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# Demand Response of Residential HVAC

Prepared For NEEA:
Christopher Dymond,
Sr. Product Manager

Prepared by:
Rick Huddle, Sr. Associate PE

Cadeo Group
107 SE Washington Street, Suite 450
Portland, OR 97214

Northwest Energy Efficiency Alliance
PHONE
503-688-5400
EMAIL
info@neea.org

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# *Executive Summary*

This report was commissioned by NEEA to understand demand response (DR) potential of residential HVAC equipment and how it's emerging technology team should evaluate and compare new residential HVAC DR technologies with other customer owned DR technologies such as batteries and water heating. It provides a summary of current knowledge, a bibliography of relevant literature, and a simple excel tool that can be used to to compare technologies on an "apples-to- apples" basis.

Residential HVAC plays a significant role in load shed DR programs. Residential HVAC experiences its highest requirements during times of extreme temperatures—the same times at which the grid wants to lower demand. This presents both a challenge and an opportunity. The Northwest Energy Efficiency Alliance (NEEA) currently concentrates on lowering the region's overall energy use. Over the next 5–10 years, however, new regulations, and shifts in grid resources in the Pacific Northwest have pushed utilities to become more interested in managing power demand.

Smart thermostats currently play the biggest role in managing residential HVAC demand in the region; however, integrated controls or equipment sizing have the potential to offer better reductions in power as well as increased customer comfort. Manufacturers are looking for guidance in how to incorporate DR in products.

The three elements to consider when evaluating DR potential are:

- Average demand reduction
- Market size
- Costs

Average demand reduction is a difficult metric to estimate with many factors in play. To address this, the research team has developed a framework that evaluators can use for emerging technologies. Levelized cost of capacity (LCoC) and Cumulative MW are more easily estimated once the average reduction is determined. Plotting LCoC vs. Cumulative MW provides an enlightening comparison of cost and DR benefits.

NEEA has a unique opportunity to assist utilities and influence how DR is incorporated into programs. The research team recommends the following actions:

- Develop an aggregator database
- Develop average load reduction estimates
- Incorporate DR in evaluations for emerging technologies
- Integrated controls guidance—particularly for inverter driven heat pumps
- Support exploration of DR test procedures and metrics

Given the increasing importance and relative newness of DR in the Pacific Northwest, NEEA can help increase its use by providing guidance on the actions above to both utility companies and manufacturers.

# Introduction

The Northwest Energy Efficiency Alliance (NEEA) currently concentrates on lowering the region's overall energy use. Over the next 5–10 years, however, new regulations and shifts in grid resources in the Pacific Northwest have pushed utilities to become more interested in managing power demand.

This report was commissioned by NEEA to understand demand response (DR) potential of residential HVAC equipment and how it's emerging technology team should evaluate and compare new residential HVAC DR technologies with other customer owned DR technologies such as batteries and water heating. It provides a summary of current knowledge, a bibliography of relevant literature, and a simple excel tool that can be used to to compare technologies on an "apples-to-apples" basis.

While other parts of the US (e.g., California, the upper Midwest, and the Northeast) have used DR programs for years, they have not been particularly prominent in the Pacific Northwest. However, with the push for decarbonization, stress on electricity infrastructure is driving the need for flexibility in clean energy use, particularly on the distribution system. Drivers include the supply side, as more electricity is provided by variable renewables; the demand side, with the use of more electric vehicles and vapor-compression heating; and more holistic issues, such as extreme weather and evolving regulatory paradigms. These issues will become only more prominent over the next 10–30 years.

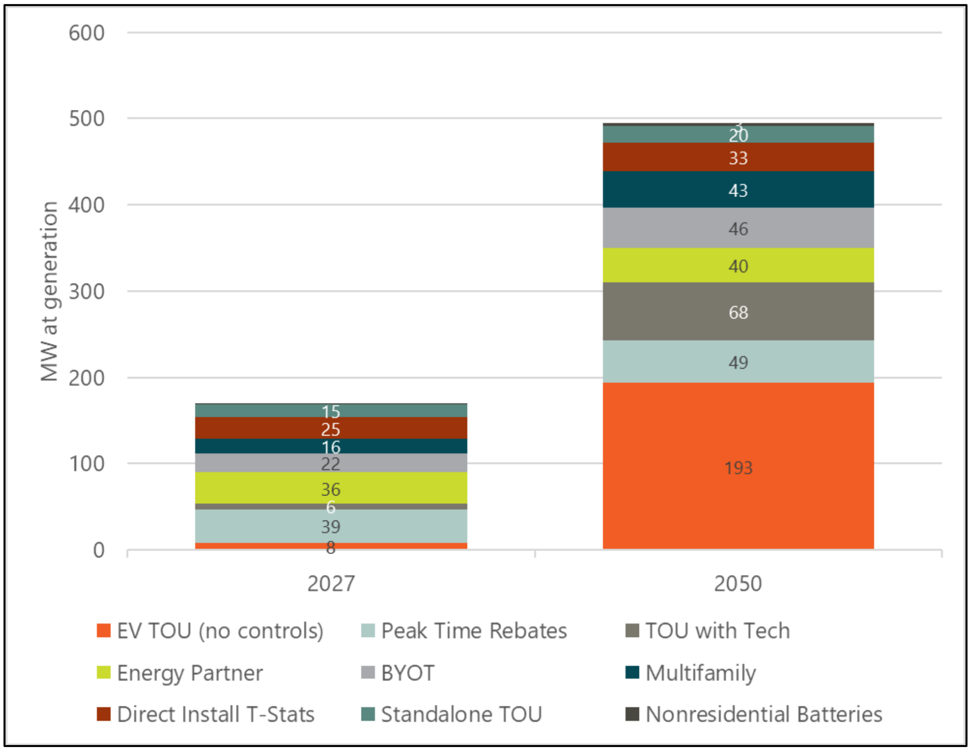
In the Pacific Northwest, both Washington and Oregon have recently passed legislation that requires utilities to incorporate more demand response in their planning. Washington passed the Clean Energy Transformation Act[1] (CETA), and Oregon passed House Bill 2021,[2] each of which requires utilities to plan for and pursue the acquisition of cost-effective DR resources.

[1] https://www.utc.wa.gov/regulated-industries/utilities/energy/conservation-and-renewable-energy-overview/clean-energy-transformation-act/clean-energy-implementation-plans-ceips

[2] https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/HB2021

Pacific Northwest utility companies are already planning how to increase their use of demand response. Portland General Electric (PGE) recently released a report[3] on the expected growth of distributed energy resources, including demand response. Figure 1 shows that PGE predicts summer DR to more than double by 2050. Though this increase will likely be dominated by an electric vehicle (EV) time of use (TOU) program, it also includes large growth in residential HVAC DR through the use of "bring your own thermostat" (BYOT) programs and direct install (DI) thermostat programs.

**Figure 1. PGE Estimated Achievable Summer Demand Response[4]**




[3] https://assets.ctfassets.net/416ywc1laqmd/1sMpwIkeZ0Imb9FuEA7F2i/128e4ffc0bc044f2fde8dcd7cbdc03c6/2021-09-17-pge-der-flex-load-potential-phase1.pdf

[4] https://assets.ctfassets.net/416ywc1laqmd/1sMpwIkeZ0Imb9FuEA7F2i/128e4ffc0bc044f2fde8dcd7cbdc03c6/2021-09-17-pge-der-flex-load-potential-phase1.pdf

Similarly, Puget Sound Energy (PSE) anticipates substantial growth in demand response in the near future. Table 1 shows the PSE Integrated Resource Plan (IRP) to acquire 29 MW of DR in the next three years and an additional 154 MW in the following five years.

**Table 1. PSE 2021 IRP Incremental Resource Additions**

| Resource Additions (MW) | 2022-2025 | 2026-2030 | 2031-2045 | Total |
|---|---|---|---|---|
| Distributed Energy Resources | | | | |
| Demand-side Resources | 256 MW | 360 MW | 1,168 MW | 1,784 MW |
| Battery Energy Storage | 25 MW | 150 MW | 275 MW | 450 MW |
| Solar - ground and rooftop | 80 MW | 150 MW | 450 MW | 680 MW |
| Demand Response | 29 MW | 154 MW | 34 MW | 217 MW |
| DSP Non-Wire Alternatives | 22 MW | 24 MW | 72 MW | 118 MW |
| Total DERs | 412 MW | 838 MW | 1,999 MW | 3,249 MW |
| Renewable Resources | | | | |
| Wind | 400 | 1,000 | 1,850 | 3,250 |
| Solar | - | 400 | 297 | 696 |
| Biomass | - | - | 105 | 105 |
| Renewable + Storage hybrid | - | - | 375 | 375 |
| Total Renewable Resources | 400 MW | 1,400 MW | 2,627 MW | 4,426 MW |
| Flexible Capacity | - | 255 MW | 711 MW | 966 MW |

The **Benefits of Demand Response** section that follows describes DR programs including grid services, benefits, and methods of implementing demand response. Traditionally, DR programs have focused on either peak demand reduction or shaping the daily demand. More recently, other grid services such as the short-term shifting of load and load modulation (e.g., frequency and voltage regulation) have become part of DR program discussions.

