Xcel Energy Colorado Demand Response Study: Opportunities in 2030

PREPARED BY

Ryan Hledik

Akhilesh Ramakrishnan

Kate Peters

Ryan Nelson

Xander Bartone

PREPARED FOR

Xcel Energy

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Brattle

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Executive Summary

Introduction

In its Colorado service territory, Xcel Energy ("PSCo") has committed to reducing the carbon emissions of its electricity service by 80 percent by 2030 relative to 2005 levels, and to delivering 100 percent carbon-free electricity by 2050. Demand response (DR) is an important resource option for providing the flexibility and reliability that will be needed as PSCo becomes increasingly reliant on non-dispatchable wind and solar generation.

In its 2021 Electricity Resource Plan (ERP), PSCo identified a need for new peaking capacity beginning in 2030. The purpose of this study is to assess the cost-effective potential for new DR opportunities in 2030. We used Brattle's LoadFlex model to assess PSCo's emerging DR opportunities. The LoadFlex modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of DR programs. Features include participation assumptions which are consistent with economically optimized incentive payment levels, sophisticated DR program dispatch simulation which accounts for operational constraints of each program, and realistic accounting of "value stacking" to ensure that benefits estimates represent the full potential value of DR while accounting for trade-offs when simultaneously pursuing multiple value streams.

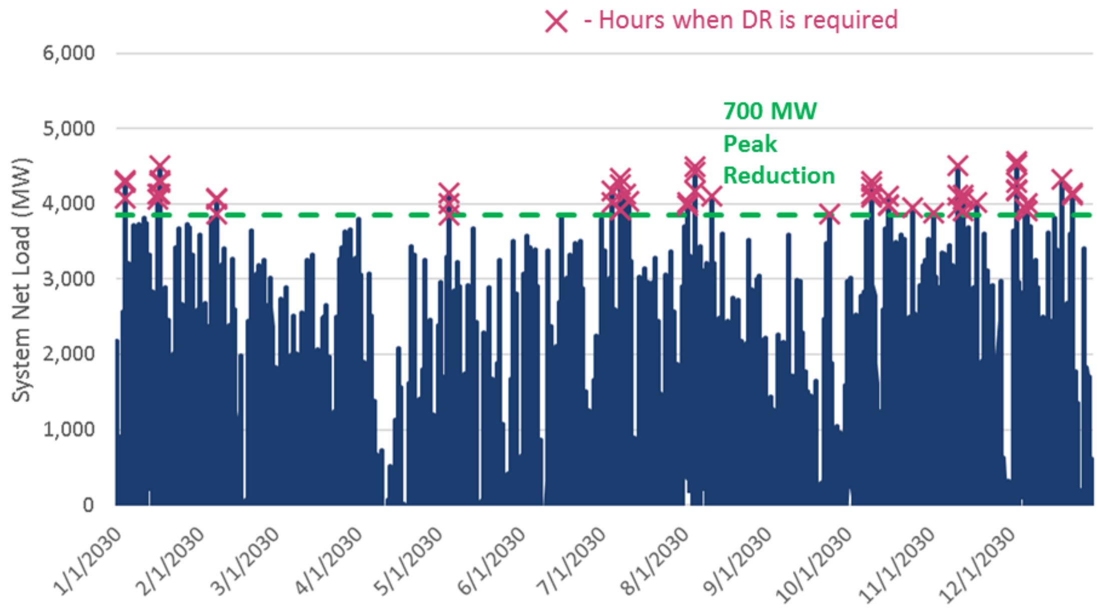
PSCo's Existing Portfolio

PSCo's existing DR portfolio is among the largest in the U.S. The existing portfolio can reduce the summer system peak by 496 MW, and represents over seven percent of system peak demand. After normalizing for PSCo's limited industrial customer DR opportunities relative to some other large utility DR portfolios, we estimate that PSCo's current DR capability ranks in the top five percent of U.S. investor-owned utilities when expressed as a percentage of system peak demand. PSCo's significant existing DR participation will serve as a constraint on the amount of new, incremental DR participation that can be achieved. Enrolling additional customers in DR programs is likely to require new programs as well as ongoing recruitment of new participants into existing programs.

The Role of DR in 2030

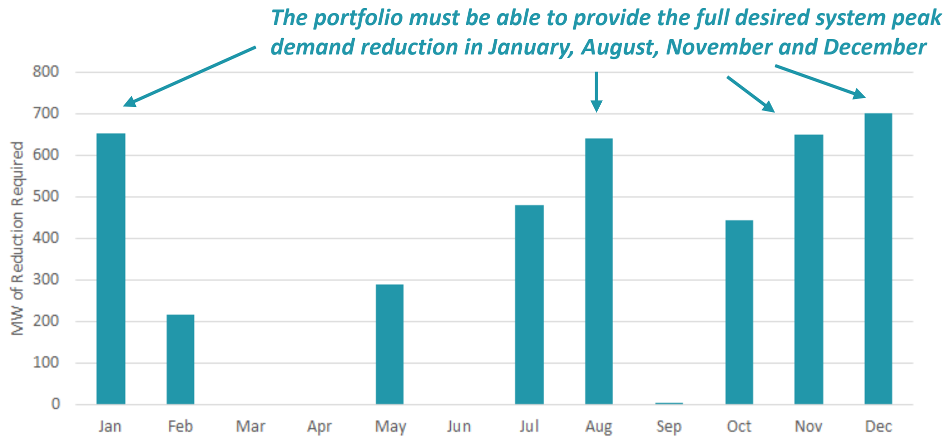
PSCo's plans to decarbonize its power supply mean that its power system will have a significantly different need for DR in 2030 than it has had historically. To provide cost-effective value in a high renewables system, DR will need to be capable of reducing net system peak demand, which is defined as the load remaining after reductions for non-dispatchable renewable generation. By 2030, this will require DR to be utilized more frequently, during more months of the year, and during a wider range of hours of the day. Figure 1 summarizes PSCo's forecasted hourly net load shape in 2030, and illustrates the hours of the year during which peak demand reductions would be needed in order to provide an illustrative 700 MW reduction in system peak demand throughout the year.

FIGURE 1: 2030 FORECASTED HOURLY SYSTEM NET LOAD



Importantly, reducing system peak demand in 2030 will require a DR portfolio with the capability to reduce load by at least as much in the winter as in the summer. In terms of net load, PSCo will effectively become a dual peaking utility by 2030, meaning PSCo's net peak will be similar in magnitude in both summer and winter, and the company will need to achieve comparable peak demand reductions in both seasons. Figure 2 illustrates the magnitude of peak demand reduction needed in each month of 2030 in order to achieve an illustrative system peak demand reduction target of 700 MW.

FIGURE 2: MEGAWATTS OF LOAD REDUCTION REQUIRED IN EACH MONTH TO ACHIEVE 700 MW SYSTEM NET PEAK DEMAND REDUCTION (2030)



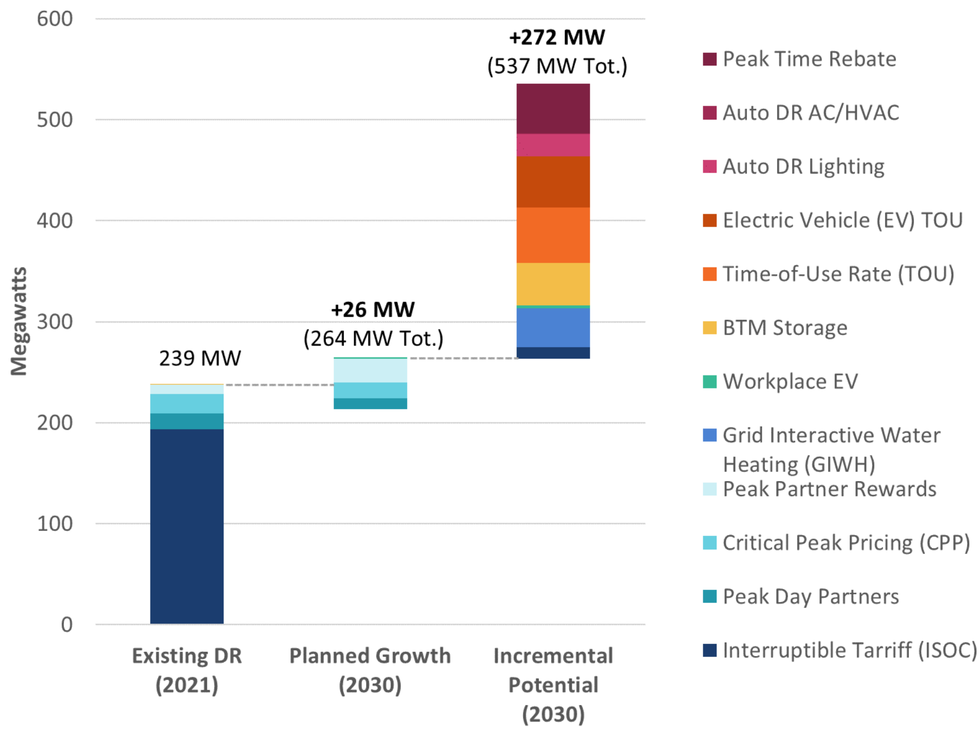
PSCo's 2030 DR Potential

The year-round need for DR limits PSCo's DR potential. While we estimate more than 1,000 MW of achievable DR potential in the summer, we estimate only 537 MW of achievable DR potential in the winter. While DR potential is higher in the summer primarily due to flexible, discretionary air-conditioning load, the winter potential of 537 MW represents the system's total annual DR limit. Increasing PSCo's DR portfolio to 537 MW by 2030 will require roughly doubling the company's winter DR capability relative to current plans. A more modest increase of 41 MW will be needed in the summer in order to match 2030 winter potential.

Figure 3 summarizes the composition of PSCo's 2030 winter DR potential. Primary drivers of achievable incremental potential are default time-of-use (TOU) rates for all customer classes[1], electric vehicle (EV) managed charging (TOU in our analysis), a targeted peak time rebate (PTR) to provide event-based behavioral DR beyond TOU impacts, and growth in PSCo's behind-the-meter (BTM) battery program.

[1] For the purposes of this study, we assess the potential associated with defaulting large C&I customers to a default TOU rate. However, PSCo currently only has plans to implement a default TOU for residential and small C&I customers.

FIGURE 3: PSCO 2030 WINTER DR POTENTIAL



PSCo's rapidly changing power system will present new challenges and opportunities for the company's DR portfolio. With attention to the evolving needs of the system, DR can continue to be a cornerstone of Colorado's decarbonization transition.

I. Introduction

Purpose

In its Colorado service territory, Xcel Energy ("PSCo") has committed to reducing the carbon emissions of its electricity service by 80 percent by 2030 relative to 2005 levels, and to delivering 100 percent carbon-free electricity by 2050. As PSCo becomes increasingly reliant on non-dispatchable wind and solar generation, the power system will have an accompanying need for new sources of carbon-free flexibility and reliability. Demand response (DR) is one attractive resource option to help address that flexibility and reliability need.

PSCo's 2021 Electric Resource Plan (ERP) identified a need for new peaking capacity beginning in 2030. While the specific resource for providing that peaking capacity was not defined, the Colorado Public Utilities Commission (PUC) issued Interim Decision No. C21-0395-I requiring that PSCo analyze the impacts of 200 MW of new DR in 2030. To address Decision No. C21-0395-I, PSCo commissioned The Brattle Group ("Brattle") to conduct a quantitative assessment of the cost-effective potential for new DR opportunities across its Colorado service territory. This report summarizes our methodology and findings.

Study Scope

Our analysis provides input to PSCo's 2022 Strategic Issues Filing and to the company's ERP modeling. The findings of this study should be interpreted as a quantitative screen of the DR opportunities available to PSCo and not a substitute for a detailed business case seeking regulatory approval of the programs. Further development of individual programs, and testing of the programs through pilots, will provide additional insight regarding the potential benefits and costs that such programs may offer to PSCo and its customers when deployed on a full-scale basis.

Our study focuses on estimating the amount of cost-effective DR capability that can be achieved that is incremental to PSCo's existing DR portfolio and to the planned portfolio growth that PSCo included in the Phase I ERP. We estimate the incremental DR potential that can be achieved through an expansion of existing program offerings, the introduction of new programs, and consideration of a broad range of potential system benefits that are available through DR. Specifically, this study is structured to quantify all DR potential that satisfies the following three conditions:

1. Incremental: All quantified DR potential is incremental to PSCo's existing DR portfolio, including planned growth.
2. Cost-effective: The present value of avoided resource costs (i.e., benefits) must outweigh program costs, equipment costs, and incentives.

3. Achievable: Program enrollment rates are based on primary market research in PSCo's service territory and supplemented with information about utility experience in other jurisdictions.

Our analysis focuses specifically on DR potential and cost-effectiveness in 2030, as that is the year in which PSCo has identified a need for new capacity.

Study Features

The scope of this study extends significantly beyond those of prior studies in Colorado. Specifically, we account for opportunities enabled by the rapid emergence of consumer-oriented energy technologies. Advanced metering infrastructure (AMI), smart appliances, electric vehicles, behavioral tools, and automated load control for large buildings are just a few of the technologies driving a resurgence of interest in the value that can be created through new DR programs. These technologies enable DR to evolve from providing conventional peak shaving services to providing around-the-clock "load flexibility" in which electricity consumption is managed in real-time to address economic and system reliability conditions.

This study also takes a detailed approach to assessing the cost-effectiveness of each DR option. While emerging DR programs introduce the potential to capture new value streams, they are also dependent on technologies that in some cases have not yet experienced meaningful cost declines. Further, opportunities to create value through DR vary significantly from one system to the next. A detailed assessment of the costs and benefits of each available DR option is necessary to identify the DR portfolio that is the right "fit" for a given utility system.

We use Brattle's Load*Flex* model to assess PSCo's emerging DR opportunities. The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of DR programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program, thus providing a more complete estimate of total cost-effective potential than prior methodologies.

- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of PSCo's customer base. This includes accounting for the market saturation of various end-use appliances, customer segmentation based on size, and PSCo's estimates of the capability of its existing DR programs.

- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program, including tariff-related program limitations and an hourly representation of load control capability for each program.

- **Realistic accounting for "value stacking":** DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program and accounting for necessary trade-offs when pursuing multiple value streams.

Report Organization

The remainder of this report is structured as follows:

- Section II describes PSCo's existing DR portfolio and benchmarks its program composition and peak demand reduction capability against that of other utilities.

- Section III explores the role of DR in PSCo's rapidly decarbonizing power system. In particular, we analyze the ways in which utilization of DR will need to change as the system becomes more reliant on non-dispatchable renewable generation.

- Section IV describes our methodological framework for evaluating PSCo's DR potential.

- Section V presents our estimates of PSCo's cost-effective, achievable DR potential in 2030, with specific consideration for the issues discussed in Section III.

- Section VI summarizes the conclusions and recommendations of our study.

II. PSCo's Existing DR Capability

PSCo's DR Portfolio

PSCo's existing DR portfolio currently has the capability to reduce system peak demand by 496 MW in the summer, roughly seven percent of the utility's system peak. That capability is primarily attributable to two DR programs. The largest is the Interruptible Service Option Credit (ISOC) program. ISOC is an "interruptible tariff" program, which provides commercial and industrial (C&I) customers with bill savings in return for a commitment to curtail electricity demand to pre-established levels when called upon by the utility. Roughly 24 percent of the peak-coincident demand of all large C&I customers is enrolled in this program.[2]

The other large program in PSCo's portfolio is the Saver's Switch program. Saver's Switch is a conventional residential load control program, in which the compressor of a central air-conditioning unit is temporarily cycled off to reduce electricity demand during DR events. Roughly thirty percent of all eligible residential customers (i.e., those with central air-conditioning) are enrolled in the program, accounting for around fifteen percent of all of PSCo's residential customers. Moving forward, PSCo's residential DR portfolio will compliment Saver's Switch with newer smart thermostat technology, through a program called "A/C Rewards." A/C Rewards contributes an additional 25 MW to PSCo's existing DR capability, and is expected to grow significantly in coming years.

