program and resource planning decisions through common inputs. The OPA framework owes a great debt to California. Indeed, many elements of it were borrowed from the work done there, but the lessons learned from evaluators, utilities and policymakers as they have gone through their first year of meeting the CPUC load impact protocols were just as valuable.

At the time of writing, the OPA framework had yet to be implemented, so it is too early to assess its usefulness or to tell what lessons might be learned from it. However, as more jurisdictions are expanding their use of DR resources as long-term resource planning increases in prevalence, similar models may be of interest.

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