The **Demand Response in Residential HVAC** section describes how residential HVAC fits into the DR landscape. Residential HVAC presents some unique challenges as a DR resource, along with some easy wins. For instance, heating and cooling are most needed during the hottest and coldest periods; these are often the times of greatest grid need, limiting the ability of residential HVAC systems to respond during those peaks without adversely affecting customer comfort. On the other hand, smart thermostats present a relatively low-cost DR program that is often popular with customers.

In assessing the landscape of residential HVAC options, we must consider:

- Can other current or emerging residential HVAC technologies provide demand response?
- How do we compare these technologies against thermostats, or against other technologies such as batteries and water heaters?

The **DR Metrics** section discusses metrics to allow comparison of DR potential. For existing technologies, utilities can evaluate DR based on detailed metrics. For emerging technologies, the research team presents a simplified method that provides a high-level, technology-focused metric that can help identify high-potential technologies and screen out technologies early that have limited potential as DR resources.

The last section, **Conclusions and Recommendations,** synthesizes the research in the preceding sections and offers actionable steps for moving forward. The Appendix summarizes recent legislation on the importance and necessity of demand response acquisitions by utility companies.

# ***Benefits of Demand Response***

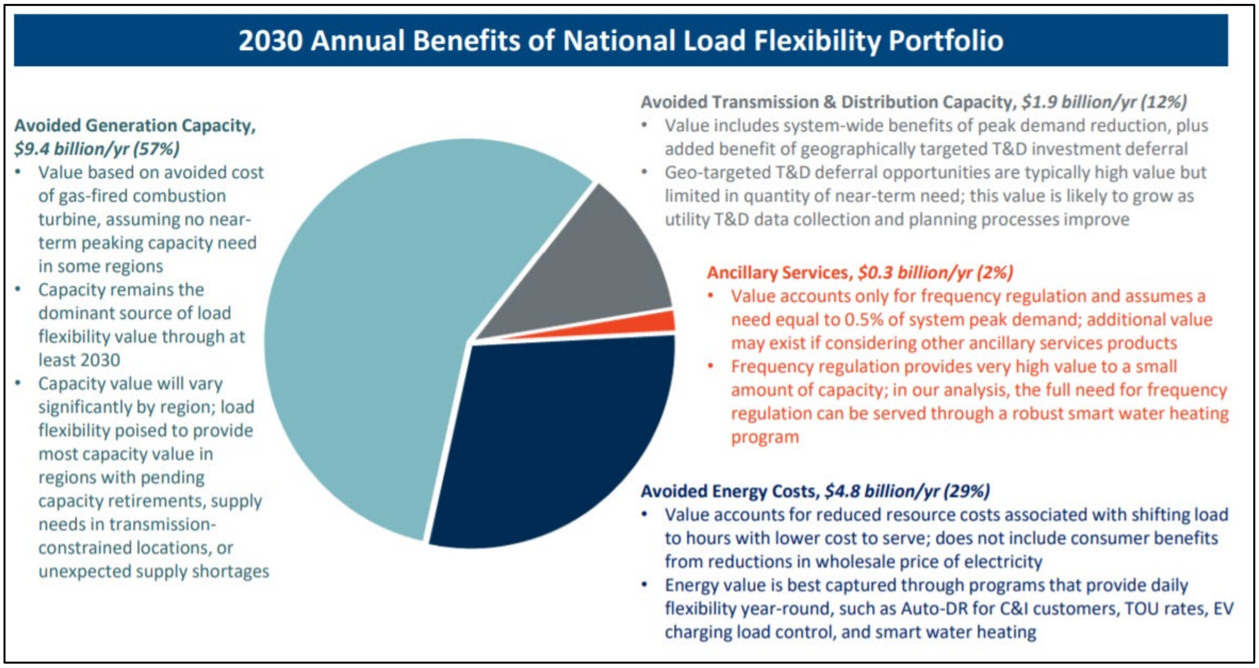
Demand response can be used to achieve various goals based on the unique characteristics of given resources and the context for the party developing the resources (whether a utility, individual customer, or an aggregator). At a high level, demand response is used to achieve the following benefits:

- **Generation capacity**: deferring the cost to build new peaking capacity to meet resource adequacy requirements at the balancing authority or market level
- **Transmission and/or distribution capacity**: deferring the cost to build more transmission and/or distribution infrastructure to meet load
- **Wholesale energy**: reducing the cost to procure/generate energy in the day-ahead, intraday, or imbalance markets to meet load
- **Ancillary services (primary or secondary)**: reducing the cost to procure ancillary services either at wholesale or on distribution such as load following, regulation, or volt-VAR optimization
- **Emissions reduction**: reducing the aggregate greenhouse gas emissions (and resulting costs) resulting from serving load
- **Rate management**: reducing utility bills for customers through time-of-use (TOU) or demand charge management

Examples exist of demand response providing all these values; however, their impacts are certainly not equal and their relative value can vary significantly across utilities, markets, and time. Most DR today focuses on generation capacity and rate management, either through utility programs focused on resource adequacy or aggregator programs in organized markets that focus on co-optimizing capacity and rates for large Commercial & Industrial (C&I) customers. Residential HVAC programs have historically focused almost exclusively on generation capacity, though the growth of residential dynamic rates has contributed to the creation of several programs focused on rate management. Programs such as Nest Renew are also beginning to find ways to use load flexibility to lower carbon impacts by optimizing load to real-time marginal emissions.[5]

In general, the greatest DR value tends to focus on peaking capacity from generation and wholesale energy savings. For example, in its national assessment of the potential for demand response, Brattle[6] estimated roughly 86% of DR value came from these two sources (see Figure 2 below). These benefits coincide with the residential HVAC challenges and opportunities discussed in the **DR Metrics** section.

**Figure 2. National Assessment of Benefits from Demand Response (Brattle)**




[5] https://nestrenew.google.com/welcome/

[6] https://www.brattle.com/wp-content/uploads/2021/05/16639_national_potential_for_load_flexibility_-_final.pdf

Demand response programs, and demand-side management in general, are used to achieve these benefits through a variety of grid services. Different types of DR can be used for different grid services and achieved through different methods. This section reviews four types of grid services and the benefits they provide:

- **Load Reduction**: permanently lowering load either through efficiency or onsite generation. This can provide value in terms of capacity, energy, carbon, and rate management.
- **Load Shed**: reducing load at a specific time in response to a dispatch signal, typically for generation capacity and/or wholesale energy costs
- **Load Shift**: regular or on-demand shifting of energy from one period to another. This can provide value in terms of capacity, energy, carbon, and rate management.
- **Load Modulation**: rapid (sub-minute) oscillation of load to provide ancillary services, typically at the wholesale level

Each of these types of grid services is illustrated in Figure 3 and discussed in detail below.