Several other programs materially contribute to PSCo's DR capability:

- Critical Peak Pricing (CPP): C&I customers are eligible for a CPP rate, which provides a discount on the participant's demand charge, and includes a higher energy charge during a limited number of events dispatched per year (15 or less) between the hours of 12 pm and 8 pm. Additionally, PSCo is currently conducting a pilot in which large customers with electric vehicle fleets are encouraged to adopt a CPP rate.

- Peak Day Partners: PSCo offers C&I customers load reduction bids that participants accept, reject, or negotiate with counter-bids. This is also referred to as a "demand bidding" program.

- Peak Partner Rewards: Large C&I customers can earn a capacity reservation payment for being available to reduce demand when needed, and an additional performance payment for providing actual load reductions during events.

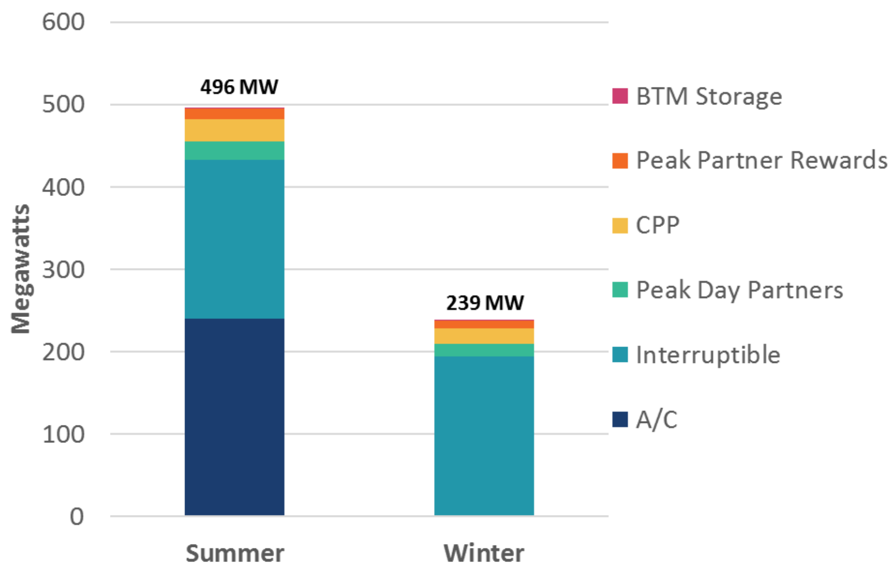
- Battery Connect Pilot: Residential customers can receive incentive payments for enrolling a behind-the-meter battery in PSCo's Battery Connect DR program. PSCo can charge and

[2] This is an approximate estimate, based on a review of current ISOC program capability and an estimate of the Large C&I class's contribution to system peak demand. In our study, the Large C&I segment is defined as those customers with maximum billing demand greater than 50 kW.

discharge the battery up to 100 times per year. PSCo is currently offering the program as a pilot, so peak demand reduction capability is limited.

While PSCo's DR programs primarily address the summer peak, the company also can use its DR portfolio to provide winter peak demand reductions. As we will describe later in this report, winter peak demand reduction capability will become increasingly important as PSCo transitions to a renewables-dependent power supply. We estimate that the current winter peak demand reduction capability of PSCo's existing DR portfolio is 239 MW. It is lower than the summer capability primarily due to the absence of cooling load. Figure 4 summarizes PSCo's existing DR capability in the summer and the winter.

FIGURE 4: 2021 PSCO DR CAPABILITY



Benchmarking PSCo's DR Capability

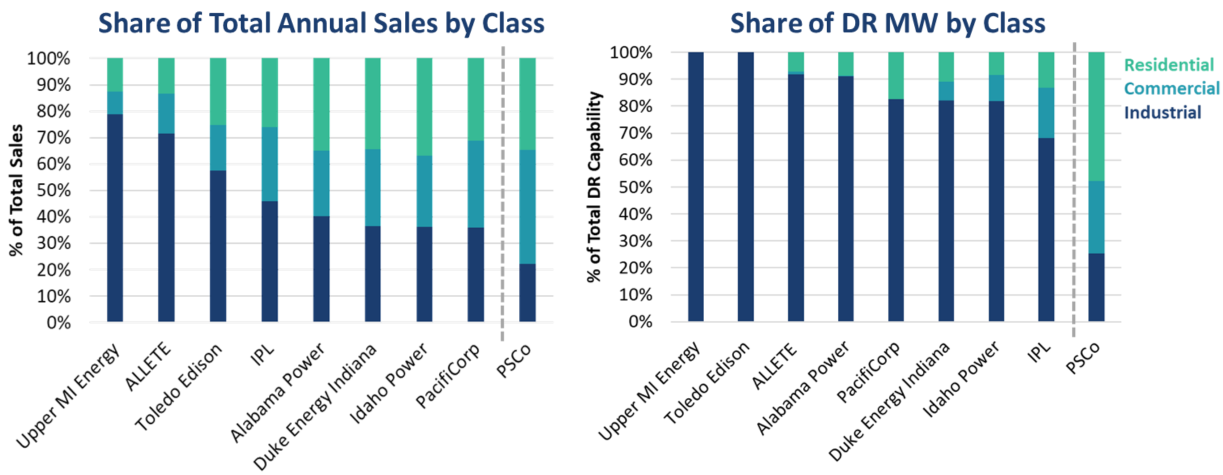
PSCo's existing DR portfolio is among the largest in the U.S. The company's peak demand reduction capability of 496 MW represents seven percent of its system peak. Expressed as a percent of peak demand, this ranks 15th out of 144 U.S. investor-owned utilities (IOUs) according to EIA data.[3]

Among the 14 utilities with larger DR portfolios than PSCo, eight of those utilities have a significantly larger industrial customer base than PSCo, with DR portfolios comprised primarily of those industrial customers. Large industrial customers can be attractive candidates for DR programs, because they often have flexible, energy-intensive processes and dedicated energy managers who are committed to reducing the facility's energy costs. While PSCo does have some industrial load enrolled in DR programs, the company's total share of industrial load in its customer base is significantly smaller than these other utilities.

[3] Form EIA-861, 2020 and data provided by PSCo.

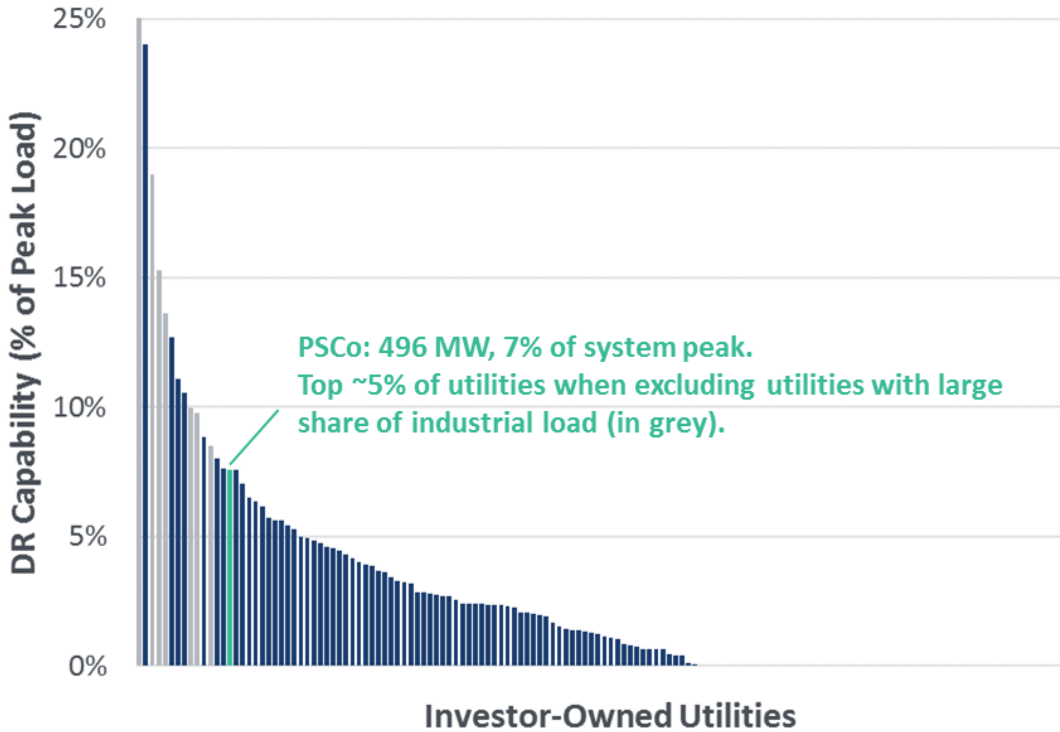
For example, Alabama Power's DR portfolio has peak reduction capability of 15 percent, with 91 percent of that capability coming from large industrial customers. 40 percent of Alabama Power's annual energy sales are to the industrial segment. In contrast, only 20 percent of PSCo's annual energy sales are to the industrial segment. Accordingly, only 25 percent of PSCo's DR capability resides with industrial customers. Figure 5 summarizes the share of sales and DR capability by class for the eight utilities with large industrial DR portfolios and PSCo, according to EIA data.

FIGURE 5: UTILITIES WITH PRIMARILY LARGE INDUSTRIAL DR PORTFOLIOS, COMPARED TO PSCO



After excluding the eight utilities with primarily industrial DR portfolios, PSCo's portfolio ranks in the top five percent of all IOUs in terms of peak reduction capability. Figure 6 summarizes these findings.

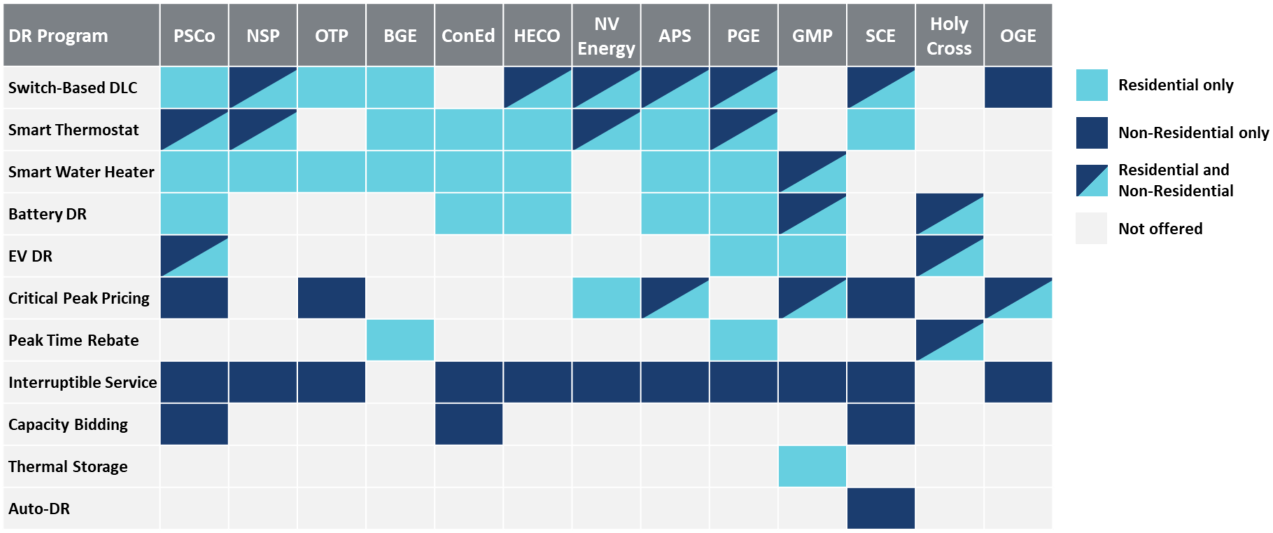
FIGURE 6: 2020 DR CAPABILITY OF EACH U.S. IOU



Notes: Light gray shading indicates utilities with large DR portfolios composed primarily of industrial load. Upper Michigan's DR capability (% of peak load) is reported as 61% but there may be an issue with data reporting. Figure data from Form EIA-861, 2020.

We also benchmarked the breadth of PSCo's DR program offerings. We created a list of comparison utilities with the largest DR portfolios from the analysis described above, as well as utilities that are often cited in industry studies and trade press as offering innovative "next generation" DR programs, such as Green Mountain Power and Portland General Electric. PSCo currently offers programs in most of the program categories identified in our review. In instances where other utilities offer programs that PSCo does not offer (peak time rebates, thermal storage, and Auto-DR), those programs were relatively rare offerings among the group of comparison utilities. Figure 7 summarizes the comparison of program offerings.

FIGURE 7: MATRIX OF DR PROGRAM OFFERINGS AT SELECTED UTILITIES



Notes: Based on Brattle review of utility websites and tariffs. NSP = Northern States Power, OTP = Otter Tail Power, BGE = Baltimore Gas & Electric, HECO = Hawaiian Electric Company, APS = Arizona Public Service, PGE = Portland General Electric, GMP = Green Mountain Power, SCE = Southern California Edison, OGE = Oklahoma Gas & Electric.

Takeaways

PSCo already has one of the largest DR portfolios in the country, with roughly 15 percent of its residential customers and 40 percent of its large C&I customers participating in some type of DR program. These significant levels of existing participation will serve as a constraint on the amount of new, incremental DR participation that can be achieved within current product offerings. Enrolling additional customers in DR programs is likely to require expansion of early stage and emerging programs (e.g., Battery Connect, A/C Rewards) as well as ongoing recruitment of new participants into existing programs.

As we discuss in the next section of this report, PSCo's DR programs will need to be utilized differently in the future than they are currently. An important consideration going forward will be on techniques for maintaining the currently high enrollment levels if DR events are called more often, at different times of day, or in other seasons of the year.

III. The Role of DR in a Rapidly Decarbonizing Power System

Introduction

PSCo's commitment to reducing the carbon emissions of its power supply by 80 percent by 2030 (relative to 2005 levels) means that the company's power system will become significantly more dependent on wind and solar generation over the next decade. According to PSCo's Phase I ERP, the share of the company's generation coming from renewables will increase from roughly 50 percent in 2022 to 80 percent by 2030 on the way to 100% carbon-free electricity by 2050.[4]

PSCo's increased reliance on renewables will require that the company's capacity planning decisions be based on net load rather than gross load. "Net load" refers to total gross load minus the expected output from non-dispatchable generation (primarily wind and solar). Net load is an important planning metric, because it can identify those hours of the year when load is expected to be high and output from wind and solar are expected to be low. For example, utilities with high market penetration of solar PV have found that the coincidence of the gross system peak and solar output has resulted in a net peak that occurs in the later evening hours. As a result, system planners in those regions have begun to plan around a net peak that occurs later in the day than they had previously considered in planning decisions.

Changes to PSCo's net load shape by 2030 could have a significant impact on the role and value of DR to the system. In this section, we analyze the implications of PSCo's power supply decarbonization plans for DR program operations and economics. The results have important implications for interpreting the company's future DR potential

System Load in 2022

At current levels of renewables generation deployment, PSCo's net load shape still reflects that of a summer peaking system. In 2022, the net system peak is forecasted to occur at 5 pm on a weekday in August. Using DR to reduce PSCo's system peak will require that load be reduced in several hours of the year. That is because when load is reduced during the hour of the system peak, the hour of the year with the second-highest load becomes the new peak, so load in that second hour must be reduced as well. The larger the target peak demand reduction for DR, the greater the number of hours of the year in which DR events will be needed.

