What Are the Limits of AMI in Supporting Load Management?

EFFICIENCY VERMONT WHITE PAPER

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Introduction

The Efficiency Vermont Triennial Plan 2018-2020 created a pathway for several technology demonstrations to be conducted throughout the plan period. One of the proposed projects in the Plan was a detailed analysis of energy savings from energy efficiency measures, using advanced metering infrastructure (AMI) technology.

The project's purpose was to determine hourly efficiency savings, following completed installations of electrical energy efficiency measures in homes and businesses, to establish the relative value of those measures in supporting grid operations.[1] This paper presents the details of that project and its results.

Specific Aims

The role of AMI technology in determining the effects of energy efficiency on regional grid operations has been widely assumed to be pertinent and useful. However, to date, AMI interval data have not been applied to research projects in such a way as to determine the effects across long periods of time—for example, across a year that contains the longitudinal span of summer and winter peak days and months.

This project sought to explore longitudinal AMI data to better understand the effects of energy efficiency on a regional grid. It also investigated the effects for distribution utilities, to inform future utility planning in a changing energy system and landscape.

Background and Significance

The beginnings of the energy efficiency industry in Vermont coincided with an era in which largely unchecked underlying electrical load growth for energy systems nationwide was a given and renewable energy resources were insignificant. The regulatory intention for early energy efficiency programs was that they be a least-cost, demand-side resource in the baseload power equation. Early program administrators began with project-centric methods relating to business and

residential customer needs. They soon shifted to defining markets with commonly understood energy efficiency needs (for example, residential lighting, manufacturing processes, grocery stores, and multifamily housing), for which they could design

[1] "Using AMI data, Efficiency Vermont will determine hourly efficiency savings in homes and businesses with recently installed efficient electrical equipment. Efficiency Vermont will then analyze this time-linked information in the context of weather data. The aim of this research paper will be to determine which efficiency resources may be most valuable in addressing the grid operator's need to absorb excess supply in times of renewable energy generation and, conversely, to reduce demand when renewable energy is not being supplied." Efficiency Vermont, *Triennial Plan 2018 – 2020.* November 2017: 26. https://www.efficiencyvermont.com/Media/Default/docs/plans-reports-highlights/2018/efficiency-vermont-triennial-plan-2018-2020.pdf

programs and customize projects within those markets. Later, they began to use market transformation principles to reduce energy demand on the customer's side of the meter.

Program administrators' intention, particularly at the outset, was to make these reductions on a scale large enough to incrementally reduce underlying load growth by achieving savings of up to 2 percent of annual retail electricity sales.[2] Regulators and program administrators set annual budgets and program targets, using annual electricity saved (MWh) as the primary quantifiable performance indicator (QPI; as it is referred to in Vermont). Regulators also introduced demand reduction targets (kW) for summer or winter peak periods, and these have since become common QPIs for energy programs nationwide. However, the emphasis on MWh reduction has signaled to energy efficiency program administrators that a kilowatt-hour saved—anywhere, and at any time—was a reliable factor through which program success could be measured.[3]

To achieve these QPIs, energy efficiency programs have relied on only six data points from their gathered data to support their savings and impact claims. Four data points relate to avoided-energy-use (kWh) time periods and two to demand reductions (kW) in peak time periods.

Twenty years after the inception of the nation's first Energy Efficiency Utility in Vermont, the world looks very different: The once steadily rising load growth curve—at least in Vermont, where the statewide energy efficiency program began in 2000—first went negative in 2007[4]; today, it is stagnant, despite increased energy use from the proliferation of consumer electronics and other new uses of electricity.[5] Some utilities have surplus energy supply,[6] which diminishes the short-term value of kWh savings by reducing the associated avoided costs of energy. Renewable portfolio standards and net metering regulations have brought more variable energy resources online. Renewable energy credits, which have provided substantial revenue in recent years, are less lucrative now because of changing trends in how the credits are valued. And peak-related costs can be a significant burden for utilities. In fact, distribution utilities incur a disproportionately high share of their annual costs from only 13 peak demand hours.

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[2] Saving 2 percent of annual retail sales has typically been a target for states with the most aggressive energy efficiency standards

[3] Energy efficiency program targets have evolved over time to include kW peak targets and even geo-targeted kW in some instances, and the avoided cost of energy varies between on- and off-peak times. However, by and large, the primary target for Efficiency Vermont has been an indiscriminate MWh target.

[4] Scudder Parker, Blair Hamilton, and Michael Wickenden. "What Does It Take to Turn Load Growth Negative? A View from the Leading Edge." In *Proceedings of the ACEEE 2008 Summer Study of Energy Efficiency in Buildings.* Washington, DC: American Council for an Energy-Efficient Economy. https://aceee.org/files/proceedings/2008/start.htm.

[5] Analysts frequently project that strategic electrification, especially for transportation and heating end uses, will spur load growth in the future.

[6] Often referred to as being "long on energy," which means the utility has energy contracts to purchase more energy, as measured in kWh, than the customers (ratepayers) will utilize in a given period of time

All of these influences are creating a new reality for energy customers whose costs are driven not simply by how much energy they use but when they use it. To better service customers, energy efficiency portfolio administrators must now better understand, plan, track, and manage programs with an eye toward energy efficiency measures' impacts at certain hours of the day and at certain times of the year.