**Figure 3. Types of Grid Services**

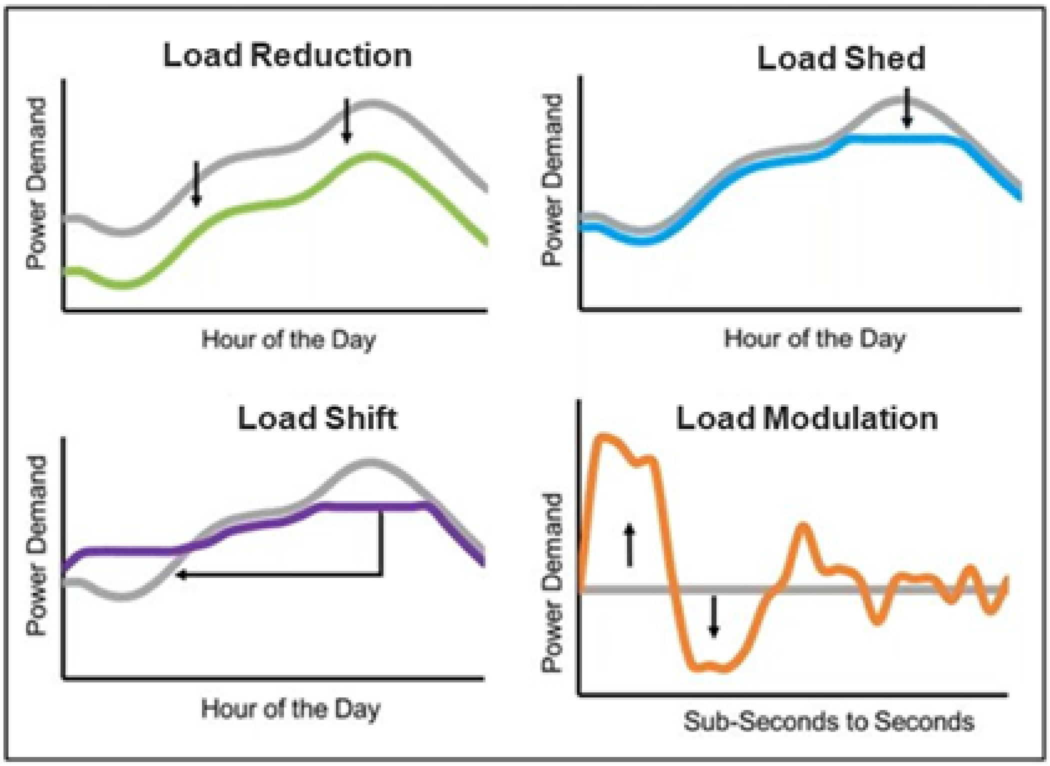
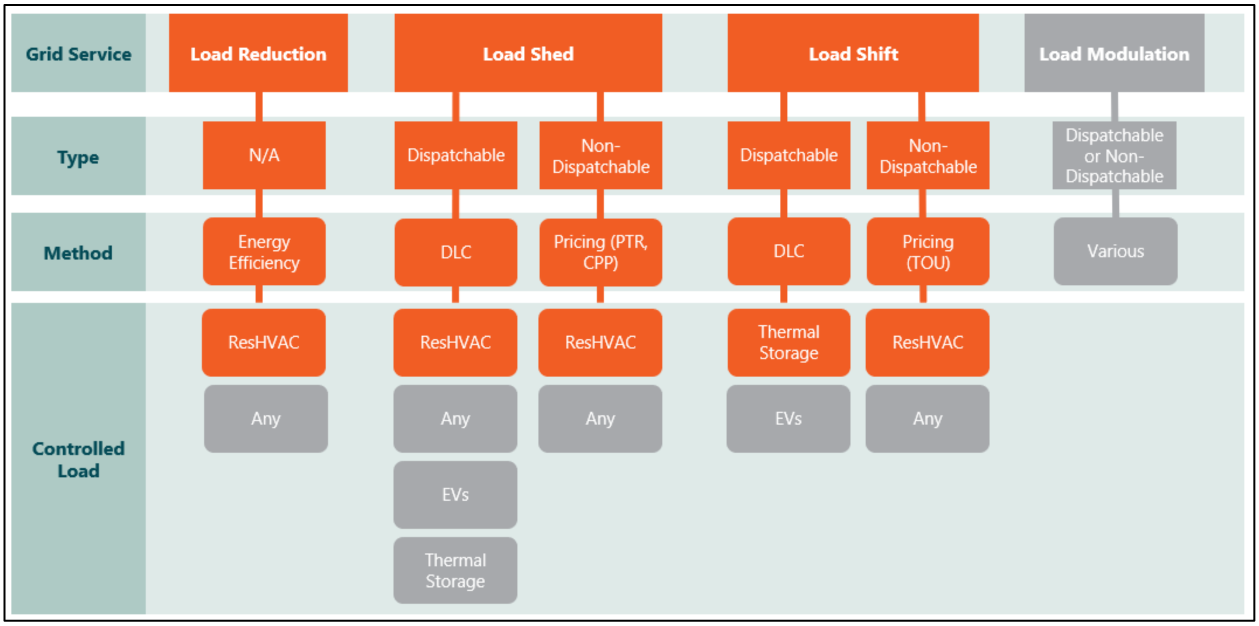



Figure 4 below provides an overview of these benefits along with their associated methods and potential controlled loads. While Figure 4 shows each benefit as a distinct category, in reality, they overlap and are interdependent. For example, load shed may lead to some shift through pre-conditioning of a home. Similarly, storing renewable energy in a battery or water heater may help reduce system peak by shifting load from times of high demand to times of high renewable generation. Some types of DR are dispatchable—that is, they are called by a third party such as a utility or aggregator in a specific demand event—while others are non-dispatchable and operate based on a pre-set schedule or routine. The benefits, types, and methods shown in orange are tied to residential HVAC technologies.

**Figure 4. DR Grid Benefits, Types, Methods, and Loads**




## *Load Reduction: Permanently Reducing Load*

For decades, residential load reduction constituted the primary method for reducing peak demand, largely through utility-funded energy efficiency programs. Load reduction provides value in that it provides a consistent reduction without the need for monitoring or dispatch. It falls short when the peaks shift over time, as observed in California recently with peak periods narrowing and moving to later in the day due to increased rooftop solar penetration (the "duck curve"). Measuring peak impacts can also be difficult at times due to the uncertainty in baselines and lack of interval data in evaluations, though this is improving with the proliferation of advanced metering infrastructure (AMI).

### *Methods*

Load reduction is typically achieved through rebates or market transformation programs on efficient equipment. These resources are typically valued not as operational resources but rather as long-term planning resources for energy and capacity. They are not dispatchable resources in most cases, although some cases of actively-managed assets (such as Nest's Seasonal Savings program or strategic energy management offerings) could potentially adjust their interventions to changing needs over time.

## Load Shed: Targeted Load Curtailment

Load shed is what comes to mind for many people as a conventional DR program and involves lowering peak power demand—typically in an emergency or extreme weather. Utilities or aggregators may need to call for a reduction event a handful of times every summer, every winter, or both. Some utilities have peak in the morning, and others in the afternoon, which can vary seasonally. This type of DR can cause a "shift" in demand through pre-conditioning of a home, snapback, snapback (explained below), or both after a DR event, particularly when working with thermal loads such as residential HVAC. The differentiation with load shift is that the increased load during off-peak times has no value; it is simply a consequence or tool for maximizing demand reductions at peak times.

### Methods

Load shed may be accomplished through either controllable or price-based/behavioral[7] methods. Controllable methods include direct load control (DLC) of residential HVAC, thermostats, or other equipment. Price-based methods use programs such as critical peak pricing (CPP) or peak time rebates (PTR) to influence consumer behavior and incentivize them to manually control their loads at peak times.

## Load Shift: Time Transfer of Load

Load shift is the transfer of loads—either on demand or based on a set schedule—from peak to off-peak periods. In regions with high levels of solar generation, this service may be used over a couple of hours in the morning or late afternoon when solar production is changing quickly. In regions with large amounts of wind power, load shift is called upon if the timing of a forecasted change in the wind speed is off by an hour or two.[8] Load shifting can be implemented on an as-needed basis in response to, for the most part, changes in supply resources or on a daily basis to more permanently change the shape of the load. Daily load shifting can often be implemented without even maintaining connectivity to a central control center through either

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[7] Controllable assets are also referred to as “firm” and price-based/behavioral are referred to as “non-firm.” Furthermore, pricing can be non-dispatchable (TOU) or dispatchable (CPP/PTR) but is always non-firm. Similarly, firm resources can be dispatchable (DLC switches) or non-dispatchable (water heater on a timer). Dispatchable refers to being “called” based on an event. Firm refers to actual control of a load.

[8] https://gmlc.doe.gov/sites/default/files/resources/Recommended%20Practice%20Grid%20Services%20from%20Devices%20Ch%201-2_0.pdf

timers or autonomous controls. This is often done to manage against time of use periods (typically 3–5 hours) or demand charges (typically 15 minutes to 2 hours).

### *Methods*

Load shift is typically accomplished through end uses or technologies with some form of storage, such as batteries, electric vehicles, pumping, or thermal energy storage. Thermal storage can come from a variety of sources including phase change materials, water heating, or ice storage. Daily shifting is affected by rates, often using energy storage and/or behavioral campaigns, though cases that use thermostats and other direct load control devices are emerging.

## *Load Modulation: Ancillary Services*

Modulation is a catch-all term for various grid benefits associated with ancillary services. This type of demand response could be called for a multitude of reasons: frequency regulation, voltage regulation, spinning reserve, or artificial inertia.[9]

Frequency regulation involves maintaining the grid frequency within an acceptable range. This may require a fast regulation, where imbalances are measured in one minute or less, or slow regulation, where the imbalance occurs within 10–15 minutes.

Voltage regulation manages the grid voltage in either a fast or slow response. This newer type of service is driven by distribution-connected solar generation, in which rapid changes in the power output can occur due to crossing cloud fronts.

Spinning reserve is a quickly deployable asset that can reduce the net load until standby generators can come online (typically 15–30 minutes.)

Artificial inertia is engaged when grid frequency drops rapidly (within ~ one second). This may happen when a large grid asset (power plant or transmission line) suddenly and unexpectedly drops offline.

[9] https://gmlc.doe.gov/sites/default/files/resources/Recommended%20Practice%20Grid%20Services%20from%20Devices%20Ch%201-2_0.pdf

### *Methods*

This load modulation type of DR is in development. It could be inherent in a piece of equipment and be non-dispatchable (such as smart inverters under IEEE 1547-2018) or it could be a piece of equipment and be dispatchable. Most cases in practice have involved inverter-based resources, such as batteries. Pilot cases with loads have typically used end uses such as grid-interactive water heaters or advanced motor controls. Most likely, residential HVAC will not provide this type of DR.

# Demand Response in Residential HVAC

This section first discusses considerations specific to DR in residential HVAC, then reviews technical solutions and their relative merits.

## Special Considerations for Residential HVAC DR

Residential HVAC possesses some unique considerations with regard to demand response. Unlike batteries or thermal energy storage (TES), residential HVAC is constrained by the time-dependent nature of customer needs for thermal comfort. Residential HVAC is most needed at the times when the grid most often needs to reduce demand—at summer and winter extreme temperatures. Indeed, HVAC (both residential and commercial) is often the driver of system peak needs.[10] Though this is a constraint, it can also be an opportunity, as changes in the residential HVAC load during those peak times will have direct and substantial impacts on system peak.