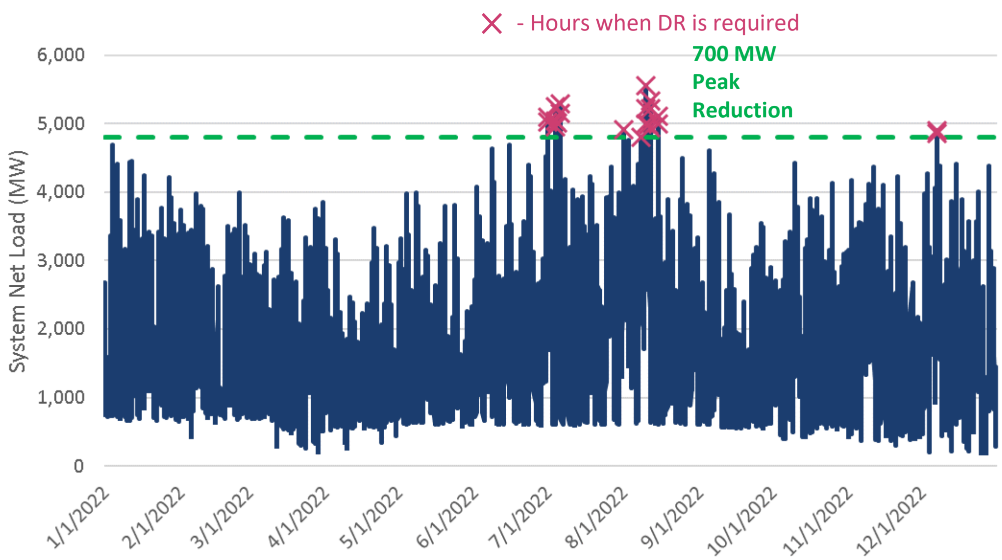
Figure 8 below illustrates PSCo's hourly forecasted 2022 system net load shape.[5] The figure also identifies (with a purple 'X') the hours of the year during which DR events would be needed in order to

[4] Public Service Company of Colorado, "Our Energy Future: Destination 2030," March 31, 2021.

[5] The hourly net load data is consistent with the assumptions in PSCo's Phase I ERP.

achieve an illustrative 700 MW reduction in PSCo's system peak demand. We selected 700 MW as a purely illustrative value, because it is approximately 200 MW larger than PSCo's existing DR capability.[6]

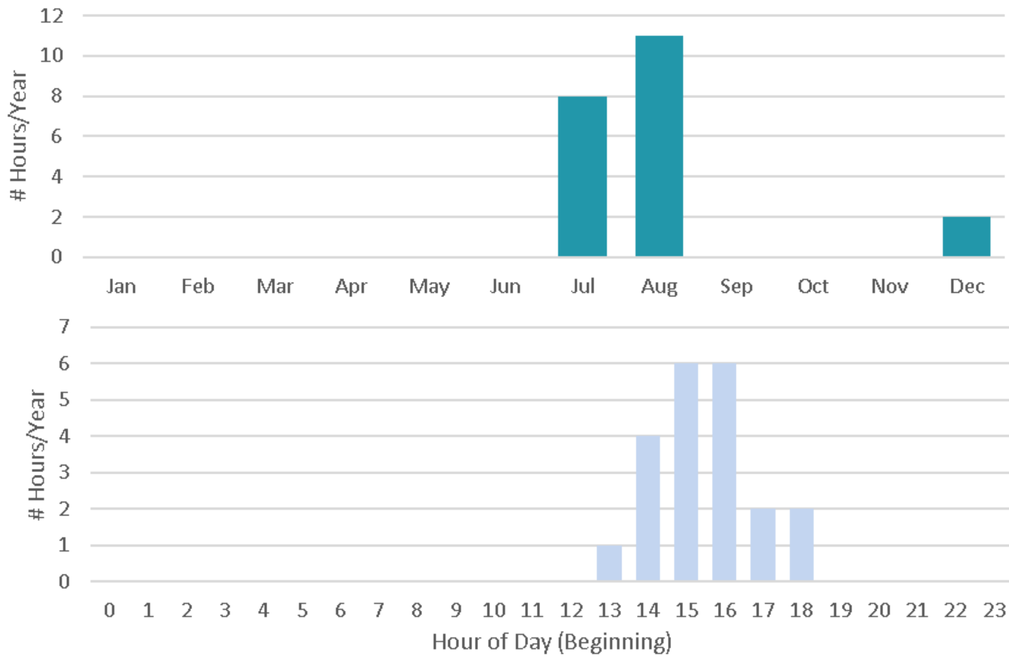
FIGURE 8: 2022 FORECASTED HOURLY PSCO SYSTEM NET LOAD



Reducing net peak demand by 700 MW in 2022 would require DR events during 21 hours of the year. Those hours are concentrated primarily in summer months (July and August) and afternoon or evening hours (1 to 7 pm). The timing of that need for load reductions aligns with the design of PSCo's DR portfolio, which typically focuses on afternoon and evening hours and includes a significant amount of air-conditioning load control. Figure 9 summarizes the months and hours of the day during which these DR events would need to occur.

[6] The PUC's Interim Decision No. C21-0395-I instructed PSCo to examine the potential impacts of 200 MW of new DR.

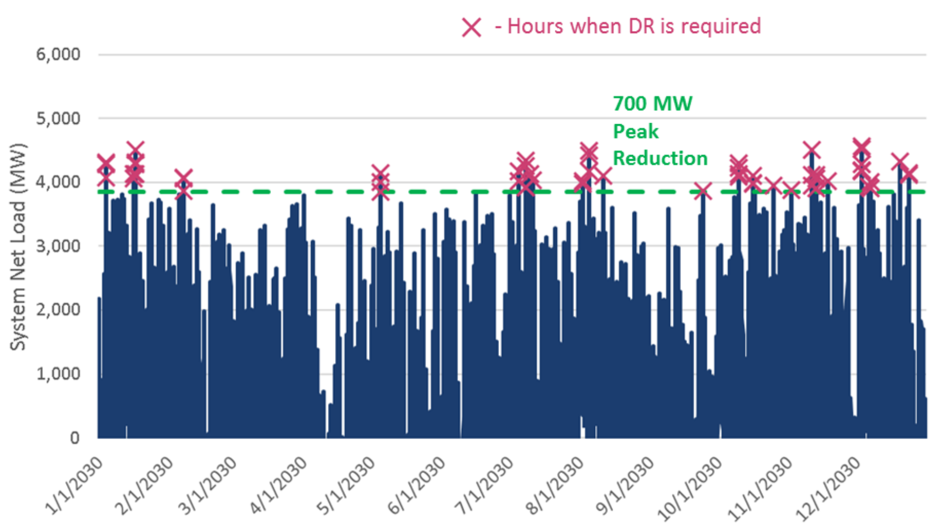
FIGURE 9: FREQUENCY OF HOURS REQUIRING DR EVENTS (2022)



System Load in 2030

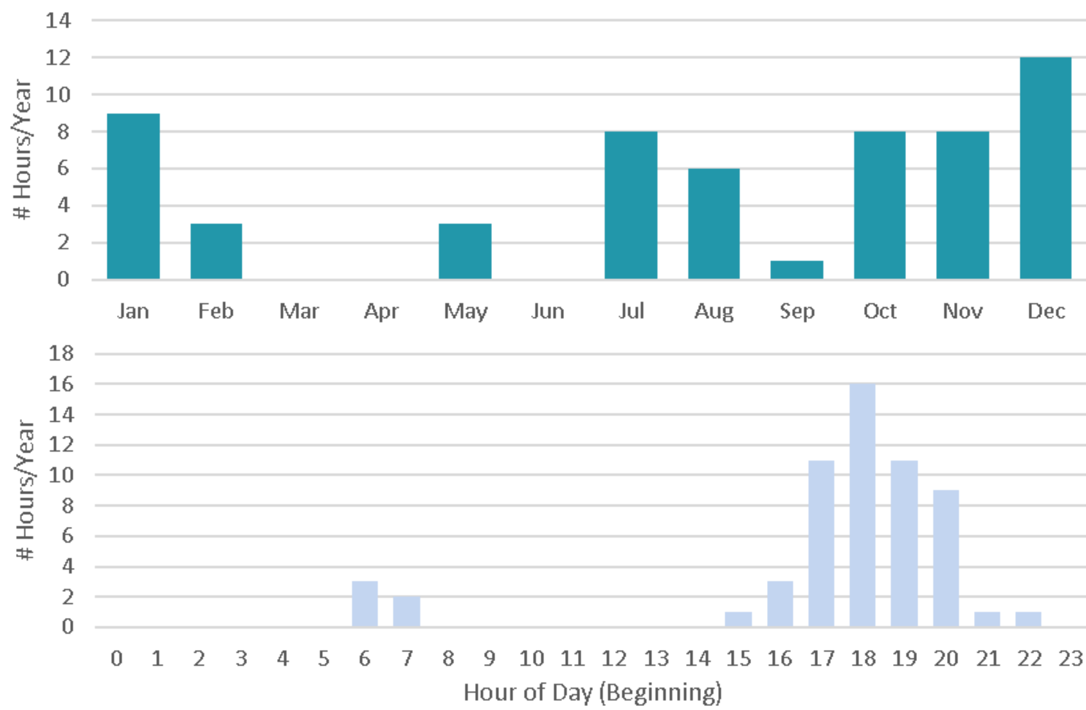
PSCo's net load shape will change significantly by 2030. Of particular relevance to DR, net load will be as high in the winter as it is in the summer. Figure 10 illustrates PSCo's forecasted hourly net load in 2030 and identifies the hours that would require DR events in order to achieve a 700 MW reduction in net system peak demand.

FIGURE 10: 2030 FORECASTED HOURLY NET SYSTEM LOAD



The number of hours requiring DR events is significantly higher in 2030, increasing from 21 in 2022 to 58 in 2030. This indicates that DR programs will need to be utilized more frequently than they have in the past, though the forecasted required number of DR events is still generally within the operational limits of PSCo's existing programs. Additionally, the DR event hours occur throughout the year, with more events occurring in the winter than in the summer. The DR events occur in a later and broader window during each day than in 2022, spanning the evening period from 3 to 11 pm and also including a few event hours in the morning between 6 and 8 am. Figure 11 summarizes the months and hours of the day during which these DR events would need to occur in 2030.

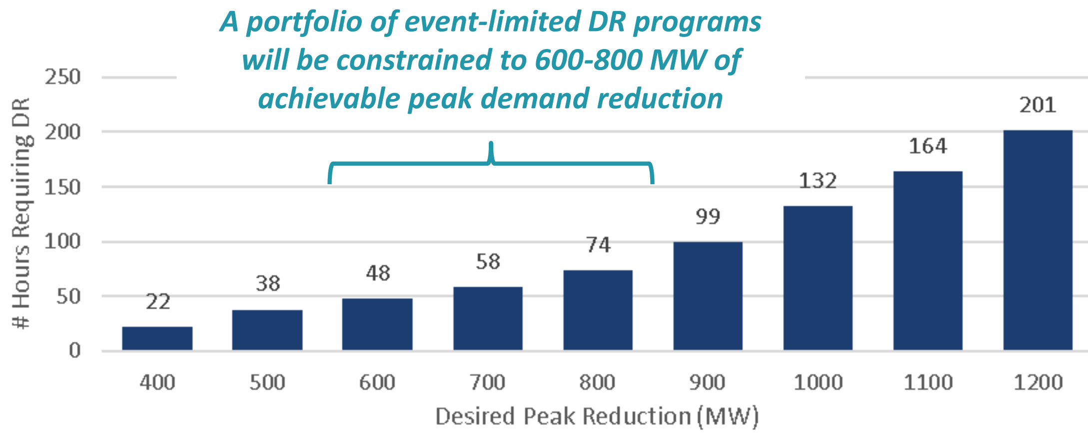
FIGURE 11: FREQUENCY OF HOURS REQUIRING DR EVENTS (2030)



In the context of PSCo's DR potential, the 2030 net load shape will effectively serve as a limit on the peak demand reduction that can be achieved through conventional "peak clipping" programs. Those programs typically are limited to 50 to 75 DR event hours per year and often have limits on the timing and season of the events.[7] As the desired peak demand reduction grows, so does the number of hours required for DR events. In 2030, a portfolio of event-limited DR programs would be constrained to roughly 600 to 800 MW of DR potential for this reason. Figure 12 summarizes the number of hours required for various target peak demand reduction levels.

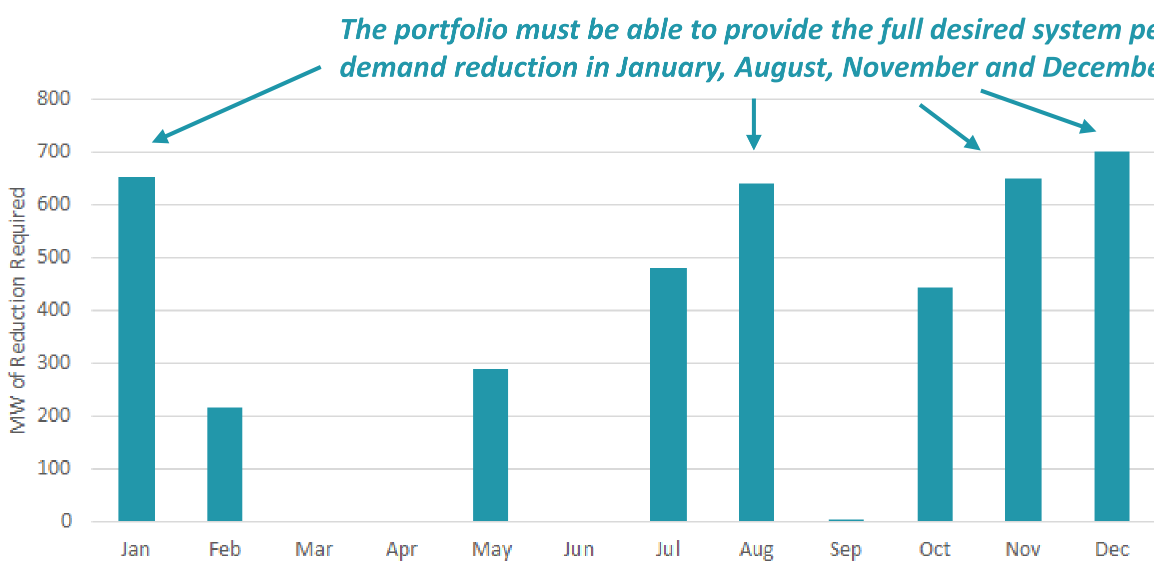
[7] These limits exist in order to limit the impact of the program on participant comfort and quality of service. They are generally regarded as necessary limits in order to achieve sufficient levels of program participation.

FIGURE 12: NUMBER OF HOURS REQUIRED TO ACHIEVE TARGET NET PEAK DEMAND REDUCTION (2030)



Additionally, peak demand reductions in 2030 will require a portfolio that is capable of reducing peak demand in both the summer and the winter. In fact, the portfolio will need to have roughly the same capability in both seasons in order to provide the target peak demand reduction. Figure 13 illustrates the magnitude of load reduction required in each month of 2030 in order to result in an overall reduction in the net system peak of 700 MW. The figure shows that a peak demand reduction of 600 to 700 MW would be needed in the winter months of November, December, and January, as well as the summer month of August.

FIGURE 13: MEGAWATTS OF LOAD REDUCTION REQUIRED IN EACH MONTH TO ACHIEVE 700 MW SYSTEM NET PEAK DEMAND REDUCTION (2030)



Takeaways

Our analysis of PSCo's 2030 net load shape identifies several critical considerations when assessing PSCo's DR potential:

- The DR portfolio will need to provide peak demand reductions of comparable magnitude in both the summer and the winter. Given that PSCo's current portfolio provides 496 MW of summer peak demand reduction but only 239 MW of winter peak demand reduction, winter capability will need to increase significantly in order for the portfolio to continue to deliver value comparable to current available load relief.