Methods

This research project drew on a 2017 Efficiency Vermont Research and Development (R+D) project, Testing the Value of Energy Efficiency in the Renewable Ramp Challenge. The 2017 work analyzed energy efficiency measures in new ways to inform the effects of efficiency and renewable (solar) energy on Vermont's statewide load curve at specific hours of the day and specific times of the year.[7] Using the analysis tool created in 2017, the present project expanded the list of measures analyzed. These calculations allowed the R+D team for this project to expand upon the prevailing assumptions for measure impacts, which only focuses on each measure's effects during the summer and winter peak periods set by the regional system operator (RTO), ISO New England.

Efficiency Vermont was unable to access utility AMI data. This constraint was a significant factor from the project's outset. The research team had intended to use the "duck curve" analysis methods for determining the hourly impact of energy efficiency measures with AMI interval data to determine the granular impact of energy efficiency measures within customers' interval data.[8] But this approach was not possible because of Efficiency Vermont's lack of access to utility AMI data in 2018.[9] To overcome this challenge, the project team used data from external sources, and used the assumed hourly impacts of these measures to complete the analysis.

The primary research objective of expanding the 2017 work into a larger 2018 project was to apply what had been an analysis of data with internal uses to an externally facing, real-world situation. To accomplish this objective, Efficiency Vermont partnered with a distribution utility, Washington Electric Cooperative (WEC), to better understand the grid impacts of energy efficiency measures. Efficiency Vermont continues to be grateful for the partnership with WEC on this topic.

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[7] For a visual representation of those effects, in and around the Duck Curve, see the 3-minute video, https://www.youtube.com/watch?v=KwA44fr7apw.

[8] "Interval data" generally refers to energy usage data at a more granular level than typical monthly measurements. Commonly interval data usage is measured in 15-minute or 1-hour intervals

[9] See Vermont Public Utility Commission Investigation 8316, "Investigation to determine the roles and responsibilities of Vermont electric distribution." https://epuc.vermont.gov/?q=node/104/27082.

Approach to the Analysis
First, project staff revisited the current assumptions used to determine the impact of efficiency measures installed via the energy efficiency utilities, to understand if the application of the avoided energy supply cost (AESC)[10] assumptions and the framework used to measure progress toward achievement of quality performance indicators (QPIs) were still aligned in the current energy landscape. A subset of the AESC components consists of:

1. Avoided cost of wholesale energy
2. Avoided cost of transmission
3. Avoided cost of capacity

The Discussion section provides details of the project team's use of available data and other data resources to respond to the research questions, presented in the next section—in the context of the analytical approach. The Analysis section describes the how the data were used.

Research Questions

The following questions were researched through this project"

Are energy efficiency measures delivering impacts at the right time?

- Do specific efficiency measures provide more value to the grid (and society at large), to ratepayers, and to distribution utilities?
- If so, to what extent should efficiency programs target those measures for optimizing grid operations during peak times?
- If not, is it more operationally efficient for a program to concentrate simply on maximizing achievement of MWh savings goals?
- How might efficiency be optimized to incorporate societal, utility, and ratepayer benefits?

Do existing energy efficiency utility tools fully consider the time-value of energy?

- Electricity use: Is it still relevant to calculate the avoided costs of electricity using only four kWh cost periods?
- Capacity: These values are determined by a utility's share of load during the single hour of the year in which the RTO uses the most power. Can hyper-targeting load reduction at this time of ISO New England's annual peak provide additional value?
- Transmission: A utility's network load is assessed at Vermont's monthly peak, using the computation of New England Power Pool (NEPOOL) Open Access Transmission tariff and Vermont Electric Power Company (VELCO) transmission tariff, or Regional Network Service (RNS). Can a targeted

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[10] Synapse Energy Economics, Resource Insight, Les Deman Consulting, North Side Energy, and Sustainable Energy Advantage. 2018. *Avoided Energy Supply Components in New England: 2018 Report*. Cambridge, Mass.: Synapse. https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080.pdf.

Efficiency Vermont effort help minimize a utility's exposure to transmission costs by cost-effectively managing load at monthly peak?
- Distribution: Distribution costs tend to be thought of as fixed. Are there any time-elements that pertain to distribution costs? Is an over-supply of renewable energy not a limiting factor today—as originally hypothesized?

Do some measures have greater impact than others?
- Given what we know about particular energy efficiency measures' abilities to shape customers' load profiles, can specific energy efficiency measures have a more valuable impact than others on peak loads and related costs?

Does renewable energy affect the value of energy efficiency measures?
- To what extent do cost-effective energy efficiency measures provide new, additional value to utilities given what is known about the ability for renewable energy supply to change the shape of load profiles?

Discussion

The project team examined the three AESC components to inform their responses to the research questions. The analysis looks at the components in terms of cost impacts from the wholesale supply level to the grid capacity level.

Avoided Cost of Wholesale Energy
Vermont's State Screening Tool[11] accounts for avoided wholesale energy costs (summer on-peak / summer off-peak / winter on-peak / winter off-peak) by utilizing ISO New England's peak energy cost periods, as shown in Table 1.