In addition, the "thermal storage" system for residential HVAC is obvious and directly related to customer satisfaction; that is, any change in thermostat setpoints or HVAC operation will be felt by the customer in a short period of time (on the order of hours, if the home is occupied). This is in contrast to batteries and water heaters, for which the storage resource is more "invisible" to the customer. As such, carefully managing the residential HVAC "thermal resource"—or internal temperature of the conditioned space—is one of the critical aspects of effectively using residential HVAC as a DR technology. Some aspects to consider when understanding DR for residential HVAC related to managing the inherent "thermal storage" include:

- **Pre-conditioning**. Adjusting the setpoint of the system prior to an event (up for heating or down for cooling) can help mitigate the customer impact (and therefore reduce the likelihood of opt-outs) by increasing the potential thermal ride-through of the space.

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[10] Sometimes need is based on market dynamics or transmission/generation outages (e.g., wildfires.)

- **Snapback**. An increase in load may occur immediately following an event as the system recovers back to the original setpoint or operating mode.
- **Opt-out**. Customers may not even participate in an event due to factors such as customer overrides or loss of connectivity.
- **Weatherization**. A more effective envelope reduces losses in the building, thereby increasing its thermal storage.

Each of these elements is discussed in more detail below.

### *Pre-conditioning*

Pre-conditioning is not universal but is most commonly used with smart thermostats or integrated controls. The home setpoint is changed to pre-condition the home and let it "ride through" the demand event. In summer, it will be cooled below the normal home setpoint, and in winter, it will be heated above the setpoint just prior to the DR event. While this may allow the home to stay conditioned throughout the event, some homeowners may find the setpoint change uncomfortable and may opt-out of the event before it even begins.

### *Snapback*

Snapback is the "extra" energy use that happens after a demand event. Demand will typically increase for a short period to re-condition the home back to the normal setpoint. If not managed with large-scale resources, this could lead to simply shifting the peak to later in the day. More advanced approaches to DR will use duty cycling or a transitional setpoint to "feather" snapback, smoothing out spikes in post-event demand.

### *Opt-out*

Impact on the customer is a critical component of DR programs. A poor customer experience can lead to high opt-out levels, program defections, or both, reducing overall load potential. While a more aggressive control strategy may lead to larger reductions in theory, an inherent trade-off exists between more aggressive strategies and the opt-out rate, which could offset any gains.

Opt-outs can occur for a variety of reasons, the two most common being customer override and loss of connectivity. Opt-outs are a reality for any dispatchable resource but are of particular concern for residential HVAC where customers are more aware of the end use, and where controls often rely on customer Wi-Fi to maintain a connection to the utility or aggregator.

Customers may override the DR call at any time and may do so because of discomfort, unwillingness, or even confusion about the event. Discomfort may come from lack of HVAC during the event and/or from the pre-conditioning.[11] Overrides can be a good indicator of the customer impact and/or awareness of an event. Programs can also reduce opt-out through more education and explanation of the event process.

Dispatchable resources may also lose communication connection and therefore opt-out by default. Some connection methods are considered more reliable than others. Wi-Fi connections for thermostats are relatively stable, depending on a homeowner's service and engagement with the device, but are largely out of the control of the utility or aggregator. Consumers are more likely to interact with the thermostat than with some other equipment (compressors, heat pumps, water heaters) and are more invested in keeping thermostats online. CTA-2045 opens up a wider range of radio pathways, such as cellular or utility-owned bandwidth, which may improve connectivity in some cases.

### *Weatherization*

The best way to improve the inherent thermal storage of a home and minimize pre-conditioning, snapback, and opt-outs is to improve the thermal resistance of homes via weatherization. In general, most homes do not have significant thermal storage, but weatherization can improve DR performance by decreasing the rate at which homes lose heat allowing them to "ride through" load shed and shift events with less impact on internal temperatures.

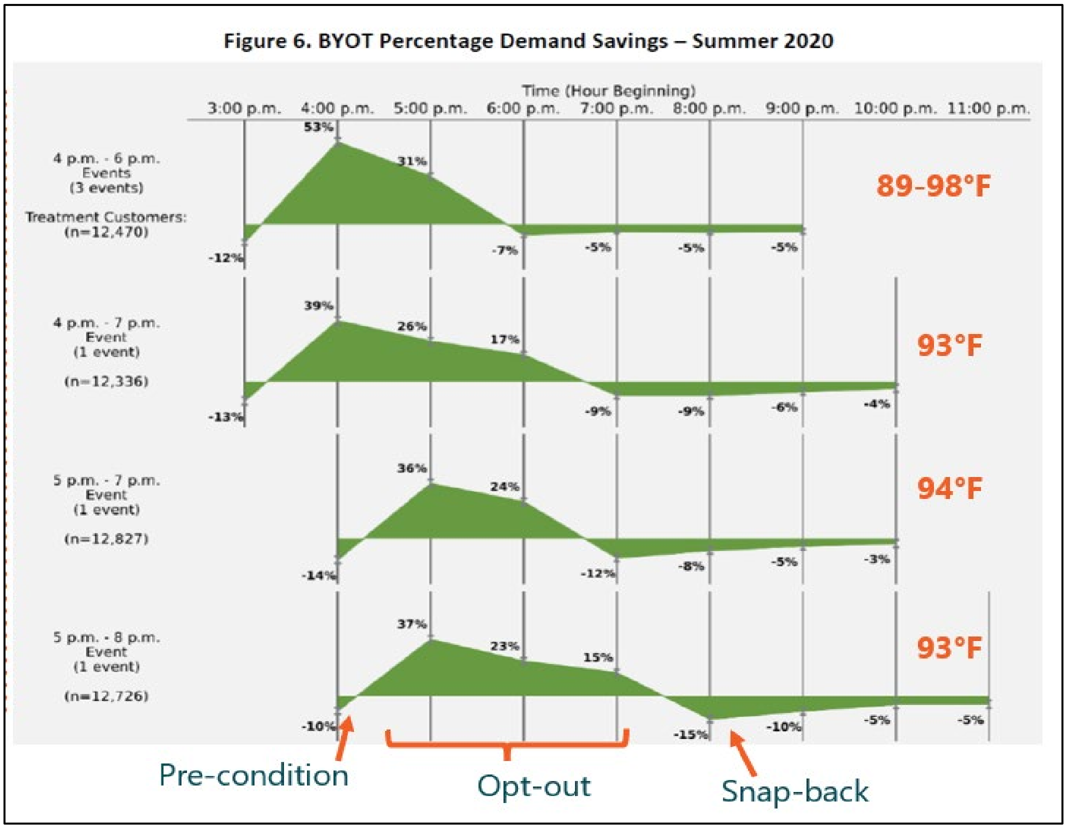
### *Illustration of Impacts*

Figure 5 below provides an empirical example of pre-conditioning and snapback in practice from PGE's BYOT program. Four different events are shown, all on summer afternoons, with different

[11] Pre-conditioning setpoints could be changed 4°F–7°F from non-event setpoint, depending on the programming and event type (shed or emergency).

durations. Before each event, the thermostat's pre-conditioning causes an increased load of 10–14%. Initial savings range from 36–53%, but as thermostats opt-out, the savings drop. After each event, load snaps back and increases from 7–15%.

**Figure 5. PGE BYOT Savings—Summer 2020[12]**




*Note:* Temperatures, Pre-condition, Opt-out, and Snapback labels added by Cadeo.

12 https://edocs.puc.state.or.us/efdocs/HAD/um1708had165015.pdf

## *DR Approaches in Residential HVAC*

Several methods of direct load control exist for residential HVAC, including: relays, smart thermostats, integrated controls, and thermal energy storage. Each method has its benefits and drawbacks, which are explored in greater detail below.

### *Relays*

Relay switches have been in use for decades by utilities and aggregators and make up a large share of residential HVAC DR across the country. Relays are switches used to cycle compressors of central AC or HP units. Relays offer several advantages, including:

- **Relatively low cost**: relays are affordable due to their simple components and lack of expensive chipsets for controls or communications.
- **Easy installation**: relays can be installed on the outdoor compressor without entering the home, making the process much more seamless.
- **Simple and inexpensive communications**: relays typically rely on low-cost one-way networks such as pager networks, 3G, or utility bandwidth.

During an event, the utility sends a signal for the units to either fully curtail or operate on a set duty cycle. Rarely do these relays provide a return signal, so operational visibility often occurs using meters at the feeder head or some other aggregate metering (more modern meters sometimes include two-way connections, though they incur greater cost).

The disadvantages of this approach are:

- **No thermostatic control**: given that the control is simply switching power on and off to the compressor, managing thermal comfort, pre-conditioning, or shifting load are not possible with this approach.
- **Poor visibility**: these programs typically only use one-way controls, and where they *do* have two-way monitoring, it is only on the power draw for the compressor (not anything on setpoint, operating mode, or indoor air temperature).
- **Poor customer experience**: given that the controls for this approach are only curtailment, such that customers sometimes don't even know when an event is happening, comfort and satisfaction can be affected.

- **Potential wear on compressors**: continually cycling compressors on and off can accelerate the need for repairs on outdoor units.

## *Smart Thermostats*

Smart thermostats, a more recent addition to utility DR programs, have grown to be one of the most popular among consumers and utilities. Utilities initially offered them to provide energy savings—mostly through automatic scheduling—but their Wi-Fi connections render them easily adapted to DR.