- By 2030, PSCO's DR programs will need to be utilized significantly more frequently than in the past. PSCo's potential for "low frequency" (<75 DR event hrs/yr) DR programs is likely capped at 600 to 800 MW due to operational limitations of those programs relative to system needs in 2030. Significant DR portfolio expansion will require new programs that have the ability to reduce peak demand with high frequency (>75 DR event hrs/yr), such as TOU rates and water heating load control.

- The analysis presented here is based on weather normalized load data and only accounts for the forecasted level of heating electrification assumed in PSCo's Phase I ERP. The need for winter DR could be more pronounced if heating electrification occurs at higher levels than assumed in the ERP. Similarly, the frequency with which DR events are needed could increase in abnormal weather conditions. On the other hand, DR potential itself could increase as electric heating would be a new candidate load for DR participation.

IV. DR Assessment Methodology

Introduction

PSCo's DR capabilities could increase by growing enrollment in existing programs and by introducing new complementary programs that address the future needs of the Colorado power system. In this section of the report we define the DR programs that we analyzed in this study and summarize our methodology for ensuring that the benefits and costs of the programs were comprehensively considered in the context of the evolving power system needs described in Section III.

Modeled DR Programs

Our discussion in Section III identified an important distinction between "low frequency" DR programs (i.e., those with less than 75 hours of annual DR event-hours) and "high frequency" DR programs (i.e., those with daily or otherwise very frequent load shifting capability). We have organized our discussion of the modeled DR programs into those two categories.

Low Frequency DR Programs

- Direct load control (DLC): Participant's central air-conditioner is remotely cycled using a switch on the compressor. The modeled program is based on PSCo's Savers Switch program. Other end-uses could be controlled in this manner as well, though air-conditioning is the most common participating end-use in these types of programs.

- Smart thermostat-based load control: An alternative to conventional DLC, smart thermostats allow the temperature set point to be remotely controlled to reduce A/C or heating usage during peak times. The modeled program is based on a continued expansion of PSCo's A/C Rewards program, which provides customers with options to use their own thermostat, self-install a thermostat purchased from PSCo's online store, or use a PSCo-installed thermostat.

- Interruptible rates: Participants agree to reduce demand to a pre-specified level and receive an incentive payment in the form of a discounted rate. The program modeled in our study is an expansion of PSCo's ISOC program.

- Peak time rebate (PTR): Participants receive a payment for measured reductions in peak period usage relative to an estimated baseline usage level during DR events. The payment is a function of the amount of reduced usage – larger reductions result in larger payments. Customers have no obligation to respond. If they do not reduce their usage, they simply continue to pay for their consumption at the applicable retail rate. Given that there is no downside to customers with this option, we model it as a default deployment. It is "layered" on top of the default TOU to provide an additional incentive to respond during a limited number of events throughout the year.

- Behavioral DR: Customers are informed of the need for load reductions during peak times without being provided an accompanying financial incentive. Customers are typically informed of the need for load reductions on a day-ahead basis and events are called sparingly throughout the year. Behavioral DR programs have been piloted by several utilities, including Consumers Energy, Green Mountain Power, the City of Glendale, Baltimore Gas & Electric, and four Minnesota cooperatives.

- EV workplace managed charging: Workplace EV chargers could be remotely controlled to reduce charging load when needed on the power system. There are many ways in which such a program could be structured, and there is not yet an established standard approach. For this study, we model an event-based load control program with a limited number of DR events per year.

- Critical peak pricing (CPP): As described previously in this report, PSCo offers CPP rates to C&I customers. We analyze a possible expansion of this program, including PSCo's planned growth as modeled in the Phase I ERP.

- Peak Day Partners: Our analysis accounts for PSCo's planned growth in its Peak Day Partners program, as modeled in the Phase I ERP.

High Frequency DR Programs

- Default time-of-use (TOU) rate: TOU rates provide a static price signal with higher price during peak hours on non-holiday weekdays. PSCo plans to fully transition all residential and small C&I customers to a TOU rate on a default basis before 2030. For the purposes of this study, we analyze the potential associated with defaulting large C&I customers to a TOU rate, although PSCo does not currently have plans to implement a default TOU for large C&I customers. The load impacts of the TOU rollout are not factored into PSCo's load forecast for its Phase I ERP, so we have included TOU rates as an incremental DR option in this study. We do not evaluate the cost-effectiveness of the rollout, since the decision has already been made to move forward with TOU rates for the residential and small C&I classes, so our analysis focuses on estimating the load impacts. Where applicable, load impacts from other DR programs are estimated as incremental to the impacts of the TOU rates, to avoid double-counting DR impacts and benefits.

- EV TOU rate: TOU rates are an effective tool for encouraging off-peak charging of EVs at home, with early evidence indicating that 80% or more of the peak period charging load of participants could be shifted to off-peak hours.[8] For this reason, our analysis focuses on TOU rates as the method for managing home EV charging. As EV adoption grows beyond levels contemplated in this study, there may be additional value in actively managing home EV charging to avoid creating new local peaks on the distribution system when the peak period ends.

[8] Smart Electric Power Alliance, "Residential Electric Vehicle Rates That Work," November 2019.

- Grid-interactive water heating (GIWH): Offers improved flexibility and functionality in the control of the heating element in the water heater. The thermostat can be modulated across a range of temperatures. Multiple load control strategies are possible, such as peak shaving, energy price arbitrage through day/night thermal storage, or the provision of ancillary services such as frequency regulation. We modeled the control of electric resistance water heaters, as these represent the vast majority of electric water heaters and are currently the most attractive candidates for a range of advanced load control strategies.

- C&I Auto-DR: Auto-DR technology automates the control of various C&I end-uses. Features of the technology allow for deep curtailment during peak events, moderate load shifting on a daily basis, and load increases and decreases to provide ancillary services. Modeled end-uses include HVAC and lighting.

DR Programs Considered but not Modeled

In addition to the DR programs that were included in the quantitative estimate of DR potential in this study, there are other DR options that potentially could contribute to PSCo's future DR opportunities. These programs were excluded from the analysis because there is limited empirical support for estimating their impacts and cost-effectiveness (e.g., they are not yet commercially available or thoroughly piloted), or because qualitative screening suggested that their potential would be small and/or cost-effectiveness would be low.

"AMI 2.0" Enabled DR

PSCo's AMI rollout will include smart meters with distributed intelligence functionality. Sometimes referred to as "AMI 2.0" the smart meters will have computational capabilities that allow third-party "apps" to be installed at the meter. These apps could enable the provision of new information and services to customers, including improved DR capability.

For example, National Grid has AMI 2.0 deployment plans, which will include meters that are equipped with software developed by Sense.[9] Sense's software uses machine learning to provide customers with real-time, appliance-level information about their energy use. In California, Sense recently partnered with OhmConnect to determine whether access to such information could boost customer response to demand response incentives.[10] The pilot concluded that information and notifications provided by Sense more than doubled the usage reductions that otherwise would have been achieved during DR events.[11]

[9] New York PSC, Cases 17-E-0238 and 17-G-0239, Order Authorizing Implementation of Advanced Metering Infrastructure with Modifications, November 20, 2020.

[10] OhmConnect offers participants a variety of financial incentives for reducing usage when it is valuable to the power grid. The response is behavioral and not driven by automated load control.

[11] Sense Press Release, November 2021: https://www.prnewswire.com/news-releases/sense-and-ohmconnect-partner-to-increase-participant-savings-by-160-301414758.html.

While PSCo's plans for leveraging its AMI 2.0 rollout are still being determined by the company, we believe this advanced metering functionality can be used to increase the impacts of the behavioral DR programs in this study (primarily TOU, PTR, and Behavioral DR). Given the currently limited empirical support for the costs and impacts, we have not included these impacts in the quantitative portion of our study.

Vehicle-To-Grid

EVs are a large source of load flexibility potential. An EV with 300 miles of range could store around 100 kWh of energy and discharge at a capacity of more than 10 kW.[12] While our study has captured the value associated with curtailing EV charging, there is significant additional potential associated with discharging the batteries to provide electricity to the power grid when it is valuable. Recent pilots in California, Texas, New York, and several European countries have begun to demonstrate the technical feasibility of this approach.

While V2G demonstration projects and pilots are underway, it is not yet a commercially viable option that is ready for full-scale deployment. Our expectation is that this will change. For example, Ford's F-150 Lightning will come with the capability to power a home ("vehicle-to-home"), a significant step in the direction of selling electricity to provide grid services. However, given the currently limited commercial applicability of V2G and uncertainty around full-scale costs of deploying the required technology, we did not model it quantitatively in this study. The topic should be revisited in future studies, as the industry gains experience with this concept. If cost-effective, V2G would increase the DR potential estimates presented in our study.

Commercial Behind-the-Meter Battery DR

Behind-the-meter (BTM) batteries at commercial facilities potentially could provide DR benefits similar to those of the residential BTM battery program modeled in this study. While PSCo could consider extending their BTM battery to larger customer segments, we did not include that option in our quantitative modeling. There is some jurisdictional precedent for residential BTM battery programs – Green Mountain Power and Portland General Electric are two examples of utilities with such programs. However, we have not observed the same program precedent for larger commercial customers. Additionally, commercial customers with a BTM battery already have the opportunity to use a battery to reduce load and be compensated for that load reduction while participating in one of PSCo's available commercial DR programs.[13]

[12] Assumes efficiency of 3 miles per kWh and a level 2 charger.

[13] Under the current DR program definitions, this would include compensation for using the battery to reduce load, but would not provide compensation for exports to the grid.

Fleet Managed Charging

As transportation electrification initiatives grow, the electrification of commercial vehicle fleets could become a large new source of load. Some types of fleets could be attractive candidates for providing demand response. For example, school busses operate on a very predictable schedule and only need to be used during specific times of day. Tapping into the idle battery of those busses while charging could provide valuable services to the power grid. Similar to vehicle-to-grid initiatives, fleet managed charging programs are still in the technical demonstration phase at this point. As fleets continue to electrify and the industry gains experience with the DR capabilities of those fleets, it will be useful to revisit the potential benefits of this program. We note that PSCo already encourages commercial owners of fleets to enroll in the company's CPP offering.

Thermal Energy Storage

Commercial customers could shift peak cooling demand to off-peak hours using ice-based storage systems. The thermal storage unit acts as a battery for the customer's A/C unit, charging at night (freezing water) and discharging (allowing ice to thaw to provide cooling) during the day. When included in DR potential studies, thermal storage systems are typically only cost-effective for niche customer segments, due to their significant physical footprint and high up-front costs. Due to that and the observation in this study that demand reductions will be needed in the winter in order for a program to provide significant capacity value, ice-based thermal storage was excluded from the analysis. Thermal energy storage is an area to monitor as a future opportunity, particularly if buildings begin to convert to electric heating and if there are accompanying technical advancements in thermal storage research and development (R&D).

Heat Pump Water Heating DR

The peak demand of heat pump water heaters could be controlled in order to provide demand response benefits. The technical feasibility of this option is still unclear, as heat pumps often need to run consistently in order to provide the desired level of comfort. Additionally, due to their high efficiency, heat pumps have significantly less peak electricity demand than electric resistance heating technologies. As a result, the per-unit benefits of shifting load out of the peak period are smaller, while the cost of achieving that control is not. Lastly, PSCo's Phase I ERP forecasts do not include a large amount of heat pump adoption by 2030. Based on these factors – technological uncertainty, questionable cost-effectiveness, and modest potential – heat pump water heating DR was excluded from the analysis. If heat pumps reach more significant levels of market penetration (i.e., beyond the timeframe of this study) and begin to exacerbate peaking conditions, then we recommend revisiting methods for managing those peaks through additional research.

DR Benefits

Modeled DR Benefits

This study accounts for several value streams that compose the core DR value proposition:

- Avoided generation capacity costs: The need for new peaking capacity can be reduced by lowering system peak demand. Important considerations when estimating the equivalence of DR and a peaking generation unit are discussed later in this section of the report.

- Reduced peak energy costs: Reducing load during high priced hours leads to a reduction in energy costs. Our analysis estimates net avoided energy costs, accounting for costs associated with the increase in energy consumption during lower cost hours due to "load building." The energy benefit accounts for avoided average line losses. Our analysis likely includes a conservative estimate of this value, as peak line losses are greater than off-peak line losses.

- System-wide deferral of transmission and distribution (T&D) capacity costs: System-wide reductions in peak demand can, on average, contribute to the reduced need for peak-driven upgrades in T&D capacity. We account for this benefit using values established for evaluating the T&D benefits of energy efficiency measures.[14]

- Load building / valley filling: Load can be shifted to reduce wind or solar curtailments or take advantage of low or negatively priced hours. DR was dispatched against forecasted hourly marginal costs consistent with PSCo's Phase I ERP to capture the economic incentive that energy prices provide for this service.

Other DR Benefits

DR may be able to provide other benefits which were not included in this analysis. We excluded these potential benefits from our analysis because they were considered likely to be small or difficult to quantify based on available data.

- Geo-targeted distribution capacity investment deferral: DR participants may be recruited in locations on the distribution system where load reductions would defer the need for capacity upgrades. Our inclusion of system-wide T&D deferral benefits partly addresses this potential value stream. Further review of PSCo's distribution plan may identify additional high-value opportunities for location-specific DR program deployment.

- Ancillary services: The load of some end-uses (such as electric resistance storage water heaters) can be increased or decreased in real time to mitigate system imbalances. We did not model the ability of DR programs to provide ancillary services, because we anticipate that the amount of

[14] Public Service Company of Colorado, "Energy Efficiency Investment: Deferred Transmission & Distribution Costs, 2017-2021 "T&D Study"," 2016.

battery storage that will enter the system by 2030 is likely to saturate the need for these services, significantly reducing the need to provide them from DR resources.

- Environmental benefits: DR programs that provide frequent load shifting may directly reduce emissions, if load is being shifted from hours when carbon emitting generation resources are on the margin to hours when renewables are being curtailed or more efficient thermal generators are on the margin. Additionally, by shifting load to hours when renewables otherwise would be curtailed, DR can improve the capacity factors of wind and/or solar generators, thus improving their economics and contributing to increased deployment. DR also can be used to facilitate cost-effective adoption of electrification measures by mitigating load impacts and associated infrastructure investment needs.

Defining DR Potential

Our cost-effectiveness test compares the costs incurred by the utility – including incentive costs – to the power system benefits provided by the program. For the purposes of our study, this cost-effectiveness test perspective is a proxy for the total resource cost (TRC) test, which is Colorado's standard test for evaluating demand-side management programs. In cases where a portion of the equipment cost is borne by the participant, we implicitly treat participant incentive payments as an approximate representation of total equipment cost of the program, less the intrinsic benefit the participant receives from adopting the technology and participating in the program. Major categories of benefits and costs included in the analysis are summarized Table 1.

TABLE 1: CATEGORIES OF BENEFITS AND COSTS INCLUDED IN THE COST-EFFECTIVENESS ANALYSIS

Benefits	Costs
Avoided generation capacity	Incentive payments
Avoided peak energy costs	Utility equipment & installation
Avoided transmission capacity	Administration/overhead
Avoided distribution capacity	Marketing/promotion
Ancillary services	

Our study focuses on estimating cost-effective, achievable potential. This is DR capability that can be plausibly obtained at cost-effective incentive payment levels. For each program, the assumed participation incentive payment level is set such that the benefit-cost ratio is equal to 1.0. Participation rates are estimated to align with this incentive payment level. When non-incentive costs (e.g., equipment and installation costs) are found to outweigh the benefits alone, the benefit-cost ratio is less than 1.0 and there is no opportunity to offer a cost-effective participation incentive payment. In that case, the program is considered to have no cost-effective potential.