Table 1. ISO New England annual peak energy cost periods

Peak type	Hours	Days	Months
Winter peak	7 a.m. – 11 p.m.	Weekdays	October through May
Winter off-peak	11 p.m. – 7 a.m.	Weekdays, and all weekend hours	October through May
Summer peak	7 a.m. – 11 p.m.	Weekdays	June through September
Summer off-peak	11 p.m. – 7 a.m.	Weekdays, and all weekend hours	June through September

These wholesale cost periods are assumed to have been relevant in past years. However, today's fuel mix and changing energy use patterns have altered the economics of wholesale energy prices for ISO New England, and these cost periods

[11] Many years ago, the Vermont Department of Public Service created a cost-effectiveness screening tool for use by the energy efficiency utilities. The Public Utility Commission requires utilities to use this screening tool to determine (and confirm) that measures installed are cost effective.

are largely outdated. Energy efficiency programs are rewarded for measures that have impacts (and avoid costs) during more expensive peak times, but the existing cost periods no longer provide a meaningful delineation between expensive and less expensive time periods. For example, the 2019 estimated avoided wholesale energy costs for the Vermont Zone locational marginal pricing (LMP) are not significantly different between the existing ISO New England time periods, as shown in Table 2.[12] The difference between Summer on-peak and Summer off-peak periods is approximately 25 percent, whereas the difference between the highest peak period (Winter on-peak) and the lowest period (Summer off-peak) is approximately 200 percent.

The colors in Tables 2 through 4 indicate cost levels (red: high; to green: low).

Table 2. Existing kWh AESC periods

Winter on-peak	Winter off-peak
$0.047	$0.038
Summer on-peak	**Summer off-peak**
$0.030	$0.024

More meaningful delineations between cost periods would require allocations of the avoided costs of kWh into the suggested categories in Table 3 and Table 4. Table 3 offers Option 1, in which the cost periods shift to:

- Cold season: December through February, all hours
- Shoulder season: March and November, all hours
- Warm season day: April through October, 8 a.m. – 10 p.m.
- Warm season night: April through October, 10 p.m. – 8 a.m.

Table 3. Option 1: Proposed new AESC periods that contain a shoulder season, and daytime and nighttime distinctions

Cold season	Shoulder season
$0.064	$0.041
Warm months - day	Warm months - night
$0.024	$0.030

Table 4 offers the following alternate cost periods that could be considered:

[12] Note that all hourly costs are from the 2018 AESC forecasts for the locational marginal price of wholesale energy at the Vermont Zone.

- Cold months - sunset: December through March, 6 p.m. – 10 p.m.
- Cold months – non-sunset: December through March, 10 p.m. - 6 p.m.
- Warm months - sunset: April through November, 7 p.m. - 11 p.m.
- Warm months – non-sunset: April through November, 11 p.m. - 7 p.m.

Table 4. Option 2: Proposed new AESC periods that recognize warm and cold months, with day and night distinctions in terms of sunset and non-sunset periods

Cold months - sunset	Cold months – non-sunset
$0.074	$0.056
Warms months - sunset	Warm months - non-sunset
$0.034	$0.028

By attributing avoided costs into more meaningful time periods in screening tools, the energy efficiency utilities (EEUs) would be have goals structured to reduce energy use at the times when wholesale energy is most expensive. For example, using the periods as described in Option 2, the "Winter months - sunset" period has costs that are nearly 300 percent of the "Warm months, non-sunset" costs. These differences would send a clear signal to the EEUs to target the installation of measures that avoid electricity supply costs on expensive winter nights, and to de-emphasize measures that avoid supply costs during relatively inexpensive summer days.

Another way to move toward a more precise valuation of avoided wholesale costs would be to consider using the average hourly value by month—as opposed to the four ISO New England cost avoidance periods. The 288-point chart in Table 5 offers a visual representation of how wholesale energy costs vary over the course of the day (columns), and over the course of each month (rows).

Table 5. The Vermont Zone avoided cost of wholesale energy, showing average hourly LMP by each of 12 months (y-axis)

	Hour of the day											
	1	2	3	4	5	6	7	8	9	10	11	12
1	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.08	0.08	0.08	0.07	0.07
2	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.08	0.08	0.08	0.08	0.08
3	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05
4	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
5	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03
6	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03
7	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03
8	0.03	0.03	0.03	0.02	0.02	0.02	0.03	0.02	0.03	0.03	0.03	0.04
9	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03
10	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
11	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
12	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.04	0.04	0.04

	13	14	15	16	17	18	19	20	21	22	23	24
1	0.07	0.07	0.07	0.07	0.08	0.09	0.10	0.09	0.09	0.07	0.07	0.07
2	0.07	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.09	0.08	0.07	0.07
3	0.05	0.04	0.04	0.04	0.04	0.05	0.06	0.06	0.06	0.05	0.04	0.04
4	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02
5	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
6	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.03
7	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03
8	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03
9	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.03
10	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.03
11	0.03	0.03	0.03	0.03	0.04	0.05	0.05	0.05	0.04	0.04	0.03	0.03
12	0.04	0.04	0.04	0.04	0.05	0.06	0.07	0.06	0.05	0.05	0.04	0.04

Even greater detail on avoided-cost of energy can be achieved with the full-year, 8,760-hour values in the 2018 AESC Report[13] (one value for every hour of the year). Another method for looking at cost periods could consider temperature and time of day, both of which are significant drivers of energy costs, especially on ISO New England summer peak days. Regardless of the method, more granular forecasts of wholesale cost data are readily available, relative to the four categories ISO New England uses. Efficiency Vermont might consider using these data to (1) more accurately track the cost avoidance of efficiency measures and (2) guide efficiency program design in favoring measures whose impact coincides with the times of greater avoided wholesale energy costs.

Locational Element of Avoided Wholesale Energy Costs

The 2018 AESC Report enabled a better understanding of the time value of energy, and the ISO New England database of historical LMP, helped Efficiency Vermont staff understand better how the avoided cost of wholesale energy might differ across locations in Vermont, during the course of a day, and between seasons.