Smart thermostats provide benefits beyond DR participation, such as bill savings and smart features (occupancy sensing, auto-scheduling, etc.). These features have led to a large base of consumer purchased smart thermostats being leveraged by utility programs. These " BYOT programs generally rely on the thermostat manufacturer or a third party to aggregate the demand response value of the thermostat for the utility. For situations in which smart thermostats aren't already in place, direct install or digital marketplaces can be effective channels to co-market efficiency and demand response to customers.

From a DR perspective, smart thermostats offer many benefits over relay controls. They allow an adjustment to setpoint, vs. direct cycling of equipment. This allows the HVAC system to provide some comfort without the utility company guessing when to cycle a relay. By design, the devices have two-way controls through a dedicated communications pathway: the customer's home Wi-Fi network. While connectivity can be an issue, leading brands such as Nest or ecobee typically have reliable uptimes due to effective digital engagement.[13] For heat pumps, thermostats can also be used to manage the operating mode and stages of the compressor. These enhanced capabilities and reliable connectivity enable HVAC to provide a wide range of services, including load reduction, shed, and shift. Smart thermostats also generally comply with OpenADR as well (given its requirement in the ENERGY STAR[14] spec and Title 24[15]), lowering the cost to integrate into utility/aggregator offerings.

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[13] This contrasts with the use of Wi-Fi for devices such as water heaters or pool pumps, where connectivity can be an issue due to locations distant from routers and low user engagement with the end use equipment.

[14] https://www.energystar.gov/sites/default/files/asset/document/FinalSHEMSFAQs4EEEPS.pdf

[15] https://www.openadr.org/index.php?option=com_content&view=article&id=81:openadr-and-title-

Smart thermostats do have a few drawbacks. First, most brands only offer low-voltage controls of ducted systems, limiting these to HVAC systems with central AC, single or two-stage air source heat pumps, and central furnaces. While these comprise most single-family homes, it excludes much of the multifamily segment and rural electrically-heated homes that often rely on zonal heating. Smart thermostats also aren't compatible with advanced HVAC systems that rely on proprietary digital controls commonly found in variable speed heat pumps (VSHPs[16]).

## *Integrated Controls*

Integrated controls for DR are a newer technology that allows a utility (or third-party aggregator) to connect directly to end use equipment. This could be done directly with manufacturer-specific connections or through open protocols such as CTA-2045 that provide a modular communications device. In either case, these controls can then be integrated using OpenADR in the cloud back to a utility or aggregator control system. This approach, outlined in AHRI 1380 for VSHP,[17] can also be applied to a broader set of technologies. It also enables controls to access more nuanced functionality not available to a thermostat, such as the power draw from a compressor in a VSHP. Cases using CTA-2045 offer the potential to leverage a broader set of radio pathways, obviating reliance on customer Wi-Fi. These factors may also reduce the amount of opt-out from comfort or connectivity issues. In sum, integrated controls allow for potentially the widest range of applications across segments and system configurations, with modular communications pathways using open protocols.

In terms of shortcomings, this approach relies either on broader adoption of CTA-2045 or puts the onus on the manufacturer to develop the hardware, firmware, and software required to enable this functionality. While CTA-2045 is becoming common with water heaters, at least one VSHP manufacturer[18] also offers integrated DR through a CTA-2045 device.

Integrated controls for VSHP units present a compelling long-term opportunity for utilities or aggregators. They have the potential to keep the homeowner more comfortable during a demand event and theoretically to provide a lower opt-out rate. In addition, extended capacity

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[16] Variable speed heat pumps are synonymous with variable capacity heat pumps (VCHPs)

[17] https://www.ahrinet.org/App_Content/ahri/files/STANDARDS/AHRI/AHRI_Standard_1380_I-P_2019.pdf

[18] Mitsubishi. See https://www.openadr.org/assets/OADR_CTA2045_Overview%20Webinar.pdf

VSHPs provide an extra benefit to the grid and homeowner at extreme temperatures through load reduction (inherent decreases in demand) during winter heating peaks. They provide higher-efficiency vapor-compression heating at lower temperatures, which can potentially limit or eliminate the use of back-up resistance heat during winter peaks. The incremental costs of integrated DR are very small when compared to the unit cost.

That said, manufacturers need clearer guidance on integrating these types of controls. Currently, they could provide DR through proprietary means or through an open protocol. The unit could also respond to demand events in several ways. Utilities or aggregators offering a united preference on communication protocols and DR functionality might help manufacturers invest wisely in a method that can be used nationwide.

### *Thermal Storage*

Thermal energy storage systems use some storage medium (ceramic tiles, water, refrigerant, phase change materials) to store energy for multiple hours each day to smooth peaks for rate management, demand response programs, or both. Though these systems are more common in commercial buildings in regions with large demand charges or peak-to-off-peak spreads, examples also occur in residential use. Established manufacturers such as Steffes or Thule Energy Storage provide solutions for both heating and cooling, though few products offer storage in both seasons. Emerging players in the space are providing new solutions that combine heat pumps with a storage medium, but applications are still nascent.

Thermal energy storage is potentially the most versatile resource in residential HVAC, theoretically capable of providing all required grid services. While connectivity could be managed in a number of ways, proprietary controls coupled with OpenADR is the most likely approach in the near term.

The primary disadvantages of thermal energy storage are the lack of available products and their relatively high upfront cost. Given that thermal energy storage offers no benefits to the end user (absent a utility program or dynamic rate), a compelling value proposition for the customer is generally lacking. Thermal storage has typically been much more costly to utilities and aggregators than has more traditional DR, making it difficult to justify the investment. That said, given the growing need for flexibility and the tremendous potential, if costs can be brought down, the U.S. Department of Energy and other agencies are investing significantly in R&D to help transform this market.

# DR Metrics

As with energy efficiency metrics, DR potential can be assessed on a technology-specific level or at a program or market level. The technology-specific level can describe the "technical potential" of a given technology, considering the potential reduction from an individual device and the potential market size of enabled devices. However, DR differs from energy efficiency in some important ways that make direct analogies with metrics difficult.

First, even the "technical potential" of the equipment or device itself must consider much more than the traditional energy efficiency paradigm. Specifically, for a DR measure, one must consider both the equipment and the controls to fully understand the impact of the technology. In addition, the ongoing active control of the equipment is almost always performed by a separate party other than the equipment manufacturer. A third party may even enter in, as the controls manufacturer may themselves not dictate the control approach. This differs from the energy efficiency realm, which typically only considers the equipment. For example, the technical potential of a smart thermostat DR offering will be a function of the HVAC equipment that the thermostat is controlling, the thermostat chosen, and the selection of the control software to dispatch the thermostats themselves.

Further, for DR technologies, program dynamics, interactive effects, and event parameters strongly influence what a population of enabled devices can actually achieve. These factors must be considered in order to accurately reflect the likely DR impact of a given device, much more so than for traditional energy efficiency measures. Factors that require consideration for DR technologies and programs include:

- **Behavioral impacts**: In DR programs that involve shifting or shedding loads, the impact to and perceptions from participating customers will have an undue influence on the expected DR potential.
- **Connectivity and interoperability**: Different communication protocols and physical communication pathways have widely different reliability and control capabilities, thus affecting the expected DR potential.

- **Influence of control strategy**: HVAC can be controlled in a number of ways, optimized more or less effectively at the device or fleet level, and may or may not consider customer impacts. Implementation of this optimization is a function of both the firmware embedded in devices and the software used to control said devices.
- **Program design**: A given program will select how to notify a participant (if at all), how many events to call, and when. All of these factors substantially influence the expected impacts of a given DR measure.
- **Event parameters**: The notification window and event length are important factors due not only to behavior, but also to the ability for control schemes to incorporate pre-conditioning or manage snapback.
- **Rare events**: Dispatchable DR is often called under extreme conditions, which lead to highly variable conditions and difficult-to-measure data. This greatly increases the difficulty of generating robust ex ante estimates.
- **Customer overrides**: All the factors discussed above influence the ability and decision to override an event. Overrides are a very important factor to consider, and yet only a small portion of what drives them comes from the equipment itself.

Because of the complex and interrelated nature of assessing the impact of DR measures, current approaches to evaluate DR potential are based primarily on evaluation data of pilot programs. While valuable, such pilot data are not useful for emerging technologies that may not yet be employed in programs or have available data. As such, for scanning purposes, the research team has developed an approach to estimate DR potential from emerging technologies based on default assumptions for participation information. This is also an active area of study.[19] In the future, more robust test procedures and metrics currently under development will hopefully help to predict DR benefits from different technologies in a standardized way.