The LoadFlex Model

The Brattle Group's Load*Flex* model was used to estimate DR potential in this study. The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of DR programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program. If only a modest incentive payment can be justified in order to maintain a benefit-cost ratio of 1.0, then the participation rate is calibrated to be lower than if a more lucrative incentive payment were offered. Prior approaches to quantifying DR potential ignore this relationship between incentive payment level and participation, which tends to under-state the potential (and, in some cases, incorrectly concludes that a DR program would not pass the cost-effectiveness screen).

- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of PSCo's customer base. In the residential sector, this includes accounting for the market saturation of various end-use appliances (e.g., central air-conditioning, electric water heating). In the C&I sector, this includes accounting for customer segmentation based on size (i.e., the customer's maximum demand) and industry (e.g., hospital, university). Load curtailment capability is further calibrated to PSCo's experience with DR programs where available (e.g., impacts from existing DLC programs or dynamic pricing pilots).

- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), Load*Flex* includes an hourly profile of load interruption capability for each program. For instance, for an EV home charging load control program, the model accounts for home charging patterns, which would provide greater average load reduction opportunities during evening hours (when EV owners have returned home from work) than in the middle of the day.

- **Realistic accounting for "value stacking":** DR programs have the potential to simultaneously provide multiple benefits. For instance, a DR program that is dispatched to reduce the system peak and therefore avoid generation capacity costs could also be dispatched to address local transmission or distribution system constraints. However, trade-offs must be made in pursuing these value streams – curtailing load during certain hours of the day may prohibit that same load from being curtailed again later in the day for a different purpose. Load*Flex* accounts for these trade-offs in its DR dispatch algorithm. DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program. Prior studies of load flexibility value have often assigned multiple benefits to DR programs without accounting for these trade-offs, thus double-counting benefits.

- **Industry-validated program costs:** DR program costs are based on a detailed review of PSCo's current DR offerings. For new programs, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors. Program costs are differentiated by type (e.g., equipment/installation, administrative) and structure (e.g., one-time investment, ongoing annual fee, per-kilowatt fee) to facilitate integration into utility resource planning models.

The Load*Flex* modeling framework is organized around six steps, as summarized in Figure 14. Appendix A provides detail on the methodology behind each of these steps.

FIGURE 14: THE LOADFLEX MODELING FRAMEWORK

Data

To develop participation, cost, and load impact assumptions for this study, we relied on a broad range of resources. Where applicable, we relied directly upon information from PSCo's experience with DR programs in its service territory. Our results are also informed by primary market research that was conducted directly with customers in PSCo's service territory in 2013, in order to better understand their preferences for various DR program options.[15] Where PSCo-specific information was unavailable, we reviewed national data on DR programs, DR potential studies from other jurisdictions, and DR program impact evaluations. A complete list of resources is provided in the References section and described further in Appendix A.

[15] Ahmad Faruqui, Ryan Hledik, David Lineweber, Allison Shellaway, "Estimating Xcel Energy's Public Service Company of Colorado Territory Demand Response Market Potential," prepared for Xcel Energy by The Brattle Group, June 11, 2013.

In an assessment of emerging DR opportunities, it is important to recognize that data availability varies significantly by DR program type. Conventional DR programs, such as air-conditioning load control, have decades of experience as full-scale deployments around the US and internationally. By contrast, emerging DR programs like EV charging load control have only recently begun to be explored, largely through pilot projects. Figure 15 summarizes data availability for each of the DR program types analyzed in this study.

FIGURE 15: DATA AVAILABILITY BY DR PROGRAM TYPE

	Participation	Costs	Peak Impacts
Residential			
Air-conditioning DLC	●	●	●
Smart thermostat	●	●	●
Peak Time Rebate	●	●	◑
Behavioral DR	◑	◑	◑
BTM Storage	◔	◔	◔
GIWH	◔	◔	◑
Default TOU	●	●	◑
EV charging TOU (home)	○	○	◔
EV managed charging (workplace)	○	○	◔
C&I			
Smart thermostat	●	●	●
CPP/PTR rates	●	●	◑
Interruptible Tarriff	●	●	◑
Peak Partner Rewards	●	●	●
TOU rates	●	●	◑
Peak Day Partners	●	●	●
Auto DR HVAC/AC	○	◔	◔
Auto DR Lighting	○	◔	◔

Notes:

● PSCo-specific data, including market research, pilot programs, and full-scale deployments

◑ Signficant program experience in other jurisdictions

◔ Some pilot or demonstration project experience in other jurisdictions

○ Speculative, estimated from theoretical studies and calibrated to PSCo conditions

V. PSCo's 2030 DR Potential

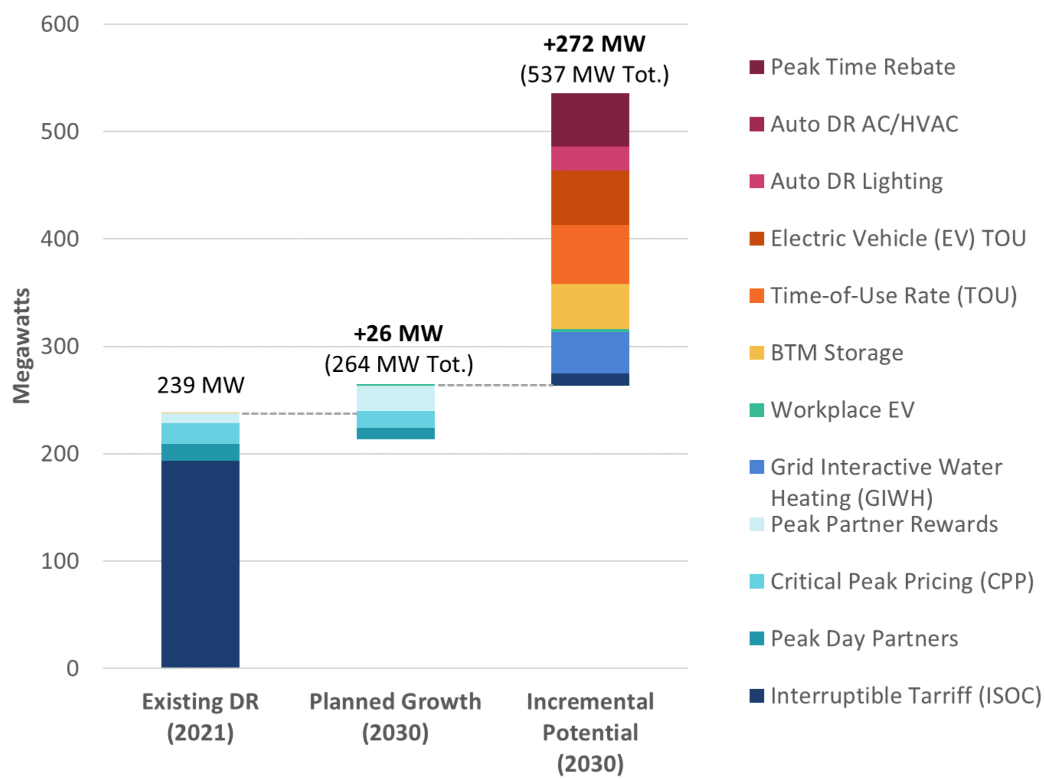
Introduction

In this section, we summarize our estimates of PSCo's total cost-effective, achievable DR potential in 2030. The estimates separately describe PSCo's existing DR capability, the amount of DR portfolio growth that PSCo included in its Phase I ERP, and our estimates of additional DR potential that is incremental to those values. Given the important seasonal considerations around PSCo's DR capability in 2030, we report DR potential for both the winter and summer seasons.

Winter Potential

We estimate that PSCo has 537 MW of cost-effective winter DR potential in 2030. That value is relative to PSCo's existing winter DR capability of 239 MW. In other words, we estimate that there is the potential to roughly double PSCo's existing winter DR capability by 2030. Primary drivers of achievable incremental potential are default TOU rates for all customer classes, EV managed charging (TOU in our analysis), a targeted peak time rebate to provide event-based behavioral DR beyond TOU impacts, and growth in PSCo's BTM battery program. Figure 16 summarizes these winter DR potential estimates.

FIGURE 16: WINTER ACHIEVABLE DR POTENTIAL (2030)



Notes: "Planned Growth" starts below the top of the "existing DR" bar because ISOC capability is forecasted by PSCo to decline under business-as-usual conditions by 2030. Numbers may not sum exactly due to rounding.

Table 2 provides additional quantitative detail behind the DR potential estimates. The values in the column labeled "Incremental Achievable Potential" indicate the cost-effective, incremental technical in each of the programs considered by PSCo. The values in the column "Total potential cost-effective potential" indicate the amount of total DR in the proposed programs that can be achieved at cost-effective incentive payment levels, inclusive of any planned DR capability. In both cases, DR potential is shown at the portfolio level, accounting for overlap in participation when multiple programs are offered simultaneously.

TABLE 2: WINTER ACHIEVABLE DR POTENTIAL (2030)

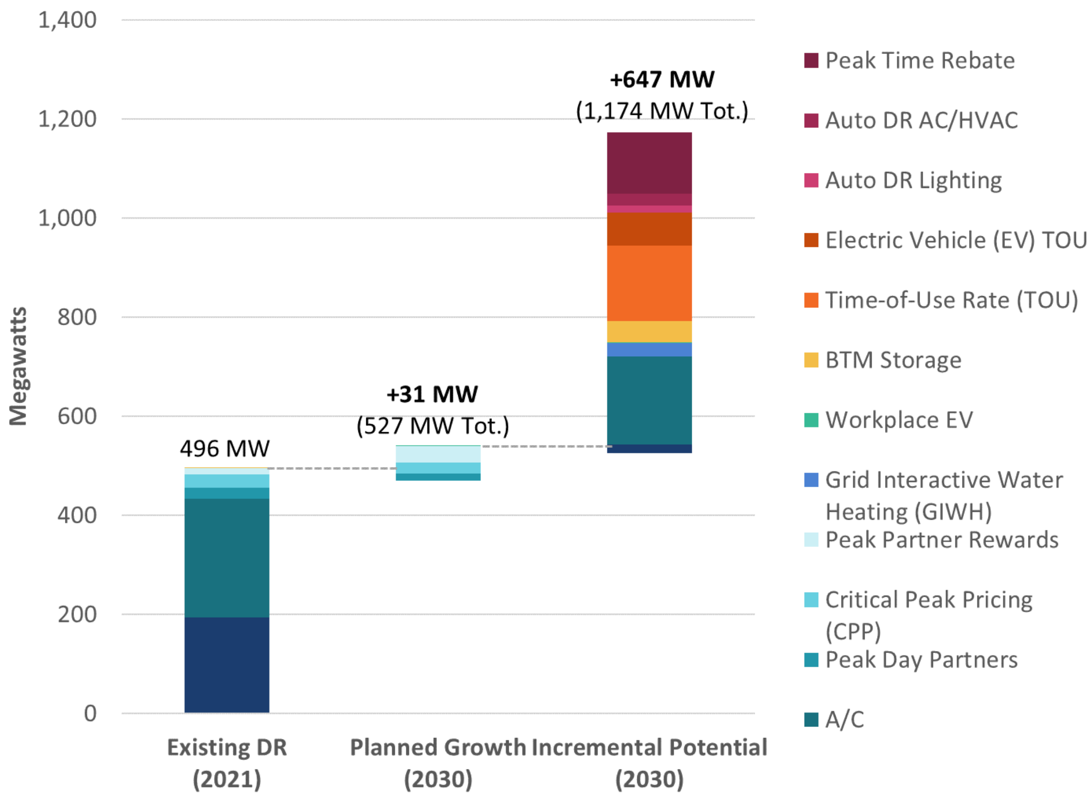
Program	Class	Existing (2021)	Planned change in ERP (2030)	Incremental Achievable Potential (2030)	Total Achievable Potential (2030)
Low-frequency programs (<75 DR hrs/yr)					
Savers Switch	Residential	0	0	0	0
Smart thermostat	Residential	0	0	0	0
Peak time rebate	Residential	0	0	49	49
Behavioral DR	Residential	0	0	0	0
BTM storage	Residential	1	0	42	43
Smart thermostat	Small C&I	0	0	0	0
Peak time rebate	Small C&I	0	0	0	0
Interruptible	Large C&I	194	-25	11	180
CPP	Large C&I	19	16	0	36
Peak Partner Rewards	Large C&I	9	23	0	32
EV Workplace Managed Charging	N/A	0	1	3	4
Peak Day Partners	Large C&I	15	10	0	26
Low Frequency Total		**239**	**26**	**106**	**370**
High-frequency programs (>75 DR hrs/yr)					
Default TOU	Residential	0	0	38	38
GIWH	Residential	0	0	38	38
EV TOU (Home)	Residential	0	0	50	50
Default TOU	Small C&I	0	0	0	0
Default TOU	Large C&I	0	0	17	17
Auto DR HVAC/AC	Small C&I	0	0	0	0
Auto DR HVAC/AC	Large C&I	0	0	1	1
Auto DR Lighting	Small C&I	0	0	15	15
Auto DR Lighting	Large C&I	0	0	7	7
High Frequency Total		**0**	**0**	**167**	**167**
Portfolio Grand Total		**239**	**26**	**272**	**537**

Notes: Numbers may not sum exactly due to rounding.

Summer Potential

In the summer, we estimate that PSCo has 1,174 MW of cost-effective DR potential in 2030. That value is relative to PSCo's existing summer DR capability of 496 MW. Similar to the winter DR potential, primary drivers of achievable incremental potential are default TOU rates for all customer classes, a targeted peak time rebate to provide event-based behavioral DR beyond TOU impacts, EV managed charging, and growth in the BTM battery program, as well as growth in A/C Rewards. PSCo's summer DR potential is 637 MW higher than its winter DR potential primarily due to flexible, discretionary air-conditioning-related load in the summer. Figure 17 and Table 3 summarize these summer DR potential estimates.

FIGURE 17: SUMMER ACHIEVABLE DR POTENTIAL (2030)



Notes: "Planned Growth" starts below the top of the "existing DR" bar because interruptible and Savers Switch capability is forecasted to decline under business-as-usual conditions by 2030. Numbers may not sum exactly due to rounding.