The broad findings from this brief analysis indicate that LMPs were noticeably lower in the northern third of Vermont from January 2016 through June 2018, relative to

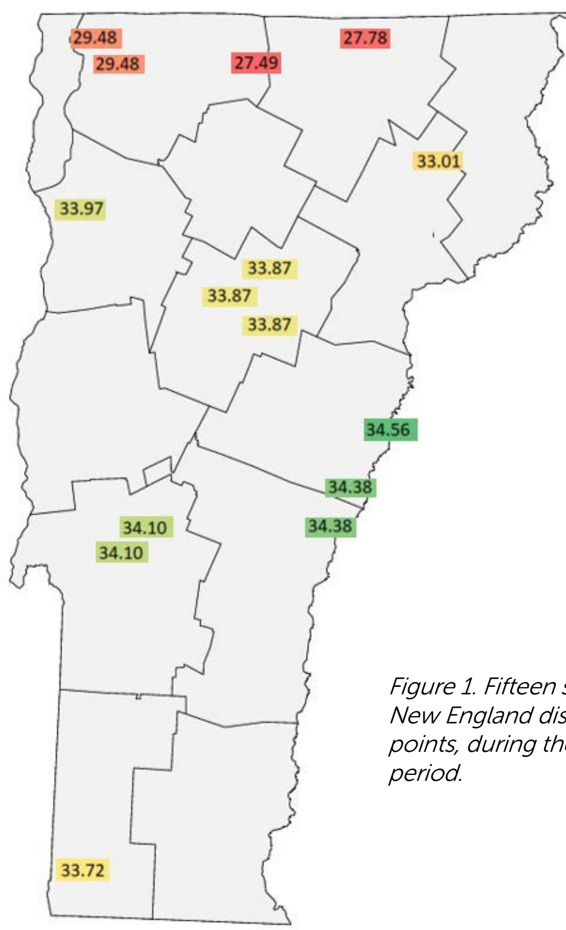


Figure 1. Fifteen selected ISO New England discrete pricing points, during the project period.

[13] Synapse, 2018 AESC Study (https://www.synapse-energy.com/project/aesc-2018-materials)

the Vermont Zone LMP. The northern third of Vermont, known also as the Sheffield Highgate Export Interface (SHEI), experiences significant grid congestion penalties during the winter months. This significantly influences the LMP disparity. The difference in LMPs ranges from approximately 8 to 16 percent lower in the SHEI region compared to the Vermont Zone LMP. Figure 1 shows average LMPs from January 2016 through June 2018 for several selected Vermont ISO New England discrete pricing points, or nodes.[14]

Avoided Cost of Transmission

Calculating avoided costs of transmission is complicated. Attributing a value for avoided transmission costs typically involves using actual costs of recent transmission upgrades as a proxy for avoided costs of future transmission upgrades. The metric does not utilize readily accessible historical cost values as noted above for wholesale energy prices.

Synapse determined that the avoided cost of transmission in New England in 2018 was $94 / kW-year.[15] Further, Synapse found that the average avoided cost of transmission across the country can range from $10/kW-year to $200/kW-year, depending on the region.[16] Transmission costs are generally allocated among the individual parties that benefit from the transmission project. These costs are based on an entity's share of load at a peak hour. In Vermont, distribution utilities commonly pay three different entities for transmission costs:[17] ISO New England; the Vermont transmission organization, VELCO; and, where applicable, the distribution utility, Green Mountain Power (GMP).

It is important to note that it is not typical to count avoided costs associated with past transmission projects when considering societal benefits. A reduction for an entity in one area involves passing these avoided costs off to another entity that is paying its share of the project. This is known as a transfer payment.

Similarly, if all Vermont distribution utilities were to reduce their demand at the time of the ISO New England transmission peak, then the transmission costs avoided by that action would be pushed onto other utilities in New England, netting savings for Vermonters, but not offering much benefit to society at large.

However, the benefit of avoiding the costs associated with future transmission upgrades is undoubtedly societally beneficial (that is, the benefits accrue across all of ISO New England territory). Moreover, although Vermont might not be transmission-constrained just now,[18] the portion of the state's contributions from its energy efficiency utilities to decreasing ISO New England's future transmission costs need to be accurately accounted. VELCO's 2018 Long-Range Transmission Plan forecasts

[14] ISO New England calculates LMPs on more than 70 nodes in Vermont.

[15] Synapse, 2018 AESC Study.

[16] Synapse conducted a general energy profile for VEIC in 2018, which was "based upon nine studies of avoided T&D spending as a result of energy efficiency, and excluding studies with only avoided transmission OR distribution spending."

[17] Generally described as *RNS charges*, or regional network service charges

[18] According to VELCO's *Long-Range Transmission Plan,* 2018.

no immediate need for transmission upgrades. However, that study includes energy efficiency impacts in its projections.

Thus, delineating between avoidance of past and future transmission costs is tantamount to having a better understanding of the true impact of demand-side management on transmission costs.

These transmission costs are allocated each month at the time of a monthly peak for the entity that is using the transmission lines to move power (a "load-serving entity"). For example, a Vermont distribution utility pays ISO New England the utility's share of the total demand at the time of the Vermont monthly peak hour, as transmission costs. The VELCO transmission payments are based on Vermont distribution utilities' share of the statewide demand at Vermont's peak hour of the month. And finally, a Vermont distribution utility, depending on its contract agreements and location, might pay GMP a transmission fee for its demand during the peak hour of the month.