In addition, as demand response includes a variety of grid services (primarily load shift and shed, but others are emerging—see the earlier **Benefits of Demand Response** section), separate metrics are necessary depending on the grid services the demand response program

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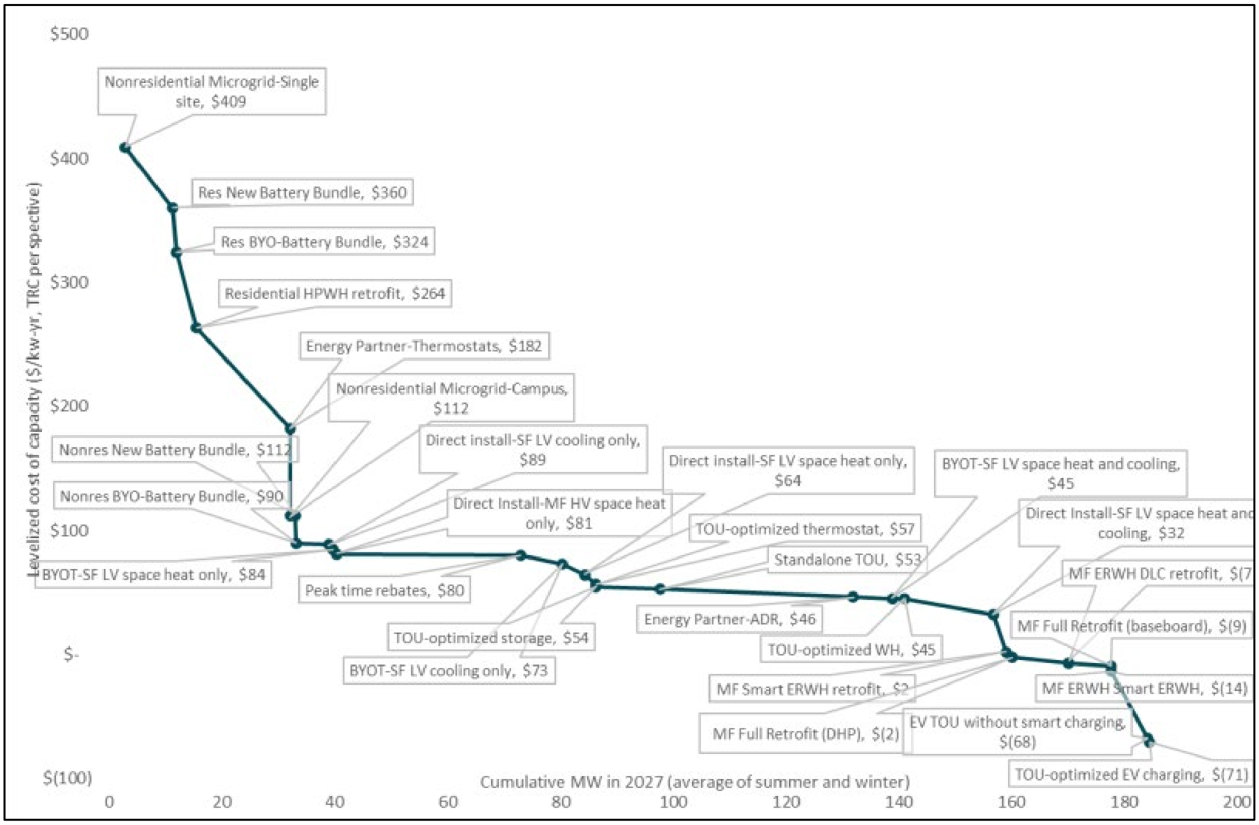
19 https://gmlc.doe.gov/sites/default/files/resources/Recommended%20Practice%20Grid%20Services%20from%20Devices%20Ch%201-2_0.pdf

aims to address. The most common grid service, and the focus of this paper, is demand response programs that provide load shed to serve generation capacity and wholesale market prices. This section discusses these metrics first—both from an evaluation perspective and a simplified scanning metric perspective— then briefly explains load shift metrics, targeted largely around rate management.

### Load Shed Metrics

To account for the aggregate impact of all factors that affect a load shed demand response program, utilities often use a levelized cost of capacity metric (LCoC, in $/kW-year). Levelized cost of capacity compares the annualized cost of a DR measure or program to an avoided cost resource (typically a peaking generator such as a simple cycle turbine or a utility-scale lithium-ion battery). As with cost effectiveness analysis of energy efficiency, the LCoC metric can be determined in several ways, most commonly from a utility cost or total resource cost perspective. An example from a recent PGE study of DR and distributed energy resource (DER) capacity potential provides an example of this approach expressed as a supply curve, as illustrated below in Figure 6.

**Figure 6. PGE Levelized Cost of Capacity for DERs**[20]




The appeal of the levelized cost of capacity approach is that it should theoretically put all capacity resources (demand-side and supply-side) on a level playing field when considered in an integrated resource plan or forward capacity market. Defining capacity can be a nuanced exercise, however, as the timing, frequency, and duration of peak periods can vary widely across utilities and time. A broader discussion of the calculation of the capacity contribution of different resources is beyond the scope of this document; however, it constitutes an important and rapidly-evolving area of research. A simplified approach often used in practice is to take the average contribution of a resource over a prototypical event during days predicted to have high probability of expected loss of load (often greater than 5%). For generating capacity, a common

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[20] https://assets.ctfassets.net/416ywc1laqmd/1sMpwIkeZ0Imb9FuEA7F2i/128e4ffc0bc044f2fde8dcd7cbdc03c6/2021-09-17-pge-der-flex-load-potential-phase1.pdf

duration assumed is 4 hours. When assessing distribution or transmission peaks, events may be as short as 1–2 hours.

Calculating LCoC for DR resources requires consideration of various technical and programmatic features. The LCoC is calculated as the ratio of the net present value of costs over the sum of kW impacts in each year, resulting in a final metric in $/kw-yr.

$$LcoC = \frac{\text{NPV(Total Costs [Technology + Controls + Program Costs])}}{\sum \text{Market Size}_t * \text{Average Load Reduction}_t}$$

As the equation suggests, costs and impacts of the technology, controls, program dynamics, and accessible market size must be considered. The key variables in this equation are:

- Average Load Reduction
- Market Size
- Total Costs

This section provides an overview of each of those variables and the nuances and program elements to consider.

Levelized cost of capacity should be evaluated for the different seasons, times of day, and durations of events. A thorough evaluation of DR potential would calculate LCoC for each of these prototypical cases to ensure an understanding of the capabilities of the resource to meet both narrow and longer peak periods. Table 2 outlines a prototypical evaluation framework for the Pacific Northwest region.

**Table 2. Prototypical Event Types for Pacific Northwest**

| Season | Time of Day | Duration |
|---|---|---|
| Winter | AM | 1 hour |
| Winter | PM | 1 hour |
| Summer | PM | 1 hour |
| Winter | AM | 4 hour |
| Winter | PM | 4 hour |
| Summer | PM | 4 hour |
| Winter | AM | 8 hour |
| Winter | PM | 8 hour |
| Summer | PM | 8 hour |

### *Average Load Reduction*

Average load reduction represents the average power reduction per measure during an event. If all equipment ran continuously and the DR control approach fully de-energized the equipment, this value would be equal to the full load power draw of the equipment. However, equipment does not always operate at full load over the full duration of the event, and a demand response signal may only partially reduce load. Additionally, from a programmatic context, average load reduction is influenced by opt-out rates, as discussed previously. Ideally, the load reduction metric represents what is actually observed during a demand response event rather than what is theoretically possible.

Average load reduction values of a demand response event are typically determined through field measurements that quantify the average load reduction observed in a fleet of resources compared to a control group that did not participate in the demand response event. For emerging technologies for which this type of measurement isn't possible, researchers should make some effort to estimate it. For instance, lab testing and field measurements of typical consumption patterns during non-DR events may provide an estimate of demand reductions expected absent opt-outs and could then be further adjusted using opt-out rates from a comparable technology observed in the field.

Potential future development of standard test procedures would model average load reduction for various technologies, alleviating the need for field measurements. These test procedures would require testing the physical and control parameters of the technology to define its performance for a given grid service and a grid service model that calculates the aggregate demand response impact of a fleet of the technology.

### *Market Size*

Market size defines the number of equipment units enrolled in a demand response program. The metric is a function of the eligible market and program participation. The “eligible market” represents the number of eligible equipment units; program participation represents the percent of the eligible market that enrolls in the program. This metric considers changes in population, equipment saturation, and the time it takes for customers to reach maximum enrollment in the program, known as the ramp period.

For existing technologies, market size can be determined through publicly-available census and stock assessment data, manufacturer sales data, and program-specific eligibility requirements. Certain assumptions are necessary to project a technology's market size into the future. Current program participation data for existing technologies are available through evaluation studies. Researchers can estimate maximum enrollment and ramp period values for emerging technologies without existing field studies based on known values from similar technologies and engineering judgment.

### *Costs*

Cost considerations would ideally include the cost of the demand response control technology and program costs associated with the demand response program. When comparing discrete individual measures, however, fixed costs such as program administration and marketing can be ignored[21] in these calculations as they are relatively consistent across offerings and are bespoke to the program administrator. The focus for program costs should be on the variable first-time and ongoing costs of the measure, such as installation labor, network charges, incentives (where applicable), and software licensing. Technology costs should be considered only if the equipment is purchased with the intent to use it for demand response. For example,

[21] In cases where technologies are new or complex or for novel DR programs, these costs may be more important.

the upfront cost associated with a smart thermostat should not be included unless the device is purchased for use in a demand response program. All technology costs should be amortized over the lifetime of the equipment.

## *Simplified Metrics for Emerging Technologies*

Emerging technologies present a particular challenge for DR metrics because hard data are lacking in terms of how the technology would perform in a real-world program. That said, simplified average load reduction, market size, and cost estimates can be used to generate a LCoC comparison metric. This section describes the process of generating this simplified LCoC.