TABLE 3: SUMMER ACHIEVABLE DR POTENTIAL (2030)

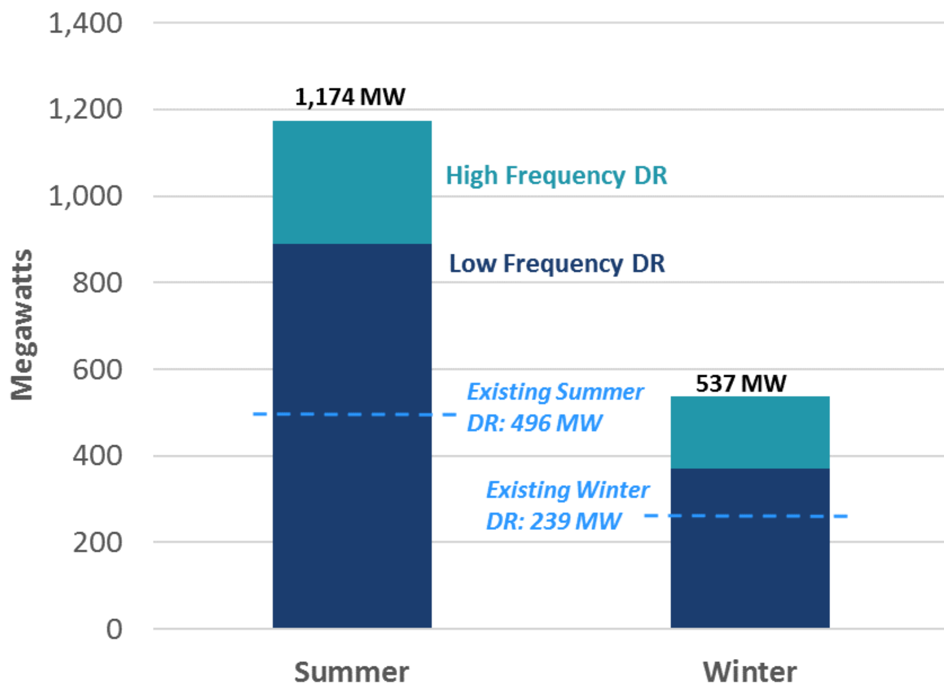
Program	Class	Existing (2021)	Planned change in ERP (2030)	Incremental Achievable Potential (2030)	Total Achievable Potential (2030)
Low-frequency programs (<75 DR hrs/yr)					
Savers Switch	Residential	214	-26	0	188
Smart thermostat	Residential	25	8	176	209
Peak time rebate	Residential	0	0	123	123
Behavioral DR	Residential	0	0	0	0
BTM storage	Residential	1	0	42	43
Smart thermostat	Small C&I	1	3	0	4
Peak time rebate	Small C&I	0	0	0	0
Interruptible	Large C&I	194	-25	17	186
CPP	Large C&I	27	23	0	50
Peak Partner Rewards	Large C&I	12	32	0	45
EV Workplace Managed Charging	N/A	0	1	2	4
Peak Day Partners	Large C&I	22	14	0	36
Low Frequency Total		**496**	**31**	**362**	**889**
High-frequency programs (>75 DR hrs/yr)					
Default TOU	Residential	0	0	126	126
GIWH	Residential	0	0	27	27
EV TOU (Home)	Residential	0	0	67	67
Default TOU	Small C&I	0	0	0	0
Default TOU	Large C&I	0	0	27	27
Auto DR HVAC/AC	Small C&I	0	0	16	16
Auto DR HVAC/AC	Large C&I	0	0	9	9
Auto DR Lighting	Small C&I	0	0	9	9
Auto DR Lighting	Large C&I	0	0	5	5
High Frequency Total		**0**	**0**	**285**	**285**
Portfolio Grand Total		**496**	**31**	**647**	**1,174**

Notes: Numbers may not sum exactly due to rounding.

Takeaways

PSCo's total system-wide DR potential will be the lesser of its winter or summer DR potential. As discussed in Section III of this report, net load conditions in 2030 will require that PSCo have the ability to reduce peak demand by similar amounts in both seasons in order to achieve the desired level of system peak demand reduction. For that reason, we estimate that PSCo's system-wide DR potential is 537 MW in 2030, as that is the maximum potential DR capability in the winter. Figure 18 summarizes PSCO's summer and winter DR potential.

FIGURE 18: SEASONAL ACHIEVABLE DR POTENTIAL (2030)



Summer DR has significantly higher potential due to flexibility in air-conditioning load. However, peak demand reductions beyond 537 MW in the summer will provide limited capacity value, because net peak demand will remain in the winter. This does not mean that summer DR programs are without value. Summer DR will continue to be needed to reduce the summer peak, and smart thermostat-based DR can be an effective tool for providing this value because in many cases customers are already choosing to adopt smart thermostats due to the variety of other benefits that they offer (remote control, energy savings, aesthetics, etc.). As heating electrification grows, thermostat programs can be repurposed to provide year-round benefits.

Figure 18 also shows that there is more potential in Low Frequency DR than in High Frequency DR. However, the potential for Low Frequency DR does not exceed the upper-bound threshold of 600 to 800 MW for event-limited DR described Section III of this report. In other words, the portfolio is not constrained by a limit on the system need for Low Frequency DR.

VI. Conclusion

This study set out to assess PSCo's achievable, cost-effective DR potential in 2030 through a detailed assessment of existing and emerging DR program impacts, benefits, and costs. We employed a robust, bottom-up modeling approach to comprehensively account for the broad range of system benefits that these programs could provide, as well as the operational constraints that are unique to DR programs. We also took into account the materially different needs for DR on PSCo's power system in 2030, as PSCo's power supply rapidly decarbonizes and becomes increasingly reliant on wind and solar generation.

We identify a need for PSCo to begin to build out its winter peak demand reduction capability. The need for growth in the winter DR portfolio is not immediate, but by 2030 we estimate that PSCo's DR portfolio will need to be able to provide comparable peak demand reductions in the summer and winter seasons in order to optimize the company's ability to target reductions in total system peak demand.

To achieve the peak demand reductions we have described, PSCo will need to utilize its DR programs more frequently than the company has in the past. DR programs will need to be utilized during more hours of the day and on more days of the year. While the system will have a continued need for "low frequency" DR programs (i.e., those with less than 75 DR event-hours per year) the need for increased utilization of the DR programs and for year-round peak reduction capability highlights the value of programs that can provide frequent – even daily – load shifting.

In that regard, PSCo's planned default TOU rollout for residential and small C&I customers will provide significant value by incentivizing year-round peak demand reductions on a daily basis. To provide all customers with further incentive to reduce peak demand, PSCo may consider eventually extending default TOU to large customers and combining the TOU rate with a peak-time rebate offering. Peak time rebates are a zero-risk option for customers, as they receive a rebate for measured demand reductions during DR events, and are not subject to a penalty if they choose not to reduce their demand. For this reason, some utilities (e.g., BGE and Pepco in Maryland) have rolled out peak time rebates to their customers on a default basis.

Our analysis identifies a number of other attractive options, which will leverage anticipated growth in emerging technologies such as EVs, behind the meter batteries, and grid-interactive water heaters. Automated load control for large commercial customers and expansion of PSCo's existing programs are opportunities as well. Additionally, we recommend tracking emerging DR opportunities not modeled in this study, such as vehicle-to-grid capability and options for leveraging the distributed intelligence in PSCo's ongoing smart metering rollout.

PSCo's rapidly changing power system will present new challenges and opportunities for the company's industry-leading DR portfolio. With attention to the evolving needs of the system, DR can continue to be a cornerstone of Colorado's decarbonization transition.

References

Auto-DR

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Appendix A: LoadFlex Modeling Methodology and Assumptions

The LoadFlex Model

The Brattle Group's Load*Flex* model was developed to quantify the potential impacts, costs, and benefits of demand response (DR) programs. The Load*Flex* modeling approach offers the flexibility to accurately estimate the broader range of benefits that are being offered by emerging "DR 2.0" programs, which not only reduce system peak demand, but also provide around-the-clock load management opportunities.

The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of DR programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program. If only a modest incentive payment can be justified in order to maintain a benefit-cost ratio of 1.0, then the participation rate is calibrated to be lower than if a more lucrative incentive payment were offered. Prior approaches to quantifying DR potential ignore this relationship between incentive payment level and participation, which tends to under-state the potential (and, in some cases, incorrectly concludes that a DR program would not pass the cost-effectiveness screen).

- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of the utility's customer base. In the residential sector, this includes accounting for the market saturation of various end-use appliances (e.g., central air-conditioning, electric water heating). In the commercial and industrial (C&I) sector, this includes accounting for customer segmentation based on size (i.e., the customer's maximum demand) and industry (e.g., hospital, university). Load curtailment capability is further calibrated to the utility's experience with DR programs (e.g., impacts from existing DLC programs or dynamic pricing pilots).

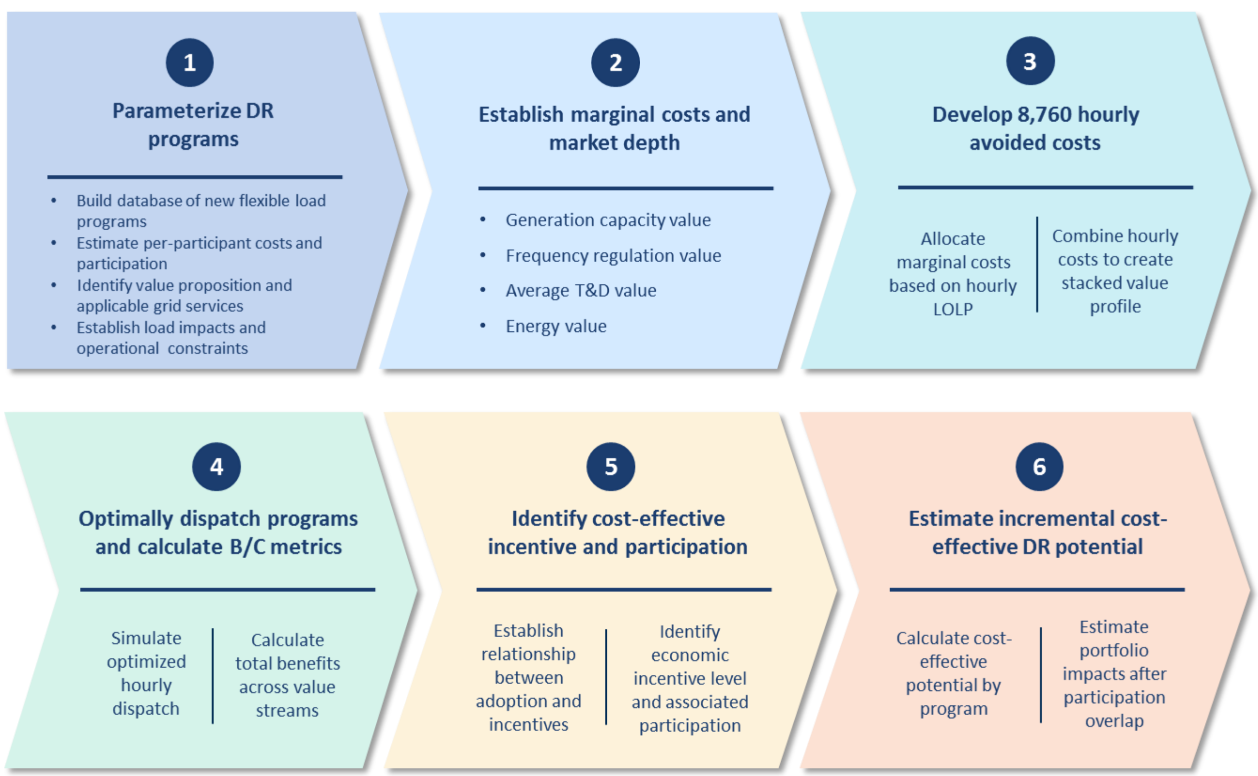
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), LoadFlex includes an hourly profile of load interruption capability for each program. For instance, for an EV home charging load control program, the model accounts for home charging patterns, which would provide greater average load reduction opportunities during evening hours (when EV owners have returned home from work) than in the middle of the day.

- **Realistic accounting for "value stacking":** DR programs have the potential to simultaneously provide multiple benefits. For instance, a DR program that is dispatched to reduce the system peak and therefore avoid generation capacity costs could also be dispatched to address local distribution system constraints. However, trade-offs must be made in pursuing these value streams – curtailing load during certain hours of the day may prohibit that same load from being curtailed again later in the day for a different purpose. LoadFlex accounts for these trade-offs in its DR dispatch algorithm. DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program. Prior studies have often assigned multiple benefits to DR programs without accounting for these trade-offs, thus double-counting benefits.

- **Industry-validated program costs:** DR program costs are based on a detailed review of the utility's current DR offerings. For new programs, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors. Program costs are differentiated by type (e.g., equipment/installation, administrative) and structure (e.g., one-time investment, ongoing annual fee, per-kilowatt fee) to facilitate integration into utility resource planning models.

The Load*Flex* methodology is organized around six steps, as summarized in Figure 19. The remainder of this appendix describes each of the six steps in further detail, documenting methodology, assumptions, and data sources.

FIGURE 19: THE LOAD*FLEX* MODELING FRAMEWORK



Step 1: Parameterize the DR programs

Each DR program is represented according to two broad categories of characteristics: Performance characteristics and cost characteristics.

Program Performance Characteristics

The performance characteristics of each DR program are represented in detail in Load*Flex* to accurately estimate the ability of the DR programs to provide system value. The following are key aspects of each program's performance capability.

Load impact profiles

Each DR program is represented with 24-hour average daily profiles of load reduction and load increase capability. These 24-hour impact profiles are differentiated by season (summer, winter, shoulder) and day type (weekday, weekend). For instance, air-conditioning load curtailment capability is highest during daytime hours in the summer, lower during nighttime summer hours, and non-existent during all hours in the winter.

Whenever possible, load impacts are derived directly from PSCo's experience with its existing DR programs and pilots. PSCo's experience directly informed the impact estimates for residential smart thermostat, residential air-conditioning direct load control, residential battery demand response, small C&I smart thermostat, small C&I critical peak pricing (opt-in), large C&I demand bidding, large C&I interruptible tariff, and large C&I critical peak pricing (opt-in). For emerging non-pricing DR programs, impacts are based on a review of experience and studies in other jurisdictions and tailored to PSCo's customer mix and climate. Methods used to develop impact profile estimates for emerging non-pricing DR programs include the following:

- C&I Auto-DR: The potential for C&I customers to provide around-the-clock load flexibility was primarily derived from data supporting a 2017 statewide assessment of DR potential in California[16], a 2013 LBNL study of DR capability[17], and electricity load patterns representative of C&I buildings in Boulder developed by the Department of Energy.[18] Customer segment-specific estimates from these studies were combined to produce a composite load impact profile for the

16 Peter Alstone et al., Lawrence Berkeley National Laboratory, "Final Report on Phase 2 Results: 2025 California Demand Response Potential Study." March 2017.

17 Daniel J. Olsen, Nance Matson, Michael D. Sohn, Cody Rose, Junqiao Dudley, Sasank Goli, and Sila Kiliccote (Lawrence Berkeley National Oaboratory), Marissa Hummon, David Palchak, Paul Denholm, and Jennie Jorgenson (National Renewable Energy Laboratory), and Ookie Ma (U.S. Department of Energy), "Grid Integration of Aggregated Demand Response, Part 1: Load Availability Profiles and Constraints for the Western Interconnection," LBNL-6417E, 2013.

18 See U.S. Department of Energy Commercial Reference Buildings at: https://www.energy.gov/eere/buildings/commercial-reference-buildings

PSCo service territory based on assumptions about PSCo's mix of C&I customers. Impacts were scaled as necessary for consistency with PSCo's prior experience with C&I DR programs.

- Water heating load control: Assumptions for grid interactive water heating and static timed water heating are derived from a 2016 study on the value of various water heating load control strategies.[19] The program definition assumes that only customers with existing electric resistance water heaters will be eligible for participating in the water heating programs.

- Behavioral DR: Impacts are derived from a review of the findings of behavioral DR pilot studies conducted around the US, including for Baltimore Gas & Electric, Consumers Energy, Green Mountain Power, Glendale Water and Power, Portland Gas Electric, and Pacific Gas and Electric. Most behavioral DR pilot studies have been conducted by Oracle (OPower) and have generally found that programs with a limited number of short curtailment events (4-10 events for 3-5 afternoon/evening hours) can achieve 2% to 3% load reduction across enrolled customers.[20] Based on these findings, we assumed that a behavioral DR program called 10 times per year between 3 pm and 6 pm would achieve a 2.5% load reduction.

- EV managed charging: Estimates of load curtailment capability are based on projections of aggregate EV charging load shapes from DOE's EVI-Pro Lite model. The ability to curtail this charging load is guided by a review of utility EV charging DR pilots, including managed charging programs at several California utilities (PG&E, SDG&E, SCE, and SMUD) and United Energy in Australia.[21]

For impacts from pricing programs, we relied on Brattle's database of time-varying pricing offerings, Arcturus 3.0. The database includes the results of nearly 400 experimental and non-experimental pricing treatments across over 66 pilot programs.[22] It includes published results from Xcel Energy's various pricing pilots during this time period. The results of the pilots in the database are used to establish a relationship between the peak-to-off-peak price ratio of the rates and the average load reduction per participant, in order to simulate price response associated with any given rate design. This relationship between load reduction and price ratio is illustrated in Figure 20.