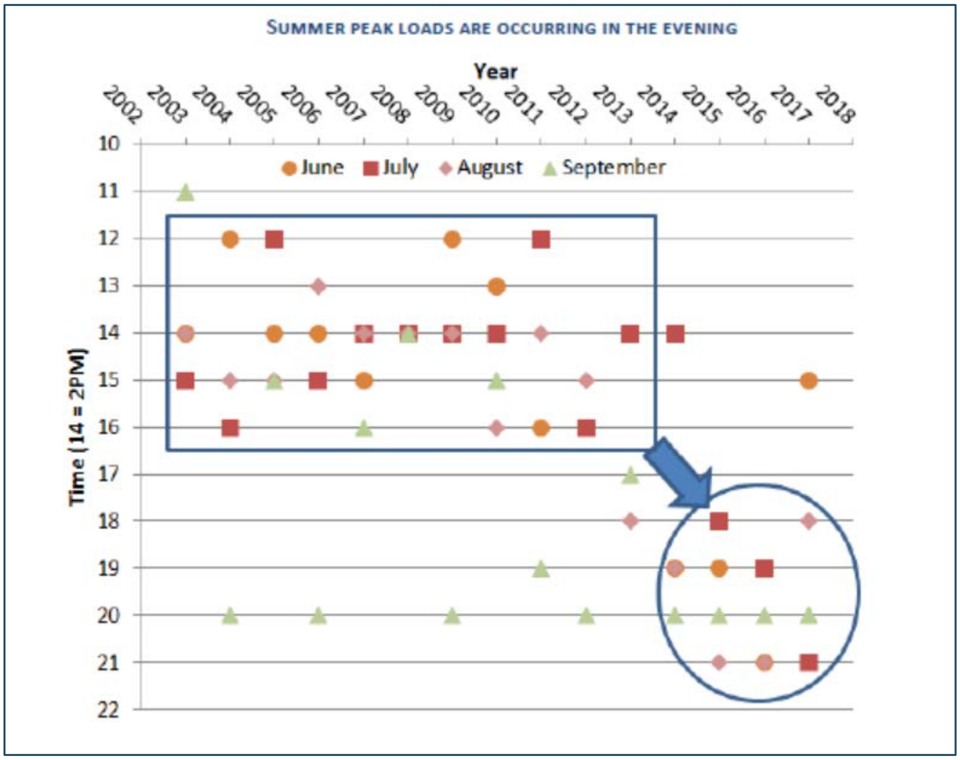
Vermont energy efficiency utilities' avoided costs of transmission are assigned based on the same, simple time periods for defining peak capacity periods. The practice stems from the historical phenomenon of Vermont's peak periods' once closely matching ISO New England's peak periods, also known as generating capacity periods. These are shown in Table 6.

Table 6. Vermont and ISO New England historically aligned peak periods

Generating capacity season	Hours and days	Months
Summer	1 – 5 p.m. Weekdays, non-holiday	June through August
Winter	5 – 7 p.m. Weekdays, non-holiday	December through January

Today, Vermont's transmission costs and associated avoided cost periods do not often match ISO New England's peak periods. Since the mid-2010s, Vermont's peak times, especially in summer, have shifted to later in the day and are now consistently outside the ISO New England peak periods.[19] Figure 2 shows this emerging trend.

[19] VELCO notes that much of this has been cause by the large number of behind-the-meter solar PV installations in Vermont



Source: *VELCO* Long-Range Transmission Plan*, 2018.*

Figure 2. Trend of Vermont's peak periods, 2002 to 2018, showing summertime later-hour peak demand.

Because Vermont's peaks rarely align with ISO New England peaks the avoided costs of local transmission cannot be accurately captured by measuring the kW impacts during the ISO New England peak.

More accurate and granular hourly impact data would (1) better track the impacts of efficiency measures on Vermont's transmission infrastructure, and (2) guide demand-side management program design toward measures whose impact coincide with the times of greater avoided transmission costs in the post-sunset hours.