### *Average Load Reduction*

Though no formula exists for determining average load reduction, an analyst can derive a reasonable estimate by looking at manufacturer data, along with sample data from evaluation reports of similar technologies. Table 3 outlines the factors to be considered for any approximation. An analyst could calculate this reduction for different seasons, times of day, and event durations.

**Table 3. Factors to Estimate Simplified Average Load Reduction**

| Load Reduction Factors | Considerations |
|---|---|
| Peak demand for equipment | Determine for:<br>• Peak demand in summer<br>• Peak demand in winter |
| Modulation vs. staged vs. cycling on/off (assume "best" control method) | Affects peak demand reduction<br>Affects opt-out rate |
| Opt-out rate:<br>based on human overrides | Determine for:<br>• 1-hour (AM/PM)<br>• 4-hour (AM/PM) |
| Opt-out rate:<br>based on connectivity (depends on connection method) | Determine for:<br>• 1-hour<br>• 4-hour |

## *Market Size*

For emerging technologies, the market size should be addressed at both current levels and at expected market size in the future (e.g., years 2030 and 2050). Table 4 outlines the factors to be considered in estimating market size.

**Table 4. Factors to Estimate Market Size**

| Market Size Factors | How to estimate/ considerations |
|---|---|
| Market size | Based on Power Plan or other sources<br>• Current year<br>• 2030<br>• 2050 |
| Program participation | Not calculated, but rated with "Low–Med–High" |

## *Costs*

Cost considerations include the cost of the technology and any associated controls. Table 5 outlines the simplified cost factors.

**Table 5. Factors to Estimate Costs**

| Cost Factors | How to Estimate/ Considerations |
|---|---|
| Equipment + controls cost | Quote/ manufacturer information |
| Connectivity costs | Use $25/year |
| Program costs | For technology-focused LCoC comparisons, this can be ignored |

## Simplified Levelized Cost of Capacity

The simplified LCoC metric is based on the three metrics described above. The equation below shows the simplified formula used in this framework.

$$LCoC_i = \frac{Annualized\ Cost\ of\ (Technology + Controls + Connectivity)}{Average\ Load\ Reduction_i\ (kW)}$$

Where

$$Annualized\ Cost\ of\ (Technology + Controls + Connectivity) =$$

$$\frac{(First\ cost\ of\ technology + controls) + (Connectivity\ costs * Equipment\ Lifetime)}{Equipment\ Lifetime}$$

And *i* = each prototypical event (e.g., Summer AM, 1-hour.)

These numbers could be compared to other equipment and a typical cost for peaker plants to operate (roughly $100/kW-year[22]).

## Sample Comparisons

As a sample comparison, Table 6 provides some illustrative calculations. Though a full engineering analysis is beyond the scope of this project, these numbers offer an example of the simplicity and utility of this framework. The research team has also provided an Excel workbook with these calculations as part of this project.

[22] For example, Puget Sound Energy's (PSE's) recent DER RFP included a schedule of avoided capacity costs that gave a value of $95/kw-yr in 2022: https://www.pse.com/-/media/PDFs/001-Energy-Supply/003-Acquiring-Energy/ExD_2021-All-Source-RFP_040121.pdf?sc_lang=en&modified=20211115231310&hash=23D0D34FF6347D8BABAB220D99B9AFE9

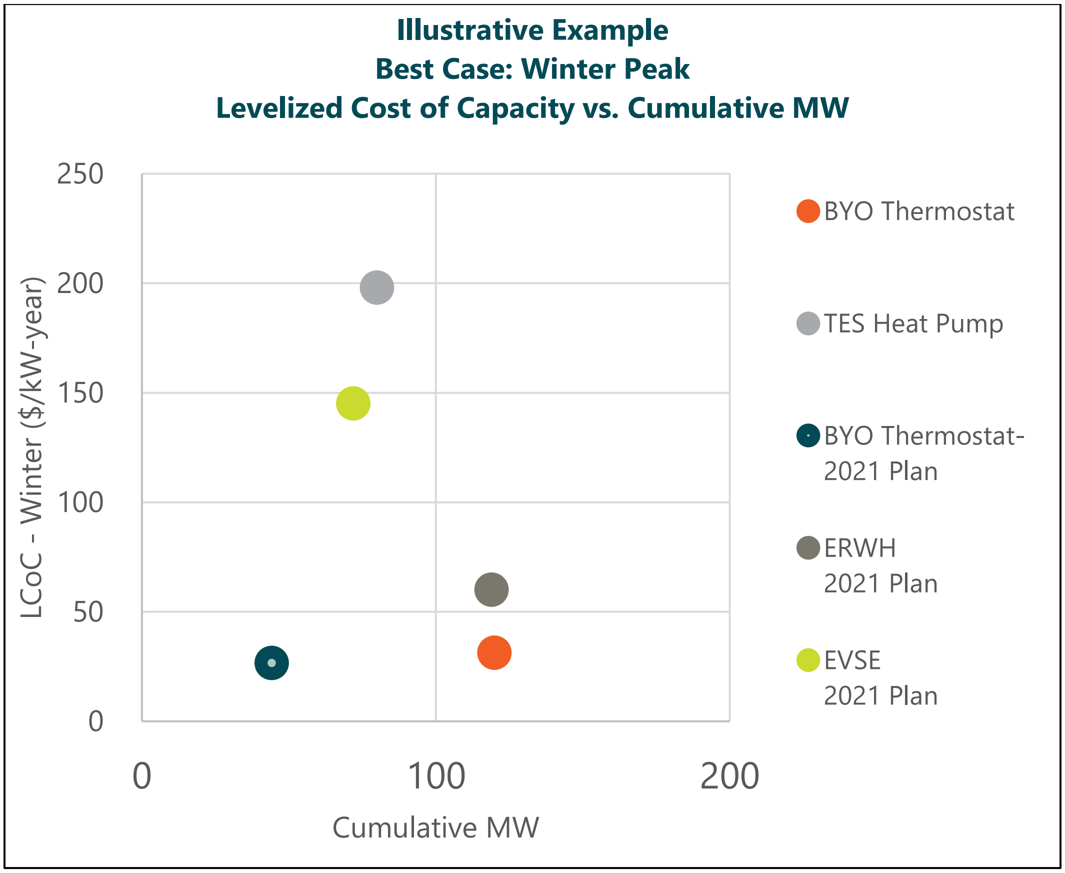
**Table 6. Illustrative Example of Simple Comparison Matrix**

| Metric | BYO Thermostat | TES Heat Pump |
|---|---|---|
| Incremental CapEx of DR | $0 | $2,000 |
| Connection Costs | $25 | $25 |
| Lifetime of Equipment | 15 | 15 |
| Annualized Costs | $25 | $158 |
| Market Size (Today) | 10,000 | 1 |
| Market Size (Reasonable) | 50,000 | 10,000 |
| Market Size (Best Case) | 150,000 | 100,000 |
| Cumulative Winter DR (MW- today) | 8 | 0 |
| Cumulative Winter DR (MW- reasonable) | 40 | 8 |
| Cumulative Winter DR (MW- best case) | 120 | 80 |
| LCoC- Winter ($/kW-year) | 31 | 198 |
| Cumulative Summer DR (MW- Today) | 10 | 0 |
| Cumulative Summer DR (MW- Reasonable) | 50 | 10 |
| Cumulative Summer DR (MW- Best Case) | 150 | 100 |
| LCoC- Summer ($/kW-year) | 25 | 158 |

*Note:* Numbers shown are for illustration only and are not based on engineering analysis.

The numbers derived can then be plotted on a graph of simplified LCoC vs. Cumulative MW (average kW * Market Size). Figure 7 shows an example of this graph. The data points labeled with "2021 Plan" are taken from the Northwest Power and Conservation Council 2021 Power Plan. Though they are not accurate comparisons to data points created using the framework described here, they are shown for illustrative purposes.

**Figure 7. Example using Simplified Comparison Framework**




*Note:* Numbers shown are for illustration only and do not indicate engineering judgement.

## *Load Shift Metric*

The most common grid service, and focus of this paper, is demand response programs that provide load shed. However, as the electrical grid evolves and adopts more renewable energy generation, demand response programs seek to include load shift. Load shift demand response programs incentivize customers to shift their electricity consumption from periods of high-cost, high-emission generation to periods of low-cost, low-emission generation over the course of a day, typically through rates.

In order to participate in load shift programs, the technology must be capable of storing energy, either thermally (as is the case with water heaters and HVAC equipment) or electrically (as is the case with electric batteries). Additionally, the technology's typical energy consumption peak must be coincident periods of high-cost, high-emissions power. While a more refined metric could potentially be developed, for now, the research team suggests simply binning resources by those that can provide capacity daily vs. those that are only peaking resources.

# Conclusions and Recommendations

Over the next 5–10 years, utility companies in the Pacific Northwest will become more focused on DR programs. Each company must consider its specific peak seasons, times of day, and event durations.

With regard to DR program expansion, residential HVAC is part of the problem and can be part of the solution. Currently, smart thermostats are playing the biggest role in demand response in the region; they are appealing to consumers, offer efficiency benefits, and have relatively good "up" time (connection to Wi-Fi). One problem with thermostats is the opt-out rate from customer override and loss of communication. Integrated controls have the potential to reduce the amount of opt-out that plagues thermostats. Still, manufacturers need guidance on which pathway to follow, whether through proprietary means or open protocol (including the allowance of control by smart thermostats).