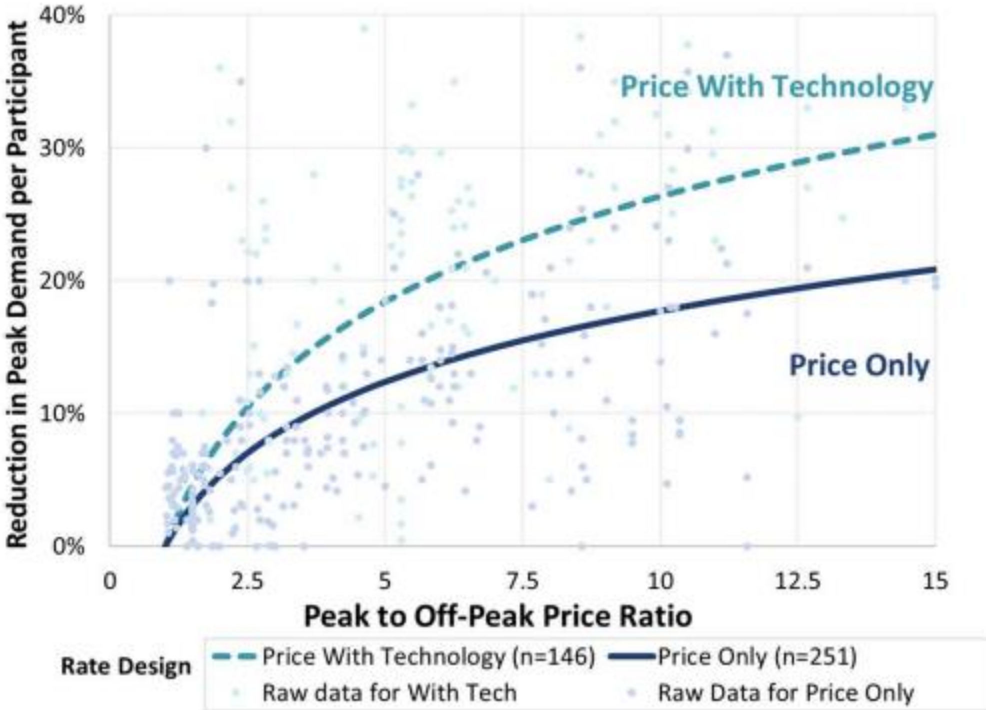
19 Ryan Hledik, Judy Chang, and Roger Lueken. "The Hidden Battery: Opportunities in Electric Water Heating." January 2016. Posted at: http://www.electric.coop/wp-content/uploads/2016/07/The-Hidden-Battery-01-25-2016.pdf

20 For example, see Jonathan Cook et al., "Behavioral Demand Response Study – Load Impact Evaluation Report", January 11, 2016, prepared for Pacific Gas & Electric Company, available at: http://www.oracle.com/us/industries/utilities/behavioral-demand-response-3628982.pdf, and OPower, "Transform Every Customer into a Demand Response Resource: How Utilities Can Unlock the Full Potential of Residential Demand Response", 2014, available at: https://go.oracle.com/LP=42838?elqCampaignId=74613.

21 Pilot programs reviewed include BMW and PG&E's i Charge Forward Pilot, SCE's Workplace Charging Pilot, SMUD's EV Innovators Pilot, SDG&E's Power Your Drive Pilot, and United Energy's EV smart grid demonstration project.

22 Sanem Sergici and Sylvia Tang, "Arcturus 3.0", forthcoming.

FIGURE 20: RELATIONSHIP BETWEEN PRICE RATIO AND PRICE RESPONSE IN RESIDENTIAL PRICING PILOTS



Notes: Treatments that have no impact and are non-significant are excluded from the graph. RTP treatments are also excluded.

Daily relationship between load reduction and load increase

Some DR programs will require a load increase to offset or partially offset the load that is reduced during a curtailment event. In Load*Flex*, each program definition includes a parameter that represents the percent of curtailed load that must be offset by increased load on the same day, including the timing of when the load increase must occur. For instance, in a water heating load control program, any reduction in water heating load is assumed to be offset by an equal increase in water heating load on the same day in order to meet the customer's water heating needs. Alternatively, a reduction in air-conditioning load may only be offset partially by an increase in consumption, but it would immediately follow the curtailment.

Where data is available, these load building assumptions are based on the same data sources described above.

Tariff-related operational constraints

Most DR programs will have administrator-defined limits on the operation of the program. This includes the maximum number of hours per day that the program can be curtailed, whether or not those curtailment hours must be contiguous, and the maximum number of days per year with allowed curtailment. Assumed operational constraints are based on Xcel Energy's program definitions and a review of common limitations from programs offered in other jurisdictions.

Ancillary services availability

Some DR programs are able to provide fast-response load increases or decreases in response to real-time fluctuations in supply and demand. PSCo's 2030 battery storage forecast suggests sufficient battery storage to saturate the company's need for frequency regulation, so we have not included ancillary services as a DR benefit in this analysis.

Table 4 summarizes the performance characteristics for each DR program in this study. In the table, "load shifting capability" identifies whether or not a program is capable of shifting energy usage from peak periods to off-peak periods on a daily basis.

TABLE 4: DR PROGRAM PERFORMANCE CHARACTERISTICS

Program	Segment	Load reduction during system peak hour (kW/part) - Winter	Load reduction during system peak hour (kW/part) - Summer	Hours Curtailed - Winter	Hours Curtailed - Summer
Low-frequency programs (<75 DR hrs/yr)					
Savers Switch	Residential	0.00	0.99	0	35
Smart thermostat	Residential	0.00	1.09	0	45
Peak time rebate	Residential	0.04	0.13	29	21
Behavioral DR	Residential	0.04	0.06	12	16
BTM storage	Residential	5.51	5.51	18	12
Smart thermostat	Small C&I	0.00	4.12	0	53
Peak time rebate	Small C&I	0.02	0.06	29	21
Interruptible	Large C&I	649	1,011	30	36
CPP	Large C&I	400	623	25	28
EV Workplace Managed Charging	N/A	0.03	0.02	24	9
Peak Day Partners	Large C&I	0.00	0.00	0	0
High-frequency programs (>75 DR hrs/yr)					
Default TOU	Residential	0.03	0.10	324	432
GIWH	Residential	0.49	0.34	1,170	1,586
EV TOU	Residential	0.55	0.74	360	488
Default TOU	Small C&I	0.01	0.03	325	422
Auto DR HVAC/AC	Small C&I	0.00	1.97	34	130
Auto DR Lighting	Small C&I	1.45	0.86	72	162
Default TOU	Large C&I	91	141	325	422
Auto DR HVAC/AC	Large C&I	40	425	52	52
Auto DR Lighting	Large C&I	344	253	72	174

Notes: Program impacts shown are for new participants and are expressed as incremental (i.e., additive) to TOU impacts.

Program Cost Characteristics

The costs of each program include start up costs, marketing and customer recruitment, the utility's share of equipment and installation costs, program administration and overhead, churn costs (i.e., the annual cost of replacing participants that leave the program), and participation incentives.

Cost assumptions are based on PSCo's current program costs, where applicable. Otherwise, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors, and are tailored for consistency with PSCo's current program costs. Notable assumptions in developing the cost estimates include the following:

- Water heating technology costs include the cost of the load control and communications equipment and the incremental cost of replacing the existing water heater (50-gallon average) with a larger water heater (80-gallon) when the existing water heater expires. The full cost of a new water heater is not assigned to the program.

- Similarly, EV charging load control equipment costs include the incremental cost of load control and communications technology, but not the full cost of a charging unit.

- The cost of AMI is not counted against any of the DR programs, as it is treated as a sunk cost justified by a broad range of benefits that the new digital infrastructure will provides to customers and to PSCo. However, a rough estimate of the cost of IT and billing system upgrades specifically associated with offering time-varying pricing programs are included in the costs for those programs.

- The cost of advanced lighting control systems is not counted against DR programs as these control systems are typically installed for non-energy benefits.

Table 5 summarizes cost assumptions for 2030. Costs are shown in nominal dollars. As discussed later in this appendix, the "base" incentive levels are derived from commonly observed payments both by PSCo and in other jurisdictions. They do not reflect the cost-effective incentive payment levels that are ultimately established through the modeling.

TABLE 5: 2030 COST ASSUMPTIONS

		One-Time Costs			Recurring Costs			
Segment	Program	Fixed Equipment Cost ($)	Variable Equipment Cost ($/part)	Other Initial Costs ($/part)	Fixed Admin & Other ($/yr)	Variable Admin & Other ($/part-yr)	Annual Incentive ($/part-yr)	Economic Life (years)
Residential	Savers Switch	$0	$0	$0	$493,750	$0	$457	15
Residential	Smart thermostat	$0	$150	$0	$75,000	$10	$25	15
Residential	Peak time rebate	$0	$0	$0	$500,000	$2	$3	15
Residential	Behavioral DR	$0	$0	$0	$0	$4	$0	15
Residential	BTM storage	$0	$0	$0	$75,000	$0	$232	15
Residential	Default TOU	$0	$0	$25	$0	$0	$0	15
Residential	GIWH	$0	$400	$30	$0	$0	$10	10
Residential	EV Home TOU Charging	$0	$0	$0	$75,000	$0	$0	15
Small C&I	Smart thermostat	$0	$363	$0	$75,000	$20	$25	15
Small C&I	Peak time rebate	$0	$0	$70	$0	$0	$0	15
Small C&I	Default TOU	$0	$0	$25	$0	$0	$0	15
Small C&I	Auto-DR (AC)	$75,000	$200	$0	$0	$12	$42	12
Small C&I	Auto DR (Lighting)	$75,000	$200	$0	$0	$5	$18	15
Large C&I	CPP	$0	$0	$1,000	$0	$20	$0	15
Large C&I	Default TOU	$0	$0	$1,000	$0	$20	$0	15
Large C&I	Interuptible Tarriff	$0	$0	$0	$283,000	$0	$99,039	15
Large C&I	Auto DR (Lighting)	$75,000	$200	$0	$0	$1,520	$5,400	15
Large C&I	Auto-DR (HVAC)	$75,000	$200	$0	$0	$2,548	$9,049	12
N/A	EV Workplace Managed Charging	$98,475	$0	$0	$75,000	$0	$0	15

Notes: All costs shown in nominal dollars. Variable equipment cost and other initial costs include 2.5% churn cost adder. Analysis assumes a 6.53% discount rate for annualizing one-time costs based on PSCo's Phase I ERP.

Step 2: Establish system marginal costs and quantity of system need

Load*Flex* was used to quantify a broad range of value streams that could be provided by DR. These include avoided generation capacity costs, avoided system-wide T&D costs, and net avoided marginal energy costs.

The system costs that could be avoided through DR deployment are estimated based on market data that is specific to PSCo's service territory. Assumptions used in developing each marginal (i.e., avoidable) cost estimate are described in more detail below.

Avoided generation capacity costs

DR programs are most appropriately recognized as substitutes for new combustion turbine (CT) capacity. CTs are "peaking" units with relatively low up-front installation costs and high variable costs. As a result, they typically only run up to a few hundred hours of the year, when electricity demand is very high and/or there are system reliability concerns. Similarly, use of DR programs in the U.S. is typically limited to less than 75 hours per year. This constraint is either written into the DR program tariff or is otherwise a practical consideration to avoid customer fatigue and program drop-outs.

The installed cost of new CT capacity is based on data provided directly by PSCo and consistent with its Phase I ERP.[23] The total cost amounts to $95.64/kW-year in 2030; this is referred to the gross cost of new entry (CONE). The gross CONE value is adjusted downward to account for the energy and ancillary services (E&AS) value that would otherwise be provided by that unit. Using PSCo's estimate of $9.72/kW-year for 2030, the resulting net CONE value is $85.92/kW-year.

DR produces a reduction in consumption at the customer's premise (i.e. at the meter). Due energy losses on transmission and distribution lines as electricity is delivered from power plants to customer premises, a reduction in one kilowatt of demand at the meter avoids more than one kilowatt of generation capacity. In other words, assuming line losses of 6.4% percent, a power plant must generate 1.064 kW in order to deliver 1 kW to an individual premise.[24] When estimating the avoided capacity cost of DR, the avoided cost is grossed up to account for this factor. For this study, Xcel Energy provided load data at the generator level, thus already accounting for line loss gross-up.

Similarly, PSCo incorporates a planning reserve margin of 18% percent into its capacity investment decisions. This effectively means PSCo will plan to have enough capacity available to meet its projected peak demand plus 18% percent of that value. In this sense, a reduction of one kilowatt at the meter level reduces the need for 1.18 kW of capacity. Including the 18% reserve margin adjustment increases

23 Xcel Energy, Public Service Company of Colorado, "Our Energy Future: Destination 2030," March 31, 2021.

24 6.4% represents an average line loss across PSCo territories and customer segments. Aggregated customer line losses range from 2 to 7%.

the net CONE value described above from $85.92/kW-year to $101.38/kW-year. This is the generation capacity value that could be provided by DR if it were to operate exactly like a CT.

Avoided transmission capacity costs

Reductions in system peak demand may also reduce the need for transmission upgrades. A portion of transmission investment is driven by the need to have enough capacity available to move electricity to where it is needed during peak times while maintaining a sufficient level of reliability. Other transmission investments will not be peak related, but rather are intended to extend the grid to remotely located sources of generation, or to address constraints during mid- or off-peak periods. Based on the findings of PSCo's 2016 Deferred Transmission & Distribution Costs study, we have assumed an avoidable transmission cost $2.95/kW-year in 2030.[25] Including the 6.4% line losses adjustment increases the avoided cost to $3.10/kW-year in 2030.

Avoided system-wide distribution capacity costs

Similar to transmission value, there may be long-term distribution capacity investment avoidance value associated with reductions in peak demand across the PSCo system. We have assumed that peak demand reductions can produce avoided distribution costs of $10.83/kW-year in 2030, based on the findings of PSCo's 2016 Deferred Transmission & Distribution Costs study.[26] Including the 6.4% line losses adjustment increases the avoided cost to $11.50/kW-year in 2030.

Avoided energy costs

Load can be shifted from hours with higher energy costs to hours with lower energy costs, thus producing net energy cost savings across the system. Hourly energy costs in this study are based on PSCo's Phase I ERP forecasted marginal energy costs.

Summary

Table 6 summarizes the potential value of each DR benefit. Values shown are the maximum achievable value. Operational constraints of the DR resources (e.g., limits on number of load curtailments per year) often result in realized benefits estimates that are lower than the values shown.

[25] Public Service Company of Colorado, "Energy Efficiency Investment: Deferred Transmission & Distribution Costs, 2017-2021 "T&D Study"," 2016.

[26] Ibid.

TABLE 6: SUMMARY OF AVOIDED COSTS/VALUE STREAMS IN 2030

Value Stream	Avoided Cost ($2030)	Description
Avoided Generation Capacity	$101.4/kW-yr	PSCo's generic CT costs minus estimated E&AS revenues from ERP, plus 18% reserve margin gross up.
Avoided Transmission Capacity	$3.1/kW-yr	Avoided transmission costs from 2016 PSCo Study, "Energy Efficiency Investment: Deferred Transmission & Distribution Costs, 2017-2021", grossed up for 6.4% line losses.
Avoided Distribution Capacity	$11.5/kW-yr	Avoided distribution costs from 2016 PSCo Study, "Energy Efficiency Investment: Deferred Transmission & Distribution Costs, 2017-2021", grossed up for 6.4% line losses.
Avoided Energy	Avg: $17.97/MWh	
Top 10th Percentile	$38.03/MWh	Hourly modeled energy prices from PSCo 2021 ERP.
Bottom 90th Percentile	$0/MWh	
Frequency Regulation	n/a	PSCo's forecasted storage deployment likely will satisfy the system need for frequency regulation.