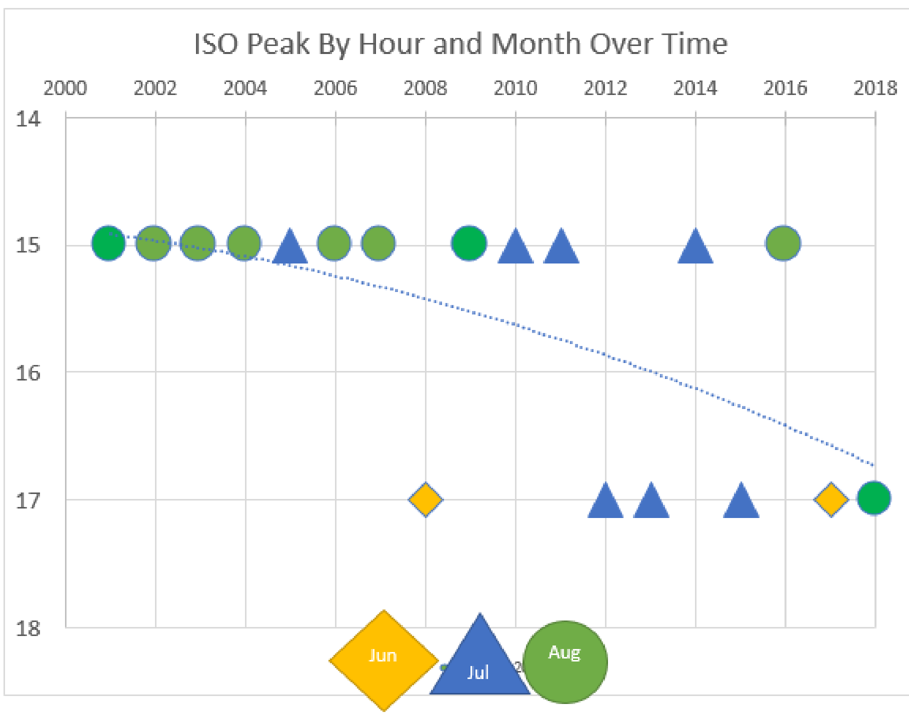
Avoided Cost of Capacity

The effect of energy efficiency on the avoided cost of capacity is measured in kW (as opposed to energy consumption, which is measured in kWh). It can be stated simply as the maximum power demand that a system can withstand, within some limits related to safety and reliability. ISO New England's Forward Capacity Market supports reliable system capacity. Power-producing entities—or, in the case of demand resources, efficiency programs like Efficiency Vermont—bid in their commitments to provide kWs of capacity at a certain date in the future. The costs ISO New England incurs in securing this capacity are then allocated to load-serving entities. The calculation is based on the difference between their existing capacity resources and actual demand at a single hour in which ISO New England experiences its maximum demand during a calendar year.

To account for an energy efficiency utility's avoided costs of capacity, the State Screening Tool uses average kW impact of an efficiency measure across the ISO New England's defined hours of summer generating capacity. Because this single hour in the summer accounts for approximately 15 percent of the operating costs for at least one distribution utility,[20] this single metric is one of the most important in terms of deriving avoided costs.

Although the metric of the "average hourly kW impact between 1 and 5 p.m." might be sufficient to estimate efficiency effects today, the peak period is shifting to later in the day. As described in the Methods section's discussion about the duck curve, as the greater amount of behind-the-meter solar comes online, demand on the grid during daylight hours goes down.

Over the past 10 years, ISO New England's peak times have also been shifting to later in the day, as shown in Figure 3.



Data Source: ISO-NE

Figure 3. Summer peak times throughout all of New England.

"Therein lies a significant challenge, for the energy efficiency industry has developed around only two main metrics to measure impact: the annual kWh saved and the ISO/RTO peak time periods.."

Prioritizing energy efficiency measures that will provide kW reduction at these later peak times will become increasingly important. However, to achieve optimal accuracy about both the measures and their ability to reduce kW during target times, energy efficiency programs and utilities must first be able to measure the efficiency effects with granularity well beyond the standard "average kW reduction" during ISO

[20] Kanarick, Mike, 2017. "Burlington Electric Launches Defeat the Peak Program." Blogpost, June 22. https://www.burlingtonelectric.com/news/111.

New England's nearly outdated peak capacity periods. This will be a significant challenge to the energy efficiency industry. At a minimum, the industry will need to recognize that two main metrics to measure impact - the annual kWh saved and the ISO peak time periods - are insufficient to gain the necessary kind of detailed understanding of measures and impacts to guide program priorities.

The team thus devoted a significant amount of project time to exploring how we might better utilize the hourly value of efficiency measures to propel programs forward in a quickly evolving energy system.

Analysis

Hourly Value of Demand-Side Management

Access to Interval Data

Throughout the course of this project hourly AMI data was unavailable from the distribution utilities for analysis, although the project team had access to a small amount of historical GMP data. From this limited data set, the team built out a few additional measure loadshapes, using pre- and post-installation energy use information to add to the data set created in the 2017 project titled Testing the Value of Energy Efficiency in the Renewable Ramp Challenge. The larger the sample size, the higher the statistical confidence in the effects of individual energy efficiency measures when using customer AMI data. However, there are limits in the type and size of measures that can be discerned from an AMI data set.

Data Reality Check

As noted in the Discussion section relating to AESC information, the energy efficiency industry understands only certain characteristics of impacts from efficiency measures: annual kWh reductions and kW reduction at RTO peak times (related to capacity). These data points do not explain the true impacts of energy efficiency on the grid. Because distribution utility costs are generally incurred from demand at "hour ending X," a loadshape that includes every hour of the year (8,760 hours) might be a logical yardstick by which to measure impacts from efficiency.[21] However, for the sake of simplicity, the team used a 288-point chart, borrowed from the solar industry, to depict more granular impacts. The 288 points represent the weather-normalized, average hourly impact for a day in a given month (that is, 12 months multiplied by 24 hours).

Gathering kW Impact

Because full access to AMI interval data was not possible, the team instead ran a few additional measures through the Duck Curve analysis tool: clothes dryers, clothes

[21] However logical the data sets of 8,760 points seemed to be, the team realized that so many points might be overwhelming. The State Screening Tool uses seven main data points: energy / power: kWh annual, kW summer, kW winter, AESC, kWh summer on / off, and kWh winter on / off. The team reasoned that while more than seven data points would be desirable, the analytic value of meaningful data was likely to diminish well before 8,760.

washers, refrigerators, freezers, cold-climate heat pumps, heat pump water heaters, LED lighting, pool pumps, dehumidifiers, and window air conditioning.

To augment the data, the project team examined a MA Energy Efficiency Advisory Council study,[22] which looked at more than 25 different residential measures and provided a 288-point loadshape for each. The study offered a weather-normalized data set, with average kW per hour by month. The Efficiency Vermont team used other data sets to fill in knowledge gaps. The team also referenced the draft Demand Response Catalog to better understand the hourly impacts of energy efficiency measures with controllable loads.