## Conclusions

The three main elements to consider when evaluating DR potential are average demand reduction, market size, and costs. Demand response metrics should ideally be based on the technology, the controls, and the programs in which they are being used. DR potential for emerging technologies can be estimated without program costs and with assumptions for some programmatic elements currently unknown for emerging technologies.

Though average demand reduction is a difficult metric to estimate, with many factors in play, the team has developed a framework that evaluators can use for emerging technologies. Levelized cost of capacity and cumulative MW are easily estimated once the average reduction is determined. Plotting LCoC vs. cumulative MW gives a good indication of the overall comparison of cost and DR potential.

## Recommendations

Utilities will certainly need help evaluating DR potential and running programs. The team has developed the following ways NEEA can support its members:

### Aggregator Database

Third-party aggregators can manage DR programs for utilities. While any size utility may choose to use an aggregator, this is especially helpful for smaller companies. NEEA could compile a list of qualified, reputable providers to help guide utilities. The California Public Utilities Commission already has a list of such providers.[23,24]

### Average Load Reduction Refinement

The team presented a framework for estimating the average load reduction of emerging technologies. NEEA could use this framework to calculate the average load reduction for a sample of existing and emerging technologies to refine future estimates.

### Incorporate DR in Evaluations for Emerging Technologies

As NEEA considers new technologies, product managers can consider their DR potential. A straightforward way to do this would be to review the factors in Table 3, Table 4, and Table 5.

### Integrated Controls Guidance

VSHPs offer a particular opportunity to provide both energy efficiency and demand response. Still, manufacturers need guidance on integrating DR; currently, they could provide DR through proprietary means or an open protocol. They could also shift toward allowing control with smart thermostats. If NEEA can state a definitive preference on communication protocols and DR functionality, this may help manufacturers invest wisely in a method that can be used nationwide.

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[23] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/registered-demand-response-providers-drps-aggregators-and-faq

[24] https://www.sce.com/residential/demand-response

## *Support Exploration of DR Test Procedures and Metrics*

As stated previously, no good test procedures exist that measure demand response. The Grid Modernization Laboratory Consortium initiated work to create such test procedures; those researchers released a preliminary report, but work appears to have stalled.[25]

Given the increasing importance of DR and its relatively new appearance in the Pacific Northwest, NEEA can play a key role in providing guidance to both utility companies and manufacturers.

[25] https://gmlc.doe.gov/resources/recommended-practice-characterizing-devices%E2%80%99-ability-provide-grid-services

# Appendix: Regulations

Several pieces of recent legislation call out the importance and necessity of demand response acquisitions by utility companies.

## WA- CETA

The Clean Energy Transformation Act (CETA; the Laws of 2019, Chapter 288) requires Washington's electric utilities to file a clean energy implementation plan (CEIP[26]) every four years. A CEIP must specify a plan to reach certain mandatory clean electricity targets and set targets for demand response.

## OR HB 2021

Oregon House Bill 2021[27] requires retail electricity providers to create a clean energy plan, which must include annual goals for meeting clean energy targets. The annual goals must include the acquisition of non-emitting generation resources, energy efficiency measures, and the acquisition and use of demand response resources.

## FERC 2222

The Federal Energy Regulatory Commission (FERC) issued Order Number 2222 in September 2020.[28] This rule enables DERs to participate alongside traditional resources in the regional organized wholesale markets through aggregations; opening U.S. organized wholesale markets to new sources of energy and grid services. This rule allows several sources of distributed electricity to aggregate to satisfy minimum size and performance requirements that each may not be able to meet individually.

Regional grid operators must revise their tariffs to establish DERs as a category of market participants. These tariffs will allow the aggregators to register their resources under one or

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[26] https://www.utc.wa.gov/regulated-industries/utilities/energy/conservation-and-renewable-energy-overview/clean-energy-transformation-act/clean-energy-implementation-plans-ceips
[27] https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/HB2021
[28] https://www.ferc.gov/media/ferc-order-no-2222-fact-sheet

more participation models that accommodate(s) the physical and operational characteristics of those resources. Each tariff must set a size requirement for resource aggregations that do not exceed 100 kW.

# Appendix A – Literature Review

A separate spreadsheet with additional summary details and hyperlinks to published reports are available.

| Title | Author | Sponsor/ Funding/ publisher | Resource Type | Year |
|---|---|---|---|---|
| PGE DER and Flexible Load Potential-Phase 1 | Cadeo, Brattle, Lighthouse Consulting | Portland General Electric | Technical Report | 2021 |
| Impact Evaluation of PGE BYOT Pilot Program, Winter 2019/2020 and Summer 2020 | Cadmus | Portland General Electric | Program Evaluation | 2021 |
| 2025 California Demand Response Potential Study | Lawrence Berkeley National Laboratory | Lawrence Berkely National Laboratory | Technical Report | 2017 |
| NWPCC: User's Guide Northwest Demand Response Model | Northwest Power And Conservation Council | Northwest Power And Conservation Council | Demand Response Model | 2021 |
| A National Roadmap for Grid-Interactive Efficient Buildings | Lawrence Berkeley National Laboratory | Lawrence Berkeley National Laboratory | Technical Report | 2021 |
| National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources | National Energy Screening Project | National Energy Screening Project | Technical Report | 2020 |
| Final Report of the California Public Utilities Commission's Working Group on Load Shift | Gridworks | California Public Utilities Commission | Technical Report | 2019 |
| The Emergence of Demand Response Programs in HVAC | Nick Kostora | ACHRNews.com | Web Article | 2017 |
| Welcoming the next generation: Residential demand response 3.0 | Jessie Mehrhoff | Utilitydive.com | Web Article | 2019 |
| Demand response potential of residential HVAC loads considering users preferences | Mubbashir Ali, et al. | IEEE | Conference Paper | 2014 |
| IEA Demand Response Tracking Report | Emi Bertoli, et al. | International Energy Agency | Technical Report | 2021 |

| | | | | |
|---|---|---|---|---|
| A Comprehensive Review on Residential Demand Side Management Strategies in Smart Grid Environment | Sana Iqbal, et all | MDPI- Swiss scientific publisher | Research Paper | 2021 |
| Custom Controls for Improved Demand Response from Heat Pump Water Heaters | Sparn, Bethany | National Renewable Energy Laboratory | Conference Paper | 2020 |
| Variable-Speed Heat Pumps for Energy Efficiency and Demand Response | Electric Power Research Institute (EPRI) | Bonneville Power Administration | Technical Report | 2014 |
| Optimal HVAC Control as Demand Response with On-site Energy Storage and Generation System | Young M. Lee | Energy Procedia | Research Paper | 2015 |
| Evaluation of Residential HVAC Control Strategies for Demand Response Programs (SYMPOSIUM PAPERS - CH-06-7 Demand Response Strategies for Building Systems) | Srinivas Katipamula, et al. | ASHRAE Transactions | Research Paper | 2006 |
| Demand Response-Enabled Residential Thermostat Controls | Xue Chen, et al. | American Council for an Energy-Efficient Economy | Conference Paper | 2008 |
| Differences in Demand Response Markets (MISO vs PJM) | Great Plains Institute | Great Plains Institute | Technical Report | 2015 |
| AHRI 1380: Demand Response through Variable Capacity HVAC Systems in Residential and Small Commercial Applications | Air-Conditioning, Heating, and Refrigeration Institute | Air-Conditioning, Heating, and Refrigeration Institute | Standard | 2019 |
| Pacific Northwest Smart Grid Demonstration Project Technology Performance Report Volume 1: Technology Performance | Battelle Memorial Institute | US Department of Energy | Technical Report | 2015 |
| Demand response hasn’t taken off in the Pacific Northwest. Will a massive heat wave change that? | Jeff St. John | Canary Media | Website Article | 2021 |

# Appendix B – Simplified LCoC Calculator

A spreadsheet tool was developed for NEEA that includes a summary of comparative technologies with each tab representing an individual technology (sample shown below)

## Thermal Storage Heat Pump

| | 4hr kW reduction |
|---|---|
| kW- Winter | 0.8 |
| kW- Summer | 1 |
| Connection | $25 |
| Life of Equipment | 15 |

| | Today | Reasonable | Best Case |
|---|---|---|---|
| Incremental CapEx of DR | $2,000 | $1,000 | $700 |
| Market Size (units) | 1 | 10,000 | 100,000 |

| | **Today** | **Reasonable** | **Best Case** | |
|---|---|---|---|---|
| Incremental CapEx of DR | $2,000 | $1,000 | $700 | 1st year |
| Connection Costs | $25 | $25 | $25 | per year |
| Lifetime of Equipment | 15 | 15 | 15 | years |
| Annualized Costs | $158 | $92 | $72 | per year |
| Market Size | 1 | 10,000 | 100,000 | total installed |
| Winter DR | 0 | 8 | 80 | MW |
| Winter LCoC | $198 | $115 | $90 | MW |
| Summer DR | 0 | 10 | 100 | $/kW-year |
| Summer LCoC | $158 | $92 | $72 | $/kW-year |