Notes: All values shown in nominal 2030 dollars.

Step 3: Develop 8,760 hourly profile of marginal costs

Each of the annual avoided cost estimates established in Step 2 is converted into a chronological profile of hourly costs for all 8,760 hours of the year. In each hour, these estimates are added together across all value streams to establish the total "stacked" value that is obtainable through a reduction in load in that hour (or, conversely, the total cost associated with an increase in load in that hour).

Capacity costs are allocated to hours of the year proportional to the likelihood that those hours will drive the need for new capacity. In other words, the greater the risk of a capacity shortage in a given hour, the larger the share the marginal capacity cost that is allocated to that hour.

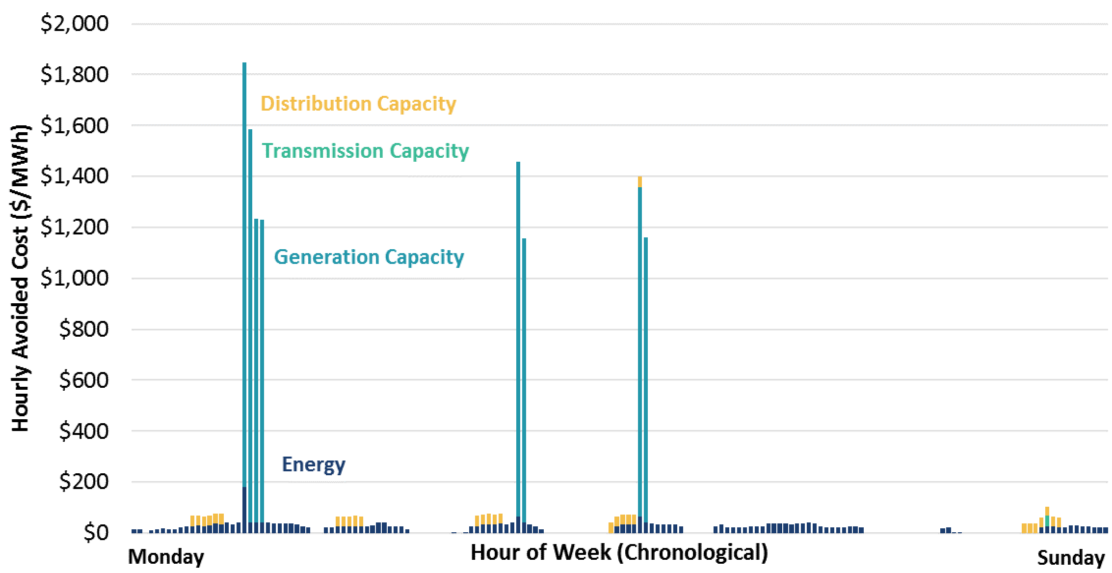
Both system and customer class load profiles are used to allocate generation, transmission, and distribution capacity costs based on the impact of avoided customer load. Reducing customer load only provides generation capacity value if that reduction occurs in the top system peak net load hours–the hours driving new capacity need. Generation capacity value is allocated based on forecasted 2030 PSCo net load. We have assumed that the class load shape is the primary driver of T&D investments due to the more localized nature of the drivers of T&D investments. PSCo provided customer class load shapes, which we used to allocate transmission and distribution capacity value, such that transmission and distribution capacity costs are highest in peak congestion hours.

Capacity costs are allocated across the top 75 load hours of the year for generation and transmission, and the top 300 hours for distribution. The allocation is roughly proportional to each hour's share of total load in the hours. This means more capacity value is allocated to the top load hour than the 75th (or 300th) load hour. The generic distribution capacity deferral value is allocated over a larger number of peak hours (300 hours, rather than 75 hours), representing that a single distribution project will address multiple feeders with load profiles that are only partially coincident.

A conceptually similar approach to quantifying capacity value is used in the California Energy Commission's time-dependent valuation (TDV) methodology for quantifying the value of energy efficiency, and also in the CPUC's demand response cost-effectiveness evaluation protocols. This hourly allocation-based approach effectively derates the value of distributed resources relative to the avoided cost of new peaking capacity by accounting for constraints that may exist on the operator's ability to predict and respond to resource adequacy needs. These constraints could result in DR utilization patterns that reflect a willingness to bypass some generation capacity value in order to provide distribution deferral value, for instance. The approach is effectively a theoretical construct intended to quantify long-term capacity value, rather than reflecting the way resource adequacy payments would be monetized by a DR operator in a wholesale market.

Figure 21 illustrates the "stacked" marginal costs associated with each value stream for a single week in the study period. The figure shows that certain hours present a significantly larger opportunity to reduce costs through load reduction – namely, those hours to which capacity costs are allocated.

FIGURE 21: CHRONOLOGICAL ALLOCATION OF MARGINAL COSTS (ILLUSTRATIVE WEEK)



Notes: Marginal costs reflect avoided costs from 2030, expressed in $2030 dollars.

Step 4: Optimally dispatch programs and calculate benefit-cost metrics

As discussed above, using DR to pursue one value stream may require forgoing opportunities to pursue other "competing" sources of value. While the value streams quantified in this study can be estimated individually, those estimates are not purely additive. A DR operator must choose how to operate the program in order to maximize its value. Accurately estimating the total value of DR programs requires accounting for trade-offs across the value streams.

Load*Flex* employs an algorithm that "co-optimizes" the dispatch of a DR program across the hourly marginal cost series from Step 3, subject to the operational constraints defined in Step 1, such that overall system value produced by the program is maximized. In other words, the programs are operated to reduce load during hours when the total cost is highest and build load during hours when the total cost is lowest, without violating any of the established conditions around their use.

Step 5: Identify cost-effective incentive and participation levels

A unique feature of Load*Flex* is the ability to identify participation levels that are consistent with the incentive payments that are economically justified for each DR program. This ensures that each program's economic potential estimate is based on an incentive payment level that produces a benefit-cost ratio of 1.0. Without this functionality, the analysis would under-represent the potential for a given DR program, or could even exclude it from the analysis entirely based on inaccurate assumptions about uneconomic incentive payments levels.

As a starting point, participation estimates for each DR program are established to represent the maximum enrollment that is likely to be achieved when offered in PSCo's service territory at a "typical" incentive payment level. The estimates are tailored to PSCo's customer base using data on current program enrollment, and informed by survey-based market research conducted for PSCo in 2013.[27] For DR programs not included in the market research study, we developed participation assumptions based on experience with similar programs in other jurisdictions and applied judgement to make the participation rates consistent with available evidence that is specific to PSCo's customer base.

Table 7 summarizes these "base" participation rates for considered DR programs. In all cases, participation is expressed as a percent of the eligible customer base. For instance, the population of customers eligible for the smart thermostat program is limited to those customers with central air-conditioning. Values represent the achievable participation level in the absence of other programs being offered. In our assessment of expanded DR portfolios that include multiple new DR programs, restrictions on participation in multiple programs are accounted for and the participation rates are derated accordingly.

Participation rates shown are consistent with a participation incentive payment level that is representative of common offerings across the U.S. Participation rates are shown for all programs at these incentive levels, regardless of whether or not the programs are cost-effective at those incentive

[27] Ahmad Faruqui, Ryan Hledik, David Lineweber, and Allison Shellaway, "Estimating Xcel Energy's Public Service Company of Colorado Territory Demand Response Market Potential," June 2013.

levels. Later in this section of the appendix, we describe adjustments that are made to these "base" incentive levels to reflect enrollment that could be achieved at cost-effective incentive levels.

TABLE 7: PARTICIPATION ASSUMPTIONS FOR ALL DR PROGRAMS

PARTICIPATION AS A PERCENTAGE OF ELIGIBLE CUSTOMERS

Segment	Program Name	2030
Residential	Savers Switch	21%
Residential	Smart thermostat	45%
Residential	Peak time rebate	90%
Residential	Behavioral DR	80%
Residential	BTM Storage	50%
Residential	Default TOU	86%
Residential	GIWH	30%
Residential	EV Home TOU Charging	20%
Small C&I	Smart thermostat	8%
Small C&I	Peak time rebate	76%
Small C&I	Default TOU	73%
Small C&I	Auto DR (AC)	5%
Small C&I	Auto DR (Lighting)	5%
Large C&I	CPP	52%
Large C&I	Default TOU	56%
Large C&I	Interuptible Tarriff	30%
Large C&I	Auto DR (HVAC)	5%
Large C&I	Auto DR (Lighting)	5%
N/A	EV Workplace Managed Charging	20%

Notes: Participation rates shown for programs when offered independently (i.e. rates do not account for program overlap).

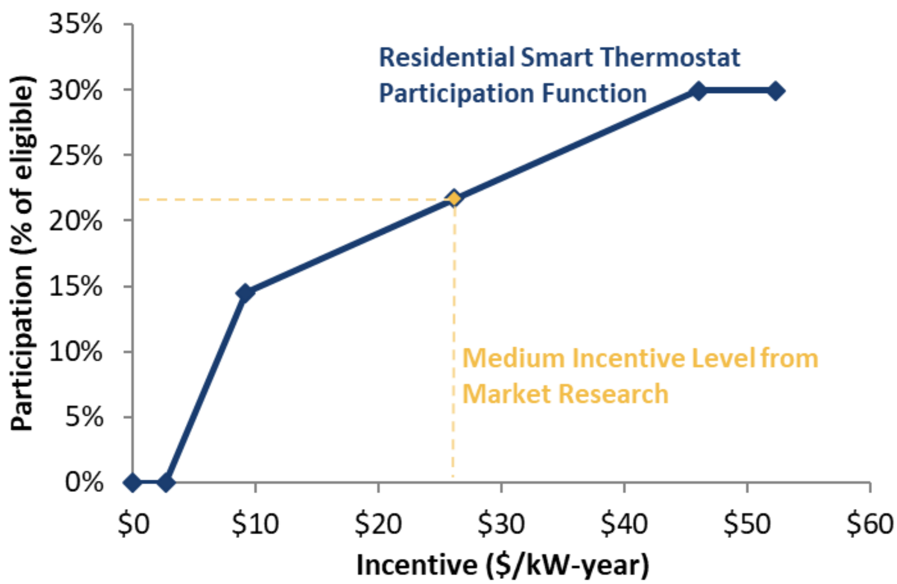
As discussed above, the cost-effectiveness screening process in many DR potential studies often treats programs as an all-or-nothing proposition. In other words, the studies commonly assume a base incentive level and then simply evaluate the cost-effectiveness of the programs relative to that incentive level. However, in reality, the incentives can be decreased or increased to accommodate lower or higher thresholds for cost effectiveness. For instance, in a region with lower avoided cost, a lower incentive payment could be offered, and vice versa. Program participation will vary according to these changes in the incentive payment level.

In LoadFlex model, participation is expressed as a function of the assumed incentive level. The incentive level that produces a benefit-cost ratio of 1.0 is quantified, thus defining the maximum potential cost-effective participation for the program.[28] The DR adoption function for each program is derived from the results of the aforementioned 2013 market research study, which tested customer willingness to participate in DR programs at various incentive levels.

[28] In some cases, the non-incentive costs (e.g., equipment costs) outweigh the benefits, in which case the program does not pass the cost-effectiveness screen.

An illustration of the participation function for the Residential Smart Thermostat program is provided in Figure 22. The figure expresses participation in the program (vertical axis) as a function of the customer incentive payment level (horizontal axis). At an incentive level of around $25/kW-yr, slightly more than 20% of eligible customers would participate in the program. If the economics of the program could only justify an incentive payment less than this (e.g., due to low avoided capacity costs), participation would decrease according to the blue line in the chart, and vice versa. Below an incentive payment level of around $10/kW-yr, customer willingness to enroll in the program quickly drops off.

FIGURE 22: RESIDENTIAL SMART THERMOSTAT ADOPTION FUNCTION



Step 6: Estimate cost-effective DR potential

After the cost-effective potential of each individual DR program is estimated, the programs are combined into a portfolio. Constructing the portfolio is not as simple as adding up the potential estimates of each individual program. In some cases, two programs may be targeting the same end-use, so their impacts are not additive.

All PSCo residential and small commercial customers will be on a default TOU rate by 2030. For this study, we assess the potential associated with defaulting large C&I customers to a TOU rate, although PSCo has no current plans to default large commercial customers to a TOU rate. To avoid double counting reduction potential, we model and report DR program impacts as incremental to TOU peak demand reductions. For example, if a customer's TOU impact is 0.5 kW reduction during system peak and is participating in a smart thermostat program that could reduce participant peak demand by 1.1 kW, only 0.6 kW of savings is attributable to the smart thermostat program, the remaining 0.5 kW attributed to the TOU program.

In other cases, two “competing” programs would likely be offered simultaneously to customers as mutually exclusive options. For instance, it is possible that C&I customers would only be allowed to enroll in either an interruptible tariff program or a CPP rate. Simultaneous enrollment in both could result in customer being compensated twice for the same load reduction – once through the incentive payment in the interruptible tariff, and a second time through avoiding the higher peak price of the CPP rate. In these cases, we relied on the results of the aforementioned 2014 market research study, which used surveys to determine relative customer preferences for these options when offered simultaneously. Participation rates were reduced in the portfolio to account for this overlap.

For the residential class, customers participating in smart thermostat programs would potentially “compete” with savings from peak time rebate participants. Participation rates were reduced by assuming that any smart thermostat participants do not also receive peak time rebate compensation.

In cases where two programs would be offered simultaneously to the same customer segment, but would target entirely different end-uses (e.g., a smart thermostat program and an EV charging load control program), no adjustments to the participation rates were deemed necessary.

About the Authors

Ryan Hledik is a Principal located in Portland, OR. Ryan's consulting practice is focused on regulatory and planning matters related to emerging energy technologies and policies. His research on the "grid edge" has been cited in federal and state regulatory decisions, as well as by *Forbes*, *National Geographic*, *The New York Times*, *Vox*, and *The Washington Post*. Ryan received his M.S. in Management Science and Engineering from Stanford University, with a concentration in Energy Economics and Policy. He received his B.S. in Applied Science from the University of Pennsylvania, with minors in Economics and Mathematics.

Akhilesh Ramakrishnan is an Associate in Brattle's Chicago office. He specializes in climate policy analysis, regulatory economics, and strategic planning for utility companies. Prior to joining Brattle, Akhilesh developed business strategy and policy for Exelon's electric and gas utility businesses on a range of issues, including electrification, distributed energy resources, resilience, utility regulatory models, rate design, and long-term financial planning. He received his M.S. in Mechanical Engineering from Columbia University, with a concentration in Energy Systems and his B.S. in Electrical Engineering from SRM University.

Kate Peters is a Research Analyst in Brattle's Boston office. She focuses on resource planning in decarbonized electric markets, renewable and climate policy analysis, and economic analysis of demand-side resources. She received her B.A. in Environmental Economics from Middlebury College with a minor in Mathematics.

Ryan Nelson is a Senior Research Analyst in Brattle's Boston office. He focuses on transmission rate casework, electric vehicle TOU rate development, and demand response programs. Ryan received his B.A. in Environmental Science and Economics, with minor in Data Analysis from Wesleyan University

Xander Bartone is a Research Analyst in Brattle's San Francisco office with expertise in electricity market design and policy analysis. He earned his B.A. in International Relations and Mathematics from Pomona College.