Testing

The Relevance of Traditional Energy Efficiency and Growing Importance for Strategic Electrification and Flexible Demand

The Efficiency Vermont team knew that it must move beyond academic studies, modeling, and other research sources to collaborating with partners in Vermont. Throughout the project period, the team monitored the ongoing penetration of new energy efficiency measures, the ramping up of beneficial electrification measures and customer-sited solar, and the implementation of controllable loads. The team also examined the extent to which the energy efficiency utilities' tools and metrics did not align well with the needs of the distribution utilities, and considered those differences, as well.

A Willing Distribution Utility Partner

Building on an established relationship with WEC, the Efficiency Vermont project team proposed to address a problem statement identified in the distribution utility's 2017 integrated resource plan (IRP): How to reduce peak-related costs.[23] The project team's approach sought a better understanding of how energy efficiency could be applied differently to address these costs. The hourly value of energy efficiency was front-and-center in this conversation.

Efficiency Vermont first analyzed and then discussed WEC's load profile to understand the factors that drive WEC's peak-related costs. The factors ranged from timing of transmission costs to capacity peak periods, to the time-value of kWh. WEC also helped the project team understand the relative importance of each of these cost factors.

The discussion continued by better understanding the current factors that contribute to WEC's demand during times of peak-related costs. The team initially tried to use AMI data to understand WEC's customer load profiles, but the team had

[22] http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

[23] http://www.washingtonelectric.coop/wp-content/uploads/2011/06/2017-WEC-IRP-draft-July-6-2017.pdf

difficulty extracting AMI data from WEC's databases.[24] So the team used proxies from existing data sets such as the Duck Curve analysis tool, from the recent study in Massachusetts, and from national sources. The project team also deployed Sense™ monitors to access data. These devices can also report information for regulatory measurement and verification (M&V) activity and for efficiency impacts.

Analysis Tool Created

The project team then estimated and modeled the impacts of demand-side management (DSM) measures on WEC's load, revenues, and peak-related costs. Per WEC's request, the Efficiency Vermont team considered all demand-side management options in the analysis: energy efficiency, electrification, and flexible load management. This three-component demand-side management approach reflected the holistic approach that can influence demand behind the meter.

The initial Demand-Side Management Calculator was a prototype Excel tool that allowed the distribution utility to easily see the effects of efficiency measures. It also offered customer impacts. One pitfall of the tool was that it did not include project costs, societal costs, societal benefits, total resource costs, or total resource benefits.[25]

Through the partnership, Efficiency Vermont acquired solid, new information about how distribution utilities are affected by DSM measures. Another significant finding was that a portfolio of measures spanning energy efficiency, demand flexibility, and strategic electrification can help align value for society, utilities, and ratepayers. For example, even with WEC's current position of having more kWh contracted than can be used by their customers (that is, the utility is "long on energy"), there is still a portfolio of demand-side solutions that can result in net benefits for all parties.

Although the energy efficiency utilities in Vermont have been charged with kW-specific, geotargeted goals in the past; and although total resource benefits now constitute the top QPI for the energy efficiency utilities, annual MWh savings targets have long been a top priority for regulators—and therefore for the energy efficiency utilities. But as different DSM measures come online and as grid operator peak periods shift, a more effective, coordinated approach to demand-side management might be possible—and within reach. Nevertheless, the ability to scale measures, to influence markets, to be cost effective, to enable a holistic customer experience, and to be the least-cost carbon lever will require improvements in coordination among all parties involved in Vermont's demand-side management landscape. Small steps might involve truly integrated resource planning, across energy efficiency utility demand resources plans and distribution utilities' integrated resource plans. The

[24] WEC's AMI data are only hourly. This interval might have been sufficient but extracting those data for any significant length of time over a large number of customers was not possible.

[25] These not-included factors offer the same kinds of cost-effectiveness weaknesses as do a utility cost test (UCT) and a ratepayer impact test (RIM)—in contradistinction to the factors captured in a total resource benefit test. It is important to recognize the pitfalls in this basic research calculator. That is, it is not a substitute for a cost-effectiveness screening tool.

planning would also need to involve Tier III (Renewable Energy Standard)[26] considerations to optimize measure portfolios for Vermont.

Conclusions

Findings Relevant to Vermont's Energy Landscape

Efficiency Vermont's AMI load management research project has demonstrated that the energy efficiency community in Vermont and elsewhere has been using outdated tools to determine impacts and associated avoided costs of DSM initiatives. Even without full access to AMI interval data, it is possible for an energy efficiency program to derive more effective uses of efficiency measures in contributing to maximizing societal value from DSM.

Traditional methods for determining energy efficiency metrics—technical reference manuals, deemed savings data, M&V studies, and other types of evaluation—have all been used to assess annual kWh savings and coincident peak kW reductions. It may be neither feasible nor useful to utilize 8,760-hour data sets as a rationale for fully assessing the kW impact of DSM measures. However, there is still room for new and incrementally more detailed data sets.

As some jurisdictions begin to examine the impacts of individual efficiency measures that make up a customer's load profile, the value of this knowledge is beginning to be understood better. AMI interval data have allowed disaggregation of measure impacts across sample sets, as was demonstrated in the first phase of this project. But measuring the effects of individual energy efficiency measures with AMI has proven to be difficult. Using smart home energy monitors can be a promising new way to analyze data and examine interval data as methods for disaggregating customer load profiles in a utility portfolio.

So far, this increased level of precision comes with an increase in cost. Those costs pertain not only to the time it takes to plan for and run analyses, but also to changing how energy efficiency utilities think about data as it pertains to their core business processes. They also apply to the maintenance costs of screening tools and potential cost increases for a regulatory M&V requirement. Such considerations must also be weighed against the alternative cost of doing nothing—that is, of ignoring the changing energy landscape and continuing to do business as usual.

Transmission cost periods might be the low-hanging fruit for editing Vermont's screening tools to be more accurate. But the question remains: Should the energy efficiency utilities' existing QPIs adjust to the impending shifts in grid operator costs related to the fact that peak capacity times are moving to later in the day?[27]

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[26] "Tier III" is the name given to a portion of Vermont 2015 Act 56, which established a renewable energy standard for the state. Tier III refers to a requirement that distribution utilities procure new renewable distributed generation via "energy transformation" projects. https://publicservice.vermont.gov/content/tier-iii-renewable-energy-standard.

[27] ISO New England. 2019. "Energy Security Improvements." ISO Discussion Paper. https://www.iso-ne.com/static-assets/documents/2019/04/a00_iso_discussion_paper_energy_security_improvements.pdf.

The importance of understanding the hourly impacts of DSM measures will likely grow, assuming Vermont continues to pursue the energy savings targets in its Comprehensive Energy Plan. This will especially be the case as the state pursues strategic electrification of transportation and space heating. One can also imagine what might happen to the regional peak magnitude (and timing) and to capacity costs as New England prepares to double the amount of behind-the-meter solar between 2017 and 2023.[28] The equation will shift even further if Vermonters switch to electric vehicles en masse, and if all of those cars were plugged in simultaneously when people return home from work.

Testing a Tool with a Distribution Utility Partner

The Efficiency Vermont project team learned several important lessons in the analysis with WEC. First, much of the peak-related cost pressure that distribution utilities experience is based on 13 peak hours of the year, and the Vermont State Screening Tool does not align well to that reality. Moreover, peak time periods are shifting to later in the day, which might make the efficiency utilities' existing assumptions and analysis irrelevant. Disaggregating a distribution utility's load will require access to individual customers' AMI data, because monthly kWh and peak kW as the only data points are far from sufficient by themselves. Moreover, the data management and analytics necessary to inform program changes from AMI data should not be underestimated.

The DSM Calculator proved that the hourly impact of DSM measures makes it possible to optimize a portfolio of measures to balance competing priorities with the societal benefits that come from EEU measures. The priorities, for example, might be revenue losses from load reduction for a utility that is long on energy. With that said, integrated resource planning across energy industry players can result in greater societal benefit than could have been achieved without distribution-level energy planning. Thus, the cooperation between Efficiency Vermont and WEC demonstrates the importance of understanding the hourly impacts of DSM measures when distributions utilities and energy efficiency utilities are collaborating toward mutually beneficial goals.

The results of this phase of the project have been captured in a WEC presentation, with visualizations of the data and Efficiency Vermont's DSM impact calculations.

This research project has highlighted the need for updates to the State Screening Tool. The tool needs to reflect changes in the energy industry, especially as it pertains to avoided costs of transmission, wholesale energy cost periods, and likely future changes to capacity periods.[29] Screening that considers these changes would allow for more accurate analyses of actual (and forecasted) avoided costs. If any adjustments are made to the tool, it should still retain its ability to enable economic impact analyses on the societal benefits. However, the evolution of energy

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[28] ISO New England, 2018. "Final 2018 PV Forecast." https://www.iso-ne.com/static-assets/documents/2018/04/final-2018-pv-forecast.pdf.

[29] Consideration should also be given to ISO New England's impending winter energy security market: ISO New England, "Energy Security Improvements," 2019.

efficiency, electrification, and flexible load programs offers an opportunity to consider how to optimize societal, utility, and ratepayer benefits.

Finally, Vermont statute requires regulated energy utilities to observe least-cost integrated planning principles[30] in going beyond wholesale energy and energy efficiency. That is, least-cost principles continue to pertain to capacity and transmission costs, which can be best addressed by truly integrated DSM planning for program effectiveness. For example, peak-related costs are becoming increasingly important statewide; tapping Efficiency Vermont's experience in DSM could easily result in greater coordination during planning, and better outcomes, for both energy and capacity contract negotiations.[31]

Future Potential Research Areas as a Result of This Project

A 2019 Efficiency Vermont project will begin to bring hourly value of DSM into day-to-day operations, starting with planning and forecasting.[32] To support this effort, Efficiency Vermont will consider which data and assumptions need to be changed so that the true economic impacts of DSM can be better quantified.

Simultaneously, Efficiency Vermont is working with Sense home energy monitors to enable data analytics that can disaggregate customer load profiles, using very short data intervals. The short-term objective of the project is to identify phantom or "always on" loads that can be reduced to help meet Efficiency Vermont's MWh savings goals. That project is likely to result in a substantial data set outlining the loadshapes of individual measures at sub-minute intervals. As the sample of meters increases into the hundreds, this loadshape repository and the data supporting it will be of great value to this body of research.

Further, the hourly value of energy use encourages the question of the hourly greenhouse gas intensity of energy. This remains an area for further exploration.

Efficiency Vermont staff will use this preliminary research as it pertains to the AESC, to better inform impending avoided costs proceedings with regulators.

[30] Least-cost integrated planning law is found in 30 V.S.A. § 218c, https://legislature.vermont.gov/statutes/section/30/005/00218c.

[31] Nearly every distribution utility in Vermont is rumored to be long on energy in 2018; GMP over-forecasted its capacity needs in May 2018. See tariff filing information in Vermont Public Utility Commission Case No. 18-0974-TF.

[32] This practice could be referred to as "interval data integration."